Ontario's Distributed Energy Resources (DER) Potential Study

Volume I: Results & Recommendations

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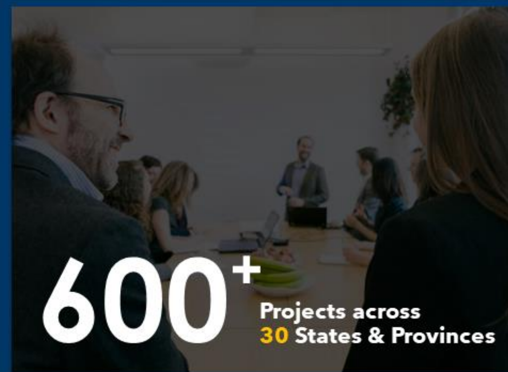
About Dunsky



Founded in 2004, Dunsky supports leading governments, utilities, corporations and non-profits across North America in their efforts to **accelerate the clean energy transition**, effectively and responsibly.

Working across buildings, industry, energy and mobility, we support our clients through three key services: we **quantify** opportunities (technical, economic, market); **design** go-to-market strategies (plans, programs, policies); and **evaluate** performance (with a view to continuous improvement).

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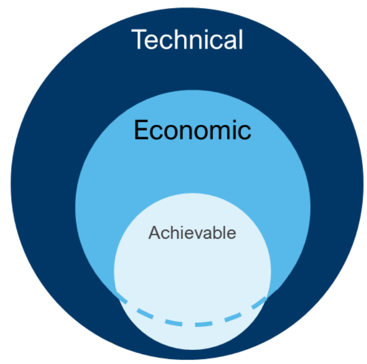
Executive Summary

Distributed Energy Resources (DERs) are a major driver of the rapidly evolving electricity landscape. As part of the IESO's DER integration efforts, the IESO commissioned a DER Potential Study to determine the types and volumes of DERs that could emerge in Ontario over a 10-year timeframe (2023-2032) and the ability of these DERs to contribute to the province's emerging system needs.

This landmark study – the first of its kind for Ontario – uncovers the substantial contributions distributed energy resources can deliver to the province's electricity system and provides key insights and recommendations to harness these resources.

Approach

The study's quantitative assessment aimed to address three key questions:



- **Technical Potential:** How much DER capacity theoretically exists in Ontario?
- **Economic Potential:** How much potential is cost-effective from a system perspective?
- **Achievable:** How much potential is likely to emerge when incorporating real-world considerations?

To understand the projected contribution of DERs under a range of possible futures, the study applied three scenarios reflecting different market, policy, and technology pathways.

- **BAU:** A business-as-usual projection reflecting existing market conditions, technological trends, and the IESO's 2021 Annual Planning Outlook (APO) Reference Case for demand.
- **BAU+:** An expanded electrification and decarbonization trajectory in-line with the IESO DER Roadmap and general policy, market, and technology advances.
- **Accelerated:** Accelerated efforts to achieve net-zero with a greater reliance on DERs to meet system needs, coupled with increased efforts to integrate DERs.

A wide range of DER measures were assessed - consisting of Demand Response (DR), Behind-the-Meter (BTM) and Front-of-the-Meter (FTM) solar and storage, small-scale waterpower, and vehicle-to-building/grid (V2B/G). For each measure, costs and market sizes were determined, along with the full range of possible grid benefits, including contributions to Seasonal Capacity, Energy, Transmission and Distribution (T&D) investment deferrals, and Ancillary Services. Economic potential results were generated based on the grid benefits of DERs relative to their costs, prioritizing the most cost-effective DER measures first. Achievable potential results were determined by incorporating customer/participant-side economics (e.g. acceptable payback thresholds) and market barriers, including the degree to which customers/participants could be remunerated for the grid benefits their DERs could provide.

Results

The economic potential results indicate there is ample cost-effective DER capacity to meet or exceed all incremental system needs under all scenarios. The achievable potential results reveal that, when factoring in real-world conditions, DERs are able to satisfy a material portion of the province's energy needs – from 1.3 to 4.3 GW of peak summer demand by 2032.

Table E-1 below provides an overview of the economic and achievable potentials, expressed in terms of seasonal capacity contributions against the incremental system needs (relative to 2022).

The economic and achievable potentials were driven primarily by the capacity and energy benefits that DERs offer, and these two value streams increased significantly under the BAU+ and Accelerated scenarios as electricity demand and carbon prices increased. T&D benefits (primarily driven by transmission investment deferrals) offer the third most important value stream. Collectively, the remaining ancillary services added a further five percent of the system value DERs provide - a value stream that may increase should the need for additional system flexibility emerge.

Table E-1: System Incremental Seasonal Capacity Needs vs Economic and Achievable Potential Results

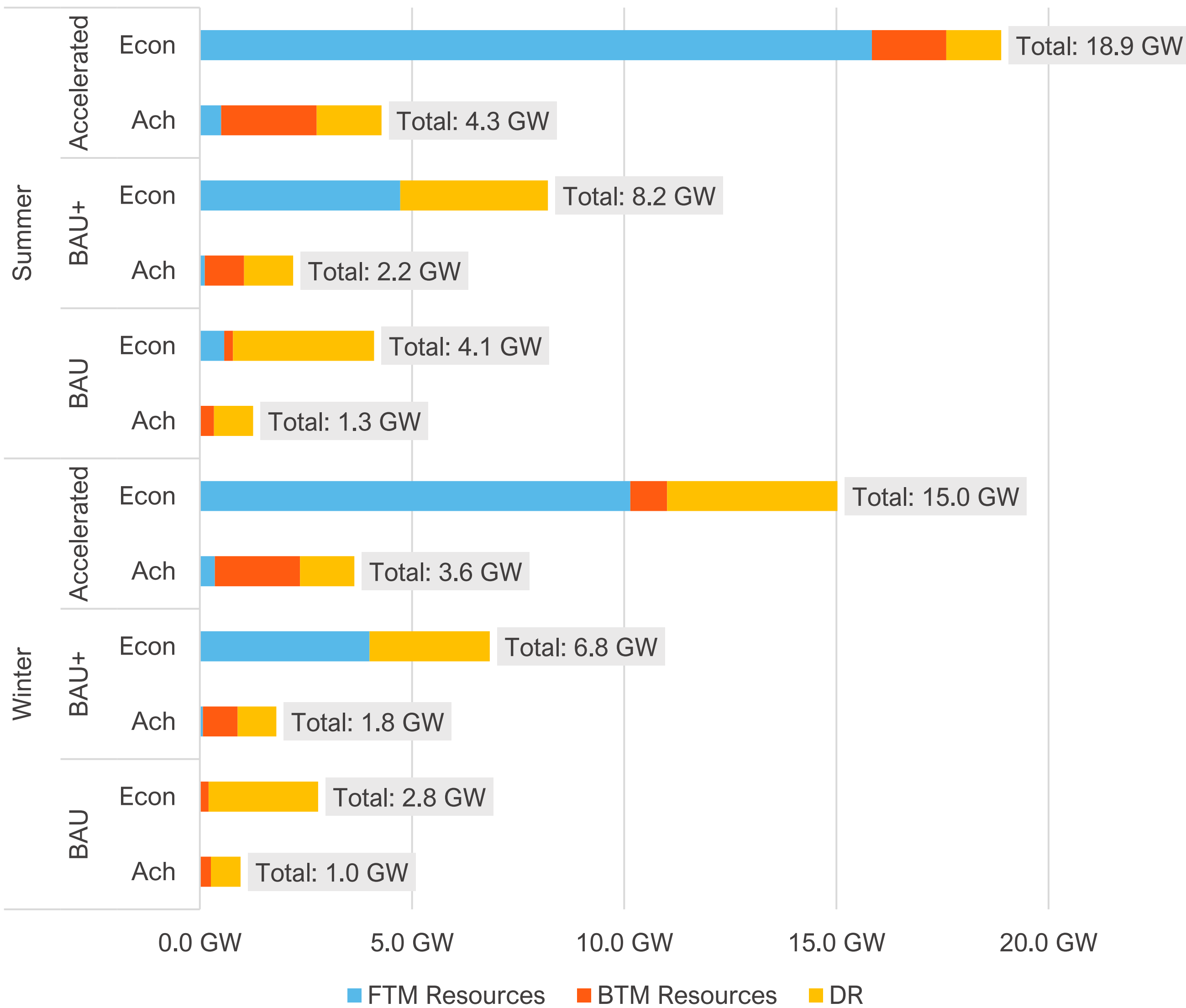
Seasonal Capacity	Potential	BAU	BAU+	Accelerated
Summer 2032	**Incremental System Needs**	**2.6 GW**	**5.6 GW**	**6.9 GW**
	Economic Potential	4.1 GW *(15% of peak demand)*	8.2 GW *(27% of peak demand)*	18.9 GW *(61% of peak demand)*
	Achievable Potential	1.3 GW *(5% of peak demand)*	2.2 GW *(7% of peak demand)*	4.3 GW *(14% of peak demand)*
Winter 2032	**Incremental System Needs**	**0.9 GW**	**6.4 GW**	**13.3 GW**
	Economic Potential	2.8 GW *(11% of peak demand)*	6.8 GW *(22% of peak demand)*	15.0 GW *(40% of peak demand)*
	Achievable Potential	1.0 GW *(4% of peak demand)*	1.8 GW *(6% of peak demand)*	3.6 GW *(9% of peak demand)*

The gap between achievable and economic potentials relates to a range of factors, including DER adoption and diffusion, market barriers, DR program participation limits and the limited financial attractiveness of some DERs to specific customers. This gap can be narrowed through actions such as improving DER compensation for services like capacity and T&D benefits, securing DERs more directly through programs or procurements, and by enhancing opportunities for DERs to participate in wholesale markets.

Figure E-1 below illustrates the economic and achievable potential for each DER type, expressed in terms of their seasonal capacity contributions. DR measures tend to dominate the economic and achievable potentials in the BAU scenario, offering the most cost-effective and sizable option to meet peak demand. In the near-term, high potential DR measures largely include Residential Thermostats, Commercial/Industrial Load Flexibility, and Large Commercial Heating Ventilation, and Air Conditioning (HVAC) controls. In the longer-term, further potential appears from Passenger Electric Vehicle (EV) measures, including smart charging and V2B/G applications.

In the BAU+ and Accelerated scenarios, BTM and FTM solar and storage as well as V2B/G make up an increasingly large portion of both the economic and achievable potential relative to DR. Given that the BAU scenario represents an extremely modest perspective on load growth and the associated energy and carbon price trajectories, the BAU+ and Accelerated scenario results likely represent the most probable depictions of future DER potentials. In the case of solar, increased potential is driven by a significant increase in energy needs and carbon price exposure and is a phenomenon that occurs despite solar's diminishing peak capacity value. **This finding reinforces the significant value solar generation can provide in helping to avoid high-priced electricity that would otherwise be satisfied by gas generation.** In the case of storage and V2B/G, increased economic and achievable potential is the result of substantial capacity needs from electrification, which itself creates more opportunities for V2B/G.

Figure E-1: Economic and Achievable Potential Capacity Contributions by Scenario and DER Type (2032)



RECOMMENDATIONS

Based on results of the potential assessment, workshops with IESO staff, and input from external stakeholders and communities, the following high-level recommendations are provided:

Target efforts on high-value high-potential DER measures: Though the study evaluated over 80 DER measures, a few key opportunities stand out. In the short term, these include residential and commercial/industrial DR measures. In the longer term, focus should expand to BTM and FTM solar and storage, as well as EV smart charging and V2B/G.

Continue with market enhancement efforts: The IESO should continue its efforts to facilitate participation of DERs in Ontario's wholesale markets. Such enhancements include enabling diverse DER aggregations and reducing size thresholds for market participation. These changes can play an important role in capturing the flexibility and reliability benefits of DERs.

Increase DER access to value-streams: Despite the system services DERs can provide, they often do not receive commensurate compensation through existing rate structures or market revenues. Increasing access to these value streams – in particular for capacity benefit and T&D deferral - can result in a greater uptake and more optimal utilization of cost-effective DERs.

Explore tailored DER procurements and programs: Programs and procurements should be considered for the high-value high-potential DER measures identified in this study – particularly in circumstances where existing and planned market pathways are currently unavailable or insufficient. Examples of tailored initiatives include procurements for non-capacity energy-generating resources like FTM solar (which face barriers in capacity-centric procurements), and smart thermostat programs for small retail customers (which have struggled to participate in the IESO's capacity auction).

Pursue complementary activities: Additional actions are essential to realizing the potential revealed through this study. These includes coordination between regulatory bodies and utilities on a DER framework, adapting and enhancing data and information collection from DERs, testing DER capabilities through pilots and demonstration projects, and integrating DERs via advanced planning and management systems.

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Glossary

Acronym	Definition
AAR	Annual Acquisition Report
AC	Air Conditioning
APO	Annual Planning Outlook
APS	Achievable Potential Study
ASHP	Air Source Heat Pump
BAU	Business-As-Usual
BTM	Behind-the-Meter
BYOD	Bring Your Own Device
C&I	Commercial and Industrial
CAES	Compressed Air Energy Storage
CDM	Conservation Demand Management
CEUS	Commercial End-Use Survey
CHP	Combined Heat and Power
CF	Coincidence Factor
CONE	Cost of New Entry
CPP	Critical Peak Pricing
DER	Distributed Energy Resources
DG	Distributed Generation
DMSHP	Ductless Mini-split Heat Pump
DR	Demand Response
DSM	Demand Side Management
EE	Energy Efficiency
EUL	Effective Useful Life
FERC	Federal Energy Regulatory Commission
FR	Frequency Regulation
FTM	Front-of-the-Meter
GA	Global Adjustment
GSHP	Ground Source Heat Pump
HDR	Hourly Demand Response

Acronym	Definition
HDV	Heavy Duty Vehicle
HP	Heat Pump
HVAC	Heating, Ventilation, and Air Conditioning
IAM	IESO Administered Market
ICI	Industrial Conservation Initiative
ISO	Independent System Operator
LDC	Local Distribution Company
LDV	Light-Duty Vehicle
LTR	Limited Time Rating
MDV	Medium Duty Vehicle
NEM	Net Energy Metering
NWA	Non-Wires Alternative
O&M	Operations and Maintenance
OEB	Ontario Energy Board
OPG	Ontario Power Generation
OR	Operating Reserve
RC	Regulation Capacity
REUS	Residential End-Use Survey
RFP	Request For Proposal
RNG	Renewable Natural Gas
SBG	Surplus Baseload Generation
SGCT	Simple Cycle Gas Turbine
SMR	Small Modular Reactors
T&D	Transmission and Distribution
TOU	Time-of-Use
TRC	Total Resource Cost Test
V2B/G	Vehicle-to-Building/Grid
VDER	Value of Distributed Energy Resources
ZEV	Zero Emissions Vehicle

1. Introduction

Distributed Energy Resources (DERs) have become a hallmark electricity system transformation, creating exciting opportunities at the micro and macro level. In Ontario and globally, electricity customers, grid operators and service providers are increasingly turning to DERs to meet on-site electricity demand, fulfill local electricity needs (i.e., non-wires solutions) and provide wholesale market services (i.e., capacity, energy and ancillary services). The opportunities associated with DERs are of particular interest to Ontario's Independent Electricity System Operator (IESO), which functions as a market and system operator as well as a planner responsible for securing the province's resource adequacy needs. With DERs already deployed extensively in Ontario, and with continued growth in the coming decade, DERs can play an important role in meeting Ontario's emerging system needs.

Distributed Energy Resources refers to energy resources that are directly connected to the electricity distribution system, or indirectly connected to the distribution system behind a customer's meter; and generates energy, stores energy, or controls load.

Through a series of engagements with stakeholders, the IESO has developed a DER Roadmap that sets out a series of initiatives to support DER integration, with the goal of maximizing the value DERs can provide to Ontario's electricity system. Specifically, the DER Roadmap highlights three focus areas:

- Expanding wholesale market participation models for DERs;
- Implementing transmission-distribution coordination protocols to enable DER participation; and
- Developing pathways for DERs to serve as Non-Wires Alternatives (NWAs).

To help inform these efforts, the IESO commissioned Dunsky Energy + Climate Advisors, supported by Power Advisory, to develop Ontario's first DER Potential Study. The intent of the study is to determine the types and volumes of DERs likely to emerge in Ontario over a 10-year timeframe and their ability to contribute to emerging system needs in the province. More specifically, the study had three key objectives:

- Identify the DER technologies most relevant to the Ontario context;
- Assess the technical, economic, and achievable potential for the above DERs over the next 10 years; and
- Develop recommendations to the IESO on focus areas, priorities, and key considerations for DER integration efforts in Ontario.

REPORTING STRUCTURE

The final report for the DER Potential Study is broken into two volumes:

- **Volume I – Results & Recommendations:** Key results, outcomes and insights from the study, as well as recommendations to inform the IESO's DER integration efforts
- **Volume II – Methodology & Assumptions:** Appendices with detailed descriptions of the methodology used to assess the technical, economic, and achievable potential of DERs. This volume also includes the supporting data files: Appendix F – Measure Screening and Approach, and Appendix G – Detailed Results and Inputs.

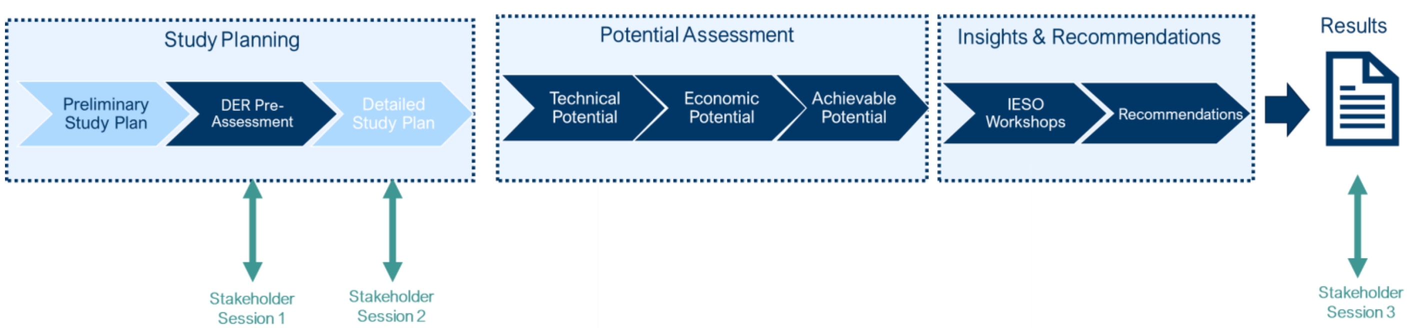
2. Study Approach

2.1 Study Overview

The study was broken down into three key phases, as illustrated in the figure below:

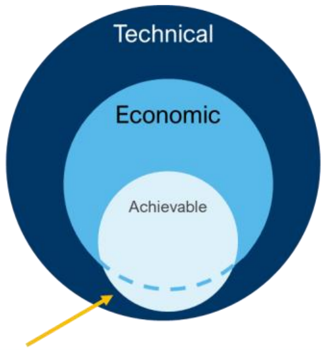
- **Study Planning**: The project team developed a preliminary study plan that set out the project's workplan, scope, methodology and key parameters. A key part of that process was conducting a DER Pre-Assessment to vet the various DER technologies available for applicability in the Ontario market and inform the selection of the DERs to be assessed in the study. Stakeholder feedback was sought on the preliminary plan as well as the pre-assessment results, which then informed the development of the detailed study plan and final measure list. The detailed plan was then presented to stakeholders in a second session and then finalized with the IESO project team.
- **Potential Assessment**: The central element of the project is the detailed modeling of the technical, economic, and achievable potential for DERs in Ontario. Building on the methodology outlined in the Detailed Study Plan, the project team leveraged Dunsky's Distributed Resources Optimization Model (DROP) and Ontario-specific market data to arrive at an estimate of the DER potential over the next decade under multiple scenarios. The initial results were reviewed by the IESO project team and recalibrated and regenerated to reflect feedback.
- **Insights and Recommendations**: The project team distilled down key findings and insights from the potential assessment to inform the development of recommendations for the IESO's consideration. A series of workshops with cross-divisional senior IESO members were held, aiming to identifying barriers and challenges impeding the DER potential found in the study, as well as potential solutions. Incorporating the responses from the workshops, the project team developed the recommendations for the IESO's consideration. The recommendations represent the view of the project team and are provided for the IESO's consideration as part of ongoing efforts for DER integration identified in the DER Roadmap.

Figure 2-1: Overview of Study Process



2.2 Methodology Overview

The DER Potential Study is intended to answer three key questions, which represent the key methodological steps involved in the study:



Note: Achievable potential is not exclusively a subset of economic potential – some uptake of DERs may be driven primarily by electricity customer benefits, regardless of their ability to deliver benefits to the system.

- **Technical Potential:** How much DER capacity theoretically exists in Ontario?
- **Economic Potential:** How much of that DER potential is cost-effective considering the benefits they bring to the system and the costs of procuring them?
- **Achievable Potential:** How much of that potential is likely to emerge over the next decade considering market barriers and dynamics?

Achievable potential is not necessarily an exclusive subset of the economic potential. Specifically, some uptake of DERs may be driven by regulatory constructs (e.g. net-metering) or broader customer benefits (e.g. bill management, resiliency) regardless of the cost-effectiveness of these resources from a system perspective.

The following sub-sections provide a summary of the approach used to quantify the technical, economic, and achievable potential. Detailed methodology is described in Volume II of the report.

2.2.1 Technical Potential

The technical potential quantifies the theoretical maximum level of grid services that could be provided by DERs in Ontario over the study period, regardless of cost-effectiveness or customer adoption. The technical potential is largely used to establish the maximum market size for each DER measure, acting as a ceiling which factors into the determination of economic and achievable potentials. It is calculated by combining the market size for each measure with a measure's unit impact, considering technical and operational constraints. Specifically, the assessment of the technical potential included three key steps:

- **Market Characterization:** Defining the technical market size for each measure over the study period. For DR measures, the maximum market size is defined as the full participation of the applicable equipment stock (e.g. the number of air conditioning units) in all services they can contribute to. For BTM and FTM DG and storage measures, market size was defined as the technology-specific physical, technical and/or market constraints that would limit potential opportunities for a given measure across Ontario (e.g. BTM solar is based on the number of buildings with a rooftop suitable for solar deployment).
- **Measure Characterization (Technical Parameters):** Defining key technical and operational characteristics for each measure to quantify its impact. These include the measure size (kW), the baseline load profile for each measure in the absence of any DR event or the assumed generation profile for generating DERs, its capability to contribute to different grid services, and any measure-specific parameters and constraints associated with the service provision (e.g. maximum number of activations per year).
- **Technical Potential Calculation:** Based on the market and measure characterization, key metrics highlighting the technical potential for each measure - in terms of nameplate capacity, summer and winter capacity contributions and energy generated – are computed. Where appropriate, competition between measures with overlapping market was considered to arrive at the total market-wide technical potential.

2.2.2 Economic Potential

Economic potential quantifies the potential for cost-effective contributions from DERs towards system needs over the study period. The economic potential is used to understand the subset of technical potential that is cost-effective from an electricity system perspective, but does not account for customer economics or expected DER adoption. Specifically, the assessment of the economic potential included three key steps:

- **Measure Characterization (Economic Parameters):** Defining key measure-specific economic inputs used in the study, including the measure's upfront costs, operations and maintenance (O&M) costs and effective useful life (EUL). Where applicable, the study captured the expected cost declines for DERs over the study period.
- **Benefit-Cost Framework:** The study applied a modified Total Resource Cost (TRC) test to assess the cost-effectiveness of DERs, consistent with the framework used by the IESO in its Energy Efficiency Achievable Potential Study (APS), but further valuing the dynamic capabilities of DERs to respond to system conditions. The analysis considered system benefits from all services that DERs can reasonably contribute to without applying participation constraints. The benefits are defined as the costs associated with avoiding the corresponding grid services and quantified using hourly modeling and market proxies where relevant. Additionally, key costs associated with securing DER capacity are considered.

Benefits Considered in the Study	Costs
• Avoided energy costs (carbon costs embedded) • Avoided surplus baseload generation (SBG) • Avoided generation capacity costs • Avoided operating reserves (OR) • Avoided regulation capacity (RC) • Avoided / deferred transmission capacity costs • Avoided / deferred distribution capacity costs • Avoided transmission and distribution line losses	• Measure upfront costs • O&M costs • Program, aggregation and/or transaction costs

ADDITIONAL DER BENEFITS NOT CONSIDERED

Beyond the benefit streams captured in the study, DERs can contribute additional benefits to the system and host customers / communities, including resilience and added reliability. The value of such benefits is typically difficult to quantify and therefore have been excluded from the benefit-cost framework, however, these may improve the cost-effectiveness of some DERs if considered.

- **Economic Potential Assessment:** Two levels of economic potential are calculated in the study:

- The measure-level economic potential provides insight into a measure's cost-effectiveness and potential when considered in isolation. Measures with a TRC above 1.0 are considered cost-effective.
- The market-wide economic potential reflects the combined economic potential of all cost-effective measures when they are considered and applied in concert towards meeting the identified system needs. To arrive at the market-wide economic potential, the pool of cost-effective DERs identified in measure-level economic potential are applied to meeting system needs, starting with the most cost-effective individual DER measures, until system needs are met, or no more cost-effective DER potential exists.

2.2.3 Achievable Potential

The achievable potential represents the expected contribution of DERs to Ontario's system needs over the next decade, considering customer preferences and market dynamics. It is calculated through three key steps:

- **DER Adoption:** Forecast of the uptake of a given DER technology as determined by the economic attractiveness of the measure to a participant and considering market barriers. These market barriers determined the customers' or developers' willingness-to-pay for a given DER under various rates of financial return, which is impacted by site and technology specific factors such as technical complexity of the installation, building code or permitting complexities, DER diffusion and customer awareness. The approach used to assess the market adoption varied based on the type of DER, and whether or not the DER was assumed to be predominantly adopted for market/program participation. For DERs predominantly driven by financial benefits of market/program participation (e.g. FTM and BTM solar and storage), the study team used Dunsky's solar and storage adoption models to forecast the uptake of the respective technologies. The detailed approach is further described in Volume II.
- **DER Participation:** Estimate the portion of adopted DERs willing to participate in markets / programs to provide grid services. Participation levels are calculated based on bill savings, participation / performance incentives and/or market revenue available to the customers/participants, program marketing efforts and the barriers associated with participation for each measure. To assess the portion of DERs likely to participate in the market or DR programs, the team applied propensity curves that capture the portion of DERs likely to participate based on incremental revenues and market barriers.
- **System Impacts:** Applying the assessed DER adoption and participation, DER measures are stacked considering their assumed dispatch characteristics, profile and constraints (as identified under Technical and Economic Potential). Through an optimization process, the combined inter-measure impacts are captured to arrive at an assessment of the total achievable potential for DERs and their corresponding contributions to different system needs.

2.3 Scenarios

The study assessed the potential for DERs in Ontario under three scenarios that reflect varying policy, regulatory and market conditions. The scenarios were designed to provide insight into the role DERs can play under different system outlooks as well as the impact of various market interventions designed to alleviate market barriers. Five key levers were identified as likely to have a large influence on the technical, economic, and achievable potential:

- **Electrification growth rates:** The pace of transportation, building and industry electrification in Ontario over the next decade;
- **Carbon pricing**: Future carbon price forecasts and allowance benchmarks;
- **Market participation and compensation:** Increased market participation and compensation for DERs through expanding service eligibility, access to procurements, and barrier reductions;
- **Technology Costs:** Cost reductions for key DERs stimulated by technology improvements and/or monetary support to offset incremental costs (e.g. federal grants for solar PV); and
- **Electricity supply resource mix:** Assumed additional resources deployed over the study period to meet emerging system needs.

The levers impact the technical, economic, and achievable potential as summarized in the table below.

Table 2-1: Levers and Impact of DER Potential

Factor	Impact of DER Potential		
	Technical Potential	Economic Potential	Achievable Potential
Electrification	✓	✓	✓
Carbon Pricing		✓	✓
Market Participation / Compensation			✓
Technology Costs		✓	✓
Supply Resource Mix		✓	✓

Three scenarios were developed to represent the combined impact of variations of the five factors described above:

- **BAU:** Business-as-usual projection reflects the existing market conditions, technological trends, and the IESO's APO Reference Case for demand.
- **BAU+:** Expanded electrification and decarbonization trajectory in-line with the IESO DER Roadmap and general policy, market, and technology advances.
- **Accelerated:** Accelerated efforts to support the transition to net-zero coupled with increased efforts to integrate DERs.

The following sub-sections provide further insight into each scenario input parameter, while the detailed scenarios assumptions are provided in Volume II – Appendix E of the report.

2.3.1 Electrification

Increased electrification of key end-uses is seen as an important enabler of a net-zero economy, and has a tremendous impact on the electricity system; primarily through increasing electricity demand, changing load patterns, and accelerating system needs. The study considered the electrification of three key sectors:

- **Transportation:** The electrification of passenger and commercial fleet light-, medium-, and heavy-duty vehicles and buses.

- **Buildings:** The increased prevalence of heat pumps (HPs) for space and water heating across the residential and commercial sectors.
- **Industry:** Fuel-switching of key industrial end-uses to electricity.

Detailed assumptions for each sector are highlighted in Volume II – Appendix E, however broadly the three levels of electrification modeled in the study reflect the following:

- **BAU:** The 2021 APO Reference Case is used as reflective of the forecasted load growth to be observed from electrification.
- **BAU+**: The scenario assumes higher levels of electrification across all three sectors. The forecasted electrification of light-duty vehicles (LDVs) is in-line with the APO High Scenario and the Federal Government's Zero Emission Vehicle (ZEV) targets of 100% of new sales by 2035. Forecasts for other vehicle segments as well as the transportation and buildings sectors were based on projections from other jurisdictions, recent federal announcements, and directionally align with the light-duty vehicle ZEV targets.
- **Accelerated**: The scenario assumes higher level of electrification across all three sectors in-line with accelerating efforts to reach net-zero. For LDVs, the accelerated scenario aligns with Electric Mobility Canada's 2030 Vision, and other vehicle class forecasts are aligned with electrification progressions in other jurisdictions and directionally align with LDV forecasts. The forecasted electrification for buildings and industry is benchmarked against EPRI's Canadian National Electrification Assessment report, with adjustments.

Increased electrification has multiple impacts on system outlook and DER potential. Electrification impacts the technical potential for DERs directly by creating new opportunities for controllable loads. Electrified transportation, and space and water heating represent very large customer loads highly amendable to demand response. Furthermore, the forecasted rates of electrification have a significant impact on system outlook as highlighted below in Figure 2-2. Most prominently, under both the BAU+ and Accelerated scenario, an increase in both summer and winter peaks is observed; with Ontario facing a significant transition towards a winter peaking regime over the next decade. This change in system outlook and demand patterns also impacts wholesale energy prices observed across the scenarios.

Figure 2-2: Seasonal System Peak Load Projections for each DER Study Scenario

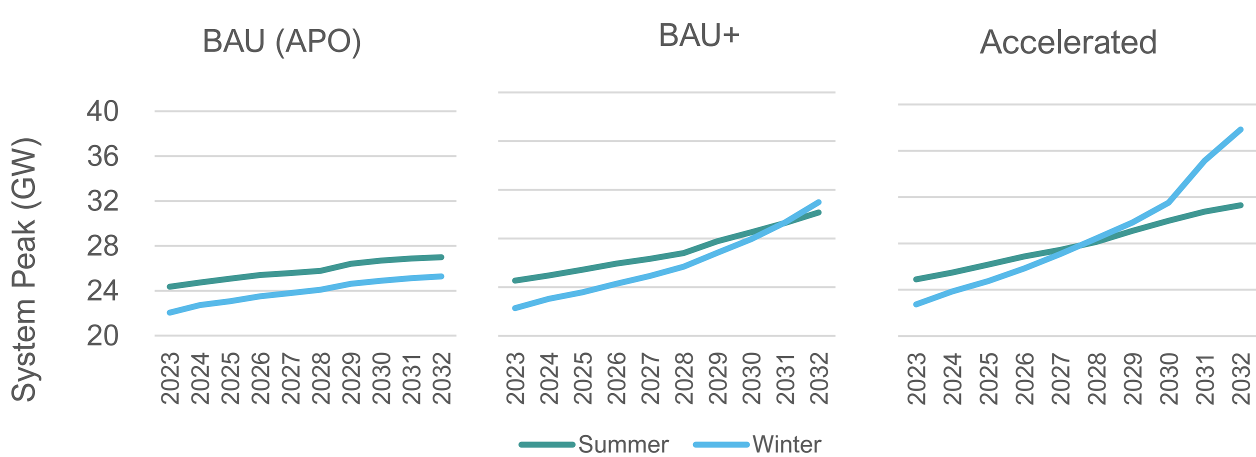


Table 2-2: Forecasted Peak Demand by Scenario and Season

	BAU	BAU+	Accelerated
Summer	27 GW	30 GW (+ 3 GW)	31 GW (+ 4 GW)
Winter	25 GW	31 GW (+ 6 GW)	38 GW (+13 GW)

2.3.2 Carbon Pricing

Given the uncertainty around future carbon pricing, the study modeled three potential scenarios to assess their impact on DER Potential. Carbon pricing for the BAU scenario was defined based on current Federal Government policy, with the BAU+ and Accelerated scenarios applying higher carbon prices. The carbon prices for each scenario are further detailed below:

- **BAU:** Carbon pricing is increased steadily to $170/tonne by 2030 as per the Government of Canada's *Pan-Canadian Approach to Pricing Carbon Pollution*.[1] The performance standard is assumed to be maintained at the current carbon-intensity benchmark of 370 tCO2/GWh, with generation facilities having to pay the carbon price on the emissions in excess of this limit.
- **BAU+:** Carbon pricing is maintained at $170/tonne by 2030, with the carbon-intensity allowance benchmark dropping to 0 tCO2/GWh by 2030.
- **Accelerated:** Carbon pricing reaches $170/tonne by 2030 and is escalated further at $15/year, reaching $350/tonne by 2042. The allowance benchmark drops to 0 tCO2/GWh by 2030.

The carbon pricing scenarios have a direct implication on wholesale energy prices and thus impact both the economic and achievable potential for DERs.

2.3.3 Market Compensation and Participation

To assess the financial benefits each DER can deliver to the DER provider (aggregator, developer, electricity customer), market compensation assumptions were developed for each scenario, accounting for increased levels of compensation (compared to current market prices typically observed) and increased market eligibility (in terms of the ability of the provider to access compensation for system services). The assumptions were developed to allow for greater DER participation and uptake in response to increased system needs with each successive scenario. Three key aspects of IESO market compensation and participation for DERs were considered in the scenarios:

- **Service Eligibility:** Expanded DER access to compensation for system services; modeled in the study through providing DERs with access to compensation for services they can technically and practically contribute to;
- **Capacity Procurements:** Expanded ability for DERs to participate in non-market procurements (e.g. competitive Requests for Proposals etc.) modeled as an increase in the capacity payments available to DERs; and

[1] Reference (accessed May 19, 2022): https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information/federal-benchmark-2023-2030.html

- **Barrier Reductions:** A proxy for addressing barriers that constrain DER participation (e.g. aggregation limits, metering requirements, etc.); these were modeled as a qualitative step reduction in the barrier levels applied to assess DERs' propensity to participate in the market, as well as an increase in the share of revenues passed through from aggregators to contributors.

The table below summarizes the assumptions for each of the levers under the three scenarios modeled in the study. Detailed assumptions are highlighted in Volume II – Appendix E.

Table 2-3: Lever Assumptions by Scenario

	BAU	BAU+	Accelerated
Service Eligibility	Current market rules	Changes being explored by IESO + NWA Framework for T&D compensation	Expanded market participation eligibility + NWA Framework for T&D compensation
Capacity Procurement	DERs compensated through capacity auction	DERs can partially participate in non-market procurements and receive up to 70% of capacity value.[2]	DERs can participate in non-market procurements and receive up to full capacity value
Barrier Reduction	Current barriers remain in place Typical customer pass-through from aggregators (35-75% depending on segment)	Step reduction in market barriers Higher customer pass-through from aggregators (50-80% depending on segment)	Step reduction in market barriers Higher customer pass-through from aggregators (75-90% depending on segment)

2.3.4 Technology Costs

Cost reductions that reduce the upfront costs of DER measures can increase the economic and achievable potential of DERs in Ontario. Successive scenarios reflect the impact of declining costs for key DER categories where such cost declines are anticipated over the study time horizon (e.g. solar PV, battery storage, V2B/G). The modeled cost reductions can be considered as a proxy for technology cost improvements and/or monetary support to offset incremental costs (e.g. federal grants for solar PV).[3] Cost declines applied to each scenario are as follows:

- **BAU:** 2 – 3 % annual average decline in upfront costs.
- **BAU+:** 3 – 5% annual average decline in upfront costs.
- **Accelerated:** 5 – 7% annual average decline in upfront costs.

[2] The Capacity Value refers to the assessed avoided cost of capacity, as determined through each modeled electricity demand scenario. The BAU+ scenario assumes that the procurement capacity cost would be somewhat lower than the assessed avoided cost, while the Accelerated scenario assumes that the full value of the avoided capacity costs would be offered in capacity procurements. Currently the capacity auction (as applied under the BAU scenario) typically offers about 35% of the assessed capacity avoided costs.
[3] Note that monetary support (i.e. incentives) should not normally be considered to improve the cost-effectiveness (i.e. TRC) scores of DER measures, however they can be interpreted as favorably influencing customer adoption in achievable potential.

2.3.5 Supply Resource Mix

The addition of other supply-side resources will impact system outlook, needs and wholesale costs, and therefore influence the DER potential in Ontario. Thus the modeled scenarios necessitate assumptions on how Ontario's supply mix may evolve over the study period. The supply resource mix assumptions were developed based on a combination of planning criteria (e.g., resource adequacy objectives), possible policy direction (e.g., lower carbon intensity of electricity supply over the next decade) and comparative project economics (i.e., renewable generation generally is the lowest cost energy resource for new supply). The supply mix was developed with input from the IESO and reflects the unique nature of the Ontario electricity sector (e.g., hybrid market design). The BAU and BAU+ scenarios reflect reasonable procurement of transmission connected resources by the IESO to meet resource adequacy needs and other planning criteria. Under the Accelerated scenario, the resource supply mix only assumes committed and planned resources; an objective of the Accelerated scenario is to assess the capability of DERs under a scenario of constrained transmission-connected resource development. The table below summarises the key assumed resource buildouts over the study period. Detailed assumptions are highlighted in Volume II – Appendix E.

Table 2-4: Supply Resource Mix Assumptions

	BAU	BAU+	Accelerated
Nuclear	• Bruce/Darlington refurbishment on schedule • New nuclear (SMRs) 300 MW by 2030 plus additional to meet baseload demand	• Bruce/Darlington refurbishment on schedule • New nuclear (SMRs) – 300 MW by 2030 • Advanced nuclear deployment in 2030s	• Darlington and Bruce refurbishment on schedule • New nuclear (SMRs) 300 MW by 2030
Gas	• All gas-fired generation remains in service through re-contracting • No new gas-fired generation • Low-carbon fuel adoption (e.g., Renewable Natural Gas (RNG))	• Gas remains for reliability purpose, low energy output in most hours, some conversion and usage of lower carbon intensive fuels (e.g., RNG, green hydrogen)	• Practically all gas-fired generation remains in service over the forecast horizon • No new gas-fired generation
Hydro-electric	• Remains constant over forecast horizon	• Remains constant over forecast horizon	• Remains consistent over the forecast horizon
Non-Hydro Renewables (wind/solar)	• Consistent addition of renewables	• Expanding growth of renewables, moderate pace of new project development	• Existing renewables operate over the forecast horizon • New renewables + storage procured to meet 1,000 MW UCAP target for 2021 AAR
Storage	• 1,250 MW by 2030 (Oneida and Meaford), more storage in the 2030s	• Multiple large-scale (i.e., 8-hour) storage resources; Oneida, Marmora and Meaford constructed by 2030, consistent growth in 2030s, moderate growth rate and new project development	• New renewables + storage procured to meet 1,000 MW UCAP target for 2021 AAR • Oneida Energy Storage (250 MW) in service by 2026
Imports	• Potential short-term firm import agreements, limited by intertie capacity	• Potential short-term firm import agreements, limited by intertie capacity	• Hydro Quebec capacity trade in 2026 • Lake Erie in service by 2026 (no firm capacity, just expanded intertie capacity)

2.3.6 Summary of Scenario Assumptions

The table below summarizes the key parameters for each modeled scenario. Detailed assumptions are presented in Volume II – Appendix E.

Table 2-5: DER Study Scenario Settings

Lever	BAU	BAU+	Accelerated
Carbon Pricing	$170/tonne by 2030 with 370 tCO2e/GWh benchmark[4]	$170/tonne by 2030 with 0 tCO2e/GWh benchmark	$170/tonne by 2030 with 0 tCO2e/GWh benchmark + $15/year escalation
Electrification	APO Reference Case	APO + (In-line with APO High scenario for EVs and current policy direction)	APO ++ (In-line with aggressive policy push for electrification of transportation, buildings and industry)
Market Participation / Compensation	Current market rules + Capacity procurement through auction + Moderate Customer pass-through from aggregators[5] (35-75%)	Changes being explored by IESO + NWA Framework + Non-market procurement of DERs (70% of capacity value)[6] + Market barrier reduction + Higher pass-through from aggregators (50-80%)	Expanded market participation + NWA Framework + Non-market procurement of DERs (100% of capacity value) + Market barrier reduction + Highest pass-through from aggregators (75-90%)
Technology Costs	Base cost assumptions (2 – 3% annual decline)	Moderate cost decline/ financial support (3 - 5% annual decline)	High-cost decline/ financial support (5 - 7% annual decline)
Supply Resource Mix	APO Forecasts	APO Forecasts + Additional non-emitting resources / storage to partially address growing supply gap	APO Forecasts + Further additional non-emitting resources / storage as per planned long-term RFP procurement (i.e., 1,000 MW of effective capacity)

2.4 Services and System Needs

The potential study was primarily focused on identifying the potential for DERs to contribute to different grid services and address emerging system needs in Ontario. Specifically, the study was focused on seven key grid needs:

- **Generation Capacity**: The ability for DERs to contribute to meeting the four-hour summer and winter peak demand event windows currently defined by the IESO.

[4] The benchmark indicates the electricity generation carbon intensity above which the generator would be subject to carbon pricing.
[5] Pass through from Aggregators, refers to the portion of the market capacity price that DER aggregators offer to DER owners to enroll them in their DER pool or program.
[6] Refers to offering DERs 70% of the assessed avoided cost of capacity, as determined through each modeled electricity demand scenario.

- **Energy:** Contribution to the system's hourly energy needs, including embedded carbon costs as well as applicable transmission and distribution (T&D) line losses.
- **Surplus Baseload Generation (SBG):** Avoiding curtailment during SBG events by consuming energy that would otherwise be spilled.
- **Operating Reserves (OR):** Contribution to 10-minute spinning (10S), 10-minute non-spinning (10NS), and 30-minute reserve (30R) needed to maintain system reliability.
- **Regulation Capacity (RC):** Contribution to variations in electricity demand and supply resource output by adjusting their output to maintain frequency and stability.
- **Transmission Capacity:** Avoiding or deferring investments in transmission capacity that are primarily triggered by thermal capacity overload.
- **Distribution Capacity:** Avoiding or deferring investments in distribution capacity that are primarily triggered by thermal capacity needs and/or outage management requirements.

IMPACT OF CHANGING PEAK LOAD PATTERNS

DERs' capacity contributions are calculated based on the IESO's 4-hour definition of capacity products. However, increasingly flatter load patterns could impact the contribution of DERs to system capacity. For example, a 4-hour battery storage system will have a reduced output if it has to contribute to a longer peak event. Similarly, DR measures that have a pre-charge or rebound event (e.g. HVAC controls) could end up contributing to an overall increase in system peak by creating new peak events outside of the IESO's typical peak window.

Future DER dispatch may therefore need to become more sophisticated by strategically staggering more participants to meet flatter and longer peak events.

For each service, projected system needs were assessed for each year in the study period. These system needs represent the maximum potential contributions for each service type, after which the value of incremental contributions is equal to zero. The projected system needs for BAU+ and Accelerated are based on adjustments to current system needs to reflect the impacts of the forecasted load growth from electrification assumed under these two scenarios. The table below highlights the projected system needs that DERs can contribute up to for each scenario by 2032. The approach used to estimate the system needs as well as the detailed annual values are outlined in Volume II – Appendix C.

Table 2-6: DER market opportunity for each grid service, based on projected system needs by scenario

	Total Market Opportunity in 2032		
Service / Value Stream	**BAU**	**BAU+**	**Accelerated**
System Capacity (MW)	3,400 MW (Summer) 1,300 MW (Winter)	4,600 MW (Summer) 6,200 MW (Winter)	9,300 MW (Summer) 14,600 MW (Winter)
Energy (TWh)	32 TWh	39 TWh	88 TWh
Surplus Baseload Generation	5 GWh (down from 110 GWh in 2022)	0 GWh (down from 61 GWh in 2022)	0 GWh (down from 61 GWh in 2022)
Operating Reserves	200 MW (10-min spinning), 620 MW (10-min non-spinning) 410 MW (30-minute)		
Regulation Capacity	150 MW		
Transmission Capacity Deferral	2,400 MW	2,740 MW	4,140 MW
Distribution Capacity Deferral	290 MW	620 MW	960 MW

TRANSMISSION AND DISTRIBUTION (T&D) DEFERRAL VALUE

DERs have been demonstrated to serve as a cost-effective solution for avoiding or deferring investment needs in the T&D system in many jurisdictions across North America. However, it is important to consider that DERs can only feasibly contribute to certain T&D deferral opportunities. For example, DERs can generally contribute to transmission capacities where they are expected to exceed capacity ratings, however end-of-life and system stability needs to be examined on case-by-case basis to determine the applicability of a DER-based non-wire alternative (NWA) solution. Furthermore, T&D benefits are very location specific. Unlike generation capacity, only DERs that are appropriately sited within the need area can contribute to addressing it.

To capture these considerations, we estimate T&D system needs as emerging needs that can technically be addressed through DERs. Additional contributions beyond those identified needs are valued at 0. Additionally, given the province-wide scope of this study, we make the simplifying assumptions that DERs that receive the T&D benefits are targeted in the specific regions where the T&D needs emerge.

3. Pre-Assessment

The study team conducted a pre-assessment to develop a comprehensive list of available DER measures and vet them for applicability in the Ontario market.[7] The goal of the pre-assessment was to identify and focus the study on DER measures that were either expected to be cost-effective (economic) or expected to be adopted regardless of cost-effectiveness in Ontario over the study period. The team identified the DER study measure list using a three-step approach, as outlined in the diagram below and described in the sections that follow.

3.1 Comprehensive List of DER Measures

First, the team developed a comprehensive list of DER measures. Given differences in energy use, market characteristics, and applicable technologies in each sector, they compiled separate residential and non-residential lists. This process drew on Dunsky's existing library of measures, which includes technologies commonly applied in programs across North America as well as emerging opportunities in energy storage, connected devices, and EV load management. A jurisdictional scan complemented the library by identifying other emerging technologies thought to be relevant to the Ontario market as well as load flexibility opportunities for key end-uses and sectors across the province. The team considered various permutations of each measure – including different control strategies, and application in different market segments – and included them in the long list where applicable.

For each measure, the team captured information on key technical, market and use characteristics. These included operational parameters, grid services offered by the measure, and other technology-specific considerations, including expected trends in cost and performance.

The full long list of measures – including a summary of key characteristics for each measure – is included in Volume II - Appendix A Long List of Measures.

3.2 Measure Screening

Next, to determine which DER technologies should be modeled in the study, the team assessed each measure in the DER long list against screening criteria (Table 3-1). The screening criteria provided insight into which DERs were likely to contribute meaningfully to Ontario's electricity system over the study period, while also capturing other relevant Ontario-specific and global factors that should be considered in measure selection. For each of the criteria, each measure was qualitatively rated as low, mid, or high. Definitions for what constituted a low, mid, or high rating for each of the criteria and the screening results by measure are included in Volume II - Appendix A.

[7] For the purpose of this study, a measure is defined as a specific technology.

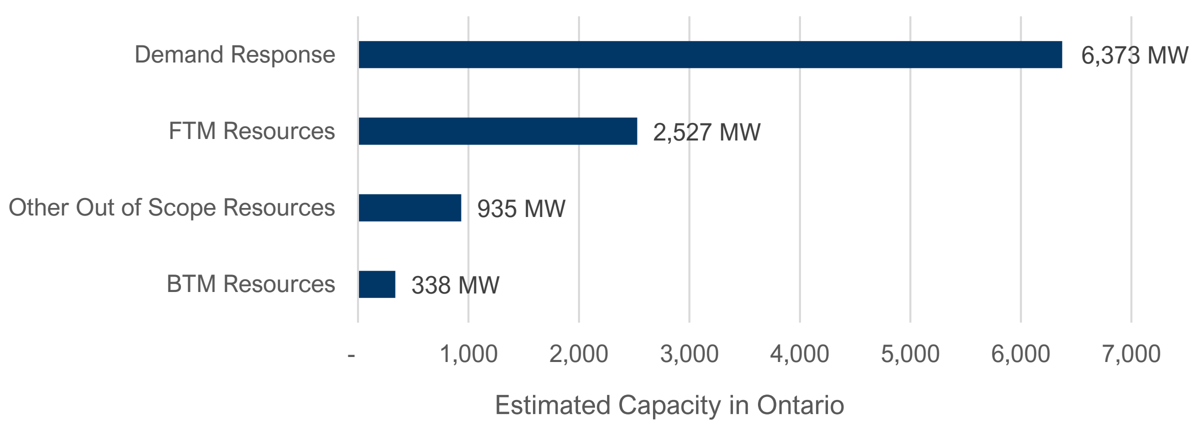
Table 3-1: Measure Screening Criteria

Screening Criteria	Definition
Alignment with / Capability to Meet System Needs	Ability to provide grid services to meet electrical system needs
Expected Opportunity Size	Size of the current and potential future market over the study period
Potential to Deliver Emissions Reductions	Ability to reduce GHG emissions associated with the electricity system
Expected Cost-Effectiveness	Achievement of cost-effectiveness over the study period
Market Readiness	Current and forecasted technology availability and degree of demonstrated use to-date
Alignment with Customer Goals / Preferences	DERs that are likely to emerge as they have the ability to meet customer needs and preferences (e.g. bill reductions, ease of use, resilience, etc.)

3.3 Estimated Baseline in Ontario

Leveraging data from the IESO's DER inventory estimates,[8] Residential and Commercial End-use Surveys, market data from the Ontario Energy Board (OEB), other resources, and professional judgement, the project team estimated the existing level of penetration of different DERs in Ontario. Our estimates suggest that 10,170 MW of DER capacity is currently deployed in Ontario. Out of this potential, 9,240 MW is within the study scope.[9] The largest share of this installed capacity – 63% – is within the DR resource type (Figure 3-1). The next largest group is FTM resources, at 25%, followed by BTM resources at 3%, and all other out-of-scope resources accounting for 9% of the current nameplate capacity.

Figure 3-1: Estimated Installed DER Capacity in Ontario by Resource Type



Across all currently installed DERs in Ontario, ten measures are estimated to represent nearly 77% of the deployed capacity.

[8] https://www.ieso.ca/en/Learn/Ontario-Power-System/A-Smarter-Grid/Distributed-Energy-Resources

[9] Out of scope resources account for 935 MW. This capacity includes approximately 600 MW of wind and 170 MW of CHP alongside other distributed energy resources contracted with the IESO or distribution connected market participants.

Table 3-2: Estimated Nameplate Capacity (MW) of Top 10 Largest DER Measures Installed in Ontario

Study Resource Type	Measure	Estimated Installed Nameplate Capacity (MW)[10]
Front-of-the-Meter	FTM Solar	2,170
Demand Response	Lighting Controls	1,740
Demand Response	AC Thermostat	1,080
Demand Response	Electric Resistance Water Heaters Smart Switch	730
Demand Response	Small Commercial Hot Water	660
Demand Response	Smart Clothes Dryer	370
Demand Response	Large Commercial HVAC Control	310
Front-of-the-Meter	FTM Small-scale Hydro	310
Demand Response	Electric Baseboard with Smart Thermostat	300
Behind-the-Meter	Res. BTM Solar with Smart Inverters	250
All other DERs, including out of scope resources	Remaining measures	2,255

The capacity contribution of these resources is difficult to estimate given the limited data on the individual contributions of aggregated DR portfolios that do participate in IAMs. However, based on the data from Virtual Hourly Demand Response (HDR) capacity auction results, as well as insights provided by the IESO, the team estimates that distribution-connected DR represent 525 MW of summer peak reductions, and 600 MW of winter peak reductions today.

The estimated baselines were used to set market sizes for measures for the first year of the study and calibrate the model to the expected contribution of resources where data was available.

3.4 Measure Selection

Based on the measure screening exercise, the team made a recommendation for each of the 81 measures in the long list, noting whether they should be included or excluded in the study. These recommendations, along with their associated rationale, are provided in **Appendix A.3 Measure Selection**. The team presented the pre-assessment, including the long-list, screening process and recommended measures, to stakeholders as part of the first stakeholder engagement session (September 2021) to solicit feedback on the appropriateness of the screening criteria and the measure recommendations.

With consideration of the comments received from stakeholders, the study DER measure list was finalized. The 52 measures selected for inclusion are grouped into three resource types - DR, BTM Resources, and FTM Resources – and are displayed in tables 3-3 to 3-5 below.

[10] The nameplate capacity refers to the rated power draw or maximum power output capability for each DER. The actual ability for a given DER to reduce system peak loads would typically be less than this, based on the estimated loads or contributions that are coincident with the system peak.

Table 3-3: DR Measures Included in the Study

Measure Group	Measure
Residential Measures	
HVAC	AC smart thermostat Dual-fuel space heating with smart switch or thermostat ASHP/DMSHP smart thermostat Electric Furnace smart thermostat* Electric baseboards smart thermostat*
Other load flexibility	Other behavioural-based flexibility
Passenger EV charging	Smart EV chargers Passenger EV telematics
Pools and spas	Residential pool pumps
Smart appliances	Smart clothes dryer
Thermal storage	Thermal storage for cooling Thermal storage for heating Thermal storage and HP
Water heating	HP water heater with smart switch Electric-resistance water heater with smart switch Smart HP water heater Smart electric-resistance water heater
Non-Residential Measures	
Back-up Generation	Back-up Generation (propane/gas/diesel)
EV Fleet Charging	LDV fleet EV telematics LDV fleet EV smart chargers MDV fleet EV smart chargers HDV fleet EV smart chargers Buses EV smart chargers
HVAC	Large C&I HVAC control Small C&I HVAC smart thermostat Small C&I ASHP/DMSHP smart thermostat
Lighting controls	Lighting controls
Other load flexibility	District cooling/heating flexibility Industrial flexibility Irrigation pump controls Refrigeration controls Greenhouse grow lights controls Other commercial flexibility
Thermal storage	Commercial HVAC thermal storage Thermal storage for refrigeration applications
Water heating	Large C&I dual-fuel water heater Large C&I electric water heater Small C&I electric water heater

** Added at a later point in the study after identifying a potential shift to a winter peak in the BAU+ and Accelerated scenarios.*

Table 3-4: BTM Resource Measures Included in the Study

Measure Group	Measure
Distributed generation	Residential BTM solar Commercial BTM solar Industrial BTM solar
Storage	Residential BTM battery storage Commercial BTM battery storage Industrial BTM battery storage
Vehicle-to-Building/Grid	Passenger LDV V2B/G LDV fleet V2B/G MDV fleet V2B/G HDV V2B/G Buses V2B/G

Table 3-5: FTM Resource Measures Included in the Study

Measure Group	Measure
Distributed Generation	FTM solar FTM small-scale hydro
Storage	FTM battery storage

MEASURE CONTROL STRATEGIES AND MEASURE BLENDING

- **Other DERs:** Measures not assessed in the study should not be interpreted as technologies that will not exist in Ontario, but rather ones likely to play a limited role over the study period given their expected market size, cost-effectiveness and/or technology maturity.
- **Control Strategies:** While some DER measures may be accessible through either direct control or scheduled variations (e.g. EV charging under TOU rates), the focus of the study is on direct control of DERs. Direct control refers to measures that are equipped with telemetry and controls such that they can be dispatched by the system operator or an aggregator (such as a local distribution utility (LDC)) when required to meet system needs. Direct control offers the greatest certainty of grid service impacts from measures, and consequently can highlight the maximum potential impact and contributions of the DERs being modeled. However, some DER technologies and customer segments may be best addressed through or combined with other strategies (e.g. price signals that nudge behavioural change). Additional considerations regarding DER control strategies and procurement pathways will be addressed in the study recommendations.
- **Blended Measures:** Some measures were characterized as "blended" measures that represent multiple technologies with similar characteristics. For example, a smart thermostat paired with a central air-source heat pump or ductless mini-split heat pump was characterized as a single measure. Blended measures were developed in cases where multiple approaches of measures could be applied to the same end-use or equipment, exhibit similar grid service impacts, and incur similar costs. This allows the study to be conducted at an appropriate level of granularity for a market-wide study, while ensuring it comprehensively captures all DER potential.

4. Technical Potential

Technical potential quantifies the theoretical maximum potential for DERs in Ontario to provide different grid services over the study period, regardless of cost-effectiveness or customer adoption, and represents the projected maximum pool of potential DER opportunities from which the Economic and Achievable potentials are calculated.

The Technical Potential is calculated by combining the market size for each measure, including forecasted market growth over the study period, with the per measure impact,[11] considering technical and operational constraints. The detailed approach used to derive the technical potential is included in **Appendix C. Technical Potential Methodology.**

The technical potential for DERs was assessed for each of the three study scenarios to reflect how variations in policy, technology, and market conditions, will impact the potential pool of technically feasible DER opportunities, as described earlier in section 2.3 of the report. The key factor influencing the technical potential across scenarios is the forecasted rate of electrification of transportation, buildings, and industry.

The technical potential results presented in this section are largely focused on the potential contribution of DERs to meeting summer and winter capacity needs by 2032,[12] calculated considering the peak load reduction *or* – in the case of generation technologies –capacity addition of each DER measure and its corresponding coincidence with the IESO seasonal peak. Where appropriate, other metrics such as nameplate capacity (MW) or energy production (GWh) are highlighted. The results are broken down by three key resource types: DR, BTM, and FTM Resources. These resource types are distinct groupings of opportunities that face unique challenges and barriers from a market and policy perspective. Interpretation of the technical potential results should consider the caveats highlighted in the call-out box below.

TECHNICAL POTENTIAL KEY CONSIDERATIONS

- The primary value of the technical potential assessment is to **establish the maximum potential market size for each DER measure.**
- Technical potential **does not account for economic, market acceptance, or other non-technical constraints.**
- The assessment highlights the **capability of measures** to provide grid services based on technical characteristics, **rather than the actual provision of services.**
- While technical potential results are presented by resource type (e.g. DR, BTM, FTM), **the technical potential is not directly additive** and should be interpreted carefully. Specifically, the technical potential is illustrative of the size of the opportunity, but does not consider interactive effects within and among resource groups (e.g. changes to load patterns caused by some measures impacting the potential for other measures), which impact the real-world potential that can be achieved.

[11] Here, impact refers to the type and magnitude of grid services that a measure can provide.
[12] Although some measures provide other grid services, summer peak capacity potential is selected as the basis of reporting as it is expected to represent the highest value service to the Ontario electricity system under the IESO's APO 2021 reference case, which guides the IESO's planning and procurement activities. Additionally, the year 2032 was selected to capture the market growth expected for each measure over the study period. Detailed results, including annual potential results and other key measure metrics (e.g. nameplate capacity), are included in the Appendix G – Detailed Results workbook.

4.1 Summary

Figure 4-1 below summarizes the maximum technical potential for DERs to contribute to summer capacity by scenario and resource type.

The technical potential for **DR** was found to be between 9.2 GW and 11.4 GW of summer peak reduction potential across scenarios. The potential represents roughly 34-37% of Ontario's forecasted summer peak of 27-31 GW during the same timeframe. The potential grows by scenario as a function of forecasted increases in electrification.

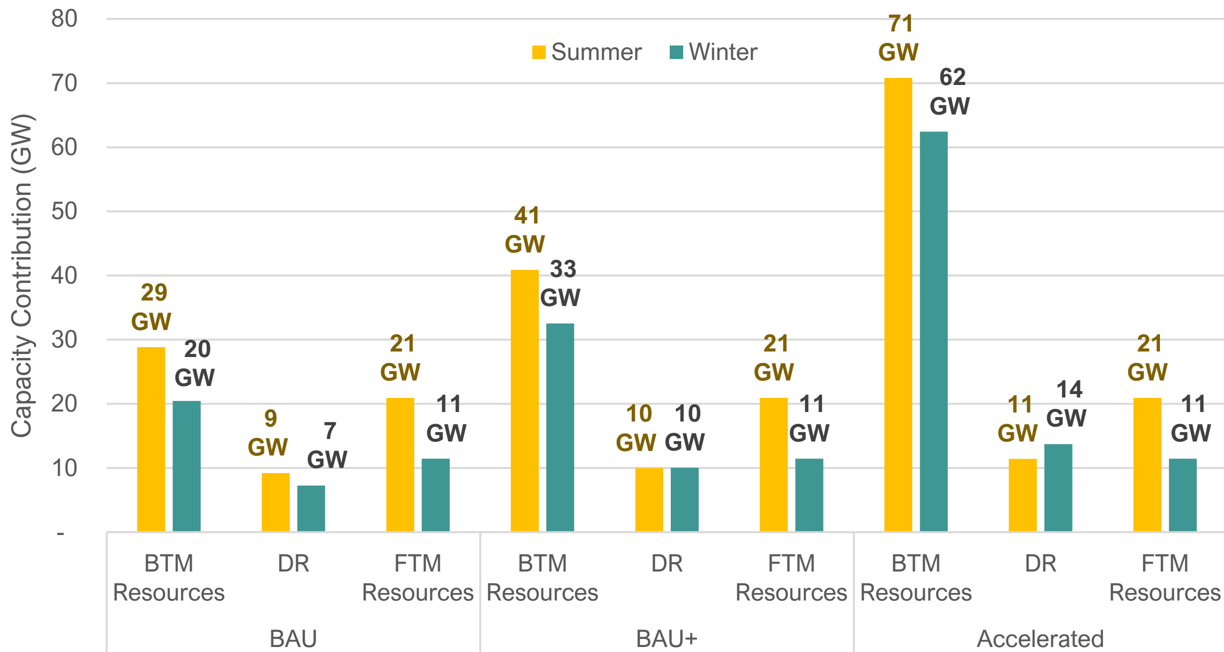
The technical potential for **BTM Resources**, which consists of BTM solar PV, battery storage and V2B/G, is approximately 28.8-70.8 GW of summer capacity additions. The potential for solar is defined by the theoretical limit for solar PV deployment on all suitable rooftops in the province and does not vary by scenario. The notable growth in potential across scenarios is a result of the forecasted load growth from electrification, which drives more opportunities for V2B/G from increased EV penetration, and larger unit sizes for battery storage installations, given that they are assumed to be sized as a function of customer loads.

The technical potential for **FTM resources** is approximately 21 GW of summer capacity additions, and 11 GW of winter capacity additions. The drop from summer to winter is attributed to solar PV's reduced winter peak coincidence, as compared to summer. However, small-scale hydro somewhat offsets the FTM resource summer-to-winter drop, due to its higher winter capacities. As there is no natural constraint on the technical potential for FTM solar PV installations,[13] the maximum potential of these resources in this study was artificially set to be equivalent to the current capacity of the marginal generating resource in Ontario (natural gas) and remains unchanged for all scenarios over the study period. We calculated the potential by sizing each FTM measure to fully displace 10 GW of natural gas while accounting for any measure-specific physical constraints, which resulted in a technical potential of 35.6 GW of nameplate FTM solar PV (based on the IESO's assumed peak coincidence factor or 28% for solar PV in Ontario). As such, the technical potential for FTM resources is unaffected by the modeled scenario levers.

Across all three resource types, the DERs investigated in this study are expected to have significantly lower winter potentials as shown in the figure below.

[13] For BTM solar, the technical potential was sized to the total available potential for rooftop solar PV arrays on Ontario's homes and businesses. However, for FTM solar, there is no similar natural physical constraint to define the technical potential.

Figure 4-1: Technical Potential for Seasonal Capacity Reduction by Scenario and Resource Type 2032

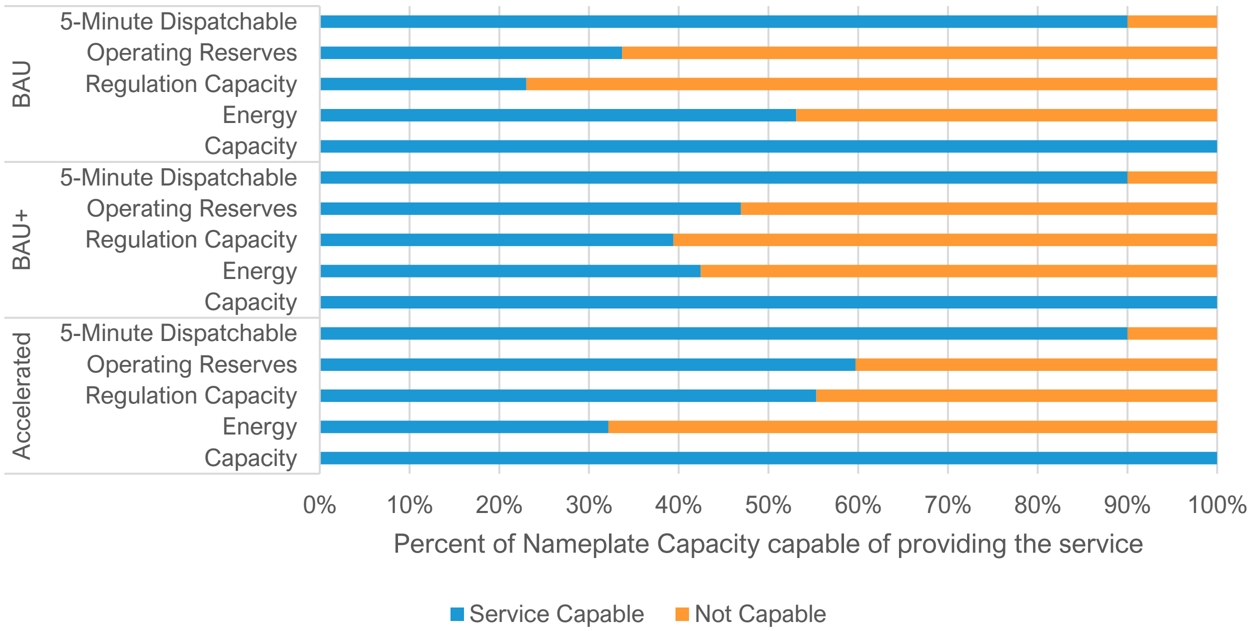


While Ontario's primary emerging system need is system peak capacity, the DERs modeled for the study have the potential to contribute to other grid services,[14] including energy, operating reserves (OR), and regulation capacity (RC). In addition, the 2021 APO identifies growing energy needs, which increase dramatically under the BAU+ and Accelerated scenarios, and provides greater opportunities for DERs to help meet Ontario's projected system needs.

Figure 4-2 below summarizes the portion of the DER technical potential nameplate capacity capable of providing each grid service (Capacity, Energy, Regulation Capacity, Operating Reserves) under each scenario. While most of the DER measures considered in this study are capable of energy shifting, less than half are generating resources (e.g. BTM Solar) capable of contributing to energy needs in Ontario. Even so, the DERs considered in the study could theoretically contribute to up to 140 TWh under all scenarios. Fewer measures are capable of providing OR and RC - those that can include measures capable of ramping loads up or down on short notice, such as battery storage and water heaters. Specifically, 34%-60% of the technical potential for DERs was identified as OR-capable (up to 174 GW of nameplate capacity in the Accelerated scenario) and 23%-55% was identified as RC-capable (up to 161 GW of nameplate capacity in the Accelerated scenario). Moreover, the vast majority (90%) of DER potential was found to be capable of participating in the 5-minute dispatchable energy market.

[14] Given the province-wide nature of the study, transmission and distribution peaks are assumed to be coincident with Ontario's system-wide summer peak events. Therefore, estimated capacity reductions refer to the theoretical potential for displacing generation, transmission and distribution capacities in Ontario.

Figure 4-2: Percentage of Technical Potential Nameplate Capacity Capable of Providing Grid Services



The following sub-sections explore the estimated technical potential for each of the three resource types (DR, BTM, FTM) in further detail, with a focus on summer peak reduction potential. Additional metrics are highlighted in the appendices and supporting data files.

4.2 Demand Response

The potential for DR in a jurisdiction typically depends on the coincidence of sectoral and end-use loads with the system peak. By 2032, Ontario's system peak is forecasted to reach 27 GW.[15] During a typical peak event (hot summer day, between 1pm and 5pm), the residential sector represents 38% of load, the commercial sector represents 37%, and the industrial sector and other[16] loads represent 25% (Figure 4-3).[17]

[15] IESO, 2021 Annual Planning Outlook.
[16]For this study, DER potential is limited to distribution-connected industrial customers (as opposed to both distribution and transmission-connected), which represent approximately 50% of industrial capacity in Ontario. The loads that were not included in this study, namely transmission-connected and other loads, are represented in gray.
[17]Contribution to peak load was calculated as the average load for each sector coincident with the system peak during a four-hour peak window (summer: 16:00 – 19:59; winter: 17:00 – 20:59).

Figure 4-3: Forecasted 2032 Contribution to Summer Peak Day Load by Sector – APO Reference

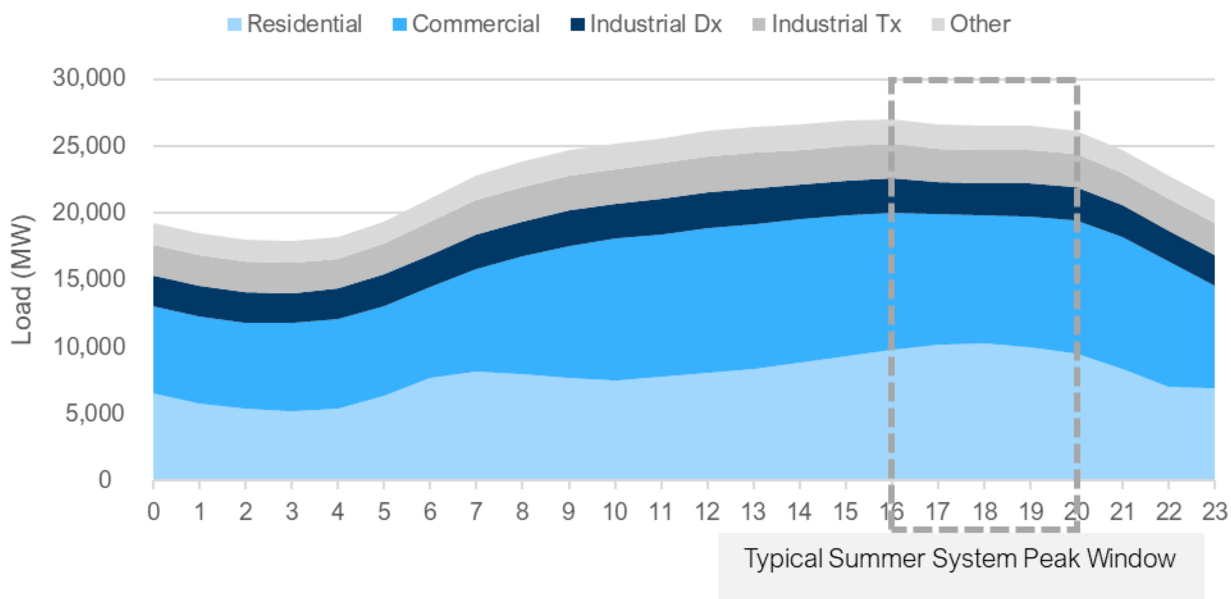
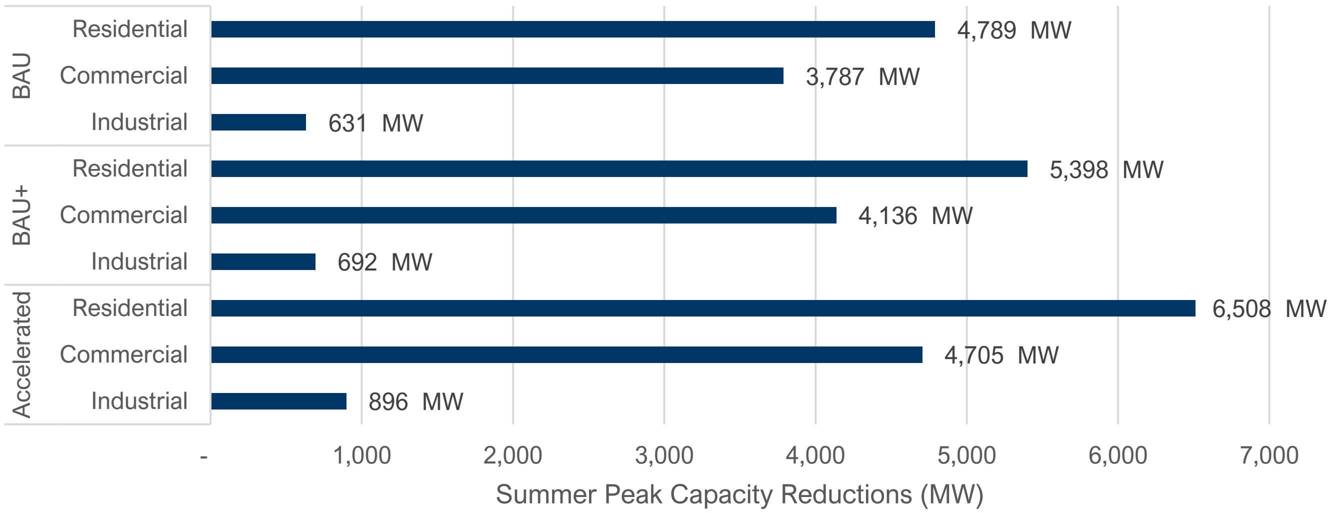


Figure 4-4 below highlights the technical potential for summer peak load reductions from DR by sector. The majority of the technical potential identified for DR in Ontario is found in the residential sector – approximately half under both the BAU and BAU+ scenarios, and more than 60% under the Accelerated scenario – attributable to the significant load flexibility opportunities found in the residential sector.

Significant DR technical potential also exists in the commercial sector, with up to 4,705 MW of summer peak load reductions. This potential primarily consists of thermal storage, HVAC and lighting measures. Technical potential for the industrial sector is more limited, with 631-896 MW of potential summer load reductions identified. The industrial DR potential is this study is limited as it includes only distribution-connected customers, and is also limited by the relatively flat load patterns observed in the sector, which reduce opportunities for load flexibility. Growth in the DR technical potential under the BAU+ and Accelerated scenarios, as compared to the BAU scenario, is driven by the increased rates of electrification for transportation, buildings, and industry.

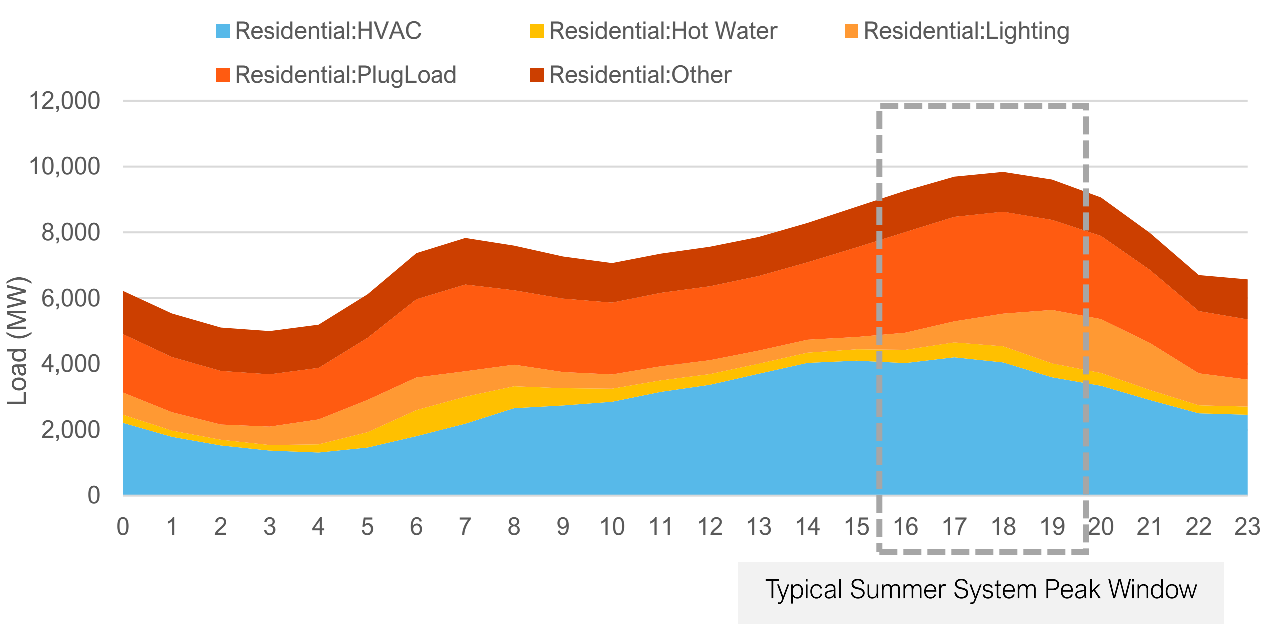
Figure 4-4: Summer Capacity Reduction for DR Measures by Scenario and Sector in 2032



4.2.1 Residential DR

Within the residential sector, the HVAC end-use represents more than 40% of the load during peak events (Figure 4-5). This is followed by plug-loads, which represent nearly 30%. Smaller loads are associated with the remaining end-uses (hot water, lighting, etc.).[18]

Figure 4-5: Forecasted 2032 Residential Contribution to Summer Peak Day Load by End-Use – APO 2021 Reference



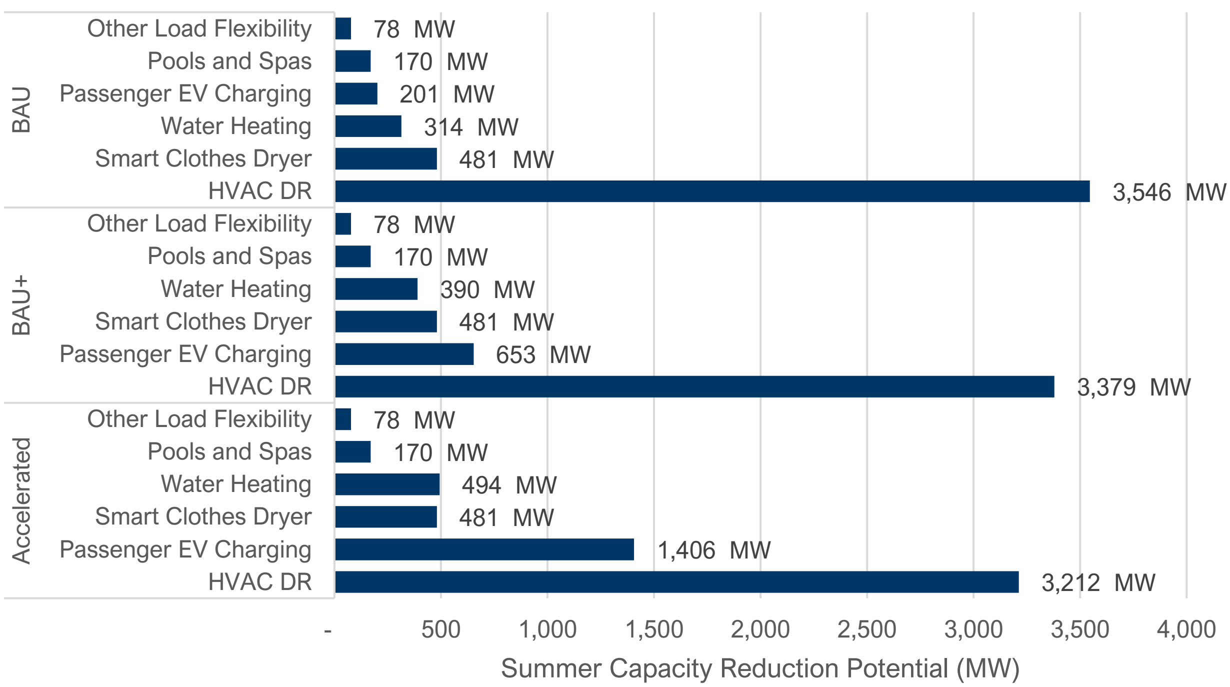
[18] Plug-loads includes clothes washers/dryers, kitchen appliances, consumer electronics, etc., while other loads include pool & spas, MURBs elevators, misc. loads, etc.

As shown in Figure 4-6, HVAC represents the largest opportunity within residential DR capacity (which is in-line with peak load contribution patterns) with between 3,212 MW and 3,546 MW of potential summer peak load reduction. This potential is primarily associated with smart thermostats connected to air conditioners (ACs) and heat pumps (HPs), and thermal storage. Interestingly, the technical potential for residential HVAC DR drops slightly under the BAU+ and Accelerated scenarios, as the growth in heat pump uptake associated with the assumed building electrification scenarios offsets less efficient air conditioning systems and reduces peak demand, thus reducing opportunities for summer peak reduction from residential HVAC DR.

Beyond HVAC, water heating and smart appliances also represent large areas of potential, with smart appliances offering a technical potential of 481 MW. Water heating controls offer an increasing potential, as the adoption of HP water heaters increases under the BAU+ and Accelerated scenarios, rising from 314 MW under BAU to 494 MW under the Accelerated scenario.

Finally, the increasing penetration of passenger EVs leads to expanding DER potential in the residential sector, with 201 MW of potential associated with managed home EV charging under the BAU scenario, ramping up to 653 MW in the BAU+ scenario, and reaching 1,406 MW under the Accelerated scenario.

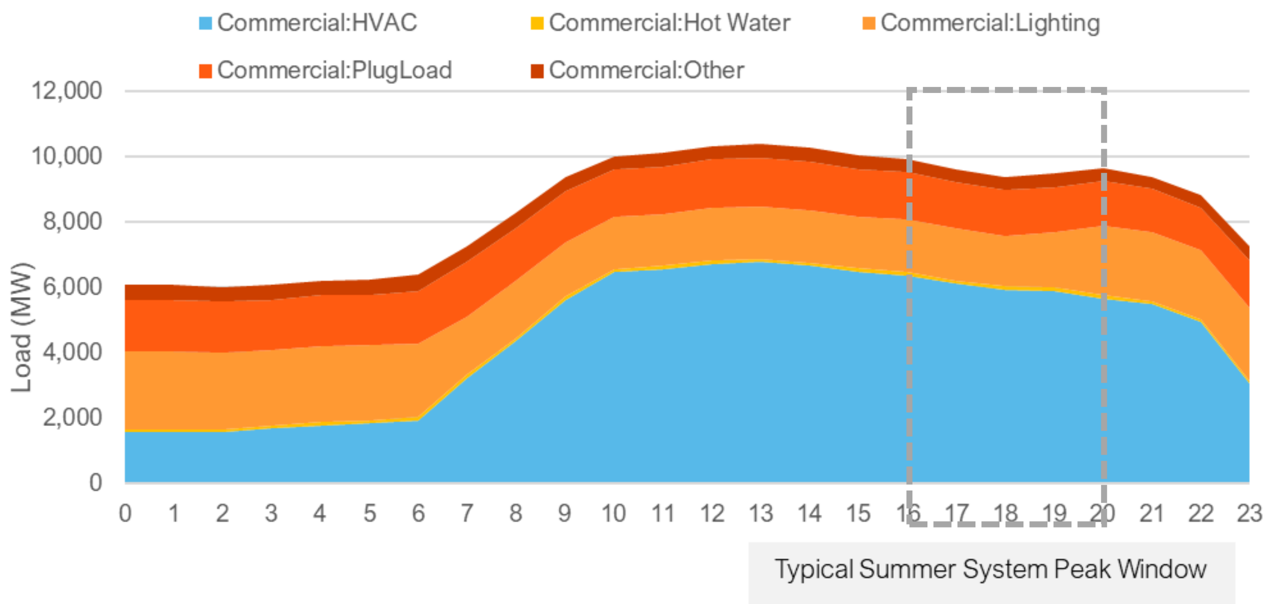
Figure 4-6: Residential DR Summer Capacity Reduction by Scenario, Resource Type, and End-Use in 2032



4.2.2 Commercial DR

Within the commercial sector, space cooling represents more than 50% of the commercial loads during system peak (
Figure 4-7). Water heating makes up a very small portion of overall load given the prevalence of gas water heating in the commercial sector. The remaining load is roughly evenly split among plug-loads, HVAC pumps and fans, lighting and other segment-specific end-uses (e.g. refrigeration).

Figure 4-7: Forecasted 2032 Commercial Contribution to Peak Day Load by End-Use – APO 2021 Reference

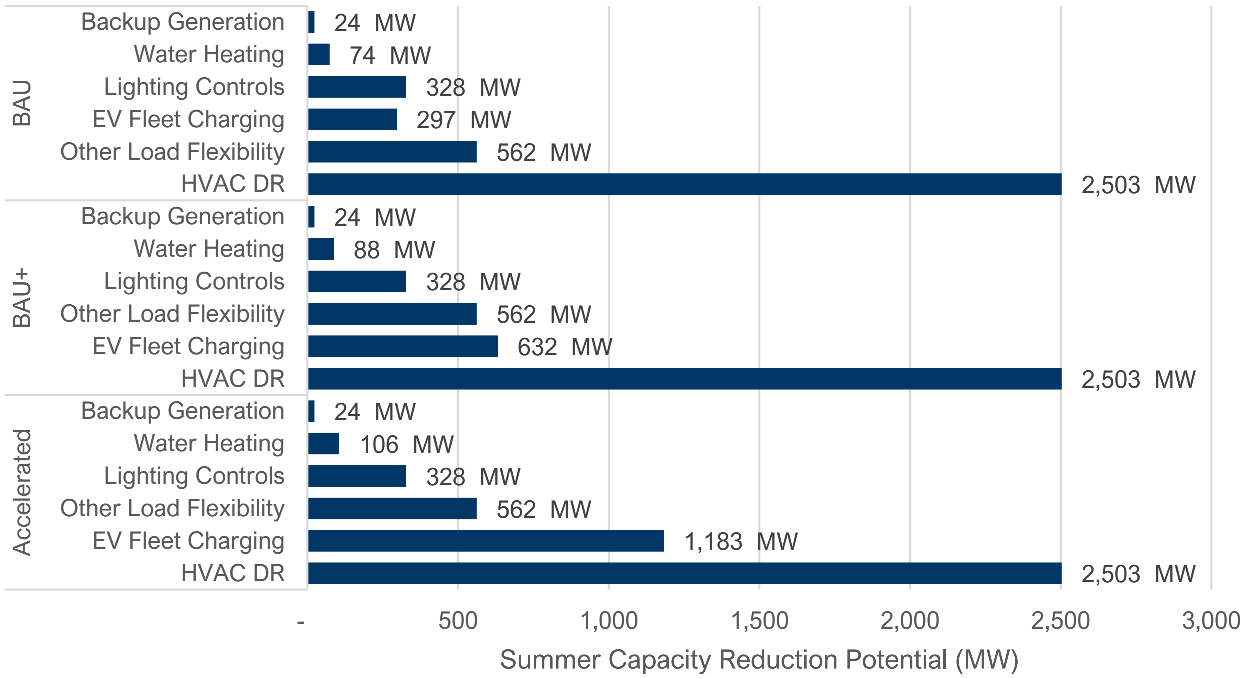


As with the residential sector, HVAC DR represents the largest technical potential for DR in the commercial sector (
Figure 4-8). Key measures include thermal storage, smart thermostats for small commercial customers, and other HVAC load controls for larger commercial customers. The second largest opportunity area under the BAU scenario is associated with "load flexibility" which is applied to end-uses that are unique to the commercial sector,[19] offering 562 MW of potential. Considerable potential is also identified for lighting controls, which represent 328 MW of potential peak reduction.

The increased adoption of EVs within commercial fleets represents a significant area of DR potential; this potential is particularly pronounced under the BAU+ and Accelerated scenarios, offering 632 MW and 1,183 MW of potential summer capacity reductions respectively. Similarly, growing opportunities are observed for HVAC measures due to increased adoption of heat pumps in the commercial sector.

[19] The 'other load flexibility' end-use includes of a number of measures with controllable loads but limited market sizes such as refrigeration controls, district heating/cooling flexibility, pump controls, and more.

Figure 4-8: Commercial DR Summer Capacity Reduction by Scenario, Resource Type, and End-Use in 2032



4.2.3 Industrial DR

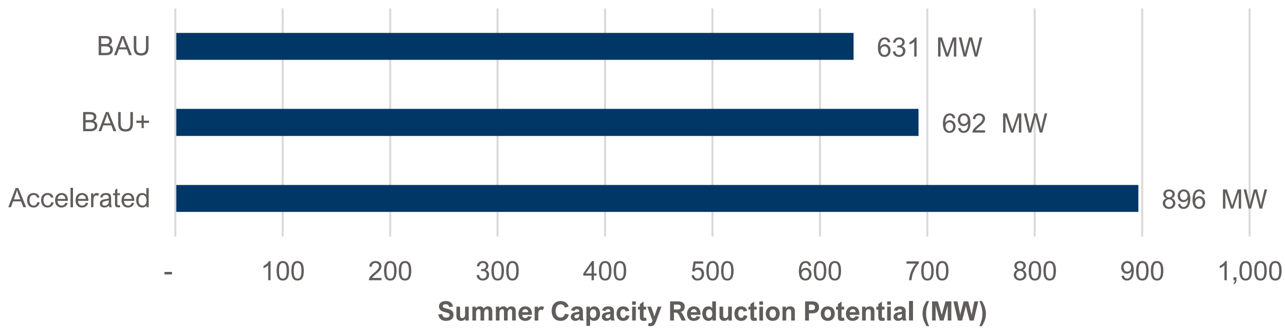
While data on the hourly breakdown of industrial end-uses is not available, peak consumption in the sector is expected to be dominated by segment-specific end-uses (e.g. machinery, process heating) as well as HVAC. Given limited data availability (wherein only the total contributions to peak load data were available for the industrial sector) the team applied a higher-level approach to modeling (described in detail in **Appendix C. Technical Potential Methodology**). Specifically, we modeled a single industrial load flexibility measure and assumed that for each industrial segment, 25% of the load was curtailable[20]. The model then applied the industrial sector propensity curve to determine what portion of the curtailable load would likely participate as DR in each segment and in each year of the study period. As indicated previously, the DR potential explored in this study is limited to distribution-connected industrial customers, which is assumed to comprise half of the overall industrial load in Ontario.[21]

Generally, given the flatter load patterns typically observed in the industrial sector as well as the operational characteristics of the facilities, roughly a quarter of loads in the industry sector are assumed to be curtailable. This curtailable portion was determined through assumptions employed by Dunsky in other studies as well as cross-referencing of multiple demand response studies conducted in other jurisdictions. As highlighted in

[20] Estimation based a jurisdictional scan of industrial curtailment programs.
[21] An estimate of the portion of Ontario's Industrial loads that are distribution-connected was provided by the IESO.

Figure 4-9, the technical potential for industrial distribution-connected DR ranges from 631 to 896 MW. The increase in potential across scenarios is a result of increased electrification of industrial end-uses under the BAU+ and Accelerated scenarios, which create new opportunities for load control.

Figure 4-9: Industrial DR Summer Capacity Reduction by Scenario, Resource Type, and End-Use in 2032



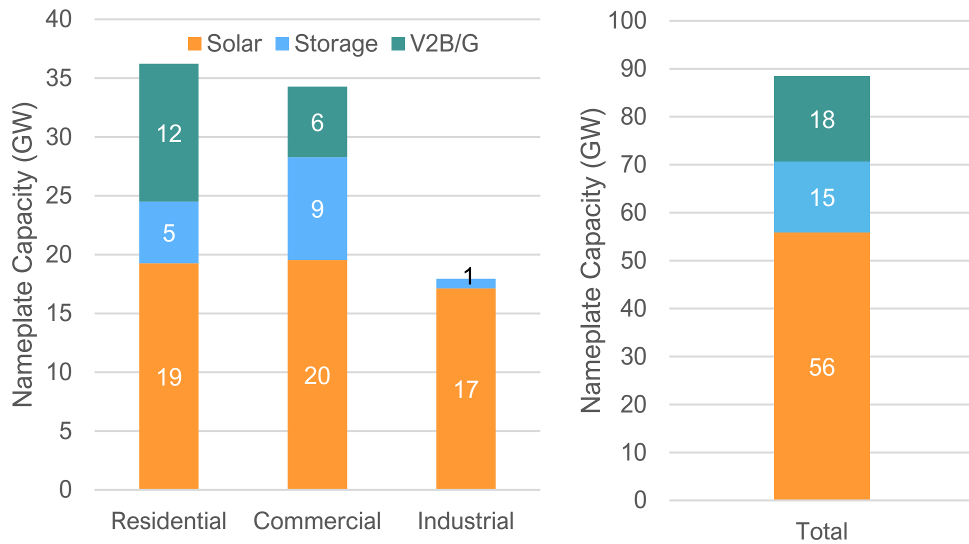
4.3 BTM Resources

The technical potential for BTM resources is limited by key technical and physical considerations. For solar PV, the potential is based on the number of buildings suitable for solar deployment and the corresponding rooftop area available for a solar PV installation, which is unchanged across scenarios. For storage measures, the potential is based on the number of buildings with suitable space for storage deployment and systems that are sized according to customers' load patterns. Despite the increased electrification loads modeled under the scenarios, increases in the technical potential for energy storage is minimal across scenarios and only modest growth can be seen in both measures over time as a result of population segment growth.[22] Given that, we focus the results in this section on the technical potential in 2032 under the BAU+ scenario.

The technical potential for BTM resources in Ontario by 2032 is estimated to be 89 GW (nameplate capacity). As shown in Figure 4-10, distributed generation accounts for the majority of the identified potential (50.9 GW). The solar PV potential is roughly equally distributed among the residential, commercial, and industrial sectors, whereas energy storage and V2B/G potential is concentrated in the residential and commercial sectors. The measure characterization approach assumes that energy storage systems are sized to the difference between a customer's peak load and average daily load, limiting overall potential.[23] This is particularly notable for the industrial sector, where a significantly smaller technical potential for industrial energy storage results from relatively flat load curves at industrial facilities. Moreover, it was assumed that industrial fleets would not participate in V2B/G programs as this could disrupt their use for industrial practices.

[22] The results highlight that load patterns of only a handful of commercial segments will change as a result of electrification; allowing for slightly larger storage deployments by customers in those segments and therefore higher technical potential.
[23] Further detail highlighted in Appendix C. Technical Potential Methodology.

Figure 4-10: Technical Potential (Nameplate Capacity) of BTM Measures by Sector and Measure Type, 2032 (BAU+ Scenario)

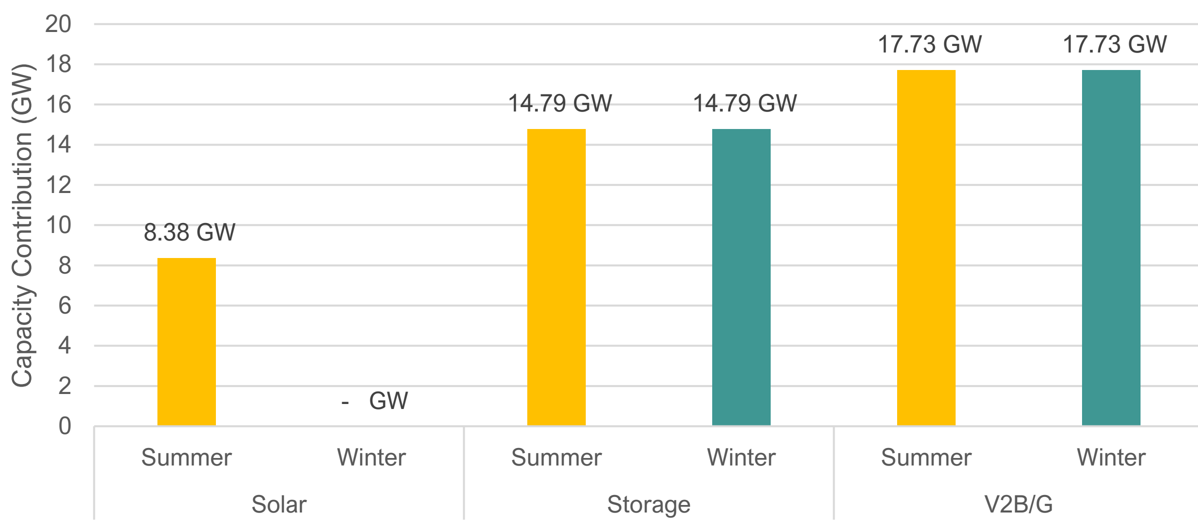


Collectively, the technical potential for BTM Resources can contribute to more than 40.9 GW of summer capacity in the BAU+ scenario. This potential is primarily from V2B/G, which makes up 17.7 GW of potential in both the summer and winter, which is triple that of the BAU scenario (5.7 GW). In the Accelerated scenario, V2B/G makes up 47.6 GW of potential capacity reductions.

Solar PV provides 8.4 GW of technical potential for summer peak capacity, and as expected, no capacity value is observed in the winter as solar production is not coincident with the winter peak events (which fall later in the day than summer peak events). The technical potential for summer peak reductions from BTM energy storage is 14.8 GW.

Additionally, the identified BTM technical potential represents 68 TWh in annual energy generation.

Figure 4-11: Seasonal Capacity Reduction for BTM Measures by Measure Type in 2032 (BAU+ Scenario)

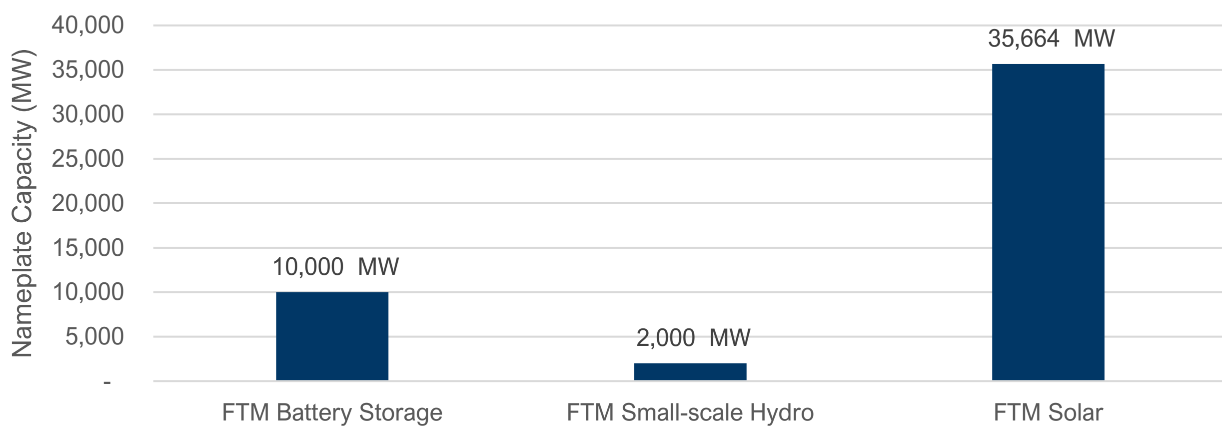


4.4 FTM Resources

For this study, the technical potential for FTM resources is sized according to the capacity required to fully displace the current capacity of natural gas fired generation in Ontario (10,000 MW), with consideration of physical constraints that could limit potential, which were assumed to primarily impact small-scale hydro. The capacity of gas fired generation is not assumed to change among the scenarios, therefore we highlight results for a single scenario in this section.

For FTM battery storage and solar PV, no physical constraints limit technical potential in Ontario and the resources are sized such that they could fully displace all currently installed natural gas fired generation capacity. The technical potential for battery storage is thus estimated to be 10 GW (nameplate capacity) and the potential for FTM Solar is estimated to be 36 GW (nameplate capacity), based on the IESO's estimated 28% summer peak coincidence factor for solar PV in Ontario. Conversely, small-scale hydro is limited by the availability of sites suitable for deployment, as identified in a previous study,[24] resulting in a technical potential for FTM small-scale hydro in Ontario of less than 2 GW.

Figure 4-12: Nameplate Capacity of FTM Measures by Measure Type in 2032

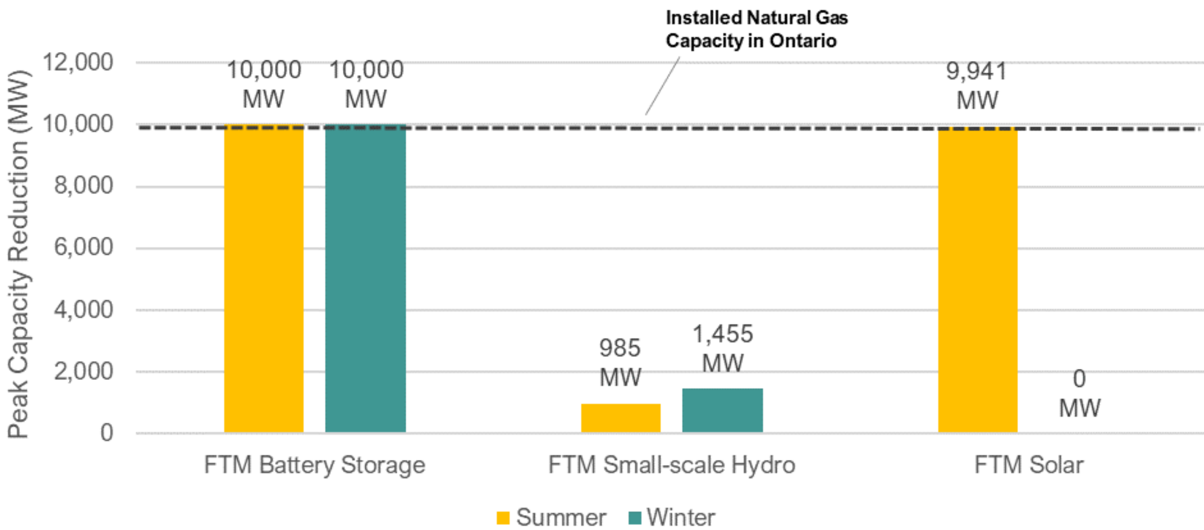


While the technical potential in terms of nameplate capacity is notably high, particularly in the case of solar PV potential, the actual capacities to address seasonal peaks are impacted by each resource's seasonal peak coincidence factors (CFs), as depicted in Figure 4-13 below. For FTM battery storage, the CF in all seasons is assessed to be 1.0, and thus the 10,000 MW of nameplate capacity can deliver 10,000 MW of seasonal peak capacity. For FTM solar PV, the summer CF is just 0.28, and thus the 36 GW of nameplate capacity delivers just 10,000 MW of summer peak capacity. In the winter, no peak reduction is expected from solar due to an absence of coincidence with the system peak window, however storage maintains full nameplate capacity in both seasons. Similarly, for FTM Small-scale Hydro, the 2,000 MW of nameplate capacity delivers 985 MW of summer peak capacity but increases to 1,455 MW in winter due to increased winter river flows.

Additionally, the identified hydro and solar capacities show considerable energy generation potentials, with 6.2 TWh and 65.6 TWh respectively.

[24] Hatch Acres. (2005). Ontario's Waterpower Potential. Available online.

Figure 4-13: Winter and Summer Capacity Reduction for FTM Measures by Measure Type in 2032



5. Economic Potential

The economic potential represents the portion of the DER technical potential that is cost-effective under a Total Resource Cost (TRC) test. This represents the maximum pool of DERs that can offer net benefits to Ontario's electricity system (i.e. the value of the benefits delivered exceeds the costs of the DER), but does not incorporate considerations affecting real-world market adoption.

The economic potential is assessed by calculating the value of all system benefits offered by each DER (capacity benefits, energy benefits, etc.), along with the costs for installing or enabling the DER. At the economic potential level, costs associated with participation or capital cost reduction incentives are not included in the TRC calculation, as is common practice in potential assessments. The economic potential for a given DER is determined by assessing the cost-effectiveness of each incremental addition of that DER to the system (i.e. additional MW of BTM solar), until the TRC value for the next incremental addition falls below the TRC threshold of 1.0. The approach used to derive the economic potential is described in detail in **Appendix D. Economic Potential Methodology.**

Since DERs impact the system load curve, thereby exerting interactive effects on the cost-effectiveness of other DERs (i.e. by changing the timing or magnitude of the annual system peak), two variations of the DER economic potential are calculated in this study:

- **Measure-Level Economic Potential** represents the cost-effective portion of the technical potential for a given measure when it is assessed in isolation. This does not consider the interactive effects among DERs and provides the theoretical maximum economic potential for a given measure, under the conditions of the applied scenario (BAU, BAU+, Accelerated).
- **Market-Wide Economic Potential** represents the combined economic potential of all cost-effective measures when they are applied to the system load curve. It accounts for interactive effects among the various measures, and the system load curve when measures are combined.

In assessing the economic potential for DERs, the analysis takes into consideration the projected system needs for the various services considered in the study described earlier in Section 2.4. Specifically, the economic potential assessment constrains each benefit stream to the projected system needs that DERs can feasibly contribute to, after which additional DERs added to the system would deliver little or no further benefit for that specific value stream. For example, for generation capacity needs, the study considers the capacity auction procurement targets for 2023-2024 and the IESO's forecasted capacity deficit 2025 onwards. DER contributions to capacity needs that fall within those projections would receive the full capacity benefits, however, incremental DER contributions that exceed the system capacity needs would no longer receive capacity benefits in the analysis. Similarly, an annual maximum market size / service need is established for other services (e.g. energy, transmission/distribution deferral, reduced SBG, OR, RC) as summarized earlier in Section 2.4 and described further in Volume II – Appendix C.

The potential results presented in this report largely focus on DER contribution to system capacity needs by 2032, with the magnitude of the system capacity needs being driven by the annual peak demand. The system capacity contribution for a given DER is defined as the average generation addition (i.e. solar PV), or demand reduction, that the DER can contribute over a four-hour summer peak demand event window. Additional metrics related to other DER value streams are included where relevant, and detailed results with additional metrics (e.g. nameplate capacity, winter peak demand reductions, energy generation (kWh) contributions, etc.) can be found in the appendices.

Consistent with the technical potential analysis, the results are broken down by three key resource types: DR, BTM Resources, and FTM Resources. Interpretation of the economic potential results should take into consideration the caveats outlined in the call-out box below.

ECONOMIC POTENTIAL CONSIDERATIONS

- The economic potential **does not account for customer adoption or market barriers.**
- The economic potential captures **the cost-effectiveness of the resources from a system perspective** rather than from a customer perspective. For example, while BTM solar may not yield a TRC greater than 1.0 based on system benefits under some scenarios, it may still be cost-effective from a customer perspective when the participant benefits available through programs (e.g. net-metering, ICI) are considered. Those customer considerations are factored into the assessment of the achievable potential.
- In the case of the BAU Scenario, the avoided capacity costs applied in the economic potential assessment reflect the assumed costs of procurement of a **new-build of Simple Cycle Gas Turbine (SCGT**). Where appropriate, market price forecasts are used as a proxy for the avoided costs of certain services (e.g. energy). **For the BAU+ and Accelerated scenario, renewables with storage was used for the avoided capacity cost.**
- The economic potential captures the **benefits from all services that DERs can reasonably contribute to** without applying existing market participation or compensation rule constraints.

5.1 Measure-Level Economic Potential

As illustrated in Figure 5-1, the measure-level economic potential provides insight into what portion of a measure's technical potential could feasibly be considered cost-effective when applied to the system. In reality, measures will compete to meet the same system needs, with more cost-effective measures prevailing. The results of the measure-level economic potential assessments represent the maximum economic potential for a given DER measure, if competition and interactive effects with other measures are not considered; as such, the measure-level economic potentials **should not be considered truly additive among measure groups.**

Figure 5-1: Illustration of the Measure-Level Economic Potential

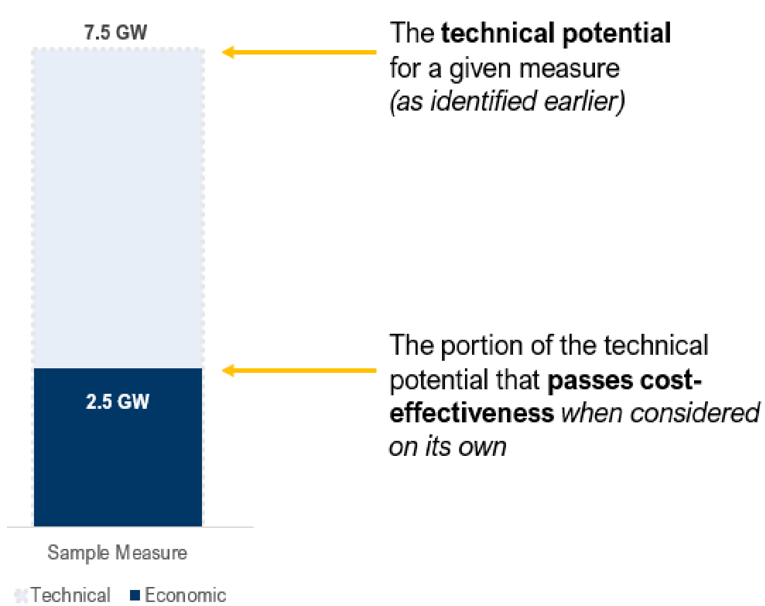


Figure 5-2 and Figure 5-3 below present the measure-level economic potentials for each DER measure type, expressed as seasonal capacity values, and compared with the associated technical potentials. This demonstrates the portion of the technical potential of each DER type that can feasibly provide benefits to the system in a cost-effective manner. Overall, the results indicate that while the technical potentials for BTM and FTM resources are relatively high compared to DR measures, from an economic potential perspective, a much higher proportion of the DR potential is cost-effective on a summer capacity basis. This trend is explored in more detail in the measure-level analysis for each DER measure type in the following sections.

Figure 5-2: Measure-Level Technical and Economic Potential for each DER Measure Type (Summer 2032)

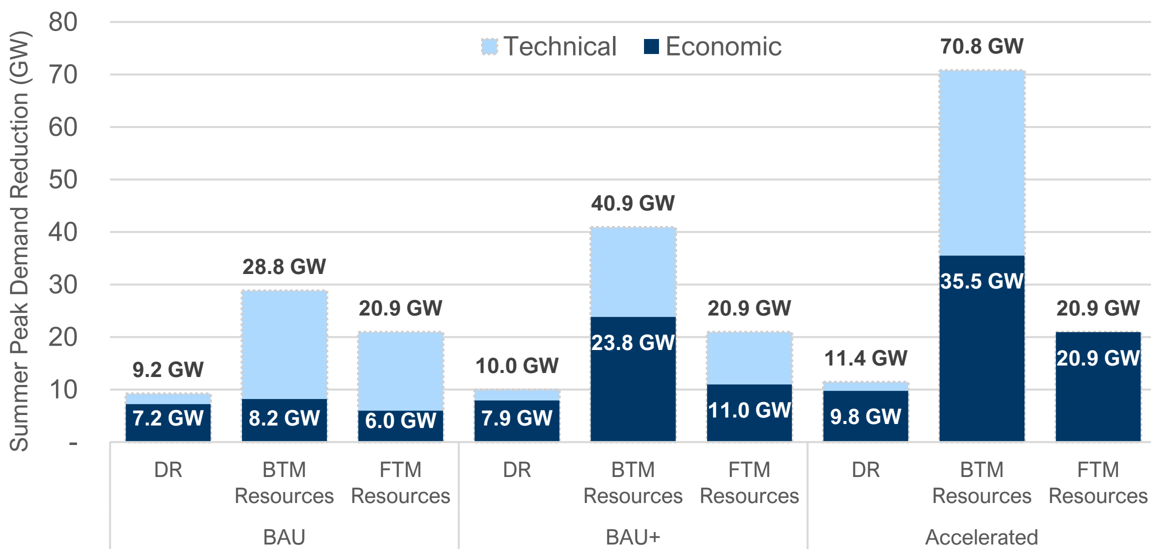
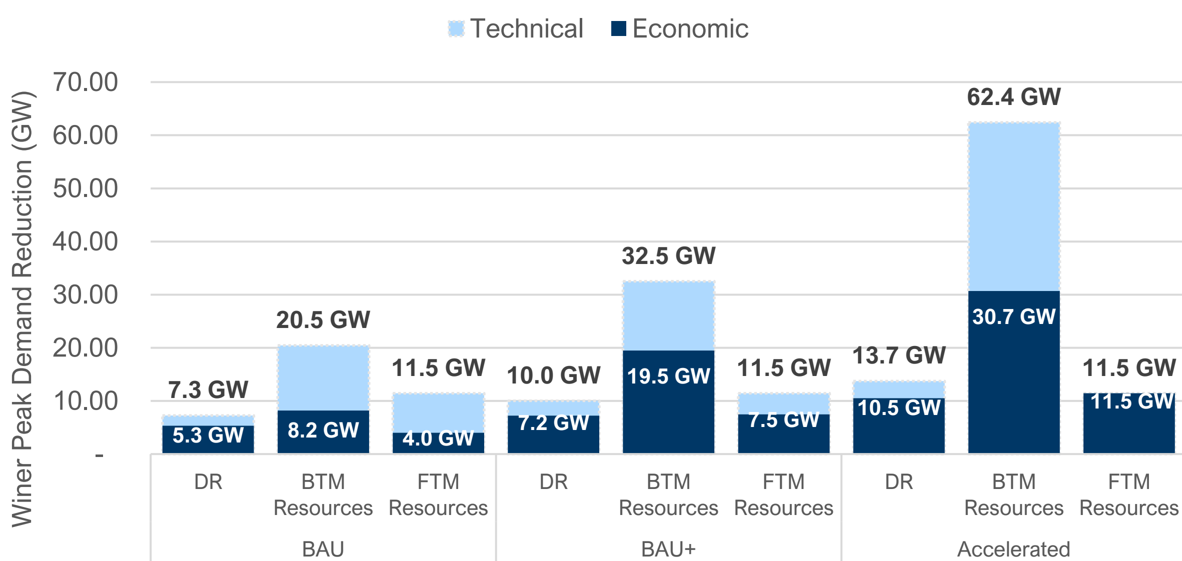


Figure 5-3: Measure-Level Technical and Economic Potential for each DER Measure Type (Winter 2032)



5.1.1 Demand Response

Overall, the majority of the technical potential for DR measures was found to be cost-effective. In the following sections, the specific DR measures in each sector are examined to indicate which opportunities offer the most economic potential, and which carry the highest benefits relative to their costs.

5.1.1.1 Residential DR

Figure 5-4 below provides the DR measure-level economic potential in the residential sector, which shows that nearly all residential DR measures provide some cost-effective potential, except for smart clothes dryers. Table 5-1 provides the TRC values for each measure alongside the economic potentials, which provides the following insights:

- The HVAC DR measures offer by far the largest cost-effective DR opportunity, predominantly driven by smart thermostats connected to AC units and heat pumps.[25] The economic potential represents a little over half the technical potential for this measure, but nonetheless its economic potential is still greater than all other residential DR measures combined under BAU and BAU+. Interestingly, the shifted peak hours under the BAU+ and Accelerated scenario load shape results in a lowered coincidence factor for residential space cooling equipment, thereby reducing the economic and technical potential for this measure, as compared to the BAU scenario.
- Behavioral DR is by far the most cost-effective measure but offers a relatively limited potential.
- Water heating controls offer notable economic potential under both scenarios. The potential under the BAU+ and Accelerated scenarios is higher than that under BAU, partially as a result of an expanded penetration of heat pump water heaters, but more importantly, due to the shifting of summer peak hours from late afternoon in BAU to early evening (when hot water use is typically higher) in the latter scenarios.
- Measures with smaller technical potential are less likely to exhaust the system benefit needs that they provide, and therefore all or almost all of the technical potential is cost-effective. However, when all these measures run together and compete under the achievable potential, it is likely that they will have a reduced ability to deliver the same level of system benefits on a measure-by-measure basis.
- EV charging is also among the most cost-effective DR measures, and nearly all of its technical potential can be counted within the economic potential. Moreover, under the BAU+ and Accelerated scenarios, the increased EV penetration leads to a notable increase in the economic and technical potential for this measure.
- For the remaining smaller opportunities associated with Pools and Spas, and Other Load Flexibility, nearly all of the technical potential was found to be cost-effective.

[25] Table 5-1 shows a notable drop in Residential AC DR potential across scenarios, which is due primarily to the shift from AC units to more efficient heat pumps, which thereby lowers the connected load for smart thermostat DR.

Figure 5-4: Measure-Level Potential for Residential DR Summer Capacity Reduction by Scenario and End-Use in 2032 (data labels indicate Economic Potentials)

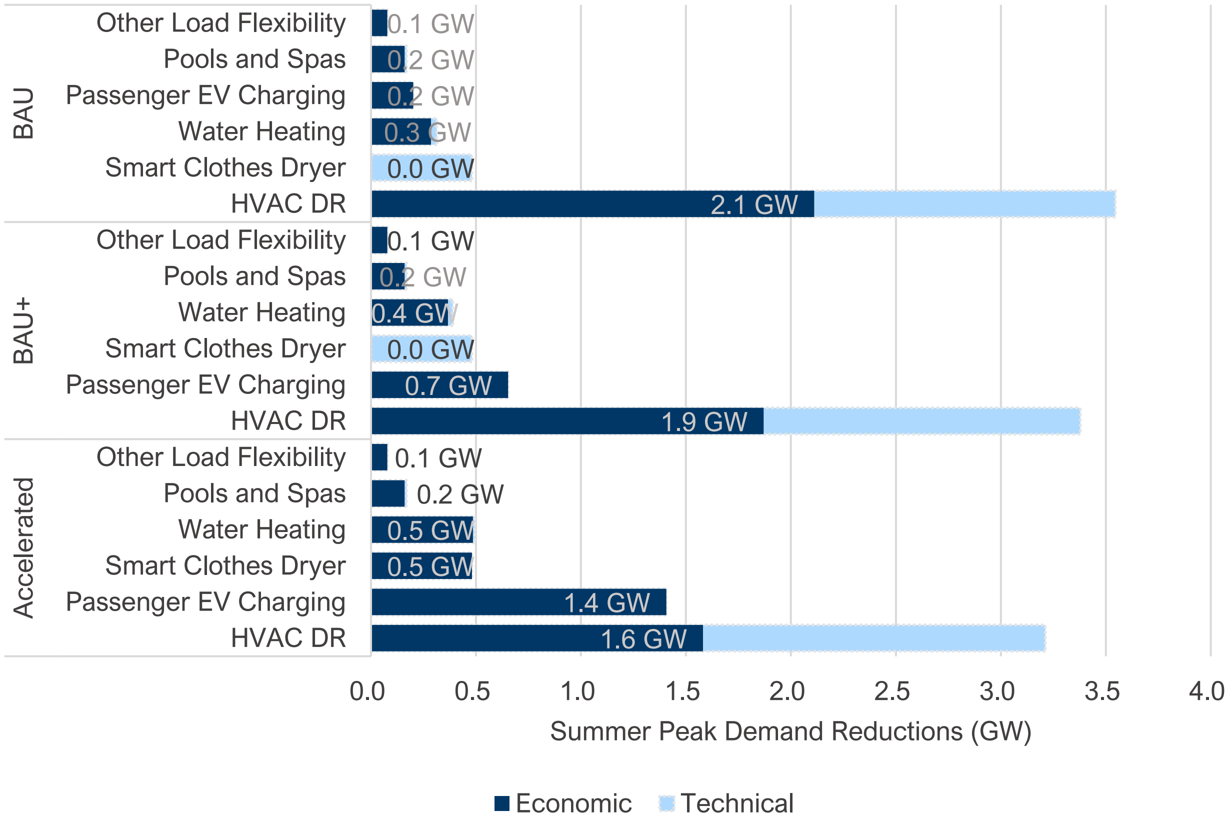


Table 5-1: Measure-Level TRC and Economic Potential for Residential DR Measures (No Competition / Interactive Effects)[26] - 2032

	Average Total Resource Cost (TRC) Ratio[27]			Economic Potential for Summer Peak Reductions (MW)			Economic Potential for Winter Peak Reductions (MW)		
Measure Name	**BAU**	**BAU+**	**Accel-erated**	**BAU**	**BAU+**	**Accel-erated**	**BAU**	**BAU+**	**Accel-erated**
Other Behavioral-based Residential Flexibility	15.1	17.0	17.3	78	78	78	84	84	84
ASHP/DMSHP Smart Thermostat	4.6	5.1	5.2	88	490	853	127	972	1,943
Smart Electric Resistance Water Heaters	3.7	4.1	4.5	33	57	72	50	87	110
Smart EV Chargers	2.9	3.5	12.0	201	653	1,406	264	858	1847

[26] Note: The Measure Level table values will inherently add up to larger totals than the corresponding values in the figures in this section because the values in the figures account for measure-level interactions and competition.
[27] The TRC values in the table reflect the average TRC for all measures that showed some economic potential (i.e. TRC greater than 1.0). Some measures have average TRC values less than 1.0, but do offer some economic potential. Segment-level details are available in Appendix G.

	Average Total Resource Cost (TRC) Ratio[27]			Economic Potential for Summer Peak Reductions (MW)			Economic Potential for Winter Peak Reductions (MW)		
Measure Name	**BAU**	**BAU+**	**Accel-erated**	**BAU**	**BAU+**	**Accel-erated**	**BAU**	**BAU+**	**Accel-erated**
Electric Resistance Water Heaters Smart Switch	2.5	2.8	3.1	249	294	371	382	450	569
Passenger EV Telematics	2.4	2.7	7.4	68	327	786	88	429	1032
Residential AC Thermostat	2.1	2.4	2.6	2,024	1,381	728	0	0	0
Electric Baseboards Smart Thermostat	2.1	2.4	2.8	0	0	0	585	585	585
Electric Furnace Smart Thermostat	2.0	2.2	2.6	0	0	0	194	194	194
Res. Pool Pumps	1.5	1.6	1.7	160	160	160	153	153	153
Smart Heat Pump Water Heaters	1.3	1.5	1.6	4	6	8	6	10	13
Dual-Fuel Space Heating Smart Thermostat/Switch	1.3	1.5	2.0	0	0	0	155	155	157
Heat Pump Water Heaters Smart Switch	0.9	1.0	1.1	0	9	34	0	15	52
Smart Clothes Dryer	0.8	0.9	2.1	0	0	481	0	0	523
Thermal Storage for Cooling	0.3	0.4	0.7	0	0	0	0	0	0
Thermal Storage and Heat Pump	0.2	0.3	0.7	0	0	0	0	0	0
Thermal Storage for Heating	0.1	0.2	0.5	0	0	0	0	0	0

5.1.1.2 Commercial DR

Figure 5-5 and Table 5-2 provide the measure-level economic and technical potential results for the commercial sector. Overall, a diverse mix of cost-effective commercial DR opportunities are identified, with almost all measures passing the cost-effectiveness screen:

- HVAC DR offers by far the largest technical potential, and the vast majority of that is cost-effective due to the high coincidence of commercial HVAC loads with the system summer peak.
- Back-up generators present another highly cost-effective measure; however, the potential is extremely limited, and even though the cost of carbon is factored into this analysis, the associated GHG emissions from these generators may make them an unattractive DR solution.
- All of the identified commercial segment-specific curtailment and load flexibility opportunities were found to be highly cost-effective and offer notable economic potential.
- Lighting controls offer an extremely cost-effective option, but their overall potential is limited.

- Relative to BAU results, the more extensive electrification of transportation in BAU+ and Accelerated scenarios causes a doubling and quadrupling, respectively, of the potential from EV charging load management opportunities.

Figure 5-5: Measure-Level Potential for Commercial DR Summer Capacity Reduction by Scenario and End-Use in 2032 (data labels indicate Economic Potentials)

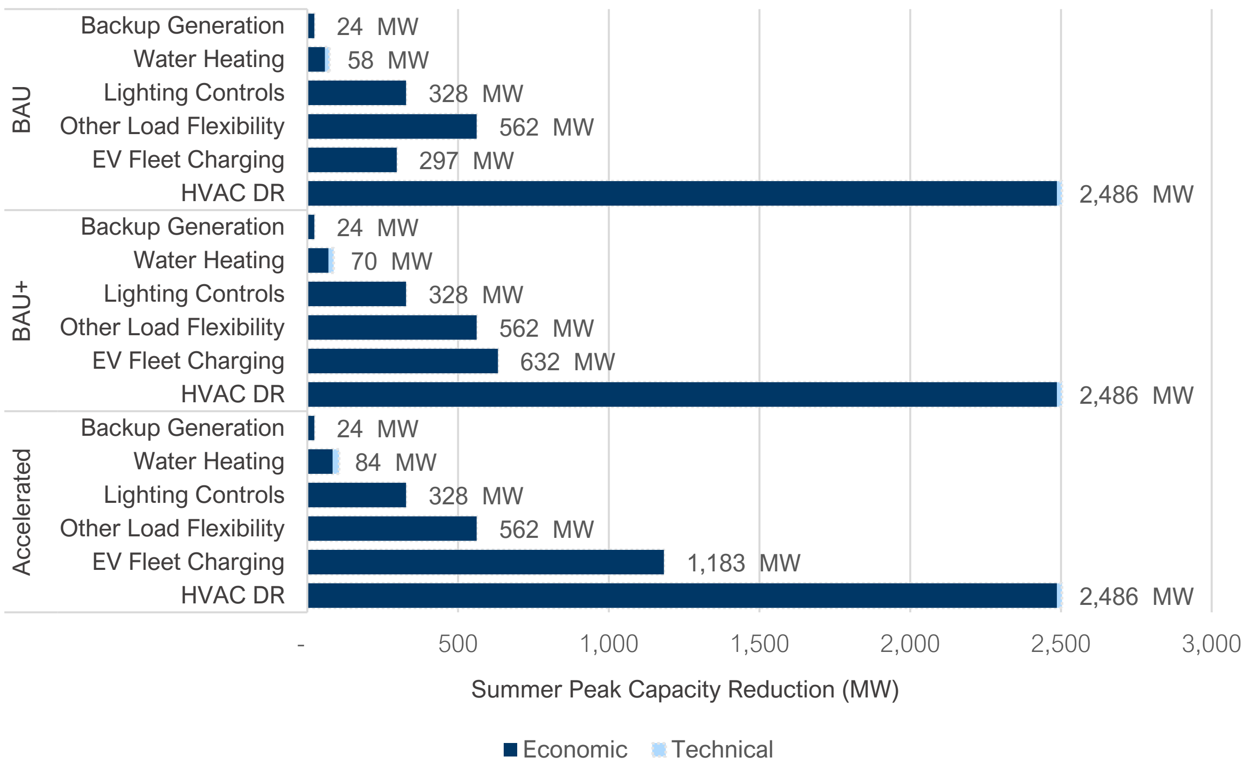


Table 5-2: Measure-Level TRC and Economic Potential for Commercial DR Measures (No Competition / Interactive Effects)[28] - 2032

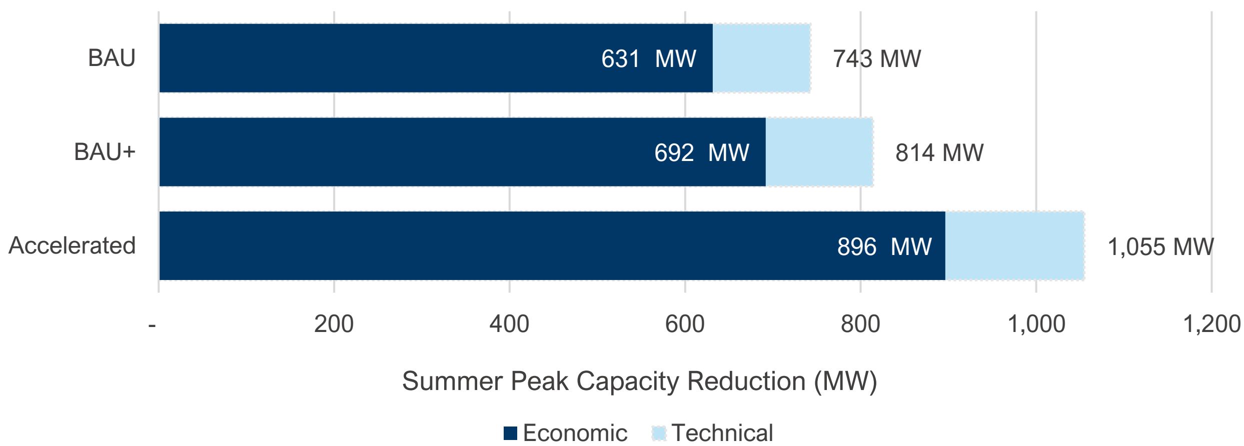
	Average Total Resource Costs (TRC) Ratio[29]			Economic Potential for Summer Peak Reductions (MW)			Economic Potential for Winter Peak Reductions (MW)		
Measure Name	**BAU**	**BAU+**	**Accel-erated**	**BAU**	**BAU+**	**Accel-erated**	**BAU**	**BAU+**	**Accel-erated**
Lighting Controls	22.0	24.9	25.3	328	328	328	579	579	579
Other Commercial Flexibility	20.3	22.9	23.3	345	345	345	401	401	401
District Cooling/Heating Flexibility	19.7	22.2	22.6	99	99	99	65	65	65
MDV Fleet EV Smart Chargers	18.7	22.1	71.2	50	150	209	41	124	173
Back-up Generation	16.6	29.0	86.9	24	24	24	24	24	24
Large Commercial HVAC Control	11.9	13.4	14.7	1,342	1,342	1,342	507	507	507
Large Commercial Hot Water	6.9	7.8	8.4	45	55	68	81	100	124
LDV Fleet EV Telematics	4.9	5.7	19.3	15	74	178	9	42	101
LDV Fleet EV Smart Chargers	4.8	5.7	17.8	46	148	318	26	84	181
HDV Fleet EV Smart Chargers	3.4	4.1	13.2	41	171	459	32	134	361
Large Commercial Dual-Fuel Water Heating	2.8	3.2	3.4	11	11	11	17	19	19
Buses: EV Smart Charging	2.3	2.8	8.8	160	164	196	143	143	164
Commercial HVAC Thermal Storage	1.6	1.8	2.7	2,234	2,234	2,234	995	995	995
Small Commercial Hot Water	1.1	1.3	1.4	3	3	4	4	5	6
Irrigation Pump Controls	0.8	0.9	0.9	37	37	37	0	0	0
Small Commercial Smart Thermostat	0.5	0.6	0.6	153	153	153	0	0	0
Greenhouses: Lights	0.4	0.5	0.5	2	2	2	14	14	14
Small Commercial ASHP/DMSHP Smart Thermostat	0.4	0.4	0.5	0	0	0	1	8	9
Thermal Storage for Refrigeration	0.3	0.3	0.6	178	178	178	155	155	155
Refrigeration Controls	0.1	0.1	0.1	9	9	9	8	8	8

[28] Note: The Measure Level table values will inherently add up to larger totals than the corresponding values in the figures in this section because the values in the figures account for measure-level interactions and competition.
[29] The TRC values in the table reflect the average TRC for all measures that showed some economic potential (i.e. TRC greater than 1.0). Some measures have average TRC values less than 1.0, but do offer some economic potential. Segment-level details are available in Appendix G.

5.1.1.3 Industrial DR

Figure 5-6 and Table 5-3 present the economic potential results for the Industrial DR measure. Industrial DR is highly cost-effective, and as a result, nearly all (85%+) of the identified technical potential was found to be economic. That said, the available volume of industrial DR is limited by the aforementioned flat load patterns observed for industrial customers.

Figure 5-6: Measure-Level Economic Potential for Industrial DR by Scenario in 2032



Overall, the study found that industrial curtailment may offer a significant amount of highly cost-effective capacity benefits. However, due to the bespoke nature of industrial operations, further study and analysis would be required to confirm these findings and identify specific industrial sub-sectors and facilities best suited to load flexibility.[30]

Table 5-3: Measure-Level TRC and Economic Potential for Industrial DR (No Competition / Interactive Effects)[31] - 2032

	Total Resource Costs (TRC) Ratio			Economic Potential for Summer Peak Reductions (MW)			Economic Potential for Winter Peak Reductions (MW)		
Measure Name	**BAU**	**BAU+**	**Accel-erated**	**BAU**	**BAU+**	**Accel-erated**	**BAU**	**BAU+**	**Accel-erated**
Industrial Flexibility	24	27	27	631	692	896	475	520	676

5.1.2 BTM Resources

Figure 5-7 and Table 5-4 present the measure-level economic potential results for BTM resources across all sectors. Overall, the magnitude of BTM technical opportunities far outstrips the DR potentials in the

[30] This study's industrial analysis was conducted at high-level relative to the residential and commercial sector analyses, owing to a lack of market, equipment penetration, and end-use data for Ontario industrial electricity customers.
[31] Note: The Measure Level table values will inherently add up to larger totals than the corresponding values in the figures in this section because the values in the figures account for measure-level interactions and competition.

previous section, however only a portion of the BTM technical opportunities are cost-effective under the TRC test:

- BTM storage offers significant cost-effective potential, particularly for non-residential applications. Non-residential battery storage TRC value increases under the BAU+ and Accelerated scenarios as avoided capacity costs increases, driven primarily by the increased peak loads associated with higher electrification of vehicles and buildings. Residential battery storage only passes the TRC screen under the BAU+ (marginally) and Accelerated scenarios, causing almost all technical potential to be economic under BAU+, and all technical potential to be cost-effective under the Accelerated scenario conditions.
- Under the BAU scenario, BTM Solar was not cost-effective due to the low system peak coincidence coupled with low energy prices, however higher carbon prices and system loads applied in the BAU+ and Accelerated scenarios render nearly half of the BTM Solar technical potential to be cost-effective, and lead to notably higher TRC values for commercial and industrial BTM Solar opportunities specifically.
- Under the Accelerated scenario, Solar PV and BTM Storage measures generate sufficient energy benefits such that they can continue to be cost-effective, even when the system capacity needs have been fully met (i.e. they can be cost-effective based entirely on their energy benefits).
- Despite the high technical potential, only approximately a third of the V2B/G potential passes the TRC screen under all scenarios. In particular, buses and HDV V2B/G measures did not prove cost-effective, since they have a low coincidence with system peak (i.e. a significant portion of these vehicles are on the road when peak load events occur), while passenger vehicles and commercial LDVs offer the vast majority of V2B/G economic potential.

Figure 5-7: Measure-Level Economic Potential for BTM Resources by Scenario and Measure Type in 2032 (data labels indicate Economic Potentials)

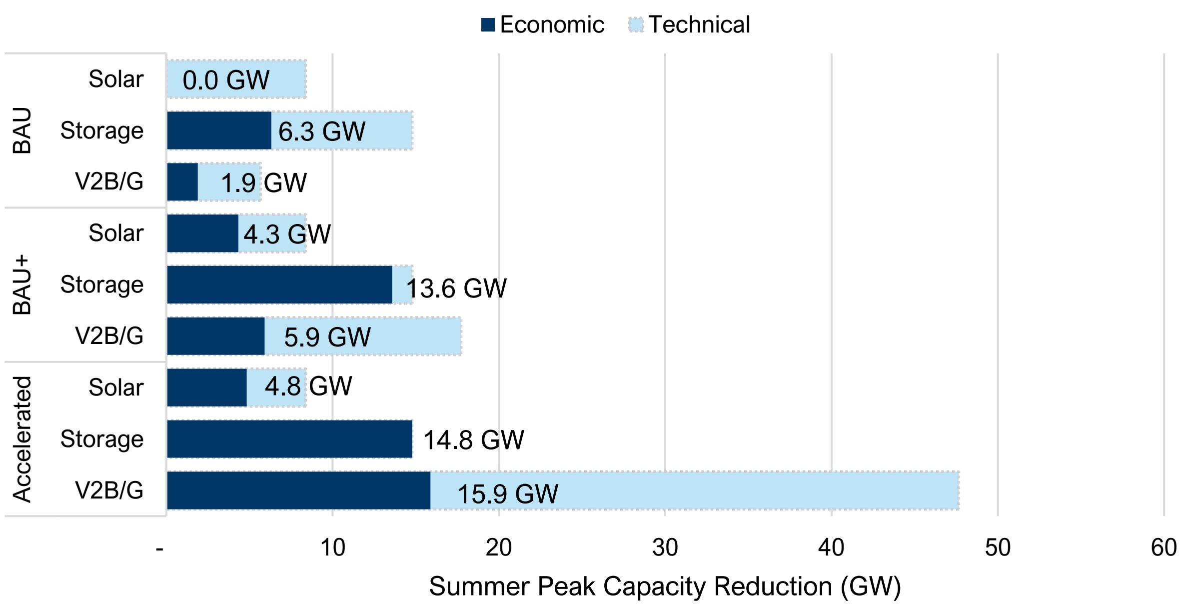


Table 5-4: Measure-Level TRC and Economic Potential for BTM resources (No Competition / Interactive Effects)[32] - 2032

	Total Resource Costs (TRC) Ratio[33]			Economic Potential for Summer Peak Reductions (MW)			Economic Potential for Winter Peak Reductions (MW)		
Measure Name	**BAU**	**BAU+**	**Accel-erated**	**BAU**	**BAU+**	**Accel-erated**	**BAU**	**BAU+**	**Accel-erated**
BTM Battery Storage Residential	0.7	1.0	4.5	0	4,025	5,229	0	4,025	5,229
BTM Battery Storage Non-Residential	1.3	1.8	7.5	5,501	8,747	8,747	5,501	8,747	8,747
Industrial Storage	1.5	2.2	9.0	813	813	813	813	813	813
Residential BTM Solar	0.4	1.2	6.8	0	1,189	1,696	0	0	0
Commercial BTM Solar	0.6	1.7	8.6	0	1,673	1,673	0	0	0
Industrial BTM Solar	0.7	1.9	9.6	0	1,467	1,467	0	0	0
Vehicle-to-Building/Grid (V2B/G)	1.5	1.8	5.6	1,204	3,910	11,067	1,204	3,910	11,067
LDV Fleet Vehicle-to-Building/Grid (V2B/G)	1.5	1.8	5.6	401	1,303	3,689	401	929	3,689
MDV Fleet Vehicle-to-Building/Grid (V2B/G)	1.8	2.2	6.7	79	236	329	79	168	329
HDV Fleet Vehicle-to-Building/Grid (V2B/G)	0.6	0.7	2.1	39	163	439	39	116	439
Buses: Vehicle-to-Building/Grid (V2B/G)	0.6	0.7	2.2	167	299	358	167	299	358

5.1.3 FTM Resources

Figure 5-8 and Table 5-5 highlight the identified economic potential for FTM resources explored in the study. 2 GW of the technical potential for FTM solar was found to be cost-effective under the BAU Scenario. Under BAU+, increased energy prices coupled with DER capital cost reductions results in a total of 4 GW of system capacity contributions. Similarly, 4 GW and 6 GW of cost-effective FTM storage potential was identified under the BAU and BAU+ scenarios respectively. Conversely, new small-scale hydro deployments were not found to be cost-effective under the BAU due to the high associated capital costs, but do become cost-effective under the BAU+ and Accelerated scenario by 2032 due to the higher electricity prices associated with these scenarios.

Generally, FTM solar and battery storage were found to be more cost-effective than the BTM versions due to the economies of scale that reduce installed costs, as well as the higher peak capacity contributions and energy production capabilities associated with larger more optimized FTM solar projects. Despite being more

[32] Note: The Measure Level table values will inherently add up to larger totals than the corresponding values in the figures in this section because the values in the figures account for measure-level interactions and competition.
[33] The TRC values in the table reflect the average TRC for all measures that showed some economic potential (i.e. TRC greater than 1.0). Some measures have average TRC values less than 1.0, but do offer some economic potential. Segment-level details are available in Appendix G – Detailed Results.

cost-effective, FTM solar and storage economic potentials are lower than the BTM versions; this was due to the artificial constraints placed on the FTM resources at the outset of this study (i.e., the technical potential ceiling was set at the current gas turbine generating capacity of 10 GW). The market-level economic potential results in the next section provide further details on the competition between BTM and FTM resources.

Figure 5-8: Measure-Level Potential for Front-of-the-Meter Resources Summer Capacity Reduction by Scenario and Measure Type in 2032 (data labels indicate Economic Potentials)

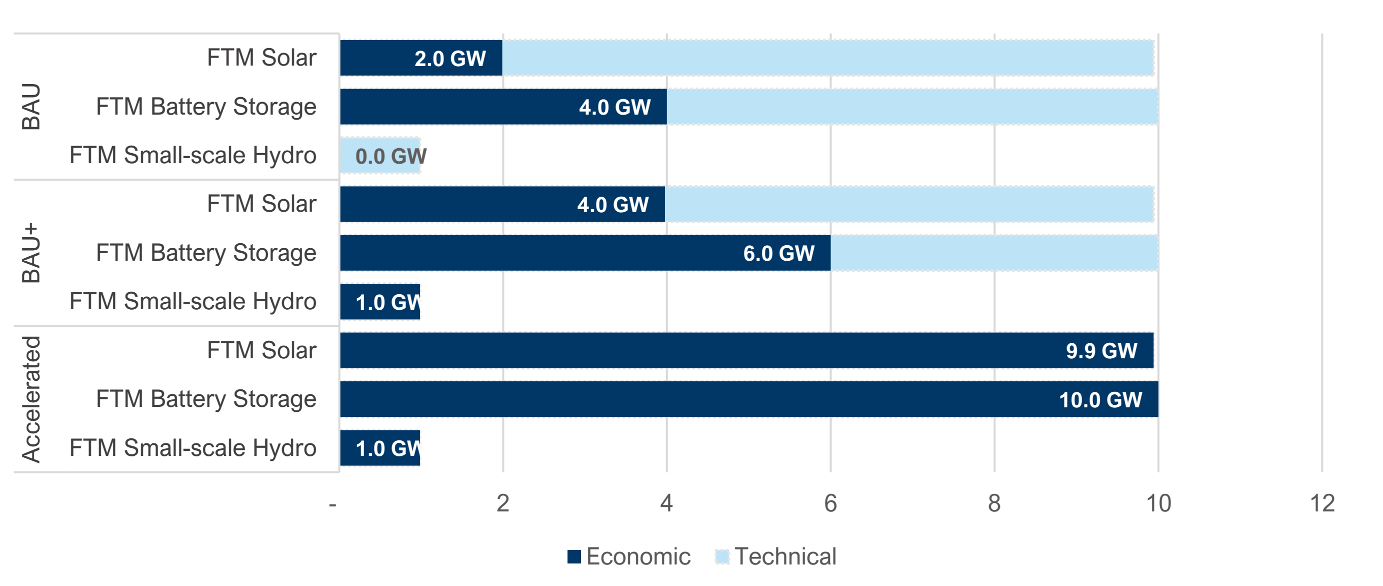


Table 5-5: Measure-Level TRC and Economic Potential for FTM Resources (No Competition / Interactive Effects)[34] - 2032

	Total Resource Costs (TRC) Ratio			Economic Potential for Summer Peak Reductions (MW)			Economic Potential for Winter Peak Reductions (MW)		
Measure Name	**BAU**	**BAU+**	**Accel-erated**	**BAU**	**BAU+**	**Accel-erated**	**BAU**	**BAU+**	**Accel-erated**
FTM Battery Storage	4.0	7.9	39.3	4,000	6,000	10,000	3,000	4,500	7,500
FTM Solar	1.8	2.9	10.1	1,988	3,977	9,941	0	0	0
FTM Small-scale Hydro	0.8	1.3	4.1	0	985	985	0	1445	1445

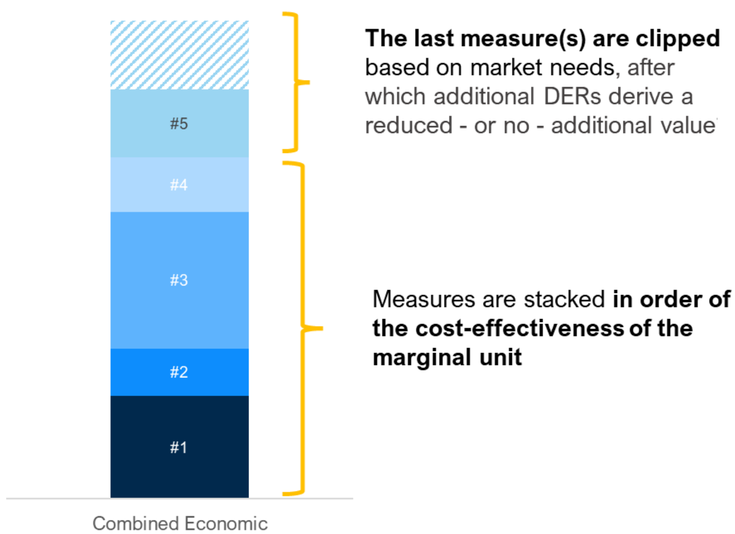
[34] Note: The Measure Level table values will inherently add up to larger totals than the corresponding values in the figures in this section because the values in the figures account for measure-level interactions and competition.

5.2 Market-Wide Economic Potential

The market-wide economic potential reflects the combined economic potential of all cost-effective measures when they are simultaneously applied towards meeting the assessed system needs. It provides a more precise estimate of the overall economic potential from the combined pool of cost-effective DERs, stated in terms of the cost-effective amount of capacity and energy benefits that DERs can feasibly offer to the Ontario electricity system.

The market-wide economic potential accounts for the impact each DER exerts on the system load curve, interactive effects among the various measures, and competition among measures to meet system needs. As with the measure-level economic potential analysis, **this assessment explores the portion of the DER technical potential that could be cost-effective, and does not account for market barriers and dynamics (e.g. customer adoption, market participation rules)**. To arrive at the Market-wide economic potential for DERs, the pool of cost-effective DERs identified in Measure-Level Economic Potential are applied to the system, starting with the most cost-effective individual DER measures. This approach is illustrated in Figure 5-9 below.

Figure 5-9: Illustration of the Market-Wide Economic Potential



5.2.1 Total Potential

Figure 5-10 highlights the total market-wide economic potential for DERs identified under each scenario. The results indicate that the total economic potential for DERs exceeds Ontario's summer capacity deficits over the next decade.[35] Specifically,

- Under the BAU scenario, DERs can cost-effectively contribute to 4.1 GW of summer capacity reductions by 2032 (representing 15% of the overall summer peak demand) relative to Ontario's forecasted deficit of 3.4 GW;

[35] While this potential analysis captured the opportunities for DERs on an hourly, daily, and seasonal basis, it does not replace the need for detailed dispatch and end-use load modeling and planning to determine the role DERs can play in a holistic and integrated long-term resource plan.

- Under BAU+, DERs can cost-effectively contribute to 8.2 GW of summer capacity (equivalent to 27% of system peak) relative to the forecasted system need of 4.6 GW; and
- Under Accelerated, DERs can cost-effectively contribute to 18.9 GW of summer capacity (equivalent to 61% of system peak) relative to the forecasted system need of 9.3 GW.[36]

The analysis also highlights that DERs can cost-effectively meet a large portion of Ontario's emerging winter peak needs.

- Under the BAU scenario, DERs can cost-effectively contribute to 2.8 GW of winter capacity reductions by 2032 (representing 11% of the forecasted winter peak) relative to Ontario's forecasted system need of 1.3 GW;
- Under BAU+, DERs can cost-effectively contribute to 6.8 GW of winter capacity (equivalent to 22% of the forecasted winter peak) relative to the forecasted system need of 6.2 GW; and
- Under Accelerated, DERs can cost-effectively contribute to 15.0 GW of winter capacity (equivalent to 39% of the forecasted winter peak) relative to the forecasted system need of 14.6 GW .

Figure 5-10: Market-Wide Economic Potential for Capacity Contributions from DERs 2032 (GW)

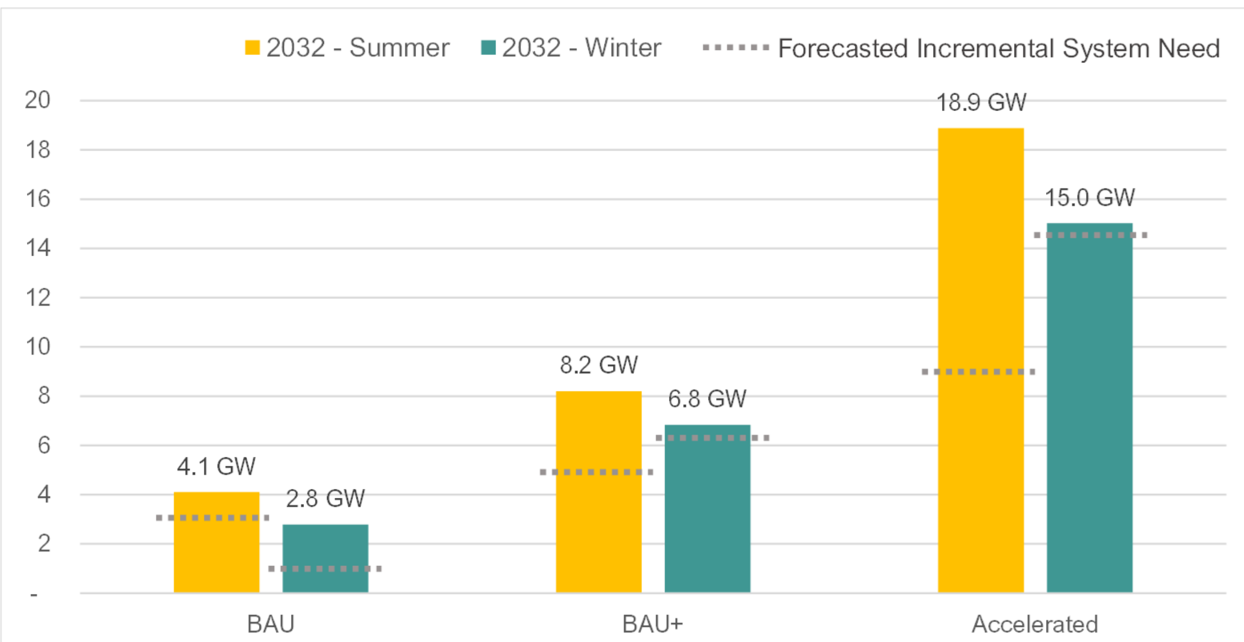


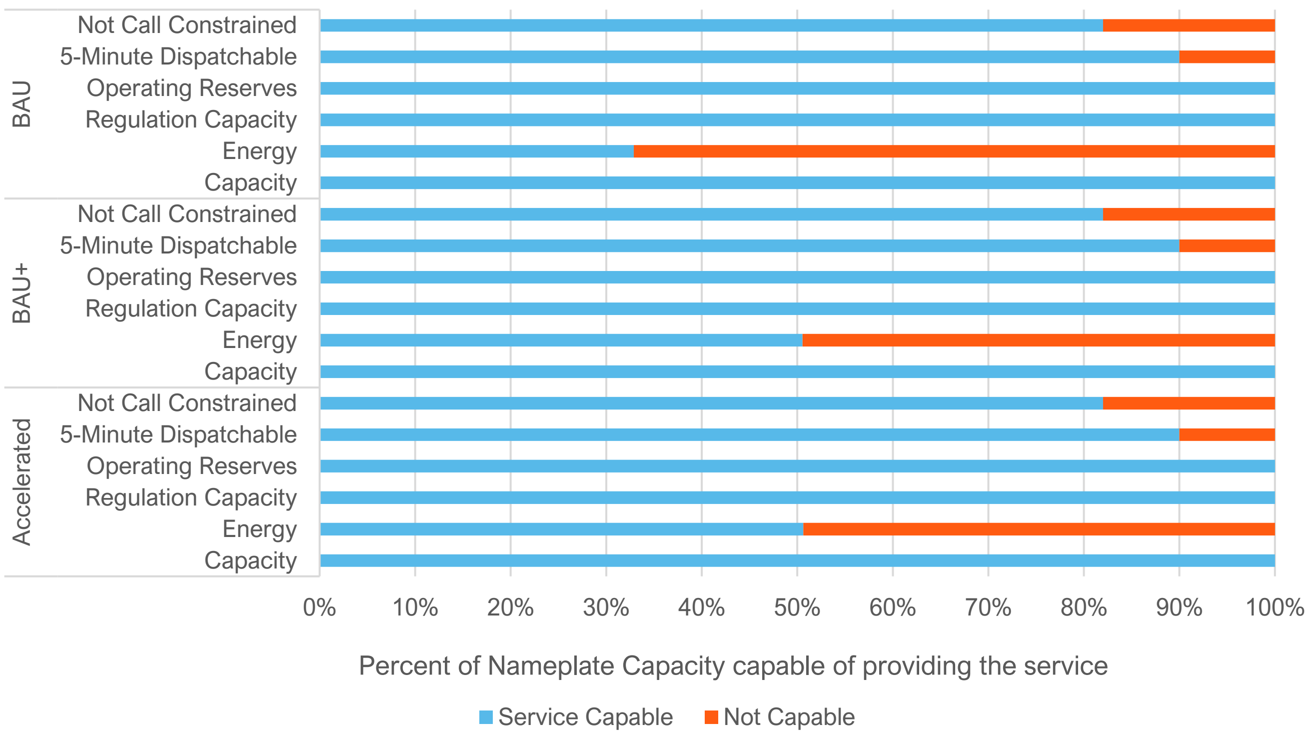
Figure 5-11 below presents the breakdown of the services offered by the DER measure mix in the market-wide economic potential. The majority (about 90%) of measures that prove cost-effective can provide 5-minute dispatchable services,[37] OR, RC and Capacity contributions under all scenarios. While only a small fraction

[36] In some scenarios, DER capacity contributions may exceed the defined system capacity needs due to measures providing further capacity as a by-product of addressing another system need (e.g. energy or T&D). In such cases, the DER capacity contributions are captured in the results, however the DER receives reduced - or no - value from the provision of those capacity contributions that exceed the system capacity needs.

[37] The value of these services was accounted for in the economic potential analysis. However, the value of five-minute dispatchability was omitted as it was determined that intra-hour price volatility was less that $5 per MWh for 60% of hours, and less than $10 per MWh for 90% of hours each year.

provides energy services under the BAU scenario, as the value of energy increases under the BAU+ and Accelerated scenarios, the portion of cost-effective DERs that provide energy services (BTM and FTM solar) also increases.

Figure 5-11: Portion of Economic Potential Nameplate Capacity Capable of Providing Various Grid Services



5.2.2 Expected Resource Contribution

In addition to confirming that DERs can cost-effectively meet Ontario's system needs, the market-wide economic potential provides insight into what may be the most cost-effective portfolio of DERs. As shown in Figure 5-12, under all scenarios, a mix of low-cost DR opportunities coupled with FTM resources were identified as the most economic mix of DERs to meet capacity needs. Specifically, for summer capacity reductions under BAU, 3.3 GW of DR capacity reductions and 0.6 GW of FTM capacity reductions can combine to meet the forecasted system needs. Under the BAU+, an additional 4.7 GW of capacity reductions from FTM resources, and 3.5 GW from DR resources were found to be the most cost-effective additions to meet the higher summer system need observed in the BAU+ scenario.

Under the Accelerated Scenario, a significant portion of economic FTM resources is unlocked to meet growing system needs assumed under that Scenario. This contributes to the DR drop in summer, as their cost-effectiveness is surpassed by FTM resources. Additionally, 1.8 GW of summer contributions and 0.9 GW of winter contributions from BTM resources are pulled in to meet emerging winter capacity needs.

Figure 5-12: Market-Wide Economic Potential By Scenario and Resource Type in 2032 (GW)

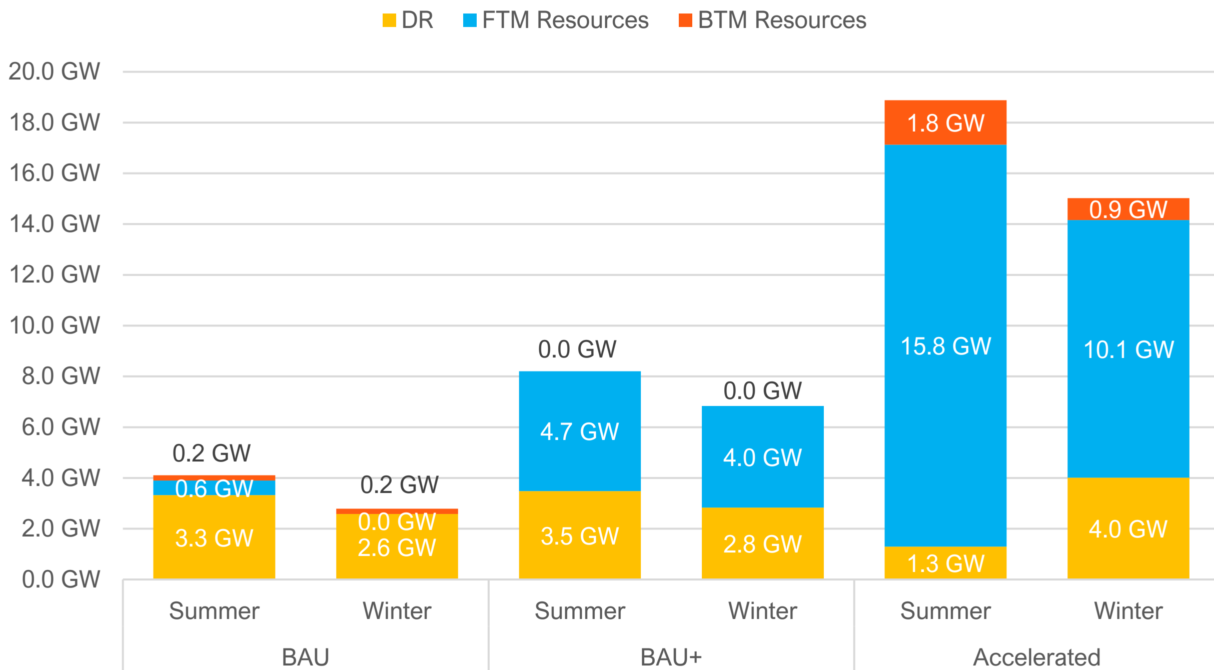


Table 5-6: Economic Capacity Reductions by Scenario and Year

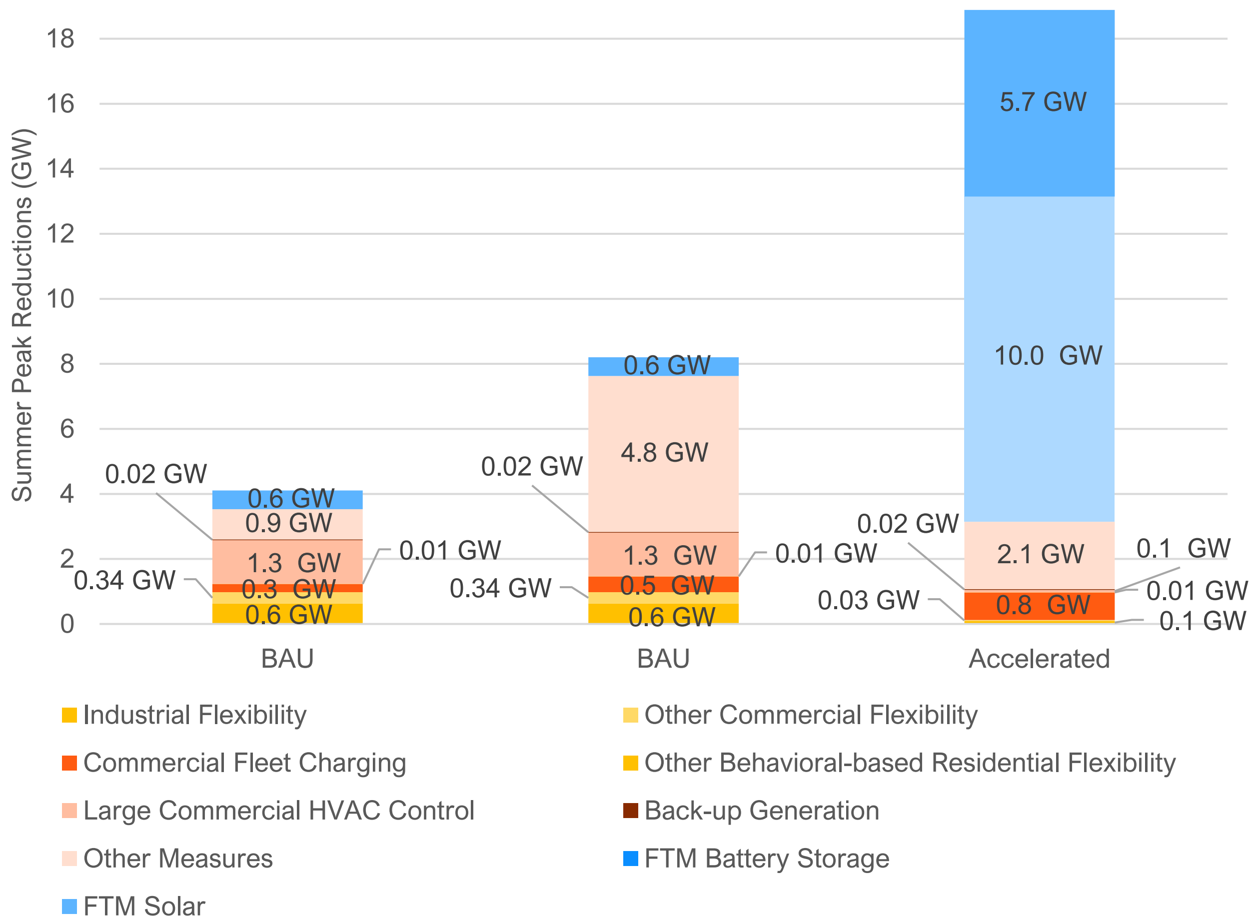
	Summer Capacity Reductions (MW)			Winter Capacity Reductions (MW)		
	2023	2027	2032	2023	2027	2032
BAU						
DR	1,208	2,741	3,327	601	1,834	2,582
FTM Resources	0	0	574	0	0	0
BTM Resources	0	0	206	0	0	206
BAU+						
DR	1,208	3,145	3,482	506	1,837	2,834
FTM Resources	0	2,148	4,722	0	1,000	4,000
BTM Resources	0	0	0	0	0	0
Accelerated						
DR	1,211	3,249	1,292	604	2,041	4,013
FTM Resources	0	6,296	15,838	0	1,000	10,145
BTM Resources	0	0	1,753	0	0	867

The market-wide economic potential stack omits a number of other cost-effective measures that were identified in the measure-level economic potential (e.g. BTM resources). This is a result of the economic analysis prioritizing the most cost-effective measures, giving them first access to meeting the system needs, and does not necessarily mean that the omitted measures would not prove cost-effective when run along side other DERs. For example, while BTM Solar did prove cost-effective under the measure-level analysis for the BAU+ and Accelerated scenarios, because the FTM Solar measure can provide the same services in a more cost-effective manner, the FTM Solar measure is counted in the market-wide economic potential, while its BTM counterpart is not.[38] The same issue extends to FTM battery storage measures relative to BTM storage. Under the achievable potential assessment in the following chapter, a dynamic market competition approach is applied to demonstrate the "real-world" conditions that balances system cost-effectiveness with required customer/investor returns, and market barriers, thereby resulting in a broader mix of achievable DER measures.

The resulting mix of DERs in the market-wide economic potential is presented in Figure 5-13. It shows that the market-wide economic potential primarily captures a subset of high value measures. Under the BAU scenario, this is primarily the low-cost peak reducing DR and load flexibility measures. Under the BAU+ and Accelerated scenarios, more FTM Solar and Storage join the mix, as the cost of energy and capacity needs increase. In fact, under the Accelerated scenario, the cost-effectiveness of FTM resources eclipses that of the Industrial and Commercial Load Flexibility measures, largely displacing them from the potential.

[38] The costs for FTM Resources assumed in the study include typical interconnections costs associated with deployments, however some projects in specific geographies may entail higher requirements that could be cost prohibitive and reduce the cost-effectiveness of these deployments. Moreover, while FTM resources benefit from the economies of scale, it is important to note that BTM resources contribute to additional benefits (e.g. resiliency) not considered in the study.

Figure 5-13: Market-Wide Economic Potential by Scenario and DER Measure 2032 (GW)



5.2.3 Cost-Effectiveness

Table 5-7 below provides the market-wide TRC values under each scenario based on the assumed lifetime benefits and costs associated with DERs in the market-wide economic potential. As with the measure-level results, the DR measure TRCs are notably higher than the FTM resource TRCs under the BAU and BAU+ scenarios. However, under the Accelerated scenario, the increase in energy prices relative to capacity prices causes FTM resources to become highly cost-effective, and thereby FTM resources capture almost all the economic potential in this scenario, and the capacity benefits available for DR measures are reduced.

A comparison of the TRC values in Table 5-7 to the results presented in Table 5-1 to Table 5-5 reveals that the market-wide economic potential TRCs are in aggregate lower than TRC values obtained from the measure-level analysis. This is due to the impact of the changes in peak timing and magnitude as each measure is applied (from the most cost-effective to the least), thereby reducing the coincidence factors and available capacity benefits for each subsequent measure applied in the market-wide economic potential analysis.

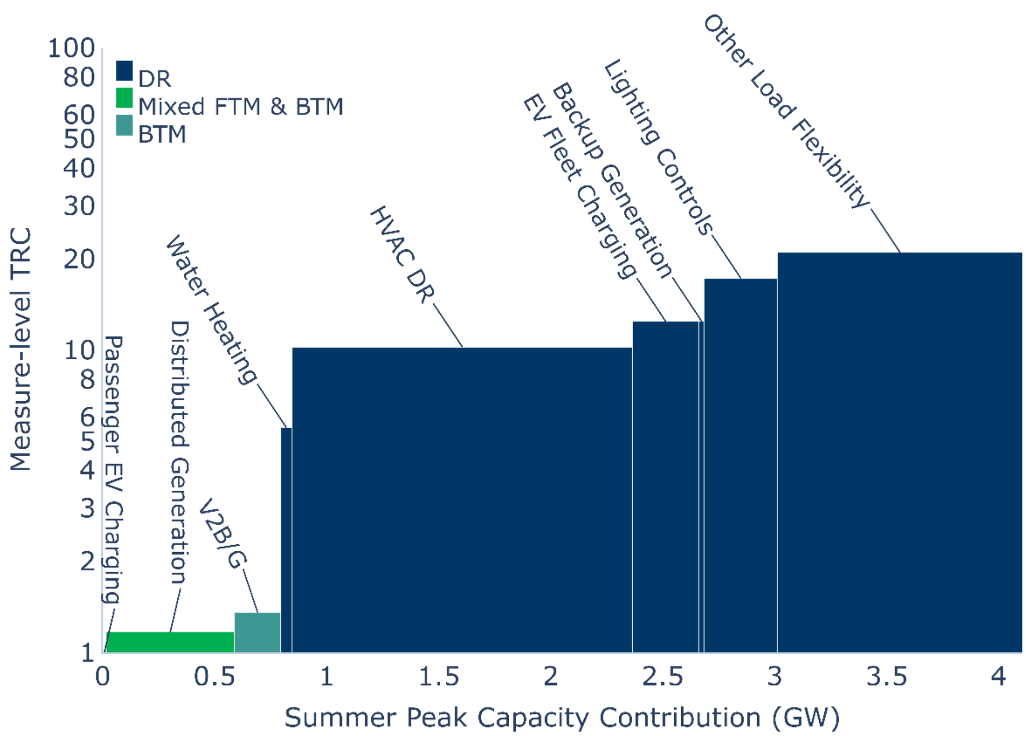
Overall, the combined market-wide TRCs for the DER portfolios under all scenarios exceed 1.0, indicating that under each scenario, DERs can contribute to meeting system needs in a cost-effective manner.

Table 5-7: TRC Values in the Market-Wide Economic Potential by Scenario and DER Measure type - 2032

	Total Resource Costs (TRC) Ratio - 2032		
Category	BAU	BAU+	Accelerated
DR Resources	12.4	21.3	10.7
BTM Resources	1.2	n/a[39]	1.8
FTM Resources	1.2	2.7	9.6
Combined TRC (all measures)	2.6	3.6	7.1

Figure 5-14: Market-Wide Economic Potential Cost-Effectiveness for the BAU scenario in 2032 to Figure 5-16: Market-Wide Economic Potential Cost-Effectiveness for the Accelerated scenario in 2032 illustrate the DER supply curve under each scenario, depicting the amount of economic potential each measure offers in order of increasing TRC values. Under the BAU scenario, the cost-effective DER resource mix leans heavily toward the DR measures, and TRCs are relatively moderate with most falling in the range of 1.0 to 10. Under the BAU+ scenario, while DR measures are still the most cost-effective, the cost-effectiveness and potential for distributed generation and storage increases significantly over the BAU scenario. Finally, under the Accelerated scenario, the greatly increased energy and capacity values alter the TRC supply curve significantly, with generating and storage resources becoming the largest contributors and offering a substantial amount of highly cost-effective potential.

Figure 5-14: Market-Wide Economic Potential Cost-Effectiveness for the BAU scenario in 2032



39 Market-wide TRC cannot be assessed for BTM resources under this scenario as there was no market-wide economic potential.

Figure 5-15: Market-Wide Economic Potential Cost-Effectiveness for the BAU+ scenario in 2032

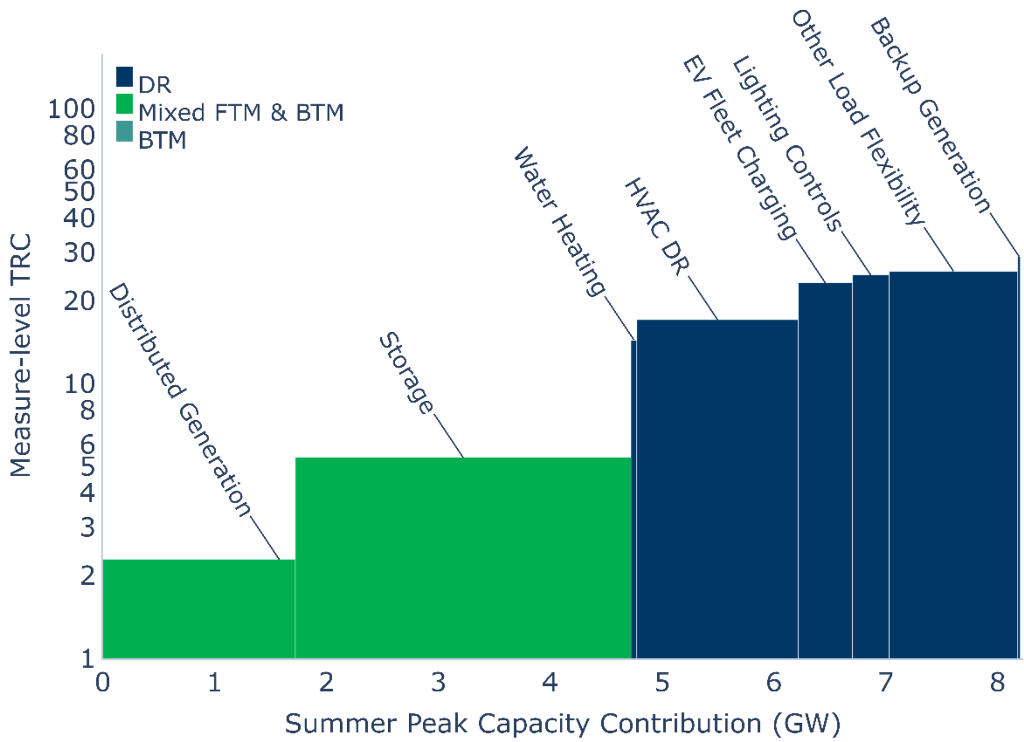
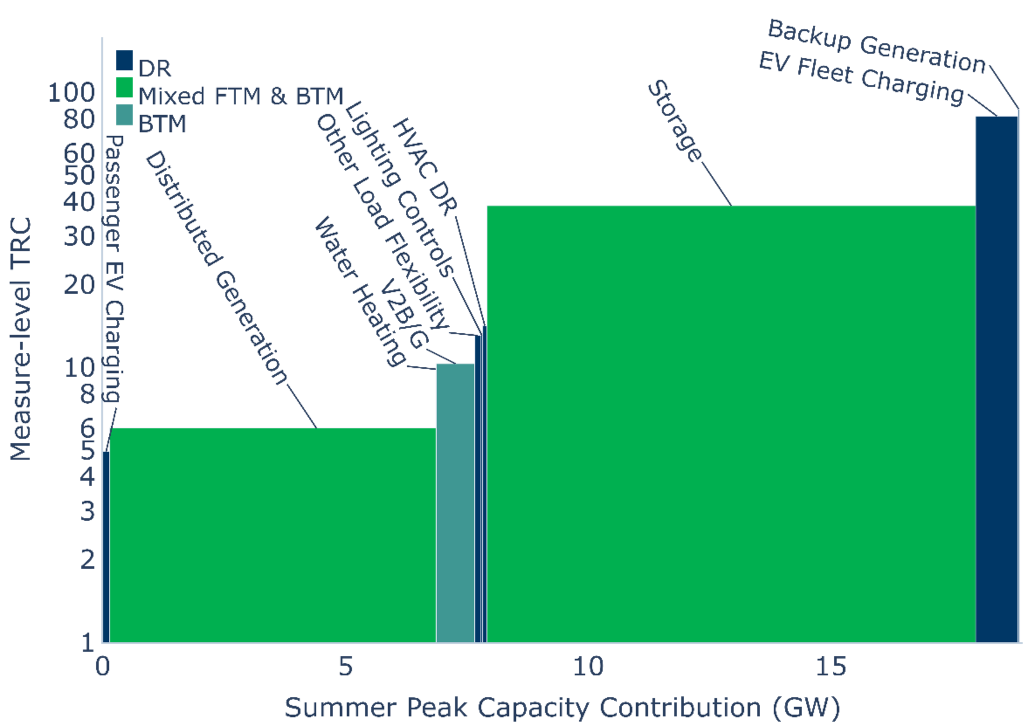


Figure 5-16: Market-Wide Economic Potential Cost-Effectiveness for the Accelerated scenario in 2032



5.2.4 Net Benefits and GHG Reductions

Figure 5-17 and Table 5-8 highlight lifetime net benefits associated with the identified market-wide DER economic potential in Ontario over the next decade.[40] The lifetime benefits increase by orders of magnitude from the BAU to the BAU+ and again from the BAU+ to the Accelerated scenarios. This is primarily driven by rapidly increasing value of energy benefits under the BAU+ and Accelerated scenarios, driven by a combination of increasing carbon price, and increased demand for electricity resulting from higher heating and vehicle electrification rates.

LIFETIME NET BENEFITS CONSIDERATIONS

The study shows a dramatic rise in lifetime benefits under the Accelerated scenario, indicating over $290B in net benefits stemming from all cost-effective DERs. It should be noted that this value is derived from the assessment of avoided costs, which assume highly constrained electricity supply under the Accelerated scenario (which assumes only renewable generation and storage are added to meet future electricity needs), causing energy avoided costs to rise nearly seven-fold over the BAU+ scenario by 2040. In reality, comprehensive and strategic integrated resource planning, in which centralized resources and energy efficiency would be combined with DERs and energy trade, would likely have a feedback effect that somewhat curtails these extremely high avoided costs. Thus, the lifetime benefits presented in this study should be interpreted as an extreme case that can be mitigated by said comprehensive integrated resource planning. However, given how cost-effective many DERs become under the Accelerated scenario, accounting for these feedback mechanisms between supply and avoided costs would not likely reduce the overall economic potential for DERs in this scenario.

In all scenarios, the avoided generation capacity and energy costs represent more than 90% of the identified benefits associated with the market-wide DER potential, demonstrating how these benefits can be expected to drive the market for DERs on the system. Energy represents a significant benefit stream and overshadows other benefits under the Accelerated scenario as system needs are exacerbated with increasing electrification and limited additions of new supply resources. Benefits associated with transmission capacity deferral represent the third largest value stream. DERs also deliver benefits associated with other services such as Distribution Capacity, Regulation Capacity and OR, but these are much smaller than the capacity and energy benefits.

While only generating resources contribute net energy to the system, almost all measures deliver some energy benefits by reducing marginal energy generation needs, thereby reducing carbon emissions during peak demand events.

[40] Lifetime benefits represent the total accrued economic benefits for all DERs installed during the study period, over the life of each DER (based on the estimated useful life of each measure which extend from 20 to 40 years beyond the end of the study period in some cases).

Figure 5-17: Lifetime Benefits and Costs associated with the Market-Wide Economic Potential (2032)

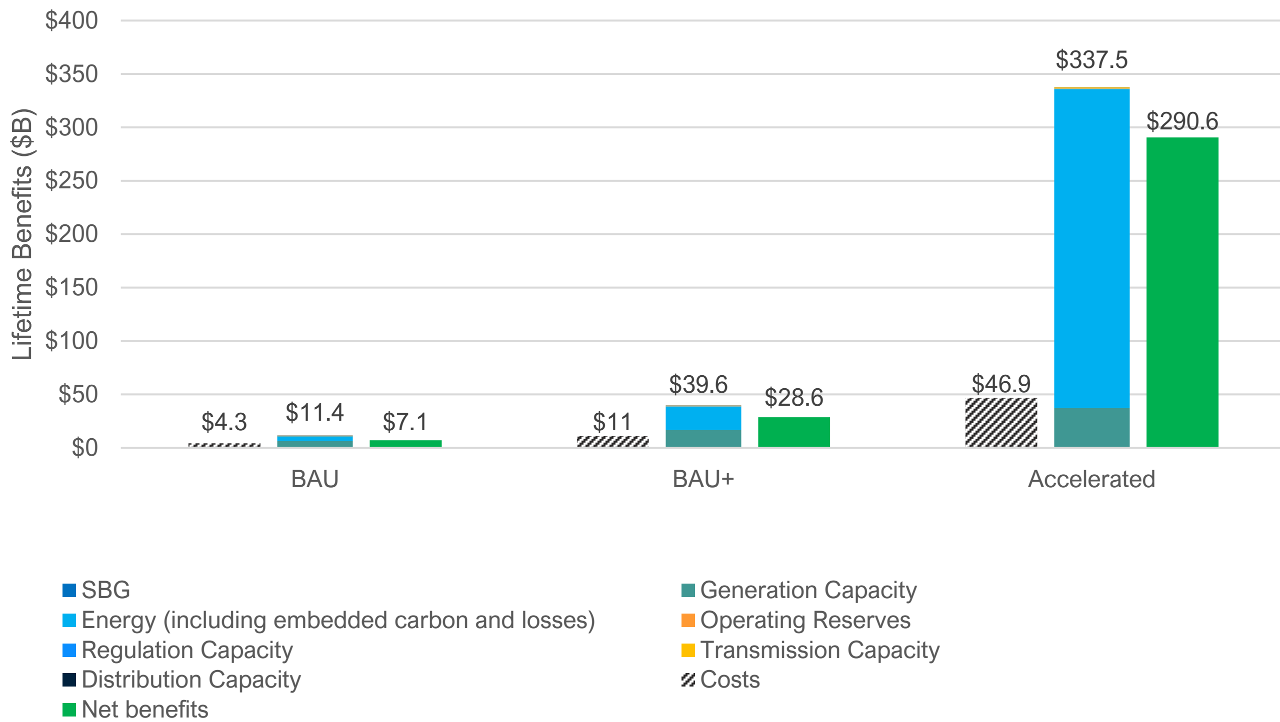


Table 5-8: Lifetime Benefits and Costs Associated with the Market-Wide Economic Potential

Market Service	BAU	BAU+	Accelerated
Benefits	$11.4 B	$39.6 B	$337.5 B
SBG	$2.8 M	$0	$0
Generation Capacity	$6.5 B	$16.8 B	$37 B
Energy[41]	$4.3 B	$22 B	$299 B
Operating Reserves	$9.9 M	$142 M	$290 M
Regulation Capacity	$23 M	$31.2 M	$36 M
Transmission Capacity	$529 M	$596 M	$749 M
Distribution Capacity	$2.3 M	$5.1 M	$6.5 M
Total Costs	$4.3 B	$11 B	$46.9 B
Net Benefits	$7.1 B	$28.6 B	$290.6 B
Lifetime GHG Emissions Reductions (CO2 eq) (Annual 2032 value)	33.7 Mt (2.3 Mt)	71.6 Mt (4.9 Mt)	164.3 Mt (10.3 Mt)

[41] Includes embedded carbon and losses

Table 5-9 below provides the annual and lifetime GHG benefits delivered by each measure group. Only measure groups that provide GHG benefits are included under each scenario (i.e. Lighting Controls, Other Load Flexibility, Pools and Spas, and Smart Appliances are excluded throughout as they do not provide GHG benefits). It should be noted that GHG attributes and impacts were not assessed in the model for load flexibility DR measures that did not include some form of energy storage (battery or thermal). Most DERs assessed provided some form of GHG benefits, however Backup Generation, Storage and Water Heating all led to increased GHG emissions. For the storage measure group, the GHG emissions increase is attributed to round trip efficiency losses, which cause batteries to expend more energy than they contribute to the system. Back-up Generation increases GHG emissions due to burning fossil fuels, and water heating controls led to a minor increase in GHG emissions by shifting energy consumption to periods with slightly higher marginal emissions.

Table 5-9: GHG Reductions from Market-Wide Economic Potential by Measure Group and Year

	Annual GHG Reduction (kt)			Lifetime GHG Reduction (kt)
	2023	**2027**	**2032**	**2032**
BAU	-71	-71	2,317	33,733
Backup Generation	-71	-73	-76	-1,154
Distributed Generation	0	0	2,388	34,837
EV Fleet Charging	0.5	1	3	25
HVAC DR	0	0.6	0.5	4
Passenger EV Charging	0	0	0.2	2
V2B/G	0	0	2	18
Water Heating	0	0	-0.002	-0.01
BAU+	-71	4,378	4,866	71,631
Backup Generation	-71	-73	-76	-1,153
Distributed Generation	0	4,482	5,042	73,561
EV Fleet Charging	0.8	3	6	44
HVAC DR	0	0.5	0.5	4
Storage	0	-34	-106	-824
Water Heating	0	0	-0.001	-0.005
Accelerated	-70	7,134	10,343	164,268
Backup Generation	-70	-73	-76	-1,153
Distributed Generation	0	7,341	12,373	180,657
EV Fleet Charging	0.9	4	-59	-464
HVAC DR	0	0.7	0.3	2
Passenger EV Charging	0	0	-582	-4,543
Storage	0	-138	-1,176	-9,171
V2B/G	0	0	-136	-1,059

Passenger EV Charging and V2B/G measure groups exhibited changing GHG impacts. Under the BAU scenario they both contributed to GHG emissions reductions, as they decreased charging during times when there were higher marginal generation GHG intensities on this system. However, in both cases they did not pass the TRC screen in the BAU+ scenario, and thus exerted no GHG impacts in this scenario. Under the Accelerated scenario, Passenger EV Charging and V2B/G did again pass the TRC screen, but in both cases led to increased emissions. In the case of Passenger EV Charging this was due to the managed charging measures pushing a greater portion of charging to occur during times with relatively higher marginal generation GHG intensities on this system. For the V2B/G measures, the increased carbon emissions are attributed to EV battery round trip efficiency losses, combined with charging occurring during periods with non-zero marginal generation GHG intensities on this system.

6. Achievable Potential

The achievable potential represents the expected contribution of DERs towards Ontario's system needs over the next decade, considering real-world factors that influence the uptake of these technologies (e.g. customer economics, technology familiarity, etc.).

Similar to the market-wide economic potential, the achievable potential assessment applies all DERs to the system - simultaneously capturing the interactive effects and competition among measures. Moreover, all measures that present a viable value proposition to a potential DER investor or customer are included in the achievable potential assessment, regardless of whether they pass the TRC cost-effectiveness screen. As a result, the achievable potential results yield a more diverse mix of measures. A detailed description of the achievable potential modeling approach is described in **Appendix E. Achievable Potential Methodology.**

The achievable potential explores the degree to which DERs can contribute to system needs, as well as the mix of DERs that would be expected to be installed system wide over the next 10 years. **The achievable potential results are expressed primarily in terms of DER contribution to system capacity (GW) by 2032, with the magnitude of the system capacity needs being driven by the summer peak demand event in each year.** The system capacity contribution for a given DER is defined as the average capacity contribution, or demand reduction, that the DER can contribute over a four-hour summer peak demand event window. Additional metrics related to other DER value streams are included where relevant, and detailed results with additional metrics (e.g. nameplate capacity, winter peak demand reductions, energy generation (kWh) contributions, avoided carbon emissions, etc.) can be found in the appendices. Interpretation of the achievable potential results should take into consideration the caveats outlined in the call-out box.

ACHIEVABLE POTENTIAL CONSIDERATIONS

- To avoid double-counting, **existing DERs are excluded from the achievable potential**. We used the APO's reacquisition scenario as a basis for existing DERs, assuming that they will continue to operate after the end of their contractual lifetime.
- The achievable potential **is based on the adoption of DERs (including adoption driven by NEM, rates, or the Industrial Conservation Initiative[42]) and the participation of those DERs in the IAMs, which are driven by the actual revenues and benefits available to customers under each scenario, as opposed to the system value identified in the economic potential.**
- Achievable potential is **not exclusively a subset of economic potential** as some DERs may still offer customers a value proposition regardless of their system TRC (e.g. BTM Solar).
- **BTM solar resources are assumed to be primarily compensated through net-metering**, and not direct market participation.
- **DR measures are modeled as an aggregated market resource** with the assumption that aggregators would provide customers with a participation / performance incentive equivalent to a percentage of the market revenues received, varying by scenario.

[42] The Industrial Conservation Initiative (ICI) program incentivizes eligible industrial and commercial customers to reduce their demand during peak periods. Customers who participate in the ICI pay a Global Adjustment based on their percentage contribution to the top five peak hours over a 12-month period.

6.1 Summary

Figure 6-1 highlights the forecasted summer system capacity that DERs are expected to contribute to by 2032. Under BAU, DERs are projected to contribute to 1.3 GW of summer capacity by 2032 (equivalent to a 5% reduction in the projected summer peak demand), which represents 7 GW of DER nameplate capacity.[43] Considering the assumed market, technology and policy changes under BAU+, DERs are forecasted to contribute to 2.2 GW of capacity by 2032 (equivalent to a 7% reduction in the projected system peak demand), and under the Accelerated scenario DERs are projected to contribute 4.3 GW (equivalent to a 14% reduction in the forecasted summer peak).

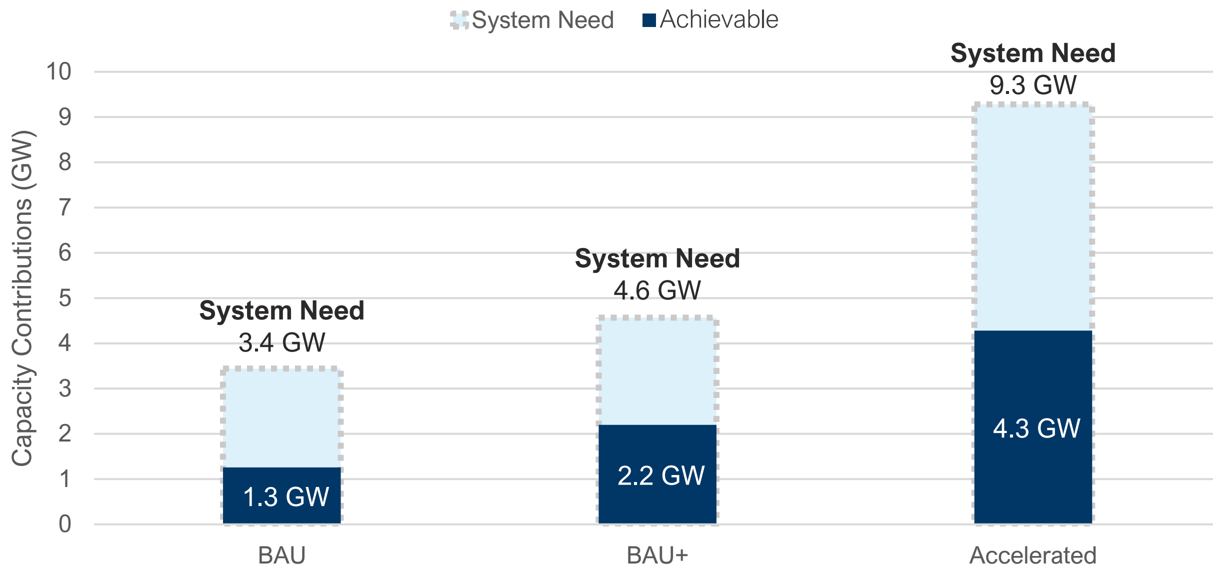
DER nameplate capacity increases to 13 GW and 25 GW in 2032 under the BAU+ and Accelerated scenario respectively. Similar to the trends observed in the Technical and Economic potentials, the DER potentials to contribute to winter peak capacity needs are somewhat lower than the summer potentials, as is illustrated in Figure 6-1, reflecting the lower winter peak coincidence factor of a few key DERs - most notably solar PV.

Overall, the findings indicate that under the modeled achievable scenarios, DERs offer the potential to provide 39%-62% of Ontario's incremental summer capacity needs over the next decade. These results represent 23%-31% of the market-wide economic potential. The differential between the economic and achievable potential is a factor of customer economics, DER barriers, market opportunities and IESO market rules that influence the adoption of DERs in the province.

As indicated above, the achievable results are notably lower than the economic potential results due to a range of factors captured in the modeling. First, the achievable potential is driven by customer/developer financial returns, and in many cases, DERs that prove cost-effective from an electricity system perspective do not offer sufficient returns to be attractive to a large number of DER providers. Thus, opportunities to increase returns to potential DER providers can notably increase the achievable potential, as is observed through the growth in potential from the BAU to the Accelerated scenarios as energy and capacity prices increase. Moreover, while not explicitly assessed here, opportunities to reduce DER market barriers by increasing awareness, removing building code restrictions, or reducing DER procurement or market participation complexities, can lead to increased achievable potentials. Stated another way, the spread between the economic and achievable DER potential is driven largely by the distributed nature of the resources, and the need to influence many decision points to encourage widespread adoption and participation of DERs in providing system services.

[43] DERs have an associated coincidence factor (CF) which represents the expected portion of the nameplate capacity that will produce power during system peak load events. Since these CFs are typically less than 1.0, the DER nameplate capacities are typically larger than their capacity contributions.

Figure 6-1: Achievable Capacity Contribution from DERs by Scenario in 2032



As shown in Figure 6-2 the identified achievable potential can also contribute to meeting Ontario's emerging winter system peak needs. Specifically, DERs are forecasted to contribute between 1 GW – 3.6 GW of winter capacity by 2032, representing 4% to 9% of the forecasted winter peak demand for that timeframe.

Figure 6-2: Achievable Winter Capacity Contribution from DERs by Scenario in 2032

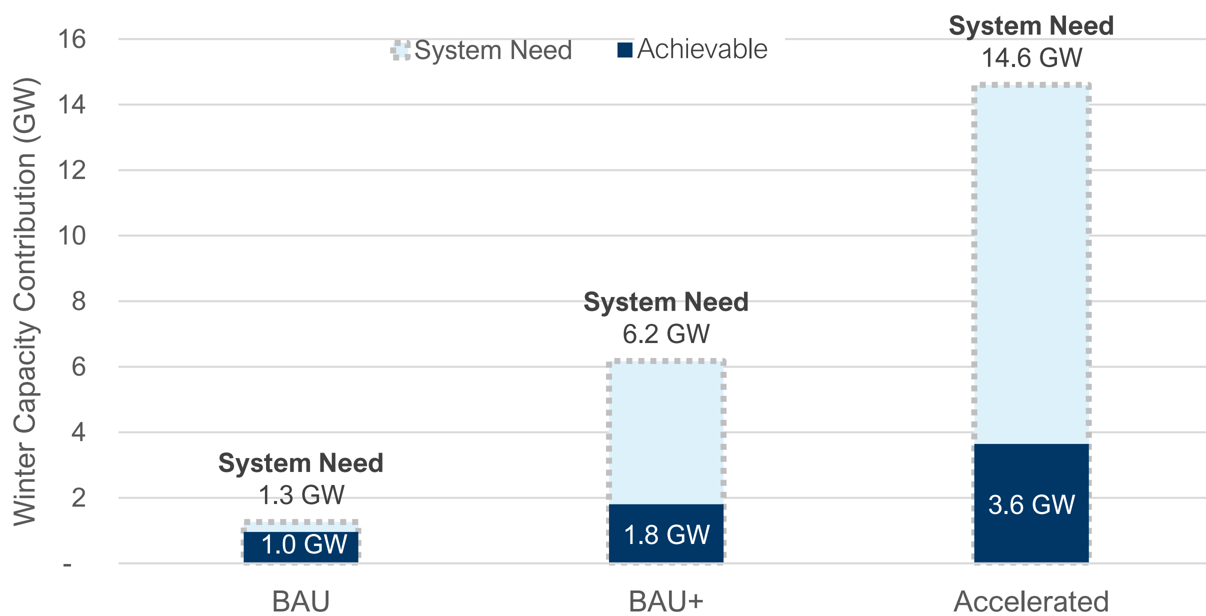


Figure 6-3 and Table 6-1 below provide the resulting mix of DERs forecasted in the achievable scenarios. The achievable DER mix can be seen to differ from the market-wide economic potential DER mix in the following ways:

- The majority of the achievable potential comes from DR opportunities, which are forecasted to contribute 0.92 – 1.53 GW of capacity by 2032. However, the DR measure achievable potential is limited by the forecasted adoption of applicable equipment (i.e. heat pumps and electric vehicles) as well as the corresponding market participation that can be expected based on the available market revenues in each scenario. Specific details on how and where DR measure adoption and participation are impacted by customer economics and market barriers is provided in the following sections.

- Despite the significant economic potential observed for FTM resources, only limited capacity of FTM solar is observed under the achievable scenarios because the current energy market value and compensation available for FTM resources are insufficient to drive significant developer investment under the BAU and BAU+ scenarios. They do become extremely economically attractive in the later years of the Accelerated scenario, but the results show a lag in the development of the full FTM resource potential due to the diffusion curves applied in the model that account for the time it takes the industry to recognize and develop emerging and distributed opportunities. Conversely, little to no FTM battery storage achievable potential is observed in any scenario due to the local distribution company non-coincident peak demand charges applied to FTM storage resources in Ontario, which undermine the business case for prospective FTM storage developers.
- BTM resources make a notable contribution to the achievable potential in all scenarios (contributing 0.31 – 2.25 GW of capacity), despite only being cost-effective under the BAU+ and Accelerated measure-level economic potential assessment. This is largely attributable to the current compensation mechanisms for BTM solar (e.g. net-metering, ICI) and non-financial drivers (e.g. resiliency, environmental benefits) that support the value proposition for customers to adopt BTM solar and storage.

Figure 6-3: Achievable Seasonal System Capacity Contributions by Scenario and Resource Type in 2032

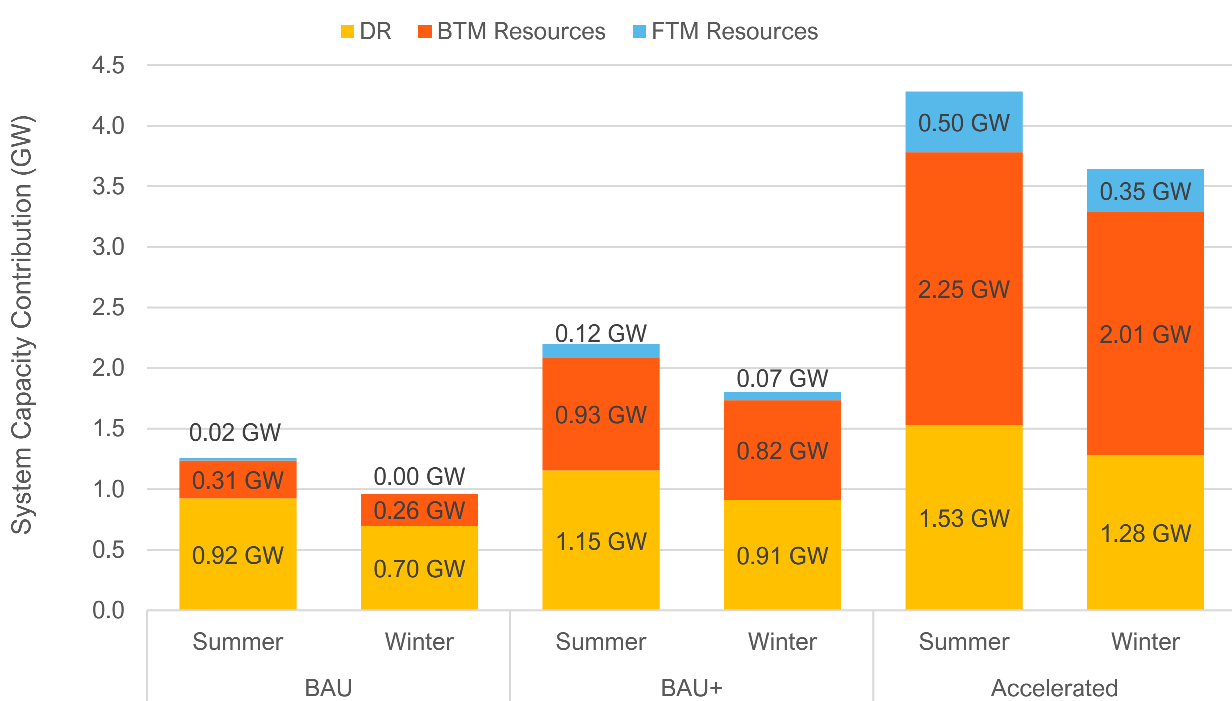


Table 6-1: Achievable Capacity Reductions by Resource Type and Year

	Summer Capacity Reductions (MW)			Winter Capacity Reductions (MW)		
	2023	**2027**	**2032**	**2023**	**2027**	**2032**
BAU	614	770	1,257	510	610	961
DR	545	664	924	444	522	699
BTM Resources	67	98	313	66	88	262
FTM Resources	3	8	20	-	-	-
BAU+	692	1,026	2,197	540	812	1,804
DR	597	756	1,155	485	597	912
BTM Resources	81	206	926	55	185	822
FTM Resources	14	64	116	-	30	70
Accelerated	894	1,652	4,282	552	1,357	3,642
DR	692	942	1,530	495	765	1,282
BTM Resources	115	491	2,251	11	439	2,005
FTM Resources	87	219	501	46	154	355

Figure 6-4 and Figure 6-5 provide the energy generation results for the achievable DER mix in 2032 under each scenario, as compared to the forecasted system needs. Overall, these results illustrate the extensive growth in energy needs expected in Ontario over the coming decade, driven by market growth along with the electrification of transportation, space heating and industry. In each scenario the achievable potentials make up just a small fraction of the forecasted incremental energy needs (5% - 10%). However, the economic potentials presented in Figure 6-5 are much higher, representing 20% of the projected need under the BAU scenario, over 50% under the BAU+, and 100% of the needs in the Accelerated scenario. While this demonstrates the impact of higher energy prices in the Accelerated scenario to support FTM and BTM solar generation economics, the remaining discrepancy between the achievable and economic potentials underlines the challenges of actually building the needed generation facilities in the absence of planned direct procurement.

Overall, these results show that energy becomes the main driver of benefits for DERs under the Accelerated scenario (as shown later in Figure 6-7). While the relative gap between achievable and economic potential is the most pronounced in this scenario, it should be noted that the avoided costs of energy rise steeply in the last 3 to 4 years of the study period, and the model's diffusion curves would predict a lag in the adoption of FTM/BTM solar in response to the improved economics. Thus, decisions to procure solar capacity in the preceding years would help to raise the achievable potentials in advance of the steeply growing needs in the later years of the study period.

Another aspect that should be considered is the seasonal energy needs, which were not assessed in the model. It would be expected that heating electrification would drive increasing winter energy needs, with solar generating more energy in the summer, and FTM small scale hydro generating more in the winter. Moreover, the study capped FTM solar technical nameplate capacity at 37 GW, which limits total annual solar production to 65 TWh - all of which proves cost-effective in 2032. Further analysis would be needed to determine how these DERs could fit into a resource adequacy plan for Ontario, considering hourly, daily, and seasonal needs.

Figure 6-4: Achievable Annual Energy Generation vs Incremental System Needs (2032)

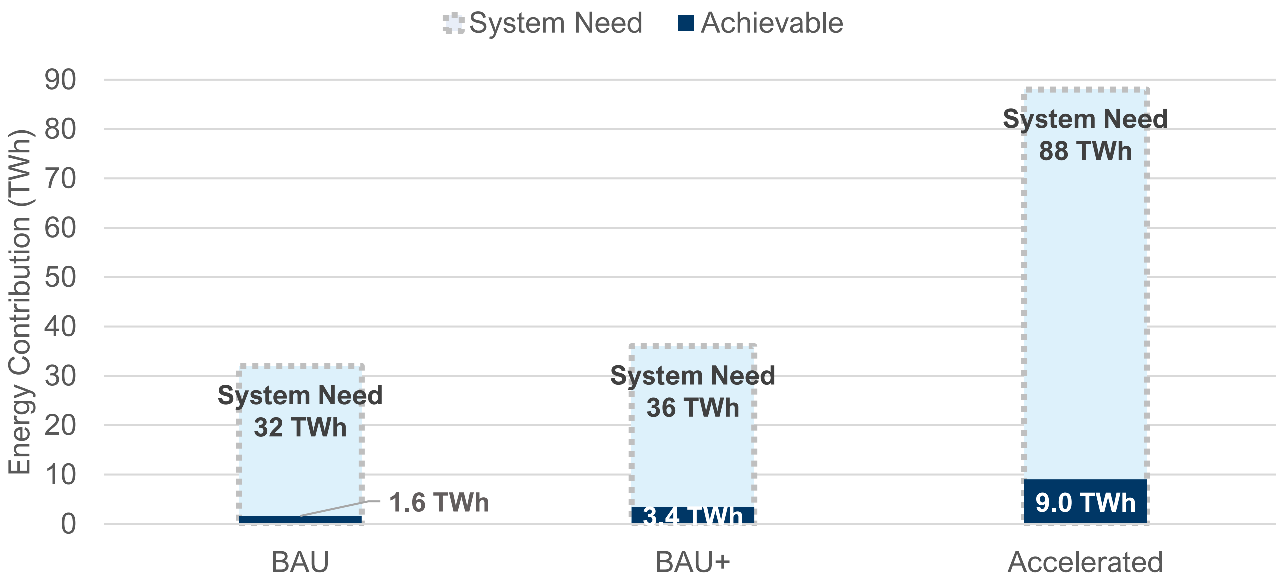


Figure 6-5: Annual Achievable and Economic Potential for Energy Generation by Scenario in 2032

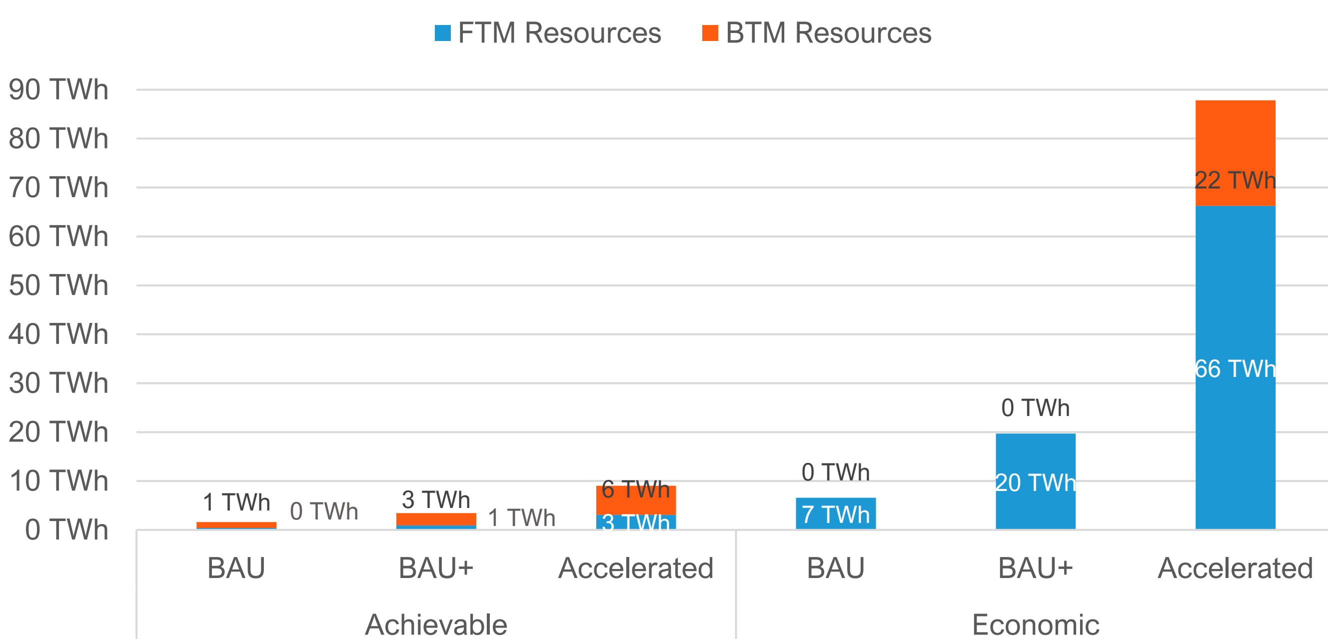


Figure 6-6 below provides a breakdown of the proportion of achievable DER potential that can provide each grid service to the system. As per the economic potential results, under all scenarios, the majority of DERs are capable of providing 5-minute dispatchability, OR, RC and capacity benefits. Moreover, only a small fraction can provide energy benefits, once again limited to the solar PV measures in all scenarios, and small-scale hydro under the Accelerated scenario. A majority of DERs are not event/call constrained (i.e. they can be called 20 times per year or more).

Figure 6-6: Portion of Achievable Potential Nameplate Capacity Capable of Providing Various Grid Services

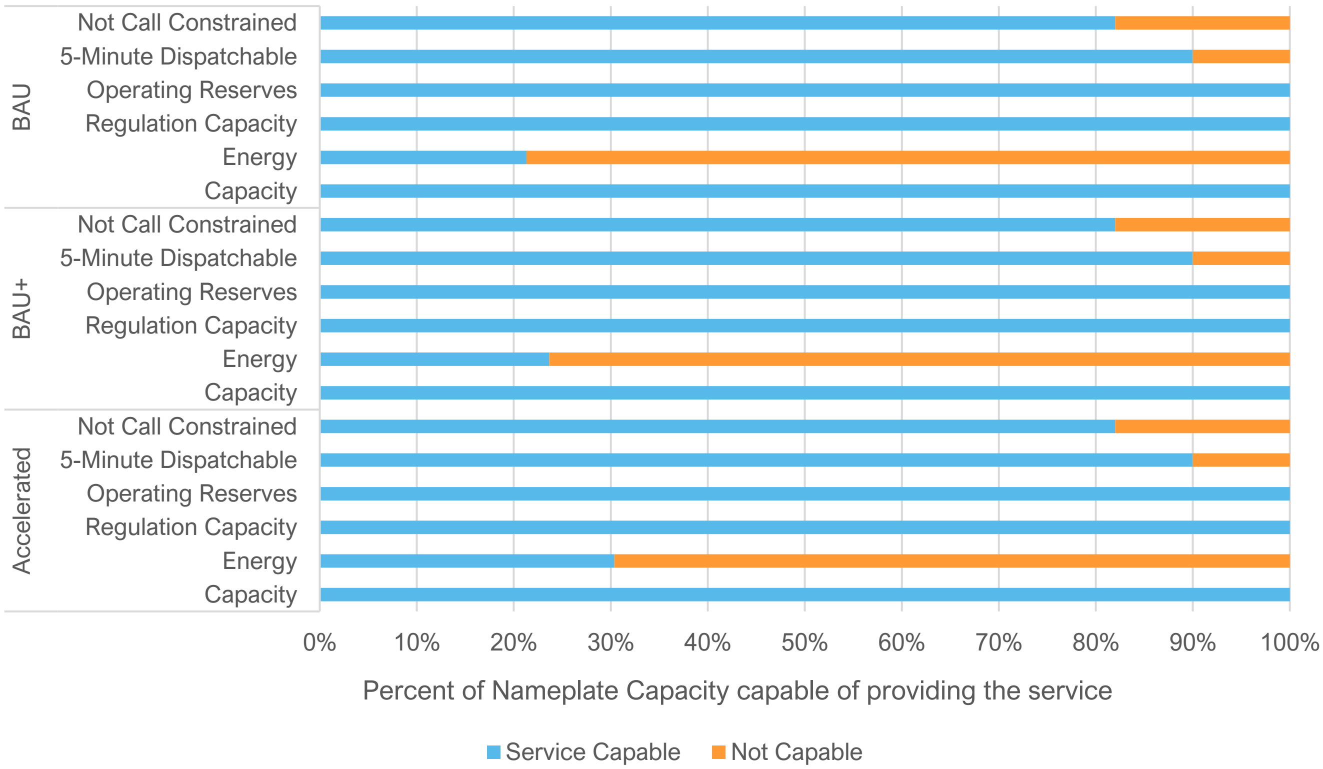


Figure 6-7 and Table 6-2 show the achievable lifetime net benefits by grid service and scenario. Overall, under the BAU and BAU+ scenarios, the results clearly show the importance of the capacity benefits offered by DERs in supporting their cost-effectiveness. However, under the Accelerated scenario, the energy benefits expand to become the most important grid service from a lifetime benefits perspective. This is due to the rapidly increasing energy avoided costs under the Accelerated scenario, along with the carbon emissions benefits (which are captured within the energy benefits in this analysis). The Accelerated scenario reveals a significant rise in net benefits stemming from adopted DERs, which exceed $42B by 2032. These benefits are derived from the assessed avoided costs, which assume highly constrained electricity supply under the Accelerated scenario, causing energy avoided costs to rise nearly seven-fold over the BAU+ scenario by 2040.[44]

[44] As noted in Chapter 5, coherent, real-world planning and integration could help to mitigate these extremely high avoided costs. However, given that many of the DERs become highly cost-effective under the Accelerated scenario, accounting for energy price feedback mechanisms between supply and avoided costs would not be expected to significantly reduce the overall achievable potential for DERs in this scenario.

Figure 6-7: Lifetime Benefits and Costs associated with the Achievable Potential (2032)

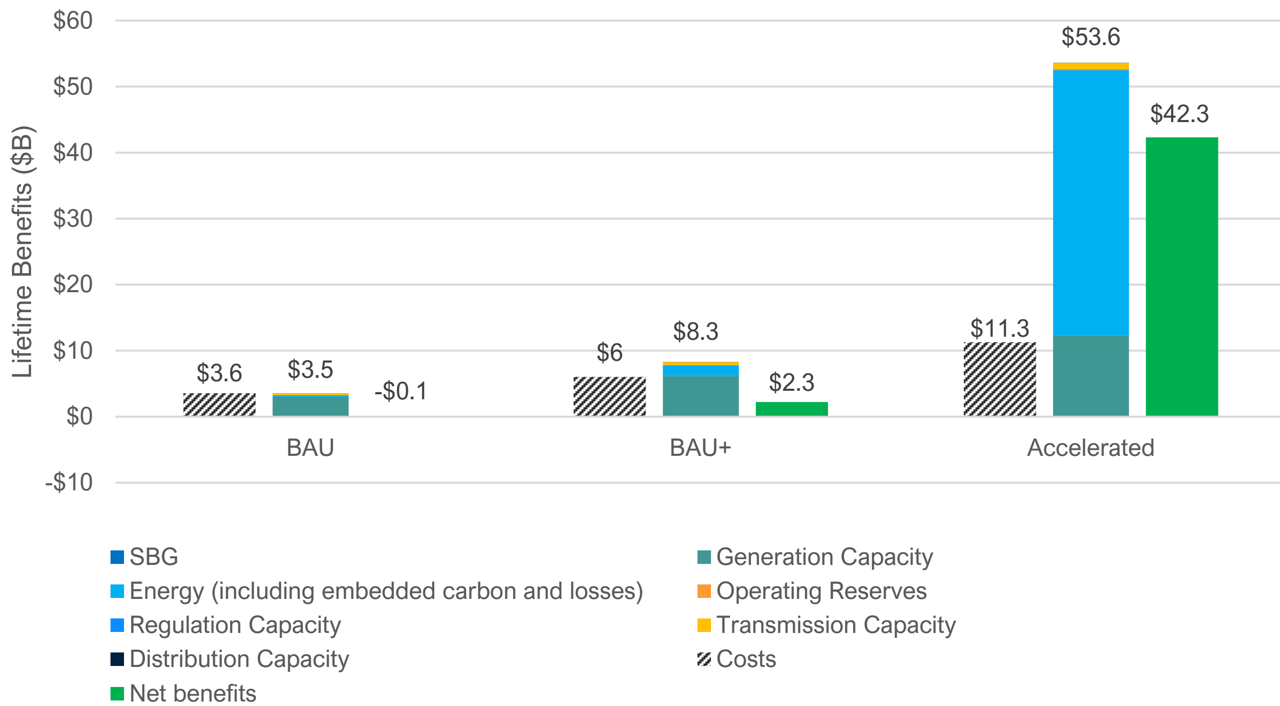


Table 6-2: Lifetime Benefits and Costs Associated with the Achievable Potential

Market Service	BAU	BAU+	Accelerated
Benefits	$3.5 B	$8.3 B	$53.6 B
SBG	$1.85 M	$0	$0
Generation Capacity	$3.0 B	$6.2 B	$12.3 B
Energy (including embedded carbon and losses)	$265.6 M	$1.6 B	$40.2 B
Operating Reserves	$49,539	$23.6 M	$68.7 M
Regulation Capacity	$0	$0	$8.4 M
Transmission Capacity	$238.6 M	$430.4 M	$1.0 B
Distribution Capacity	$2.5 M	$4.9 M	$9.5 M
Total Costs	$3.6 B	$6.0 B	$11.3 B
Net Benefits	-$0.1 B	$2.3 B	$42.3 B
Lifetime GHG Emissions reductions ($CO_{2\,eq}$) (Annual 2032 value)	0.9 Mt (57 kt)	1.8 Mt (122 kt)	4.8 Mt (321 kt)

GHG EMISSIONS REDUCTIONS FROM DERS

DERs can play a vital role in reducing GHG emissions related to energy use in Ontario. To put the assessed carbon benefits into perspective, in 2019 Ontario's electricity sector accounted for 3.3

megatonnes (Mt) of CO_2(eq), and thus the annual DER carbon reduction benefits in 2032 would represent a 2-10% reduction in GHG emissions compared to this baseline.

This study attributed two key opportunities for DERs to reduce emissions, which are captured in the quantification of DER benefits:

- For generating DERs, such as solar PV and small-scale hydro, benefits are quantified based on the energy production from these resources that directly displaces the high-carbon content electricity from gas-fired generation facilities.
- DR and storage measures can theoretically shift consumption from times when high-emitting resources are on the margin to times when lower-emitting resources are on the margin, but with storage incurring a roundtrip efficiency penalty that could somewhat hamper the overall carbon benefits and actually result in net-positive emissions. For all scenarios, in the latter years of this study due to high load growth, gas generation appeared on the margin nearly 100% of the time. Such conditions significantly limited the carbon-abatement opportunities of DR, and resulted in a net increase in emissions as a result of storage. Under a counterfactual hypothetical circumstance where the marginal generating resources alternated between gas and non-emitting generation (such as renewables or nuclear), DR and battery storage would have resulted in significantly more emissions reductions.

This study did not estimate the *net* GHG reductions from electrification

Under the BAU+ and Accelerated scenarios, higher levels of heating electrification and electric vehicle adoption would logically lead to net GHG emissions reductions as fossil fuel usage is displaced by largely clean electricity. While the overall GHG benefits (accounting for GHG reductions from fossil fuel use occurring outside of the electricity sector) was not included in this study, the contribution of DERs to Ontario's electricity system would help to enable such electrification.

Table 6-3 below provides the annual and lifetime GHG emissions benefits by measure group and achievable scenario. Only measure groups that provide some GHG impacts are presented under each scenario, and as was noted above in the economic potential discussion, the GHG impacts of DR measures that do not include any form of energy storage were not assessed in the model. As with the economic potential results, Storage and Back-up Generation both lead to increases in GHG emissions, due to round-trip efficiency losses and fossil fuel consumption, respectively. In the achievable scenarios, Water Heating measures do lead to GHG emissions reductions due to a shifting in the timing of their impacts, and increased uptake relative to the economic scenarios. Measure by measure GHG emissions impacts by year can be found in the MS Excel tables included in Appendix G – Detailed Results.

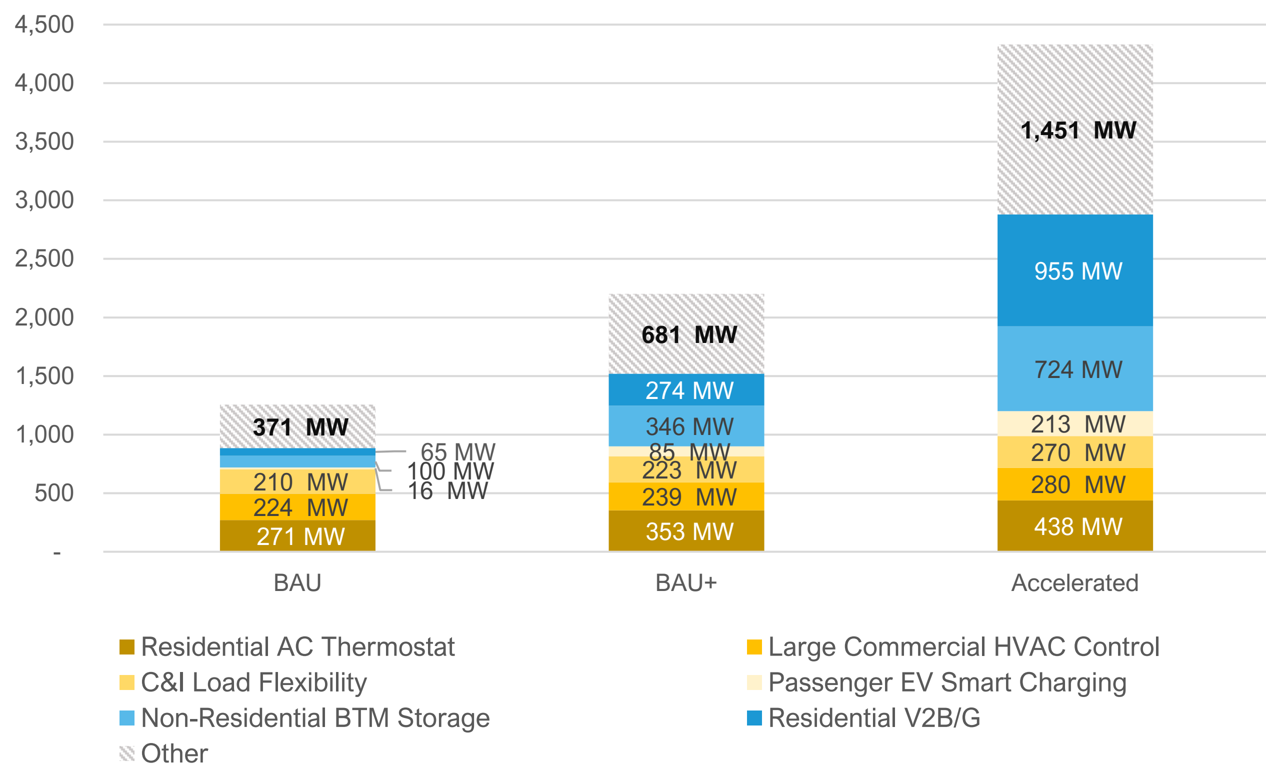
Table 6-3: Achievable GHG Reduction by Measure Group and Year

	Annual GHG Reduction (tonnes CO2 eq)			Lifetime GHG Reduction (tonnes CO2 eq)
	2023	2027	2032	2032
BAU	906	13,064	57,450	850,342
Backup Generation	-1,030	-1,067	-1,134	-17,103
Distributed Generation	2,559	15,094	60,464	882,214
EV Fleet Charging	4	9	18	137
HVAC DR	22	15	19	151
Passenger EV Charging	7	7	9	69
Storage	-671	-1,024	-2,032	-15,962
V2B/G	11	27	97	755
Water Heating	1	1	1	5
BAU+	10,484	42,221	122,057	1,817,626
Backup Generation	-1,127	-1,166	-1,238	-18,675
Distributed Generation	12,448	45,273	128,834	1,879,788
EV Fleet Charging	5	14	31	244
HVAC DR	55	74	157	1,227
Other Load Flexibility	0	0	0	1
Passenger EV Charging	11	18	91	706
Storage	-915	-2,064	-6,235	-48,938
V2B/G	0	66	405	3,160
Water Heating	1	0	2	14
Accelerated	23,588	94,676	320,562	4,789,858
Backup Generation	-1,311	-1,356	-1,440	-21,724
Distributed Generation	26,346	99,306	338,362	4,940,116
EV Fleet Charging	10	24	46	357
HVAC DR	29	95	211	1,652
Other Load Flexibility	0	0	3	23
Passenger EV Charging	38	80	220	1,717
Storage	-1,530	-3,804	-18,252	-143,324
V2B/G	0	325	1,402	10,936
Water Heating	2	1	2	18

Figure 6-8: Achievable Summer System Capacity Contributions from Top 6 DER Measures (2032) below shows a measure-level breakdown of the forecasted achievable potential, identifying the six DER types comprising the bulk of the achievable capacity. Specifically, residential AC thermostats represent a significant opportunity of 271 – 438 MW of summer peak reduction potential, with Large Commercial HVAC DR measures

contributing another 224 – 280 MW of potential. This growth is likely a by-product of the increased prevalence of smart thermostats in the market over time as well as higher market participation accessibility and revenues, which result in cost-effective opportunities emerging over the study period. The growth in residential HVAC DR is particularly notable given that no residential HVAC DR is observed in the capacity auction today. Non-residential BTM storage also represent a large portion of the identified achievable potential, contributing between 100 MW to 724 MW of capacity. With the forecasted increase in EV uptake under the BAU+ and Accelerated scenarios, up to 955 MW of V2B/G potential, and 213 MW of smart charging potential is projected by 2032. The "Other" category captures the contribution of all other DER measures considered in the study, such as BTM solar, FTM solar, FTM storage and non-HVAC residential DR.

Figure 6-8: Achievable Summer System Capacity Contributions from Top 6 DER Measures (2032) [45]



6.2 DR Potential

As shown in Figure 6-9, the capacity contributions from DR measures are expected to grow over the study period, reaching from 0.9 GW to 1.5 GW of Summer peak capacity contributions by 2032:

- Nearly half of the forecasted achievable DR potential is expected to come from **HVAC DR** consistently across the study period. Under BAU and BAU+, a little over 50% of the HVAC DR opportunities are expected to come from the residential sector, enabled through the increased penetration of smart thermostats; this increases to nearly 70% under the Accelerated scenario. Commercial DR measures represent the majority of the remaining DR potential, with the industrial measure offering 8 - 15% of the total potential. Despite the reduction in HVAC DR technical potential between BAU and BAU+ (as heat

[45] C&I Load Flexibility includes Other Commercial Flexibility and Industrial Flexibility measures.

pumps displace less efficient ACs), the contribution of HVAC DR increases from 380 MW to 490 MW under the BAU+ scenarios due to higher participation incentives stemming from the increased market revenues for DR measures, resulting from higher overall capacity benefit values under the BAU+ scenario. Similarly, under the Accelerated scenario, the further increase in incentives result in the highest HVAC DR achievable potentials.

- **EV smart charging** represents a high growth area, with up to 252 MW of capacity contributions by 2032 under the Accelerated scenario from passenger and fleet EV charging opportunities. The potential particularly increases in the latter part of the decade as EV uptake in the province surges. Relative to commercial fleets, passenger EV charging opportunities have higher system capacity contributions (enabled by the prevalence of controls through onboard EV telematics) and higher propensity to participate in managed charging initiatives.
- Beyond HVAC and EV charging, the remaining capacity contributions from DR are distributed among **water heating, commercial lighting controls and other end-uses**. In particular, a large portion of the "other flexibility" represents segment-specific DER opportunities in the commercial and industrial sector.

Figure 6-9: Achievable System Capacity Contributions from DR Resources

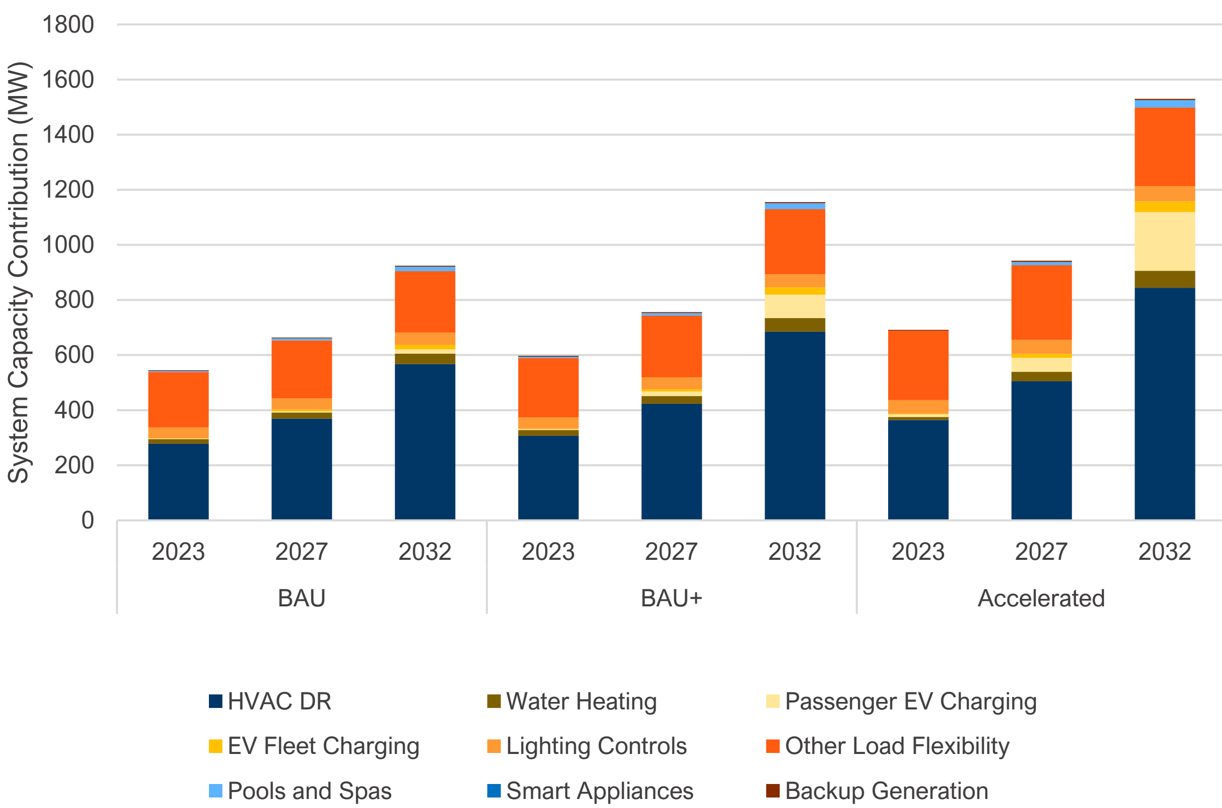


Table 6-4: Achievable Seasonal System Capacity Contributions from DR Resources

	System Summer Capacity Contribution (MW)								
	BAU			BAU+			Accelerated		
	2023	2027	2032	2023	2027	2032	2023	2027	2032
Residential	**75**	**144**	**336**	**100**	**202**	**523**	**111**	**284**	**783**
HVAC DR	59	115	273	77	154	374	96	194	489
Other Load Flexibility	1	1	1	2	2	2	2	2	3
Water Heating	10	15	30	13	20	41	3	25	52
Passenger EV Charging	2	5	16	3	17	85	10	51	213
Pools and Spas	4	7	16	5	10	21	-	12	27
Commercial	**322**	**367**	**429**	**339**	**391**	**462**	**387**	**458**	**539**
HVAC DR	219	254	294	230	270	311	268	311	356
Lighting Controls	39	41	44	42	44	47	49	51	55
Other Load Flexibility	52	56	63	55	59	65	55	68	76
EV Fleet Charging	1	5	17	2	8	27	3	14	39
Water Heating	7	7	7	8	8	8	8	9	9
Backup Generation	3	3	3	3	4	4	4	4	4
Industrial	**148**	**153**	**159**	**158**	**163**	**170**	**193**	**200**	**207**

	System Winter Capacity Contribution (MW)								
	BAU			BAU+			Accelerated		
	2023	2027	2032	2023	2027	2032	2023	2027	2032
Residential	**57**	**106**	**240**	**77**	**156**	**421**	**17**	**237**	**697**
HVAC DR	35	69	156	46	92	224	13	117	309
Other Load Flexibility	1	1	1	2	2	2	2	3	3
Water Heating	15	23	47	20	30	64	0	39	80
Passenger EV Charging	2	7	21	4	22	111	1	67	280
Pools and Spas	4	7	15	5	9	20	-	12	26
Commercial	**238**	**262**	**299**	**250**	**277**	**320**	**284**	**328**	**377**
HVAC DR	95	106	120	97	110	124	113	128	142
Lighting Controls	68	72	77	73	77	83	87	92	98
Other Load Flexibility	59	64	72	62	67	75	65	78	88
EV Fleet Charging	1	5	14	1	6	20	2	10	28
Water Heating	12	12	12	13	13	14	13	15	16
Backup Generation	3	3	3	3	4	4	4	4	4
Industrial	**149**	**154**	**160**	**159**	**164**	**171**	**194**	**200**	**208**

6.3 BTM Resources

As highlighted earlier, BTM resource capacity (summer) represents 0.31 GW – 2.25 GW of achievable potential in 2032 (which reflects 1.4 – 9.0 GW of nameplate capacity):

- Despite limited uptake forecasted in early years of the study period, between 1 GW and 4.9 GW (nameplate) of new **BTM solar** are forecasted to be deployed in Ontario by 2032. However, the deployed BTM solar capacity is only expected to contribute 50 to 246 MW towards capacity needs due to low - and declining - coincidence with system peak for new solar additions. The achievable potential primarily consists of residential and small commercial BTM solar deployments that are enabled by the favorable business case available to net-metering customers with assumed access to TOU rates.[46]
- 178 MW of **BTM storage** capacity is forecasted under BAU, increasing to 485 MW under BAU+, and 962 MW under Accelerated. Under all scenarios, BTM storage adoption is concentrated among commercial and industrial customers due to benefit streams from demand charge management and ICI participation resulting in favourable economics. Beyond bill management, benefits from capacity contributions are the key market value stream driving uptake in the BAU and BAU+ scenario. However, under Accelerated, higher arbitrage opportunities create significant new revenue opportunities. Despite the lack of a solid business case, some residential BTM storage capacity is observed, with 34 – 144 MW forecasted by 2032, likely driven by a combination of financial motivations as well as other non-energy benefits (e.g. resiliency). The majority of the deployed BTM storage capacity is expected later in the study period (2027 onwards) as technology costs decline.
- 84 MW of capacity contribution are expected from **V2B/G** under BAU, increasing to 337 MW under BAU+ and reaching 1,043 MW in the Accelerated scenario as a result of increased passenger and fleet EV penetration.

Figure 6-10, Table 6-5 and Table 6-6 highlight the achievable installed nameplate capacity for key BTM resources and the corresponding system capacity contributions.

[46] Presently, it is common practice for LDCs to remove net-metering participants from the TOU rate structure and instead place them on the tiered rate structure.

Figure 6-10: Achievable Summer System Capacity Contribution from BTM Resources

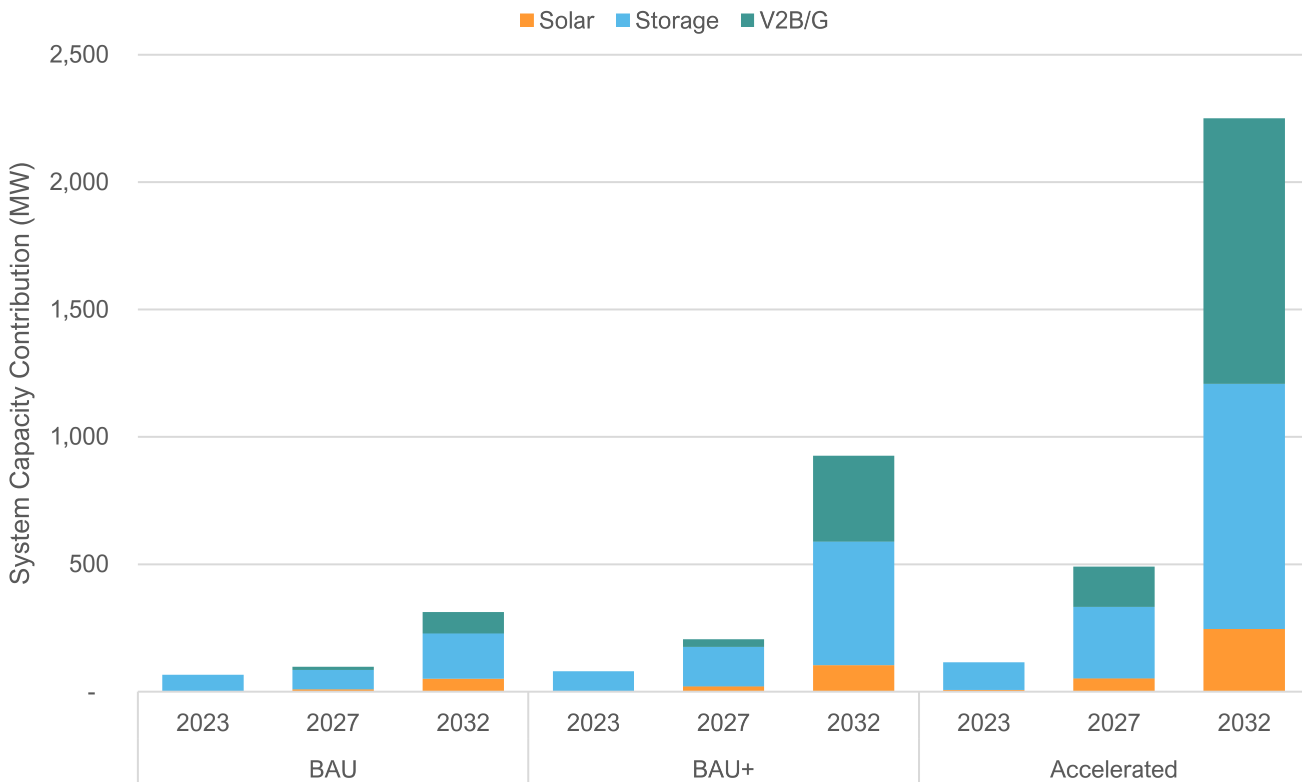


Table 6-5: Achievable Installed BTM Nameplate Capacity

	Installed Nameplate Capacity (MW)								
	BAU			BAU+			Accelerated		
	2023	2027	2032	2023	2027	2032	2023	2027	2032
Residential	**7**	**178**	**771**	**19**	**268**	**1,098**	**66**	**512**	**1,853**
BTM Solar	5	169	737	14	247	1,027	56	471	1,709
BTM Storage	2	9	34	5	21	71	10	41	144
V2B/G	0	30	196	0	74	821	0	451	2,863
Commercial	**46**	**65**	**366**	**69**	**258**	**1,300**	**147**	**687**	**2,966**
BTM Solar	2	18	266	16	150	954	72	483	2,242
BTM Storage	44	47	100	54	108	346	75	204	724
V2B/G	0	7	56	0	17	188	0	23	264
Industrial	**20**	**20**	**47**	**20**	**43**	**160**	**33**	**119**	**1,069**
BTM Solar	-	-	3	-	17	92	10	83	975
BTM Storage	20	20	44	20	26	68	23	36	94

Table 6-6: Achievable Seasonal System Capacity Contribution from BTM Resources

System Capacity Summer Contribution (MW)									
	BAU			BAU+			Accelerated		
	2023	2027	2032	2023	2027	2032	2023	2027	2032
Residential	**2**	**18**	**71**	**6**	**33**	**123**	**13**	**65**	**231**
BTM Solar	0	9	37	1	13	52	3	24	87
BTM Storage	2	9	34	5	21	71	10	41	144
V2B/G	0	10	65	0	25	274	0	150	955
Commercial	**44**	**48**	**113**	**55**	**115**	**393**	**79**	**228**	**835**
BTM Solar	0	1	13	1	7	47	4	24	111
BTM Storage	44	47	100	54	108	346	75	204	724
V2B/G	0	2	19	0	6	63	0	8	88
Industrial	**20**	**20**	**44**	**20**	**27**	**72**	**24**	**40**	**142**
BTM Solar	-	-	0	-	1	5	0	4	48
BTM Storage	20	20	44	20	26	68	23	36	94

System Capacity Winter Contribution (MW)									
	BAU			BAU+			Accelerated		
	2023	2027	2032	2023	2027	2032	2023	2027	2032
Residential	**2**	**19**	**99**	**1**	**45**	**345**	**1**	**191**	**1,099**
BTM Solar	-	-	-	-	-	-	-	-	-
BTM Storage	2	9	34	1	21	71	1	41	144
V2B/G	0	10	65	0	25	274	0	150	955
Commercial	**44**	**49**	**118**	**34**	**114**	**409**	**7**	**211**	**812**
BTM Solar	-	-	-	-	-	-	-	-	-
BTM Storage	44	47	100	34	108	346	7	204	724
V2B/G	-	2	19	-	6	63	-	8	88
Industrial	**20**	**20**	**44**	**20**	**26**	**68**	**2**	**36**	**94**
BTM Solar	-	-	-	-	-	-	-	-	-
BTM Storage	20	20	44	20	26	68	2	36	94

6.4 FTM Resources

As highlighted earlier and shown below in Figure 6-11, Table 6-7 and Table 6-8, FTM Resources are forecasted to have a limited contribution under the modeled achievable potential scenarios:

- Limited uptake of **FTM solar** is observed under BAU, with 210 MW of installed capacity contributing to 20 MW of system capacity needs. Increased energy prices coupled with cost declines modeled under the BAU+ and Accelerated scenarios result in up to 500 MW and 1,630 MW of installed capacity respectively, contributing to 46 MW to 151 MW of peak capacity respectively. However, the potential remains significantly lower than that identified in the economic potential due to market barriers to adoption, primarily the relatively low compensation available compared to system costs.
- Under BAU, no **FTM battery storage** capacity is observed due to the unfavourable economics for investors. This is largely due to the demand charges FTM storage resources are subjected to in Ontario, which diminish the business case. Under BAU+ however, 70 MW of deployed capacity are observed in the second half of the study, resulting in an equal magnitude of capacity contributions by 2032. Under the Accelerated scenario, substantially more FTM storage is observed, reaching 340 MW of capacity by 2032.
- Across the BAU and BAU+ scenarios, no new small-scale hydro capacity is forecasted in the market over the next decade. However, the notable increase in energy prices observed under the Accelerated scenario results in 20 MW (nameplate capacity) of new small-scale hydro deployments.

Figure 6-11: Achievable System Capacity Summer Contribution from FTM Resources

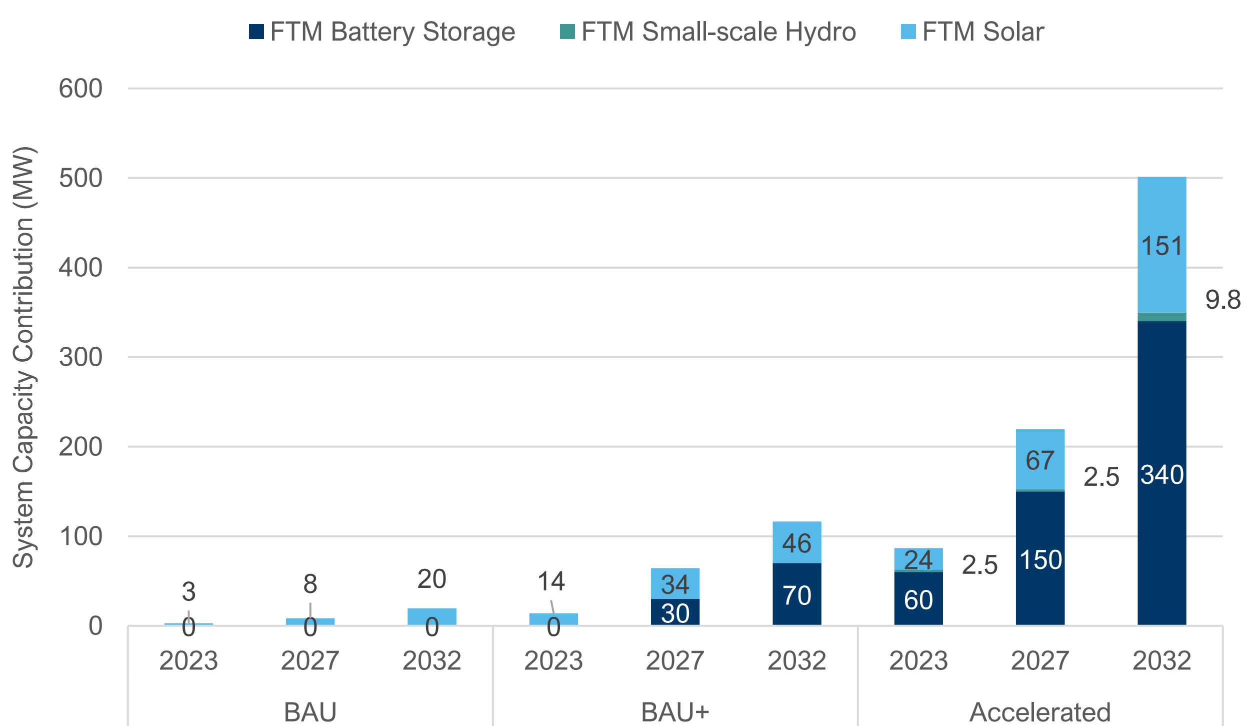


Table 6-7: Achievable Installed FTM Capacity

	Installed Nameplate Capacity (MW)								
	BAU			BAU+			Accelerated		
	2023	2027	2032	2023	2027	2032	2023	2027	2032
FTM Battery Storage	-	-	-	-	30	70	60	150	340
FTM Small-scale Hydro	-	-	-	-	-	-	5	5	20
FTM Solar	30	90	210	150	370	500	260	720	1,630

Table 6-8: Achievable Seasonal System Capacity Contribution from FTM Resources

	Achievable System Capacity Summer Contribution (MW)								
	BAU			BAU+			Accelerated		
	2023	2027	2032	2023	2027	2032	2023	2027	2032
FTM Battery Storage	-	-	-	-	30	70	60	150	340
FTM Small-scale Hydro	-	-	-	-	-	-	2	2	10
FTM Solar	3	8	20	14	34	46	24	67	151

	Achievable System Capacity Winter Contribution (MW)								
	BAU			BAU+			Accelerated		
	2023	2027	2032	2023	2027	2032	2023	2027	2032
FTM Battery Storage	-	-	-	-	30	70	42	150	340
FTM Small-scale Hydro	-	-	-	-	-	-	4	4	15
FTM Solar	-	-	-	-	-	-	-	-	-

7. Key Takeaways

The assessment of the technical, economic, and achievable potential highlights several key insights into the role DERs can play in Ontario's electricity system, the barriers that constrain their uptake, and some of the levers that can help address these barriers. This section summarizes key findings and takeaways from the analysis, which are then used to inform the development of actionable recommendations for IESO's DER integration efforts.

- **There is sufficient economic potential for DERs to cost-effectively meet Ontario's projected capacity deficits over the next decade.** In all scenarios, the total economic potential for DERs exceeds Ontario's forecasted summer and winter incremental capacity needs over the study's ten-year time horizon. In all cases, the majority of the benefits DERs can bring to the system pertain to Capacity and Energy contributions, followed by T&D deferral/avoidance (primarily related to transmission). For most measures, the benefits from ancillary services represents less than five-percent of the system value DERs can provide.

Table 7- 1: Summary of DER Potential by Scenario

Seasonal Capacity	Potential	BAU	BAU+	Accelerated
Summer 2032	**Incremental System Needs**	**2.6 GW**	**5.6 GW**	**6.9 GW**
	Economic Potential	4.1 GW *(15% of peak demand)*	8.2 GW *(27% of peak demand)*	18.9 GW *(61% of peak demand)*
	Achievable Potential	1.3 GW *(5% of peak demand)*	2.2 GW *(7% of peak demand)*	4.3 GW *(14% of peak demand)*
Winter 2032	**Incremental System Needs**	**0.9 GW**	**6.4 GW**	**13.3 GW**
	Economic Potential	2.8 GW *(11% of peak demand)*	6.8 GW *(22% of peak demand)*	15.0 GW *(40% of peak demand)*
	Achievable Potential	1.0 GW *(4% of peak demand)*	1.8 GW *(6% of peak demand)*	3.6 GW *(9% of peak demand)*

- **With each successive scenario, higher energy prices and increased access to compensation for capacity benefits improves the cost-effectiveness of generation and storage measures.** In the BAU scenario, the vast majority of the cost-effective potential in 2032 is derived from DR measures. Under the BAU+ scenario, while a substantial amount of distributed generation and storage resources become cost-effective, DR measures remain the most cost-effective of the DERs studied. With greater growth under the Accelerated scenario, storage and generation measures become even more cost-effective, displacing much of the potential from DR and V2B/G measures.

It is important to note that the BAU scenario presents a very modest perspective on electricity demand growth from electrification, and the resulting avoided costs streams are notably lower than under the BAU+ and Accelerated scenarios. Overall, the BAU+ and Accelerated scenarios likely present a more probable picture of future electricity system needs and DER potentials in Ontario.

- **A variety of DERs offer highly cost-effective economic opportunities to address system needs, with significant growth over time and across scenarios.** In the short-term, under all scenarios, the largest cost-effective DER opportunities are found in large commercial and industrial lighting, HVAC, water heating and other load segment-specific load flexibility opportunities. Over time, FTM battery storage and solar PV deployments become increasingly cost-effective, due to technology cost reductions and increases in wholesale energy prices (driven by increased demand and higher carbon prices and carbon price exposure).[47] Similarly, larger BTM storage deployments in the commercial and industrial sectors (that benefit from economies of scale) offer notable economic potential. Passenger and fleet EV smart charging and V2B/G measures offer cost-effective DER opportunities, with limited volumes of potential in the early years of the study, but growing dramatically as EV adoption increases in the latter years of the study period. Small-scale BTM solar deployments were not found to be cost-effective under the BAU scenario as energy prices and the low coincidence of solar generation with system peak demand led to insufficient electricity system benefits relative to the installed system costs. However, under the BAU+ and Accelerated scenarios, the energy price increases are sufficient to render BTM solar cost-effective.
- **The modeled market, policy, and technology changes under the BAU+ and Accelerated scenarios can enable DERs to provide a higher portion of the 2032 incremental capacity needs in Ontario.** In addition to the increase in DER opportunities observed under the BAU+ and Accelerated scenarios, primarily driven by the electrification of new loads, the modeled interventions can help unlock significantly higher DER capacity in the market. Specifically, under the assumed market, technology and policy changes under BAU+, DERs are forecasted to contribute to 2.2 GW of summer capacity by 2032 (equivalent to a 7% reduction in the projected system peak demand), and under the Accelerated scenario DERs are projected to contribute 4.3 GW of summer capacity (equivalent to a 14% reduction in the projected system peak), nearly tripling the achievable potential relative to the BAU scenario. A similar trend is observed in the winter, with the potential for winter capacity contributions from DERs increasing from 1.0 GW (4% of peak) in BAU to 3.6 GW (9% of peak) under the Accelerated Scenario.
- **While the economic potential for DERs is large enough to meet incremental system needs, less than a third of the identified potential was found to be achievable over the next decade**. While an abundance of DER potential passes the TRC test, just a fraction (ranging from a quarter to a third of the economic potential depending on the scenario) is projected to be achievable under the assumptions applied in this study. This gap between economic and achievable potential is driven by a combination of DER developer/customer economics and market barriers. The results indicate that there are opportunities to improve the financial attractiveness to DER providers by compensating them for all system benefits that DERs provide.

  For example, for DERs that provide capacity benefits, Ontario capacity auction prices are notably lower than the assessed avoided cost of capacity to the system (i.e. the estimated cost of building new capacity resources under each scenario). Expanding opportunities for DERs to compete in future capacity procurements will increase achievable potential and the value that DERs can provide to Ontario's electricity system. Further, some DERs are not currently eligible to receive compensation for all the bulk system

[47] For example, carbon pricing represents approximately 20% of the energy avoided costs under the Accelerated scenario by 2032.

benefits they offer. For example, resources smaller than 1 MW are not eligible to provide and be compensated for wholesale services like OR and RC. Allowing further access to wholesale markets will increase revenue opportunities for these resources. Establishing a compensation framework for avoided T&D costs will also help to increase achievable potential and unlock economic potential of DERs in Ontario.

Despite the effect improved compensation may have to increase the achievable potential, a material gap is expected to persist between economic and achievable potentials, owing to other market barriers such as eligibility rules, building code and zoning barriers, and time lags between improving economics and DER development.

- **A wide range of DERs are achievable in Ontario over the next decade under existing market conditions.** Under the BAU scenario, in the short-term, traditional large commercial and industrial DR opportunities (primarily HVAC, lighting and general process curtailment) are expected to provide the largest contributions to summer capacity needs. Despite low participation in early years, residential HVAC DR opportunities are expected to grow significantly over time to offer the largest single contribution to summer capacity. Additionally, 1 GW of new solar capacity (nameplate) and 178 MW of storage capacity are expected to be installed behind-the-meter over the next decade.
- **There is some misalignment between the mix of DERs identified in the economic potential and the DERs forecasted to be achievable**. Specifically, some resources that offer large cost-effective economic potential are forecasted to have a very limited achievable potential. For example, very limited FTM resources are observed under the BAU scenario, despite high cost-effectiveness and significant economic potential, due to energy and capacity market revenues not being sufficient to provide adequate returns required by investors. In the case of FTM battery storage, despite this measure's cost-effectiveness, the non-coincident peak demand charges applied to FTM resources diminish the business case for investment. Conversely, some resources that are less cost-effective from a system perspective in the short-term (e.g. BTM solar and storage) are achievable in larger volumes as a result of enabling out-of-market retail programs and price signals (e.g. net-metering/TOU, ICI) and non-financial drivers (e.g. resiliency, environmental benefits) that offer an attractive value proposition to adopting customers. This finding further highlights that under current market conditions, access to out-of-market benefit streams (in particular customer bill savings associated with ICI participation) appears to be the key driving factor supporting current DER adoption. More broadly, these findings shed light on circumstances where wholesale price signals and retail price signals neither align with each other nor with the economic value of DERs.
- **Uptake and participation of DERs is increased by electrification, carbon pricing, commensurate compensation, and barrier reductions.** The main motivator behind electrification and carbon pricing is to achieve broad economic decarbonization – and both work in tandem to increase DER potential. Electrification results in the growth of new and large loads that can be amenable to demand flexibility, expanding opportunities for EV managed charging (and V2B/G), space and water heating control, and industrial load flexibility. Electrification also increases grid peaks and energy needs, which amplify opportunities for capacity resources (like DR and storage) and solar PV respectively. Solar PV benefits not only from increased energy needs, but is bolstered substantially by reducing reliance on gas-turbine generated energy increasingly exposed to escalating carbon prices.
- **Offering greater compensation for the value DERs offer to the system could help to increase DER adoption.** While the above-mentioned factors increase the system value of DERs, supporting the

uptake of DERs requires that DERs benefit from the value they deliver – either through revenue or through bill savings (in the case of DERs operating under load customers). This can take the form of compensation for avoided capacity costs, access to energy markets (or to energy prices reflective of energy value), and compensation for T&D deferral and avoidance. Finally, the reduction in other barriers - through more simplified procurement processes or programs, up-front incentives, and more streamlined enrolment, aggregation, metering, telemetry, and settlement requirements – can further increase the portion of the economic potential that can be achieved.

- **A handful of DERs are expected to contribute to the vast majority of the achievable potential over the next 10 years.** Conventional large commercial and industrial DR opportunities - that currently represent the majority of DR participation in the capacity auction - are expected to continue to grow over the next decade. Similarly, new residential DR opportunities are expected to experience significant growth over time and across the scenarios; especially HVAC DR enabled through smart thermostats. Additionally, EV smart charging and V2B/G – predominantly in the passenger vehicle segment – will represent an increasing portion of the DER potential in Ontario, particularly later in the decade. Furthermore, nearly 1 GW of BTM Energy Storage capacity is expected to contribute to summer and winter capacity needs by 2032 under the Accelerated Scenario. Combined, these resources contribute to 66%-70% of the forecasted achievable DER potential in Ontario, depending on the scenario. Beyond these resources, up to 5,000 MW of new BTM solar nameplate capacity is forecasted to be deployed in Ontario over the study period. These resources primarily offer a mix of capacity and low-carbon energy benefits, while also delivering T&D benefits to certain areas of the grid.

POST-2032 CONSIDERATIONS

Although this study focuses on the 2023-2032 timeframe, the importance of DERs in meeting Ontario's system electricity system needs will continue to grow past 2032.

- As the electrification of transportation, space heating, and industry progresses, they will offer increased opportunities to provide grid services as DERs.
- The importance of distributed generation (e.g. solar) will increase to address the growing energy needs and to avoid the high cost and emissions of gas-turbine generated energy.
- Energy storage will also likely play an important role to firm up the capacity of renewables on the grid, further benefiting from technology and cost improvements.

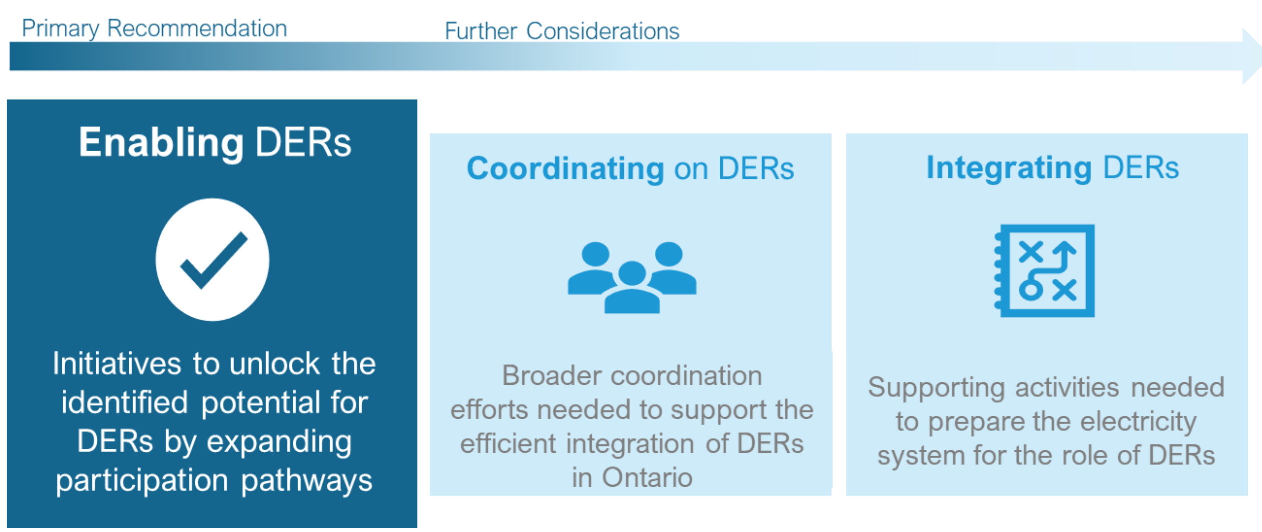
Key drivers that will impact the post-2032 DER landscape will likely be similar to those that most influenced the economic and achievable potentials in this study (i.e. increasing energy prices, the cost of carbon, and capacity avoided costs, etc.).

8. Recommendations

The study demonstrates the growing role that DERs can play in Ontario's electricity system to cost-effectively meet emerging system needs. Specifically, the analysis of the technical, economic, and achievable potential for DERs provides insight into the opportunities DERs may bring to the system, the challenges and barriers impeding their realization, and the levers available to encourage their adoption and participation. This section highlights steps that the IESO, among other actors, can take to reduce barriers and address challenges to DER adoption in Ontario. More specifically, it identifies prospective IESO actions to support the deployment of cost-effective DERs in the recognition that they can satisfy the resource adequacy needs as identified in the IESO's 2021 Annual Planning Outlook and 2022 Annual Acquisition Report.

To arrive at these recommendations, the project team led a series of workshops with IESO staff across the relevant divisions. The workshops were focused on identifying barriers limiting the DER potential found in the study, along with broader considerations pertaining to the integration of DERs in the electricity system. As a group, the participants then identified and weighed various levers that are available to the IESO to address these barriers.

The following recommendations and considerations were assembled based on the quantitative potential assessment results and the input and insights provided by workshop attendees. The recommendations represent the view of the project team and are provided for the IESO's consideration as part of ongoing efforts for DER integration identified in the DER Roadmap. These recommendations support several of the IESO's existing efforts and offer proposals for new, complementary initiatives. While many of the recommendations are directly targeted toward initiatives within the IESO's purview, a number of them will require collaboration and coordination with other electricity sector actors.



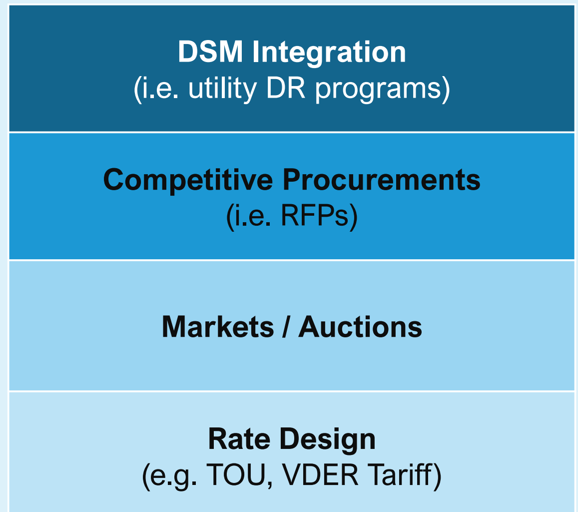
8.1 Enabling DERs

The following section outlines recommendations for the IESO's consideration based on the results of the study as presented in the Key Takeaways section.

DER PARTICIPATION PATHWAYS

Several pathways have been explored in other jurisdictions for securing DER capacity to address system needs. These approaches vary in cost, complexity, level of control, and commercial arrangement. The various approaches are not necessarily mutually exclusive; meaning that they can be combined to offer multiple participation pathways tailored to the characteristics of different DERs, the local market and regulatory context, and the nature of the system needs.

In the recommendations, we highlight different enablement pathways for different DERs under consideration given the findings of the study; however in reality, multiple pathways may be required to attain a greater proportion of the identified economic potential for DERs in Ontario.



We consider a range of potential participation pathways for DERs that are economic under the BAU scenario and have a high potential to provide capacity and energy contributions within the next 10 years, detailed below:

- **CDM Integration:** IESO could develop new programs, similar to conservation and demand management (CDM) programs, that could incentivize DERs to deliver energy and/or capacity; these programs could be enduring in nature or could seek to capture value in the near-term in advance of new market and/or procurement opportunities.
- **Competitive Procurement:** IESO could further incorporate DERs into its procurement initiatives, such as RFPs, that work alongside wholesale markets to acquire energy and/or capacity from targeted DER that have high potential.
- **Markets / Auctions:** IESO could enable DERs through existing or new DER participation models in IESO Administered Markets, including participation in the IESO's Capacity Auction.
- **Rate Design:** IESO could coordinate with the Ministry of Energy and OEB to pursue new rate designs or regulations that would support the deployment of economic DERs. For example, time-of-use rates and Critical Peak Pricing could encourage the consumption of energy only during low demand times. Value of Distributed Energy Resources (VDER) tariffs, similar to what is established in New York by the New York State Public Service Commission, could also support the deployment of DERs by providing a new way to compensate DERs for the energy they generate.

Table 8-1 below outlines key considerations and recommendations related to the various enablement pathways IESO may consider in the near term, given the high economic potential of key DERs identified in the study. Specifically, the recommendations focus on resources with high economic potential and TRC.

The focus of the IESO's efforts will likely need to be tailored to the market, policy and technology conditions that impact these opportunities under the modeled scenarios. For example, the rapid growth of transportation electrification points to the value of focusing on EV smart charging and V2B/G, in-line with the opportunities identified in the BAU+ and Accelerated Scenarios. Similarly, technology cost declines, carbon pricing and the other factors may create a need for the IESO to pivot to new enablement pathways for those resources that have high economic potential under the BAU+ and Accelerated scenario.

Table 8-1: Considerations and Recommendations for Enablement Pathways

Resource Groups	Enablement Pathway – Consideration and Recommendations
Residential HVAC DR	• Limited viability through existing participation pathways (e.g., challenging requirements of Capacity Auction and Hourly Demand Response (HDR) participation model) • The IESO should enable residential DR via programs, and in parallel, explore options to reduce capacity auction participation barriers for residential DR • Residential HVAC DR could be enabled through an IESO-led program (e.g., residential DR program) or a program led by another entity in coordination with the IESO (e.g., LDC-led program) • Residential HVAC DR could also be enabled through electricity rate design, including the implementation of Critical Peak Pricing (CPP) and direct load control (DLC)
Commercial HVAC DR	• Existing participation pathways exist through the Capacity Auction, including the HDR participation model • Given the high-TRC, additional Commercial HVAC DR could be enabled through an IESO-led program (e.g., commercial DR program) or a program led by another entity in coordination with the IESO (e.g., LDC-led program), particularly for the small commercial sector that has similar barriers as residential customers • Commercial HVAC DR may also be enabled through electricity rate design, including dynamic rates for Class B customers
BTM Storage (Residential, Commercial and Industrial)	• Participation pathways currently exist through the Capacity Auction, including HDR, as well as via the lucrative ICI participation model, however in the latter two pathways, net-injection by a BTM storage resource is not permitted • Additional BTM Storage may be enabled through enhancements to the IESO Market participation model to enable net-injection • BTM storage, and possibly DR, could be considered for future capacity procurements • IESO, OEB, or LDC-led programs could also support BTM Storage (including residential) deployment; for example, BTM storage resources could benefit from enhanced TOU rates including CPP
V2B/G	• Given the untested nature of this resource, it is unclear how effectively V2B/G could participate in IESO Markets • IESO should leverage pilot programs and explore partnerships with other potential program delivery agents (e.g., third parties, LDCs), to prepare for widespread emergence of V2B/G capability in the market, recognizing that each customer segment may require its own approach • Once the market is more mature, IESO should prepare transitioning from pilot to regular program or market integration

Resource Groups	Enablement Pathway – Consideration and Recommendations
	• Another potential approach could be to enable V2B/G through advanced electricity rate design and net-metering, including the ability to provide peak capacity by injecting electricity during critical peak periods
FTM Solar	• While an existing participation model for FTM solar exists in IESO Markets, variable generation is not yet eligible to participate in the IESO's Capacity Auction • Given its high value of avoided-energy in some scenarios, in spite of low capacity contributions, FTM solar should be targeted in future IESO procurements
FTM Battery Storage	• An existing participation model for FTM battery storage exists in IESO Markets, however, only existing, uncommitted FTM battery storage is enabled via the IESO's Capacity Auction • FTM battery storage could be enabled via IESO-led procurement, including upcoming LT RFP • Given high TRC and economic potential, it would also be reasonable for IESO to develop targeted (energy storage only) procurements to further enable FTM battery storage participation • Working with LDCs to exclude FTM storage from non-coincident peak demand charges would also improve the business case for these resources
Residential EV Passenger Charging	• Given the untested nature of the resource, it is not yet clear how residential EV passenger charging would participate through IESO Markets • IESO should leverage pilot programs and explore partnerships with other potential program delivery agents (e.g., third parties, LDCs), to prepare for residential EV passenger charging programs • Similar to residential HVAC DR, residential EV Passenger Charging could also be enabled through electricity rate design, including the implementation of Critical Peak Pricing (CPP) which would encourage customers to avoid charging during peak hours or critical events
EV Fleet Charging	• Given the untested nature of the resource, it is not likely that EV fleet charging would have a clear participation pathway through IESO Markets • IESO should leverage pilot programs and explore partnerships with other potential program delivery agents (e.g., third parties, LDCs), to prepare for EV fleet charging programs, should conditions emerge • Once the market is more mature, IESO should plan to transition from pilot to regular program implementation • Similar to residential EV passenger charging, EV fleet charging could also be enabled through electricity rate design, including the implementation of Critical Peak Pricing (CPP) which would encourage customers to avoid charging during peak hours or critical events
BTM Solar **(Residential, Commercial and Industrial)**	• Given the current benefits of participating via net-metering, it is not likely that residential BTM solar would participate directly through IESO Markets • Commercial and industrial BTM solar may potentially be enabled via IESO Market Participation pathways, however, other IESO programs may be preferable for customers • Enhancements to regulations (e.g., net metering) may also serve to unlock potential of BTM solar. For example, mandating NEM under TOU rates (as was assumed in this study) improves customer economics, thereby supporting BTM solar adoption, and could further encourage the installation and pairing of BTM storage

Four key recommendations are therefore proposed for the IESO's consideration.

1. Continue with the DER Market Vision and Design Project

As quantified in this study, a diverse and significant amount of cost-effective DER potential could be developed to meet bulk and regional electricity regional needs, while benefitting customers through bill savings and reduced environmental impacts. In addition, changes to the wholesale market could enable the reacquisition and continued operation of existing DERs contracted by the IESO as contract terms expire.

The IESO's Market Vision and Design Project is a key element of the IESO's DER Integration activities and will inform the design and implementation of wholesale market participation for DERs in Ontario. These efforts aim to remove barriers to participation for resources capable of providing wholesale market services, including DR aggregations and BTM resources. The changes being considered by the DER Market Design Vision would bring Ontario closer to alignment with other North American jurisdictions subject to FERC Order 2222 and could unlock larger portions of the identified economic potential for DERs. Changes currently under consideration in the IESO's DER Market Vision and Design Project include, among other things:

- Reducing the threshold for market participation below 1 MW;
- Enabling heterogeneous DER aggregations;
- Establishing locational requirements that allow DER aggregations to be geographically broader than a single point of interconnection; and
- Enabling DERs and DER aggregations to offer a broad range of services and products to the IAM.

The IESO's DER integration efforts aim to strike a balance between the cost and complexity of the above changes relative to the benefits, with the aim to secure DER potential at the lowest enablement cost and in the most appropriate manner. The IESO's current proposal for foundational and enhanced market participation models may be a lever to mitigate some of these challenges. For example, the study indicates that 13.6 GW of BTM storage is economic under BAU+, illustrating the potential benefits associated with aggregation models that can enable BTM storage to provide the full set of services it can offer.

2. Develop Tailored DER Programs and Procurements

Current IESO resource acquisition mechanisms that are available or in development (i.e., Capacity Auction, Long-Term 1 RFP) require the participant to register as an IESO Market Participant and, therefore, certain DER configurations are excluded from participation. For example, despite the material potential for residential HVAC DR identified in the study, there has been no successful residential HVAC DR participation in the IESO's recent Capacity Auctions.

As shown in the potential assessment results and discussed in Table 8-1: Considerations and Recommendations for Enablement Pathway above, residential HVAC DR, BTM storage, and FTM solar all offer notable economic potential, and while they are eligible to participate in the market, current participation rules and compensation mechanisms are likely to leave substantial potential untapped. On the other hand, Commercial DR has a successful track record of participation via the Capacity Auction (including under the HDR participation model), and BTM solar has also seen notable uptake via net metering. Moreover, FTM battery storage will likely benefit from upcoming IESO procurements.

The IESO should consider the development of tailored initiatives to acquire services from DERs that are cost-effective but that have limited opportunities to participate or succeed in the IAM or other procurements in the near term. Given the diversity of DERs with identified economic potential, a "one-size fits all" approach for enabling DERs may not be feasible due to the specific barriers and challenges faced by each DER type. Targeted procurements or programs would help encourage the uptake of DERs that can provide high-value to the system, but are not easily or fully compensated for their full value through existing mechanisms, or do not have the opportunity to compete in the current market against other resources. DERs that would benefit from such targeted procurements or programs include Residential DR, FTM solar, and BTM storage.

Example initiatives could include:

- Launching resource-specific procurements for high-potential DERs that currently struggle to participate in the market.
- Engaging program delivery partners for the development and implementation of initiatives, such as LDCs or other service providers.
- Enabling non-market participation pathways such as CDM initiatives for customer-facing programs.
- Aligning program design with a regulatory framework that enables retail level participation, such as net-metering, time-of-use rates, and possibly critical peak pricing.

Given that changes to the IAM as contemplated by the DER Market Design Vision are anticipated for 2026, and resource adequacy needs are emerging in 2025, it would be prudent for the IESO to pursue initiatives that target high-potential DERs in the near term.

A RETAIL DR PROGRAM

Given the significant potential for HVAC DR identified in the study, a specific program could be developed to capture cost-effective peak load management measures related to residential and commercial HVAC systems - measures that have no-to-limited participation under the current HDR participation model of the IESO's Capacity Auction. To ensure incremental capacity is obtained, the HVAC DR program could focus on customer segments ineligible for ICI participation. The program could be delivered centrally by the IESO or regionally by program partners (e.g., LDCs or other service providers), offering streamlined participation pathways unlocking significant DER Potential.

3. Develop T&D Compensation Frameworks

Insights from the study confirm that DERs can cost-effectively contribute to T&D needs in certain circumstances, and that compensating DERs for this value can be the key to unlocking further DER potential (and the associated bulk system benefits). This study identifies notable opportunities for DERs to contribute to transmission investment deferral (in the order of 2,400 – 4,150 MW) - all of which can be met cost-effectively when included as part of the overall DER value stack (which include DER capacity and energy benefits). The financial benefits associated with transmission deferral was found to be much larger than the distribution deferral opportunity, with the transmission deferral value representing 96% of the T&D avoided costs under all scenarios. Ultimately, this makes transmission deferral the third-largest benefit stream in the economic potential, suggesting that transmission deferral opportunities should be prioritized when considering options to support new DER capacity.

This finding reinforces the rationale behind the IESO's current plans to develop Non-Wire Alternatives compensation approaches as part of its DER Roadmap. Through these efforts, the IESO can contribute to a comprehensive approach ensuring that DERs are appropriately compensated where they are able to avoid or defer traditional capital investments or provide other transmission or distribution grid services. The current framework for compensating DERs only reflects the value of the DER as a supply resource and does not reflect the value associated with the deferral of grid investments. Models have been established in other markets that could guide IESO's consideration, including New York's Value of DERs (VDER) program, which establishes a standard methodology for determining the value of distribution and transmission system investment deferral and locational capacity value. Alternative mechanisms, including local capacity market models being investigated through the York Region NWA Pilot, RFP-based procurements, and other mechanisms being considered can also be used to provide appropriate compensation to DERs. The IESO should coordinate closely with the OEB, LDCs, transmitters, and DER providers on the design of a new framework.

In addition, through the Regional Planning Process Review (RPPR), the IESO worked with stakeholders to identify opportunities for improvements to the process. Consistent with key recommendations from the RPPR, the IESO should continue with its plans to evolve the regional planning process to improve the ability for DERs to be identified and developed in response to regional needs.

4. Align telemetry and metering requirements with expected resource contribution

Given the diversity of cost-effective DERs that were identified, the IESO should consider adopting telemetry requirements that are tailored to the expected DER services, the magnitude of such services, and the practical capabilities of different resources and aggregations. In particular, a balance is needed between having appropriate telemetry to ensure visibility (for reliable system operations), and avoiding imposing significant and prohibitive cost burdens. This balance will be particularly critical to unlocking the significant potential identified across key measure groups like residential HVAC DR or BTM battery storage, as the imposition of current real-time visibility and market settlement requirements would substantially diminish the DER potential identified through this study.

Engagements with service providers can be used to identify the specific challenges concerning establishing baselines, Measurement & Verification (M&V) requirements, and other aspects of telemetry, metering, and settlement. Additionally, exploring and piloting opportunities for leveraging smart meter data and/or other embedded mechanisms (e.g. smart inverters or smart thermostat data) can help provide innovative solutions for addressing these barriers.

8.2 Other Considerations

Beyond the specific recommendations for the IESO to enable DERs, a range of other considerations were identified that can also assist in improving the uptake and participation of DERs to deliver system value.

8.2.1 Coordinating on DERs

While the IESO's efforts are primarily focused on enabling the participation of DERs in IAMs and as NWAs, findings from the study highlight the important interactions between wholesale and retail price signals in enabling DERs, as well as the broader impact of policy levers on DER potential in Ontario. The following recommendations propose a number of coordination initiatives the IESO should engage in to support the efficient integration of DERs in the province.

Contribute to a coordinated DER framework

The IESO should continue to actively engage with stakeholders from government, OEB and LDCs for alignment and coordination on how existing and future initiatives by each party interact, and their role in a holistic DER framework for Ontario. Given that a significant amount of DERs in Ontario are achievable due to regulatory constructs (e.g., net metering, ICI, time-of-use rates, etc.), the IESO should remain engaged in broader regulatory proceedings as non-market-based processes drive adoption and ultimately impact the IESO's planning, procurement, and operations. For example, enhancements to net-metering, such as coupling it with TOU rates, could help unlock the identified achievable potential for BTM solar and battery storage.

The IESO should also work with stakeholders to alleviate regulatory barriers to DER participation. For example, the study's results highlight that despite offering highly cost-effective and large economic potential, FTM battery storage resources face challenging economics that constrain their achievable potential, such as being subjected to generic uniform transmission rates that include monthly peak non-coincident demand charges. Additionally, new retail price signals, such as specific time-of-use electricity rates, could impact the potential for DERs that would participate in IAMs – either by acting as a competing opportunity, or by influencing the baselines against which IAM performance is measured. Opportunities to consolidate and simplify the potentially fragmented offerings available to potential DER participants, and issues around dual participation in wholesale markets and retail programs (and double counting risks), should be examined alongside the appropriate stakeholders.

This engagement can take multiple forms, including through regulatory processes, joint efforts with other actors (e.g. the OEB-IESO Joint Targeted call) and/or convening stakeholders for the development of a comprehensive, cohesive and coordinated DER framework for Ontario.

Inform policy discussions

A number of the factors modeled as scenario levers and identified as having high impact on the achievable potential for DERs in Ontario pertain to federal, provincial, and municipal energy and climate policies and targets.

Efforts and plans for the electrification of buildings, transportation and industry will have critical implications on system needs, the technical potential for DERs and potential contribution they can offer the system. The electrification of heating and transportation leads to an increase in DER opportunities (e.g. smart-charging EVs, smart thermostats, co-locating energy storage with new heat pumps). However, the particulars around electrification can heavily influence DER potential in ways that may not be obvious. For example, if the electrification of space and water heating proceeds through geothermal (ground-sourced heat pumps) rather than air-sourced heat pumps, it will result in far lower summer and winter system peaks than presented in this study; while this reduces DR potential from HVAC and water heating, it substantially reduces the new capacity and energy needs imposed by electrification and can result in lower overall system costs and GHG emissions.

Similarly, the impact of carbon pricing on wholesale energy prices may increase DER revenues and stimulate higher market activity. The IESO should consider coordinating and aligning relevant initiatives to foster policy certainty and improve market confidence, thereby enabling further investment in DERs.

An integrated DER, electrification, and GHG mitigation strategy, in the context of not just the electricity system but the energy system at large, can reduce total system costs and overall energy costs to customers, while contributing to GHG-mitigation goals. The IESO can play a key role in supporting analysis, informing discussions, and contributing to a strategic electrification plan for the province. This could include developing an integrated electrification potential study to determine the cost-effectiveness of efficient electrification - in combination with demand flexibility - with the aim of determining an optimal path forward.

Engage in pilot and demonstration projects for emerging DERs

A large portion of the identified economic and achievable DER potential comes from technologies that have a limited track-record (e.g. V2B/G, EV smart charging through onboard telematics) or have not yet been demonstrated at a large scale in Ontario to-date. The IESO has already funded several initiatives through the Grid Innovation Fund and other funding streams, and expansion of these efforts as well as consolidation of learnings and best practices is an important step towards unlocking the full potential of DERs in Ontario. Working with solution providers, LDCs, government and other stakeholders, the IESO should continue to identify and develop pilot and demonstration projects for DERs, focusing on those that represent large segments of the potential identified in the study, but are not currently widespread in Ontario and/or do not have a demonstrated track record.

Such pilots will be critical to test and demonstrate the technology applications and gather analytics that can then inform planning assumptions and confirm the forecasted achievable potential and contributions for these resources. Additionally, pilots can be used to explore new control and coordination models for DERs (e.g. different transmission-distribution interoperability frameworks) and to identify requirements that may need to be established to manage the operational characteristics of new technologies (e.g. V2B/G control protocols, BTM battery storage state-of-charge monitoring).

8.2.2 Integrating DERs

The following considerations highlight proposed initiatives that the IESO could undertake to prepare the electricity system for the DERs identified in the study. While the study does not directly assess the impact of the interventions suggested below, key study insights emphasize their importance in unlocking the identified DER potential.

Invest in DER data collection and information sharing systems

A significant challenge in the study process was identifying the baseline level of DER adoption in Ontario as well as participation levels in IAMs. Currently, there is no centralized or conveniently accessible repository of information related to DERs. With the growth in DER penetration and contributions to system needs forecasted over the next decade, increasing visibility into DERs is critical. In particular, for DERs that are enabled through non-market participation and the IESO may not have visibility of, alternative datasets such as net-metering interconnections from the OEB/LDCs, program databases or other non-traditional data sources (e.g. EV registration data, electric service upgrades) can be used to better estimate the population of DERs in Ontario and their key characteristics (e.g. technology type, nameplate capacity, location, date of installation, capability). If incentives are leveraged either through the IESO or other sector actors, such incentives can be made contingent on the sharing of such static information (along with making them contingent on DER participation in grid resource programs). Over time, the IESO should consider investments in new capabilities that leverage smart meter data and data analytics to assess the behaviour of DERs. Better visibility and awareness of DERs in Ontario will support continued improvement in identifying the potential for DERs to meet system needs, while supporting planning and real-time operations.

Expand advanced planning capabilities and coordination

If the forecasted achievable DER potential in this study is realized, DERs will play a key role in Ontario's electricity system, and forecasting the uptake and impacts of DERs – both within and outside of market participation - will need to become a central part of the IESO's planning processes, especially as DERs begin to have a material impact on system outlook. Such advanced planning capabilities would also permit the IESO to assess the impacts of the changing system dynamics observed in the study (e.g. transition to winter peaks, flatter peak load patterns) and identify DER solutions that can respond to emerging system needs. In addition to increasing capabilities, the IESO should increase planning coordination with LDCs as well as with federal, provincial, and municipal energy and climate and electrification objectives to arrive at a full picture of the system.

Continue to explore challenges and solutions for T-D Interoperability

The increased prevalence and role DERs will play across the system means that enhanced operational coordination between the transmission and distribution systems is necessary to enable DERs, maximize the value they bring the system, and safeguard system reliability. Considering that LDCs are expected to pursue more NWA opportunities in the future, it is appropriate for the IESO to coordinate with LDCs on new processes related to the operations of DERs. For example, LDCs may procure DERs, such as DR, to defer traditional capital investment. Currently, the IESO does not have visibility into DERs that may be operating in response to local market signals, and this lack of coordination could lead to the IESO over- or under-scheduling resources operating in the IAM. The IESO has several key initiatives planned under the DER Roadmap, including engagement with the Transmission-Distribution Coordination Working Group (TDWG), that will inform the development of frameworks and protocols for operational, transactional and data flows to prepare for DERs. Additionally, learnings from the York Region NWA Demonstration and other pilot projects such as those supported by the IESO's Grid Innovation Fund should be consolidated in developing these frameworks.

Investigate and adopt new methods and processes to manage DERs

DERs add further challenges to already complex system operations processes that Independent System Operators (ISOs) follow. The IESO should assess the impacts of DERs on grid operations protocols and investigate the need for new methods, processes and tools to manage those impacts. For example, process automation, increasing control room resourcing, capacity-building, investments in new capabilities, increased coordination with LDCs about planning responsibilities, and other processes may be needed to handle the increasing complexity of managing hundreds-of-thousands of new DERs providing numerous services across the system at a given point in time. Delaying such investments may impact the ability of DERs to reliably contribute to the IAMs and to system needs.