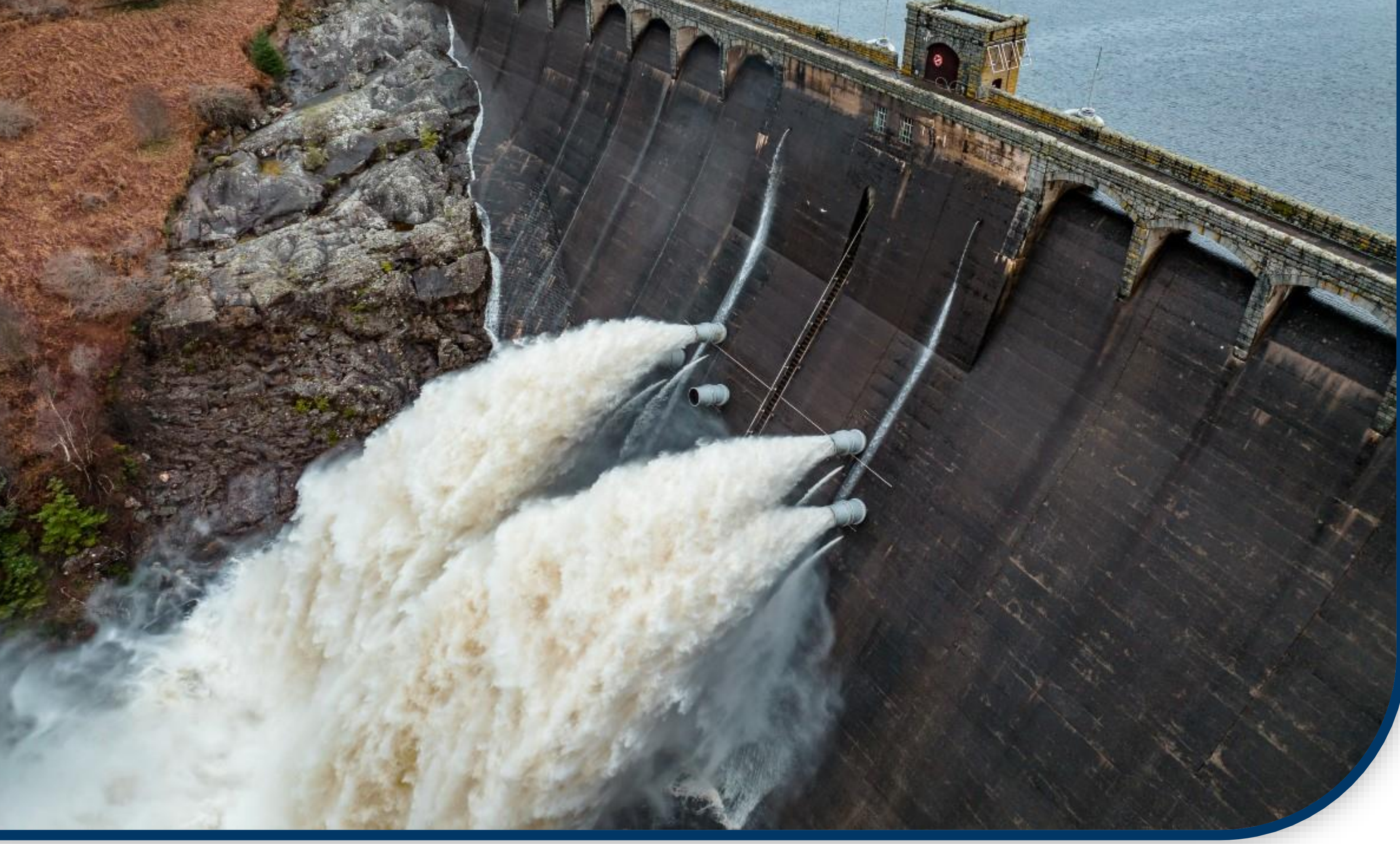

Long Duration Energy Storage (LDES) Opportunity Assessment

A Critical Component in Growing Ontario's Clean Energy Economy

Prepared for:

Energy Storage Canada

Report by:

Dunsky Energy + Climate

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About

Energy Storage Canada (ESC) is the only national trade association in Canada dedicated solely to the advancement and development of the energy storage industry. Working with our diverse members and partners, we ensure energy storage is a vital consideration for policy and decision-makers across Canada, with the aim of creating a reliable, sustainable, and affordable electricity grid. Our continued advocacy has positioned the organization as a leader for the industry across Canadian jurisdictions.

Our goal is to drive the development of viable markets, raise awareness regarding the opportunities and benefits storage provides, and ensure regulatory fairness for all energy storage technologies. With nearly 90 members to date, we represent the end-to-end value chain of Canada's energy storage industry and our technology agnostic approach provides broad support through collaboration, education, advocacy, and research at all levels, for all energy storage technologies.

For more information about ESC, please visit www.energystoragecanada.org

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Executive Summary

Ontario's electricity demand is expected to grow significantly through 2050, driven by economic growth and the need to transition the province to a net-zero economy. To reach net zero, there is a consensus amongst stakeholders that Ontario must decarbonize the existing electricity supply and scale up non-emitting generation as much as 2 to 3 times the current levels by 2050.

As Ontario's generation mix and demand profile continues to diversify and evolve, so will the challenges of balancing and delivering power to a growing provincial economy**. A critical component of this system transformation will be integrating energy storage systems (ESS) featuring a variety of storage technology types**. Ontario is already recognized as a national leader in ESS adoption, a reputation earned through a decade of ongoing market reforms and initiatives culminating in 2023 with the procurement of 880 MW of storage capacity by the Independent Electricity System Operator (IESO). By mid-decade, Ontario is expected to see over 2,500 MW of energy storage capacity installed throughout the province.

There is growing recognition that Long Duration Energy Storage (LDES) – energy storage systems that can discharge for over 10 hours at their maximum power rating and act as a low or zero-carbon energy source – have a potential role in decarbonizing Ontario's energy system. The government of Ontario has recently taken steps to advance the exploration of two pumped storage projects and requested further input from the IESO on the need for LDES capacity as a prelude to potential future procurements. While several studies have assessed the feasibility of achieving net zero for Ontario's electricity system considering a range of emerging clean technologies, the explorations have been fairly limited in the scope and depth of consideration of LDES technologies.

This report explores through a high-level analysis the potential role and benefits that LDES can contribute to Ontario's electricity system by reducing potential supply, planning, and deployment risks associated with the pathway to net zero. For this analysis, we focus on the IESO's *Pathways to Decarbonization* (P2D) study as it represents the most robust vision put forward to date by the system operator.

Our initial assessment suggests that deploying up to 6 GW of Long-Duration Energy Storage (LDES) starting in 2032 could be a cost-effective solution to mitigating potential supply, planning, and deployment risks on Ontario's pathway to net zero.

Specifically, the study explores the potential role LDES can play under three scenarios:

- **Scenario 1 - Buildout Risk:** Uncertainty around the pace of deployment of new nuclear assets and hydrogen turbines creates long-term capacity needs.
- **Scenario 2 – Hydrogen Supply Risk:** New nuclear assets are assumed to be deployed at the pace and scale outlined in the P2D. However, supply chain issues around blue

hydrogen supply (as outlined in the P2D) result in limitations on the deployment of hydrogen-powered turbines.

- **Scenario 3 – Planning and Procurement Risk:** New nuclear assets are assumed to be deployed at the pace and scale outlined in the P2D. However, import capacity constraints, limited contracting of existing assets and higher-than-expected peak demand contribute to higher capacity shortfalls.

Under these scenarios, increased natural gas-fired electricity generation is the most likely backstop for managing the risk of capacity shortfall in Ontario. Relying on natural gas as a key backstop and risk management tool on the path to net zero has potentially significant economic and environmental implications, ranging from commodity price volatility to running afoul of nationally mandated emissions reduction targets.

Our high-level analysis focuses on the assessment of the benefit-cost of LDES deployments under each scenario to estimate the magnitude of cost-effective LDES deployments that can maintain the affordability and reliability of Ontario's future electricity system should these risks unfold. Up to 6 GW of LDES were found to be cost-effective across all three scenarios. This increases to up to 10 and 18GW under scenarios 2 and 3, respectively, if capacity shortfalls exacerbate further.

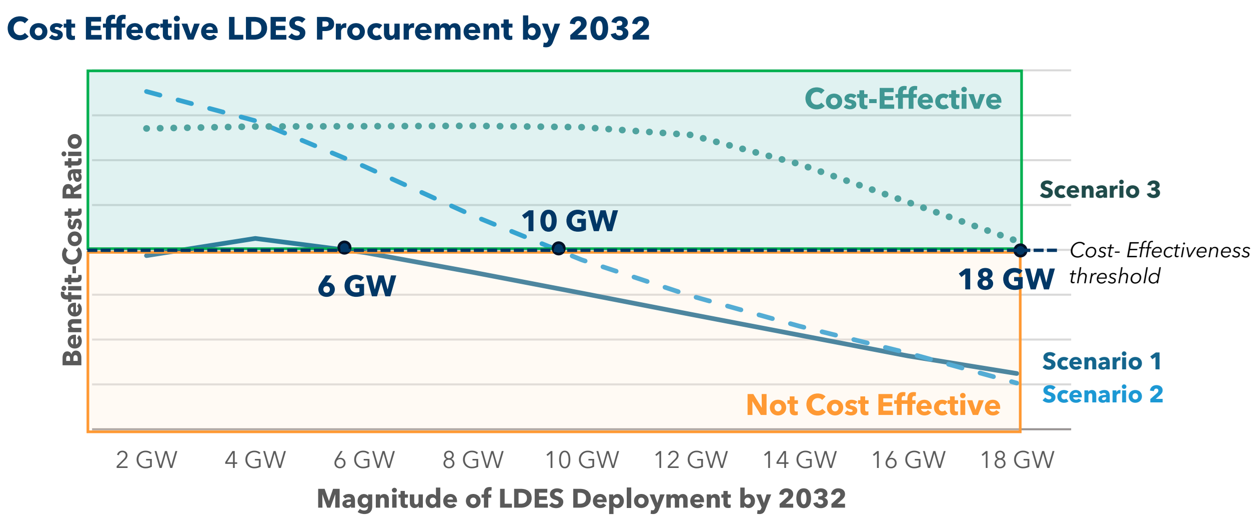

Figure A: Range of LDES procurement in Ontario

While recognizing that the use of hydrogen turbines in the pathway outlined in the P2D is a proxy of the need for a wider range of gas peaker replacement options, we identify that LDES powered by wind is a cost-effective alternative for ensuring and maintaining grid reliability during this transition and therefore merits closer attention.

Our high-level analysis suggests that deploying 6 GW of LDES could provide between $11B to $20B in ratepayer savings over its lifetime relative to the baseline P2D scenario.

In summary, our initial assessment suggests that LDES can be an important risk management tool as Ontario pursues its pathway to a net-zero electricity system. Indeed, LDES can serve as a reliable backstop for capacity shortfalls and a key provider of a broad range of grid ancillary services to support reliability while also providing increased operational flexibility and support during contingency events.

Given the potential benefits to Ontario and the timelines inherent in procuring LDES options, further analysis is necessary to define the potential, set appropriate targets, and advance timely procurements.

As an immediate, no-regrets move, the IESO can begin incorporating LDES into all future planning and explore in greater depth the potential of distinct LDES options to deliver grid benefits, including enhancement of resource adequacy, operating reserves, regulations compliance, and emission reductions. The thorough exploration of LDES would then enable the IESO to establish an appropriate LDES procurement target for Ontario, taking into account all the costs and benefits, including the mitigation of potential risks associated with a slower build-out of new resource options, insufficient hydrogen supply and/or unforeseen planning and recontracting risks that may result in inadequate supply from existing resources.

The outcomes of this exploration can inform the establishment and communication of clear targets for LDES deployment in Ontario from 2030 through 2050, as well as for procurements starting mid-decade. Considering the challenges of abbreviated procurement lead times (e.g. community consent, supply chain constraints), the prospect of first-of-a-kind permitting processes, the longer lead times required for many LDES technologies (estimated to up to seven years), as well as the sunset of the 30% Federal Investment Tax Credit (ITC) by 2033, clarity on timelines and early procurement calls – starting as early as 2025 will be critical to unlocking the full contribution of LDES towards a resilient, low-emission, and economically vibrant Ontario.

Contents

1. Introduction

Ontario's electricity demand is expected to grow significantly until 2050, driven by sustained population and economic growth. Additionally, to mitigate the impacts of climate change and retain our economic competitiveness, the province needs to transition to a net-zero economy that significantly reduces greenhouse gas (GHG) emissions and increases reliance on cleaner energy sources. This will require the economy-wide decarbonization of buildings, transportation, industry, and energy supply. Furthermore, as heating, transportation, and a range of heavy and light industries transition from fossil fuels to electric alternatives, Ontario will see significantly higher electricity demand. Thus, the province's electricity grid will be the crucial enabler of the province's transition to a net zero economy.

To reach net zero, the consensus amongst stakeholders and of system modelling indicates that Ontario must decarbonize its existing electricity supply and scale up generation to 2 to 3 times current levels by 2050. Several studies[1] have evaluated net-zero-aligned pathways for decarbonizing Ontario's electricity system. The range of solutions found in these analyses includes improvements in energy efficiency, significant expansion of renewable generation, deployment of large-scale nuclear and SMRs, use of hydrogen-powered turbines, and a large-scale expansion of the medium- and high-voltage transmission network.

Different pathways envision different mixes within these solutions, but all are highly sensitive to the assumptions underlying the analysis, and thus, each potential pathway carries inherent risks. These uncertainties include the pace and magnitude of the deployment of technologies such as SMRs, hydrogen turbines or even the scale of electricity demand. Uncertainty equals risk. The risk that potential pathways may not unfold as envisioned has potential implications for the affordability and reliability of Ontario's future electricity system.

Ontario must design a clear risk mitigation strategy. Currently, the most likely backstop for managing such risk in Ontario is increased natural gas-fired electricity generation[2]. This is not ideal, given that increased natural gas-fired generation works against the necessity to decarbonize the grid. It is also unclear whether new natural gas-fired generation builds represent the most cost-effective way[3] to ensure grid reliability should Ontario be forced to deviate from its planned path forward on decarbonization.

Relying on natural gas as a principal backstop and risk management tool on the path to net zero has potentially significant economic and environmental implications. Economically, it increases exposure to volatile prices and the risk of stranded assets, limiting the potential for low-cost renewable energy and nuclear as alternative energy sources when

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[1] Outlined in Section 3: The Need for LDES
[2] On November 16th, the IESO published its response to the Federal government's draft Clean Electricity Regulation (CER). In its response, the IESO states that "it plays a critical role in maintaining system reliability" and that "reduction in natural gas is enabled by nuclear refurbishments, new small modular reactors, other additional renewable generation (e.g., wind, solar) and significant conservation." Thus, any threat to grid reliability would position natural gas as the most likely backstop.
[3] When paired with battery storage, wind and solar can offer dispatchable grid power at increasingly more competitive costs than gas peakers in Ontario. A Renewables Powerhouse - Clean Energy Canada

paired with storage to ensure reliability. Environmentally, aside from direct emissions, there is a risk of indirect emissions resulting from methane leakage during transportation and extraction[4]. Carbon capture and storage (CCS) of carbon emissions remains a promising but unproven technology[5]. If Ontario ends up pursuing a strategy contingent on increased natural gas use, it ensures that net zero will not be achieved and risks a high-cost outcome.

Therefore, a critical component of this system transformation will be integrating energy storage systems (ESS) featuring a variety of storage technology types. Ontario is already recognized as a national leader in ESS adoption, a reputation earned through a decade of ongoing market reforms and initiatives culminating in 2023 with the procurement of 880 MW of storage capacity by the Independent Electricity System Operator (IESO). By mid-decade, Ontario will see over 2,500 MW of energy storage capacity installed across the province.

As Ontario's generation mix and demand profile continues to diversify and evolve, so will the challenges of balancing and delivering power to a growing provincial economy. Several studies have assessed the feasibility of achieving net zero for Ontario's electricity system with consideration for a range of emerging clean technologies, but until now, most have had a fairly limited scope and depth of exploration of the potential role of Long Duration Energy Storage (LDES) – energy storage systems that can discharge for over 10 hours at its maximum power rating and act as a low or zero-carbon energy source.

In particular, as relatively flat winter peak trends unfold, LDES can be a critical component in shaping transition pathways by firming low-cost variable generation sources like wind and solar energy and supporting baseload resources like nuclear and hydro as reliable resources for meeting capacity needs and key provider of an array of grid ancillary services to support reliability and increased operational flexibility and support during contingency events.

This report, then, examines the potential of LDES technologies to reduce risks and ensure success as Ontario continues its transition to net zero. Specifically, the study:

- Highlights the **Technology Readiness** of LDES by exploring the range of LDES technologies and their corresponding technical maturity and commercial availability.
- Identifies **The Need for LDES** by evaluating the supply, deployment, and planning risks in the various net-zero pathways explored to date.
- Demonstrates **The Value Proposition** LDES offers the system through high-level modelling, which confirms LDES is a cost-effective guardrail to ensure that Ontario stays on track toward its decarbonization goal.
- Provides **Recommendations** for Ontario's electricity sector stakeholders to capture the benefits associated with LDES.

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[4] Canada's second most abundant greenhouse gas is CH4, making up 13% of national GHG emissions. In 2018, 43% of Canada's anthropogenic CH4 emissions originated from oil and gas systems. The major sources of oil and gas CH4 emissions are from activities that occur during upstream production, which include venting (intentional releases; ~ 52%), incomplete combustion during flaring (~ 1.4%), and fugitive emissions (unintentional releases from faulty equipment, or drilling; ~ 42%) MacKay, K., Lavoie, M., Bourlon, E., Atherton, E., Baillie, J., Fougère, C., & Risk, D. (2021). Methane emissions from upstream oil and gas production in Canada are underestimated. Scientific Reports, 11(1), 1-8. https://doi.org/10.1038/s41598-021-87610-3

[5] The P2D also raised concerns about CCS, indicating that carbon capture and storage CCS was considered unlikely given the technical and economic challenges of using it on peaking plants.

2. Technology

Long-duration energy storage or LDES typically refers to an energy storage system that can discharge for 10 hours or more at its maximum power rating to act as a firm low or zero carbon energy source[6]. These technologies differ from other battery storage systems that discharge over much shorter durations. LDES technologies can serve many purposes when integrated into a grid, providing operating reserves, peaking capacity, multi-day storage, and even seasonal energy storage.

2.1 Classifications

LDES systems and technologies come in many shapes and sizes but are broadly categorized as **electrochemical**, **mechanical**, or **thermal**[7]. Each category can be subdivided further, but these broad categories help explain the fundamental technologies, inputs, supply chains, and grid-supporting use cases.

- **Electrochemical LDES** includes technologies such as static, flow, or metal anode batteries. Some of these can include zinc-bromine hybrid flow, aqueous zinc halide, aqueous vanadium redox flow, aqueous symmetric sodium ion membranes, calcium anodes, nickel-hydrogen anodes, iron flow anodes, zinc anodes, zinc-air, iron-air anodes, iron-salt anodes, and many others. Electrochemical LDES has the widest variety of options for the technology configuration, and new systems are frequently coming to market. Electrochemical batteries are easily scalable, have long life cycles, are unaffected by deep discharges, and can have very low self-discharge.

- **Thermal LDES** systems use stored thermal energy, which can be used most for building heating and industrial processes. Latent heat can be captured through solid-to-liquid transformation, sensible heat in a single medium, and thermochemical heat from endothermic and exothermic reactions. The medium and materials used – such as salts, graphite, water, solid and liquid metals, and waxes – offer various temperature ranges, storage durations, and use cases. These systems are low-cost due to abundant, inexpensive raw materials and, in some cases, incredibly high energy densities. Further, the energy capacity of the thermal LDES systems can also be extended by increasing the amount of storage material and is independent of the system's power capacity.

- **Mechanical systems** take a very different form and employ water, air, or heat in compression systems or turbines, using gravity or pressure to store energy for longer durations. The most well-established LDES technologies include pumped hydro storage, which accounts for 95% of total energy storage capacity worldwide today, as

[6] According to a literature survey carried out by NREL, using +10 hours is an ideal definition for long-duration energy storage (LDES). This is because it has the largest number of citations across the studies surveyed by NREL and is increasingly being used after its adoption by the Advanced Research Projects Agency-Energy (ARPA-E), which defines LDES as 10–100 hours. NREL LDES Survey
[7] Some classifications of LDES include a fourth category, chemical, to refer to energy-carrying chemicals or fuels such as hydrogen or natural gas. These are not considered within this report.

well as compressed air storage that can be held above- or underground. However, other systems, such as liquid CO_2 and liquid air energy storage, allow for energy storage through high pressure and/or low temperatures.

2.2 Technical Readiness

Different types of LDES systems are at different levels of technological readiness. Some are already widely available and commercially used, while others are still in the pilot and demonstration phases or are being researched and developed. These technologies are developing quickly, with pilots and demonstrations advancing to commercialization more rapidly than in previous years. Broadly, there are three stages of technical readiness[8]:

1. **Established LDES Technologies**: Pumped hydro and compressed air are well-established mechanical-based LDES technologies. Although there can be some challenges regarding siting and permitting, the technology, expertise, and supply chains are globally available and established. Additionally, flow batteries have gained wide-scale acceptance among electrochemical technologies and are commercially available around the world, with many projects announced and under construction[9]. Latent heat systems have also been deployed worldwide, primarily for industrial energy storage.

2. **LDES in the pilot and demonstration phase:** This intermediate stage signifies the ongoing transition from theoretical viability to practical application. The progression from the pilot and demonstration phase to full-scale deployment is driven by market demand, regulatory support, and heightened awareness of the importance of long-duration energy storage. As a result, stakeholders are closely monitoring the performance of these technologies for scaling them up for broader implementation in the energy landscape. The technologies include hydrogen storage, liquid air energy storage, zinc-based batteries, and molten salt technologies.

3. **Research and Development Stage:** These technologies were recently in research and development. Many thermal energy storage systems are still in the pilot phase and seeking funding for demonstration projects. Start-ups and laboratories are exploring many other options for liquid metal energy storage. Sensible heat is an energy storage technology in the R&D phase, using molten salts and rocks. Metal anode batteries are another category of LDES technology recognized as having grid-scale deployment potential.

While the classification above clarifies the different stages of market readiness for LDES from a technical perspective, these technologies also differ in their technical qualifications, including size, capacity, and efficiency, as shown in Table 1 in Appendix A.

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[8] Technical Readiness Levels (TRLs) is a method for understanding the technical maturity of a technology. This report categorized technologies into three stages based on their Technology Readiness Level (TRL). The Research and Development Stage includes all technologies with a TRL of 1 to 6. The Pilots and Demonstration Stage includes all TRL 6 and TRL 8 technologies. Finally, technologies with a TRL of 9 are categorized under the Commercial Stage. Technology Readiness Level (TRL) Assessment Tool (canada.ca)
[9] Net-Zero Power Report

Regardless, LDES development and deployment are gaining momentum. This growth is fueled by major government agencies such as the US Department of Energy and California's Energy Commission, major utilities, research labs, and investors. Overall, the technical maturity and commercial readiness of LDES technologies are driven by three fundamental factors:

1. **The validation of the role of LDES technologies through pilot and demonstration programs:** Utilities around the world are currently testing and piloting LDES technologies to improve reliability and resource adequacy and enable greater integration of renewable energy sources. LDES technology providers also leverage these pilots and demonstrations to enhance their technologies and increase technical and manufacturing readiness. Some note-worthy programs targeted at LDES include,

    - NYSERDA's Renewable Optimization and Energy Storage Innovation Program has set aside $16.6 million for five projects demonstrating long-duration storage technologies. These projects aim to integrate renewable energy sources and reduce emissions. Furthermore, an additional $17 million has been allocated to procure more LDES projects that address cost, performance, siting, and renewable integration challenges.

    - At the federal level, the US Department of Energy has also launched the Long Duration Storage Shot, part of the Earthshots program, which aims to reduce the cost of long-duration energy storage by 90% within ten years, which has $1.16 billion allocated for the program.

2. **The establishment and consideration of procurement targets for LDES:** Several jurisdictions, including California and New South Wales in Australia, have already established procurement targets for long-duration energy storage. States such as New York, Michigan, and Minnesota have also recognized the necessity of incorporating long-duration energy storage in their system planning.

    - **California PUC has set a target of 1000 MW** of long-duration energy storage by 2028 and invested over $380 million in the Long Duration Energy Storage Program to support the commercialization and demonstration of long-duration energy storage systems[10].

    - In the 2022 Electricity Statement of Opportunities (ESOO) report, the **Australian Energy Market Operator (AEMO) emphasized the urgent need to procure 2000 MW of long-duration storage** in New South Wales by 2029 to mitigate reliability risks[11].

[10] California Energy Commission, Long Duration Energy Storage Program
[11] AEMO Update

- **New York's Energy Storage Roadmap[12]** established a requirement for long-duration energy storage. The analysis completed for Roadmap **identified a need for 24 GW of 100-hour battery-type storage with 50% round-trip efficiency** to replace the contributions of 18 GW of a fully dispatchable hydrogen-based resource, along with 13 GW of incremental in-state renewable resources to provide additional energy to charge this storage resource.

- Michigan has introduced bill HB 4256 that mandates that the Michigan Public Service Commission conduct a study to determine the amount of long-duration energy storage required in Michigan and to establish targets for procuring the necessary long-duration storage.

3. **The improvement of access to financing and technical resources for LDES providers:** Most providers of LDES technology either use conventional components like turbines, compressors, heat exchangers, and pumps or base their technology solutions on minerals like Zinc and Iron that are readily available. As a result, mineral extraction companies, turbine and engine manufacturers, large-scale developers, and utilities often partner with LDES companies to provide technical and financial support. As the partnerships expand, so does the sector's ecosystem, leading to increased connectedness. This, in turn, promotes experimentation, knowledge sharing, and coordination on investments, unlocking the potential driving the industry's technical and commercial maturity. With more technology providers trying to develop technologies in this space, the technical understanding and workforce needed to deploy LDES continue to grow.

   - **Partnerships with Extraction Companies:** LDES companies such as Form Energy and VRB Energy[13] have established key relationships with raw material suppliers to improve their commercialization prospects. Mineral extraction companies assist LDES companies by ensuring a secure supply chain, minimizing supply disruptions, and providing financial support to bridge funding gaps.

   - **Venture Capital Support:** Venture capital plays a critical role in elevating the competitiveness of long-duration energy storage (LDES) by offering essential financial backing for research, development, and implementation. Leading VC funds, including Breakthrough Energy Ventures, Energy Foundry, and the European Investment Bank, are instrumental in expediting the market entry of innovative LDES solutions.

[12] New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage. The study suggests that New York's electric grid may need other forms of long-duration energy storage if hydrogen-based or zero-carbon fuel-based resources are unavailable, too expensive, or infeasible to build in certain locations.
[13] Cooperation Framework Agreement between VRB Energy and Pangang

2.3 Cost Competitiveness

To examine the cost competitiveness of LDES technologies, five alternative technologies were compared to 10-hour long-duration energy storage (including lithium-ion) on a net capacity cost basis[14]. As seen in **Figure** 1, the net capacity cost of LDES technologies[15] is comparable to that of combined cycle natural gas, combined cycle natural gas with carbon capture, natural gas peakers, and small modular reactors (SMRs). Among the assessed technologies, the net capacity cost of hydrogen peakers is the highest.

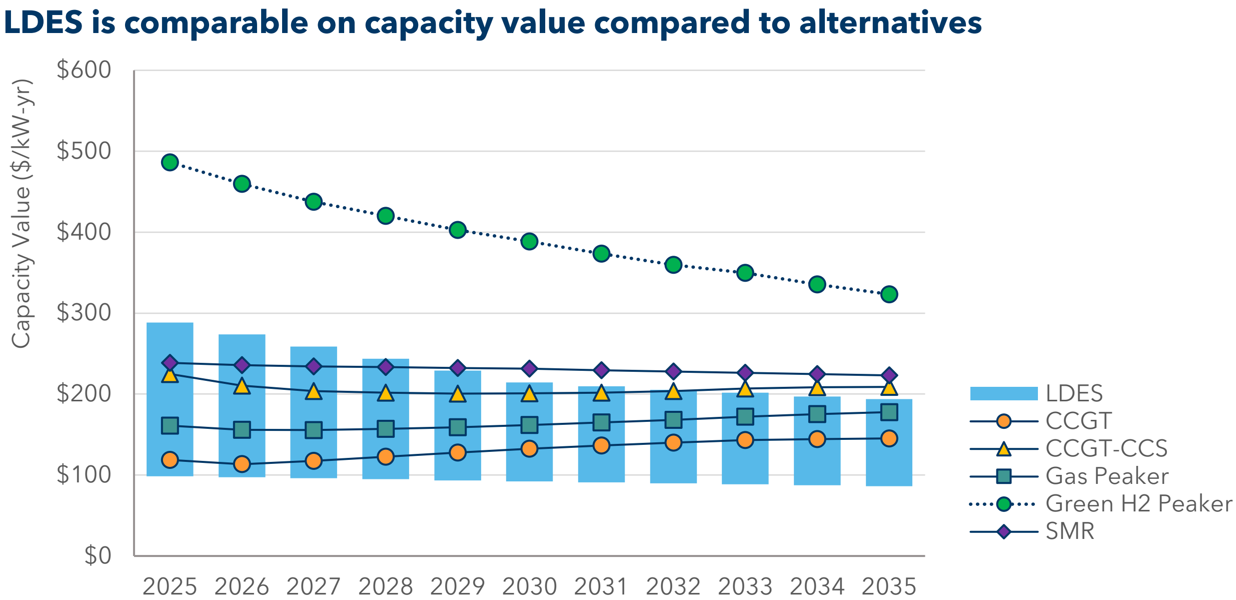

Figure 1 Net Capacity Costs of LDES vs Alternatives[16]

Net Capacity Cost Calculation: *Net capacity cost refers to the annual revenue needed to cover a new capacity resource's capital and fixed costs (net of market revenues) over its lifetime. To determine the net capacity cost of a generation asset, we begin by calculating the gross lifetime costs. This includes upfront capital costs, fixed and variable O&M costs, fuel costs, and carbon tax. We then subtract the lifetime energy revenues from the gross lifetime costs to arrive at the net capacity cost for the asset.*

Energy storage is not a generation asset, and to estimate a proxy net capacity cost for LDES, we assume that the round-trip energy losses are captured as fuel costs.

The net capacity cost of all fossil fuel-based resources increases marginally due to the increase in carbon tax and natural gas prices, while the net capacity cost of LDES will continue to drop. Thus, over the next decade, on a net capacity cost basis, LDES will continue to be a

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[14] Additional Details on the Methodology Net Capacity Calculation is provided in Appendix B
[15] This does not include the incremental cost of a generation resource. However, the LDES is assumed to be charged from the grid at a prevailing marginal price of $75/MWh.
[16] The calculations do not include the impacts of the Investment Tax Credit.

more economical capacity option compared to natural gas combined cycle[17] and gas peakers[18].

The net capacity cost of peaker plants powered by green hydrogen[19] falls significantly due to the dropping costs of renewable generation and electrolyzers. This analysis assumes that green hydrogen is produced from a dedicated onshore wind asset coupled with a battery storage facility in Ontario. However, it remains the most expensive capacity option among the assessed technologies[20]. The net capacity costs for SMRs decrease marginally; however, if SMRs are deployed at the pace and magnitude as envisioned in the P2D, the net capacity costs could be comparable to LDES.

Therefore, from a cost perspective, **LDES could be a more cost-effective capacity option even without consideration of the Investment Tax Credit**. The 30% Federal Investment Tax Credit available to LDES technologies until 2033 would further improve cost-effectiveness.

[17] Assumes a natural gas combustion turbine with carbon storage. Upfront capital and O&M costs were obtained from EIA's Annual Energy Outlook. Carbon taxes and prices are included, assuming carbon prices will increase from $65/ton to $170/ton by 2032 and remain steady thereafter. Assumes an 85% capture rate, and the carbon taxes were assumed to apply to only 15% of the theoretical emissions from similar natural gas combined cycle facilities. The heat rate was assumed to be 12,000 BTU/kWh for the combined cycle with carbon storage.
[18] The Expedited Long-Term Request for Proposal (RFP) has stated a Fixed Capacity Payment of $1093 per MW-business day for natural gas facilities. On a 250-day basis, this translates to a capacity value of $273 per kW-year. As a result, the estimated net capacity costs for natural gas peakers in the analysis are approximately 60% lower than the most recent E-LT1 RFP results.
[19] The battery storage balances the variability of wind generation to increase the utilization of the electrolyzer, which is sized to the average capacity factor of onshore wind. The cost of storing and transporting hydrogen by rail is factored into the calculation. Additionally, the cost and performance of hydrogen turbines are assumed to be similar to that of natural gas peakers.
[20] Due to the technical and safety challenges of transporting hydrogen through pipelines, the net capacity costs of blue hydrogen were not considered in this analysis. The production costs of blue hydrogen are lower than those of green hydrogen. However, the delivery cost through a pipeline from Alberta adds about $3.5/kg, making blue hydrogen comparable if not more expensive than locally produced green hydrogen in Ontario. https://doi.org/10.1016/j.ijhydene.2021.12.025

3. The Need for LDES

3.1 Ontario's Net Zero Pathways

Several net-zero pathway studies have explored how Ontario can decarbonize its building, transportation, and industrial sectors to achieve net zero by 2050. To power these sectors, there is consensus that the electricity system's demand will increase by 2 to 3 times current levels by 2050. Despite that directional alignment, the different pathways differ in terms of the exact magnitude of demand growth as well as the range of solutions that are deemed least-cost and best fit for meeting the emerging system needs.

IESO's ***Pathways to Decarbonization***[21] (P2D) evaluates two scenarios – a moratorium on new natural gas generation by 2035 and a pathway to a decarbonized electricity system by 2050. The latter scenario relies on significant large nuclear, SMR deployment and hydrogen turbines while not considering LDES in any significant way.

By 2050, P2D adds 68,800 MW of new capacity to reach a total system capacity of 88,400 MW. This includes a much wider generation mix, with new nuclear, wind, and hydrogen turbines accounting for over a quarter of the installed capacity each, while solar, demand response, imports from Quebec, energy storage, and hydroelectric power account for the remaining capacity.

The P2D report identifies several caveats, including the current moratorium on offshore wind, the risks of relying on hydrogen imports, and the uncertainty of imports from Quebec, given winter capacity constraints. Additionally, for SMRs, the study recognizes that long lead times, supply chain risks, and uncertain technological readiness (TRL 6) are key risks and could delay deployment.

THE COMPLIMENTARY ROLE OF SHORT AND LONG-DURATION ENERGY STORAGE

The role of long-duration energy storage (LDES) is multifaceted and plays a crucial role in addressing emerging reliability needs. While 4-hour lithium-ion systems excel in responding to short-term demand fluctuations, LDES meets the challenges associated with longer summer and winter peaks, integration of higher levels of renewable energy (RE) or nuclear energy, greater grid reliability and T&D infrastructure deferral.

It is essential to acknowledge that 4-hour and longer-duration storage systems have distinct roles within the energy storage portfolio. The 4-hour lithium-ion systems are well-suited for addressing immediate grid demands such as peaking reliability needs and capacity shortfalls. Numerous studies, including the P2D and other related analyses, have recognized and emphasized the critical role of short-term storage in ensuring grid stability and reliability.

However, as the energy landscape evolves and the penetration of renewable energy sources continues to grow, the incremental value of LDES becomes evident. Longer-duration storage systems are uniquely positioned to support the integration of higher

[21] Pathways-to-Decarbonization

levels of renewable energy by providing sustained power output during extended periods of low renewable generation, such as winter peaks or lulls in solar and wind resources.

This study predominantly focuses on the significance of longer-duration storage in supporting the integration of clean electricity through additional nuclear and renewable energy capacity, increasing system reliability, and addressing emerging system needs. Doing so aims to add an additional layer of analysis regarding the critical need for a balanced energy storage portfolio to meet Ontario's emerging system needs. While 4-hour storage systems will be important in addressing peak needs, longer-duration storage emerges as a key enabler for the continued evolution and optimization of the energy storage landscape.

3.2 LDES in Net Zero Pathways Studies

To date, most net-zero pathway studies have been fairly limited in the scope and depth of consideration of LDES technologies. For example, the P2D study was primarily focused on short-term battery storage technologies, with minimal consideration of LDES. The IESO recognizes other technologies could play a role, but it does not consider other LDES technology options beyond hydrogen turbines to meet capacity and peaking needs.

In addition to looking at the IESO's P2D study, we reviewed four major national pathways studies for their treatment of LDES. These four studies represent some of Canada's most comprehensive decarbonization studies.

- **Canada's Energy Future 2023 (EF2023)** from the Canadian Energy Regulator: The EF2023 report only evaluates storage generally based on the potential for energy arbitrage and acknowledges that this is a limitation in the modelling. It indicates that the storage selected by the model was "only battery storage." However, with no evaluation of capacity or the other contributions to reliability provided by storage, including LDES, this cannot be seen as a reasonable evaluation of the potential for LDES in decarbonization.
- **Canadian Energy Outlook 2021** – Horizon 2060 (IET2021) from the Institut de l'énergie Trottier: This was the only study that gives any detail on LDES and provides a table giving the price assumptions for a range of LDES technologies. However, the report gives energy storage results in general terms, not specifying between long-duration and short-duration storage.
- **Canadian National Electrification Assessment (CNEA)** from the Electric Power Research Institute: The study does not specify the types of storage selected. However, it states, "most of the capacity is battery storage."
- **North American Renewable Integration Study:** A Canadian Perspective (NARIS) from the National Renewable Energy Lab of the US Department of Energy – This study only considered four-hour lithium-ion batteries as a storage technology.

While all the studies – including the P2D - illustrate the underlying conditions that demonstrate substantial needs for the services provided by LDES, overall, they do not provide a comprehensive evaluation of LDES technologies and the role they can play, only acknowledging that there may be a role for LDES or highlighting that other resources could be a proxy for LDES.

Future decarbonization studies should improve the approach to evaluating LDES technologies (as described in the call-out box below[22]). While the above studies have examined broad trends and contributed to our understanding of the texture of decarbonization solutions, improving on those results now requires better focus and precision, including a more judicious approach to assessing storage. At a minimum, future pathways studies should include the following improvements.

- A robust evaluation of different LDES technologies in addition to short-duration storage.
- Clear delineation and reasonable assumptions regarding the reliability needs for planning and grid support, as well as the potential contribution of storage to meet those needs.
- An evaluation of how different storage durations can contribute to reliability and grid support.
- Limits on deploying generating technologies and transmission that reflect realistic and attainable ramping of the construction and capital requirements.

Need for Evolved Energy Models: Grid planning is a complex process that requires careful consideration of different factors. In the past, planners only modelled a few representative days of the year to simplify the process. This streamlining was reasonable when the grid was dominated by fossil-fueled power plants that could adjust their output when reality diverged from the model. However, this approach is no longer suitable for a decarbonized grid, which relies heavily on renewable energy sources like wind and solar. The production of these resources can vary significantly, which means that the energy needed on one day might have been generated on another day or season that was not part of the simplified model. **To address this issue, a more comprehensive modelling approach must be used to look at all hours of the year**. By doing so, it becomes easier to identify when there will be production surpluses and deficits and use LDES to reconcile them.

CASE STUDY: The California Public Utilities Commission prepares a reference resource plan every two years, which helps guide utility planning processes. It uses two models for this purpose. The first model determines what new resources are needed to meet future energy needs, while the second model analyzes how the resource portfolio performs over the entire year to ensure that all needs are met. Initially, the CPUC did not select any LDES resources when it ran the first model. During an extensive public process, the commission identified weaknesses in its models and made the necessary changes. **After running the two models, the commission determined that nearly 1 GW of LDES resources will be necessary by 2026 to meet the projected capacity needs in California.**

[22] Jeremy Twitchell (2023) Laying the groundwork for long-duration energy storage, Bulletin of the Atomic Scientists, 79:6, 372-376, DOI: 10.1080/00963402.2023.2266939

3.3 Risks in Pathways to Net Zero

The proposed pathways to net zero explore different technology solutions to help Ontario reduce its reliance on natural gas and ensure reliability. However, each pathway carries inherent supply, planning, and deployment risks. If these risks materialize, there will be a significant capacity shortfall that will not only diminish efforts to achieve net zero but also have a significant impact on the affordability, safety and reliability of Ontario's electricity system. We will explore the potential contributions and role of LDES in mitigating the risks in each scenario.

For the purpose of this analysis, we focus on the IESO's P2D study, as it represents the most robust vision put forward to date by the system operator. As seen in Figure 2, under the P2D study, the build-out of SMRs and hydrogen turbines is critical in ensuring system reliability and successfully meeting Ontario's 2050 electricity demand.

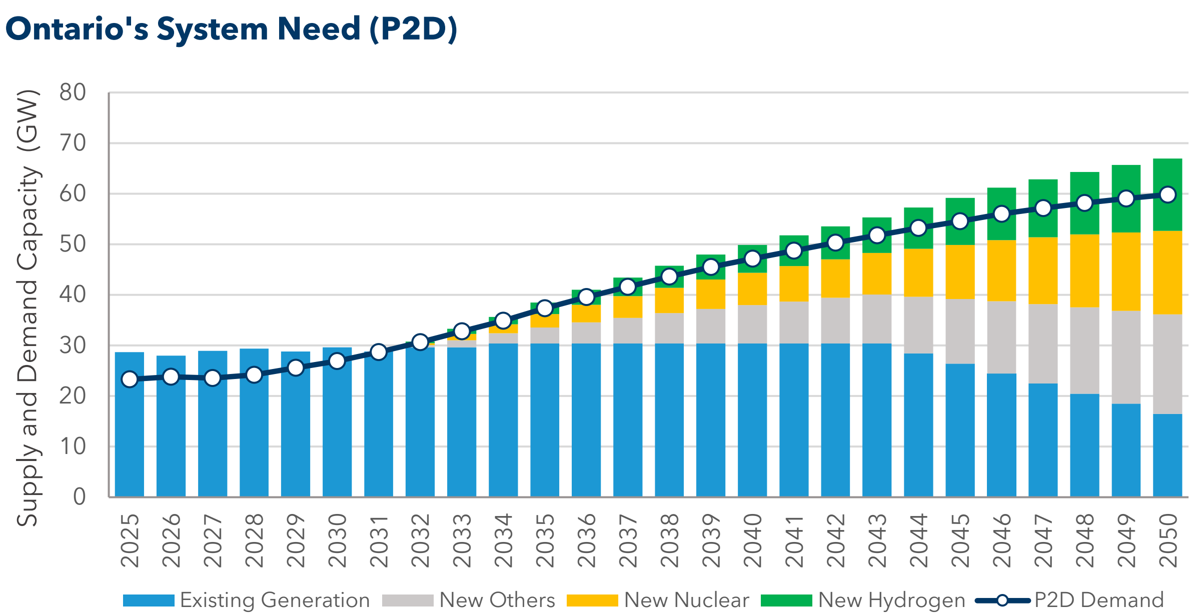

Figure 2: Ontario's System Supply and Demand under P2D[23]

We identify three key potential risks to the pathway laid out in the P2D that could impact the transition to a net-zero electricity system. These risks are explored in the next sub-sections.

Build-out Risk

Small Modular Reactors (SMRs) are rapidly approaching technical maturity by integrating established nuclear technology principles, innovative design features, advanced safety measures, and successful testing and validation. They are purported to be more cost-effective compared to traditional nuclear power generation by using off-site, standardized manufacturing and modular construction. There is a high potential for widespread economies of scale to rapidly bring down costs and construction lead times for SMRs. However, despite

[23] Others include hydroelectric, wind, solar, bioenergy, demand response and dispatchable load.

ambitious plans to deploy a large capacity of SMRs over the coming decades, global deployment has been limited. As a result, there is limited real-world experience on the cost of building and operating such projects. [24]

The economies of scale for SMRs depend on design convergence and effective supply chains. With dozens of potential designs proposed globally, only a handful will be competitive in the long-term – Ontario has endorsed the General Electric - Hitachi design, but this will be first-of-its-kind. There is substantial potential for Canada to drive the supply chain development for these reactors, and Ontario can benefit immensely from this, but the timeline for developing these supply chains is still uncertain.[25]

SMRs still face regulatory and permitting challenges despite the relative inherent safety compared to traditional nuclear because of their passive cooling systems. Regulatory authorities have processes to evaluate traditional reactors and must adapt their regulatory and permitting processes – with many jurisdictions intending to deploy SMRs – but effective deployment depends on proven economies of scale. Regulatory and permitting delays across many authorities will have compounding effects, slowing global deployment.

Ontario has accepted the environmental assessment of the Darlington SMR, but the Canadian Nuclear Safety Commission has never licensed a reactor that is not a CANDU design.[26] Further global SMR deployment will depend on policy and regulatory support to secure private sector investment. The sizable opportunity for SMRs will depend on the speed of deployment in the coming years, which relies on the timely navigation of regulatory and permitting requirements[27].

> ➔ **Takeaway:** *There is a significant risk that SMR projects may not be deployed at the pace or magnitude envisioned in P2D due to regulatory delays, supply chain issues and other global deployment/technology developments.*

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[24] IEA, Nuclear Power and Secure Energy Transitions.
[25] Government of Ontario, A Strategic Plan for the Deployment of Small Modular Reactors
[26] OPG, Bruce Power, NB Power, and SaskPower: Feasibility of Small Modular Reactor Development and Deployment in Canada (2021)
[27] Energy Storage Canada is supportive and acknowledges the role that SMRs would play in meeting Ontario's capacity and reliability constraints.

Hydrogen Supply Risk

The P2D uses Hydrogen-powered turbines as an effective proxy for a wider range of gas peaker replacement options. However, this vision is primarily based on an abundance of low-cost blue H2, likely to be transported from Western Canada to Ontario through dedicated pipelines. As noted in a Techno-Economic analysis of Hydrogen Pipelines by the Transition Accelerator[28], the operations of hydrogen pipelines are challenging for various reasons.

Firstly, the design, construction, and operation of hydrogen pipelines are more complex than pipelines that transport other gases and liquids because hydrogen has a low density. Second, hydrogen pipelines are prone to embrittlement. Lower-strength steel and polyethylene pipelines are less susceptible to hydrogen attack and embrittlement than high-pressure, high-carbon steel. Therefore, hydrogen is a more viable option for small distribution pipelines than large inter-provincial distribution. Furthermore, the safety risks associated with hydrogen are greater than those with natural gas because hydrogen has a large flammability range in the air, requires a small amount of energy for ignition, and its flame is invisible.

If Ontario instead increases reliance on locally produced green or pink hydrogen, this will further increase provincial generation and transmission infrastructure expansion beyond current procurement planning, potentially competing with transportation and industry sector electricity demand for electrification, intensifying uncertainties for system transformation. Producing 1kg of green hydrogen requires 50 kWh of renewable energy. Therefore, to support the operations of 15 GW of hydrogen turbines and provide winter reliability, we would need to direct 66.5 TWh[29] of renewable capacity to hydrogen production, increasing Ontario's 2050 energy needs by 22%[30].

This could exacerbate the current capacity constraints in Ontario and challenge the path to net zero by 2050. While we don't anticipate that the grid would be running electrolyzers to produce green hydrogen while also using green hydrogen to generate electricity, adding the demand to create green hydrogen to the system will result in more hours where the system is closer to load resource balance. The additional demands on the electricity grid would create spillover effects into times when demand is high enough to interrupt green hydrogen production. However, this possibility could be mitigated by producing green hydrogen at non-grid connected facilities, using a combination of co-located renewable generation, energy storage, and power from the Ontario electric grid. Short and long-duration energy storage could be leveraged to increase electrolyzer utilization and alleviate potential grid capacity constraints.

There could be an opportunity for pink hydrogen to be produced through nuclear power from both new and existing nuclear generation assets. This process has the potential to be a major source of Ontario's zero carbon hydrogen supply but has not as yet been deployed at scale. Moreover, like green hydrogen, pink hydrogen would require additional generation for electrification to substitute for the nuclear power committed to electrolysis.

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[28] Transition Accelerator: The-Techno-Economics-of-Hydrogen-Pipelines
[29] According to the P2D, 15 GW of hydrogen turbines would generate approximately 11.6 TWh of electricity with a capacity factor of around 9%. If Ontario pivoted towards green hydrogen, 5.7 GWh of clean electricity would be needed to generate 1 GWh from hydrogen turbines. GE Whitepaper
[30] Assumes that the P2D does not include the energy requirements to produce green hydrogen, because it models low-carbon hydrogen as a theoretical compliance path.

➔ **Takeaway:** *There is a significant risk of inadequate blue and green hydrogen supply to power hydrogen turbines, which, if materialized, could result in 15 GW of capacity shortage by 2050.*

Planning and Procurement Risk

Load Forecasting Risk

As the pace of innovation and disruptions in the electricity sector has increased, system planners face higher uncertainty around forecasted demand patterns, impacting forecasts' accuracy and precision. The IESO's Annual Planning Outlook (APO) forecasts the system's energy demand for a 10-year period. An analysis of the past four revisions of the APO provide insight into the changing system outlooks planners expect year-over-year, with each consecutive APO consistently showing a higher demand than the previous one. As seen in **Figure 3,** in 2019, the APO indicated that the winter demand in Ontario would be around 23 GW by 2040; the most recent revisions to the APO have revised the projected demand to 30 GW.

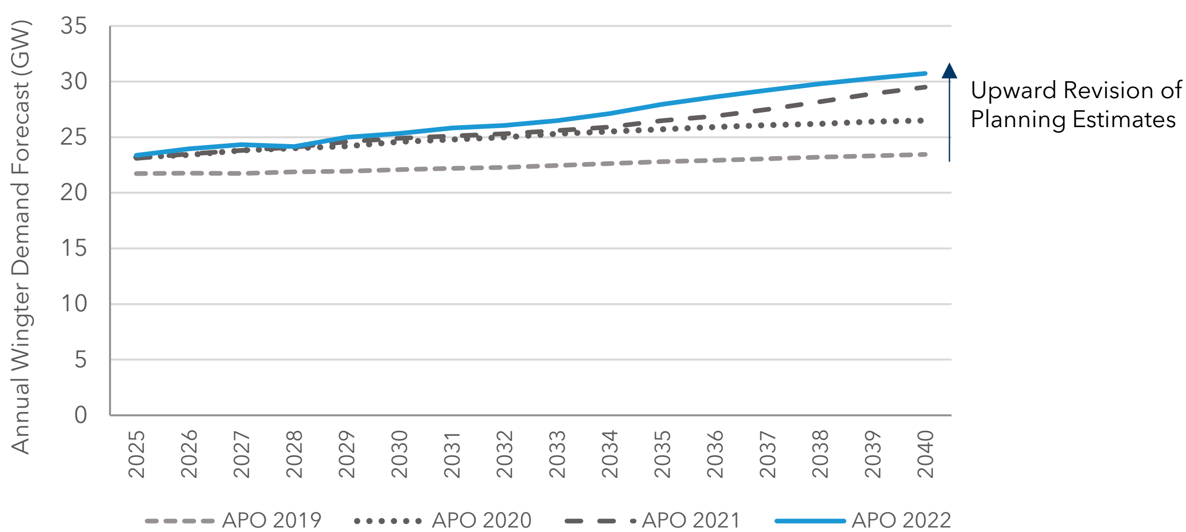

Figure 3: Winter Peak Demand Forecasts by Annual Planning Outlook 2019 - 2022

Import Capacity Risks

Additionally, the Pathways to Decarbonization (P2D) strategy relies on imports, assuming that 3.8 GW of energy would be provided through Quebec. However, there is a risk of insufficient import capacity from Quebec. Quebec already has major heating needs during the winter months, making it a winter-peaking region. In addition to its own energy production capacity and long-term power purchase agreements (PPAs) with Independent Power Producers (IPPs), Hydro-Quebec also depends on short-term PPAs and power purchases from Independent Electricity System Operator (IESO), New York Independent System Operator (NY-ISO), and

ISO New England, as well as demand response programs, such as "interruptible" or residential Demand Response. While interconnections exist between IESO and Hydro-Quebec's transmission grid, Quebec's winter capacity constraints could limit the imports that are positioned in the P2D study. This is especially true because coincident peaks are likely in a P2D world wherein Ontario will shift to a winter peaking system.

Compounding uncertainties and potential coincident peaks is the fact that building interprovincial transmission lines is a challenging task. These projects often require crossing provincial and territorial boundaries, which means coordination among multiple regulatory bodies. This can lead to delays and increased complexity due to different regulatory regimes. The sheer scale of transmission projects, especially over long distances, can also result in substantial construction costs. Allocating these costs fairly among provinces and stakeholders can be a difficult negotiation process. Furthermore, even if the transmission networks are built as planned, it is unclear how increasing energy demands across all jurisdictions, the transition to winter-peaking regimes with widespread electrification, and extreme weather patterns will affect the available export capacities from Ontario's neighbouring provinces and states.

Resource Recontracting Risk

Additionally, the APO 2022 modelled the scenario with no contract extension for legacy assets. The scenario assumes contracts and commitments are not reacquired except for hydroelectric resources. As a result, the installed capacity decreases from 41 to 29 GW in the next decade before levelling off at approximately 23 GW through 2043.[31]

> ➔ **Takeaway:** Underestimation of future demand, constraints on imports and uncertainty around the re-commitment of assets could significantly impact system reliability.

Role of LDES Meeting Capacity Shortfalls

The above analysis focuses on the potential for a gap in the IESO's plan through delayed deployment of new nuclear and hydrogen supply risks, uncertain planning, and procurement risks. LDES is one of the solutions to address capacity shortfalls, and this study aims to highlight the potential for LDES to mitigate some of the risks by reducing the total amount of shortfall possible. The evaluation assumes LDES would play a role in firming up variable generation resources such as wind and solar to meet capacity shortfalls. Additionally, LDES and renewables could offset a portion of natural gas or baseload generation. However, the degree to which LDES will reduce capacity shortfall depends on the resources built and what has yet to be retired.

[31] In its latest Resource Adequacy Update - Evaluating Procurement Options for Supply Adequacy, the IESO is exploring designing its long-term procurements to enable the participation of existing and new wind and solar facilities willing to repower.

4. The Value Proposition

4.1 Modeled Scenarios

Based on the IESO's Pathways to Decarbonization study, Ontario's peak demand[32] is expected to grow from 23 GW today to 60 GW by 2050. The P2D anticipates adding 69 GWs of capacity by 2050 to meet this need. In this case, the analysis assumes that the contracts for the current generation capacity are extended as per the 2022 APO until 2043 and will ramp down linearly to 16.5 GW by 2050, as anticipated in the P2D study. Moreover, this assumes the anticipated capacity buildout will be proportional to the expected capacity shortfall.

Figure 4 below shows that under this base case, assuming perfect foresight, Ontario will not experience any capacity shortfall.

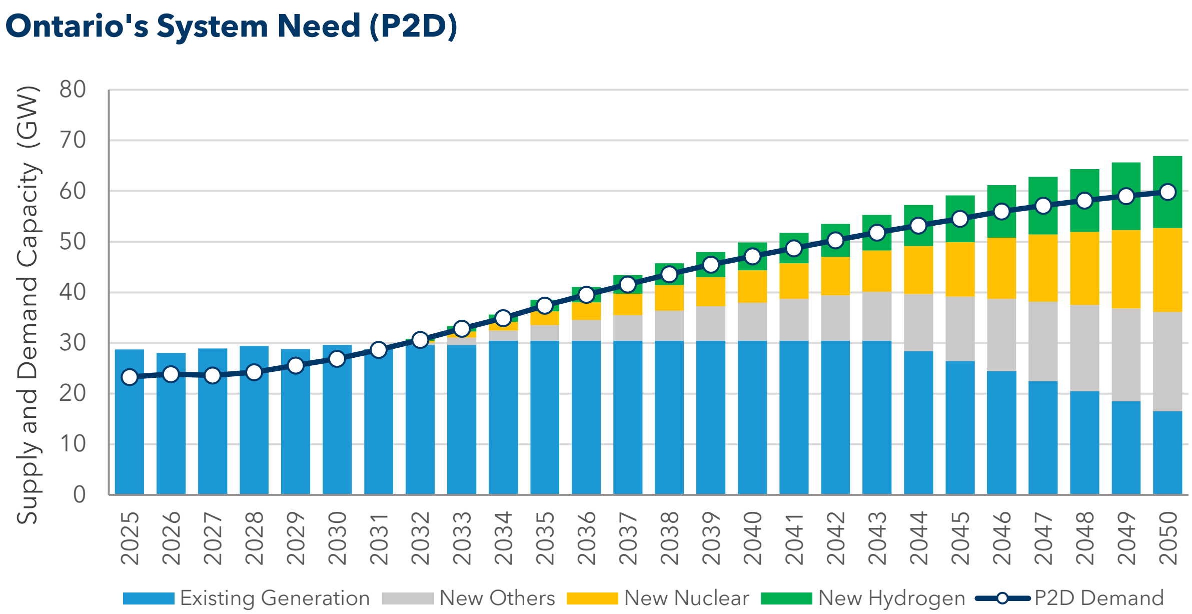

Figure 4: Ontario's Capacity Needs until 2050[33]

Building on the inherent risks in Ontario's net-zero pathway discussed in a previous section, **we developed three illustrative scenarios that map out potential trajectories for Ontario should the identified risks materialize**. The scenarios are not forecasts of the future but rather intended to serve purely as illustrative case studies of potential outcomes under the identified risks.

- **Scenario 1 - Buildout Risk**: Under this scenario, the deployment of new nuclear assets and hydrogen turbines in Ontario is assumed to occur at a slower-than-expected pace or magnitude (relative to that outlined in the P2D). This scenario assumes that only 60% of the SMR capacity and 10% of the hydrogen capacity are deployed as envisioned in the P2D. This could result in a significant capacity shortage of 4 GW by 2035 and 19 GW in

[32] Assumes winter peak demand, since Ontario is expected to switch to a winter peaking system by mid 2030.
[33] Others include hydroelectric, wind, solar, bioenergy, demand response and dispatchable load.

2050. In this hypothetical scenario, to maintain reliability, the IESO could contemplate deploying new natural gas in the near term until 2035. At the same time, there could be a focus on a rapid expansion of wind and LDES to firm up variable renewable generation and provide the much-needed capacity.

- **Scenario 2 – Hydrogen Supply Risk:** In this scenario, new nuclear assets are assumed to be deployed at the pace and scale outlined in the P2D. However, the limited availability of blue hydrogen supply (as envisioned in the P2D as a proxy for wider gas decarbonization) results in limitations on the deployment of hydrogen-powered turbines. Ontario could instead produce some green hydrogen, limiting impacts on peak demand so as not to exacerbate capacity needs, which could limit the deployment of green hydrogen-powered combustion turbines to 1.5 GW (10% of the anticipated capacity in the P2D) by 2050. This could result in a significant capacity shortage of 3 GW by 2035 and 13 GW in 2050. LDES plays a similar role in this scenario by firming wind to alleviate capacity shortfalls.
- **Scenario 3 – Planning and Procurement Risk:** Under this scenario, new nuclear assets are assumed to be deployed at the pace and scale outlined in the P2D, and H2 turbine deployment is assumed to be 50% of the capacity buildout as anticipated in the P2D. This scenario captures the risk of capacity shortfall due to contracts expiring, higher-than-expected peak demand or import constraints and assumes that only 50% of the import capacity, as anticipated in the P2D, is realized. This could result in a significant near-term capacity shortage of 12 GW by 2035 and 9 GW in 2050. In this case, LDES powered by wind still has a role in providing system reliability.

Modelling Approach: To assess the value of LDES in different scenarios, we first determine the corresponding capacity, reliability, and regulation requirements. Then, we assign a grid service value to each requirement. LDES assets are then assumed to operate according to a priority order, which is regulation, reserves, and generation capacity. The analysis assumes that only a portion of the reserves and regulations are allocated to a specific technology. Additional modelling details are presented in Appendix B.

The results of the analysis should be reviewed with consideration of the following caveats:

1. This analysis is a **high-level examination of the key benefits LDES can provide** by mitigating potential supply, planning, and deployment risks. We did not use a production cost model to determine potential savings. Instead, we estimate the potential benefits from LDES based on an assumed avoidance of counterfactual resources (e.g. natural gas, green hydrogen).
2. The scenarios presented are **not intended to forecast the pace and magnitude of the SMR and H2 build-out** but rather to draw attention to the potential risk in the pathway to decarbonization. The purpose is to demonstrate potential capacity shortfalls if risks materialize.
3. We understand that relying on **LDES alone cannot substitute for a baseload generation**, such as SMRs. Therefore, Ontario should adopt a portfolio-based approach that involves a combination of LDES, wind and nuclear power to address possible capacity shortfalls. Consequently, the IESO should incorporate LDES in its system planning.

Further detailed analysis is required to establish appropriate LDES targets in Ontario.

4.2 Key Results

Scenario 1: Build-out Risk

In this scenario, as seen below in **Figure 5**, about 10 GW (60%) of SMRs and 1.5 GW (10%) of hydrogen turbines envisioned in the P2D will be deployed by 2050. Thus, if SMRs and Hydrogen turbines are not deployed at the pace and magnitude necessary to support reliability, the result is a capacity shortfall of 4 GW by 2035, which could grow to 19 GW by 2050.

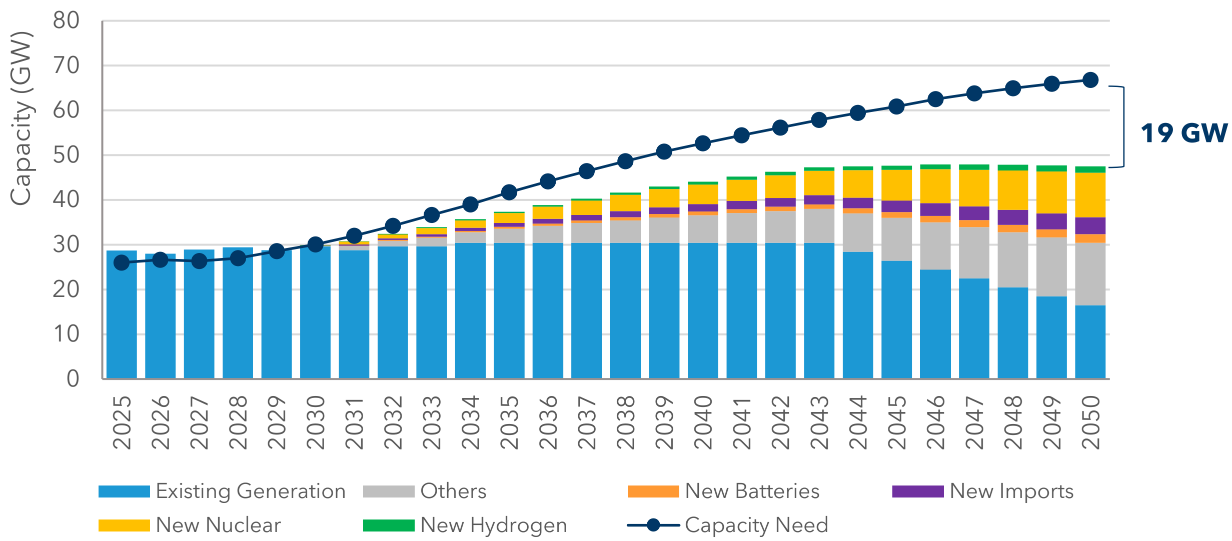

Figure 5: Ontario Capacity Outlook Under Scenario 1

In this scenario, we assume that LDES firmed by wind could offset some portion of the capacity shortfall. However, it is unlikely that the capacity provided by LDES can fully substitute the capacity generated by SMRs and other baseload power plants. After analyzing other studies and using professional judgment, as seen in Figure **6**, we have assumed that approximately 24 GW LDES capacity could offset the expected shortfall of 19 GW in capacity by 2050[34]. After determining the technical potential of LDES to offset the capacity shortfall, we iterated through different procurement capacities[35] by 2032[36] to determine the cost-effective amount of LDES necessary to maximize system benefits.

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[34] We assume that about 1.7 GW of LDES can offset about 1 GW of baseload generation. This is based on the analysis conducted by Aurora [Long Duration Energy Storage in Spain](), which estimated that 15 GW of LDES could replace 10 GW of natural gas CCGT. The IESO should conduct similar capacity expansion and production cost modelling exercises that could provide a capacity offset value for LDES that is more Ontario-specific. Since hydrogen turbines are run at low-capacity factors (9%), we assume that LDES can replace H2 capacity on a one-to-one basis.

[35] While iterating through various procurement capacities, the capital and O&M costs per kW remained constant across all system sizes. Only the amount of grid needs assigned to the project varied.

[36] The year 2032 has been selected for procurement to maximize the benefits of the Investment Tax Credit (ITC). It is anticipated that the ITC will decrease from 30% in 2033 to 15% in 2034. Any delays in procurement beyond 2032 would lead to an increase in project costs and a reduction in net benefits to the system.

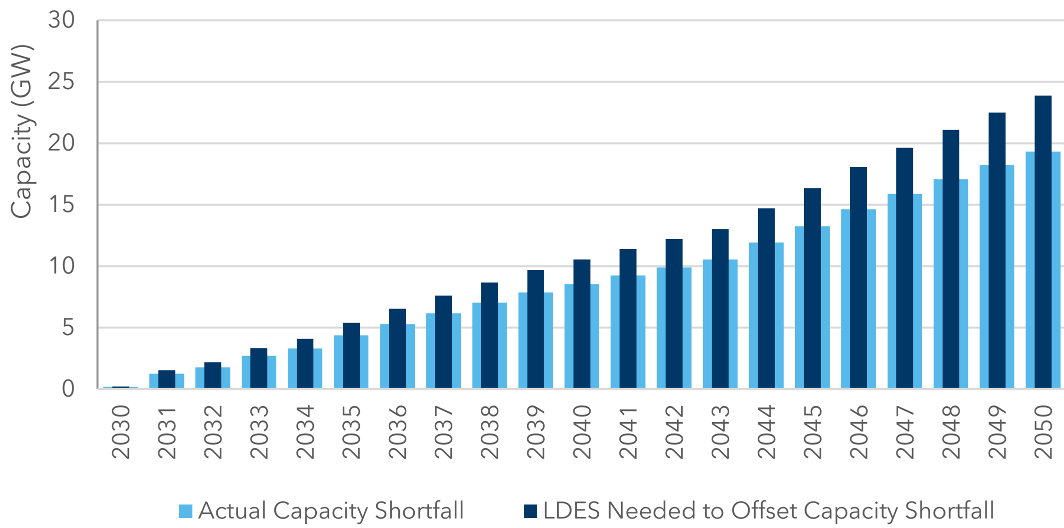

Figure 6: Technical Potential of LDES to Offset Capacity Shortfall as envisioned in Scenario 1

In **Figure 7,** the benefit-cost ratio for different levels of LDES deployment by 2032 is mapped for scenario 1. Assuming a cost-effectiveness threshold of 1.1[37], **up to 6 GW of 10-hr LDES deployed by 2032 are estimated to be cost-effective under this scenario.**

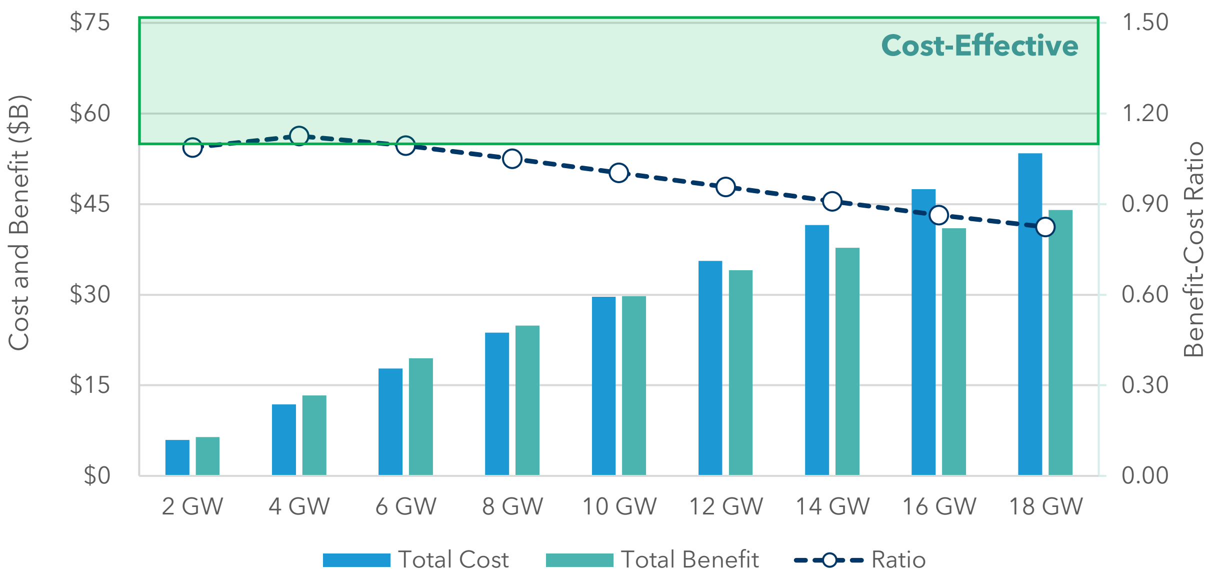

Figure 7: Benefit-Cost Ratios of LDES Deployment Levels by 2032

Thus, under scenario 1, the IESO should consider procurement of up to 6 GW of 10-hr LDES to maximize system benefits and hedge against capacity shortfall. As seen in **Figure 8**, the

[37] A threshold of 1.1 benefit to cost ratio is used as the threshold for cost-effectiveness to provide a conservative estimate in consideration of uncertainty in the analysis .

overall system benefits from 6 GW of 10-hr LDES[38] deployed by 2032 would exceed the costs. The largest driver of benefits is Generation Capacity[39] (66% of overall benefits), followed by transmission deferral[40] (17%), Arbitrage[41] (12% of overall benefits), and then reserves and regulation[42] (4% of overall benefits). The costs are net of the investment tax credit[43] and include operational costs[44] and charging costs[45] (assuming that LDES is charged by wind[46]).

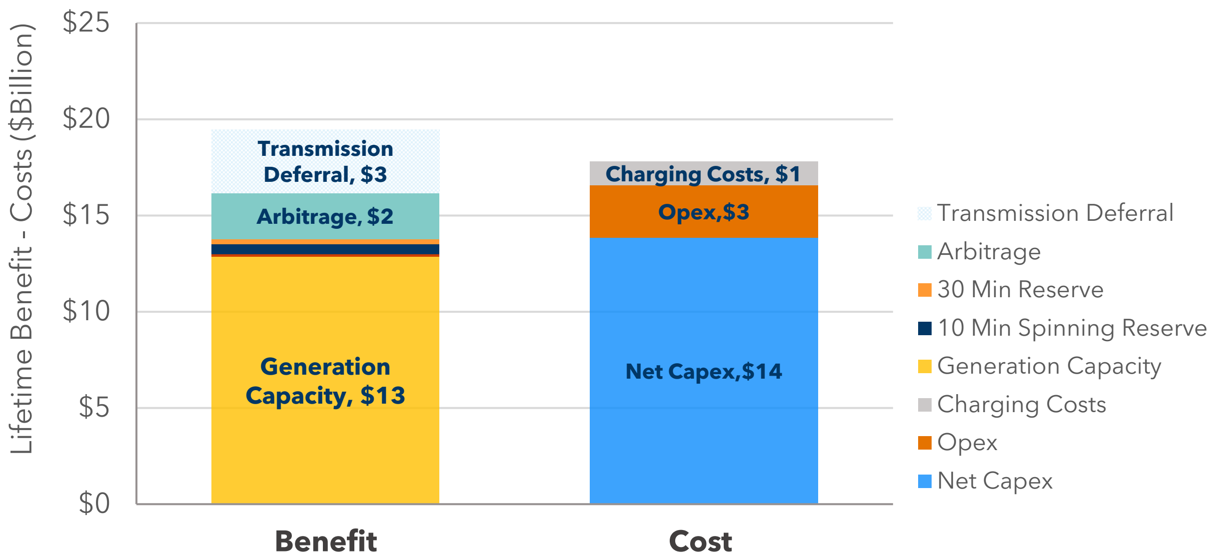

Figure 8: Benefit-Cost Analysis of 6 GW LDES under Scenario 1 (In service 2032)

As shown in **Figure 9**, procuring up to 6 GW of 10-hour Long Duration Energy Storage (LDES), if deployed by 2032, could reduce the capacity shortfall until 2036. This will give IESO

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[38] Assumes a generic LDES technology with 10-hour discharge duration, with an RTE of 65%, an annual degradation rate of 1% and a project life of 30 years. The analysis assumes that the LDES is cycled 130 times a year.
[39] The generation capacity needs were determined by the technical potential of the LDES, as described in **Figure 6**. It was assumed that the avoided generation capacity costs were based on the Net Cost of New Entry for a small modular reactor from 2025 to 2050. If SMRs are delayed due to regulatory and permitting hurdles, then an LDES would likely be compensated similarly to an SMR on a generation capacity cost basis.
[40] The Transmission deferral avoided costs were obtained from the DER Study conducted by Dunsky for the IESO. We assume that the portion of the LDES's capacity allocated to generation also contributes to transmission deferral.
[41] The arbitrage values were determined using the difference between the average off-peak and average on-peak avoided energy costs published by the IESO. The arbitrage potential assumes that LDES cycles 130 times a year, and its arbitrage potential is capped at 60% of its energy capacity since it would typically reserve energy for regulation and operating reserves.
[42] Assumes that up to 10% of Ontario's regulation and reserve requirements are allocated to LDES, and the LDES system allocates capacity in the following order of priority: regulation, 10-min reserves, 30 reserves and finally, the remaining capacity is allocated to available generation capacity needs.
[43] Assumes that 30% ITC is applied to upfront capital cost. Assumes that by 2032, the upfront cost of LDES will be CA$3,300 per kW.
[44]. The operation and maintenance costs are assumed to be $32/kW-year.
[45] Charging costs are the round-trip energy losses when charging from onshore wind.
[46] Assumes that the cost of onshore wind in Ontario is $60/MWh in 2024, drops to $30/MWh by 2040, and remains constant thereafter.

enough time to acquire additional energy and capacity resources to address future reliability risks. A larger procurement of LDES could not only reduce capacity shortfalls but also provide a significant runway for IESO to build out the capacity required to support Ontario's energy and reliability needs.

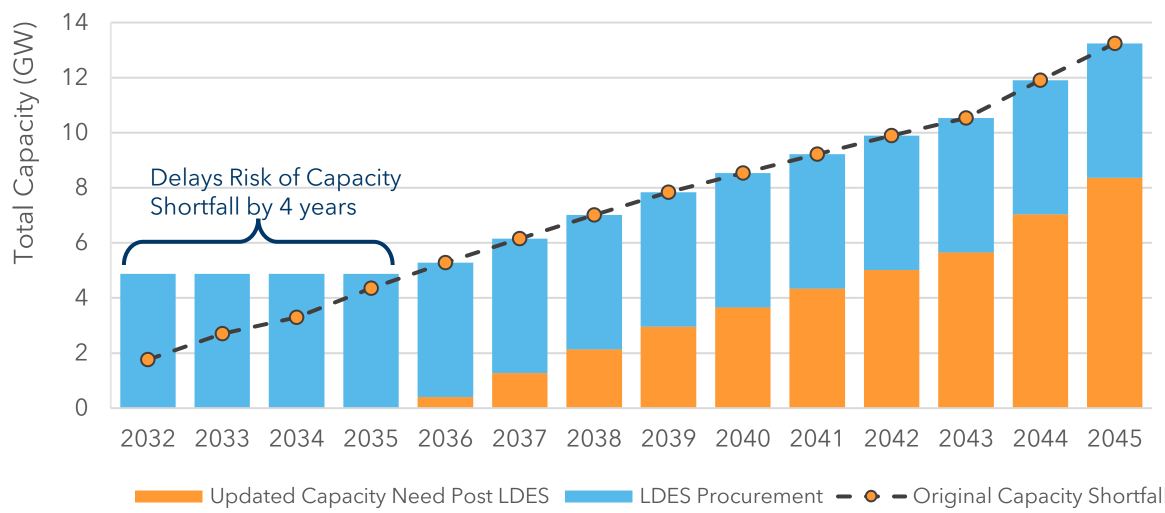

Figure 9: Impact of 6 GW LDES Procurement on Capacity Shortfall[47]

[47] Based on high-level modeling, we assume that 6 GW of 10-hour LDES can offset up to 5 GW of firm capacity.

Scenario 2: Hydrogen Supply Risk

In this scenario, as seen below in **Figure 10**, our analysis assumes approximately 17 GW (100%) of SMRs and 1.5 GW (10%) of hydrogen turbines, as envisioned in the P2D, will be deployed by 2050. Within this framework, if the risk of blue and green hydrogen supply materializes and hydrogen turbines are not deployed at the pace and magnitude necessary to support reliability, there could be a capacity shortfall of 3 GW by 2035, which could grow to 13 GW by 2050.

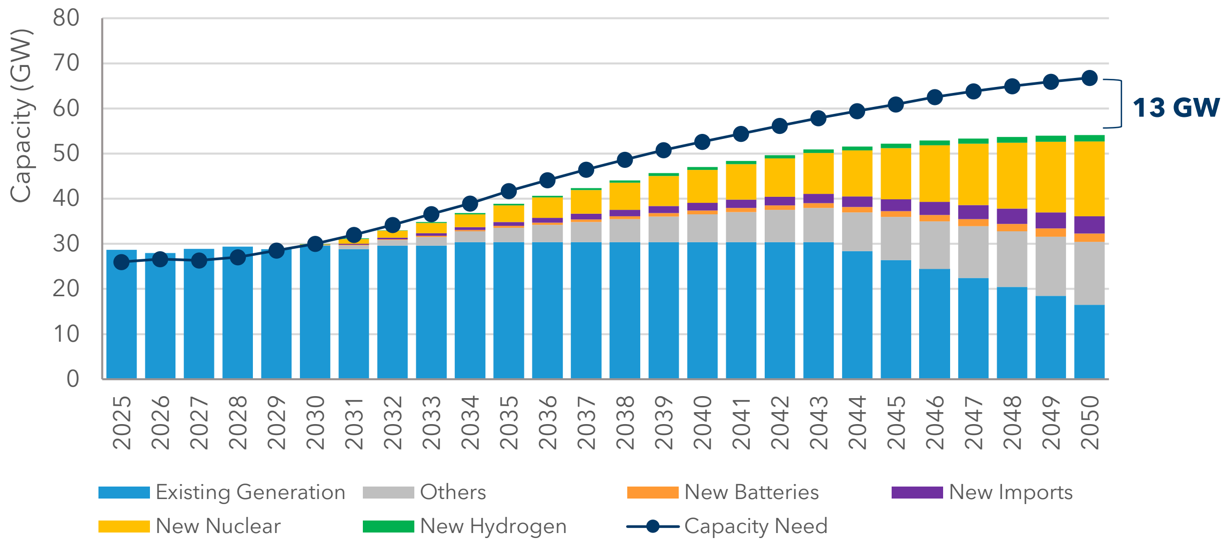

Figure 10: Ontario Capacity Outlook Under Scenario 2

In this scenario, we assume that LDES firmed by wind could offset some portion of the capacity shortfall. Since hydrogen turbines are assumed to run at a low-capacity factor (9% as in the P2D), for the purpose of simplicity, we assume that LDES can fully substitute the capacity provided by hydrogen turbines. After analyzing other studies and using professional judgment, as seen in Figure 11, we have projected that approximately 13 GW LDES capacity could offset the expected shortfall of 13 GW in capacity by 2050[48].

After determining the technical potential of LDES capacity needed to offset the capacity shortfall, we iterated through different procurement capacities[49] by 2032[50] to determine the economic potential of LDES necessary to maximize system benefits.

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[48] We assume that about 1.7 GW of LDES can offset about 1 GW of baseload generation. This is based on the analysis conducted by Aurora Long Duration Energy Storage in Spain, which estimated that 15 GW of LDES could replace 10 GW of natural gas CCGT. The IESO should conduct similar capacity expansion and production cost modelling exercises that could provide a capacity offset value for LDES that is more Ontario-specific. Since hydrogen turbines are run at low-capacity factors (9%), we assume that LDES can replace H2 capacity on a one-to-one basis.

[49] While iterating through various procurement capacities, the capital and O&M costs per kW remained constant across all system sizes. Only the amount of grid needs assigned to the project varied.

[50] The year 2032 has been selected for procurement to maximize the benefits of the Investment Tax Credit (ITC). It is anticipated that the ITC will decrease from 30% in 2033 to 15% in 2034. Any delays in procurement beyond 2032 would lead to an increase in project costs and a reduction in net benefits to the system.

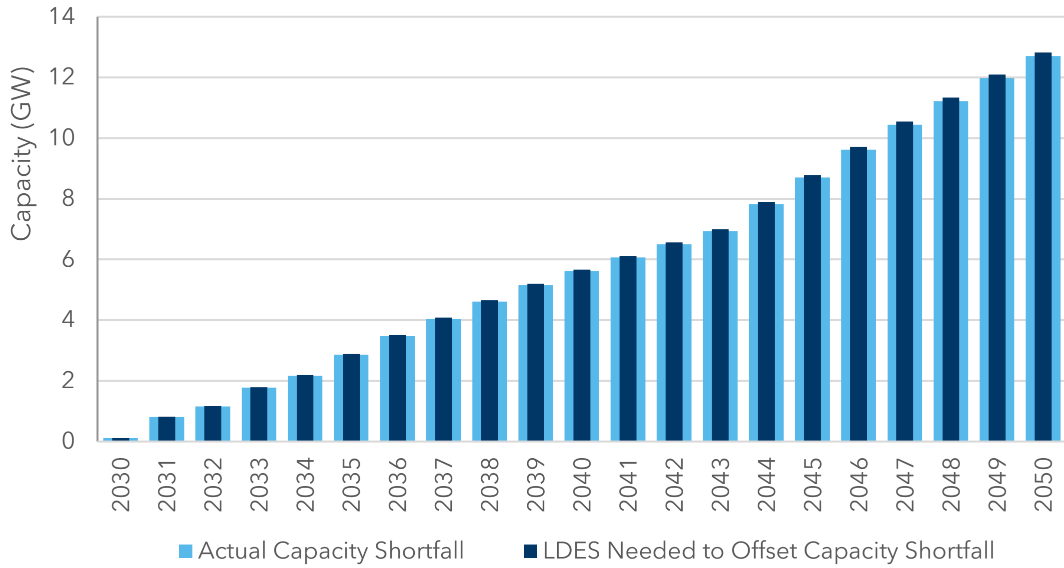

Figure 11: Technical Potential of LDES to Offset Capacity Shortfall as envisioned in Scenario 2

In Figure 712, the benefit-cost ratio for different levels of LDES deployment by 2032 is mapped for scenario 1. Assuming a cost-effectiveness threshold of 1.1, **up to 10 GW of 10-hr LDES deployed by 2032 are estimated to be cost-effective under this scenario.**

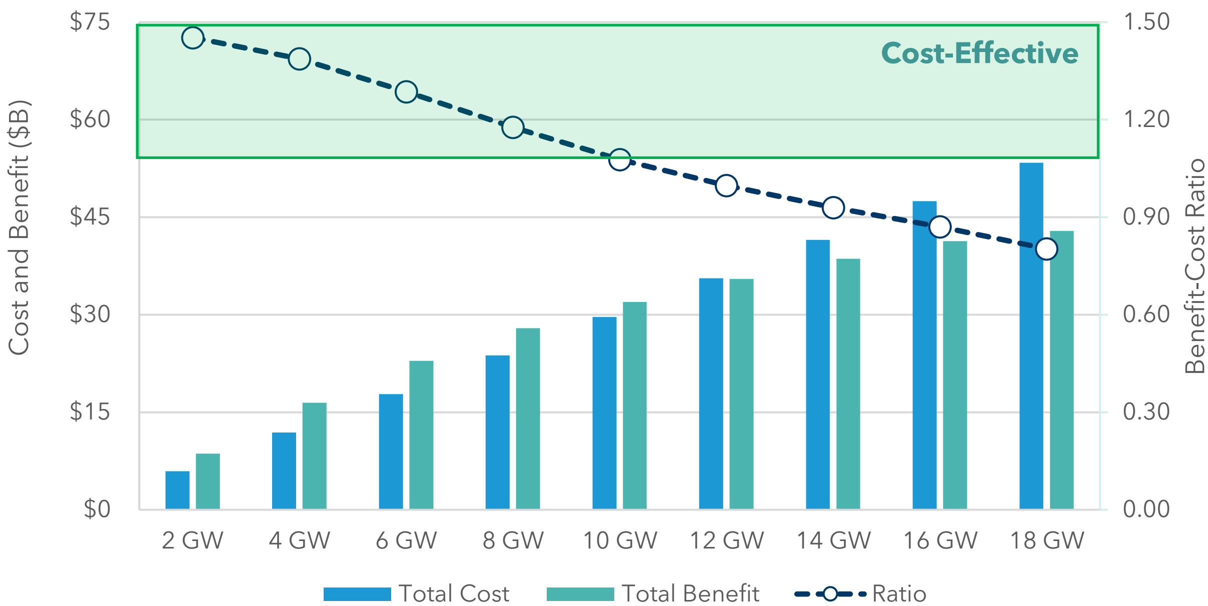

Figure 12: Benefit-Cost Ratios of LDES Deployment Levels by 2032

Thus, under scenario 2, the IESO should consider procurement of up to 10 GW of 10-hr LDES to maximize system benefits and hedge against capacity shortfall. As seen in **Figure 13**, the overall system benefits from 10 GW of 10-hr LDES[51] deployed by 2032 would exceed the costs. The largest driver of benefits is Generation Capacity[52] (68% of overall benefits), followed by transmission deferral[53] (13%), Arbitrage[54] (13% of overall benefits), and reserves and regulation[55] (6% of overall benefits). The costs are net of the investment tax credit[56] and include operational costs[57] and charging costs[58] (assuming that LDES is charged by wind[59]).

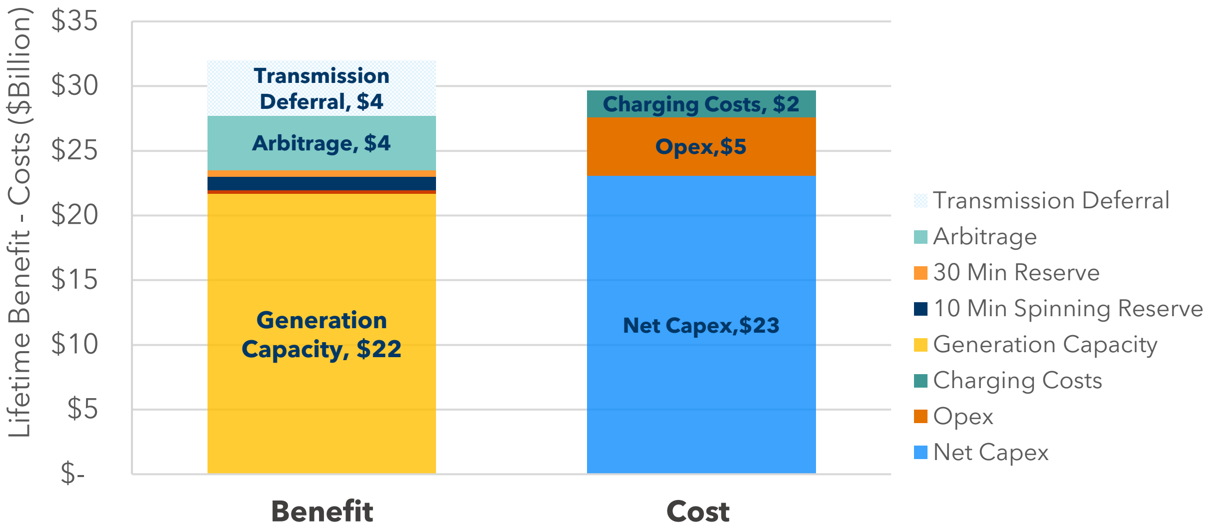

Figure 13: Benefit-Cost Analysis of 10 GW LDES under Scenario 2 (In service 2032)

As shown in **Figure 14**, the procurement of up to 10 GW of 10-hour Long Duration Energy Storage (LDES) deployed by 2032 could reduce the capacity shortfall until 2046. This could give IESO enough time to acquire additional energy and capacity resources to address future

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[51] Assumes a generic LDES technology with 10-hour discharge duration, with an RTE of 65%, an annual degradation rate of 1% and a project life of 30 years. The analysis assumes that the LDES is cycled 130 times a year.
[52] The generation capacity needs were determined by the technical potential of the LDES, as described in **Figure** 11. It was assumed that the avoided generation capacity costs were based on the Net Cost of New Entry for a natural gas peaker small modular reactor from 2025 to 2035 and a green hydrogen peaker from 2035 onwards.
[53] The Transmission deferral avoided costs were obtained from the DER Study conducted by Dunsky for the IESO. We assume that the portion of the LDES's capacity allocated to generation also contributes to transmission deferral.
[54] The arbitrage values were determined using the difference between the average off-peak and average on-peak avoided energy costs published by the IESO. The arbitrage potential assumes that LDES cycles 130 times a year, and its arbitrage potential is capped at 60% of its energy capacity since it would typically reserve energy for regulation and operating reserves.
[55] Assumes that up to 10% of Ontario's regulation and reserve requirements are allocated to LDES, and the LDES system allocates capacity in the following order of priority: regulation, 10-min reserves, 30 reserves and finally, the remaining capacity is allocated to available generation capacity needs.
[56] Assumes that 30% ITC is applied to upfront capital cost. Assumes that by 2032, the upfront cost of LDES will be CA$3,300 per kW.
[57]. The operation and maintenance costs are assumed to be $32/kW-year.
[58] Charging costs are the round-trip energy losses when charging from onshore wind.
[59] Assumes that the cost of onshore wind in Ontario is $60/MWh in 2024, drops to $30/MWh by 2040, and remains constant thereafter.

reliability risks. A larger procurement of LDES could not only reduce capacity shortfalls but also provide a significant runway for IESO to build out the capacity required to support Ontario's energy and reliability needs.

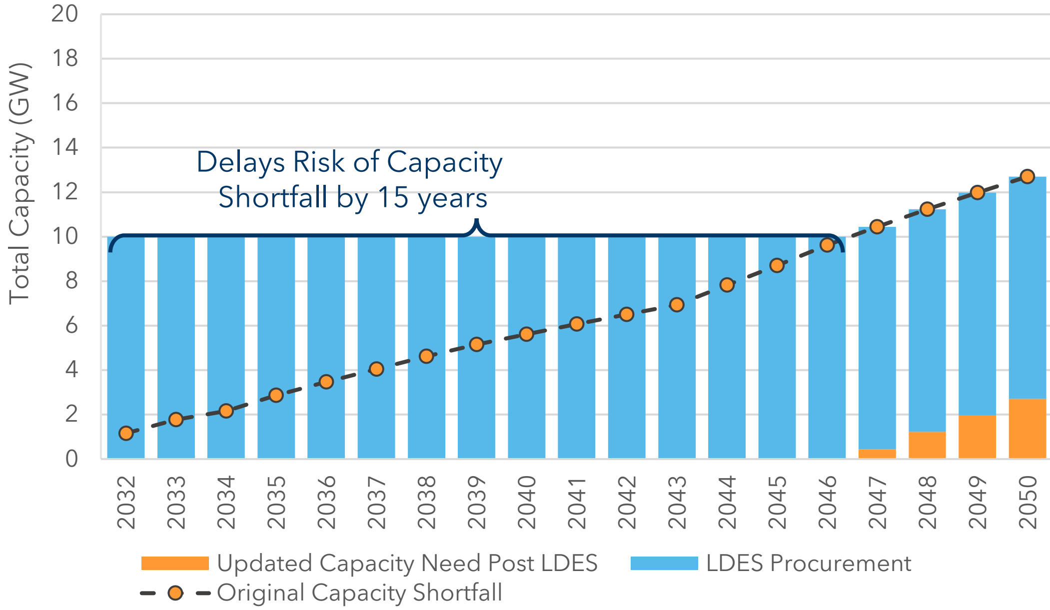

Figure 14: Impact of 10 GW LDES Procurement on Capacity Shortfall

Scenario 3: Planning and Procurement Risk

In scenario 3, as seen in **Figure 15** below, about 17 GW (100%) of SMRs and 7.5 GW (50%) of hydrogen turbines envisioned in the P2D are deployed by 2050. In this scenario, we assume that Quebec's winter capacity constraints could limit the import capacity to Ontario by 50%. Additionally, we assume that existing generation assets are not recommitted, which results in a significant near-term capacity shortfall of 12 GW by 2035 and 9 GW by 2050.

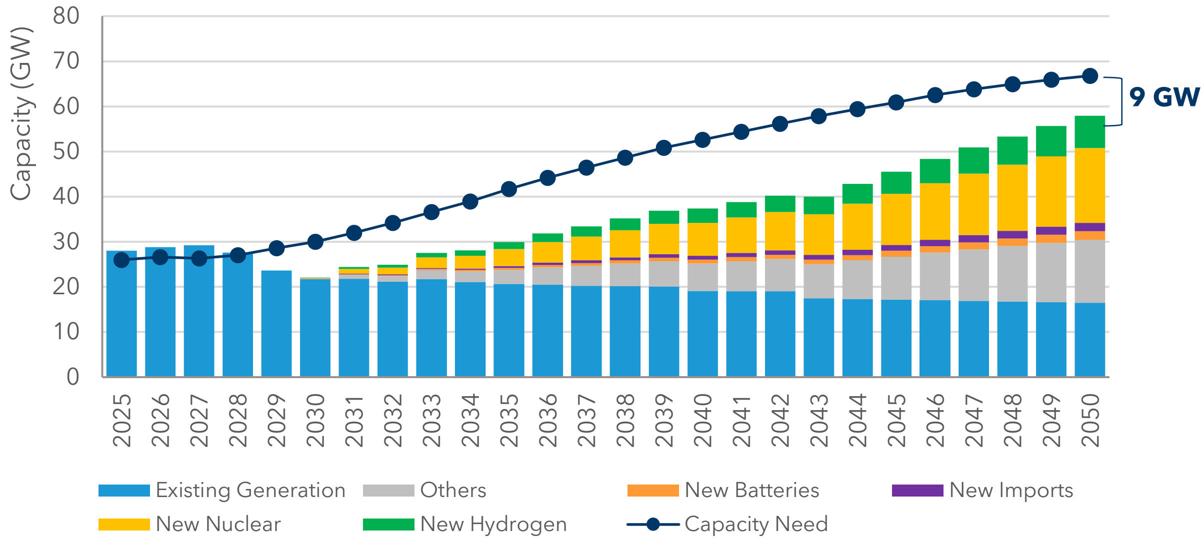

Figure 15: Ontario Capacity Outlook Under Scenario 3

This scenario assumes that LDES, firmed by wind, could offset some portion of the capacity shortfall. Since hydrogen turbines are assumed to run at a low capacity factor (9% as in the P2D), for simplicity purposes, we conclude that LDES can fully substitute the capacity provided by hydrogen turbines and the expected capacity from imports.

As illustrated in **Figure 16**, we determined the technical capacity potential for LDES for each year from 2030 to 2050.[60] We then modelled various LDES capacities[61] procured by 2032[62] to determine the amount of LDES that is cost-effective.

[60] We assume that about 1.7 GW of LDES can offset about 1 GW of baseload generation. This is based on the analysis conducted by Aurora Long Duration Energy Storage in Spain, which estimated that 15 GW of LDES could replace 10 GW of natural gas CCGT. The IESO should conduct similar capacity expansion and production cost modelling exercises that could provide a capacity offset value for LDES that is more Ontario-specific. Since hydrogen turbines are run at low-capacity factors (9%), we assume that LDES can replace H2 capacity on a one-to-one basis.
[61] While iterating through various procurement capacities, the capital and O&M costs per kW remained constant across all system sizes. Only the amount of grid needs assigned to the project varied.
[62] The year 2032 has been selected for procurement to maximize the benefits of the Investment Tax Credit (ITC). It is anticipated that the ITC will decrease from 30% in 2033 to 15% in 2034. Any delays in procurement beyond 2032 would lead to an increase in project costs and a reduction in net benefits to the system.

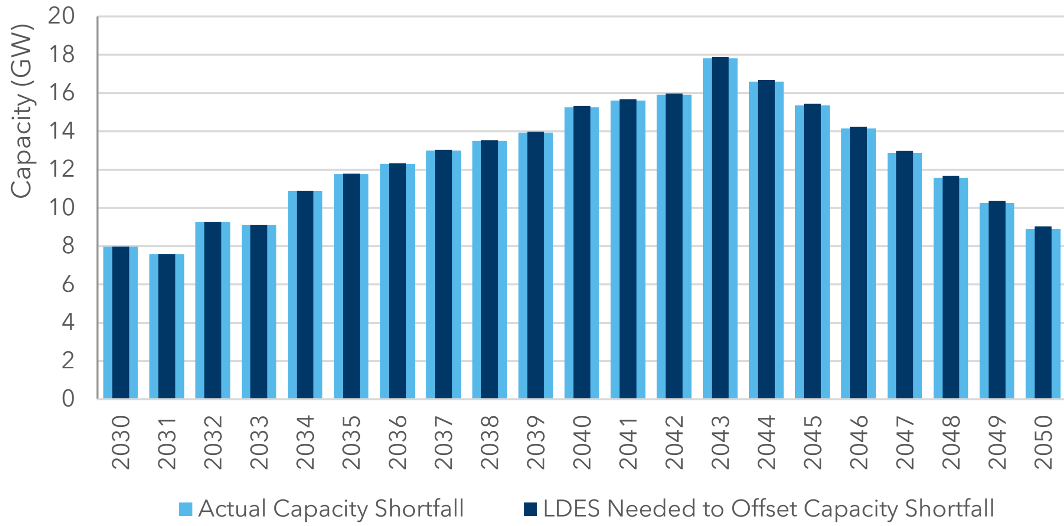

Figure 16: Technical Potential of LDES to Offset Capacity Shortfall as envisioned in Scenario 3

In **Figure 7**, the benefit-cost ratio for different levels of LDES deployment by 2032 is mapped for scenario 3. Assuming a cost-effectiveness threshold of 1.1, **up to 18 GW of 10-hr LDES deployed by 2032 are estimated to be cost-effective under this scenario.**

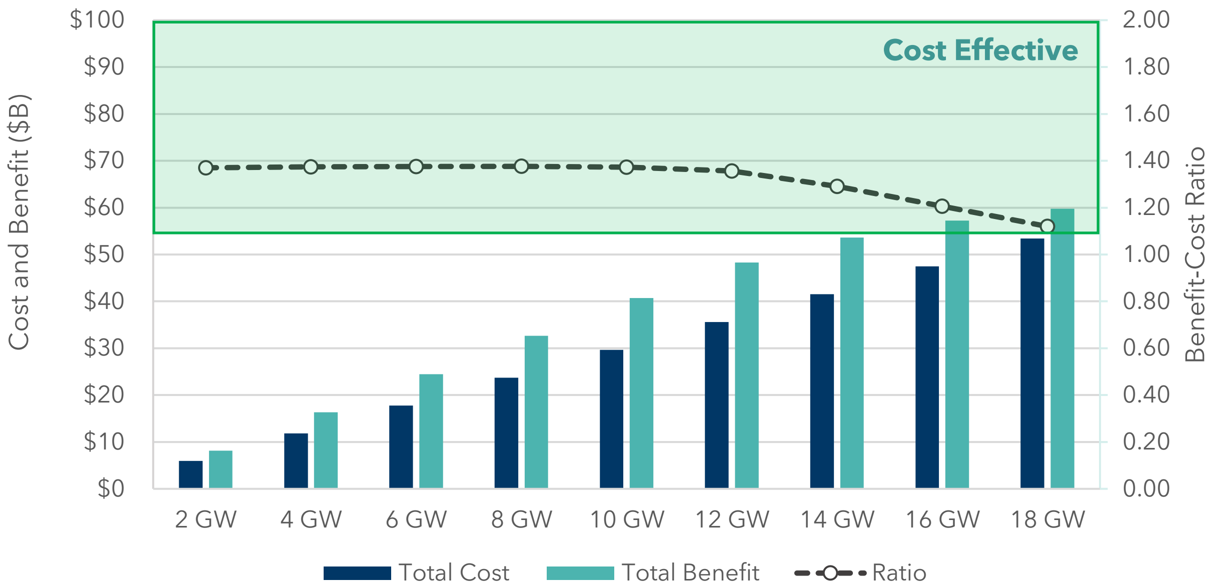

Figure 17: Benefit-Cost Ratios of LDES Deployment Levels

As seen in Figure 17, the benefit-cost ratios are largely stable up to 10 GW and then begin to decline thereafter. Thus, under scenario 3, the IESO should consider procurement of up to 10 GW of 10-hr LDES to maximize system benefits and hedge against capacity shortfall. As seen in

Benefit-Cost Ratio of 10 GW of LDES in Service by 2032

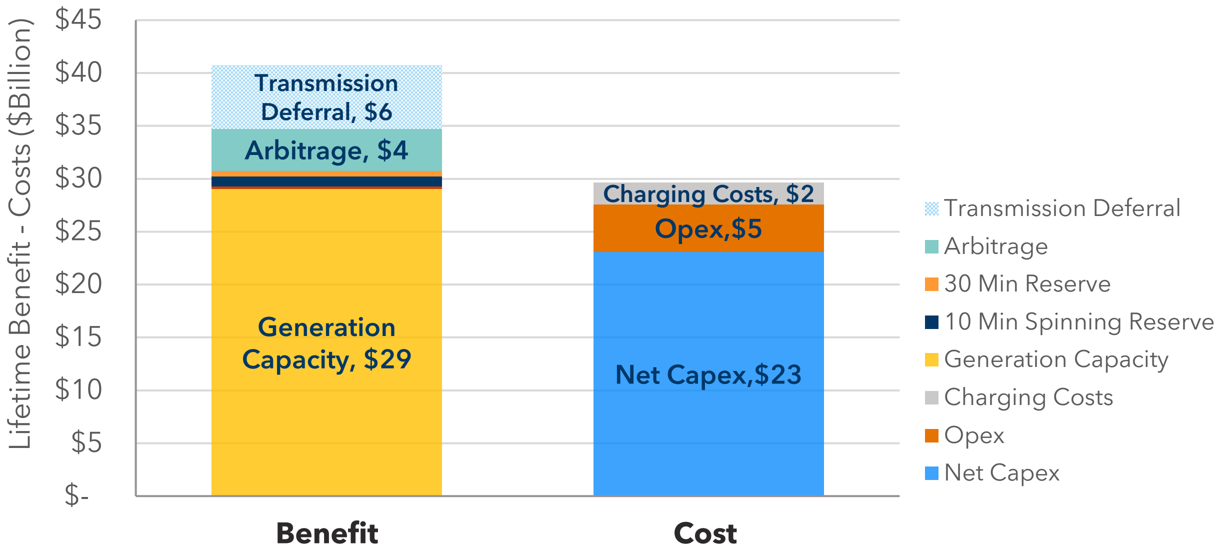

Figure **18**, the overall system benefits from 10 GW[63] of 10-hr LDES[64] deployed by 2032 would exceed the costs. The largest driver of benefits is Generation Capacity[65] (71% of overall benefits), followed by transmission deferral[66] (15%), Arbitrage[67] (10% of overall benefits), and reserves and regulation[68] (4% of overall benefits). The costs are net of the investment tax credit[69] and include operational costs[70] and charging costs[71] (assuming that LDES is charged by wind).

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[63] Under scenario 3, the benefit-cost ratios are the highest up to 10 GW of LDES capacity.
[64] Assumes a generic LDES technology with 10 10-hour discharge duration, with an RTE of 65%, an annual degradation rate of 1% and a project life of 30 years. The analysis assumes that the LDES is cycled 130 times a year.
[65] The generation capacity needs were determined by the technical potential of the LDES, as described in **Figure 16**. It was assumed that the avoided generation capacity costs were based on the Net Cost of New Entry for a natural gas peaker small modular reactor from 2025 to 2035 and a green hydrogen peaker from 2035 onwards.
[66] The Transmission deferral avoided costs were obtained from the DER Study conducted by Dunsky for the IESO. We assume that the portion of the LDES's capacity allocated to generation also contributes to transmission deferral.
[67] The arbitrage values were determined using the difference between the average off-peak and average on-peak avoided energy costs published by the IESO. The arbitrage potential assumes that LDES cycles 130 times a year, and its arbitrage potential is capped at 60% of its energy capacity since it would typically reserve energy for regulation and operating reserves.
[68] Assumes that up to 10% of Ontario's regulation and reserve requirements are allocated to LDES, and the LDES system allocates capacity in the following order of priority: regulation, 10-min reserves, 30 reserves and finally, the remaining capacity is allocated to available generation capacity needs.
[69] Assumes that 30% ITC is applied to upfront capital cost. Assumes that by 2032, the upfront cost of LDES will be CA$3,300 per kW.
[70]. The operation and maintenance costs are assumed to be $32/kW-year.
[71] Charging costs are the round-trip energy losses when charging from onshore wind.

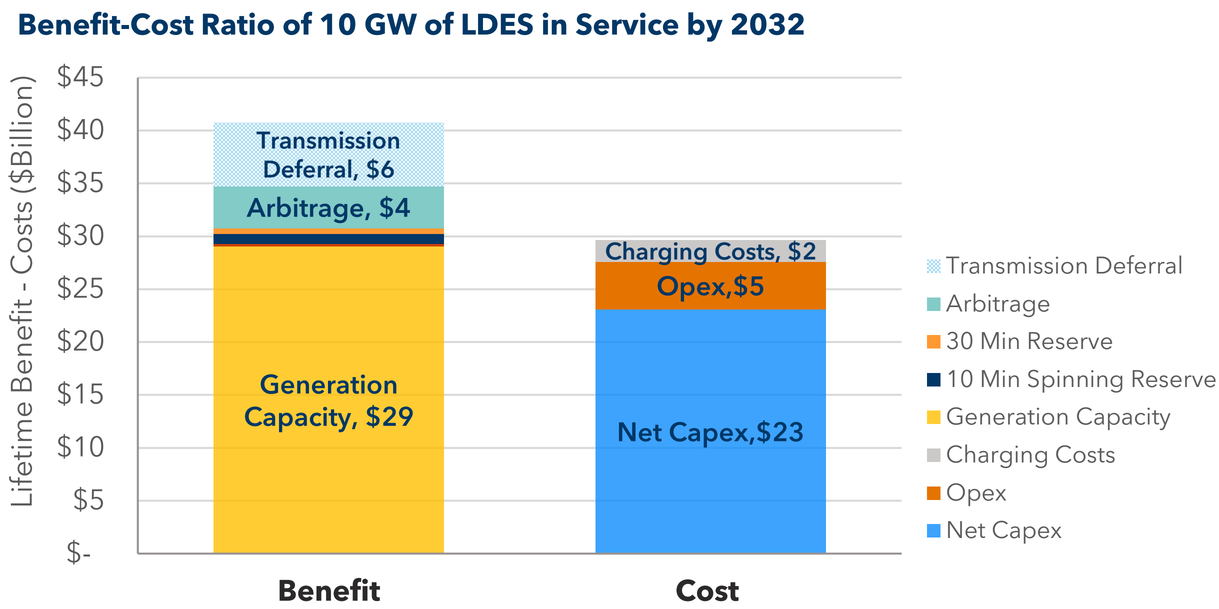

Figure 18: Benefit-Cost Analysis of 6 GW LDES under Scenario 3 (In service 2032)

4.3 Key Takeaways

LDES provides multiple benefits, such as environmental sustainability, grid reliability, and economic development. **As illustrated in Figure 19 below, based on our initial high-level analysis, across all three scenarios, up to 6 GW of 10-hr LDES deployed starting in 2032 could be cost-effective in Ontario.** This can increase to up to 10 and 18 GW under scenarios 2 and 3, respectively, if capacity shortfalls exacerbate further.

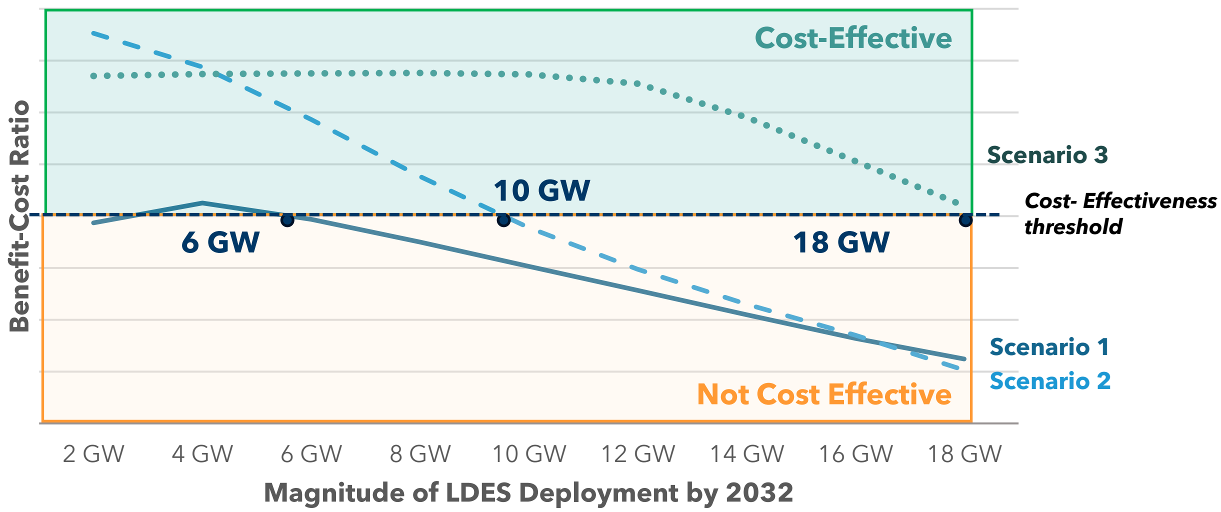

Figure 19: Range of LDES procurement in Ontario

As seen in Figure 20 below, when we analyze LDES with a range of technology characteristics, 6 GW of 10-hr LDES could be cost-effective across the three scenarios.

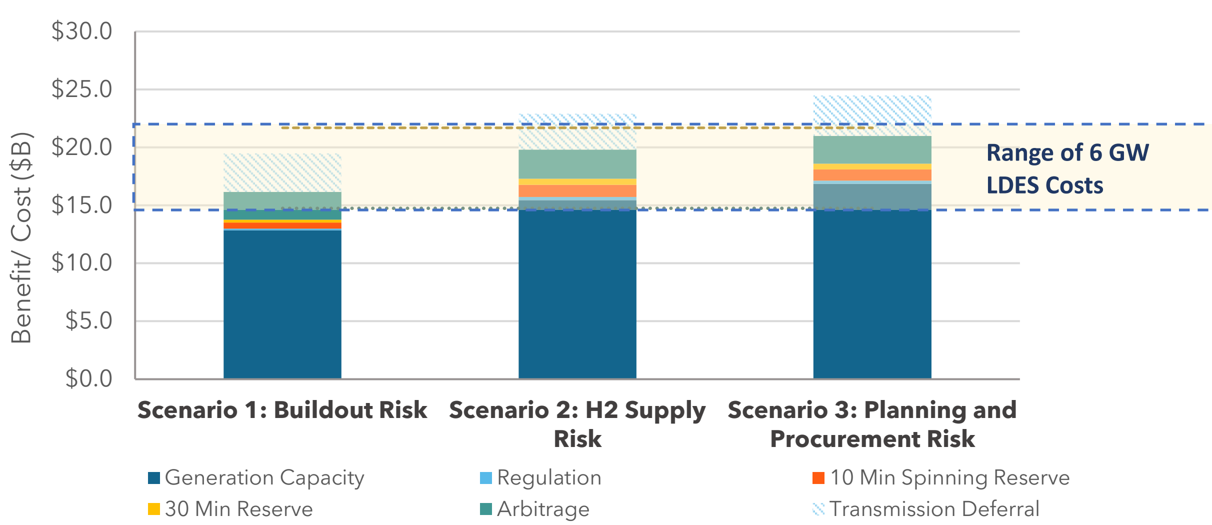

Figure 20: Range of LDES Costs Across Scenarios[72]

[72] See Appendix B for detailed assumptions.

The estimated upfront investment for the deployment of 6 GWs of LDES would be somewhere between $12B to $17B[73], which represents only 3-5% of the total investments expected in the P2D[74]. Additionally, based on our high-level assessment, the lifetime cost of LDES could be significantly lower than that of equivalent hydrogen peakers. On a head-to-head basis, LDES[75] powered by wind would cost up to 40% cheaper than blue[76] hydrogen peakers.

Based on our high-level analysis, commissioning 6 GW of LDES by 2032 could provide savings of around $11B to $20B compared to the IESO's baseline P2D scenario. These savings represent the difference in the lifetime cost of operating a 6 GW LDES powered by wind versus a green/blue hydrogen turbine of a similar capacity. Further detailed analysis is required to validate these estimates[77].

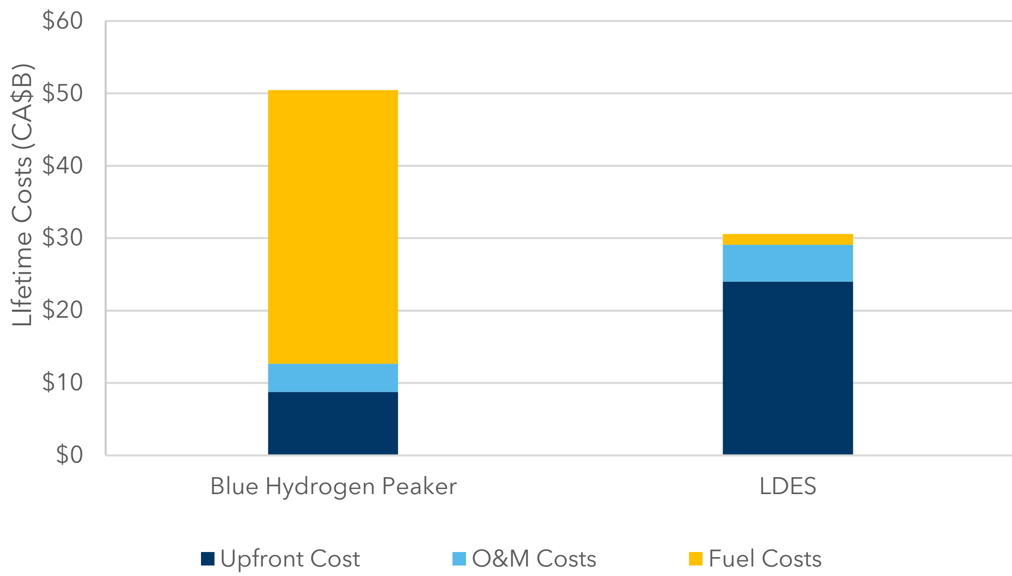

Figure 21: Lifetime Costs of 6 GW of LDES and Hydrogen Peaker by 2032 (2024 CA$B)

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[73] Includes 30% ITC

[74] The P2D anticipates that an investment in the range of $375 to $425 billion will be required for a bulk system decarbonization.

[75] Assumes the upfront cost of LDES is $4000 per kW by 2032. Assumes that LDES is charged from low-cost onshore wind, which is assumed to be $60 per MWh over the life of the asset. The assumed lifetime is 25 years, and it runs at a capacity factor of 10%.

[76] Includes the final delivered price of blue hydrogen from Alberta to Ontario City Gate from an 85% Steam-Methane Reformation CCS. https://doi.org/10.1016/j.ijhydene.2021.12.025 The assumed cost of blue hydrogen is $55/MMBTU by 2032. Upfront capital ($1460/kW) and O&M costs are assumed to be similar to those of natural gas peakers. The fuel cost in the IESO P2D is assumed to be US$41/MMBTU, which is about CA$55/MMBTU. The assumed lifetime is 25 years and runs at a capacity factor of 10%. This graph does not include a carbon tax.

[77] To accurately determine the operational system-wide savings, running a production cost model with LDES is necessary. Operational constraints might limit the capabilities of LDES and thus lead to lower system-wide savings. Therefore, we recommend that the IESO incorporate LDES within their production cost models to determine the system-wide savings.

4.4 Additional Benefits

System Benefits:

- **Diversity of Supply**: Ontario's energy needs could be met through a balanced mix of energy generation technologies, complemented by long-duration energy storage to ensure capacity and reliability.
- **Reduced Wind Curtailment:** LDES enables better integration of intermittent renewable sources like wind power by storing excess energy during windy periods and discharging it during lulls, reducing the need to curtail wind power production.
- **Reduced Nuclear Maneuvering:** LDES relieves the need for nuclear assets to reduce their output in the event of surplus system supply. LDES could allow nuclear assets to operate at optimal levels regardless of system conditions, thereby improving longevity and lifetime performance.
- **Offset Natural Gas Generation:** LDES allows for the storage of excess renewable energy during periods of low demand, reducing reliance on natural gas generation during peak demand. This shift contributes to a significant reduction in greenhouse gas emissions, aligning with Ontario's Net Zero Goals.
- **Inertia:** LDES systems can enhance grid stability by providing inertia, helping to maintain a consistent frequency. This is especially crucial in a system with a high penetration of renewable energy sources, which may lack the inherent inertia traditionally provided by fossil fuel generators.
- **Thermal Energy:** Thermal-based long-duration energy storage technologies have the ability to store and release thermal energy and make these resources suitable for integrating with industrial processes that require heat. This opens opportunities for using stored energy in various industrial applications, further diversifying its use cases.

Economic Benefits:

- **Made in Ontario Development:** Investing in and procuring LDES technologies locally fosters the development of a domestic industry. This not only strengthens the resilience of the energy supply chain but also promotes technological innovation and expertise within the province.
- **Economic Benefits (Jobs, GDP):** The growth of the LDES sector has a multiplier effect on the economy. Beyond direct employment, it stimulates related industries and services, increasing economic activity, higher GDP, and a more robust and diversified economy.

Need for greater than 12-hour energy storage: This report analyzed the value proposition of 10-hour LDES technology; however, energy storage for 12 hours or more could be critical to achieving economy-wide decarbonization and high levels of renewable energy penetration. Energy storage for 12 hours is considered diurnal and can time-shift solar and wind generation to periods of higher demand.

Ontario intends to rely heavily on solar (6,000 MW) and wind (17,600 MW), which is roughly a third of new installed capacity by 2050, from the Pathways to Decarbonization study from the IESO, so addressing the mismatch in supply and demand with 12+ hour storage could be critical.

Another key benefit is the potential for deferred or avoided transmission system upgrades by installing storage downstream from high-capacity transmission nodes – in this case, storage capacity installed to mitigate this would not need to see significant discharge frequency since simply preventing overloading during a few peak events in a year could provide the benefit to the system of preventing costly transmission system upgrades.

Mechanical LDES technologies, like pumped hydro and compressed air, have the potential to meet this need, as well as grid-scale thermal energy storage.

5. Recommendations

PLAN

1. **Incorporate LDES in all future planning:** Our high-level analysis suggests that across all scenarios, there is up to 6 GW of cost-effective LDES potential in Ontario. Further analysis and explorations are required by the IESO to validate the potential and corresponding benefits. We recommend that the IESO conduct a more detailed analysis that considers a full array of LDES technologies in future planning with consideration of the potential benefits to the grid, such as resource adequacy, operating reserves, regulations compliance, and emission reduction.
2. **Avoid locking in short-term procurements that undermine net zero efforts:** Prioritize solutions that align with long-term net-zero emission goals and avoid locking in technology that may hinder decarbonization. Select technologies that address immediate needs without crowding out the potential for decarbonized solutions.

PROCURE

1. **Adopt a multi-year procurement strategy with competitive auctions**: The IESO should consider multi-year procurement plans for LDES that provide certainty to developers and ensure competitiveness. A clear roadmap and competitive auctions can encourage market-driven solutions and achieve the best value for the grid and consumers.
2. **Establish clear targets for LDES Deployment**: Based on outcomes from its analysis, IESO should define and communicate specific targets for deploying LDES in Ontario. This could provide a roadmap for the necessary scale of implementation, foster investor confidence, encourage strategic planning, and facilitate integration into the energy infrastructure.
3. **Prioritize early procurements to capitalize on competitive pricing, leverage federal funding, and address potential risks: Starting the procurement process early allows for more competitive pricing and takes** advantage of incentives such as the Investment Tax Credit (ITC). Early procurements will also be critical to mitigate the challenges of abbreviated procurement lead times, the prospect of first-of-a-kind permitting processes and the longer lead times required for many LDES technologies.

PREPARE

1. **Build confidence in the capabilities of LDES:** Establish a dedicated funding stream for testing and demonstration of innovative LDES technologies in the province.
2. **Secure buy-in from municipalities and federal entities:** The IESO must collaborate with municipal and federal entities for successful LDES projects. This could help address regulatory and permitting challenges.
3. **Strategic site selection to maximize value:** IESO should analyze strategic sites for LDES installations, considering factors like proximity to renewable energy sources, local transmission needs, and relevant infrastructure. Strategically placing LDES projects can maximize their value, optimize grid integration, minimize transmission losses, and enhance system efficiency.

Appendix A: LDES Technology

A.1 LDES Technical Characteristics[78]

Table 1: Readiness of LDES Technologies

Market Readiness	Technology	LDES Category	Max Deployment (MW)	Max Nominal Duration (Hrs)	Average RTE (%)
Commercial	Pumped hydro (PSH)	Mechanical	10-100	0-15	50-80
	Compressed air (CAES)		200-500	6-24	40-70
	Latent heat (aluminum alloy)	Thermal	10-100	25-100	20-50
	Hybrid flow battery, liquid electrolyte & metal anode	Electrochem.	>100	25-50	55-75
Pilot/ Demonstration	Gravity-based		20-1000	0-15	70-90
	Liquid CO2		10-500	2-24	70-80
	Liquid air (LAES)		50-100	10-25	40-70
	Aqueous electrolyte flow batteries		10-100	25-100	40-80
R&D Stage	Sensible heat (e.g., molten salts, rock material, concrete)		10-500	200	55-90
	Metal anode batteries		10-100	50-200	40-70

[78] This is an illustrative list of key LDES technologies, but not exhaustive list of LDES technology options.

Appendix B: Analytical Approach

To determine the total benefit of long-duration energy storage under various scenarios, we first establish the grid needs (capacity, reliability, and regulation) and then allocate a grid service value to each need.

B.1 Modelling Caveats

- The scenarios presented are not intended to forecast the pace and magnitude of the SMR and H2 build-out but rather to draw attention to the potential risk in the pathway to decarbonization. The purpose is to demonstrate that if those risks materialize, then LDES could have a role to play in addressing Ontario's capacity shortfalls.
- We understand that relying on LDES alone cannot substitute for a baseload generation, such as SMRs. Therefore, Ontario should adopt a portfolio-based approach that involves a combination of LDES, wind and nuclear power to address possible capacity shortfalls. Consequently, the IESO should incorporate LDES in its system planning.
- We did not run a production cost model to determine the potential savings. The estimate of $11 billion to $20 billion is based on the difference between substituting hydrogen turbines powered by blue hydrogen from Alberta with LDES.

B.2 Grid Needs Assessment

After analyzing IESO's Pathways to Decarbonization and the IESO's 2022 Annual Planning Outlook, we determined the anticipated capacity buildout necessary to maintain reliability[79]. First, we determined the capacity shortfall using the winter peak demand from the P2D and leveraging the APO generation capacity forecast. Then, we determined the capacity shortfall in each year and assumed that the new capacity[80] in the P2D would be deployed proportional to the capacity shortfall.

Table 2: Assumed Capacity Buildout in P2D

Capacity Build Out	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Total Winter Demand (GW)	26	27	26	27	29	30	32	34	37	39	42	44	46	49	51	53	54	56	58	59	61	63	64	65	66	67
Existing Generation (APO Case 2)	29	28	29	29	29	30	29	30	30	30	30	30	30	30	30	30	30	30	30	28	26	24	22	20	18	17

[79] The P2D study does not provide an annual capacity buildout, instead it only provides the total new capacity build by 2050 and 2035.
[80] Assumed effective capacity.

Capacity Build Out	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
New Nuclear	-	-	-	-	-	-	1	2	2	3	4	5	5	6	7	7	8	8	9	10	11	13	14	15	16	17
New H2	-	-	-	-	-	-	1	1	2	2	3	4	5	5	6	6	7	7	8	9	10	11	12	13	13	14
New Imports	-	-	-	-	-	-	-	-	1	1	1	1	1	1	2	2	2	2	2	2	3	3	3	3	4	4
New Batteries	-	-	-	-	-	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	2	2	2	2
New Others	-	-	-	-	-	-	1	1	2	2	3	4	4	5	6	6	7	7	8	9	10	11	11	12	13	14
Actual Capacity Shortfall	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Max LDES Needed to Offset Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

In each scenario, we assessed the impact on Ontario's generation capacity if one or more risks materialize.

- **Scenario 1 – Build Out Risk:** We assume that only 60% of the SMRs are deployed based on the P2D, and only 10% of hydrogen turbines are deployed in Ontario due to supply challenges in delivering blue hydrogen through pipelines from Alberta and increased restrictions on green hydrogen production in Ontario due to capacity constraints.

Table 3: Assumed Capacity Buildout in Scenario 1

Capacity Build Out	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Total Winter Demand (GW)	26	27	26	27	29	30	32	34	37	39	42	44	46	49	51	53	54	56	58	59	61	63	64	65	66	67
Existing Generation (APO Case 2)	29	28	29	29	29	30	29	30	30	30	30	30	30	30	30	30	30	30	30	28	26	24	22	20	18	17
New Nuclear	-	-	-	-	-	-	1	1	1	2	2	3	3	4	4	4	5	5	5	6	7	8	8	9	9	10
New H2	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1
New Imports	-	-	-	-	-	-	-	-	1	1	1	1	1	1	2	2	2	2	2	2	3	3	3	3	4	4
New Batteries	-	-	-	-	-	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	2	2	2	2
New Others	-	-	-	-	-	-	1	1	2	2	3	4	4	5	6	6	7	7	8	9	10	11	11	12	13	14
Actual Capacity Shortfall	-	-	-	-	-	-	1	2	3	3	4	5	6	7	8	9	9	10	11	12	13	15	16	17	18	19

Capacity Build Out	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Max LDES Needed to Offset Capacity	-	-	-	-	-	-	2	2	3	4	5	7	8	9	10	11	11	12	13	15	16	18	20	21	23	24

- **Scenario 2 – H2 Supply Risks:** We assume that 100% of the SMRs and 10% of the hydrogen turbines based on the P2D are deployed in Ontario but are powered through green hydrogen from wind facilities in Ontario.

Table 4: Assumed Capacity Buildout in Scenario 2

Capacity Build Out	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Total Winter Demand (GW)	26	27	26	27	29	30	32	34	37	39	42	44	46	49	51	53	54	56	58	59	61	63	64	65	66	67
Existing Generation (APO Case 2)	29	28	29	29	29	30	29	30	30	30	30	30	30	30	30	30	30	30	30	28	26	24	22	20	18	17
New Nuclear	-	-	-	-	-	-	1	2	2	3	4	5	5	6	7	7	8	8	9	10	11	13	14	15	16	17
New H2	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1
New Imports	-	-	-	-	-	-	-	-	1	1	1	1	1	1	2	2	2	2	2	2	3	3	3	3	4	4
New Batteries	-	-	-	-	-	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	2	2	2	2
New Others	-	-	-	-	-	-	1	1	2	2	3	4	4	5	6	6	7	7	8	9	10	11	11	12	13	14
Actual Capacity Shortfall	-	-	-	-	-	-	1	1	2	2	3	3	4	5	5	6	6	7	7	8	9	10	10	11	12	13
Max LDES Needed to Offset Capacity	-	-	-	-	-	-	1	1	2	2	3	4	4	5	5	6	6	7	7	8	9	10	11	11	12	13

- **Scenario 3 – Procurement Risks:** Under this scenario, SMRs are assumed to be deployed at the pace and scale outlined in the P2D, and H2 turbine deployment is assumed to be 50% of the capacity buildout as anticipated in the P2D. This scenario captures the risk of capacity shortfall due to contracts expiring, higher-than-expected peak demand or import constraints and assumes that only 50% of the import capacity, as anticipated in the P2D, is realized.

Table 5: Assumed Capacity Buildout in Scenario 3

Capacity Build Out	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Total Winter Demand (GW)	26	27	26	27	29	30	32	34	37	39	42	44	46	49	51	53	54	56	58	59	61	63	64	65	66	67

Capacity Build Out	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Existing Generation (APO Case 1)	28	29	29	28	24	22	22	21	22	21	21	21	20	20	20	19	19	19	17	17	17	17	17	17	17	17
New Nuclear	-	-	-	-	-	-	1	2	2	3	4	5	5	6	7	7	8	8	9	10	11	13	14	15	16	17
New H2	-	-	-	-	-	-	-	1	1	1	2	2	2	3	3	3	3	4	4	4	5	5	6	6	7	7.1
New Imports	-	-	-	-	-	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	2	2	2	2
New Batteries	-	-	-	-	-	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	2	2	2	2
New Others	-	-	-	-	-	-	1	1	2	2	3	4	4	5	6	6	7	7	8	9	10	11	11	12	13	14
Actual Capacity Shortfall	-	-	-	-	5	8	8	9	9	11	12	12	13	13	14	15	16	16	18	17	15	14	13	12	10	9
Max LDES Needed to Offset Capacity	1	-	-	2	5	8	8	9	9	11	12	12	13	14	14	15	16	16	18	17	15	14	13	12	10	9

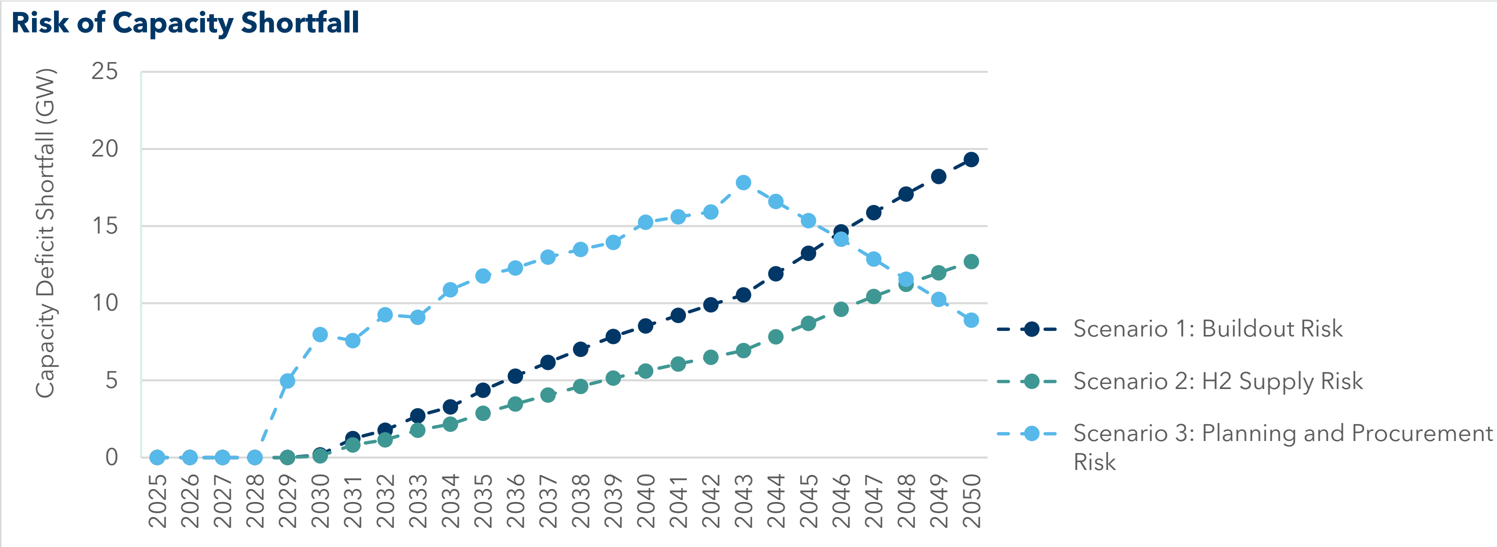

Figure 22: Capacity Needs Assessment Under Various Scenarios

Once we have determined Ontario's generation capacity needs, we will determine the regulation and operating reserve needs.

- Reliability Needs: We assume Ontario's spinning and operating reserve requirements are proportional to the peak demand and continue to grow as the peak demand[81] grows. The reliability needs as a proportion of system peak demand is held constant among the scenarios. We assume that the 10-minute reserve requirements will grow from 1,460 MW in 2025 to 3,760 MW by 2050, while the 30-minute reserve requirements will grow from 730 MW in 2025 to 1,880 MW by 2050.
- Regulation: We assume Ontario's regulation requirements are proportional to the peak demand and continue to grow as the peak demand grows. We assume the regulation requirements will grow[82] from 250 MW in 2025 to 650 MW by 2050.

The Grid Needs are assumed to be constant among the scenarios. In our modelling, we assume that 10% of the system's 30-minute operating reserve requirements are designated for the project. Additionally, 7% of the total 10-minute spinning requirements are assigned to the LDES. When it comes to regulation, we assume that only 10% of the total regulation capacity is allocated to the LDES project.

[81] Assumes 30-min spin is 2.8%- and 10-min spin at 5.6% of the system peak demand.
[82] Assumes that regulation capacity is 1% of the total system peak demand.

B.3 Grid Service Value

Generation Capacity Value: The value for generation capacity is based on the Net Cost of New Entry for the next marginal resource. In this analysis, the Net CONE represents the annual revenues a new resource would need to earn, specifically in the capacity market, after netting out energy. The Net CONE values are estimated for each year from 2025 to 2050 and are used as a proxy for generation capacity values.

- **Scenario 1 – Build Out Risk:** Under this scenario, the generation capacity values are based on the Net CONE for small modular reactors from 2025 to 2050.
- **Scenario 2 – H2 Supply Risks:** Under this scenario, the generation capacity values are based on the Net CONE for a natural gas peaker from 2025 to 2035, after which the generation capacity values are based on the Net CONE for a green hydrogen-powered gas peaker.
- **Scenario 3 – Procurement Risks:** Similar to scenario 2, the generation capacity values are based on the Net CONE for a natural gas peaker from 2025 to 2035, after which the generation capacity values are based on the Net CONE for a green hydrogen-powered gas peaker.

Table 6: Generation Capacity Values ($/kW-yr) by Scenario

Capacity Value ($/kW-yr)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2040	2045	2050
Scenario 1: Buildout Risk	239	236	234	233	232	231	230	228	226	225	223	215	206	198
Scenario 2: H2 Planning Risk	161	156	156	157	159	162	165	168	172	175	178	282	282	282
Scenario 3: Procurement Risk	161	156	156	157	159	162	165	168	172	175	178	282	282	282

Operating Reserve and Regulation Values: The 10-minute and 30-minute reserve and regulation serve values are assumed to be proportionate based on the generation capacity values in each scenario. The 2025 reserve and regulation serve values were developed based on the IESO's forecast of prices and a scan of values in neighbouring jurisdictions.

Table 7: Operating Reserve and Regulation Values ($/kW-yr) in Scenario 1

Service Value ($/kW-yr)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2040	2045	2050
Regulation	$227	$224	$223	$222	$221	$220	$218	$217	$215	$214	$212	$204	$196	$188
30. in Spinning Reserve	$209	$207	$205	$205	$204	$203	$201	$200	$198	$197	$196	$188	$181	$173
30 Min Reserve	$146	$145	$144	$143	$143	$142	$141	$140	$139	$138	$137	$132	$127	$121

Table 8: Operating Reserve and Regulation Values ($/kW-yr) in Scenario 2

Service Value ($/kW-yr)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2040	2045	2050
Regulation	$227	$220	$219	$221	$224	$228	$232	$237	$242	$247	$250	$397	$397	$397
10 Min Spinning Reserve	$209	$202	$202	$204	$206	$210	$214	$218	$223	$227	$231	$366	$366	$366
30 Min Reserve	$146	$142	$141	$143	$144	$147	$150	$153	$156	$159	$161	$256	$256	$256

Table 9: Operating Reserve and Regulation Values ($/kW-yr) in Scenario 3

Service Value ($/kW-yr)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2040	2045	2050
Regulation	$227	$220	$219	$221	$224	$228	$232	$237	$242	$247	$250	$397	$397	$397
10 Min Spinning Reserve	$209	$202	$202	$204	$206	$210	$214	$218	$223	$227	$231	$366	$366	$366
30 Min Reserve	$146	$142	$141	$143	$144	$147	$150	$153	$156	$159	$161	$256	$256	$256

Arbitrage and T&D Values: The arbitrage values are based on the difference in the peak and off-peak values defined in the IESO avoided costs study. The T&D deferral values are based on the IESO DER Potential Study.

Table 10: Arbitrage and T&D Values across the scenarios

Service Value	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2040	2045	2050
Arbitrage Values ($/MWh)	$6	$20	$10	$13	$13	$18	$20	$20	$18	$23	$23	$61	$55	$55
Transmission Deferral ($/kW-yr)	$44	$45	$46	$47	$48	$49	$50	$51	$52	$53	$54	$60	$52	$52

B.4 LDES Technology Characterization

We recognize that different types of long-duration energy storage (LDES) technologies are available in the market today, each with different storage or physical principles and architectures. To capture the extent of their technical capabilities, we have assumed a range to capture the broad array of LDES performance characteristics. The following table captures the key assumptions on the sensitivity of the technical parameters.

Table 11: LDES Technical Assumptions

Parameters	Low Cost	Base Costs	High Costs
Duration	10 hours		
Degradation Rate	-%	1%	2%
Round Trip Efficiency (AC-AC)	75%	65%	53%
Project Life	30 years		
2032 Capital Cost (CA$/kW)	$2,740	$3,295	$4,000
Fixed O&M ($/kW-yr)	27 $/kW-yr	33 $/kW-yr	40 $/kW-yr

B.5 Net Cost of New Entry Cost Calculations (Net CONE)

To estimate the Net Cost of New Entry, we first determine the Net Lifetime Costs of the marginal unit and the Net Lifetime Revenues from the marginal unit.

$$Net\ CONE\ (\frac{\$}{kW} - yr) = \frac{Total\ Lifetime\ Present\ Costs - Total\ Lifetime\ Revenues}{Usable\ Capacity\ \times Lifetime\ (Years)}$$

For each generation unit, we calculate the total lifetime[83] present costs.

$$\begin{aligned} &Total\ Lifetime\ Present\ Costs \\ &\quad = Capacity\ Costs + Fixed\ and\ Variable\ O\&M + Fuel\ Costs + Carbon\ Tax_{LIfetime} \end{aligned}$$

For each generation unit, we calculate the total lifetime present revenues, which, in this case, we assume only the energy revenues[84].

$$Total\ Lifetime\ Revenues = Total\ Energy\ Revenues$$

2030 Assumptions

	Natural Gas CCGT	Natural Gas CCGT (85% CCS)	Natural Gas Peaker	Green H2 Peaker	Blue H2 Peaker	SMR
Capacity Factor	80%	80%	15%	15%	15%	93%
Capacity Costs ($/kW)	$1,367	$3,581	$2,215	$2,215	$2,215	$11,530
Fixed O&M Costs ($/kW-yr)	$19	$62	$40	$40	$40	$150
Variable O&M Costs ($/MWh)	$3	$13	$9	$9	$9	$5
Fuel Costs ($/MWh)	$24	$46	$85	$453	$531	$9
Carbon Tax ($/MWh)	$56	$8	$48			

[83] Assumes a discount rate of 6%

[84] Assumes energy revenues of $75 per MWh over 2025 to 2050. Higher energy costs assumed since Ontario is expected to be energy constraint.

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