Canadian Energy Storage report: 2019 case study for the Ontario market

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Canadian Energy Storage Report:
2019 Case Study for the Ontario Market

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Note that this report reflects the beliefs and opinions of the NRC authors based on best available information at the time of writing. This report does not necessarily represent the views of the advisory board members, their affiliated organization, or any other stakeholder groups.

Preface

Since the time the analyses described in this Ontario Chapter study were performed, several changes to energy policy and environmental regulations in Ontario have been implemented. The specific policies/regulations and their anticipated impacts on the inputs and results of these analyses are listed in the table below.

Table 1. Policy Changes and their Impacts on this Study since the Time of the Analysis

Policy	Key Change Since Time of This Analysis	Estimated Impacts of Change to Analysis Results
Global Adjustment	The Industrial Conservative Initiative (ICI) under which registered Class-A customers will pay Global Adjustment in a specified way might be replaced in the future since Ontario government has decided to cancel many Electricity Conservation Programs.	Due to the uncertainty related to the ICI, the change in the Global Adjustment payment method by registered Class-A customers is not yet clear. According to the existing policy, savings on the Global Adjustment payment for a Class-A customer is a significant portion of the installed ES system's benefit. The worst-case scenario of the impact of the policy change would be assumed to be the entire removal of the ICI that is equivalent to the case without inclusion of the Global Adjustment savings. The cases with and without the ICI are represented by Use Cases #2 and #1, respectively. Other scenarios for the replacement of the ICI would have to be studied separately in the future.
Release of Annual Planning Outlook 2020	The 2020 APO has a lower demand growth forecast compared to 2017 LTEP report data. "Installed Capacity" values have also been updated by generation type as well as by the nuclear generation facility refurbishment schedule.	The changes in demand forecasts are lower but the differences are minor and do not impact the overall results of the study. Also, this uncertainty in demand forecasts is covered with the high sensitivity case. Effects of additional installed capacity requirements are also analyzed in the high-case scenario in this study. The changes in the nuclear refurbishment dates are minor and will not impact the study outputs. It should be noted that the Ontario Energy Board (OEB) is taking steps to enable distributed energy resources (DERs), and the IESO is working to enable energy storage in Ontario's market, both of which are positive steps for the future business case for storage.

The following figure and tables demonstrate the differences between the IESO 2017 Long-term Energy Plan and 2020 Annual Planning Outlook datasets. A comparative analysis was done to ensure the analysis in this report aligns with stakeholder vision for the future Ontario grid.

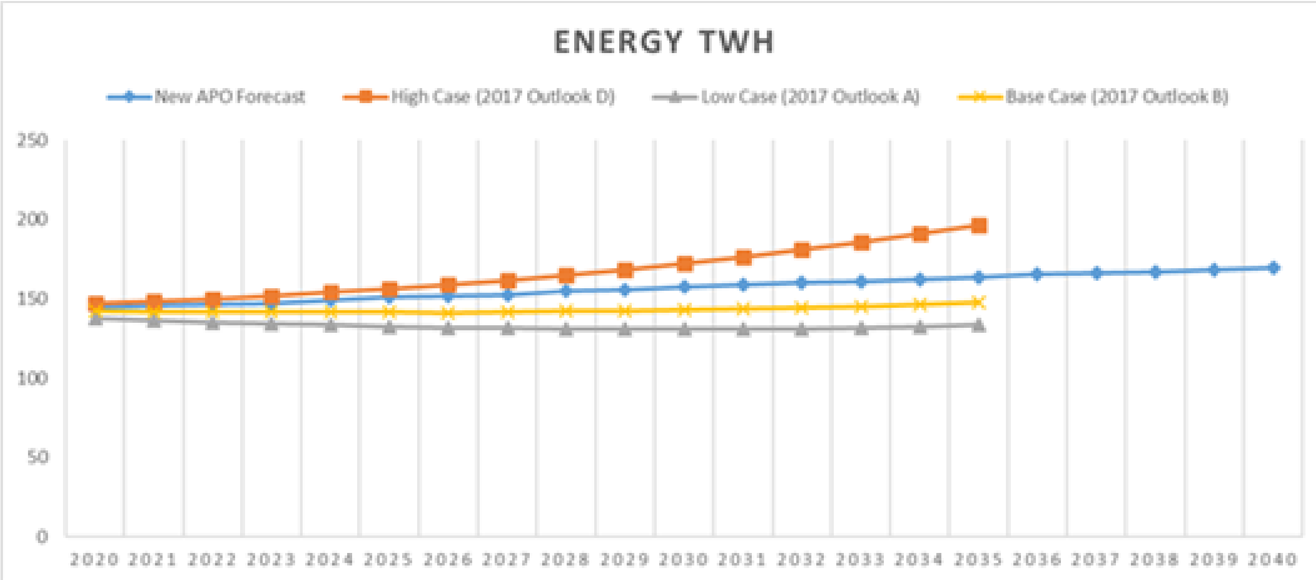

Figure 1. Demand forecast comparison of 2020 APO and 2017 LTEP

Table 2. Installed Capacity Comparison by Generation Fuel Type between 2020 APO and 2017 LTEP

Capacity (GW)		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Hydro	New 2020 APO	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
	LTEP 2017	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
	Difference	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**
Natural Gas	New 2020 APO	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7
	LTEP 2017	9.8	9.8	9.8	9.8	9.8	9.8	9.4	9.4	9.4	9.4	9.4
	Difference	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.3**	**1.3**	**1.3**	**1.3**	**1.3**
Wind	New 2020 APO	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
	LTEP 2017	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
	Difference	**-0.2**	**-0.2**	**-0.2**	**-0.2**	**-0.2**	**-0.2**	**-0.2**	**-0.2**	**-0.2**	**-0.2**	**-0.2**
Solar	New 2020 APO	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
	LTEP 2017	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
	Difference	**-0.3**	**-0.3**	**-0.3**	**-0.3**	**-0.3**	**-0.3**	**-0.3**	**-0.3**	**-0.3**	**-0.3**	**-0.3**
Nuclear	New 2020 APO	11.3	10.4	10.4	9.5	10.3	7.5	8.3	9.1	8.3	9.1	8.3
	LTEP 2017	11.3	10.4	10.4	8.6	10.3	7.5	8.3	8.3	8.3	9.1	8.3
	Difference	**0.0**	**0.0**	**0.0**	**0.8**	**0.0**	**0.0**	**0.0**	**0.8**	**0.0**	**0.0**	**0.0**
Biomass	New 2020 APO	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	LTEP 2017	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
	Difference	**-0.2**	**-0.2**	**-0.2**	**-0.2**	**-0.2**	**-0.2**	**-0.2**	**-0.2**	**-0.2**	**-0.2**	**-0.2**
Demand Response	New 2020 APO	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
	LTEP 2017	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
	Difference	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Total	New 2020 APO	41.0	40.1	40.1	39.1	40.0	37.1	38.0	38.8	37.9	38.8	37.9
	LTEP 2017	40.2	39.4	39.4	37.6	39.3	36.4	36.9	36.9	36.8	37.7	36.8
	Difference	**0.7**	**0.7**	**0.7**	**1.6**	**0.7**	**0.7**	**1.1**	**1.9**	**1.1**	**1.1**	**1.1**

Table 3. Nuclear Generation Plant Refurbishment Schedule Comparison between 2020 APO and 2017 LTEP

New 2020 APO		
Unit	Out of Service	In Service
Bruce G3	1/1/2023	6/30/2026
Bruce G4	1/1/2025	12/31/2027
Bruce G5	7/1/2026	6/30/2029
Bruce G6	1/1/2020	10/19/2023
Bruce G7	7/1/2028	6/30/2031
Bruce G8	7/1/2030	6/30/2033
Darlington G1	10/15/2021	12/15/2024
Darlington G2	10/14/2016	2/15/2020
Darlington G3	2/15/2020	6/15/2023
Darlington G4	5/1/2023	5/31/2026
Pickering G1	12/31/2022	
Pickering G4	12/31/2022	
Pickering G5	12/31/2024	
Pickering G6	12/31/2024	
Pickering G7	12/31/2024	
Pickering G8	12/31/2024	

2017 LTEP			
Unit	Refurbishment Outage Start	Refurbishment Outage End	Projected End-of-Service
Bruce 3	January 2023	June 2026	
Bruce 4	January 2025	December 2027	
Bruce 5	July 2026	June 2029	
Bruce 6	January 2020	December 2023	
Bruce 7	July 2028	June 2031	
Bruce 8	July 2030	June 2033	
Darlington 1	June 2021	May 2024	
Darlington 2	October 2016	February 2020	
Darlington 3	February 2020	February 2023	
Darlington 4	February 2023	December 2025	
Pickering 1			December 2022
Pickering 4			December 2022
Pickering 5			December 2024
Pickering 6			December 2024
Pickering 7			December 2024
Pickering 8			December 2024

Executive Summary

Canada is in the enviable position of being relatively rich in natural resources and having one of the cleanest, least expensive and most reliable electricity grids in the world. However, a decrease in infrastructure investments in the 1990's along with an increase in the integration of renewables, a rise in smart grid technologies, and changes in demand and policies at a national and provincial level have created an increased awareness that fundamental changes in the way we build, own and operate our electricity systems may be required. Many studies, organizations and experts worldwide have concluded that these changes provide a perfect opportunity for energy storage (ES) technologies to demonstrate their value in supporting energy security and climate change goals, as well as creating a more integrated and optimized energy system. However, few comprehensive studies exist at a national or provincial level that comprehensively address the market potential and costs and benefits, as well as economic and environmental impacts of significant ES utilization given the complexities of the analysis and the marketplace.

Understanding the potential value of ES may help provide cost effective solutions for secure and reliable electric grids, and may also provide opportunities as an economic engine to drive the global competitiveness of Canadian energy products and home-grown expertise. However, most studies undertaken to date have reviewed ES on a project-by-project basis, which makes it difficult to ascertain the full value and costs of implementing the technology. It is within this context that the NRC, through its Energy Storage for Grid Security and Modernization Program, has undertaken the development of a Canadian Energy Storage Study, with support and input from NRCan's Office of Energy Research and Development (OERD), strategic partners and consultants, stakeholders across the value chain, and an expert advisory board. This study, comprised of three pillars of analysis, is intended to provide a neutral and independent analysis jurisdiction by jurisdiction across Canada that outlines the potential costs and benefits of the adoption of ES technologies.

Pillar 1 - Grid Needs and ES Market Opportunity

- Identify ES use cases
- Define specific application requirements
- Identify the impacts on grid power planning and operations
- Review the current market structure

Pillar 2 - Technology Assessment and Valuation

- Assess ES Technologies and trends
- Match technology and application requirements
- Propose valuation and performance frameworks
- Evaluate individual ES profitability and dispatch on the electricity grid.

Pillar 3 - Environmental and Socio Economic Assessment

- Assess environmental and socio-economic metrics
- Assess GHG emissions at the grid level
- Compare life cycle GHG emissions of ES technologies

This version of the study contains the framework for the entire study as well as the detailed analysis for Ontario. It is expected that the framework and the Ontario chapter will be updated in the future to take into account further refinements based on stakeholder feedback as other jurisdictions proceed, as well as reflect any specific regulatory or technical changes that occur over the duration of the project. Other provinces will be completed independently, due to the varied nature of the markets, generation and supply mix, and providers/technologies used in each market. However, the overall framework will be consistent, and will leverage learning across Canadian jurisdictions and from other early ES markets.

Pillar 1 - Grid Needs and ES Market Opportunity

The Pillar 1 analysis involved quantifying the indicative size, location, and timing of ES systems deployment that would maximize the benefits to the electricity ratepayers in the province of Ontario through a technology-agnostic approach with transparent assumptions on the business-as-usual status of the Ontario bulk electric system. Various scenarios were modelled and sensitivities were built up from the Independent Electric System Operator's (IESO) Annual Planning Outlook with ES systems expansion. With these results, locations for potential ES systems' deployments throughout Ontario were found using best practice power system operational analyses to minimize capital and operational costs across generation, transmission, distribution and demand. Along with ES systems' locations, the analysis determined optimum ratios of power and energy for potential ES systems' sizes in MW/MWh. These potential ES systems' deployments would achieve maximum benefits to consumers (all electricity grid users) as well as the optimum ES systems' deployment timings of the modelled scenarios.

Key Findings in Pillar 1

- The analysis identified the economic benefits of adding ES systems into the Ontario footprint for a base-case scenario, a low-case scenario, and a high-case scenario, each analyzed against a "business-as-usual" scenario in which ES was not built into the Ontario footprint:
  - Low Case - 745 MW built resulting in $50 million of gross lifetime benefits to the grid
  - Base Case – 2,636 MW built resulting in $200 million of gross lifetime benefits
  - High Case – 5,743 MW built resulting in $900 million of gross lifetime benefits.
- The sensitivity analysis identified that ES technology cost has the most significant impact on the amount of ES built.
- Results showed that ES systems can increase the overall benefits of the Ontario system by improving efficiency, providing resiliency and reliability, and increasing system flexibility. Value stacking through participation in a combination of wholesale market services and distribution services (DS) (which are evaluated even though Ontario does not have a DS market) is critical for maximizing system benefits and economic benefits.

The methodology involved a multi-phased approach in which sizing and location analysis were examined with respect to various policy futures and uncertainties in the Ontario grid. The first phase involved an economic cost benefit analysis for individual cases. The second phase examined three cases from the first phase which resulted in: a) the highest amount of ES built, b) the least amount of ES built, and c) a base case model representing the median build for all case results.

Study results for sizing and location are presented below for each case examined.

Load growth cases examined the impact of high growth and low growth forecasts on ES builds. The high load growth scenario used the IESO 2020 Annual Planning Outlook data and the low load growth scenario used the IESO 2017 LTEP Outlook A for demand and energy forecast per year. Results from the load growth model show that ES builds scale with demand and energy growth as indicated by the 1,108 MW increase in ES built in the high load growth scenario and 1,412 MW decrease in the low load growth scenario.

Fuel price cases examined the fluctuation in fuel prices of Natural Gas, Oil, Biomass, and Landfill Gas (LFG). The high scenario assumed a 140% multiplier and the low scenario assumed a 60% multiplier on fuel prices. Results from the fuel price model show that ES builds were similar to the base case for the high scenario and decreased to 1,095 MW in the low scenario.

Technology cost cases examined the uncertainty of ES build costs using high and low scenarios. The high scenario assumed a 140% multiplier and the low scenario assumed a 60% multiplier for ES build costs compiled from mixed industry benchmarking data. Results from the technology cost model show that ES builds inversely scale with technology costs as indicated by the 1,892 MW reduction in ES built in the high technology cost scenario and 3,106 MW increase in low technology cost scenario.

The Carbon Tax case examined the fluctuation of the carbon tax on CO2 emissions. The high scenario assumed a 125% multiplier and the low scenario assumed a 75% multiplier for the carbon tax rate. Results from the carbon tax model show that ES builds were similar to the base case for the high scenario and decreased to 1,041 MW in the low scenario.

The economic benefits of ES were analyzed as the combined value of the storage capacity value, ancillary services value, energy arbitrage value, and the difference in fixed operation and maintenance costs (FOM) and generation cost between the “business-as-usual” case and storage case. The present value of benefits was determined by summing all benefits from 2020 through 2039 and applying a 7% discount factor. Net Present Value (NPV) is the difference between total present value benefits and total present value costs. The cost and benefits for each case are summarized in Table 4 below.

Table 4. Total Cost, and Net Present Value for the Low, Base, and High Cases

Case	Total Benefit PV ('$MM')	Total Cost PV ('$MM')	NPV ('$MM')
Low Case	771	642	46
Base Case	2,859	2,460	200
High Case	6,096	4,074	903

Pillar 2 – Technology Assessment and Valuation

Key Findings in Pillar 2

- A two-step ES valuation analysis was used for general ES classes as well as specific ES projects. The top ES classes in terms of potential profit were CAES-c, NaS, and Li-ion, out of 19 ES technology classes simulated.
- A 15-year 10MW 2Hr Li-ion battery was simulated for three use cases according to IESO rules and regulations using actual data, resulting in benefit-to-cost ratios of 0.6 to 0.98.
- The benefit-to-cost results are likely a lower bound due to current market participation restrictions, existing market products, and a lack of publicly available data.

The Energy Storage (ES) valuation analysis performed in Pillar 2 evaluated the economic benefits that were available for classes of ES technologies and individual project-level examples operating on the Ontario electric system, as well as the potential for each individual ES project to be dispatched to meet grid needs. This was accomplished using an evaluation framework that included a two-stage, top-down funnel approach. The first stage used Ontario-specific grid data, technology data from a survey completed by the NRC, and assumptions from Pillar 1. The second stage used actual hourly, public price and load data in addition to assumptions from Pillar 1 to perform a more detailed dispatch and profitability analysis. This approach, from general to specific, provided a more granular snapshot of ES potential at a technology-specific and individual project level.

In the first stage, 19 ES technology classes were simulated at the generation and transmission levels, using pricing for each market and service from a survey of Ontario electric system stakeholders as well as Ontario-specific financial ownership structures. Use cases relied on load following (not presently part of IESO's markets or services) as the top or anchor service to maximize potential profitability or potential net present value (NPV). The top three ES technology classes were compressed air energy storage in salt caverns (CAES-c), sodium sulfur battery ES (NaS) and lithium-ion battery energy storage (Li-ion).

In the second stage, a more granular analysis focused on simulating a specific example of a 15-year 10MW 2Hr Li-ion battery ES as a single IPP-owned system in three Ontario-specific use cases. The three use cases were: a) real-time energy and operating reserves, b) global adjustment (GA) Class-A in addition to real-time energy and operating reserves, and c) demand reduction / capacity auction in addition to real-time energy and operating reserves. Whereas the first stage of the valuation analysis included all potential services from the survey at the generation and transmission levels, the second stage only included those in which ES is allowed to participate according to IESO market rules and regulations and using actual historical IESO data. An intensive time series dispatch simulation with an hourly resolution was performed for an individual Li-ion ES project to model operation over its lifetime along with bidding results into the Ontario markets according to a generic North American ISO dispatch order or hierarchy.

Combining both ES valuation stages, CAES-c, NaS and Li-ion ES technology classes show the potential for benefit-to-cost ratios (applicable to the ES owner) greater than 1. The hypothetical use case with GA, Class-A, and with real-time energy and operating reserves, showed a benefit-to-cost ratio of 0.98. A more detailed analysis of a single 10MW 2Hr Li-ion battery participating in actual IESO markets and services in three specific use cases showed benefit-to-cost ratios of between 0.6 and 1. With potential IESO policy changes on GA payment methods for Class-A customers, the benefit of ES from providing GA payment savings could be altered or even completely removed, resulting in the same profit values as for the studied case in which only real-time energy and operating reserves are served.

It is noted that these benefit-to-cost ratios are likely a lower bound. Currently ES benefits or revenue streams in Ontario are constrained, which decreases benefit-to-cost ratios. ES is presently not allowed to participate in all IESO markets and services (IESO's ESAG 2020); in particular, benefits from regulation service and frequency regulation could increase benefit-to-cost ratios. If a new IESO market for load following or ramping is needed and ES is allowed to participate, then ES profitability or benefit-to-cost ratio would increase further. Finally, some Ontario data sets were unavailable at the time of this report so a use case with regulation service could not be simulated.

Pillar 3 - Environmental and Socio-Economic Assessment

Many industry reports predict ES costs to decrease significantly over the next five years, driven by scale and related cost savings, improved standardization and technological improvements, and supported in turn by increased demand. This rise in demand would be a result of regulatory / pricing innovation, high renewables penetration, interests in system operators to seek non-wires solutions, and the needs of an aging and changing power grid in the context of a modern society.

In this study, the socio-economic impact for ES deployment was evaluated through the number of jobs created and GDP added by ES deployment in Ontario during ES projects' stages. The results of the analysis showed that most economic impacts are projected to be generated during the construction and operation phases in a similar way to renewable energy projects. By 2030, the total direct impact GDP added to Ontario's economy is estimated to be $768M and the number of jobs created due to the construction and operation stages is 5,781. However, the economic impact is likely to be lower than the economic impact in, for example, solar PV projects, as ES systems are usually modular and imported with lower construction-phase costs.

Key Findings in Pillar 3

- Energy storage deployment is estimated to increase Ontario's GDP by $768M and add 5,781 jobs.
- ES deployment would provide the incremental environmental benefit of reducing GHG emissions from the Ontario electricity system by 11% by 2030 (a reduction of 4.5 $MtCO_{2\text{-}eq}$).
- The life cycle GHG impacts of Li-ion battery ES and VRFB systems are mostly due to the emissions during manufacturing (cradle-to-gate stage) of their ES system components.
- The life cycle GHG emissions of Li-ion battery ES and VRFB systems indicate that the overall contribution of the use stage to the overall life cycle impact depends upon the time-of-day grid marginal emissions factors when they are dispatched and the round-trip efficiency.

Energy storage deployment in the Ontario electricity system could significantly reduce the projected GHG emissions of the Ontario electricity grid from 2020 to 2030. Storage operation could reduce grid-level $CO_{2\text{-}eq}$ emissions by 11% by 2030 with a grid-level GHG emissions reduction of 4.5 $MtCO_{2\text{-}eq}$.

The comparative life cycle GHG impact between Li-ion battery systems and VRFB systems indicates that VRFB systems are more environmentally friendly than Li-ion battery systems, and VRFBs generate approximately 76% less life cycle GHG emissions than Li-ion battery systems. The life cycle GHG emissions of Li-ion battery ES and VRFB systems are mostly due to the emissions during manufacturing (cradle-to-gate stage) of their ES systems components.

The contribution of the operations stage to the overall life cycle impact depends upon hourly grid marginal emissions factors that reflect the changes to the power-grid mix and the round-trip efficiency. VRFB systems were projected to displace less emissions per $MWh_{dispatched}$ during the operations phase, originating from the time-of-day marginal emissions factors when dispatched, exacerbated by low system round-trip efficiency. However, varying operation patterns for ES could achieve higher carbon reductions.

Further study is recommended to perform a comparative analysis of life cycle GHG impacts of ES systems for different stationary grid applications, as the cradle-to-gate and operation phase GHG impacts would be affected by lifetime utilization of a specific application.

Résumé

Le Canada occupe une situation enviable : pays relativement riche en ressources naturelles, son réseau d'électricité est l'un des moins polluants, des moins onéreux et des plus fiables de la planète. Toutefois, la diminution des investissements dans les infrastructures dans les années 1990, l'intégration accrue des énergies renouvelables, l'essor des technologies de réseaux intelligents, ainsi que l'évolution de la demande et des politiques nationales et provinciales, nous ont fait reconnaître la nécessité d'apporter des changements fondamentaux à la manière dont nous bâtissons, possédons et exploitons nos réseaux d'électricité. De plus, un grand nombre d'études, d'organisations et d'experts dans le monde ont conclu que de tels changements constituent une occasion rêvée de montrer que les technologies de stockage de l'énergie (SE) ont leur utilité dans la réalisation des objectifs associés à la sécurité énergétique et aux changements climatiques, et que le SE pourrait conduire à un réseau énergétique mieux intégré et optimisé. Malgré cela, peu d'études ont examiné de manière exhaustive les possibilités commerciales, la rentabilité ainsi que les retombées économiques et

environnementales du SE aux paliers national et provincial, en raison des complexités d'une telle analyse et de la nature du marché.

Une meilleure compréhension de la valeur potentielle des énergies renouvelables peut contribuer à fournir des solutions rentables pour des réseaux électriques sûrs et fiables, et peut également offrir des possibilités en tant que moteur économique pour stimuler la compétitivité mondiale des produits énergétiques canadiens et l'expertise nationale. Cependant, la plupart des études réalisées jusqu'à présent n'ont examiné le stockage d'énergie qu'un projet à la fois, ce qui complique l'évaluation de la valeur générale de la technologie et du coût de sa mise en œuvre. C'est dans ce contexte que le CNRC, par l'entremise de son programme « Stockage d'énergie pour la modernisation et la sécurisation des réseaux », a entrepris une étude canadienne sur le stockage d'énergie. Pour la réaliser, le CNRC peut compter sur l'appui et la contribution du Bureau de recherche et de développement énergétiques (BRDE) de RNCan, de partenaires stratégiques et d'experts-conseils, d'intervenants de toute la chaîne de valeur et d'une commission consultative d'experts. Cette étude, composée de trois axes d'analyse, vise à fournir une analyse neutre et indépendante, province par province, d'un bout à l'autre du pays, qui souligne les coûts et les avantages potentiels de l'adoption des technologies de SE.

1er axe – Besoins du réseau et possibilités du SE sur le marché	2e axe – Évaluation de la technologie	3e axe – Évaluation environnementale et socioéconomique
• Déterminer les cas d'utilisation du SE • Établir les exigences spécifiques de l'application • Préciser les répercussions du SE sur l'aménagement et l'exploitation du réseau • Passer en revue la structure actuelle du marché	• Évaluer les technologies de SE et les tendances qui s'y associent • Apparier la technologie aux contraintes de l'application • Proposer un cadre pour l'évaluation et le rendement • Évaluer la rentabilité de chaque technologie de SE et lui trouver une place dans sur le réseau	• Chiffrer les retombées environnemtales et socioéconomiques du SE • Évaluer les émissions de GES à la grandeur du réseau • Comparer le volume de GES émis par les technologies de SE durant leur cycle de vie

Ce document présente le cadre général de l'étude mentionnée plus haut et les résultats de l'analyse détaillée de la situation en Ontario. Le cadre de l'étude et l'analyse de l'Ontario seront sans doute actualisés par la suite, en fonction des perfectionnements suggérés par les intervenants, à mesure que l'on s'attaque aux autres régions, ou des amendements apportés à la réglementation, voire des changements techniques qui surviendront tout au long du projet. Face à la variété des marchés, de la composition du mélange énergétique (production et approvisionnement), et des fournisseurs/technologies propres à chaque marché, on analysera la situation dans les autres provinces séparément. Cependant, l'exercice gardera le même cadre et on tirera parti de ce qu'on a appris dans les différentes régions du pays ainsi que sur d'autres marchés où l'on a rapidement adopté le SE.

1er axe – Besoins du réseau et possibilités du SE sur le marché

Le premier axe d'analyse supposait une quantification de l'envergure des systèmes de SE, de leur emplacement et du moment de leur déploiement qui s'avéreraient les plus profitables pour ceux qui achètent de l'électricité en Ontario. On a recouru pour cela à une approche technologiquement agnostique qui s'appuie sur des hypothèses transparentes concernant le statu quo sur le marché de l'électricité ontarien. Plusieurs scénarios ont été modélisés et l'on a pris en compte diverses particularités concernant l'expansion du SE en Ontario, tirées de l'Annual Planning Outlook (perspectives annuelles d'aménagement) de la Société indépendante d'exploitation du réseau d'électricité (SIERE). De là, on a déterminé les endroits où les systèmes de SE pourraient être déployés en Ontario, après analyse des pratiques exemplaires en matière d'exploitation du réseau de façon à minimiser les coûts d'immobilisation et de fonctionnement au niveau de la production, du transport, de la distribution et de la demande. Parallèlement à l'emplacement des systèmes de SE, l'analyse a permis d'établir le rapport optimal entre la puissance des systèmes de SE éventuels et la quantité d'énergie stockée en MW/MWh. Un tel déploiement des systèmes de SE potentiels aboutirait aux plus grands avantages pour le consommateur (tous les abonnés au réseau confondus) et surviendrait au meilleur moment, selon les scénarios modélisés.

Principales constatations du 1er axe d'analyse

- L'analyse a établi les avantages économiques de l'addition de systèmes de SE à l'empreinte du réseau ontarien pour trois scénarios (intégration de base, faible intégration et intégration élevée des systèmes). Dans chaque cas, les résultats ont été comparés au scénario du statu quo, c'est-à-dire un scénario selon lequel le stockage d'énergie ne trouverait pas sa place dans le réseau ontarien.
    - Faible intégration – 745 MW d'ajoutés avec des retombées brutes de 50 millions de dollars pour la vie utile de la technologie
    - Intégration de base – 2 636 MW d'ajoutés avec des retombées brutes de 200 millions de dollars pour la vie utile de la technologie
    - Intégration élevée – 5 743 MW d'ajoutés avec des retombées brutes de 900 millions de dollars pour la vie utile de la technologie.
- Selon l'analyse de sensibilité, c'est le coût de la technologie de SE qui exerce le plus d'impact sur le nombre de systèmes mis en place.
- Les résultats indiquent que les systèmes de stockage d'énergie peuvent avoir des avantages globaux plus importants pour le réseau ontarien en améliorant son efficacité, en le rendant plus résilient et fiable, et lui donnant plus de souplesse. Afin de maximiser leurs avantages pour le réseau et leurs retombées économiques, il est capital qu'il y ait empilement de valeurs par la participation à un mélange de services de vente en gros et de distribution (ce que l'on a évalué, bien que l'Ontario n'ait aucun marché de distribution de l'électricité).

La méthode employée comprenait une approche en plusieurs phases en vertu de laquelle on a analysé l'importance et l'emplacement des systèmes de SE selon diverses possibilités sur le plan des politiques publiques et des incertitudes concernant le réseau d'électricité ontarien. Dans un premier temps, on a procédé à une analyse de rentabilité des différents cas. Ensuite, trois cas de la phase précédente ont fait l'objet d'une analyse plus poussée : a) celui où l'on érigeait le plus grand nombre d'installations de SE, b) celui où on en construisait le moins et c) le modèle de base correspondant à la médiane des résultats de la première phase.

Les résultats de l'analyse sur l'envergure et l'emplacement des systèmes de SE pour ces trois scénarios apparaissent ci-dessous.

L'analyse de la <u>croissance de la charge</u> examinait l'impact d'une forte et d'une faible croissance sur le nombre de systèmes de SE aménagés. Le scénario supposant une forte croissance de la charge s'appuyait sur les données de l'Annual Planning Outlook de 2020 de la SIERE, tandis que celui présumant une faible croissance reposait sur le document LTEP Outlook de 2017 de l'organisme, qui prévoit la demande et la production annuelles d'énergie. L'analyse qui repose sur la croissance de la charge indique que le nombre d'installations de SE aménagées augmente avec la demande et la production d'électricité, comme l'indique la hausse de 1 108 MW de la capacité des systèmes de SE obtenue avec le scénario de forte croissance et la baisse de 1 412 MW découlant du scénario de faible croissance de la charge.

L'analyse du <u>prix des combustibles</u> portait sur la fluctuation du prix du gaz naturel, du pétrole, de la biomasse et du méthane capté dans les décharges. Le scénario élevé supposait un effet multiplicateur de 140 %

et le scénario faible, un effet multiplicateur de 60 %. Les résultats du modèle indiquent qu'on bâtirait autant d'installations de SE dans le scénario de base que le scénario élevé, mais que la capacité de stockage baisserait à 1 095 MW dans le scénario de faible intégration.

L'analyse du coût technologique portait sur l'incertitude liée au coût de construction des installations de SE pour le scénario élevé et le scénario faible. Dans le premier cas, on a supposé un effet multiplicateur de 140 % et dans le second, un effet multiplicateur de 60 %, établis à partir de diverses données comparatives de l'industrie. Selon les résultats du modèle, le nombre de systèmes de stockage d'énergie aménagés varierait inversement avec le coût de la technologie, comme le révèle la plus faible capacité de stockage de 1 892 MW qui a été obtenue avec l'hypothèse d'un coût élevé de la technologie et la capacité de stockage de 3 106 MW résultant d'une technologie peu coûteuse.

L'analyse de la taxe carbone portait sur la fluctuation de ladite taxe en fonction des émissions de CO_2. Dans le scénario élevé, on présumait un effet multiplicateur de 125 % et, dans le scénario faible, un effet multiplicateur de 75 %. Les résultats indiquent que le nombre d'installations de SE érigées est le même pour le scénario de base et le scénario à intégration élevée, mais que la capacité de stockage diminue à 1 041 MW pour le scénario à faible intégration.

Les retombées économiques du SE ont été analysées d'après la valeur combinée de la capacité de stockage, des services auxiliaires, de l'arbitrage de l'énergie ainsi que l'écart entre les coûts d'exploitation et de maintenance fixes, et le coût de production quand il y a statu quo ou stockage de l'énergie. On a établi la valeur actualisée des retombées par totalisation des retombées de 2020 à 2039, suivi de l'application d'un facteur d'actualisation de 7 %. La valeur nette actualisée (VNA) correspond à la différence entre la valeur totale actualisée des retombées et les coûts totaux actualisés. Le tableau 4 résume le coût et les retombées de chaque cas.

Table 4. Coût total et valeur nette actualisée des trois scénarios

Scénario	VA retombées (en M$)	VA coût (en M$)	VNA (en M$)
Faible	771	642	46
Base	2 859	2 460	200
Élevé	6 096	4 074	903

2e axe – Évaluation de la technologie

Principales constatations

- Une analyse en deux temps a servi à évaluer les types généraux de technologies de SE et des projets particuliers. Les meilleures technologies de SE sur les 19 simulées, en ce qui concerne les profits potentiels, sont le stockage sous forme d'air comprimé (CAES-c), le stockage dans des batteries au sulfure de sodium (NaS) et le stockage dans des batteries au lithium ionique.
- On a simulé le stockage de 10 MW dans des batteries au lithium ionique de deux heures sur une période de 15 ans pour trois cas d'utilisation selon les règles et la réglementation de la SIERE à partir des données réelles et obtenu un rapport avantages/coût allant de 0,6 à 0,98.
- En réalité, ce rapport est sans doute plus faible à cause des restrictions qui s'appliquent à la participation au marché, des produits déjà disponibles sur le marché et du manque de données publiques disponibles.

L'évaluation du stockage de l'énergie (SE) réalisée dans le cadre du deuxième axe portait sur les retombées économiques liées à divers types de technologies de SE avec, pour illustration, quelques projets en cours sur le réseau d'électricité ontarien. L'analyse a aussi examiné la possibilité d'adapter chaque projet de SE en fonction des besoins du réseau. Pour effectuer une telle évaluation, on a utilisé pour cadre une approche en entonnoir en deux temps, allant du haut vers le bas. En un premier temps, on s'est servi des données spécifiques au réseau ontarien, des données sur les technologies issues d'un sondage du CNRC et des hypothèses découlant du premier axe d'analyse. Ensuite, on a utilisé le prix horaire réel de l'électricité, le prix public et les hypothèses du premier axe d'analyse pour analyser plus en profondeur l'intégration du SE et sa rentabilité. Cette approche, qui va du plus général au plus spécifique, a permis de brosser un tableau plus granulaire des possibilités du SE, selon la nature de la technologie et des projets.

Lors de la première étape, on a simulé 19 technologies de SE au niveau de la production et du transport de l'électricité, en appliquant les prix en vigueur sur chaque marché et pour chaque service, établis d'après une enquête auprès des intervenants du réseau de l'électricité ontarien et la façon dont la propriété financière est structurée en Ontario. Les cas d'utilisation s'appuyaient sur la supervision de la charge (ce qui n'est pas le cas pour l'instant, sur les marchés ou pour les services de la SIERE) en tant que principal service permettant d'optimiser la rentabilité de l'électricité ou sa valeur nette actualisée (VNA) potentielle. Les trois meilleures technologies de SE étaient le stockage d'énergie sous forme d'air comprimé dans des cavernes de sel (CAES-c), le stockage au moyen de batteries au sulfure de sodium (NaS) et le stockage avec des batteries au lithium ionique.

La deuxième étape consistait en une analyse plus granulaire reposant sur une simulation, en l'occurrence le stockage de 10 MW sur 15 ans dans des batteries au lithium ionique de deux heures appartenant à des producteurs indépendants d'énergie pour trois cas d'utilisation typiquement ontariens, à savoir a) le stockage d'énergie en temps réel et les réserves d'exploitation, b) le rajustement global (RG) pour les abonnés de la classe A en plus du stockage d'énergie en temps réel et des réserves d'exploitation, et c) la réduction de la demande/la mise aux enchères de l'offre, en plus du stockage en temps réel et des réserves d'exploitation. Alors que l'analyse réalisée à la première étape englobait la totalité des services éventuels mentionnés lors du sondage sur la production et le transport de l'énergie, celle de l'étape suivante ne portait que sur les services autorisant le SE, selon les règles de la SIERE applicables au marché, et s'appuyait sur les données historiques réelles de la SIERE. Pour modéliser l'exploitation pendant la durée entière d'un projet de SE à batteries au lithium ionique, on a simulé la répartition horaire de l'électricité au moyen d'une longue série de données chronologique en y intégrant les résultats des enchères sur les marchés ontariens selon un ordre de répartition ou une hiérarchie génériques pour les exploitants indépendants d'Amérique du Nord.

Lorsque l’on combine les résultats des deux étapes, on constate que le rapport avantages/coût potentiel (pour le propriétaire du système de SE) est supérieur à un pour les technologies CAES-c, NaS et lithium ionique. Dans le cas d’utilisation hypothétique (RG, classe A avec stockage de l’énergie en temps réel et réserves d’exploitation), le rapport est de 0,98. L’analyse plus poussée du système de stockage de 10 MW avec des batteries au lithium ionique de deux heures sur les marchés et avec les services réels de la SIERE pour les trois cas d’utilisation spécifiques révèle un rapport avantage/coût situé entre 0,6 et 1. Comme la SIERE pourrait modifier sa politique sur les méthodes de paiement avec RG pour ses abonnés de la classe A, les économies que permettrait le SE au niveau du RG pourraient être différentes, voire disparaître complètement, si bien que les bénéfices seraient identiques à ceux du cas d’utilisation n’incluant que le stockage en temps réel et les réserves d’exploitation.

Notons que ces rapports avantages/coût ne devraient constituer qu’une valeur plancher. Les avantages ou revenus actuels tirés du SE en Ontario sont régis pour l’instant, d’où le rapport avantages/coût plus faible. À l’heure actuelle, la SIERE n’autorise pas le SE sur tous ses marchés ni pour tous ses services (Groupe consultatif de la SIERE sur le stockage de l’énergie, 2020). Ainsi, les profits issus du service de régulation et de la régulation de la fréquence pourraient augmenter le rapport avantages/coût. Si la SIERE créait un nouveau marché pour la supervision ou la hausse graduelle de la charge, il se pourrait qu’on assiste à une plus forte augmentation de la rentabilité ou du rapport avantages/coût du SE. Enfin, certains jeux de données ontariennes n’étaient pas disponibles au moment où le présent document a été rédigé, ce qui a interdit la simulation d’un cas d’utilisation incluant le service de régulation.

Troisième axe – Évaluation environnementale et socioéconomique

Beaucoup de rapports de l’industrie prévoient que des économies d’échelle, une plus grande normalisation et le perfectionnement des technologies devraient sensiblement réduire le coût du SE au cours des cinq prochaines années, puis que la hausse de la demande maintiendra cette tendance. La plus forte demande découlerait des innovations au niveau de la réglementation et des prix, d’une meilleure pénétration des énergies renouvelables, de l’engouement des exploitants pour les solutions sans fil et des contraintes liées à un réseau d’électricité vieillissant, qui doit s’adapter aux besoins de la société contemporaine.

Dans cette analyse, on a évalué les retombées socioéconomiques d’un plus vaste déploiement du SE en fonction du nombre d’emplois créés et du montant que le SE ajouterait au PIB ontarien, aux diverses étapes des projets. Les résultats montrent que la majorité des retombées économiques devraient survenir aux étapes de la construction et de l’exploitation, un peu comme c’est le cas pour les projets sur l’énergie renouvelable. D’ici à 2030, le montant global ajouté directement au PIB de l’Ontario devrait être de 768 MS et le nombre d’emplois créés aux deux étapes précitées devrait s’établir à 5 781. Néanmoins, les retombées devraient être plus faibles que celles, par exemple, des projets d’énergie solaire photovoltaïque, car les systèmes de SE sont souvent modulaires et tributaires de l’importation, ce qui réduit les coûts durant l’étape de la construction.

Principales constatations

- On estime que le stockage de l'énergie devrait augmenter le PIB de l'Ontario de 768 M$ et créer 5 781 emplois.
- Le déploiement de systèmes de SE aurait l'avantage supplémentaire, sur le plan de l'environnement, de réduire le volume de GES libérés par le réseau d'électricité ontarien de 11 % d'ici à 2030 (baisse de 4,5 Mt en $CO_{2\text{-eq}}$).
- L'impact global du SE (batteries au lithium ionique ou VRFB) sur les GES viendrait principalement des émissions dégagées durant la fabrication des composants du système de SE (jusqu'à sa mise en marché).
- Les émissions totales de GES pendant la vie utile des batteries au lithium ionique et VRFB indiquent que la fraction de l'impact global attribuable à la phase d'utilisation dépend des émissions marginales au moment où l'électricité est consommée durant la journée, et aussi de l'efficacité générale du système de SE.

Déployer le stockage d'énergie à la grandeur du réseau d'électricité ontarien pourrait réduire sensiblement les émissions de GES que le réseau devrait libérer de 2020 à 2030. En recourant au stockage, on pourrait diminuer les émissions de $CO_{2\text{-eq}}$ du réseau complet de 11 % d'ici à 2030, pour un total de 4,5 Mt en $CO_{2\text{-eq}}$.

Quand on compare l'impact des batteries au lithium ionique et celui des batteries à oxydoréduction au vanadium (VRFB) sur les émissions de GES, on constate que les systèmes de SE à VRFB sont plus écologiques que ceux à batteries au lithium ionique, car les premières libèrent environ 76 % moins de GES pendant leur cycle de vie. Les GES dégagés par les systèmes à batteries au lithium ionique et à batteries VRFB durant leur cycle de vie le sont principalement lors de la fabrication des composants (jusqu'à la mise en marché).

La part que le stade de l'exploitation ajoute à l'impact du cycle de vie dépend des émissions marginales horaires du réseau, lesquelles reposent sur la variation de la composition de la charge et de l'efficacité globale. On estime que les systèmes VRFB déplaceraient moins d'émissions par mégawatt distribué pendant la phase d'exploitation, à cause des émissions marginales au moment de la journée où l'électricité est consommée, ce qu'exacerbe la faible efficacité globale du système. Toutefois, la variabilité des modalités d'exploitation du système de stockage d'énergie pourrait mener à une plus grande réduction des émissions de carbone.

On préconise une analyse comparative plus poussée sur l'impact des systèmes de SE sur les émissions de GES pendant leur cycle de vie, pour les différentes applications stationnaires du réseau d'électricité, car la vie utile d'une application donnée pourrait modifier l'effet de sa fabrication et de son exploitation sur le volume de GES.

National Research Council Canada Conseil national de recherches Canada

Canada

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1 Introduction

The National Research Council of Canada (NRC) and its partners are embarking on a 5-year project to develop a Canadian Energy Storage Study. This work builds upon previous work in Canada and internationally to perform a comprehensive independent analysis of the potential costs and benefits of adopting Energy Storage (ES) technologies in each jurisdiction. In order to do this in a uniform fashion and ensure a fact-based approach to the detailed assessment of the various factors under consideration, the project team is focusing on three pillars of analysis, shown in Figure 2. This common framework will be applied to each province in turn, and will be released as chapters of the overall Canadian Energy Storage Study.

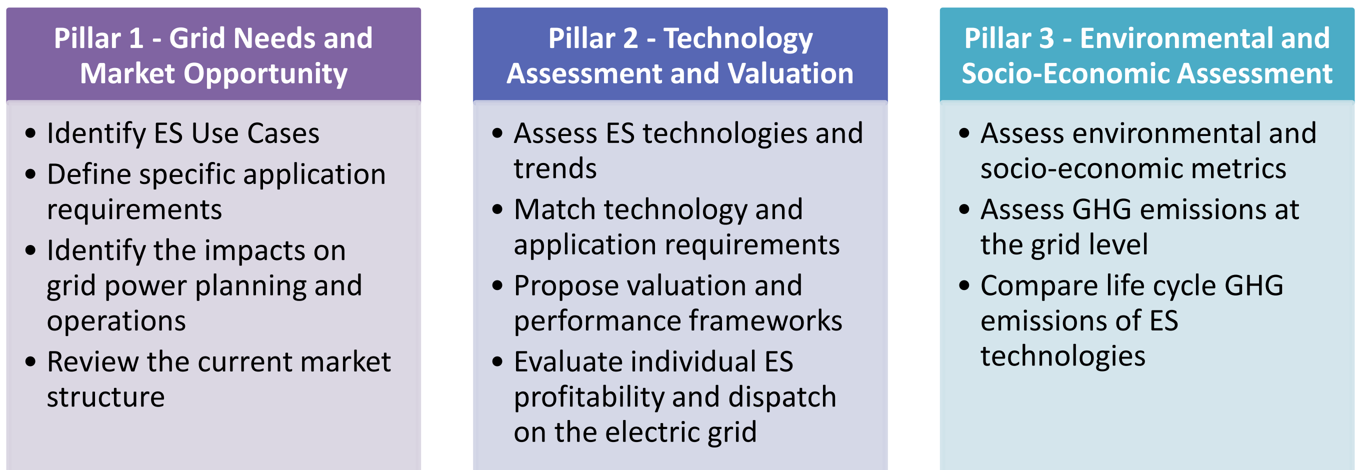

Figure 2. Three pillars of analysis in the Canadian Energy Storage Study project

Across all three pillars, engagement of key stakeholders such as regulators, power producers, and policy makers, along with storage technology vendors and system integrators, is critical. This has been initiated through the creation of an advisory board which has members from many key organizations. Additionally, several events have been held in which the methodology and initial results have been presented. Given that the project is ongoing over a number of years, it is expected that the project team will continue to identify and engage key stakeholders within each province, assess particular stakeholder needs and opportunities, organize and document stakeholder input, and disseminate study results. This study will also leverage recent Program of Energy Research and Development (PERD) projects (2A02.002, NRESOT-04 and NRESOT-05), focusing on real time load data collection and analysis, a CanmetENERGY project on the Canadian ancillary services market, and an NRC TEA (Techno Economic Analysis) platform including a Canadian ES valuation tool and databases therein (ES-Select Canada).

Results for each province will be completed independently due to the varied nature of the markets, generation and supply mix, and providers / technologies used in each market. However, the overall framework will be consistent and will leverage learning across Canadian jurisdictions, as well as from other early ES markets such as California and PJM in the Eastern U.S.

As outlined in the detailed project scope below, the project will be completed in phases, starting with overall framework development, which was applied first in Alberta. The current jurisdiction is Ontario, and this will be followed with other jurisdictions throughout Canada.' The goal of this analysis will be to allow the market to compete in an open and fair manner, for both ES technologies and for existing assets and technologies. More specifically, it is expected that this analysis will produce the following results:

- Pillar 1 result: A clear understanding of the market need for the services that ES might provide in each jurisdiction at the generation, transmission, and distribution levels, including the development of standardized use cases.
- Pillar 2 result: An assessment of the realistic market opportunity for ES, including an analysis of the current and future state of the art of individual technologies, the value of each technology in individual use cases, and the identification of specific regulatory or market barriers that might prevent deployment.
- Pillar 3 result: A uniform assessment of the environmental and economic impacts of the adoption of ES, including the possibility of increased engagement of the electricity and manufacturing sectors in new technology commercialization, for both local use and export opportunities.

2 Grid Needs and Market Opportunity Pillar

Pillar 1 is a macro-level analysis that generates outputs that are used by the other two Pillars. The Pillar 1 analysis identifies ES use cases, defines specific application requirements, and identifies the impacts on grid power planning and operations. Details on the Pillar 1 objectives, background, methodology, and results are found in the sections below.

This study provides an analytically driven process for examining the cost of ES and potential value streams for each scenario. Project economics and net benefits were modelled for business-as-usual and policy futures with and without the addition of ES systems to the Ontario grid over the 2020-2030 study horizon. Detailed scenarios were modelled to identify key cost-effective opportunities and to analyze the value of ES systems by examining:

- Cost Reductions to the overall system including generation cost, startup and shutdown costs, and emissions cost.
- Revenues through charging and storing during periods of low prices and discharging during periods of high prices.
- Deferral or avoidance of transmission and distribution equipment upgrades.
- Deferral or avoidance of peaking plants capital costs, maintenance costs, and emissions costs.
- Firming renewables such as wind or solar through periods of intermittency, allowing them to participate in capacity markets.
- Increasing flexibility, reliability, and resiliency during emergency operating conditions and load swings.
- Reducing GHG emissions by shifting renewable energy generated at off peak times.

2.1 Introduction to Pillar 1

The Energy Storage industry is seen by many analysts and advocates to be rapidly advancing with regard to cost, performance, and market penetration. This is mainly based on various analyses which show that ES provides various benefits to an electricity grid/market. Therefore, many project developers and planners are looking to ES in order to increase resiliency and reliability, and help end users manage energy costs in utility, commercial and consumer markets. According to a report compiled by Bloomberg New Energy Finance and the International Energy Agency (IEA), in 2016 there were 5 GWh of ES installed globally (excluding pumped hydro), and this number is expected to grow to 300 GWh by 2030[1].

The objective of Pillar 1 of this study is to perform an independent analysis of the potential benefits and costs of implementing ES. The analysis involves optimizing the size, location, and timing of potential ES deployments on the Ontario grid in order to maximize the benefits to the ratepayers in the province of Ontario over the study time horizon of 2017 to 2030. The study also considers various policy changes and goals, both existing and expected at a federal and provincial level.

In order to achieve these goals, the NRC, with the support of organizations on the Advisory Board, the Contributing Partners Committee, and Acelerex Consulting, conducted a technology-agnostic ES production

[1] https://www.greentechmedia.com/articles/read/global-energy-storage-double-six-times-by-2030-matching-solar-spectacular#gs.KvJY1h0

cost model analysis for the province of Ontario. This analysis extended the most recent Ontario Long Term Outlook[2] to specifically look at the potential value streams that ES might provide over the long-term, while comparing this to the overall cost of deployment and operation. Various ES benefits were evaluated, including opportunities to reduce the price paid for electricity usage, reducing peak demands, avoiding the cost of transmission and distribution investments, avoiding capital investments in new capacity, increasing renewable penetration, and reducing GHG emissions.

This study required a large amount of grid and market data, which were collected from various sources including federal and provincial governments, industry representatives, and internationally-accepted benchmarking reports. From these data, a large-scale, complex co-optimization model was built to simulate various scenarios of ES development in Ontario.

The results of this pillar are the total potential market size for ES in the province, including an optimization of the location, type, and timing of ES deployments that would result in the lowest-cost system given the scenarios and assumptions that have been outlined below. It should be noted that changes to the market, technology, or policies, or increased scope of the study to include other storage technologies or sites (such as ES specifically optimized to be distributed behind the meter) may provide a different view than that presented in this study.

2.2 Energy Storage Study Review

This section presents a review of previous ES studies. While this is not meant to be a comprehensive review of such studies, it provides a sample of studies that demonstrated impacts on transmission and distribution deferral and renewables integration. Table 5 presents a review of applicable ES studies.

Table 5. Review of Applicable ES Studies

<table>
<tr><th>Study</th><th>Year</th><th>Study Description and Findings</th><th>Study Valuation</th></tr>
<tr><td>The Economic Potential for ES in Nevada</td><td>2018</td><td>A statewide deployment of up to 175 MW of utility-scale storage could be cost-effective in 2020 if storage costs are at the lower end of the expected cost range. The study finds 700 MW-1,000 MW in 2030 due to declining battery costs and evolving system conditions.
Total 2020 benefits exceed total costs only at the low end of deployments analyzed, and only if the low-end range of installed storage costs can be realized. In 2030, total benefits exceed total costs across the full range of cost projections and deployment scenarios, although the net benefit of incremental additions in 2030 drops to zero at 700 MW for the high battery cost scenario.</td><td><table>
<tr><td colspan="2">2030 (1,000 MW)*</td></tr>
<tr><td>Model Benefits</td><td>Nominal M$/year</td></tr>
<tr><td>Avoided Capacity Investment</td><td>$78M</td></tr>
<tr><td>Production Cost Savings</td><td>$40M</td></tr>
<tr><td>Deferred T&D Investment</td><td>$12M</td></tr>
<tr><td>Avoided Distribution Outages</td><td>$40M</td></tr>
<tr><td>Benefit</td><td>$170M</td></tr>
</table></td></tr>
</table>

[2] Ontario Long Term Outlook 2017

<table>
<tr>
<td></td>
<td></td>
<td>*Data approximated from Economic Potential for Storage in Nevada, Figures 1 and 2, shown for maximum ES deployment of 1,000 MW.</td>
<td>
<table>
<tr><td>Storage Costs</td><td>$100M - $150M</td></tr>
<tr><td>Net Benefits</td><td>$10M - $40M</td></tr>
</table>
</td>
</tr>
<tr>
<td>New York State Energy Storage Roadmap</td>
<td>2018</td>
<td>This study was conducted to determine the ranges of ES that could result in net positive benefit to ratepayers, compared to alternatives, in meeting electric system needs including installed capacity, transmission/sub-transmission, and distribution needs that arise under various scenarios, sensitivities, and time horizons (2020, 2025, and 2030). Identify performance specifications (MW, MWh) of the deployed storage as well as costs and benefits consistent with Benefit Cost Analysis framework.
The study results called for 1,500 MW (7,267 MWh) of ES by 2025 and 2,795 MW (12,557 MWh) by 2030. 2030 valuation shown in the adjacent column.</td>
<td>
<table>
<tr><td colspan="2">2030</td></tr>
<tr><td>Model Benefits</td><td>NPV in 2017 M$</td></tr>
<tr><td>Ancillary Services</td><td>$140M</td></tr>
<tr><td>Capacity Value</td><td>$732M</td></tr>
<tr><td>Distribution Savings</td><td>$1,410M</td></tr>
<tr><td>FOM</td><td>$214M</td></tr>
<tr><td>Gen Cost Savings</td><td>$550M</td></tr>
<tr><td>Avoided CO2</td><td>$44M (1.97 MT)</td></tr>
<tr><td>Benefit</td><td>$3,090M</td></tr>
<tr><td>Costs</td><td>$1,902M</td></tr>
<tr><td>Net Benefits</td><td>$1,188M</td></tr>
</table>
</td>
</tr>
<tr>
<td>Massachusetts State of Charge Study</td>
<td>2016</td>
<td>This study found that the addition of 1,766 MW of ES by 2030 would bring a total 10-year storage value of $3.4 billion, with $2.3 billion coming from system benefits, i.e. cost savings to ratepayers, and the other $1.1 billion coming from potential market revenue. Given the relative lack of supportive policies at present, the study also presented a comprehensive suite of policy recommendations to generate 600 MW of advanced ES in the Commonwealth by 2025, thereby capturing $800 million in system benefits to Massachusetts ratepayers. Additional benefits include an approximately 350,000 metric ton reduction in GHG emissions over a 10-year time span, equivalent to taking over 73,000 cars off the road.</td>
<td>
<table>
<tr><td colspan="2">2025</td></tr>
<tr><td>Benefit Description</td><td>Ratepayer Benefit</td></tr>
<tr><td>Energy Cost Reduction</td><td>$93.43M</td></tr>
<tr><td>Reduced Peak Capacity</td><td>$371.35M</td></tr>
<tr><td>Ancillary Services Cost Reduction</td><td>$67.95M</td></tr>
<tr><td>Wholesale Market Cost Reduction</td><td>$66.93M</td></tr>
<tr><td>T&D Cost Reduction</td><td>$103.62M</td></tr>
<tr><td>Cost Reduction of Integrating Distributed</td><td>$74.41M</td></tr>
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<table>
<tr><td></td><td></td><td></td><td><table><tr><td>Renewable Generation</td><td></td></tr><tr><td>Total System Benefits</td><td>$777.35M</td></tr></table></td></tr>
<tr><td>California Energy Storage Roadmap</td><td>2014</td><td>The California Energy Storage Roadmap was one of the first of its kind for ES studies. Rather than concentrating on an ES deployment target, strategy, and valuation assessment, the roadmap focuses on finding a better understanding of three categories of challenges expressed by stakeholders, including:
Expanding revenue opportunities
Reducing costs of integrating and connecting to the grid
Streamlining and spelling out policies and processes to increase certainty.</td><td>The report outlined next step categories for further study:
Define grid needs to identify gaps in existing markets and identify new products
Clarify existing wholesale market product and models available for ES
Refine existing and add new wholesale and retail market products to meet grid needs
Identify gaps in rate treatment and clarify if existing rules address gaps
Determine storage configurations and multiple use applications to enable prioritization and development of requirements
Assess existing methodologies for valuing ES and develop a common methodology</td></tr>
</table>

2.3 Ontario Energy Planning Review

The Ontario Energy planning review includes the 2016 Long-Term Energy Plan and Implementation Report along with the 2016 Ontario Planning Outlook.

2.3.1 Long-Term Energy Plan

With the phasing out of coal-fired electricity generation from 2014 onwards, emissions for Ontario's electricity sector account for only about 2% per cent of the province's total greenhouse gas emissions. Ontario has a robust electrical supply sufficient to meet electricity demand up to the next decade, which leaves the province well positioned to plan for and adapt to renewable technologies.

The essential forecast data from the 2016 Ontario Planning Outlook for demand, supply, imports, exports, and emissions have been referred to and used as a benchmark for the base case modelling of the Ontario system.

2.3.2 Ontario Planning Outlook

The Ontario Planning Outlook overviews the current state of Ontario's electricity system as well as an outlook for demand, generation, and transmission resources.

The report indicates that Ontario's electricity system is well positioned to continue to meet provincial needs, and successfully adapt to significant changes such as retirement of the coal fleet and the addition of new wind, solar, bioenergy, waterpower, refurbished nuclear, and natural gas-fired resources. This has reduced Ontario's greenhouse gas emissions by more than 80%. It also indicates that the implementation of the Climate Change Action Plan, the Climate Change Mitigation and Low-Carbon Economy Act, 2016 (which has since been repealed), and the Vancouver Declaration will have an impact on the demand and supply of electricity including through greater electrification of the economy.

The report presents the IESO's planning outlook at the time for the 2016 through 2035 period, including range of demand and emissions outlooks which are used to model the sensitivities.

2.4 Ontario Electricity Markets

2.4.1 Real-Time Market

Ontario has a real-time energy market process. The market clearing price (MCP) is set every five minutes based on the bids and offers settled in the wholesale market. For each five-minute interval, dispatch instructions are provided by the IESO based on accepted offers and bids. Non-dispatchable generators are paid the hourly Ontario energy price (HOEP) which is calculated using the average of the 12 five-minute market clear price during the hour. Non-dispatchable loads pay the HOEP.

2.4.2 Day-Ahead Commitment Process

The day-ahead commitment process (DACP) commits certain dispatchable resources and the economics scheduling of imports, providing a dependable view of the next day's available supply and anticipated Ontario demand. Dispatchable generators, dispatchable loads, importers, exporters, and linked wheels are all eligible for participation in the DACP. Self-scheduling and intermittent generators must submit a schedule or forecast of estimated or planned generation for the next day.

2.4.3 Real-Time Operating Reserve Markets

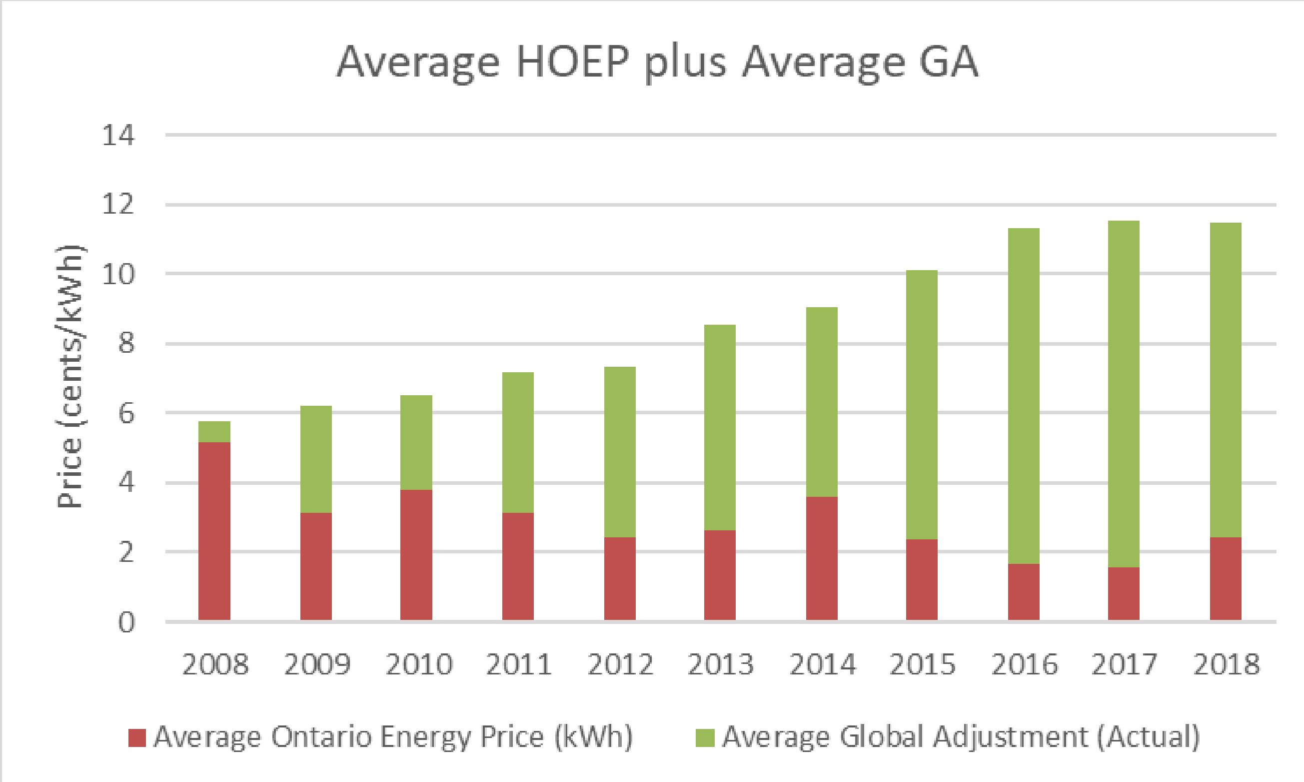
With the Operating Reserves (OR) markets, IESO ensures that additional supplies of energy are available for an unanticipated event in the real-time energy market. IESO provides three real-time operating reserve market classes offered by dispatchable generators, and dispatchable loads are for 10-minute synchronized spinning reserves, 10-minute non-synchronized non-spinning reserves, and 30-minute non-synchronized reserves.

2.4.4 Global Adjustment

The global adjustment (GA) is the component of the total commodity cost for electricity that covers the cost of building new electricity infrastructure in the province, maintaining existing resources, as well as providing conservation and demand management programs. The global adjustment is calculated as a total dollar amount for each month based on the difference between market revenues and the several components, broken down by fuel types and programs.

Customers who participate in the Industrial Conservation Initiative (ICI), referred to as Class-A customers, pay global adjustment (GA) based on their percentage contribution to the top five peak Ontario demand hours over a 12-month period. Class-B customers are charged based on their consumption with regular energy billing and whether they are wholesale metered, retailed contact or small business and residential.

Responding to changes in the Hourly Ontario Energy Price (HOEP), the global adjustment varies from month to month − generally, when the HOEP is lower, the global adjustment is higher in order to cover the costs of regulated and contracted generation. Figure 3 represents the total commodity cost with portions of HOEP and GA.



Source: IESO power data

Figure 3. Average HOEP plus Average Global Adjustment

2.4.5 Demand Response

The Demand Response program rewards the customers for reducing their electricity use when needed. Demand response provides benefits to Ontario's electricity system by enhancing reliability, as well as reducing system costs and greenhouse gas (GHG) emissions.

The IESO uses the demand response auction to acquire demand response capacity from market participants that can provide this capacity through the energy market in exchange for an availability payment. The demand response auction is conducted on an annual basis to procure demand response capacity for the upcoming summer and winter commitment periods. In the IESO system, physical DR resources are revenue-metered and virtual DR resources are not. A post-auction summary of the 2019 demand response auction is shown in Table 6.

Table 6. Demand Response Auction

Period	2019 Summer Commitment Period	2019 Winter Commitment Period
Total Virtual DR Cleared	636.8 MW	675.3 MW
Total Physical DR Cleared	181.6 MW	178.9 MW
Auction Clearing Price	$234.64/MW-day	$200/MW-day

Source: IESO 2019 Post-Auction Summary Report

2.4.6 Ancillary Services Market

The IESO contracts for four ancillary services to help ensure the reliable operation of the power system: certified black start facilities, regulation service, reactive support and voltage control service, and reliability must-run.

2.4.6.1 Certified Black Start Facilities

In the event of a system-wide blackout, black start facilities would be called upon during restoration efforts by helping to re-energize other portions of the power system. Certified black start facilities help system reliability by being able to restart their generation facility with no outside source of power.

2.4.6.2 Regulation Service

Regulation service acts to match total system generation to total system load (including transmission losses) and helps correct variations in power system frequency, maintaining the stability of the power system. Regulation service is mainly provided by generation facilities with automatic generation control (AGC) capability, which can vary output in response to IESO signals. In addition to this, alternative technologies such as aggregated loads, flywheels and battery storage are used to provide regulation services.

2.4.6.3 Reactive Support and Voltage Control

Reactive support and voltage control service is contracted from all the generators under IESO. This allows IESO to maintain acceptable reactive power and voltage levels on the grid. Both active and reactive are required to serve loads and support the transfer of active power over the transmission network.

2.4.6.4 Reliability Must-run Contracts

Reliability must-run contracts allow the IESO to call on the contracted facility to produce electricity if needed to maintain system reliability.

2.4.7 Transmission Rights Market

The IESO sells transmission rights (TRs) on a monthly basis through an auction process. TRs entitle the owner to a payment if the price of energy in Ontario is different from the price in an intertie zone. This TR market allows market participants to reduce price risks associated with transmission congestion and price volatility.

2.5 Energy Storage Use Cases

Energy storage can provide various grid services in a more economic fashion than the large generation assets historically used.

2.5.1 Energy Arbitrage

Energy arbitrage is the ability to purchase lower cost energy to charge the storage device and sell the stored energy during higher cost periods. This maximizes profit for the ES owner while also potentially increasing asset utilization of both the ES system and base-load generation[3]. This can be applied for day-ahead and real-time markets. Energy arbitrage can also reduce natural gas burn when lower or zero marginal costs are used to charge the ES and when ES discharges to displace fuel burn of natural gas peaking resources.

2.5.2 Economic Renewable Shifting

Economic shifting of renewables can be provided by ES when renewable energy generated at off peak times can be stored and sold for higher revenue at peak load hours. The Electric Power Research Institute (EPRI) notes that potential benefits can include economic benefit to the customer from discharging the stored energy during suitable periods in response to a real-time market or during a demand response/load control event, utility system peak demand reduction and the reduction in associated costs by discharging the stored energy during system peak periods, as well as utility operational benefits by using the stored energy as an emergency support resource[1].

2.5.3 Spinning Reserve

Spinning reserve, which is needed to maintain grid stability during emergency operating conditions and load swings, can be provided by ES and therefore allow conventional generation to operate at full capacity rather than keeping some capacity in reserve. As defined by EPRI, spinning reserve is the portion of unloaded synchronized generating capacity that is under Independent Systems Operators (ISO) control, capable of being loaded in 10 minutes, and can run for at least two hours[4]. Depending on the ES application, the system can be made available in seconds to minutes to respond to the outage event.

2.5.4 Frequency Regulation

Frequency regulation describes the increase, known as regulation up, or reduction, known as regulation down, of power generation to maintain the system frequency at approximately 60 hertz. As defined by EPRI, regulation is the portion of a unit's unloaded capability that can be loaded, or loaded capability that can be unloaded, in response to automatic generation control (AGC) signals from the ISO[2]. Regulation provides control area balancing as well as frequency bias and time error correction.

2.5.5 Frequency Response

ES is a modular, fast-responding solution to frequency response service which is typically provided by conventional thermal peaking plants. ES can cover all ranges of frequency response including primary, secondary, and tertiary, although it is particularly adept at providing fast acting primary response services.

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[3] See "Uses for Distributed Photovoltaic and Storage Systems," EPRI, 2010.

[4] See "Revenues from Ancillary Services and the Value of Operational Flexibility", EPRI, 2002.

2.5.6 Black Start

In the case of an area-wide grid outage, ES can displace diesel generators used for black starting of generating plants.

2.5.7 Capacity Deferral

The deployment of ES can provide peaking capacity thus deferring the capital cost intensive buildout of peaker plants and reducing the cost in the capacity market. Furthermore, adding ES to a renewable portfolio can contribute to lowering over-all capacity market costs. Therefore, the batteries will be rewarded by the capacity credit in turn, and we can evaluate the capacity value of the battery based on the market local capacity price. With capacity deferral, there could be benefits to fixed and variable O&M cost savings. Energy Storage can also replace low capacity factor and inefficient emitting peaking resources.

2.5.8 Transmission and Distribution Upgrade Deferral

Energy storage can be used to serve a small portion of peak demand that is served by the T&D equipment whose capacity must be increased due to growing peak demand and demand growth. The value proposition of the ES usage includes the deferral or avoidance of the T&D equipment upgrades, reduced T&D investment risk, and the life extension of the existing T&D equipment. Considering the potential high capital cost, fuel burn (diesel generation due to increased peak demand and demand growth), and emissions from T&D upgrades, ES is especially well-suited to serve as a distributed energy resource in circumstances involving a) strict air emissions regulations, b) noise related constraints, and c) fuel storage or other safety-related challenges that restrict use of combustion-based distributed generation.

2.5.9 Load Following

Load following is where the ES charges at low load and discharges at high load, and it is driven by a load signal instead of the price signal.

2.5.10 Stacked Services

The practice of 'stacking' grid services aims to maximize potential profits from ES services. Stacked services benefits may be broken down into capacity savings, fuel savings, VOM savings, FOM savings, primary, secondary, and tertiary reserve savings, forecast error savings, black start savings, T&D deferral, and cost to load savings. These services can be thought of as stacked in terms of capacity nominated for service as well as energy allocated.

2.6 Methodology

2.6.1 Methodology Overview

This study quantifies the net benefits of adding Energy Storage to Ontario over the period of 2020-2030, including end effects by comparing the base case (business-as-usual) to sensitivity cases which allow for expansions and retirements of both storage and peaker plants.

For each case, a three-step modelling approach is used to determine the *when*, *where*, and *how much* of the ES, CC, and CT expansions and their optimal dispatch. The modelling consists of three phases:

- **Capacity Optimization** to determine the expansion of storage and peaker plants by region,
- **Production Cost** including Annual, Short Term, and Real Time Optimization, to determine the dispatch of the storage and peaker plants by node and associated prices,
- **Stacked Services Emulator** to model the provision of ancillary services by the ES at each node.

The study methodology is outlined in Figure 4.

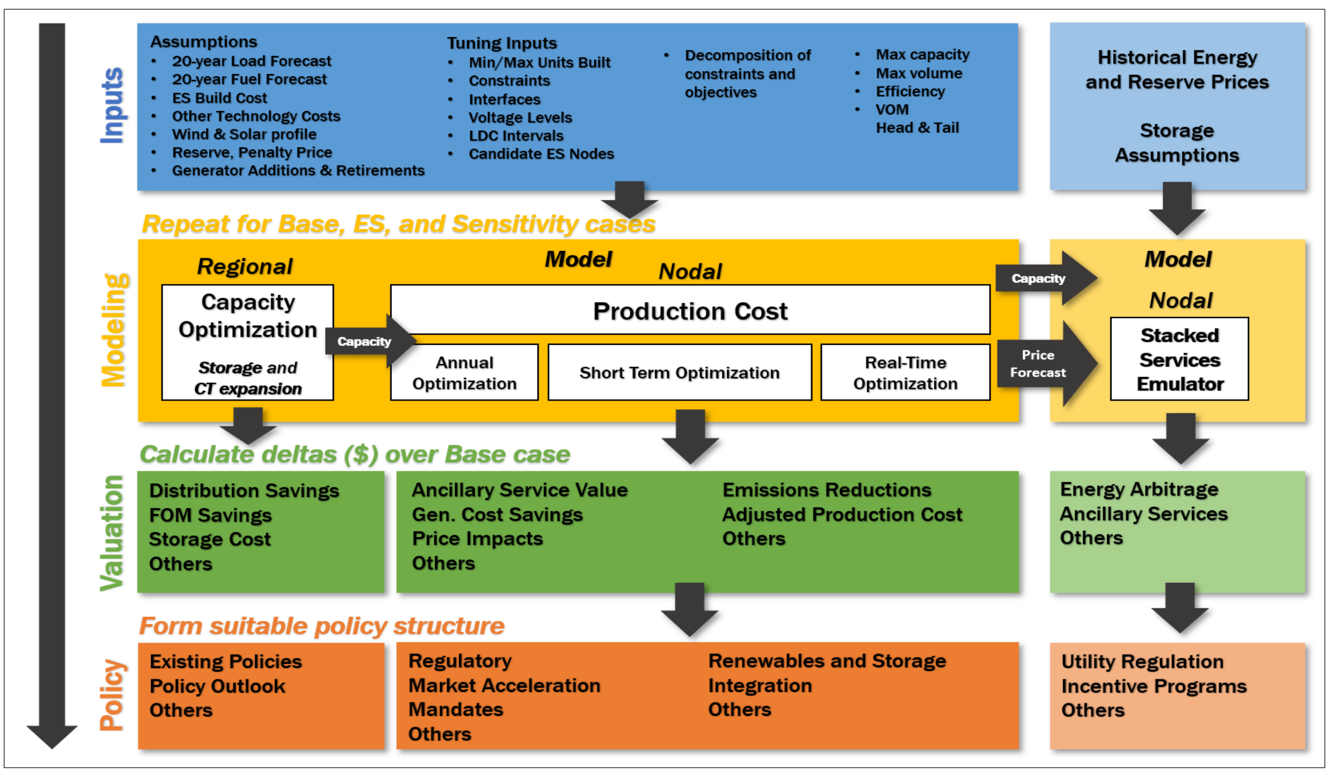

Figure 4. Methodology

This model was prepared to look at ES expansion sensitivities and can be extended to be used for other types of technologies and technology evaluations or policy futures to look at the combined impact capacity expansion and short run marginal cost in transmission planning.

2.6.1.1 *Indicative Constraints for Multi-Phase Modeling Process*

Figure 5 shows key constraints and simulation settings for each modeling phase.

	Capacity Optimization	Annual Optimization	Hourly Production Cost	Real-time Optimization	Emulator
Optimization	• Find the optimal generation additions/retirements and transmission upgrades	• Intertemporal constraints decomposition	• Unit commitment/economic dispatch • Market clearing/energy pricing	• Real-time balancing between generation and load	• Energy arbitrage • Ancillary services • Peak shaving • Provision
Key Constraints	• Energy balance • Feasible energy dispatch • Feasible builds • Network constraints • Reserve Margin	• Maintenance/forced outages • Max energy constraints • Fuel supply • Emission constraints • Network constraints	• Min up/down time • Power balance • Reserve and regulation constraints	• Power balance • Ramping constraints • Network constraints	• Power capacity • Energy capacity
Simulation Settings	• Chronological • 10 year	• Chronological • 1 year	• Chronological • 24 hour dispatch with hourly intervals	• Chronological • 1 hour horizon with 15 min interval	• 24-hr look-ahead with one hour interval

Figure 5. Constraints for Various Phases of Modeling

2.6.2 Technologies Considered

The study methodology is designed to be agnostic to ES technology assumption sets. The study considers all ES technologies, including long duration (e.g. Ice Maker, CAES, flow battery, NaS battery), medium-long duration (e.g. NaS, flow battery, Lithium-ion), medium-short duration (e.g. lead acid, NiCd, Lithium-ion), and short duration (e.g. Lithium-ion, flywheel). The study also considers ES installations for behind-the-meter, grid-scale, C&I deployments, and EV storage potential.

2.6.3 Capacity Optimization Phase

The capacity optimization phase takes as inputs capital costs and operational costs of current assets and future assets to run the grid, as well as new technologies assumptions, and performs a cost minimization. The capacity optimization phase determines the size in MW and location of ES. The objective function of the capacity optimization modelling minimizes the production cost and the capital cost of the system. An annual optimization is performed over each year of the study horizon. The study horizon, shown in Figure 6, ranges from the years 2020 through 2030 which decomposes monthly hydro profiles as well as enforces any annual constraints such as emission constraints.

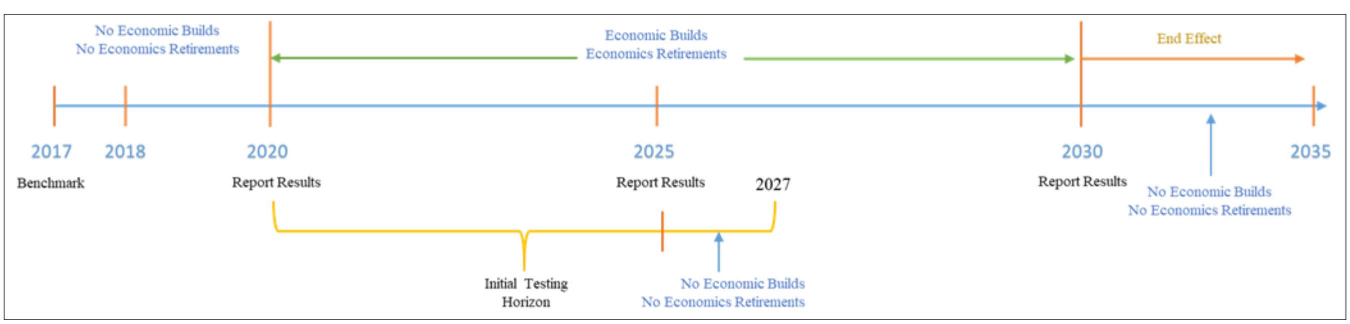

Figure 6. Capacity Expansion Horizons

2.6.3.1 Illustrative Formulation of Capacity Optimization Model

Minimize [sum of capital costs of thermal generators] + [sum of variable costs of thermal generators] + [investments in energy efficiency] + [investments in demand response] + [variable demand response costs] + [investments in VER] + [investments in ESS for power capacity] + [investments in ESS for energy capacity] + [variable costs of ESS for power output]

$$\min_x \sum_i a_i P_i + \sum_{i,t} \Delta_t g_{i,t} c_i + \sum_{ee} a_{ee} P_{ee} + \sum_d a_d P_d + \sum_{d,t} \Delta_t (d_{d,t}^+ + d_{d,t}^-) c_d + \sum_r a_r P_r + \sum_s a_s P_s + \sum_s a_{es} E_{s,max} + \sum_{s,t} \Delta_t (g_{s,t}^+ + g_{s,t}^-) c_s$$

The storage objects are modelled based on fixed durations (0.5h, 2h, 4h and 6h), and their Energy Capacity Investment is converted to Power Capacity Investment using these durations.

2.6.3.2 Expansion Objects

In the capacity optimization phase, expansion is allowed for Natural Gas (CC) generator and Energy Storage (ES) technologies. Energy storage technology expansion objects are characterized as distribution-connected ES. Within these ES expansion objects, one expansion object is created for each ES duration for all 10 IESO zones. This results in 4 ES expansion objects per zone for a total of 40 ES objects.

Expansion object types are characterized by their varying capital costs and fixed operation and maintenance costs (FOM) as well as a deferral value (D-Value) that represents a $/kW-yr value offset by installing generation-like systems in distribution systems. Distribution-connected ES utilizes the market capital cost for ES and the D-Value. Energy storage expansion object types are detailed in Table 7. See Section 2.8 for further details on ES technology assumptions.

Table 7. Energy Storage Expansion Object Types

Expansion Object Type	ES Durations	ES Capital Cost	D-Value
Storage: Distribution Connected	Long (≥6h), Medium Long (4h)	Market ES capital cost	35

2.6.4 Production Cost Phase

The production cost (PC) phase is responsible for optimizing to find the lowest-cost system dispatch and corresponding energy prices for both hourly day-ahead market and sub-hourly real-time markets. The PC phase adheres to system constraints including minimum ramp up and down times, power balance, and reserve and regulation constraints.

2.6.4.1 Hourly Production Cost

The hourly production cost phase simulates day-ahead dispatch schedules and solves for the least-cost dispatch (in MWh) of the ES sized in the Capacity Optimization phase with respect to the variable costs of current and future assets. The hourly production cost is a nodal model that enforces N-1 contingency criteria.

2.6.4.2 Sub-Hourly Production Cost

The sub-hourly production cost phase simulates real time dispatch schedules and optimizes the system variable costs of the current assets along with future assets and refines the sizing of ES in terms of MW and MWh.

2.6.4.3 Energy Storage Node Selection in Production Cost

Energy storage is connected in each zone to the nodes with a high-density demand center. These nodes are selected for their high load participation factor and within a voltage range of 13.8kV to 69kV. These nodes are spread across the entire IESO to observe the effects and analyze the benefits. For modelling of these nodes, each ES bucket (Long, Medium Long, Medium Short, and Short duration) is tied to five separate nodes, totaling 20 nodes in each zone. The list of nodes is compiled in Table A-8 of the Appendix, page 172.

2.6.4.4 Energy Storage Expansions in Production Cost

Energy storage expansion capacity by year across Ontario is found in the Capacity Optimization phase. Initially marginal deferral value (D-value) of ES was set equal to \$55/kW-yr and we obtained results with high amounts of ES build by 2030. Also, there was high storage build in ONBRUCE region mainly due to retiring nuclear by 2030. To test the system response, the overall marginal D was set equal to \$35/kW-yr and had the capacity optimization re-run. The results obtained have even distribution within zones according to the load share per zone and are the ideal case to be considered for the further studies.

2.6.4.5 Retirement of Thermal Units in Production Cost

Capacity retirement of thermal units by year across the IESO region is found in the Capacity Optimization phase. The major economically retired units are Natural Gas and Oil.

2.6.5 Valuation Metrics

Acelerex has conducted a detailed costs and benefits analysis based on the least-cost capacity expansion results and market fundamentals information. Acelerex has created system-level valuation metrics to evaluate energy storage deployment benefits and costs in the Ontario system. Table 8 shows a non-exhaustive list of the valuation methods and metrics used to monetize the benefits and costs of the energy storage deployment. Valuation results are presented in Section 2.12.

Table 8. Energy System Benefits Analysis Metrics

System Analysis Metrics	Formula & Description	Stage
Ancillary Services (\$MM)	Storage MW (or MWH) x AS market price *Storage participation was capped at 50% of total AS market in the model. This is a conservative assumption, and actual storage participation could be higher.*	Market Data and Production Cost
Deferral Savings (\$MM)	Storage MW x DRV value from utility VDER tariffs *Avoided Distribution Infrastructure. Reflects the actual DRV by utility (no LSRV was included). Only Long and Medium Long duration storage (≥4 hours) captured this benefit.*	Input
FOM (\$MM)	Difference in fixed operations and maintenance costs on the system	Capacity Optimization
Gen Cost Savings (\$MM)	Base Case Total Generation Cost – Storage Case Total Generation Cost *Difference in Total Cost to Generate required Energy, including fuel, VOM.*	Production Cost
Price Impacts (\$/MWh)	Δ Energy Price *The hourly market price impact effect can be estimated using the energy price differences between the base case and the base case with storage.*	Production Cost
Emission Reduction (tonnes)	Δ Emission *Avoided CO_2, NO_x, and SO_x emissions in tonnes.*	Production Cost

Storage Cost ($MM)	Installed Cost – average 20% accelerated federal tax benefit *Variable Operations and Maintenance costs were estimated at $15-$20/kW/year depending on the duration, and these costs along with charging cost are netted into the "Gen Cost Savings" benefit.*	Capacity Optimization
Adjusted Production Cost ($MM)	Generation Production * Price + Energy Sales (Exports) * IESO Generation-weighted Price + Emergency Energy Cost *For most models, emergency energy is not allowed to occur and therefore is $0.*	Production Cost
Storage Energy Arbitrage	$\sum_{i,j}(Discharging\ MW_i \times Energy\ Price_i - Charging\ MW_j \times Energy\ Price_j)$ *Storage Energy Arbitrage Value is calculated according to storage hourly/sub-hourly dispatch. The energy price is hourly price/sub-hourly price in the electricity wholesale market.*	Acelerex SSE
Storage Ancillary Services	$\sum_i Storage\ Ancillary\ Services\ Dispatch\ MW_i \times Ancillary\ Services\ Prices_i$ *Storage Ancillary Services Value is calculated according to storage hourly/sub-hourly dispatch to ancillary services. The ancillary services prices are hourly/sub-hourly prices in the ancillary services markets.*	Acelerex SSE

2.7 Input Data and Forecast

2.7.1 Demand

Regional and zonal forecast load data was obtained by projecting historical load data from the IESO Annual Planning Outlook 2020 Demand Forecast Report and data from IESO 18-Month Outlook Tables to each of the 10 zonal regions in the Ontario region.

2.7.2 Load Profile and Forecast

Acelerex model applies 2017 Ontario Hourly Zonal Demand Data from the IESO database as the historical load profile for each zone and the Annual Planning Outlook to calculate the zonal hourly load forecasts in Ontario for 2020-2035. Figure 7 shows 2017 Ontario Hourly Zonal (Stacked) Load Demand profile and Figure 8 shows the Annual Planning Outlook and energy demand forecast.

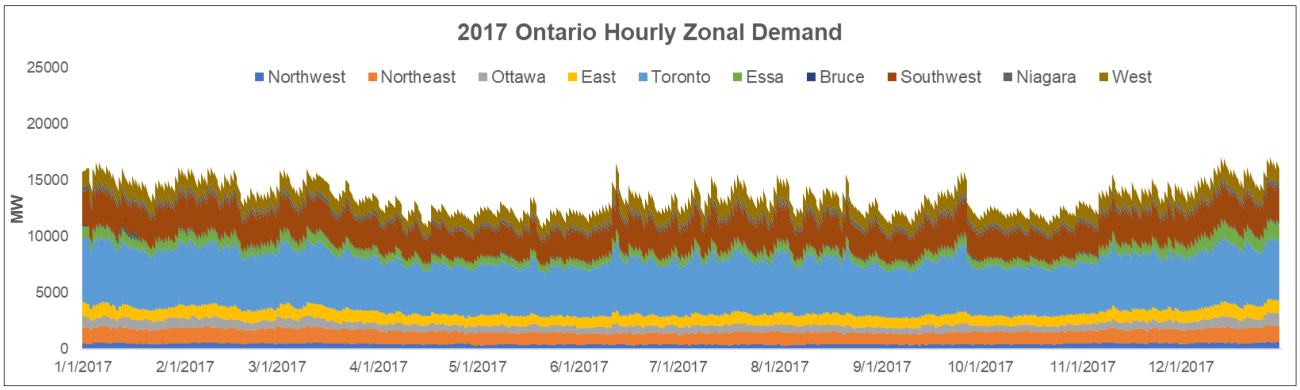

Figure 7. Historical Ontario Load Profile by Zone

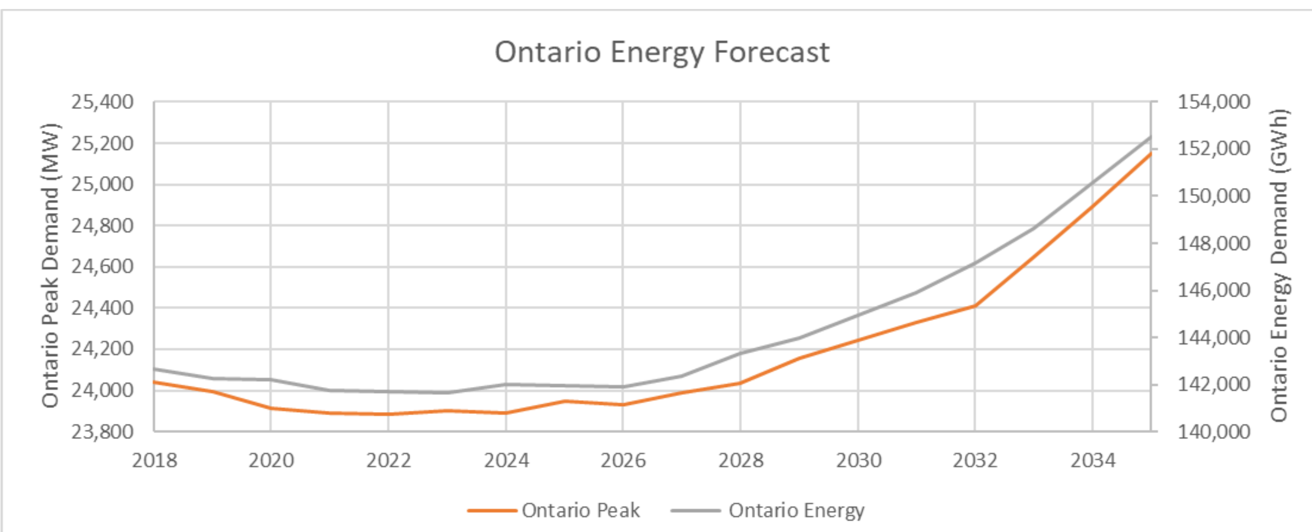

Figure 8. Annual Planning Outlook 2020 Ontario Peak Demand and Energy Forecast

2.7.2.1 Annual Zonal Demand Forecast

The annual peak demand forecast and annual energy demand forecast were extended from the IESO Annual Planning Outlook Demand Forecast Report from 2018 through 2035 for each of the 10 zones in the IESO Region and are presented in Figure 9 and Figure 10.

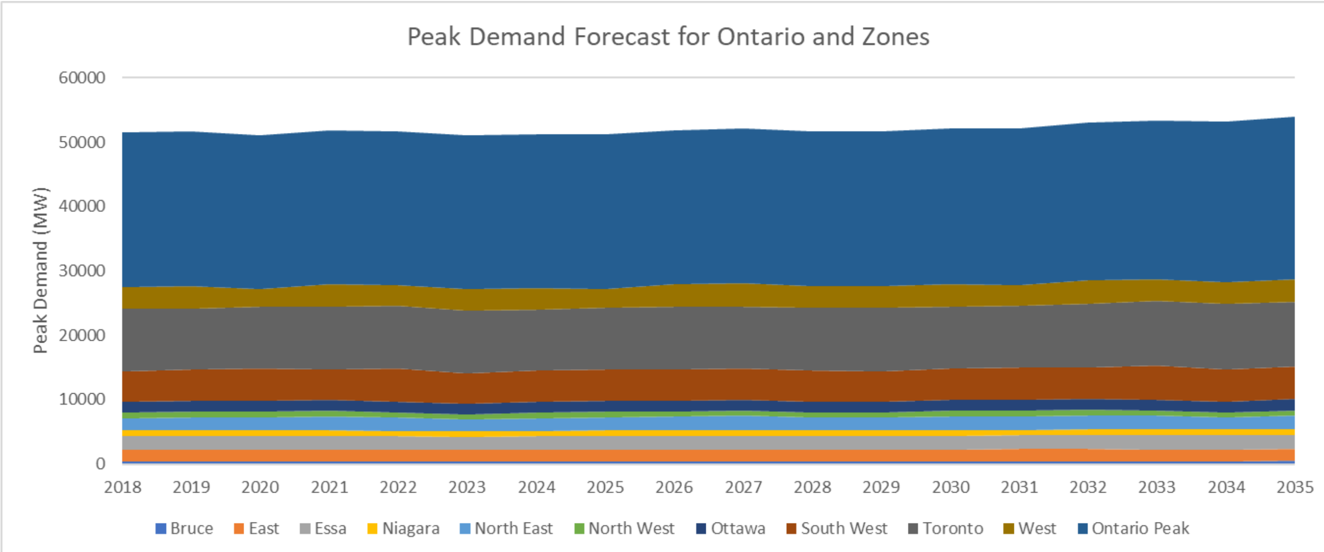

Figure 9. Forecast Peak Demand by Year and Zone, MW [3]

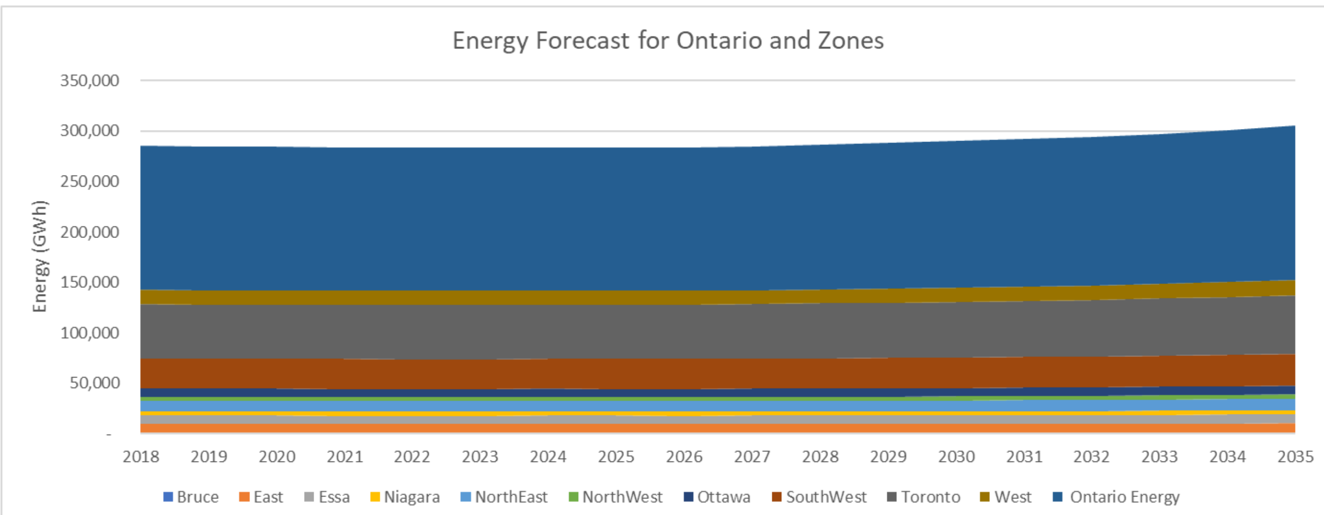

Figure 10. Forecast Energy Demand by Year and Zone, GWh [3]

2.7.2.2 Hourly Zonal Demand Forecasts

Using the Annual Zonal Peak Demand and 2017 Ontario Hourly Zonal Demand Data, a forecasted zonal hourly load forecast in Ontario for 2020-2035 is calculated. Figure 11 shows the forecasted hourly zonal load profile for each zone.

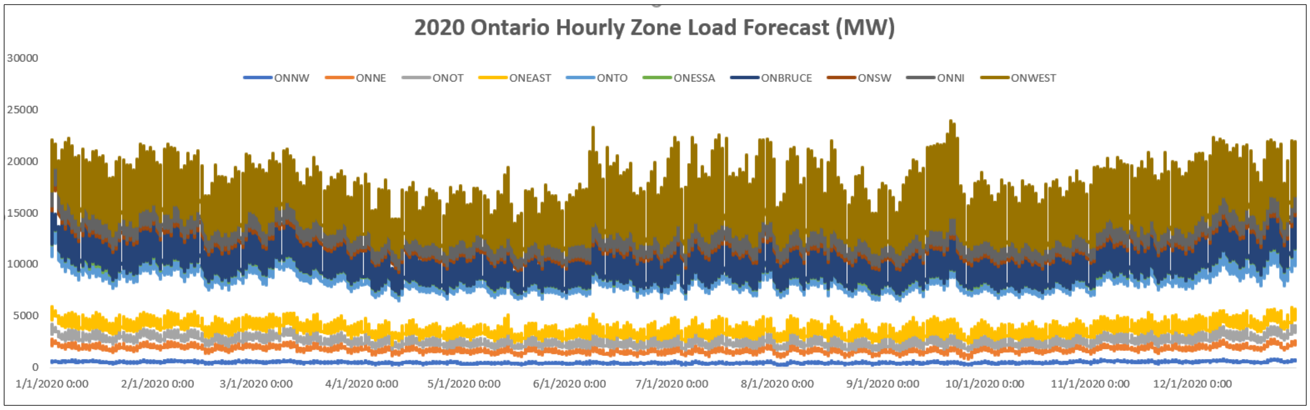

Figure 11. Ontario Hourly Zonal Load Forecast

The Acelerex model includes zonal load forecasts from 2018-2035 of all the Ontario internal zones. The individual hourly load forecasts of each zone in 2030 are shown in the following tables.

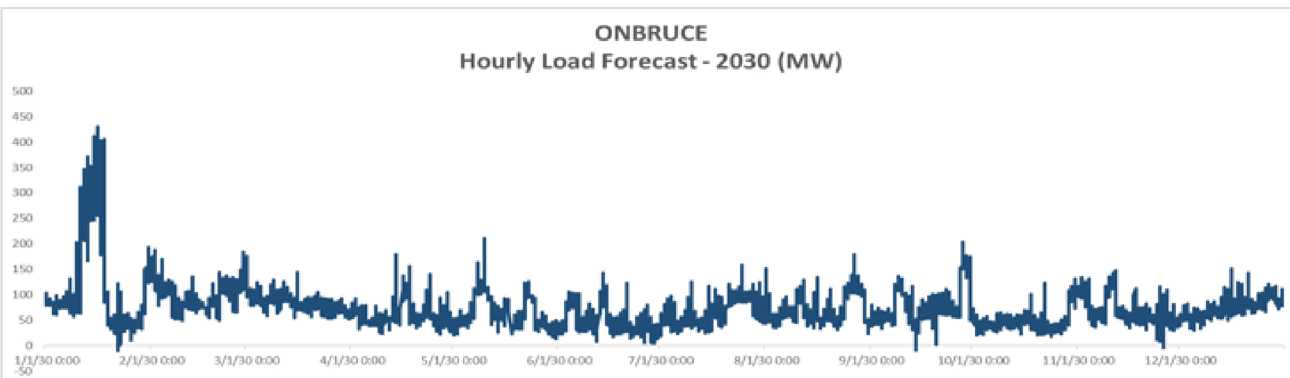

Figure 12. Ontario Bruce Zone Load Forecast

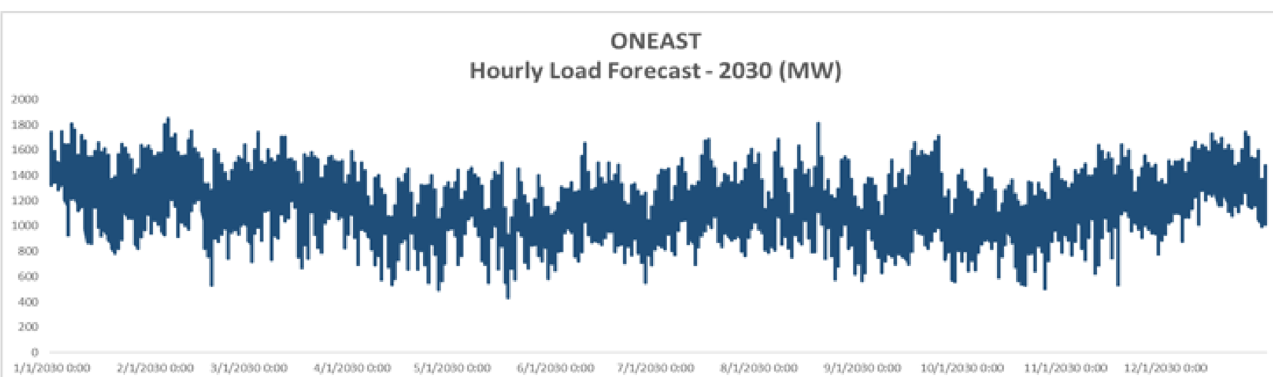

Figure 13. Ontario East Zone Load Forecast

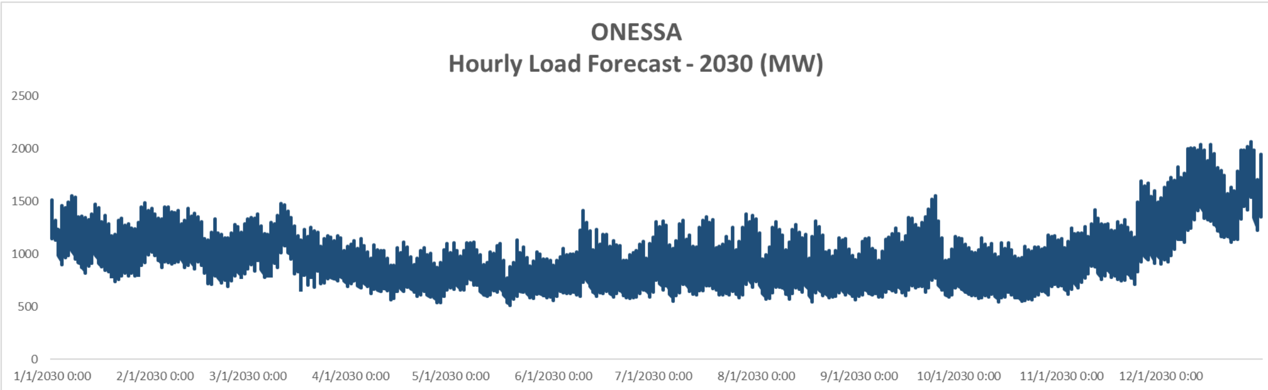

Figure 14. Ontario Essa Load Forecast

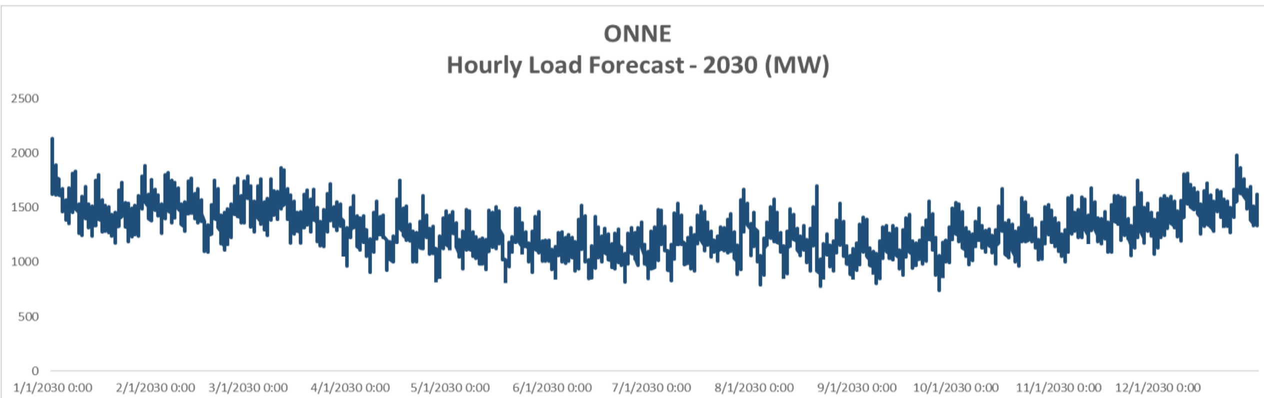

Figure 15. Ontario Northeast Zone Load Forecast

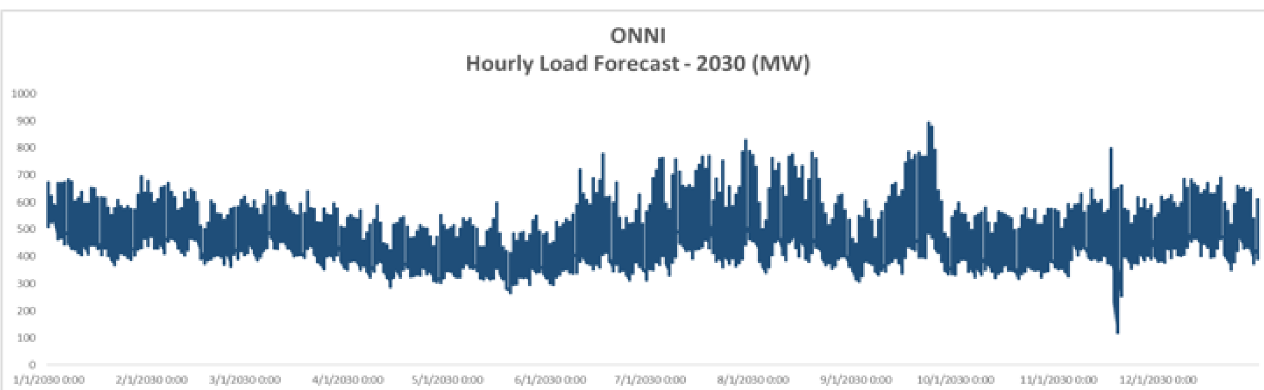

Figure 16. Ontario Niagara Zone Load Forecast

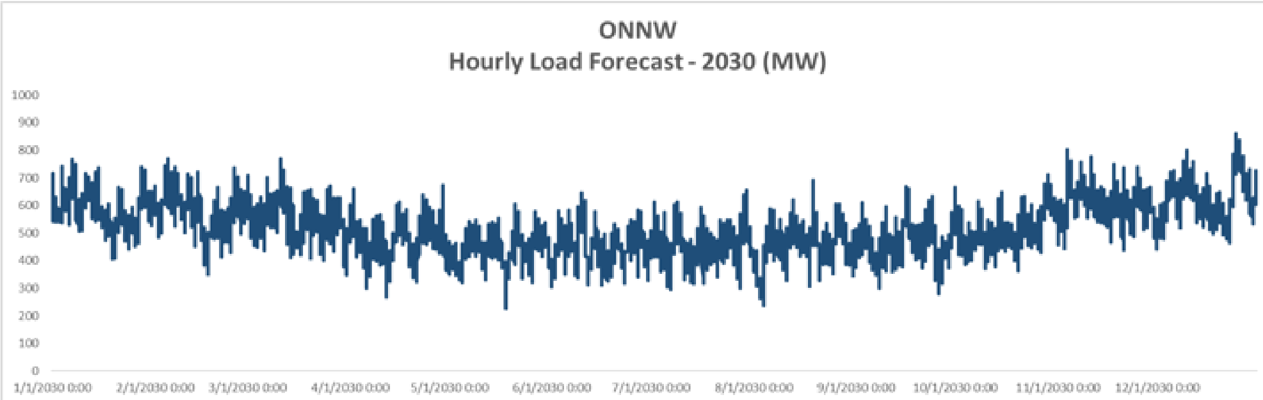

Figure 17. Ontario Northwest Zone Load Forecast

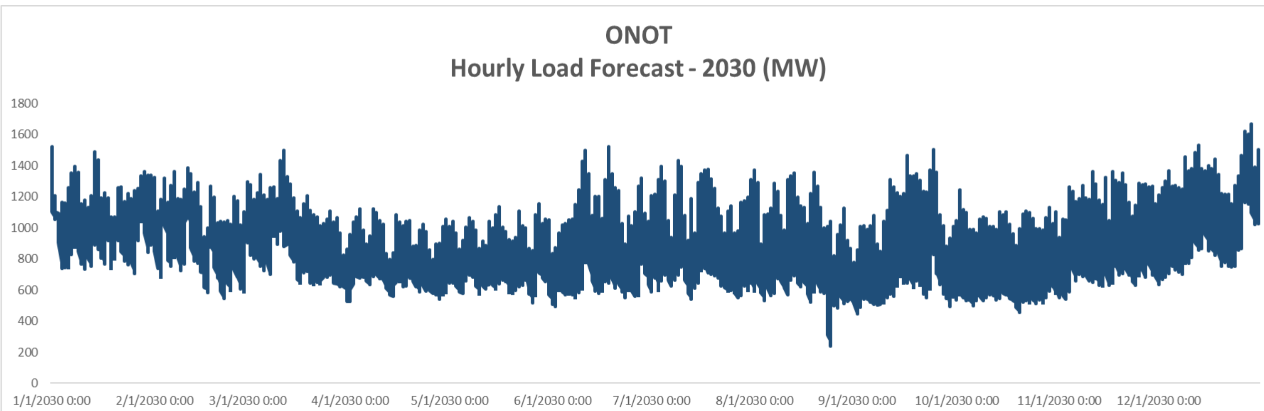

Figure 18. Ontario Ottawa Zone Load Forecast

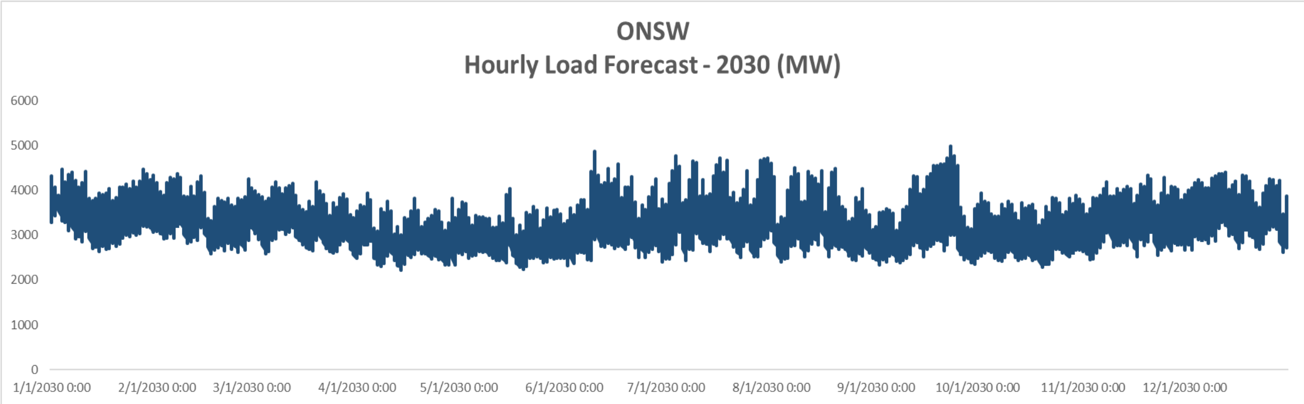

Figure 19. Ontario Southwest Zone Load Forecast

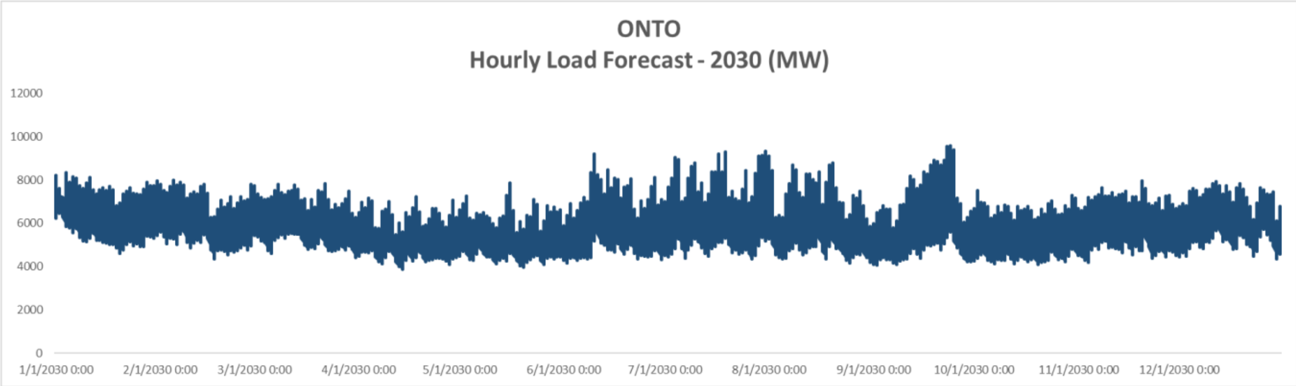

Figure 20. Ontario Toronto Zone Load Forecast

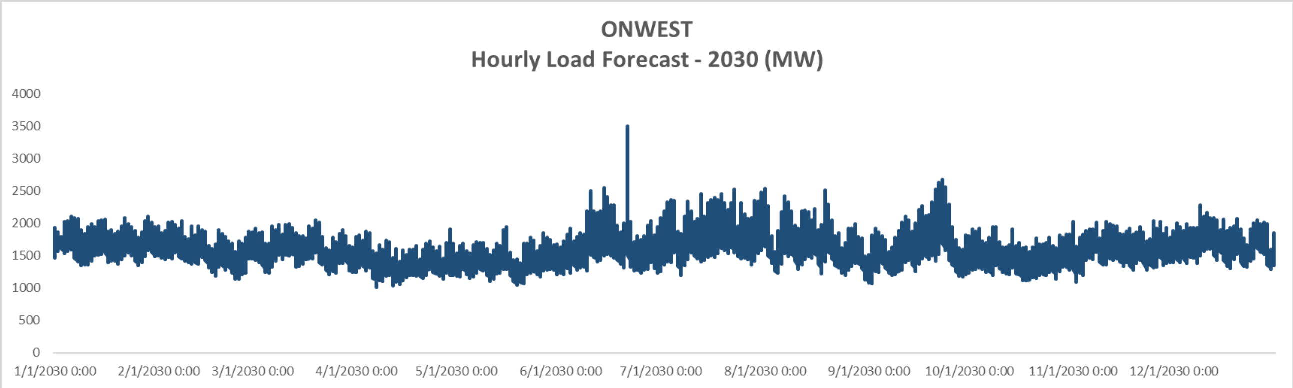

Figure 21. Ontario West Zone Load Forecast

2.7.3 Generation and Capacity by Fuel

2.7.3.1 Generation by Fuel Type

As per the Annual Planning Outlook 2020, Ontario produces more than 50% of its electricity from nuclear, with renewable resources providing about 30% and generators production carbon emissions providing less than 10%. In addition, conservation has reduced energy consumption by about 9%.

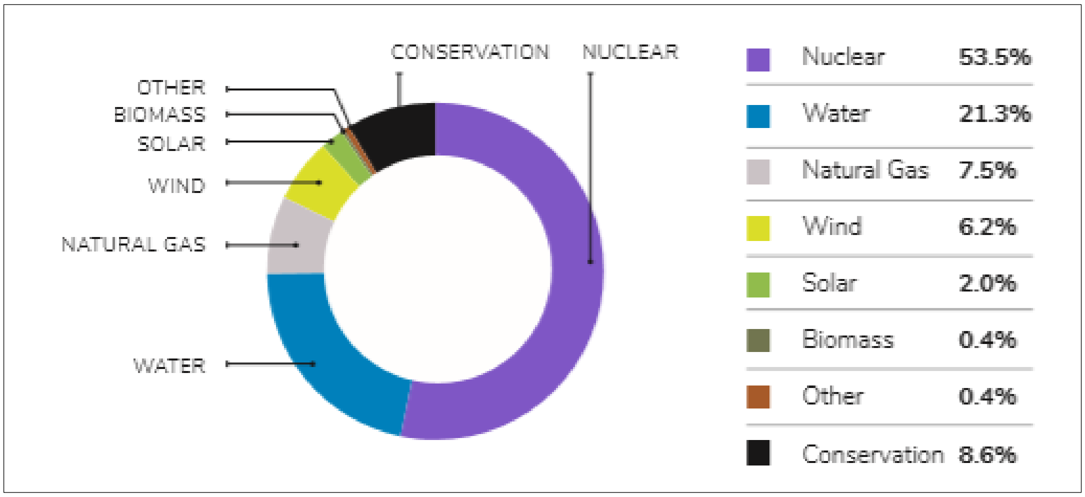

Figure 22. Ontario Generation by Fuel Type and Conservation in TWh [7]

2.7.3.2 Maintenance and Retirement Schedule

To have the most cost-effective and emission-free option to produce the baseload generation, Ontario has plans to refurbish their nuclear generating stations. Ontario will face a shortfall in capacity beginning in the early-to-mid 2020s as the Pickering Nuclear Generating Station reaches its end of life, and nuclear units at Darlington and Bruce are temporarily removed from service for refurbishment. The nuclear refurbishment outage and projected end of services schedule is detailed in Table 9.

Table 9. Nuclear Refurbishment Schedule [11]

Unit	Refurbishment Outage Start	Refurbishment Outage End	Projected End-of-Service
Bruce 3	January 2023	June 2026	
Bruce 4	January 2025	December 2027	
Bruce 5	July 2026	June 2029	
Bruce 6	January 2020	December 2023	
Bruce 7	July 2028	June 2031	
Bruce 8	July 2030	June 2033	
Darlington 1	June 2021	May 2024	
Darlington 2	October 2016	February 2020	
Darlington 3	February 2020	February 2023	
Darlington 4	February 2023	December 2025	
Pickering 1			December 2022
Pickering 4			December 2022
Pickering 5			December 2024

Pickering 6			December 2024
Pickering 7			December 2024
Pickering 8			December 2024

2.7.3.3 Capacity Forecast

According to the 2017 Long-Term Energy Plan (Module-3 Supply), the year-end historical and forecasted installed generation capacity by fuel type from 2017 through 2030 is shown in Figure 23. The figure indicates nuclear refurbishments and a consistent amount of installed capacity for the rest of the fuel types.

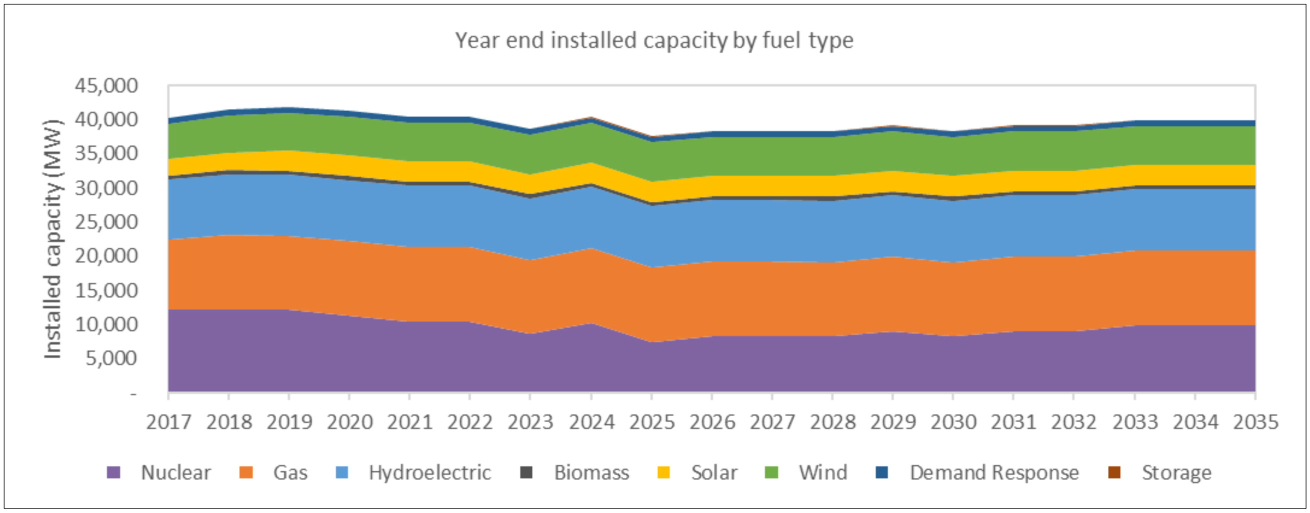

Figure 23. Year-end Installed Capacity by Fuel Type Forecast [7]

Capacity Margins are the resources above requirements. They indicate the resource adequacy and describe the extent to which resources exceed or fall below targeted levels. Using the reserve margin values of 2017 Long-Term Energy Plan (Module-3 Supply), the total capacity requirement has been calculated. Forecast summer peak demand, reserve margin, reserve requirement, and total capacity requirement are detailed in Figure 24.

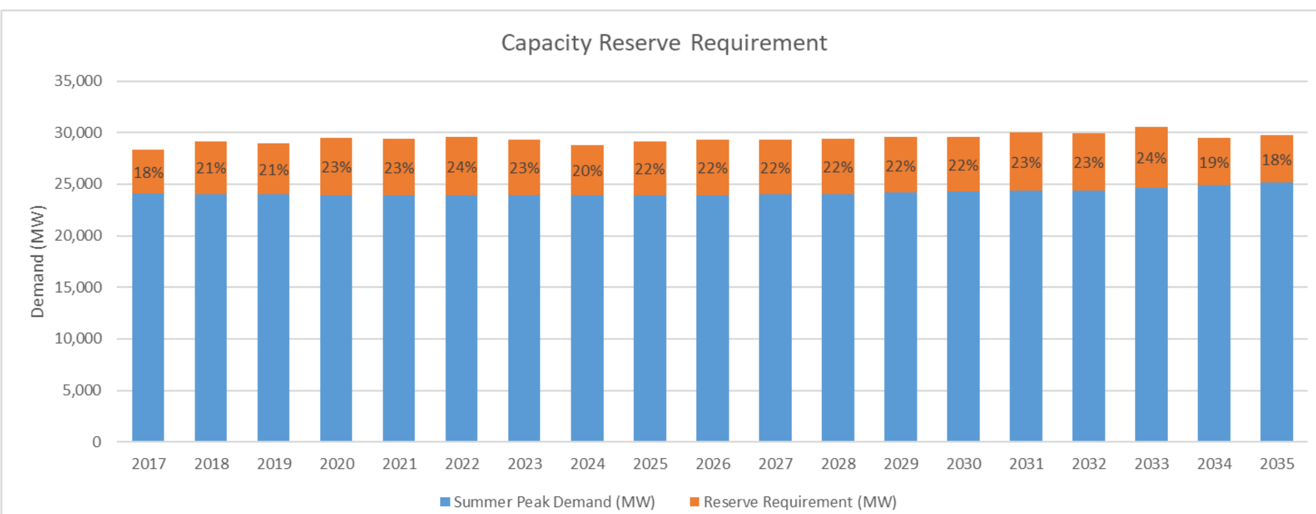

Figure 24. Summer Peak Demand and Total Capacity Requirement Forecast [9]

2.7.4 Fuel Price Forecasts

Fuel price forecast data has been adapted from multiple sources including the IESO Fuels Technical Report [11] and the EIA 2018 Annual Energy Outlook [12].

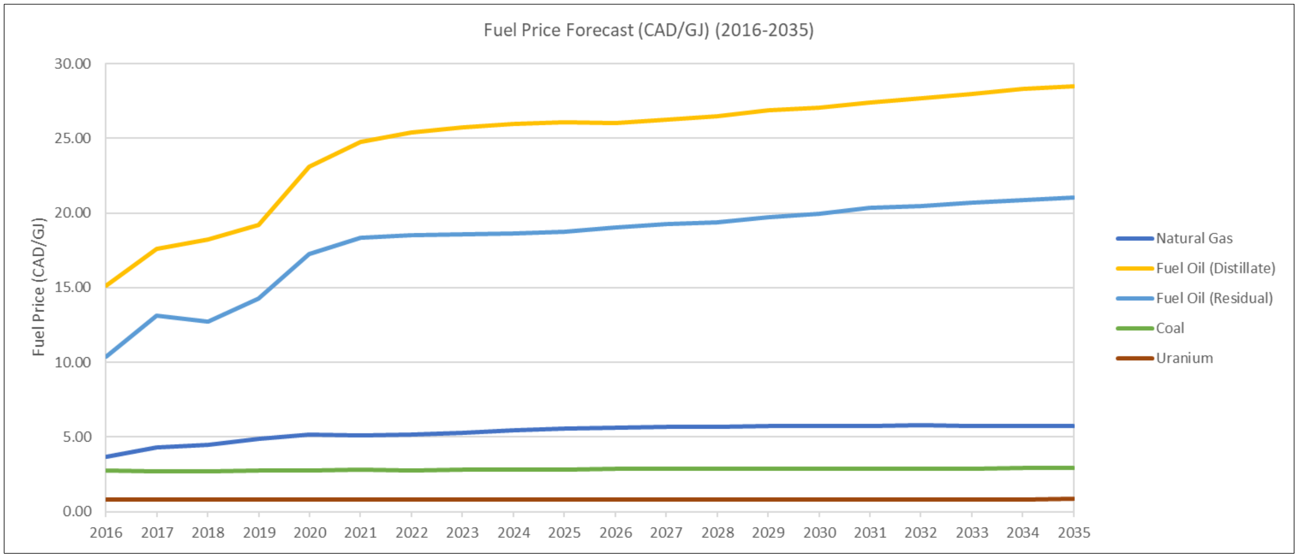

Figure 25. Fuel Price Forecast from 2016 in CAD$/GJ [11], [12]

2.7.4.1 Intertie Import and Export

Ontario efficiently imports and exports electricity as part of the regular operation of its electricity market, and currently has interconnections with its five neighbours: Quebec, Manitoba, Minnesota, Michigan and New York. Being a part of an interconnected grid means that Ontario has the ability to export and import power to provide operational and planning flexibility, and enhance the reliability and cost-effectiveness of the electricity system. Figure 26 summarizes the relationship between Ontario’s zones, major internal interfaces and interconnections, and connection type in a single diagram.

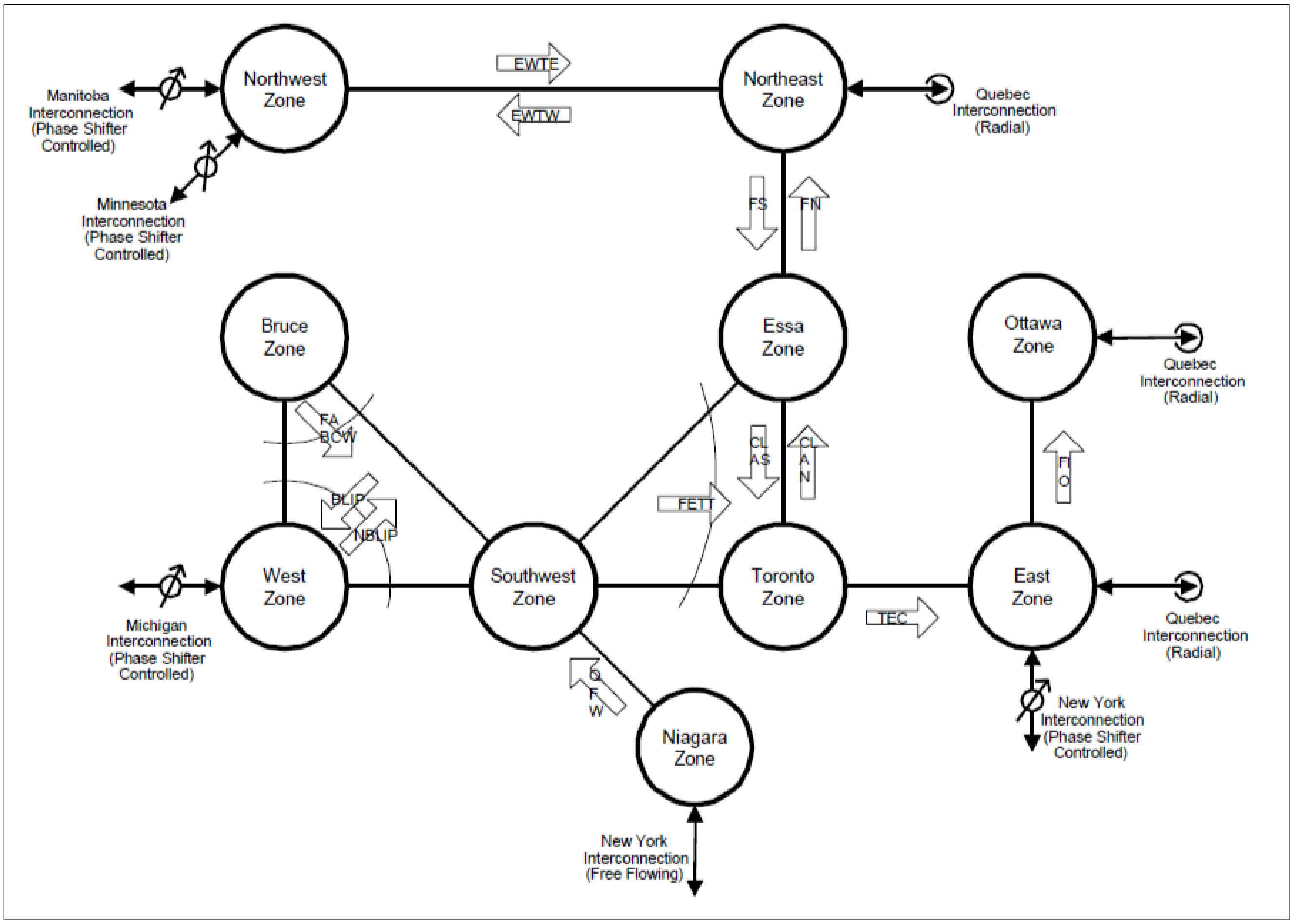

Figure 26. Ontario Zones and Interconnections [4]

2.7.4.2 *Historical Intertie Flows*

Historical 2017 interconnection net flow and hourly flows are seen in Table 10 and Figure 27, respectively.

Table 10. Historical 2017 Intertie Net Flow in GWh [5]

Intertie	Control Area	2017 Net Flow (GWh)
MBSI	Manitoba	47
MISI	Michigan	7633
MNSI	Minnesota	423
NYSI	New York	7999
PQAT		-2625
PQBE	Québec	-1016
PQDA		-0.5
PQDZ	Dymond-Rapide Des Iles Intertie	-99
PQHA		0
PQHZ		87
PQPC	Chats Falls – Paugan Intertie	-99
PQQC		177
PQXY	Chenaux – Bryson Intertie	-132

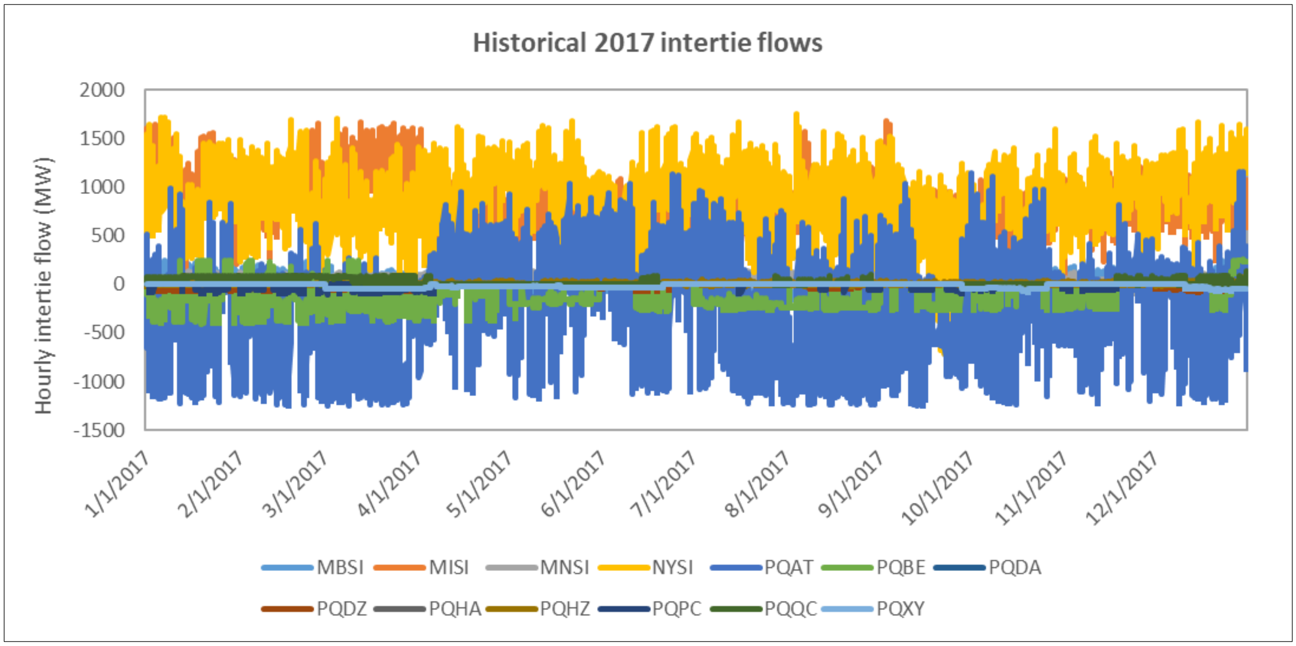

Figure 27. Historical 2017 Intertie Flows

2.7.4.3 Interconnection Data

Table 11. Interconnection Circuit and Connection Type [4]

Interconnection Control Area	Circuit	Connection Type
Ontario – Manitoba Transfer	2 x 230 kV	Synchronous (PAR controlled)
	115 kV	Open
Ontario – Minnesota	115 kV	Synchronous (PAR controlled)
Ontario – Michigan	2 x 230/345 kV	Synchronous (PAR controlled)
	230/115 kV	Synchronous (PAR controlled)
	230 kV	Synchronous (PAR controlled)
Ontario – New York Niagara	2 x 230/345 kV	Synchronous (Free flow)
	2 x 230 kV	Synchronous (Free flow)
Ontario – New York St. Lawrence	2 x 230 kV	Synchronous (PAR controlled)
Ontario – Quebec North	2 x 115 kV	Radial
Ontario – Quebec South	2 x 230 kV (East)	Radial
	5 x 230 kV (Ottawa)	Radial
	2 x 115 kV (Ottawa)	Radial

The interconnection limits are used to ensure system and/or plant stability, acceptable pre-contingency and post-contingency voltage levels and/or acceptable thermal loading levels. Table 12 Interconnection Flow Limits [4] shows the interconnection flow out and flow in limits for summer in MW for Ontario interties.

Table 12. Interconnection Flow Limits [4]

Interconnection	Limit – Flow out of Ontario (MW)	Limit – Flow into Ontario (MW)

Manitoba	225	293
Minnesota	150	100
Quebec North (Northeast)	95	65
D4Z	0	65
H4Z	95	0
Quebec South (Ottawa)	1,570	1,865
X2Y	0	65
Q4C	120	n/a
P33C	0	300
D5A	200	250
H9A	0	0
HVDC	1,250	1,250
Quebec South (East) B31L + B5D	470	800
New York St. Lawrence	300	300
New York Niagara	1,650	1,500
Emergency Transfer Limit	2,160	1,860
Michigan	1,700	1,700
Emergency Transfer Limit	2,250	2,250

2.7.4.4 *Imports and Exports Forecast*

The total imports and exports forecast for the IESO system are detailed in Table 13.

Table 13. Imports and Exports Forecast [6]

Year	Exports (TWh)	Imports (TWh)	Net Exports (TWh)
2017	18.2	9.3	8.9
2018	17.5	9.3	8.1
2019	19.9	7.7	12.3
2020	18.0	8.9	9.1
2021	14.9	9.6	5.3
2022	13.9	10.2	3.7
2023	9.8	11.1	-1.3
2024	13.8	7.8	5.9
2025	7.6	13.6	-5.9
2026	8.0	13.5	-5.5
2027	8.1	11.3	-3.2
2028	8.7	10.2	-1.5
2029	9.0	9.2	-0.1
2030	8.9	8.3	0.6
2031	7.4	10.2	-2.8
2032	9.5	7.9	1.6
2033	10.1	7.6	2.4
2034	10.4	7.2	3.2
2035	9.8	6.9	3.0

2.7.4.5 Transmission Data

The 10 geographical zones in Ontario's power transmission system are shown in Figure 28 and include Bruce, Ontario East, Essa, Niagara, Ontario Northeast, Ontario Northwest, Ottawa, Ontario Southwest, Toronto, Ontario West, and Ontario Peak.

The Ontario power transmission system interconnects to Hydro-Québec, Manitoba, NYISO, and MISO. Ontario's Internal Zones, Internal Interfaces and External Interconnections as provided in Ontario's Transmission System report are shown in Figure 29.

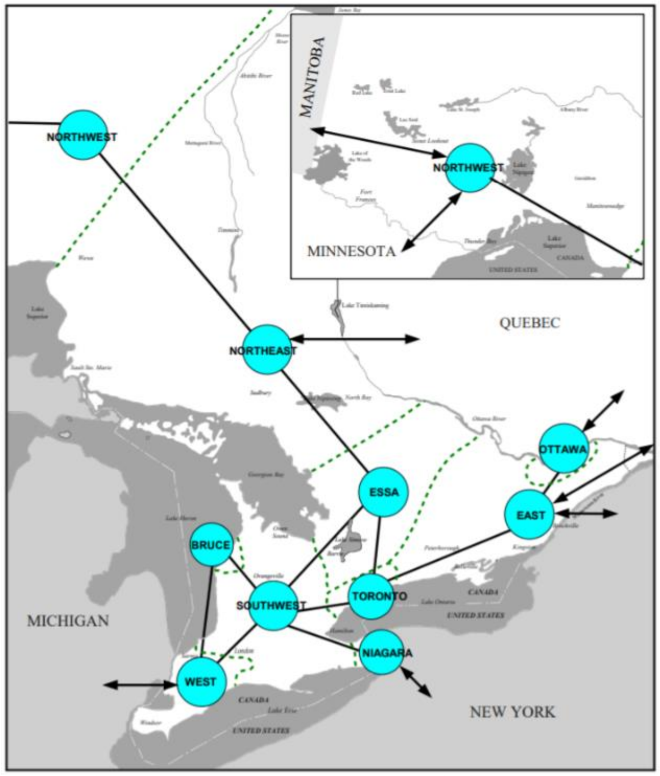

Figure 28. Ontario Geographical Zones

2.7.4.6 Generation and Transmission Map

A high-level view of the generation and transmission is provided in the following diagram taken from the Ontario System Map, available online on the IESO website.

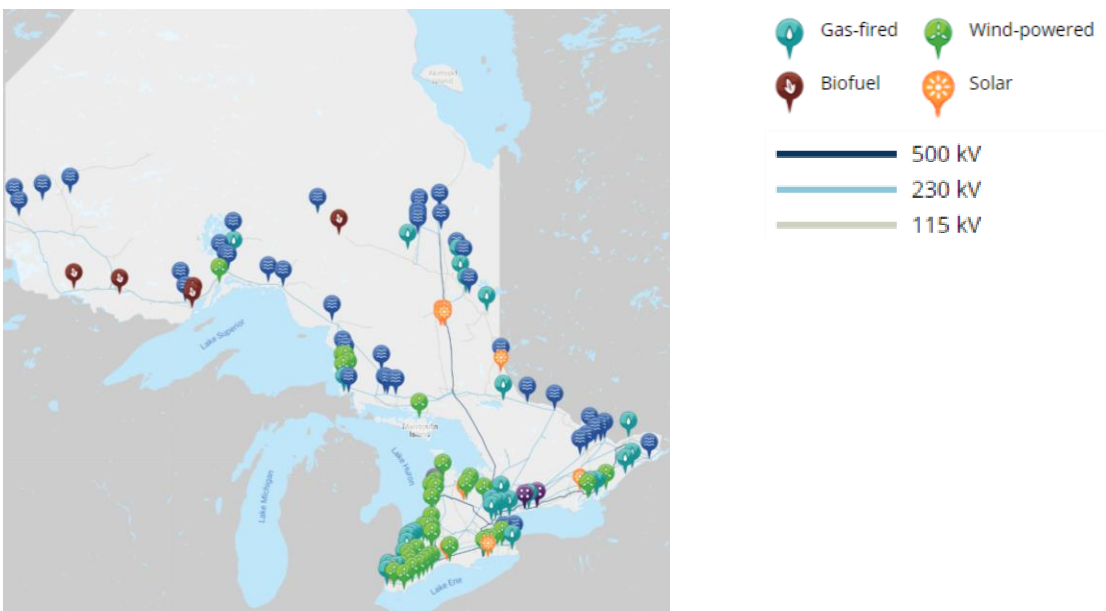

Figure 29. Ontario Generation by Fuel Type and Transmission Map [16]

2.7.5 Emission Price Forecast

The Greenhouse Gas Pollution Pricing Act from the Government of Canada is applied to CO2 emissions in the model and summarized in Table 14 [13].

Table 14. Canadian Carbon Tax [13]

Year	CAD/tonne CO_2e	USD/tonne CO_2e	USD/lb. CO_2e

2018	10	7.6	0.0034
2019	20	15.2	0.0069
2020	30	22.8	0.0103
2021	40	30.4	0.0138
2022	50	38	0.0172
2023	50	38	0.0172
2024	50	38	0.0172
2025	50	38	0.0172
2026	50	38	0.0172
2027	50	38	0.0172
2028	50	38	0.0172
2029	50	38	0.0172
2030	50	38	0.0172
2031	50	38	0.0172
2032	50	38	0.0172
2033	50	38	0.0172
2034	50	38	0.0172
2035	50	38	0.0172

Note: USD/CAD=0.76, tonne/lb.=2204.62

2.7.5.1 Ancillary Services

The IESO contracts for four ancillary services to help ensure the reliable operation of the power system: certified black start facilities, regulation service, reactive support and voltage control service, and reliability must-run. The facilities and annual amount for 2017 are shown in Table 15 Ancillary Services Annual Cost and Quantity in 2017 [18].

Table 15. Ancillary Services Annual Cost and Quantity in 2017 [18]

Ancillary Services	Facilities	Annual Amount
Certified Black Start Facility	4 generation facilities	$1,441,372.93
Regulation Services	7 generation facilities + 2 Alternative Technologies providing ± 228.8MW with typically ±100MW of regulation service scheduled	$50,066,335.83
Reactive Support and Voltage Control	57 generation facilities having 215 generation units	$22,339,048.57
Total Amount for Ancillary Services in 2017		$73,846,757.33

With operating reserves, the IESO ensures that additional supplies of energy are available should an unanticipated event take place in the real-time energy market. The three types of operating reserve classes are offered by dispatchable generators and dispatchable loads. The following Figure 30 shows the operating reserve prices in \$/MWh for Operating reserve 10 min Sync, Operating reserve 10 min Non-sync and Operating reserve 30 min.

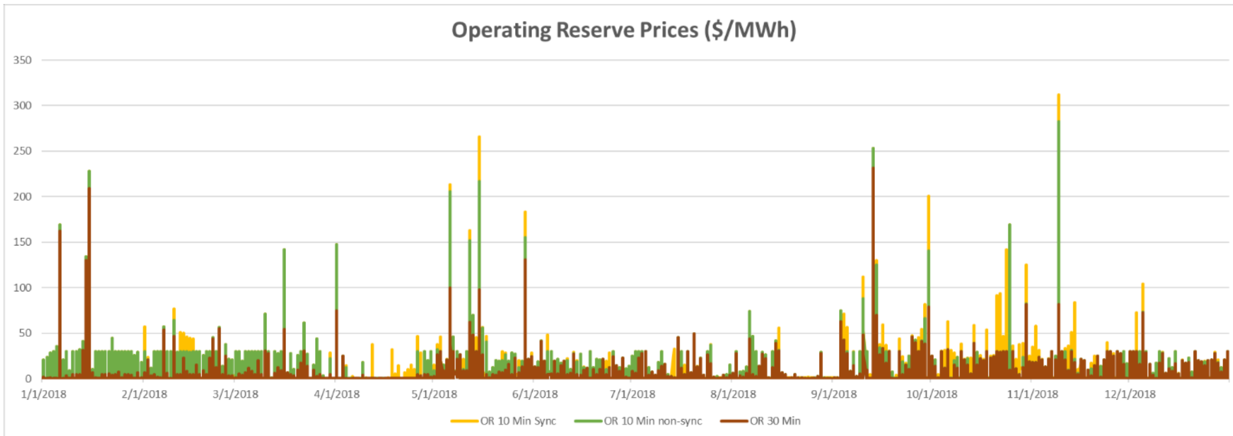

Figure 30. Operating Reserve Prices in 2018 [17]

2.8 Technology Assumptions

2.8.1 General Assumptions

Table 16 shows the general data input assumptions. All data input assumptions are subject to change.

Table 16. General Data Input Assumptions

Parameter	Value
Canada Inflation Rate	2017: 1.6%
	2018: 2.2%
Discount Rate	7.0%
USD to CAD Exchange Rate	0.76 USD = 1 CAD

For the capacity expansion planning phase, the Acelerex study considers new economic expansion for technologies such as energy storage and conventional combine cycle natural gas (CC).

Indicative assumptions for average heat rates, variable operation and maintenance charges, and fixed operation and maintenance charges are detailed below by fuel type.

Table 17. Average Heat Rate, VOM, and FOM Charge by Generation Fuel Type

Fuel	Average Heat Rate (BTU/kWh)	Average VOM ($/MWh)	Average FOM ($/kW-yr)
Biomass	13,362	4	110
Coal	9,967	2	42.1
LFG	10,000	5	-
Uranium	10,000	6	100.3
Natural Gas	7,926	6	14.3
RFO	11,080	5	-
Wind	-	-	39.7
Solar	-	-	22

Source: EIA reports

2.8.2 Energy Storage

Energy storage technologies are split into duration 'buckets' to represent various ES technology types. These durations include Long (6+ hours), Medium-Long (4 hours), Medium-Short (2 hours), and Short (30 minutes). The representative technologies for each bucket are detailed in Table 18 Representative Energy Storage Technologies and Cost Decline Assumptions

Table 18. Representative Energy Storage Technologies and Cost Decline Assumptions

	Representative Technologies and Cost Decline Assumptions
Long duration (6+ hours)	• Li-ion, flow batteries, thermal storage, emerging battery chemistries such as metal based (could also include compressed air and pumped hydro)

	• *Cost decreases 11% annually until 2020, then declines decrease linearly until reaching 3%/year in 2028+*
Medium Long duration (4 hours)	• Li-ion, flow batteries, Zn-Air, Zn-Br, Advanced Lead Acid, NAS • *Cost decreases 11% annually until 2020, then declines decrease linearly until reaching 3%/year in 2028+*
Medium Short (2 hours)	• Li-ion, VRLA • *Cost decreases 10% annually until 2020, then declines decrease linearly until reaching 3% annual declines in 2028+*
Short (30 mins)	• Li-ion, Flywheel, Ultracapacitors • *Cost decreases 10% annually until 2020, then declines decrease linearly until reaching 3% annual declines in 2028+*

Source: EPRI and SANDIA reports

2.8.3 Energy Storage Build Cost

The installed cost of energy storage duration buckets for future study years are shown in Table 19 Forecasted Installed Cost of Energy Storage by Duration for Capacity and Energy. All costs are in 2018 dollars and reflect bulk distribution and transmission system installed costs including a basic estimate for land lease costs and interconnect.

Table 19. Forecasted Installed Cost of Energy Storage by Duration for Capacity and Energy

Duration and Installed Cost	2018	2020	2025	2030
Long (6 hrs)				
per kW	$2,270	$1,800	$1,200	$1,000
per kWh	$380	$300	$200	$165
Medium long (4 hrs)				
per kW	$1,600	$1,280	$840	$700
per kWh	$400	$320	$210	$175
Medium short (2 hrs)				
per kW	$1,080	$875	$600	$500
per kWh	$540	$435	$300	$250
Short (half hour)				
per kW	$630	$510	$350	$290
per kWh	$1,260	$1,020	$700	$580

Source: Blended cost of technologies and sources including Lazard Levelized Cost of Storage 2017, GTM Research, Bloomberg, Navigant Research and storage developers. In the report, the Lazards 4.0 cost will be documented.

2.8.3.1 Energy Storage Fixed Operation and Maintenance Cost

The following formula is applied to calculate FOM of the energy storage system:

$$ESS\ FOM = -Deferral\ Value\ * Duration\ Factor + Storage\ FOM - EA - AS$$

Where the deferral value is the transmission plus distribution plus peak power plants value of capital and operational costs in the distribution system, and the duration factor is the capacity contribution to the peak.

The methodology used to determine the energy arbitrage (EA) and ancillary service (AS) components per storage bucket is as follows:

1. Assumed 6 months summer and 6 months winter and simplified the EA and AS terms using 2025 mid-horizon and simulating one day for each season for production costs.
2. Place a 1MW - L, 1MW - ML, 1MW - MS, and 1MW - S energy storage object in each of the 10 IESO zones.
3. Run the 2025 production cost model for a peak day and an off-peak day.
4. Calculate the net profit for aggregated energy storage by bucket as the sum of profit per bucket for each ES object.

Table 20 shows the values of marginal cost of deferral, duration factor, storage FOM, EA, AS, and the final calculated ESS FOM.

Table 20. Energy Storage FOM Parameters for Distribution Connected Systems

Storage Bucket	Marginal D ($/kW-yr)	Factor	Storage FOM ($/kW-yr)	Energy Arbitrage ($/kW-yr)	Ancillary Services ($/kW-yr)	ESS FOM ($/kW-yr)
Marginal D=35						
Long (6+ hours)	35	1	10	57.2	0	-82.2
Medium Long (4 hours)	35	1	15	56.8	0	-76.8
Medium Short (2 hours)	0	0	20	0	44	-24
Short (30 mins)	0	0	20	0	40	-20
Marginal D=40						
Long (6+ hours)	40	1	10	57.2	0	-87.2
Medium Long (4 hours)	40	1	15	56.8	0	-81.8
Medium Short (2 hours)	0	0	20	0	44	-24
Short (30 mins)	0	0	20	0	40	-20
Marginal D=45						
Long (6+ hours)	45	1	10	57.2	0	-92.2
Medium Long (4 hours)	45	1	15	56.8	0	-86.8
Medium Short (2 hours)	0	0	20	0	44	-24
Short (30 mins)	0	0	20	0	40	-20
Marginal D=50						
Long (6+ hours)	50	1	10	57.2	0	-97.2
Medium Long (4 hours)	50	1	15	56.8	0	-91.8
Medium Short (2 hours)	0	0	20	0	44	-24

Storage Bucket	Marginal D ($/kW-yr)	Factor	Storage FOM ($/kW-yr)	Energy Arbitrage ($/kW-yr)	Ancillary Services ($/kW-yr)	ESS FOM ($/kW-yr)
Short (30 mins)	0	0	20	0	40	-20
Marginal D=55						
Long (6+ hours)	55	1	10	57.2	0	-102.2
Medium Long (4 hours)	55	1	15	56.8	0	-96.8
Medium Short (2 hours)	0	0	20	0	44	-24
Short (30 mins)	0	0	20	0	40	-20

2.8.4 Energy Storage Technical Life and Economic Life

Technical Life represents the physical life of the generator and is used in the capacity optimization phase to force the retirement of the generator after a certain period after it has been constructed. Economic Life sets the number of years over which the energy storage build cost is spread. We assumed the economic life for all the energy storage is 10 years and the technical life for four buckets of the energy storage technology is in Table 21.

Table 21. Energy Storage Technology and Economical Life and Efficiency

Storage Bucket	Technical Life	Economic Life	Efficiency (%)
Long	20	10	80
Medium Long	20	10	85
Medium Short	10	10	87
Short	10	10	87

Source: Industrial data EPRI and Lazards

Table 22. Valuation Data Assumption Source

Data	Source
Indicative Fade Curve	Acelerex Battery Characteristics Proprietary Database
Storage Cost ($/kWh)	Blended cost of technologies and sources including Lazard Levelized Cost of Storage 2017, GTM Research, Bloomberg, Navigant Research and storage developers
Fixed Operational and Maintenance Charge ($/kW-year)	Acelerex Battery Characteristics Proprietary Database
Variable Operational and Maintenance Charge ($/kW-year)	Acelerex Battery Characteristics Proprietary Database
Connection Cost ($/MW)	Acelerex Battery Characteristics Proprietary Database
EPC Cost ($/kWh)	Lazard
Target Size of Project (MW/MWh)	TBD
Maximum Discharge C-rate and Maximum Charge C-rate	Acelerex Battery Characteristics Proprietary Database

2.8.5 Wind and Solar Installation Assumptions

Acelerex has used the 2017 Long Term Energy Plan as its benchmark for the forecasted installed capacities of Wind and Solar Generation. To distribute the generators among the zones, wind and solar power density maps, existing zonal generation capacity and demand are used.

Figure 31 shows the wind power density map from which wind power density per area is derived which is further used for determining the approximate location and sizing of wind power installations during the period of 2020-2030.

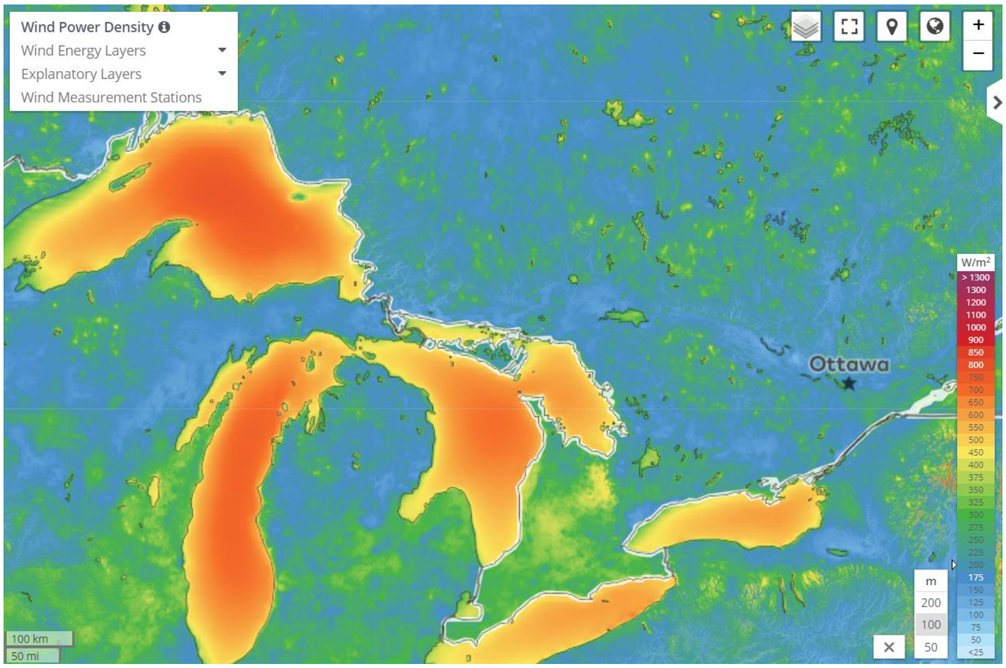

Figure 31. Wind Power Density Map of Ontario

The added wind generation is decided based on the zonal generation capacity, demand and wind energy potential. The energy density maps referred to are taken from Global Wind Atlas.

Table 23. Added Wind Power Generation

Zone	Area km2	10% Highest W/m2	Demand	Generation	Added Wind Generation
ONBRUCE	4284	658	333	8063	400
ONEAST	33696	340	1849	5428	200
ONESSA	45784	464	2103	779	0
ONNE	256334	466.3258	2145	4861	200
ONNI	2852	555	845	3054	100
ONNW	650466	439.92	827	1126	0
ONOT	6879	265	1663	156	0
ONSW	31600	650	4961	2653	200
ONTO	6117	450	9614	8470	300
ONWEST	22672	584	2746	6377	250

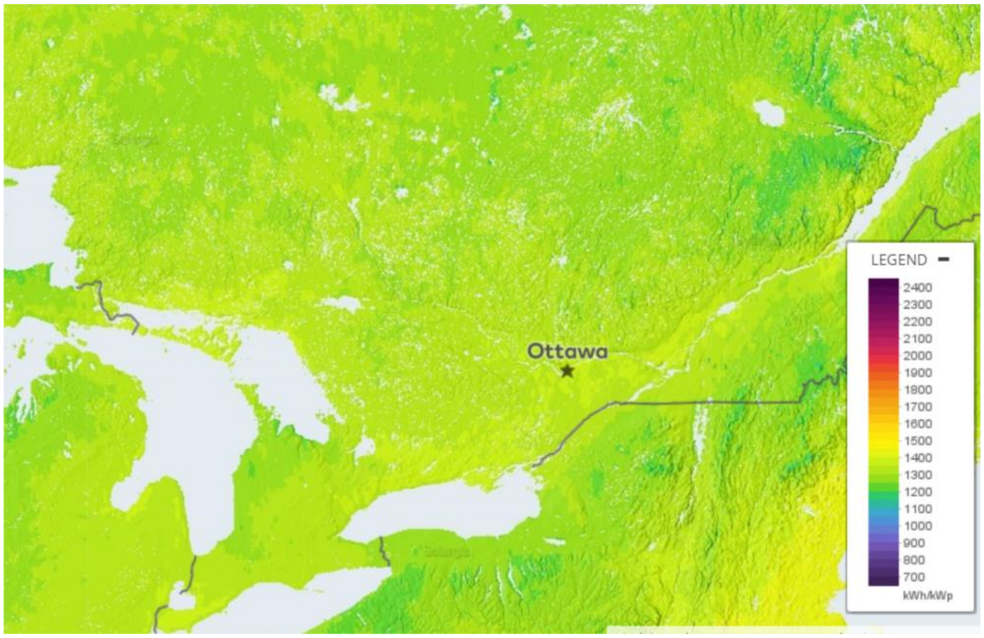

Figure 32. Solar Power Density Map for Ontario

The added solar generation is decided based on the zonal generation capacity, demand and solar energy potential. The energy density maps referred to are taken from Global Solar Atlas.

Figure 33. Added Solar Power Generation

Zone	GTI kwh/m2-yr	Global Solar Energy MWh/yr	Demand	Generation	Added Solar Generation
ONBRUCE	1541	6601644	333	8063	600
ONEAST	1606	54115776	1849	5428	300
ONESSA	1510	69133840	2103	779	40
ONNE	1590	4.08E+08	2145	4861	300
ONNI	1605	4577460	845	3054	200
ONNW	1587	1.03E+09	827	1126	0
ONOT	1526	10497354	1663	156	0
ONSW	1598	50496800	4961	2653	300
ONTO	1638	10019646	9614	8470	660
ONWEST	1629	36932688	2746	6377	540

Based on these assumptions, the input data for wind and solar generation is shown in the table below.

Table 24. Zonal Solar and Wind Generation

	ONBRUCE	ONEAST	ONESSA	ONNE	ONNI	ONSW	ONTO	ONWEST	ONNW
Solar Installed Capacity (MW)	600	300	40	300	200	400	560	550	0
Wind Installed Capacity (MW)	1069	470.8	0	494.1	100	1541.3	300	1623.2	98.9

2.8.6 Natural Gas Expansion

To meet the increasing demand over the study horizon for 2020-2030, we have included the conventional Natural Gas expansion generators in our model with the construction and maintenance cost. As and when a generator becomes financially viable, it will be added to our system to meet the demand. The general characteristics of the natural gas generator are mentioned in Table 25.

Table 25. Natural Gas Generator Characteristics for Expansion

Generator Characteristics	Value	Units
Maximum Capacity Rating	600	MW
Heat Rate	6690	BTU/kWh
VOM Cost Rate	0.59	$/MWh
FOM Cost Rate	9.84	$/kW/year
Construction Cost for 2017	1082	$/kW
Construction Cost for 2018	1079	$/kW
Construction Cost for 2019	1075	$/kW
Construction Cost for 2020	1068	$/kW
Construction Cost for 2021	1065	$/kW
Construction Cost for 2022	1062	$/kW
Construction Cost for 2023	1059	$/kW
Construction Cost for 2024	1055	$/kW
Construction Cost for 2025	1052	$/kW
Construction Cost for 2026	1043	$/kW
Construction Cost for 2027	1036	$/kW
Construction Cost for 2028	1029	$/kW
Construction Cost for 2029	1024	$/kW
Construction Cost for 2030	1019	$/kW
Construction Cost for 2031	1014	$/kW
Construction Cost for 2032	1011	$/kW

2.8.7 Ancillary Service Assumptions

Spinning reserves are modelled in four categories mentioned in Table 26 with the assumed load risk values.

Table 26. Spinning Reserves with their Load Risk Percentage

Spinning Reserves	Load Risk
Regulation	1%
10 Minute Spinning Reserve	2.5%
10 Minute Non-Synchronous	2%
30 Minute Non-Synchronous	2.5%

2.8.8 Demand Response

The demand response for the Ontario network is modelled using the total demand response value of 847MW for the IESO. This value is distributed over the zones of the IESO network according to their respective values at the IESO peak. Each zone will provide their demand response values at their individual peaks as shown in Table 27. The 2017 zonal demand and long-term energy plan are used to evaluate the demand response model.

Table 27. Demand Response and Zonal Distribution [1][2][3]

Zone	ONNW	ONNE	ONOT	ONEAST	ONTO	ONESSA	ONBRUCE	ONSW	ONNI	ONWEST
Demand Response (MW)	13.4	36.8	53.6	54.2	342.3	52.5	3.6	169.2	30.4	90.9
Jan (GWh)	0.21	0.59	0.86	0.87			0.06			
Feb (GWh)	0.21	0.59		0.87						
Mar (GWh)		0.59		0.87						
Apr (GWh)										
May (GWh)							0.06			
Jun (GWh)			0.86		5.48			2.71		1.45
Jul (GWh)					5.48			2.71	0.49	1.45
Aug (GWh)								2.71	0.49	1.45
Sep (GWh)			0.86		5.48		0.06	2.71	0.49	1.45
Oct (GWh)										
Nov (GWh)	0.21					0.84			0.49	
Dec (GWh)	0.21	0.59	0.86	0.87		0.84				

2.9 Case and Sensitivity Descriptions

2.9.1 Load Growth Sensitivity

For the load growth sensitivity, the high case is considered using the IESO Annual Planning Outlook 2020 load forecast with Outlook D and low case with Outlook A. In Figure 34, a comparison between load growth sensitivity input data is shown. Using the peak load and energy forecast data of Outlook D and Outlook A, the process explained in section 2.7.1 is repeated to observe results for load growth sensitivity.

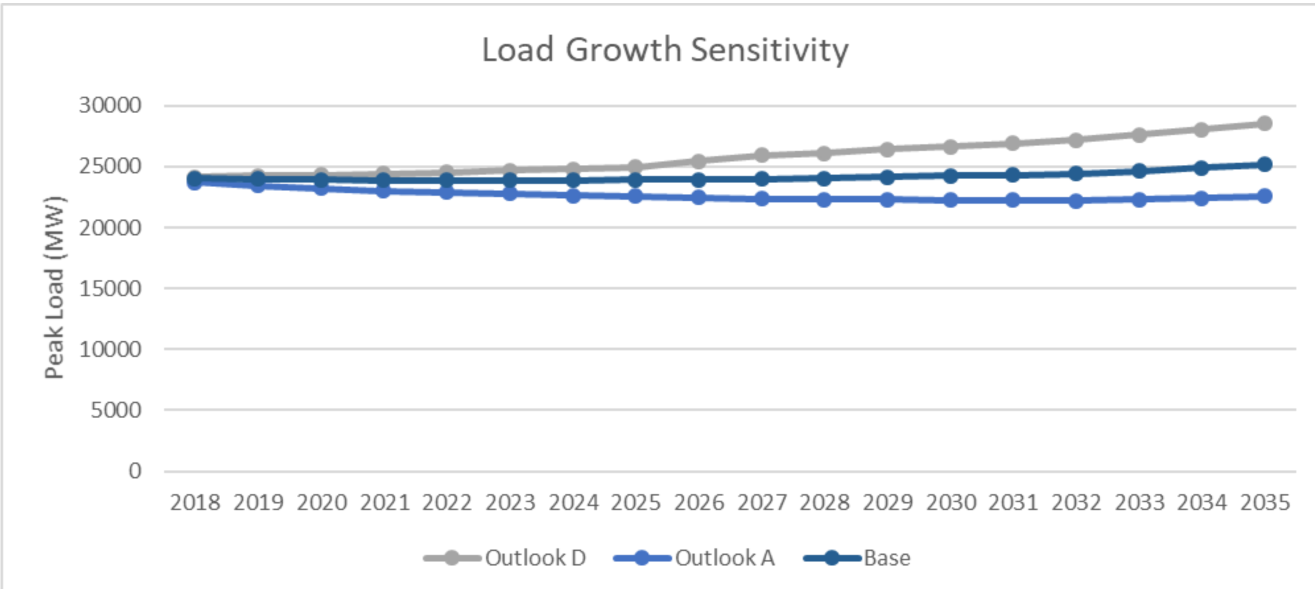

Figure 34. Load Growth Sensitivity Input Data

2.9.2 Fuel Price Sensitivity

A variance of 40% is added to all the fuel prices which includes Natural Gas, Oil, Biomass, LFG and Uranium to study the effect of increase/decrease in fuel prices forecast on the Energy Storage. The average Natural Gas price forecast for high, base and low scenarios is shown in Figure 35.

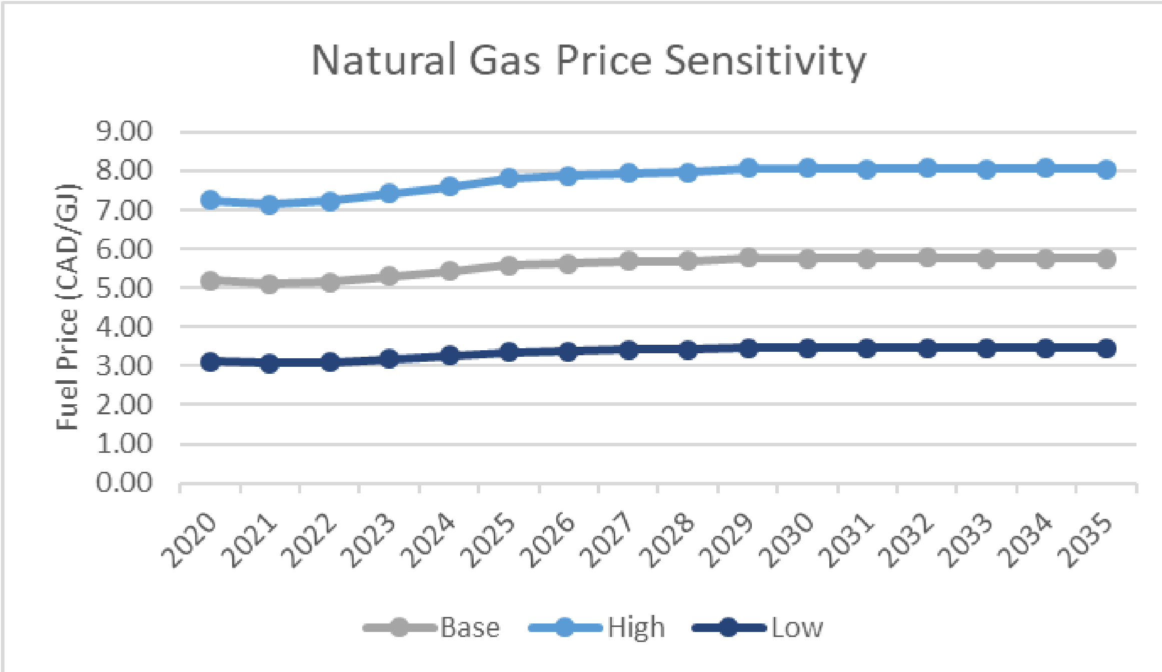

Figure 35. Natural Gas Fuel Price Sensitivity Input Data

2.9.3 Carbon Tax Sensitivity

A variance of 25% is added to CO_2 Tax to study the effect of increase/decrease in CO_2 Tax forecast on CO_2 Emissions and ES. The average CO_2 Tax forecast for high, base and low scenarios is shown in Figure 36.

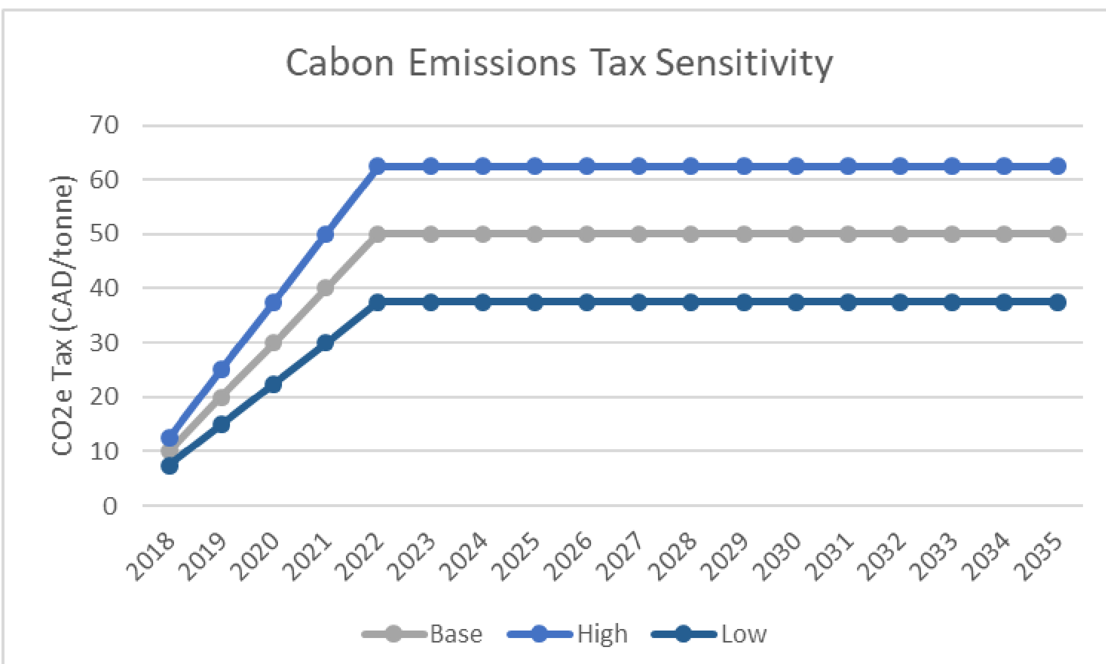

Figure 36. Carbon Emissions Tax Sensitivity Input Data

2.9.4 Energy Storage Cost Sensitivity

Figure 37 shows the energy storage cost sensitivity by bucket, where a variance of +/- 40% is applied to energy storage cost, increasing/decreasing the energy storage cost.

Figure 37. Technology Sensitivity by Bucket (Long, Medium Long, Medium Short, Short Duration)

2.9.5 Energy Storage Fixed Operating and Maintenance Cost Sensitivity

The Energy Storage build has been analyzed for Marginal D values equal to 55$/kW-yr, 50$/kW-yr, 45$/kW-yr, 40$/kW-yr and 35$/kW-yr. The FOM values calculated for each type of storage modelled is shown in Table 28.

Table 28. FOM Values for Type L, ML, MS and S for Marginal D Sensitivity

Marginal D ($/kW-yr)	L FOM ($/kW-yr)	ML FOM ($/kW-yr)	MS FOM ($/kW-yr)	S FOM ($/kW-yr)
55	102.2	96.8	24	20
50	97.2	91.8	24	20
45	92.2	86.8	24	20
40	87.2	81.8	24	20
35	82.2	76.8	24	20

2.10 Benchmark

This section provides a comparison between the Acelerex model and IESO actual data and Annual Planning Outlook 2020 data. Parameters like Energy Prices, Generation Capacity, Wind and Solar Capacity, Net Import and Export, Carbon Emissions and Fuel Price Congestion are used as the benchmark to validate the modelling.

2.10.1 Benchmark Energy Prices

The energy price has been benchmarked using IESO data of the 2018 Hourly Ontario Energy Price (HOEP). The comparison of 2020 model energy prices and 2018 IESO HOEP is shown in Figure 38. The zonal IESO hourly energy prices are provided in Production Cost results [21].

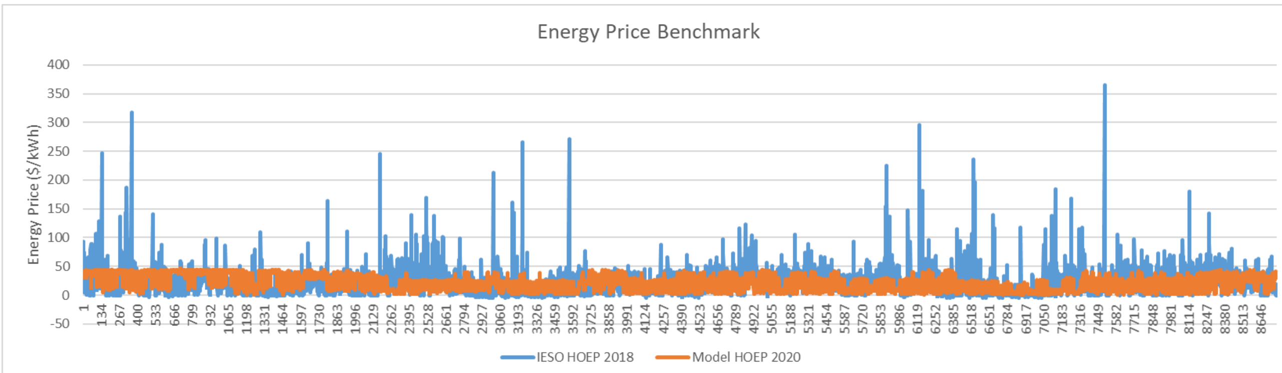

Figure 38. Energy Price Benchmark [21]

2.10.2 Zonal Price Benchmark

Figure 39 shows the zonal price benchmark between the annual average price obtained from IESO data of 2018 for each zone with the Acelerex production cost model results for the year 2020. The zonal energy prices are provided in Production Cost results compiled in Table 53 and [21].

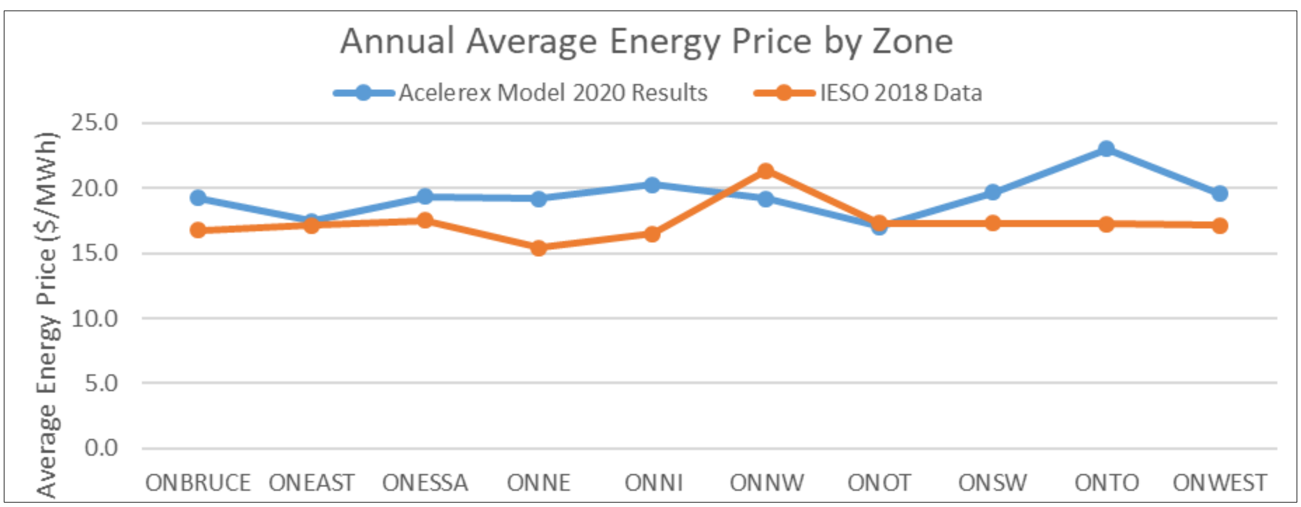

Figure 39. Zonal Energy Price Benchmark [21]

2.10.3 Benchmark Capacity by Fuel Type

Figure 40 shows the benchmark of Capacity by Fuel type. Benchmark shown is between 2020-2030 Acelerex Model Installed Capacity by Fuel Type and 2020-2030 Annual Planning Outlook 2020 Capacity by Fuel Type. The installed capacity by fuel type from 2020-2030 is shown in Capacity Optimization results in Table 33 and Appendix Table A-6 [19], page 171.

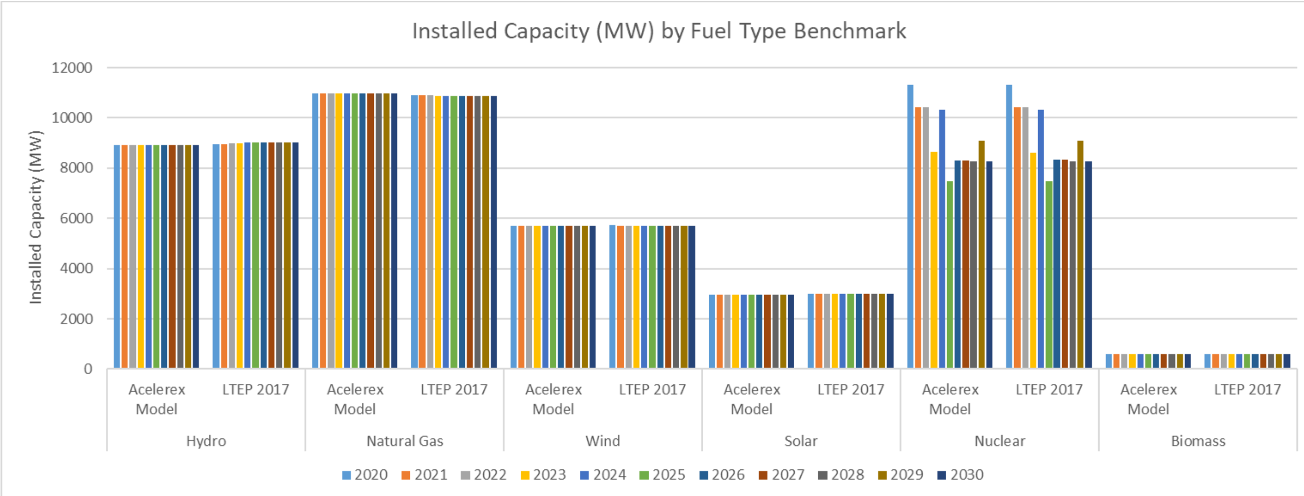

Figure 40. Benchmark Capacity by Fuel Type [19]

2.10.4 Benchmark Wind and Solar Firm Capacity

Being intermittent sources, wind and solar will not produce power continuously at their rated maximum capacity. A percentage of their installed capacity derived from the IESO 2018 Outlook tables [15] depicted in Figure 41 is used to formulate the Firm Capacity of all the Wind and Solar generators. The benchmarked Solar and Wind Firm Capacity in MW is shown in Figure 42 and data is provided in the Appendix Table A-5, page 171.

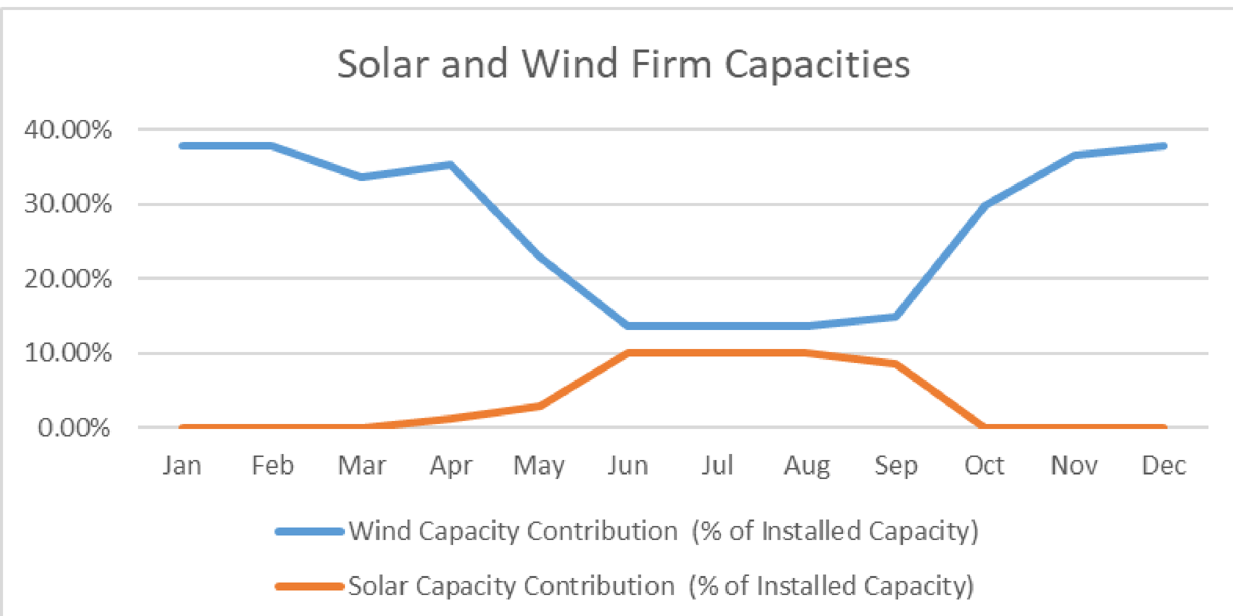

Figure 41. IESO 2018 Outlook Firm Capacity [15]

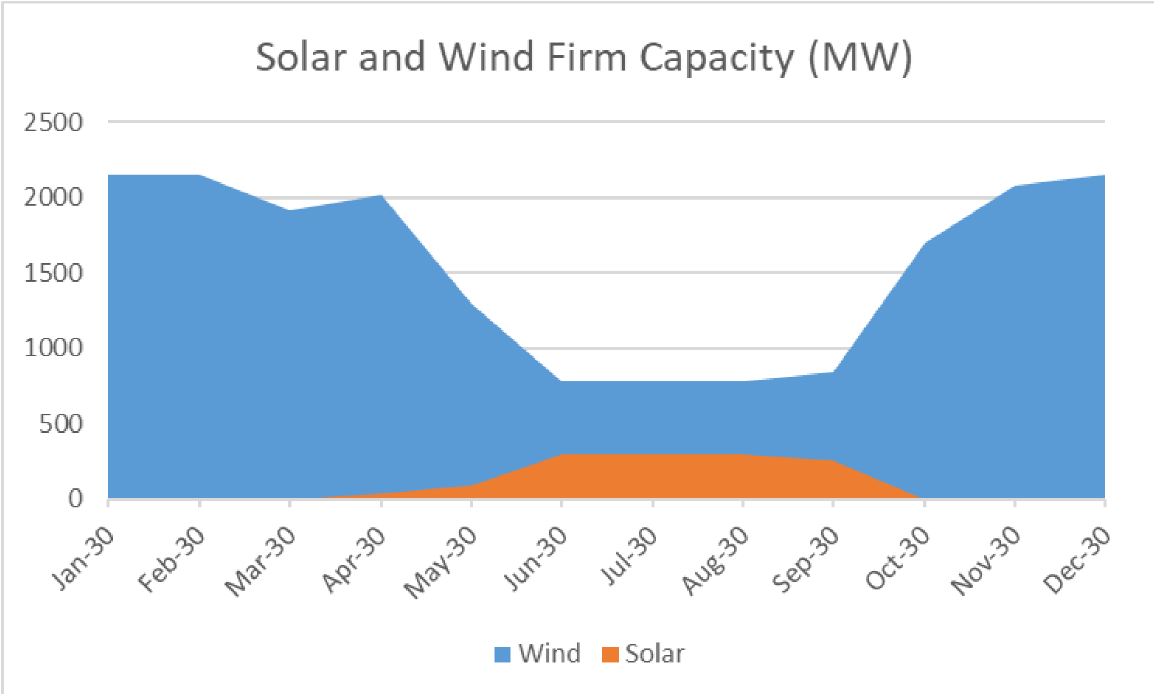

Figure 42. Solar and Wind Firm Capacity in MW [19]

2.10.5 Benchmark Generator Capacities

The firm capacity of all the generators in the model has been updated according to the IESO Generator Output Capabilities (GOC) 2018 report. Figure 43 shows the GOC 2018 benchmark value and its comparison with firm capacity modelled from 2018 to 2032. The benchmark firm capacity is provided in Capacity Optimization results shown in Table 33 and [19].

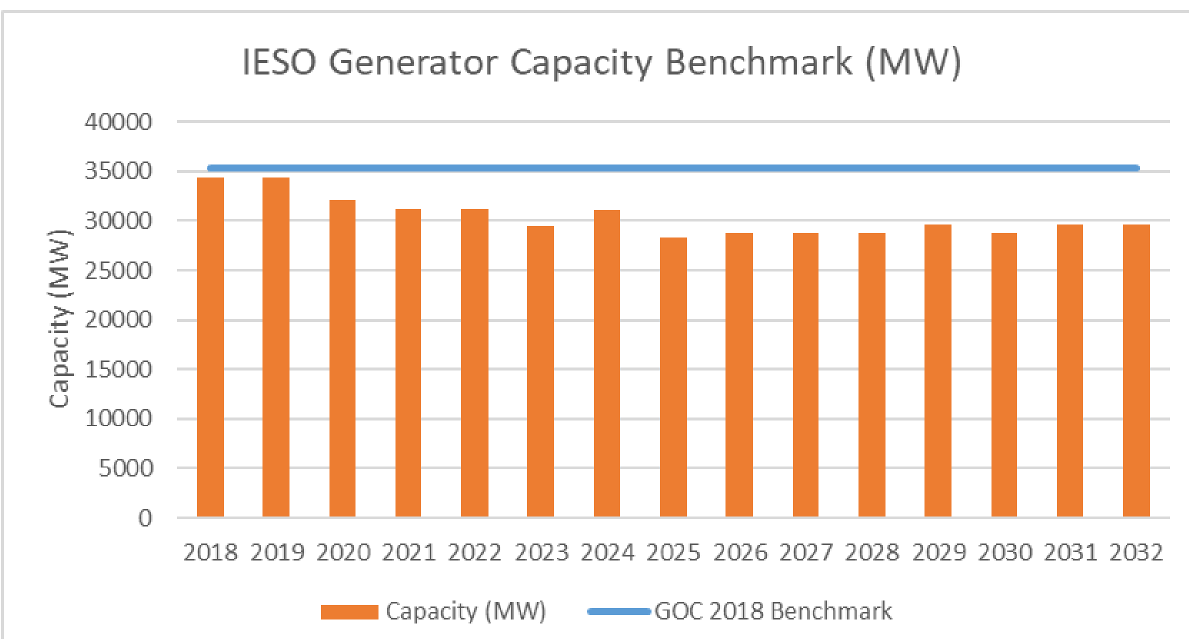

Figure 43. Generator Capacity Benchmark using 2018 IESO GOC [19]

2.10.6 Net Export Energy Benchmark

The import and export have been benchmarked using the IESO Annual Planning Outlook 2020 data. Figure 44 shows the comparison chart of Net Exports between the IESO data and Acelerex Capacity Optimization result shown in Table 38 and [19].

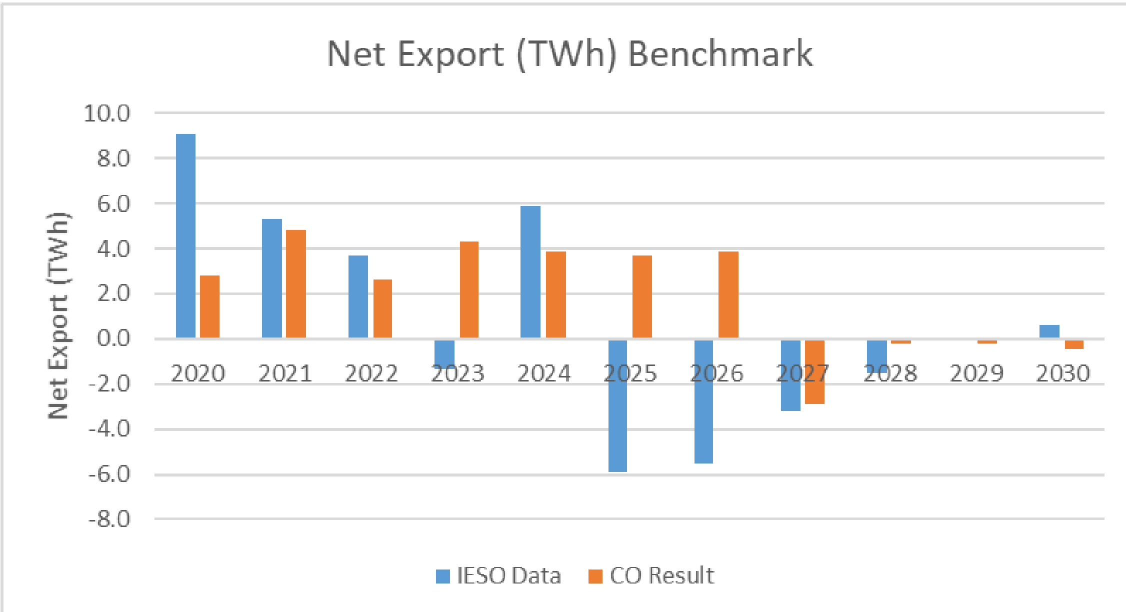

Figure 44. Import and Export Forecast Benchmark Comparison [19]

2.10.7 Benchmark CO2 Emission

Figure 44 shows the benchmark of CO2 emissions with the IESO Outlook B with and without Cap and Trade. The benchmark CO2 emissions are provided in Production Cost results shown in Table 55 and [21].

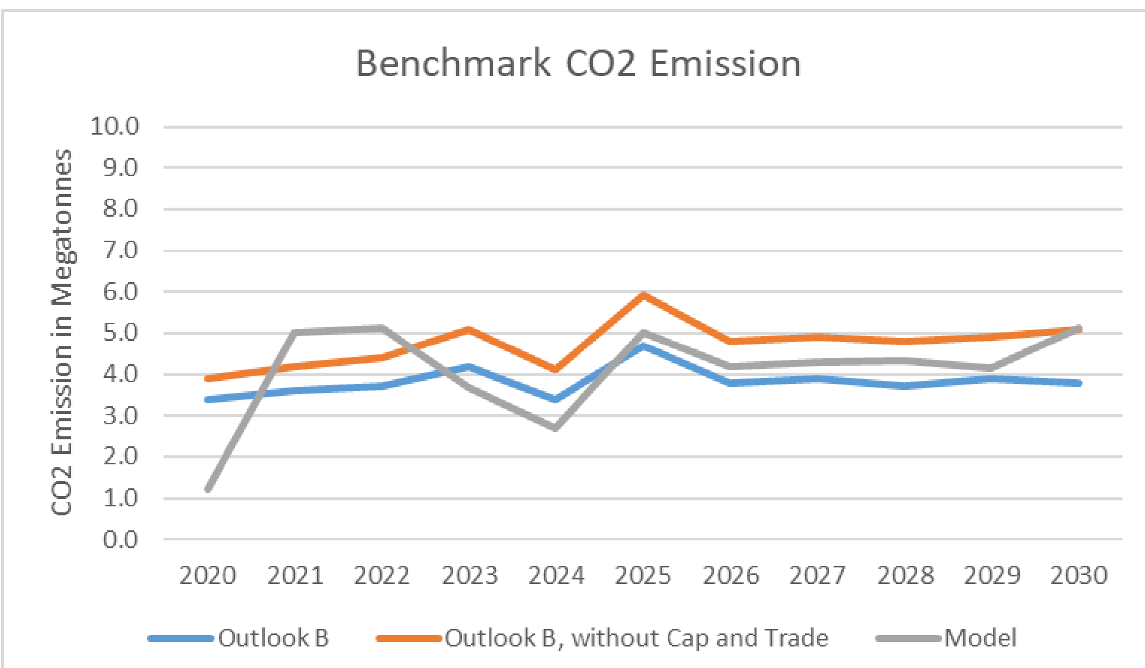

Figure 45. CO2 Emissions Benchmark with IESO Outlook [21]

2.11 Simulation Results

2.11.1 Generation by Fuel Type

Figure 46 shows the year 2020 generation by fuel type (GWh) and the percentages for the Ontario region from the Production Cost simulations. The production cost results show the consistent supply from nuclear and hydro as the base generation and increased amount of solar and wind generation as per the IESO Annual Planning Outlook 2020. The production cost simulation results from 2020-2030 are populated in Table 50 and [21].

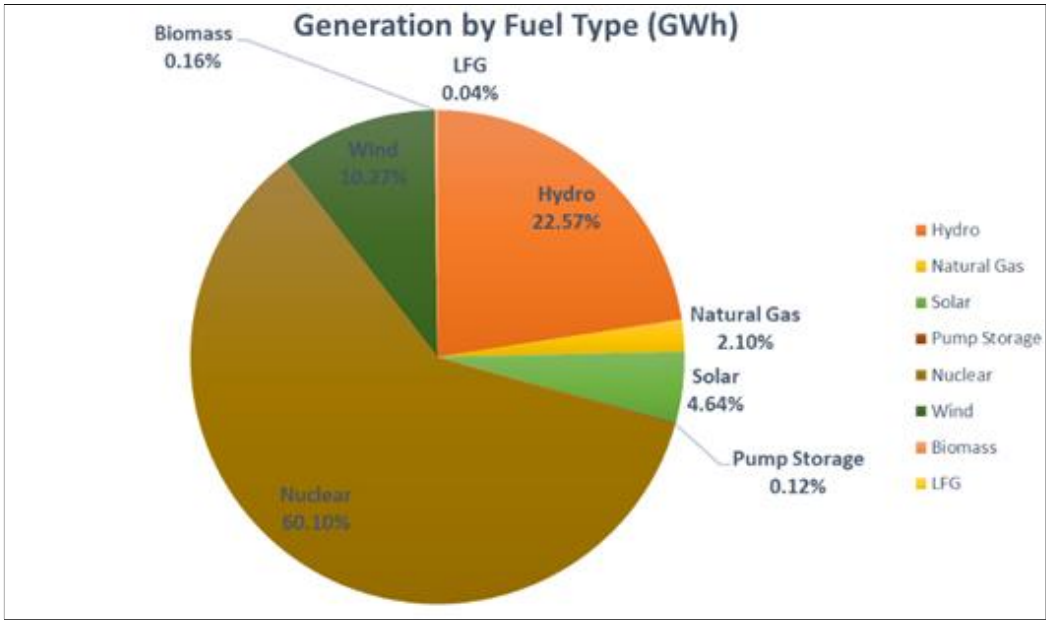

Figure 46. Generation by Fuel Type [21]

2.11.2 Ontario Energy Price Results

The 2020 hourly energy price forecast results in $/MWh from the simulation of the production cost model are in Figure 47. As observed, the energy prices in each zone are different, with a consistent profile overall. ONTO has the maximum energy prices among the zones. The production cost simulation energy price results from 2020-2030 are populated in Table 53 and [21].

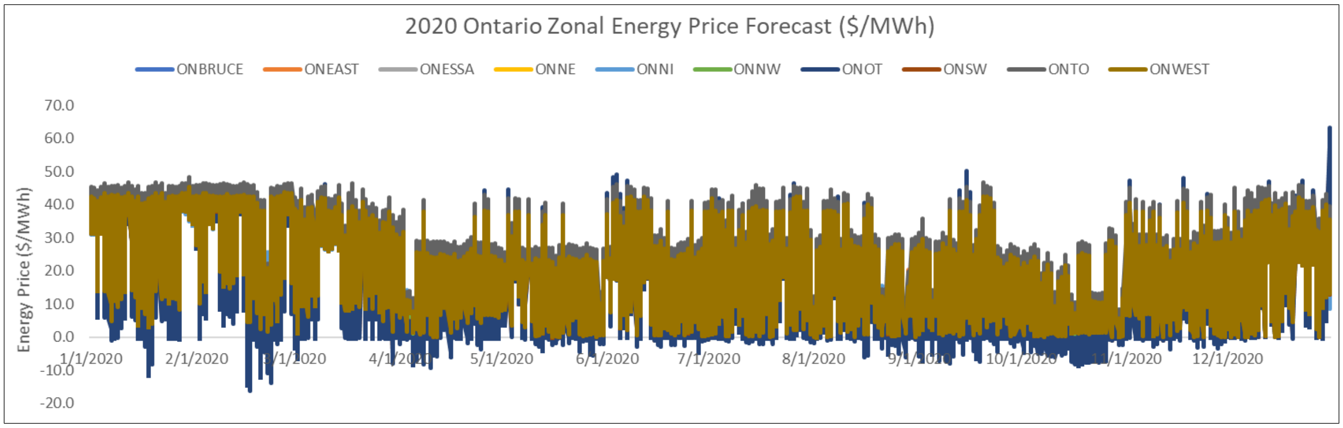

Figure 47. 2020 Hourly Energy Price Forecast Results

2.11.3 Ontario Pillar 2 Metrics

Table 29. Ontario Pillar 2 Metrics

No.	Parameter	Value	Description
1	Escalation of Benefits (%/yr)	<1%	Percentage at which annual change in the value of benefits is expected to occur
2	Discount Rate (%/yr)	7.0%	Rate of return as a percentage used to calculate the multiplier that converts the anticipated future value (return) to the present value
3	Electricity Price Escalation (%/yr)	Base Case = 8.4% Base + Storage = 9%	Rate of increase of the electricity cost used for calculating the cost of operational losses through the life of a project
4	Energy Price Suppression	Refer to Table 48 and Table 77	Annual average price (PC output)
5	Cost of Energy for Charge ($)	Sum of Year (Hourly Charge MW x Hourly Price)	Rate to be paid at off-peak times to charge an energy storage device. This is used to calculate the annual cost of operational losses (PC output)
6	Project Life (Select 10/15/20) years	Refer to Table 21	Length of period for which the cash flow and payback values are calculated

2.11.4 Acelerex Stacked Services Emulator Results

The Acelerex Stacked Services Emulator maximizes hourly profits from energy storage services using an objective function to maximize potential hourly profits from energy storage services. The stacked-services emulator includes four main applications of energy storage including energy arbitrage, ancillary services, peak shaving, and renewable economic shifting, where the ancillary services include primary reserve, secondary reserve, and tertiary reserve. It also includes all characteristics of energy storage, such as efficiency, size, duration, capacity fade curve, and initial state of charge (SOC).

The Acelerex Stacked Service Emulator is used to simulate dispatch profiles for energy storage, and for this study the tool is used with historical IESO energy prices of 2018 to determine energy arbitrage potential at all market nodes in the IESO footprint.

Results for the energy arbitrage analysis using the long duration and medium-long duration energy storage system are presented in Table 30. The long duration system is modelled as a 1 MW capacity, 6-hour duration system, and the medium-long duration as a 1 MW capacity, 4-hour duration system. The energy arbitrage term in FOM equation from 2.8.3.1 was set using the annual revenue.

Table 30. EA Revenue from Acelerex SSE Simulation

Storage	Capacity	Duration	Efficiency	Energy Arbitrage Revenue for 2018
L	1 MW	6-hours	80%	$57,227
ML	1 MW	4-hours	85%	$56,799

2.11.5 Base Case Results

The Base Case scenario examines a potential future for the Ontario region without the addition of energy storage. The base case results are used to validate the model. The natural gas generators in the IESO are enabled to economically expand and retire.

2.11.5.1 Capacity Optimization Results

The capacity optimization phase takes as inputs capital costs and operational costs of current assets and future assets to run the grid, as well as new technologies assumptions, and performs cost minimization. The capacity optimization phase determines the natural gas generators that will economically expand or retire. The objective function of the capacity optimization modelling minimizes the production cost and the capital cost of the system. An annual optimization is performed over each year of the study horizon 2020-2030 including 2018, 2019, 2031 and 2032 to have end effect.

The base case capacity optimization study results are summarized in [19] and tables as follows. The IESO Demand metrics input for the capacity optimization base case are provided in Table 31. It indicates the IESO peak with coincidental value as well as sum of zonal peaks with total energy demand and demand response model values.

Table 31. Demand by Year for Base Case (Input)

Demand (MW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030

IESO Peak (MW) (Regional) (Coincidental value)	23922	24211	23937	23745	23920	23875	24067	24311	23879	24059	24275
IESO Peak (MW) (Zonal Peak total)	27086	27929	27728	27065	27282	27167	27789	28044	27541	27499	27872
IESO Energy (GWh) (Zone)	149445	143519	140131	131559	139521	121685	128251	141108	147374	145198	146412
Demand Response (MW)	847	847	847	847	847	847	847	847	847	847	847

Capacity planning requirements with an average planning margin of 28% are shown in Table 32.

Table 32. Planning Capacity by Year for Base Case (Output)

Capacity Requirement	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capacity Reserve (MW)	9065	7916	8182	6529	8107	5253	5597	5348	5725	6374	5348
Capacity Reserve Margin (%)	38%	33%	34%	28%	34%	22%	24%	22%	28%	23%	26%

Base case capacity optimization results for the installed capacity by fuel type with total installed and firm capacity are shown in Table 33.

Table 33. Installed Capacity by Year for Base Case (Input)

Capacity	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal (MW)	0	0	0	0	0	0	0	0	0	0	0
Hydro (MW)	8905	8905	8905	8905	8905	8905	8905	8905	8905	8905	8905
Natural Gas (MW)	9762	9762	9762	9762	9762	9762	9414	9414	9401	9401	9401
Oil (MW)	0	0	0	0	0	0	0	0	0	0	0
Demand Response (MW)	847	847	847	847	847	847	847	847	847	847	847
Solar (MW)	2950	2950	2950	2950	2950	2950	2950	2950	2950	2950	2950
PS (MW)	146	146	146	146	146	146	146	146	146	146	146
Uranium (MW)	11322	10441	10441	8627	10325	7469	8317	8317	8284	9101	8284
Wind (MW)	5697	5697	5697	5697	5697	5697	5697	5697	5697	5697	5697
Biomass (MW)	587	587	587	587	587	587	587	587	587	587	587
LFG (MW)	32	32	32	32	32	32	32	32	32	32	32
Installed Capacity (MW)	40248	39367	39367	37553	39251	36395	36896	36896	36849	37666	36849
Total Firm Capacity (MW)	33071	32177	32177	30363	32074	29218	29740	29705	30476	29659	30488

Economic build results, by years, for the capacity optimization base case are presented in Table 34.

Table 34. Economic Builds by Year for Base Case (Output)

Economic Builds (Incremental)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal (MW)	0	0	0	0	0	0	0	0	0	0	0

Hydro (MW)	0	0	0	0	0	0	0	0	0	0	0
Natural Gas (MW)	0	0	0	0	0	0	0	0	0	0	0
Oil (MW)	0	0	0	0	0	0	0	0	0	0	0
Other (MW)	0	0	0	0	0	0	0	0	0	0	0
Solar (MW)	0	0	0	0	0	0	0	0	0	0	0
PS (MW)	0	0	0	0	0	0	0	0	0	0	0
Uranium (MW)	0	0	0	0	0	0	0	0	0	0	0
Wind (MW)	0	0	0	0	0	0	0	0	0	0	0
Biomass (MW)	0	0	0	0	0	0	0	0	0	0	0
LFG (MW)	0	0	0	0	0	0	0	0	0	0	0
Total Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0

Economic build cost results for the capacity optimization base case are shown in Table 35.

Table 35. Economic Build Cost by Year for Base Case (Output)

Economic Build Cost (Incremental)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal ($000)	0	0	0	0	0	0	0	0	0	0	0
Hydro ($000)	0	0	0	0	0	0	0	0	0	0	0
Natural Gas ($000)	0	0	0	0	0	0	0	0	0	0	0
Oil ($000)	0	0	0	0	0	0	0	0	0	0	0
Other ($000)	0	0	0	0	0	0	0	0	0	0	0
Solar ($000)	0	0	0	0	0	0	0	0	0	0	0
PS ($000)	0	0	0	0	0	0	0	0	0	0	0
Uranium ($000)	0	0	0	0	0	0	0	0	0	0	0
Wind ($000)	0	0	0	0	0	0	0	0	0	0	0
Biomass ($000)	0	0	0	0	0	0	0	0	0	0	0
LFG ($000)	0	0	0	0	0	0	0	0	0	0	0
Total Build Cost ($000)	0	0	0	0	0	0	0	0	0	0	0

Table 36 presents the economic retirement results for the capacity optimization base case. This shows that natural gas generation is retiring in years 2020, 2026 and 2028.

Table 36. Economic Retirements by Year for Base Case (Output)

Economic Retirements (Incremental)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal (MW)	0	0	0	0	0	0	0	0	0	0	0
Hydro (MW)	0	0	0	0	0	0	0	0	0	0	0
Natural Gas (MW)	1199	0	0	0	0	0	348	0	13	0	0
Oil (MW)	0	0	0	0	0	0	0	0	0	0	0
Other (MW)	0	0	0	0	0	0	0	0	0	0	0
Solar (MW)	0	0	0	0	0	0	0	0	0	0	0

PS (MW)	0	0	0	0	0	0	0	0	0	0	0
Uranium (MW)	0	0	0	0	0	0	0	0	0	0	0
Wind (MW)	0	0	0	0	0	0	0	0	0	0	0
Biomass (MW)	0	0	0	0	0	0	0	0	0	0	0
LFG (MW)	0	0	0	0	0	0	0	0	0	0	0
Total Capacity (MW)	1199	0	0	0	0	0	348	0	13	0	0

Table 37 presents results for the net planned builds and retirements by year for the capacity optimization base case. This indicates the planned maintenance/retirements of nuclear plants.

Table 37. Net Planned Builds/Planned Retirements by Year for Base Case (Input)

Net: Planned Builds/Planned Retirements	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal (MW)	0	0	0	0	0	0	0	0	0	0	0
Hydro (MW)	0	0	0	0	0	0	0	0	0	0	0
Natural Gas (MW)	0	0	0	0	0	0	0	0	0	0	0
Oil (MW)	0	0	0	0	0	0	0	0	0	0	0
Other (MW)	0	0	0	0	0	0	0	0	0	0	0
Solar (MW)	0	0	0	0	0	0	0	0	0	0	0
PS (MW)	0	0	0	0	0	0	0	0	0	0	0
Uranium (MW)	-817	-881	0	-1814	1698	-2856	848	0	-33	817	-817
Wind (MW)	0	0	0	0	0	0	0	0	0	0	0
Biomass (MW)	0	0	0	0	0	0	0	0	0	0	0
LFG (MW)	0	0	0	0	0	0	0	0	0	0	0
Total Capacity (MW) (Incremental Increase "+", Incremental Decrease "-")	-817	-881	0	-1814	1698	-2856	848	0	-33	817	-817

Table 38 shows results for the net energy imports and exports for each of the internal and external interties for the capacity optimization base case.

Table 38. Net Energy Imports and Exports by Year for Base Case (Output)

Net: Imports/Exports	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ISO-NE (GWh)	10894	5474	26410	28589	15370	22905	52116	-25776	47371	-20558	388
ISO-NE Extra Region (GWh)	-12495	-29435	-43980	-44160	-5600	-40722	-44711	8488	-37439	-3014	-25974
NYISO (GWh)	-66375	-50932	-59977	-39679	-54729	-36437	-62408	-43594	-85436	-41385	-49301
NYISO Extra Region (GWh)	7006	12438	12592	5216	3230	4569	4882	7595	15483	11917	15589
AE (GWh)	-7908	-8250	-7741	-6555	-6587	-6509	-6528	-6532	-6521	-6356	-6246
AP (GWh)	22542	22902	22100	26125	25922	25242	26338	21950	22943	22810	21699

BGE (GWh)	-8444	-8464	-8109	-3170	-3641	-3456	-3411	-4845	-5434	-4849	-5316
DLCO (GWh)	4681	4146	5888	5073	5888	4167	4143	6166	4853	4298	6275
DP&L (GWh)	-10832	-11431	-10878	-9838	-9588	-9867	-10084	-11716	-12110	-11753	-12013
JCP&L (GWh)	-9854	-9393	-9685	-11529	-11251	-11687	-10844	-15568	-14957	-15014	-14501
METED (GWh)	-2485	-2097	-1939	3352	3676	3121	3380	1097	653	1015	725
PECO (GWh)	23874	25281	23336	17386	16571	17155	17838	22341	23279	22354	22957
PENELEC (GWh)	15945	17650	18275	16643	15246	16541	16475	15122	16476	16190	16998
PEPCO (GWh)	-15702	-15823	-15679	-15727	-15645	-14265	-14538	-12442	-12576	-12714	-12141
PJM (GWh)	116900	132911	115720	91696	93191	100960	115840	116078	93388	129291	117895
PPL (GWh)	-87829	-104143	-87250	-79753	-84474	-87946	-104529	-91537	-65744	-104161	-90889
PSE&G (GWh)	18327	17245	18988	15227	12683	15439	14993	15854	17369	14553	14644
RECO (GWh)	-1745	-1738	-1735	-1735	-1739	-1737	-1735	-1732	-1734	-1726	-1721
HQ (GWh)	4086	4081	4081	3945	4086	4081	4081	4081	4084	4081	4081
Total Net Interchange (GWh) (+ Net Export, - Net Import)	-585	-423	-419	-1107	-2611	-1555	-1298	-5030	-3948	-4979	-3149

Fuel prices by year for each generator category are shown in Table 39 for the capacity optimization base case.

Table 39. Fuel Price by Year for Base Case (Input)

Fuel Prices (IESO)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal ($/MMBTU)	2.24	2.24	2.23	2.24	2.26	2.28	2.28	2.29	2.29	2.30	2.31
Hydro ($/MMBTU)	0	0	0	0	0	0	0	0	0	0	0
Natural Gas ($/MMBTU)	4.16	4.10	4.14	4.25	4.35	4.48	4.51	4.56	4.56	4.63	4.62
Oil ($/MMBTU)	13.86	14.70	14.85	14.89	14.96	15.04	15.30	15.47	15.54	15.81	16.00
Solar ($/MMBTU)	0	0	0	0	0	0	0	0	0	0	0
PS ($/MMBTU)	0	0	0	0	0	0	0	0	0	0	0
Uranium ($/MMBTU)	0.65	0.65	0.65	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.67
Wind ($/MMBTU)	0	0	0	0	0	0	0	0	0	0	0
Biomass ($/MMBTU)	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.32
LFG ($/MMBTU)	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50

Energy generation by fuel type results for the capacity optimization base case are presented in Table 40 below.

Table 40. Energy by Fuel Type by Year for Base Case (Output)

Energy By Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal (GWh)	0	0	0	0	0	0	0	0	0	0	0
Hydro (GWh)	35216	35189	35189	35189	35216	35189	35189	35189	35216	35189	35189
Natural Gas (GWh)	3554	2785	2763	6096	3328	4301	4929	13340	18065	14335	17886
Oil (GWh)	0	0	0	0	0	0	0	0	0	0	0
Other (GWh)	0	0	0	0	0	0	0	0	0	0	0
Solar (GWh)	6932	6915	6915	6915	6932	6915	6915	6915	6932	6915	6915

PS (GWh)	179	178	178	178	179	178	178	178	179	178	178
Uranium (GWh)	87117	82769	79407	66728	75879	57902	64395	64345	66731	67364	66315
Wind (GWh)	15248	15218	15218	15218	15248	15218	15218	15218	15248	15218	15218
Biomass (GWh)	571	0	0	0	0	297	0	629	792	756	1298
LFG (GWh)	42	42	42	128	129	130	130	263	264	263	263
Total Energy (GWh) (Output)	148860	143096	139712	130452	136910	120130	126953	136077	143426	140219	143263
Energy Check (Gen+Interchange-Load) (Zone)	0	0	0	0	0	0	0	0	0	0	0

Energy prices by zone for the capacity optimization base case are presented in Table 41.

Table 41. Zonal Energy Price by Year for Base Case (Output)

Zonal Price ($/MWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ONBRUCE ($/MWh)	27.5	27.7	28.9	38.0	38.6	39.3	39.9	46.5	47.3	47.2	47.7
ONEAST ($/MWh)	27.3	27.6	28.6	39.2	38.6	40.0	40.2	46.9	47.3	47.1	47.7
ONESSA ($/MWh)	25.9	25.1	20.9	58.1	32.6	43.2	48.4	48.9	47.6	47.4	48.0
ONNE ($/MWh)	28.1	28.1	29.4	38.5	38.9	39.6	40.2	46.6	47.5	47.3	47.9
ONNI ($/MWh)	28.1	28.6	30.1	38.8	39.6	40.1	41.0	46.4	47.5	47.3	47.7
ONNW ($/MWh)	28.5	27.8	29.0	38.4	38.7	39.7	40.0	46.9	47.9	47.6	48.3
ONOT ($/MWh)	27.9	28.2	29.2	39.6	39.0	40.7	41.0	46.8	48.5	47.9	48.7
ONSW ($/MWh)	27.5	27.7	29.0	38.2	38.8	39.4	40.0	46.5	47.4	47.2	47.7
ONTO ($/MWh)	27.4	27.6	28.8	38.1	38.7	39.3	40.0	46.5	47.3	47.2	47.7
ONWEST ($/MWh)	28.2	28.4	29.8	38.8	39.2	40.0	40.7	46.9	47.8	47.5	48.2

CO2 emissions by year for the capacity optimization base case are shown in Table 42 below.

Table 42. CO2 Emissions by Year for Base Case (Output)

CO2 Emissions	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
IESO CO2 (ton)	1762452	1080584	1071603	2437204	1345518	1899967	1940180	5677822	7688487	6148471	7950324

Additional metrics for the capacity optimization base case are presented in Table 43 and include generation cost, fixed operation and maintenance cost, total cost, total fuel cost, variable operation and maintenance cost, and cost to load.

Table 43. Metrics by Year for Base Case (Output)

Metrics	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Emissions Cost ($000)	36307	29824	36863	83840	46286	65359	66742	195317	264484	211507	273491
Total Generation Cost ($000)	1253259	1150647	1116409	1120910	1108174	944259	1040589	1477073	1752266	1577559	1773786

Generation Cost ($000)	1216952	1120823	1079546	1037071	1061888	878900	973846	1281756	1487782	1366051	1500295
FOM Cost ($000)	1657933	1601836	1556506	1389829	1510716	1274451	1352061	1350636	1385082	1388369	1381185
Total Fuel Cost ($000)	678118	614401	593307	609799	594065	514035	569403	839320	1007390	899928	1020130
Cost to Load ($000)	4127163	3993063	4067523	5047842	5418727	4810077	5146864	6576539	6996385	6863490	7001535
VOM Cost ($000)	538834	506423	486239	427272	467823	364865	404443	442436	480392	466124	480165

2.11.6 Production Cost Results

Production cost analysis was performed on the base case without energy storage for the years 2020-2030. Results for production cost without energy storage are presented in [21] and in the tables as follows. The production cost has the capacity builds and retirements as obtained in base case capacity optimization.

Table 44 shows the Demand of IESO with its peak load and maximum energy value derived by adding zonal values from the results of the production cost base case.

Table 44. IESO Demand by Year for Base Case (Input)

Demand (MW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
IESO Peak (MW) (Zone)	23922	24211	23937	23745	23920	23875	24067	24311	23879	24059	24275
IESO Energy (GWh) (Zone)	141901	142263	142109	141865	141965	142094	142125	142618	143076	144236	145094

Table 45 shows the Zonal demand of IESO from the results of the production cost base case.

Table 45. Zonal Demand by Year for Base Case (Output)

Zonal Demand	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ONBRUCE (GWh)	521	523	521	520	521	521	524	525	525	528	532
ONEAST (GWh)	9764	9760	9752	9746	9747	9776	9778	9803	9828	9907	9979
ONESSA (GWh)	8350	8362	8357	8359	8337	8376	8370	8399	8413	8492	8547
ONNE (GWh)	11613	11606	11572	11545	11582	11624	11627	11658	11648	11762	11863
ONNI (GWh)	4254	4256	4253	4254	4251	4260	4259	4275	4290	4324	4351
ONNW (GWh)	4347	4341	4329	4318	4335	4353	4348	4361	4355	4402	4442
ONOT (GWh)	7878	8242	8164	7965	8100	7898	7981	8003	8025	8112	8062
ONSW (GWh)	28591	28583	28581	28581	28564	28626	28604	28710	28830	29049	29236
ONTO (GWh)	52632	52632	52632	52630	52592	52694	52668	52866	53098	53483	53816
ONWEST (GWh)	13951	13957	13946	13947	13937	13966	13966	14019	14065	14177	14266

Table 46 shows the Zonal Generation from the results of the production cost base case.

Table 46. Zonal Generation by Year for Base Case (Output)

Zonal Generation	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ONBRUCE (GWh)	47038	47056	47057	41587	47303	41294	41615	41565	43747	44585	43620

ONEAST (GWh)	7484	8070	8544	10210	9161	10798	10308	10258	10125	10058	10404
ONESSA (GWh)	2556	2565	2565	2568	2557	2568	2569	2569	2563	2568	2570
ONNE (GWh)	9868	9998	10105	10997	10610	11681	11318	11431	11407	11378	11716
ONNI (GWh)	13540	13557	13558	13637	13543	13651	13636	13619	13605	13621	13680
ONNW (GWh)	4928	4874	4852	4952	4950	5362	5282	5296	5295	5281	5393
ONOT (GWh)	102	130	163	339	255	420	340	361	357	345	398
ONSW (GWh)	5075	5109	5143	5330	5178	5431	5350	5328	5323	5308	5405
ONTO (GWh)	46404	42477	39290	33305	35816	25306	31003	30940	30984	30896	31255
ONWEST (GWh)	7515	7526	7856	10966	9679	12245	11325	11519	11644	11372	12699
Total Generation (GWh)	144510	141363	139133	133891	139052	128757	132746	132885	135051	135411	137139

Table 47 shows the fuel consumption in GTBU from the results of the production cost base case.

Table 47. Fuel Consumption by Year for Base Case (Output)

Fuel Consumption	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal (GBTU)	0	0	0	0	0	0	0	0	0	0	0
Hydro (GBTU)	32616	33196	33539	34655	33776	35005	34750	34694	34528	34556	34749
Natural Gas (GBTU)	19965	21840	26783	66111	47654	83122	69260	70416	71495	68150	83841
Oil (GBTU)	0	0	0	0	0	0	0	0	0	0	0
Solar (GBTU)	6706	6778	6811	6894	6828	6909	6898	6893	6896	6888	6899
PS (GBTU)	178	178	178	178	178	178	178	178	178	178	178
Uranium (GBTU)	868539	827690	794073	667282	756813	579024	643948	643447	665322	673643	663153
Wind (GBTU)	14839	14993	15046	15197	15048	15213	15195	15195	15155	15187	15202
Biomass (GBTU)	2277	579	68	977	1810	8157	6989	7221	7347	7080	8919
LFG (GBTU)	573	586	628	1239	1036	1522	1353	1560	1574	1576	1789

Table 48 shows the annual average electricity price from the results of the production cost base case.

Table 48. Average Annual Electricity Price by Year for Base Case (Output)

Average Annual Electricity Price	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
IESO ($/MWh)	20.48	22.80	25.59	35.71	31.40	40.24	37.82	39.92	39.64	39.18	42.03

Table 49 shows the Fuel Prices used for generation in IESO by Fuel type from the results of the production cost base case.

Table 49. Fuel Prices by Year for Base Case (Input)

Fuel Prices	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal ($/MMBTU)	2.24	2.24	2.23	2.24	2.26	2.28	2.28	2.29	2.29	2.30	2.31
Natural Gas ($/MMBTU)	4.16	4.10	4.14	4.25	4.35	4.48	4.51	4.56	4.56	4.63	4.62
Oil ($/MMBTU)	13.86	14.70	14.85	14.89	14.96	15.04	15.30	15.47	15.54	15.81	16.00

Uranium ($/MMBTU)	0.65	0.65	0.65	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.67
Biomass ($/MMBTU)	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.32
LFG ($/MMBTU)	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50

Table 50 shows the generation in IESO by Fuel type from the results of the production cost base case.

Table 50. Generation by Fuel Type by Year for Base Case (Output)

Generation by Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal (GWh)	0	0	0	0	0	0	0	0	0	0	0
Hydro (GWh)	32616	33196	33539	34655	33776	35005	34750	34694	34528	34556	34749
Natural Gas (GWh)	3032	3332	4082	10018	7255	12582	10497	10703	10870	10371	12725
Oil (GWh)	0	0	0	0	0	0	0	0	0	0	0
Solar (GWh)	6706	6778	6811	6894	6828	6909	6898	6893	6896	6888	6899
Pump Storage (GWh)	178	178	178	178	178	178	178	178	178	178	178
Uranium (GWh)	86854	82769	79407	66728	75681	57902	64395	64345	66532	67364	66315
Wind (GWh)	14839	14993	15046	15197	15048	15213	15195	15195	15155	15187	15202
Biomass (GWh)	228	58	7	98	181	815	698	722	734	708	891
LFG (GWh)	57	59	63	124	104	152	135	156	157	158	179
Total Energy Generation (GWh)	144510	141363	139133	133891	139052	128757	132746	132885	135051	135411	137139

Table 51 shows the net import and exports from each connected external region from the results of the production cost base case.

Table 51. Net Imports and Exports by Year for Base Case (Output)

Net: Imports (-) / Exports (+)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ISO-NE (GWh)	-45212	-44852	-43774	-24774	-25006	-24467	-25905	-42960	-44691	-44080	-43552
ISO-NE Extra Region (GWh)	13968	13968	13966	13966	13966	13966	13968	13971	13978	13978	13971
NYISO (GWh)	-25259	-23294	-24077	-31992	-34189	-28453	-29185	-21337	-20600	-20554	-23407
NYISO Extra Region (GWh)	18109	18111	18111	18114	18107	18114	18108	18112	18108	18114	18114
AE (GWh)	-9305	-9103	-9020	-7080	-6796	-7076	-6884	-6583	-6417	-6575	-6420
AP (GWh)	13024	14186	14310	17316	17288	17866	17762	17484	18030	17548	17510
BGE (GWh)	-23121	-22927	-22019	-14726	-14489	-14402	-14140	-14287	-13938	-14217	-13588
DLCO (GWh)	4640	4282	6303	6916	7742	5874	5937	7607	6255	5725	7399
DP&L (GWh)	-13892	-13619	-13544	-12753	-12670	-12941	-12872	-12769	-12765	-12944	-12915
JCP&L (GWh)	-5577	-5874	-5942	-12395	-12543	-12445	-12457	-12253	-12367	-12400	-12216
METED (GWh)	-2518	-3222	-3634	-5674	-5887	-5609	-6843	-5891	-6744	-6045	-5785
PECO (GWh)	2168	1559	502	-10207	-9554	-10768	-10474	-6470	-5638	-6675	-7063

PENELEC (GWh)	6250	7210	8953	15868	15664	16706	16539	17070	17130	17162	17464
PEPCO (GWh)	-24159	-25357	-25574	-26126	-25656	-25765	-25565	-25555	-25126	-25375	-24781
PJM (GWh)	105455	104387	102945	99745	95153	101270	100130	100962	98641	102314	100663
PPL (GWh)	5507	7120	6094	1719	1650	929	595	1003	2360	1341	539
PSE&G (GWh)	-28902	-28909	-28275	-27862	-27583	-27854	-27593	-27137	-26964	-27217	-26868
RECO (GWh)	-1486	-1482	-1483	-1451	-1452	-1453	-1451	-1451	-1451	-1447	-1445
HQ (GWh)	-3010	-3273	-3448	-3790	-3637	-4001	-3915	-3927	-3922	-3892	-3981
Total Net Interchange (GWh)	13321	11089	9605	5185	9892	509	4244	4410	6119	5236	6361

Table 52 shows generation cost by fuel type results for the production cost base case.

Table 52. Generation Cost by Year for Base Case (Output)

Generation Cost	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal ($000)	0	0	0	0	0	0	0	0	0	0	0
Hydro ($000)	0	0	0	0	0	0	0	0	0	0	0
Natural Gas ($000)	83000	89475	110775	281171	207512	372182	312564	320918	326272	315247	387549
Oil ($000)	0	0	0	0	0	0	0	0	0	0	0
Solar ($000)	0	0	0	0	0	0	0	0	0	0	0
Pump Storage ($000)	0	0	0	0	0	0	0	0	0	0	0
Uranium ($000)	566287	540481	519324	437737	497226	381577	425006	425962	441108	447299	441660
Wind ($000)	0	0	0	0	0	0	0	0	0	0	0
Biomass ($000)	5282	1343	158	2268	4199	18924	16213	16753	17044	16425	20692
Landfill Gas ($000)	859	880	942	1858	1553	2284	2029	2340	2361	2364	2684

Table 53 shows Energy Price for each Ontario zone from the results of production cost base case.

Table 53. Zonal Price by Year for Base Case (Output)

Zonal Price	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ONBRUCE ($/MWh)	19.2	21.5	24.3	34.3	30.1	38.8	36.4	38.5	38.3	37.8	40.7
ONEAST ($/MWh)	17.5	20.0	23.1	34.0	29.0	38.9	36.0	37.8	37.3	36.8	39.8
ONESSA ($/MWh)	19.4	21.6	24.4	34.4	30.2	38.9	36.6	38.7	38.5	38.0	40.8
ONNE ($/MWh)	19.2	21.5	24.3	34.3	30.0	38.9	36.4	38.5	38.3	37.8	40.7
ONNI ($/MWh)	20.3	22.0	24.3	34.0	30.4	37.6	35.8	38.7	38.6	38.1	40.9
ONNW ($/MWh)	19.2	21.5	24.3	34.3	30.0	38.9	36.4	38.5	38.3	37.8	40.7
ONOT ($/MWh)	17.0	19.7	22.8	33.8	28.7	38.7	35.7	37.5	36.9	36.4	39.5
ONSW ($/MWh)	19.7	21.9	24.6	34.4	30.3	38.8	36.5	38.7	38.5	38.1	40.9
ONTO ($/MWh)	23.0	25.3	28.1	38.2	33.9	42.8	40.4	42.4	42.2	41.7	44.5
ONWEST ($/MWh)	19.6	21.8	24.5	34.4	30.2	38.7	36.4	38.6	38.5	38.0	40.8

Cost to Load results for the production cost base case are shown in Table 54 below.

Table 54. Cost to Load by Year for Base Case (Output)

Cost to Load	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ONBRUCE ($000)	11257	12615	14086	19085	17213	21242	20471	21378	21117	21108	22543
ONEAST ($000)	187700	214647	246477	348121	302316	392315	367849	384895	380935	379170	409603
ONESSA ($000)	178873	199601	224938	305269	273625	340141	323341	338970	339327	338514	363433
ONNE ($000)	236398	263328	296022	407619	362873	461607	436700	459315	454584	454813	490521
ONNI ($000)	91580	99588	108910	150956	136624	166030	159601	171382	171478	170763	183308
ONNW ($000)	87915	97820	109851	151745	134912	172306	162252	171070	169241	169322	183506
ONOT ($000)	149102	172795	198820	282165	244458	318696	297828	311908	308094	307704	331355
ONSW ($000)	598456	665587	743742	1021151	908789	1144860	1084582	1147512	1146791	1141946	1227283
ONTO ($000)	1263200	1391114	1538765	2059457	1845531	2296531	2181157	2288447	2285679	2276932	2430143
ONWEST ($000)	289787	324051	361313	498066	442026	557264	528872	559627	558823	555964	597884

CO2 emission in each zone with the total IESO results are presented in Table 55- for the production cost base case.

Table 55. CO2 Emissions by Year for Base Case (Output)

Emissions (CO2)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ONBRUCE (ton)	0	0	0	0	0	0	0	0	0	0	0
ONEAST (ton)	92612	122478	155358	332948	241111	417350	332776	341604	333207	317000	370245
ONESSA (ton)	0	417	0	418	0	70	1246	826	729	278	1113
ONNE (ton)	206087	194569	223251	543429	441939	888175	736852	778779	777164	758893	907465
ONNI (ton)	21801	12184	12006	43436	33829	47483	43485	33667	41859	35077	58544
ONNW (ton)	85078	25719	9153	54679	76252	317351	270493	278168	281504	269476	339560
ONOT (ton)	38043	48735	61479	128205	96127	158888	128104	135540	133961	129364	149251
ONSW (ton)	20645	25659	38266	112223	57124	153212	120362	111305	113262	103066	142508
ONTO (ton)	154275	196942	260611	750739	471516	973003	777335	755417	774600	739068	922215
ONWEST (ton)	741753	734654	862141	2072321	1573483	2570209	2211139	2282246	2333872	2223365	2742772
Total CO2 Emissions (ton)	1360294	1361358	1622265	4038398	2991382	5525740	4621791	4717550	4790159	4575589	5633673

Table 56 shows the fixed operation and maintenance cost results from the production cost base case.

Table 56. FOM Cost by Year for Base Case (Output)

FOM	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Biomass ($000)	64581	64581	64581	64581	64581	64581	64581	64581	64581	64581	64581
Solar ($000)	64900	64900	64900	64900	64900	64900	64900	64900	64900	64900	64900
Natural Gas ($000)	190216	190216	190216	190216	190216	190216	190216	190216	190216	190216	190216
Uranium ($000)	1135355	1083788	1038458	871781	988981	756404	842084	840658	871745	878705	871521
Wind ($000)	226183	226183	226183	226183	226183	226183	226183	226183	226183	226183	226183

Variable operation and maintenance results for the product cost base case are presented in Table 57 below.

Table 57. VOM Cost by Year for Base Case (Output)

VOM	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Biomass ($000)	911	231	27	390	724	3260	2792	2886	2935	2831	3563
Landfill Gas ($000)	286	293	314	619	518	761	676	780	787	788	895
Natural Gas ($000)	11515	13694	17085	43284	30443	54772	45103	45085	45758	43677	54263
Uranium ($000)	521123	496614	476444	400369	454088	347414	386369	386068	399193	404186	397892

The capacity factors of each generation by fuel type from the production cost base case are shown in Table 58.

Table 58. Capacity Factor by Year for Base Case (Output)

Capacity Factor	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Biomass (%)	2.9	3.0	0.1	1.2	2.3	10.4	8.9	9.2	9.4	9.1	11.4
Hydro (%)	49.7	48.1	48.4	49.4	48.5	49.8	49.4	49.4	49.3	49.3	49.8
Landfill Gas (%)	31.2	21.0	22.5	44.5	37.2	79.6	48.6	56.0	56.5	56.6	82.7
Natural Gas (%)	2.4	3.2	4.0	9.9	7.1	12.5	10.1	10.3	10.4	10.0	12.1
Oil (%)	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9
Pump Storage (%)	26.8	26.3	26.8	26.8	26.8	26.8	26.8	26.8	26.8	26.8	26.8
Solar (%)	82.4	84.3	86.5	76.6	83.4	79.6	80.3	80.3	83.4	84.5	83.1
Uranium (%)	30.0	29.8	30.1	30.1	30.1	30.1	30.1	30.1	30.1	30.1	30.1
Wind (%)	2.9	3.0	0.1	1.2	2.3	10.4	8.9	9.2	9.4	9.1	11.4

Final cost metrics with total cost to load, total fuel cost and total generation cost results for the product cost base case are presented in Table 59 below.

Table 59. Metrics by Year for Base Case (Output)

Metrics	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Cost to Load ($000)	3094268	3441147	3842924	5243634	4668366	5870991	5562653	5854504	5836070	5816237	6239581
Total Fuel Cost ($000)	655428	632179	631198	723034	710491	774966	755812	765973	786785	781335	852585
Total Generation Cost ($000)	1217286	1180584	1180873	1306618	1299168	1371259	1349743	1363076	1400240	1390217	1502996

2.11.7 Base Case with Storage Results

In the base case, natural gas generators in IESO are enabled to economically expand and retire.

2.11.7.1 Capacity Optimization Results

The capacity optimization phase for the base + storage case determines the MW size and location of energy storage. An annual optimization is performed over each year of the study horizon 2020-2030 including 2018, 2019, 2031 and 2032 to have end effect.

In the base case with energy storage, the natural gas generator in IESO is enabled to economically build and retire. Energy storage is also enabled to economically build and retire with a maximum allowable expansion capacity of 3000 MW per year. The MS- and S-duration energy storage types participate in ancillary services. The base case has deferral value of 35$/MW-yr.

The base + storage case capacity optimization study results are summarized in [20] and in the tables as follows.

Table 60 presents the energy storage built by duration bucket for the capacity optimization of base with storage case, indicating that the majority of the ES builds will occur in 2025 and 2030.

Table 60. Energy Storage Built Bucket for Base Case with Storage

Demand (MW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Long (6+ hours)	0	0	0	0	0	0	0	0	0	0	0
Medium Long (4 hours)	0	0	0	0	0	834	0	0	0	0	1057
Medium Short (2 hours)	112	0	0	0	0	263	0	0	0	0	125
Short (30 mins)	38	0	0	0	0	87	0	0	0	0	120
Total	150	0	0	0	0	1184	0	0	0	0	1302

Demand metrics for the base case with energy storage capacity optimization are provided in Table 61. It indicates the IESO peak with coincidental value as well as the sum of zonal peaks with total energy demand and demand response model values.

Table 61. Demand by Year for Base Case with Storage (Input)

Demand (MW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
IESO Peak (MW) (Regional) (Coincidental value)	23922	24211	23937	23745	23920	23875	24067	24311	23879	24059	24275
IESO Peak (MW) (Zonal Peak total)	27086	27929	27728	27065	27282	27167	27789	28044	27541	27499	27872
IESO Energy (GWh) (Zone)	148514	143428	140322	132635	139187	121720	129070	141652	147721	144685	146990
Demand Response (MW)	847	847	847	847	847	847	847	847	847	847	847

Capacity planning requirements with an average planning margin of 28% are shown in Table 62.

Table 62. Planning Capacity by Year for Base Case with Storage (Output)

Capacity Requirement	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capacity Reserve (MW)	8089	6940	7206	5552	7131	5253	5597	5348	5253	5293	5341
Capacity Reserve Margin (%)	34	29	30	23	30	22	23	22	22	22	22

Base + Storage case capacity optimization results for the installed capacity are shown in Table 63.

Table 63. Installed Capacity by Year for Base Case with Storage (Input)

Capacity	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal (MW)	0	0	0	0	0	0	0	0	0	0	0

Hydro (MW)	8905	8905	8905	8905	8905	8905	8905	8905	8905	8905	8905
Natural Gas (MW)	8724	8724	8724	8724	8724	8724	8377	8377	7892	7282	7282
Oil (MW)	0	0	0	0	0	0	0	0	0	0	0
Demand Response (MW)	847	847	847	847	847	847	847	847	847	847	847
Solar (MW)	2950	2950	2950	2950	2950	2950	2950	2950	2950	2950	2950
PS (MW)	146	146	146	146	146	146	146	146	146	146	146
Uranium (MW)	11322	10441	10441	8627	10325	7469	8317	8317	8284	9101	8284
Wind (MW)	5697	5697	5697	5697	5697	5697	5697	5697	5697	5697	5697
Biomass (MW)	587	587	587	587	587	587	587	587	587	587	587
LFG (MW)	32	32	32	32	32	32	32	32	32	32	32
Installed Capacity (MW)	39211	38330	38330	36516	38214	35358	35858	35858	35340	35548	34731
Total Firm Capacity (MW)	31721	30840	30840	29026	30724	28845	29345	29345	28827	29035	29291

Economic build results, by years, for the capacity optimization base case are presented in Table 64. It shows the Energy Storage builds in the years 2020, 2025 and 2030.

Table 64. Economic Builds by Year for Base Case with Storage (Output)

Economic Builds (Incremental)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal (MW)	0	0	0	0	0	0	0	0	0	0	0
Hydro (MW)	0	0	0	0	0	0	0	0	0	0	0
Natural Gas (MW)	0	0	0	0	0	0	0	0	0	0	0
Oil (MW)	0	0	0	0	0	0	0	0	0	0	0
Other (MW)	0	0	0	0	0	0	0	0	0	0	0
Solar (MW)	0	0	0	0	0	0	0	0	0	0	0
PS (MW)	0	0	0	0	0	0	0	0	0	0	0
Uranium (MW)	0	0	0	0	0	0	0	0	0	0	0
Wind (MW)	0	0	0	0	0	0	0	0	0	0	0
Biomass (MW)	0	0	0	0	0	0	0	0	0	0	0
LFG (MW)	0	0	0	0	0	0	0	0	0	0	0
CC Expansions (MW)	0	0	0	0	0	0	0	0	0	0	0
ES Expansions (MW)	150	0	0	0	0	1184	0	0	0	0	1302
Total Capacity (MW)	150	0	0	0	0	1184	0	0	0	0	1302

Economic build cost results for the capacity optimization base case are shown in Table 65. It shows the cost of Energy Storage expansion in the years 2020, 2025 and 2030.

Table 65. Economic Build Cost by Year for Base Case with Storage (Output)

Economic Build Cost (Incremental)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal ($000)	0	0	0	0	0	0	0	0	0	0	0
Hydro ($000)	0	0	0	0	0	0	0	0	0	0	0

Natural Gas ($000)	0	0	0	0	0	0	0	0	0	0	0
Oil ($000)	0	0	0	0	0	0	0	0	0	0	0
Other ($000)	0	0	0	0	0	0	0	0	0	0	0
Solar ($000)	0	0	0	0	0	0	0	0	0	0	0
PS ($000)	0	0	0	0	0	0	0	0	0	0	0
Uranium ($000)	0	0	0	0	0	0	0	0	0	0	0
Wind ($000)	0	0	0	0	0	0	0	0	0	0	0
Biomass ($000)	0	0	0	0	0	0	0	0	0	0	0
LFG ($000)	0	0	0	0	0	0	0	0	0	0	0
CC Expansions ($000)	0	0	0	0	0	0	0	0	0	0	0
ES Expansions ($000)	94624	0	0	0	0	834747	0	0	0	0	798626
Total Build Cost ($000)	94624	0	0	0	0	834747	0	0	0	0	798626

Table 66 presents the economic retirement results for the capacity optimization base case. This shows the natural gas generators retiring in the years 2020, 2026, 2028 and 2029.

Table 66. Economic Retirements by Year for Base Case with Storage (Output)

Economic Retirements (Incremental)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal (MW)	0	0	0	0	0	0	0	0	0	0	0
Hydro (MW)	0	0	0	0	0	0	0	0	0	0	0
Natural Gas (MW)	2237	0	0	0	0	0	348	0	485	610	0
Oil (MW)	0	0	0	0	0	0	0	0	0	0	0
Other (MW)	0	0	0	0	0	0	0	0	0	0	0
Solar (MW)	0	0	0	0	0	0	0	0	0	0	0
PS (MW)	0	0	0	0	0	0	0	0	0	0	0
Uranium (MW)	0	0	0	0	0	0	0	0	0	0	0
Wind (MW)	0	0	0	0	0	0	0	0	0	0	0
Biomass (MW)	0	0	0	0	0	0	0	0	0	0	0
LFG (MW)	0	0	0	0	0	0	0	0	0	0	0
CC Expansions (MW)	0	0	0	0	0	0	0	0	0	0	0
ES Expansions (MW)	0	0	0	0	0	0	0	0	0	0	150
Total Capacity (MW)	2237	0	0	0	0	0	348	0	485	610	150

Table 67 presents results for the net planned builds and retirements by year for the capacity optimization base case. It indicates the planned maintenance/retirements of nuclear plants.

Table 67. Net Planned Builds/Planned Retirements by Year for Base Case Storage (Output)

Net: Planned Builds/Planned Retirements	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal (MW)	0	0	0	0	0	0	0	0	0	0	0
Hydro (MW)	0	0	0	0	0	0	0	0	0	0	0

Natural Gas (MW)	0	0	0	0	0	0	0	0	0	0	0
Oil (MW)	0	0	0	0	0	0	0	0	0	0	0
Other (MW)	0	0	0	0	0	0	0	0	0	0	0
Solar (MW)	0	0	0	0	0	0	0	0	0	0	0
PS (MW)	0	0	0	0	0	0	0	0	0	0	0
Uranium (MW)	-817	-881	0	-1814	1698	-2856	848	0	-33	817	-817
Wind (MW)	0	0	0	0	0	0	0	0	0	0	0
Biomass (MW)	0	0	0	0	0	0	0	0	0	0	0
LFG (MW)	0	0	0	0	0	0	0	0	0	0	0
Total Capacity (MW) (Incremental Increase "+", Incremental Decrease "-")	-817	-881	0	-1814	1698	-2856	848	0	-33	817	-817

Table 68 shows results for the net energy imports and exports for each of the internal and external interties for the capacity optimization base case.

Table 68. Net Energy Imports and Exports by Year for Base Case with Storage (Output)

Net: Imports/Exports	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ISO-NE (GWh)	-22082	-286	15116	26803	40501	14242	41983	3305	9875	-886	4474
ISO-NE Extra Region (GWh)	-18490	-25020	-34067	-54744	-41207	-29797	-36546	1439	-25099	-36894	-7578
NYISO (GWh)	-32804	-48234	-57906	-23309	-45495	-29983	-52553	-69358	-59087	-35085	-65942
NYISO Extra Region (GWh)	8793	10994	12727	4043	1970	-2095	1466	10755	17242	16265	12154
AE (GWh)	-7909	-8227	-7749	-6590	-6584	-6492	-6496	-6529	-6515	-6382	-6257
AP (GWh)	22795	22915	21878	25931	26111	25046	25921	21946	22889	23009	21527
BGE (GWh)	-8470	-8482	-8085	-3174	-3694	-3493	-3522	-4908	-5445	-4815	-5345
DLCO (GWh)	4682	4146	5888	5073	5888	4167	4052	6156	4853	4298	6275
DP&L (GWh)	-10937	-11364	-10895	-9775	-9605	-9767	-9883	-11704	-12109	-11934	-11953
JCP&L (GWh)	-9241	-9339	-8969	-12267	-10775	-12092	-11582	-15582	-14921	-14633	-14843
METED (GWh)	-2170	-2062	-2083	2944	3706	2918	3000	1043	647	1256	592
PECO (GWh)	24154	25133	23249	17155	16422	16843	17131	22215	23256	22923	22799
PENELEC (GWh)	16438	17706	18762	16294	15497	16137	15616	15131	16374	16512	16672
PEPCO (GWh)	-15708	-15823	-15719	-15685	-15698	-14260	-14446	-12442	-12576	-12718	-12123
PJM (GWh)	109588	94780	110232	76304	71824	66234	63632	99294	91017	94206	92739
PPL (GWh)	-80068	-66093	-81784	-64362	-62320	-53453	-52395	-74324	-63262	-68898	-65688
PSE&G (GWh)	18727	17161	17587	15310	13222	14933	14164	16557	14996	15823	13921
RECO (GWh)	-1745	-1738	-1735	-1735	-1739	-1737	-1735	-1732	-1734	-1726	-1721
HQ (GWh)	4086	4081	4081	3945	4086	4081	4081	4081	4084	4081	4081
Total Net Interchange (GWh) (+ Net Export, - Net Import)	-362	247	527	2162	2109	1433	1888	5343	4484	4401	3785

Fuel prices by year for each generator category are shown in Table 69 for the capacity optimization base case.

Table 69. Fuel Price by Year for Base Case with Storage (Input)

Fuel Prices (IESO)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal ($/MMBTU)	2.24	2.24	2.23	2.24	2.26	2.28	2.28	2.29	2.29	2.30	2.31
Hydro ($/MMBTU)	0	0	0	0	0	0	0	0	0	0	0
Natural Gas ($/MMBTU)	4.16	4.10	4.14	4.25	4.35	4.48	4.51	4.56	4.56	4.63	4.62
Oil ($/MMBTU)	13.86	14.70	14.85	14.89	14.96	15.04	15.30	15.47	15.54	15.81	16.00
Solar ($/MMBTU)	0	0	0	0	0	0	0	0	0	0	0
PS ($/MMBTU)	0	0	0	0	0	0	0	0	0	0	0
Uranium ($/MMBTU)	0.65	0.65	0.65	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.67
Wind ($/MMBTU)	0	0	0	0	0	0	0	0	0	0	0
Biomass ($/MMBTU)	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.32
LFG ($/MMBTU)	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50

Energy generation by fuel type results for the capacity optimization base case are presented in Table 70 below.

Table 70. Energy by Fuel Type by Year for Base Case with Storage (Output)

Energy By Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal (GWh)	0	0	0	0	0	0	0	0	0	0	0
Hydro (GWh)	35216	35189	35189	35189	35216	35189	35189	35189	35216	35189	35189
Natural Gas (GWh)	3554	2785	2763	5964	3328	4266	4926	13340	17760	14275	17637
Oil (GWh)	0	0	0	0	0	0	0	0	0	0	0
Other (GWh)	16	86	83	152	168	192	232	232	116	126	192
Solar (GWh)	6932	6915	6915	6915	6932	6915	6915	6915	6932	6915	6915
PS (GWh)	179	178	178	178	179	178	178	178	179	178	178
Uranium (GWh)	87117	82769	79407	66728	75879	57902	64395	64345	66731	67364	66315
Wind (GWh)	15248	15218	15218	15218	15248	15218	15218	15218	15248	15218	15218
Biomass (GWh)	571	0	0	0	0	297	0	629	792	756	1298
LFG (GWh)	42	42	42	128	129	130	130	263	264	263	263
Total Energy (GWh) (Output)	148876	143182	139795	130473	137078	120287	127182	136309	143237	140284	143205
Energy Check (Gen+Interchange-Load) (Zone)	0	0	0	0	0	0	0	0	0	0	0

Energy prices by zone for the capacity optimization base case are presented in Table 71.

Table 71. Zonal Energy Price by Year for Base Case with Storage (Output)

Zonal Price ($/MWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ONBRUCE ($/MWh)	27.5	27.7	28.9	38.0	38.5	39.3	39.9	46.5	47.3	47.2	47.7
ONEAST ($/MWh)	27.2	27.7	28.6	39.0	39.5	40.9	41.5	47.1	47.3	47.3	48.0
ONESSA ($/MWh)	25.9	25.7	20.4	56.3	21.6	43.6	52.1	50.1	47.8	48.0	48.3
ONNE ($/MWh)	28.2	28.1	29.4	38.5	38.9	39.7	40.1	46.6	47.5	47.3	48.0

ONNI ($/MWh)	28.5	28.6	29.8	39.2	38.8	40.1	40.3	46.3	47.4	47.2	47.7
ONNW ($/MWh)	28.6	27.9	29.1	38.5	38.7	39.9	40.1	46.9	47.9	47.6	48.4
ONOT ($/MWh)	28.0	28.3	29.3	39.9	38.1	40.4	40.6	46.6	48.3	47.7	48.6
ONSW ($/MWh)	27.5	27.7	29.0	38.2	38.7	39.5	40.0	46.5	47.4	47.2	47.8
ONTO ($/MWh)	27.4	27.6	28.8	38.2	38.7	39.4	39.9	46.5	47.3	47.1	47.7
ONWEST ($/MWh)	28.3	28.4	29.8	38.9	39.2	40.1	40.6	46.9	47.8	47.5	48.2

CO2 emissions by year for the capacity optimization base case are shown in Table 72 below.

Table 72. CO2 Emissions by Year for Base Case with Storage (Output)

CO2 Emissions	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
IESO CO2 (ton)	1762452	1080584	1071603	2386351	1345518	1885521	1938865	5677822	7561236	6123980	7847036

Additional metrics for the capacity optimization base case are presented in Table 73 and include generation cost, fixed operation and maintenance cost, total cost, total fuel cost, variable operation and maintenance cost, and cost to load.

Table 73. Metrics by Year for Base Case with Storage (Output)

Metrics	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Emissions Cost ($000)	36307	29824	36863	82090	46286	64862	66697	195317	260107	210665	269938
Total Generation Cost ($000)	1253259	1150647	1116409	1114786	1108174	942665	1040443	1477073	1736305	1574467	1760720
Generation Cost ($000)	1216952	1120823	1079546	1032696	1061888	877803	973746	1281756	1476198	1363802	1490782
FOM Cost ($000)	1630387	1574366	1529035	1362359	1483170	1174843	1252715	1251289	1277898	1271653	1181343
Total Fuel Cost ($000)	678118	614401	593307	606133	594065	512939	569303	839320	997547	898008	1012038
Cost to Load ($000)	4103097	3990983	4069866	5088820	5387832	4808638	5165453	6593718	7002202	6826564	7026782
VOM Cost ($000)	538834	506423	486239	426563	467823	364865	404443	442436	478651	465794	478744

2.11.8 Production Cost Results

Production cost analysis was performed on the base case without energy storage for the years 2020-2030. Results for production cost with energy storage are presented in [22] and the tables that follow. The deferral value in this case is D=35$/MW-yr. The production cost has the capacity builds and retirements as obtained in base + storage case capacity optimization.

Table 74 shows the Demand of IESO with its peak load and maximum energy value derived by adding zonal values from the results of the production cost base case.

Table 74. IESO Demand by Year for Base Case with Storage (Input)

Demand (MW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030

IESO Peak (MW) (Zone)	23921	24211	23937	23745	23920	23875	24067	24311	23879	24059	24275
IESO Energy (GWh) (Zone)	142756	142648	142487	142215	142345	144920	145074	145467	145922	147068	149277

Table 75 shows the Zonal demand of IESO from the results of the production cost base case.

Table 75. Zonal Demand by Year for Base Case with Storage (Output)

Zonal Demand	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ONBRUCE (GWh)	553	554	552	548	552	766	788	780	779	784	1093
ONEAST (GWh)	9806	9801	9792	9783	9788	9963	9983	10005	10030	10108	10206
ONESSA (GWh)	8390	8402	8395	8395	8376	8699	8715	8733	8745	8824	8818
ONNE (GWh)	11653	11646	11612	11581	11622	11874	11898	11919	11910	12024	12431
ONNI (GWh)	4287	4288	4285	4284	4283	4595	4598	4598	4612	4649	4964
ONNW (GWh)	4404	4398	4385	4369	4390	4668	4692	4693	4686	4733	5006
ONOT (GWh)	8369	8268	8191	7990	8122	8170	8195	8218	8239	8315	8305
ONSW (GWh)	28625	28617	28614	28612	28597	28801	28790	28887	29007	29225	29455
ONTO (GWh)	52687	52687	52686	52679	52646	52930	52926	53116	53348	53732	54346
ONWEST (GWh)	13983	13988	13977	13975	13968	14454	14490	14519	14564	14675	14652

Table 76 shows the Zonal Generation from the results of the production cost base case.

Table 76. Zonal Generation by Year for Base Case with Storage (Output)

Zonal Generation	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ONBRUCE (GWh)	47065	47082	47082	41612	47327	41505	41842	41784	43966	44804	44099
ONEAST (GWh)	7579	8165	8632	10269	9261	11033	10617	10607	10573	10520	10876
ONESSA (GWh)	2591	2600	2599	2599	2591	2845	2865	2855	2848	2852	2800
ONNE (GWh)	9916	10029	10134	10998	10625	11655	11337	11458	11427	11387	11861
ONNI (GWh)	13576	13584	13584	13663	13578	13929	13920	13881	13859	13881	14185
ONNW (GWh)	4981	4922	4903	4994	4994	5555	5516	5518	5518	5505	5755
ONOT (GWh)	138	166	196	363	286	609	538	565	564	548	545
ONSW (GWh)	5101	5135	5164	5346	5194	5494	5430	5382	5393	5379	5443
ONTO (GWh)	46447	42518	39316	33296	35829	25110	30821	30739	30809	30727	31075
ONWEST (GWh)	7503	7485	7819	10900	9590	11962	11112	11302	11428	11066	12022
Total Generation (GWh)	144897	141685	139429	134039	139274	129697	133996	134092	136385	136670	138661

Table 77 shows the fuel consumption in GTBU from the results of the production cost base case.

Table 77. Fuel Generation by Year for Base Case with Storage (Output)

Fuel Consumption	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal (GBTU)	0	0	0	0	0	0	0	0	0	0	0
Hydro (GBTU)	32698	33257	33603	34694	33864	35147	34979	34926	34862	34890	35125
Natural Gas (GBTU)	19413	21050	25918	64729	46220	73051	59302	60587	61887	58036	68479

Oil (GBTU)	0	0	0	0	0	0	0	0	0	0	0
Solar (GBTU)	6724	6794	6821	6897	6841	6915	6909	6905	6914	6905	6915
PS (GBTU)	178	178	178	178	178	178	178	178	178	178	178
Uranium (GBTU)	868539	827690	794073	667282	756813	579024	643948	643447	665322	673643	663153
Wind (GBTU)	14859	15012	15058	15199	15051	15218	15213	15210	15172	15211	15218
Biomass (GBTU)	2210	538	63	964	1710	6921	6014	6315	6373	6167	7015
LFG (GBTU)	563	572	613	1227	1025	1559	1312	1599	1610	1600	1949

Table 78 shows the annual average electricity price from the results of the production cost base case.

Table 78. Average Annual Electricity Price by Year for Base Case with Storage (Output)

Average Annual Electricity Price	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
IESO ($/MWh)	20.5	22.9	25.7	35.8	31.6	41.3	38.7	41.4	41.5	40.8	44.5

Table 79 shows the Fuel Prices used for generation in IESO by Fuel type from the results of the production cost base case.

Table 79. Fuel Prices by Year for Base Case with Storage (Output)

Fuel Prices	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal ($/MMBTU)	2.24	2.24	2.23	2.24	2.26	2.28	2.28	2.29	2.29	2.30	2.31
Natural Gas ($/MMBTU)	4.16	4.10	4.14	4.25	4.35	4.48	4.51	4.56	4.56	4.63	4.62
Oil ($/MMBTU)	13.86	14.70	14.85	14.89	14.96	15.04	15.30	15.47	15.54	15.81	16.00
Uranium ($/MMBTU)	0.65	0.65	0.65	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.67
Biomass ($/MMBTU)	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.32
LFG ($/MMBTU)	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50

Table 80 shows the generation in IESO by Fuel type from the results of the production cost base case.

Table 80. Generation by Fuel Type by Year for Base Case with Storage (Output)

Generation by Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal (GWh)	0	0	0	0	0	0	0	0	0	0	0
Hydro (GWh)	32698	33257	33603	34694	33864	35147	34979	34926	34862	34890	35125
Natural Gas (GWh)	2949	3212	3951	9809	7038	11087	9015	9250	9442	8863	10449
Oil (GWh)	0	0	0	0	0	0	0	0	0	0	0
Solar (GWh)	6724	6794	6821	6897	6841	6915	6909	6905	6914	6905	6915
Pump Storage (GWh)	178	178	178	178	178	178	178	178	178	178	178
Uranium (GWh)	86854	82769	79407	66728	75681	57902	64395	64345	66532	67364	66315
Wind (GWh)	14859	15012	15058	15199	15051	15218	15213	15210	15172	15211	15218
Biomass (GWh)	221	54	6	96	171	692	601	631	637	617	701
LFG (GWh)	56	57	61	123	103	156	131	160	161	160	195

Total Energy Generation (GWh)	144540	141333	139087	133724	138927	127294	131421	131605	133899	134187	135096

Table 81 shows the net imports and exports from each connected external region from the results of the production cost base case.

Table 81. Net Imports and Exports by Year for Base Case with Storage (Output)

Net: Imports (-) / Exports (+)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ISO-NE (GWh)	-45178	-44807	-43765	-24729	-24976	-24118	-25375	-42905	-44688	-44081	-43544
ISO-NE Extra Region (GWh)	13968	13968	13966	13966	13966	13966	13968	13971	13978	13978	13971
NYISO (GWh)	-25340	-23314	-24060	-31978	-34137	-27546	-28516	-20426	-19695	-19575	-21945
NYISO Extra Region (GWh)	18109	18110	18112	18114	18107	18114	18108	18112	18107	18114	18114
AE (GWh)	-9302	-9102	-9023	-7078	-6786	-7062	-6869	-6575	-6416	-6563	-6404
AP (GWh)	12986	14190	14312	17366	17273	17909	17787	17528	18005	17529	17581
BGE (GWh)	-23112	-22934	-22011	-14703	-14487	-14249	-14010	-14163	-13787	-14071	-13330
DLCO (GWh)	4628	4282	6303	6912	7741	5890	5941	7612	6264	5730	7402
DP&L (GWh)	-13903	-13627	-13543	-12744	-12673	-12917	-12887	-12753	-12763	-12952	-12913
JCP&L (GWh)	-5580	-5889	-5940	-12375	-12543	-12385	-12401	-12225	-12377	-12362	-12192
METED (GWh)	-2512	-3227	-3628	-5673	-5906	-5606	-6869	-5900	-6750	-6091	-5797
PECO (GWh)	2165	1532	461	-10239	-9554	-10761	-10472	-6410	-5500	-6614	-6903
PENELEC (GWh)	6250	7207	8978	15905	15669	16926	16692	17191	17225	17264	17684
PEPCO (GWh)	-24151	-25340	-25581	-26099	-25660	-25740	-25542	-25501	-25085	-25358	-24585
PJM (GWh)	105464	104399	102944	99713	95152	101263	100109	100941	98615	102431	100597
PPL (GWh)	5505	7126	6112	1725	1658	909	615	982	2359	1324	506
PSE&G (GWh)	-28880	-28901	-28268	-27850	-27541	-27783	-27512	-27067	-26928	-27189	-26757
RECO (GWh)	-1486	-1482	-1483	-1451	-1452	-1453	-1450	-1451	-1451	-1447	-1445
HQ (GWh)	-4045	-3322	-3486	-3810	-3674	-4036	-4018	-4033	-4024	-4010	-3054
Total Net Interchange (GWh)	14415	11131	9600	5029	9823	-1321	2700	3071	4909	3942	3015

Table 82 shows generation cost by fuel type results for the production cost base case.

Table 82. Generation Cost by Year for Base Case with Storage (Output)

Generation Cost	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal ($000)	0	0	0	0	0	0	0	0	0	0	0
Hydro ($000)	0	0	0	0	0	0	0	0	0	0	0
Natural Gas ($000)	80704	86238	107200	275295	201268	327088	267621	276120	282428	268464	316542
Oil ($000)	0	0	0	0	0	0	0	0	0	0	0
Solar ($000)	0	0	0	0	0	0	0	0	0	0	0
Pump Storage ($000)	0	0	0	0	0	0	0	0	0	0	0

Uranium ($000)	566287	540481	519324	437737	497226	381577	425006	425962	441108	447299	441660
Wind ($000)	0	0	0	0	0	0	0	0	0	0	0
Biomass ($000)	5127	1248	146	2237	3967	16056	13952	14650	14786	14309	16275
Landfill Gas ($000)	845	858	919	1841	1538	2338	1968	2399	2415	2401	2924

Table 83 shows Energy Price for each Ontario zone from the results of production cost base case.

Table 83. Zonal Price by Year for Base Case with Storage (Output)

Zonal Price	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ONBRUCE ($/MWh)	19.3	21.6	24.4	34.4	30.2	39.9	37.3	40.0	40.1	39.5	43.2
ONEAST ($/MWh)	17.5	20.1	23.2	34.1	29.2	40.2	37.1	39.6	39.6	38.8	42.9
ONESSA ($/MWh)	19.4	21.7	24.5	34.5	30.4	40.0	37.4	40.1	40.2	39.6	43.3
ONNE ($/MWh)	19.2	21.5	24.3	34.4	30.2	39.9	37.4	40.0	40.1	39.5	43.2
ONNI ($/MWh)	20.4	22.1	24.4	34.1	30.6	38.6	36.7	39.9	40.1	39.5	42.9
ONNW ($/MWh)	19.2	21.5	24.3	34.4	30.2	39.9	37.4	40.0	40.1	39.5	43.2
ONOT ($/MWh)	17.1	19.7	22.9	33.9	28.9	40.1	36.9	39.4	39.3	38.5	42.7
ONSW ($/MWh)	19.7	22.0	24.7	34.5	30.5	39.8	37.4	40.1	40.2	39.6	43.2
ONTO ($/MWh)	23.1	25.4	28.2	38.3	34.1	43.9	41.3	43.9	44.0	43.3	47.0
ONWEST ($/MWh)	19.6	21.8	24.5	34.4	30.4	39.8	37.3	40.0	40.2	39.5	43.2

Cost to Load results for the production cost base case are shown in Table 84 below.

Table 84. Cost to Load by Year for Base Case with Storage

Cost to Load	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ONBRUCE ($000)	11286	12647	14124	19106	17272	21673	20863	22002	21904	21812	23633
ONEAST ($000)	188167	215074	247073	348849	303774	402573	375993	399301	399958	396193	435492
ONESSA ($000)	179035	199772	225199	305670	274696	346518	327955	347813	350786	348917	378847
ONNE ($000)	236960	263887	296736	408505	364677	472541	445546	473863	473608	471836	516779
ONNI ($000)	91766	99841	109217	151232	137145	169119	162402	175600	176619	175513	190356
ONNW ($000)	88123	98009	110104	152093	135581	176428	165658	176697	176662	175883	193467
ONOT ($000)	149457	173155	199399	282723	245625	326821	304124	323245	323434	321024	351710
ONSW ($000)	599116	666413	744815	1023078	912632	1168157	1103171	1179348	1187611	1178940	1283127
ONTO ($000)	1264284	1392404	1540816	2062756	1852278	2338257	2213131	2346776	2361855	2345237	2534051
ONWEST ($000)	290128	324494	361892	499035	443873	569133	538351	575592	579273	574769	626141

CO_2 emission results are presented in Table 85 for the production cost base case.

Table 85. CO_2 Emissions by Year for Base Case with Storage

Emissions (CO_2)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ONBRUCE (ton)	0	0	0	0	0	0	0	0	0	0	0
ONEAST (ton)	89637	119231	151616	327633	235872	387775	290029	308099	299618	287988	317621
ONESSA (ton)	0	417	0	366	0	0	417	763	454	139	0

ONNE (ton)	200476	186871	216465	531378	427551	779796	641247	691980	684361	664227	753372
ONNI (ton)	21384	11772	10801	42867	32758	43020	37980	27992	32639	27151	51135
ONNW (ton)	82837	24043	8803	53327	72337	269386	231494	240379	243335	232315	265264
ONOT (ton)	36519	47692	59874	124736	93960	149360	115207	125783	124470	119577	131744
ONSW (ton)	19209	24298	35837	107962	53935	118144	88291	71323	79824	70610	80673
ONTO (ton)	145669	188393	248390	729140	452611	811638	612107	586781	616413	582655	667464
ONWEST (ton)	727088	708511	838257	2037908	1530634	2294236	1951659	2027936	2081111	1936396	2345914
Total CO2 Emissions (ton)	1322820	1311229	1570043	3955318	2899658	4853355	3968430	4081037	4162226	3921057	4613186

Table 86 shows the fixed operation and maintenance cost results from the production cost base case.

Table 86. FOM Cost by Year for Base Case with Storage

FOM	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Biomass ($000)	64581	64581	64581	64581	64581	64581	64581	64581	64581	64581	64581
Solar ($000)	0	0	0	0	0	0	0	0	0	0	0
Natural Gas ($000)	64900	64900	64900	64900	64900	64900	64900	64900	64900	64900	64900
Uranium ($000)	190216	190216	190216	190216	190216	190216	190216	190216	190216	190216	190216
Wind ($000)	1135355	1083788	1038458	871781	988981	756404	842084	840658	871745	878705	871521

Variable operation and maintenance results for the product cost base case are presented in Table 87 below.

Table 87. VOM Cost by Year for Base Case with Storage

VOM	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Biomass ($000)	884	214	25	385	684	2768	2404	2524	2547	2465	2805
Landfill Gas ($000)	282	286	306	614	513	779	656	800	805	800	975
Natural Gas ($000)	11155	13192	16496	42334	29482	47676	38101	38087	38947	36535	43201
Uranium ($000)	521123	496614	476444	400369	454088	347414	386369	386068	399193	404186	397892

Capacity factors of each generation by fuel type by year for the production cost base case are shown in Table 88.

Table 88. Capacity Factor by Year for Base Case with Storage (Output)

Capacity Factor	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Biomass (%)	2.9	0.7	0.1	1.2	2.2	10.4	7.7	8.0	8.1	7.9	11.4
Hydro (%)	49.7	48.2	48.5	49.4	48.6	49.8	49.6	49.6	49.5	49.6	49.8
Landfill Gas (%)	31.2	20.5	22.0	44.1	36.8	79.6	47.1	57.4	57.8	57.5	82.7
Natural Gas (%)	2.4	3.1	3.9	9.7	6.9	12.5	8.6	8.8	8.9	8.4	12.1
Oil (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pump Storage (%)	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9
Solar (%)	26.8	26.4	26.5	26.7	26.5	26.8	26.8	26.8	26.8	26.8	26.8
Uranium (%)	82.4	84.3	86.5	76.6	83.4	79.6	80.3	80.3	83.4	84.5	83.1

Wind (%)	30.0	29.8	29.9	30.1	29.8	30.1	30.1	30.1	30.1	30.1	30.1

Final metrics with total cost to load, total fuel cost and total generation cost results for the product cost base case are presented in Table 89 below.

Table 89. Metrics by Year for Base Case with Storage (Output)

Metrics	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Cost to Load ($000)	3098323	3445696	3849375	5253046	4687552	5991221	5657193	6020237	6051711	6010123	6533603
Total Fuel Cost ($000)	652964	628826	627589	717110	708547	727059	708547	719131	740737	732472	777400
Total Generation Cost ($000)	1213657	1175322	1174870	1296874	1288514	1292652	1272592	1286997	1325411	1311343	1380967

2.11.9 Sensitivity Case Summary

Sensitivity results include fuel price fluctuations, load growth scenarios, carbon tax fluctuations, technology cost uncertainty, and variations on technology cost assumptions. The results below present the energy storage capacity built for each of the sensitivity studies applied to the base case with energy storage scenarios in terms of MW. The Power and Energy of the storage built in each sensitivity case is shown in Figure 48.

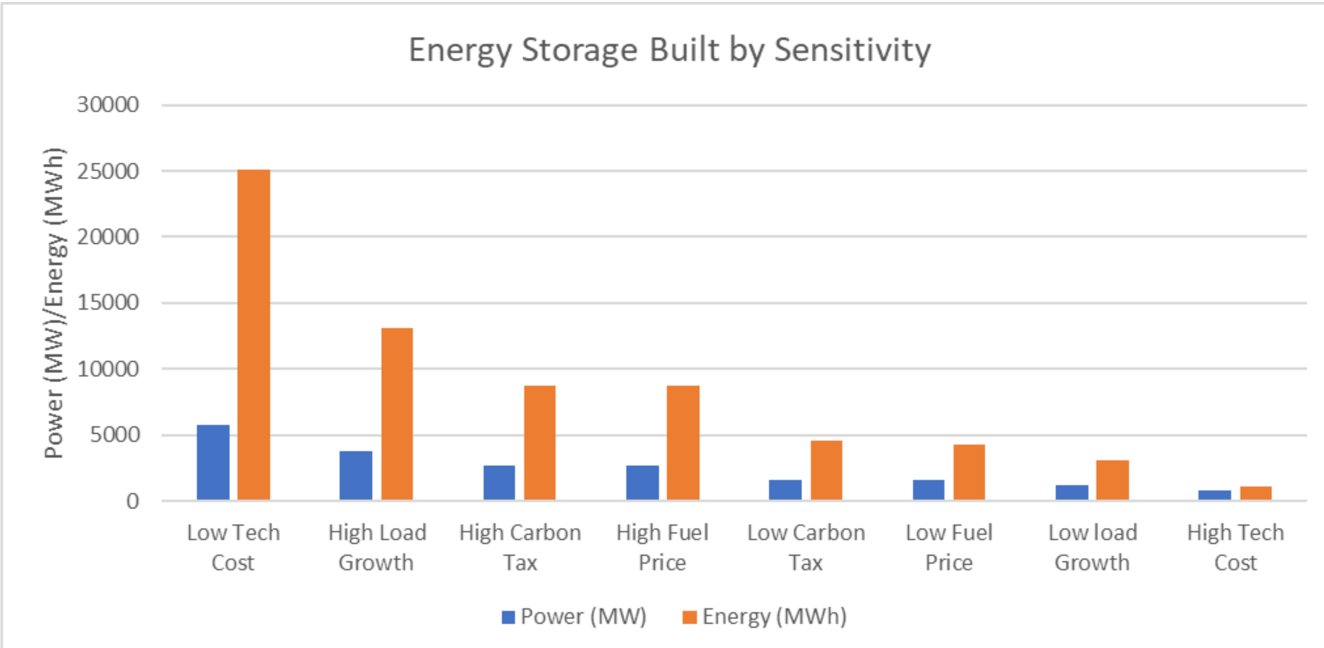

Figure 48. Energy Storage Built Power and Energy for each Sensitivity Case

A breakdown of the sensitivity results by IESO Region is shown in Table 90 below.

Table 90. Energy Storage Built in Sensitivity Cases

Region	High Load Growth	Low Load Growth	High Tech Cost	Low Tech Cost	High Fuel Price	Low Fuel Price	High Carbon Tax	Low Carbon Tax
ONBRUCE	375	128	75	575	134	165	208	142
ONEAST	375	113	75	575	375	142	165	142
ONESSA	375	113	75	575	134	165	375	347
ONNE	375	113	75	575	375	142	375	142
ONNI	375	142	75	575	176	165	176	142
ONNW	375	113	75	575	375	142	375	142
ONOT	375	113	75	568	134	165	178	142
ONSW	375	142	75	575	375	157	375	142
ONTO	370	110	75	575	322	137	165	132
ONWEST	375	136	70	575	245	165	255	123

2.11.9.1 High Load Growth Summary

Results for base case with demand and energy growth according to IESO Annual Planning Outlook 2020 Outlook D to account for EV adoption are summarized here. Table 91 shows the energy storage build by year and by bucket type under the high load growth scenario indicating an increase in amounts compared to base case.

Table 92 and Table 93 show the cost metrics along with average HOEP and emissions for high load growth scenarios without and with ES.

Table 91. Storage Built by Year by Duration Type for High Load Growth Scenario

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
ES_L (MW)	0	0	0	0	0	0	0	0	0	0	0	0
ES_ML (MW)	0	0	0	0	0	1150	0	781	0	0	1069	3000
ES_MS (MW)	112	0	0	0	0	263	0	0	0	0	125	500
ES_S (MW)	38	0	0	0	0	88	0	0	0	0	120	245
Grand Total (MW)	150	0	0	0	0	1500	0	781	0	0	1314	3745

Table 92. Sensitivity Metrics for High Load Growth Scenario without Energy Storage

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average HOEP ($/MWh)	27.7	28.1	29.5	39.3	39.8	40.6	41.4	47.5	48.1	48.1	49.1
Cost to Load ($MM)	4137	4059	4141	5262	5588	5080	5417	7143	7607	7502	8048
Emissions (kiloton)	1898	1143	1077	3283	1686	2677	2804	9204	11419	10417	14248
Emissions Cost ($MM)	39	32	37	113	58	92	96	317	393	358	490
FOM Cost ($MM)	1686	1630	1584	1418	1539	1303	1389	1395	1430	1433	1432
Generation Cost ($MM)	1229	1126	1080	1107	1089	937	1025	1386	1593	1542	1708
Total Fuel Cost ($MM)	688	619	594	671	619	564	615	930	1098	1053	1199
Total Generation Cost ($MM)	1268	1157	1117	1220	1147	1034	1127	1872	2174	2072	2515
VOM Cost ($MM)	541	507	486	437	470	373	411	456	494	489	509

Table 93. Sensitivity Metrics for High Load Growth Scenario with Energy Storage

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average HOEP ($/MWh)	27.6	27.8	29.0	38.4	38.8	39.6	40.1	46.6	47.4	47.3	47.9
Cost to Load ($MM)	4155	4057	4162	5245	5559	5042	5433	7019	7431	7369	7786

Emissions (kiloton)	1898	1126	1077	3236	1686	2581	2738	7769	9501	8711	11635
Emissions Cost ($MM)	39	31	37	111	58	89	94	267	327	300	400
FOM Cost ($MM)	1652	1596	1551	1384	1505	1172	1258	1197	1223	1222	1131
Generation Cost ($MM)	1229	1125	1080	1103	1089	935	1026	1449	1631	1579	1825
Total Fuel Cost ($MM)	688	618	594	667	619	562	615	985	1132	1085	1301
Total Generation Cost ($MM)	1268	1156	1117	1215	1147	1024	1120	1717	1958	1878	2225
VOM Cost ($MM)	541	507	486	436	470	372	411	464	499	494	524

2.11.9.2 Low Load Growth Summary

Results are summarized below for base case with demand and energy growth according to IESO Annual Planning Outlook 2020 Outlook A to account for EV adoption. Table 94 shows the energy storage build by year and by bucket type under the low load growth scenario and indicates a decrease in amount compared to base case.

Table 95 and Table 96 show the cost metrics along with average HOEP and emissions for low load growth scenarios without and with Energy Storage.

Table 94. Storage Built by Year by Duration Type for Low Load Growth Scenario

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
ES_L (MW)	0	0	0	0	0	0	0	0	0	0	0	0
ES_ML (MW)	0	0	0	0	0	0	0	0	0	0	479	479
ES_MS (MW)	112	0	0	0	0	263	0	0	0	0	125	500
ES_S (MW)	38	0	0	0	0	87	0	0	0	0	120	245
Grand Total (MW)	150	0	0	0	0	350	0	0	0	0	724	1224

Table 95. Sensitivity Metrics for Low Load Growth Scenario without Energy Storage

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average HOEP ($/MWh)	27.4	27.7	28.8	37.8	37.9	38.6	39.1	46.2	46.9	46.3	47.1
Cost to Load ($MM)	4075	3958	4013	4894	5277	4618	4928	6414	6703	6509	6718
Emissions (kiloton)	1548	1061	1054	1780	1260	1363	1376	4922	6065	4682	6604
Emissions Cost ($MM)	32	29	36	61	43	47	47	169	209	161	227
FOM Cost ($MM)	1621	1565	1520	1353	1474	1238	1313	1311	1339	1342	1335
Generation Cost ($MM)	1199	1119	1078	981	1055	841	925	1217	1349	1238	1392
Total Fuel Cost ($MM)	663	613	592	562	588	481	526	782	887	790	925
Total Generation Cost ($MM)	1231	1149	1114	1042	1098	887	972	1386	1558	1400	1619

VOM Cost ($MM)	536	506	486	418	467	360	399	434	463	448	467

Table 96. Sensitivity Metrics for Low Load Growth Scenario with Energy Storage

Energy Storage Duration “Bucket”	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average HOEP ($/MWh)	27.6	27.8	29.0	38.4	38.8	39.6	40.1	46.6	47.4	47.3	47.9
Cost to Load ($MM)	4051	3960	4013	4938	5253	4655	4951	6419	6699	6481	6725
Emissions (kiloton)	1548	1061	1054	1727	1260	1350	1348	4922	5994	4647	6481
Emissions Cost ($MM)	32	29	36	59	43	46	46	169	206	160	223
FOM Cost ($MM)	1614	1558	1513	1346	1467	1223	1298	1297	1322	1319	1274
Generation Cost ($MM)	1199	1119	1078	976	1055	839	923	1217	1343	1235	1380
Total Fuel Cost ($MM)	663	613	592	559	588	480	524	782	881	787	915
Total Generation Cost ($MM)	1231	1149	1114	1036	1098	886	969	1386	1549	1395	1603
VOM Cost ($MM)	536	506	486	418	467	359	398	434	462	448	465

2.11.9.3 High Fuel Price Summary

Results for base case with energy storage and increase in all fuel prices by 40% are summarized here. Table 97 shows the energy storage build by year and by bucket type under the high fuel price scenario and indicates a slight change in amount compared to base case.

Table 98 and Table 99 show the cost metrics along with average HOEP and emissions for high fuel price scenarios without and with Energy Storage.

Table 97. Storage Built by Year by Duration Type for High Fuel Price Scenario

Energy Storage Duration “Bucket”	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
ES_L (MW)	0	0	0	0	0	0	0	0	0	0	0	0
ES_ML (MW)	0	0	0	0	0	844	0	0	0	0	1057	1902
ES_MS (MW)	112	0	0	0	0	263	0	0	0	0	125	500
ES_S (MW)	38	0	0	0	0	87	0	0	0	0	120	245
Grand Total (MW)	150	0	0	0	0	1194	0	0	0	0	1302	2646

Table 98. Sensitivity Metrics for High Fuel Price Scenario without Energy Storage

Energy Storage Duration “Bucket”	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average HOEP ($/MWh)	27.6	27.9	29.1	38.8	38.8	40.8	41.4	47.8	48.3	48.4	48.9
Cost to Load ($MM)	4028	3937	4011	4878	5298	4818	5133	6116	6300	6351	6302

Emissions (kiloton)	25	25	24	39	28	307	75	136	339	178	539
Emissions Cost ($MM)	0.5	0.7	0.8	1.4	1.0	10.6	2.6	4.7	11.7	6.1	18.5
FOM Cost ($MM)	1658	1602	1557	1390	1511	1274	1352	1351	1385	1388	1381
Generation Cost ($MM)	1319	1254	1205	1015	1154	915	987	990	1052	1042	1072
Total Fuel Cost ($MM)	796	758	728	614	699	564	599	603	648	636	668
Total Generation Cost ($MM)	1320	1255	1205	1016	1155	926	989	995	1064	1048	1091
VOM Cost ($MM)	523	497	477	401	456	351	387	387	404	406	404

Table 99. Sensitivity Metrics for High Fuel Price Scenario with Energy Storage

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average HOEP ($/MWh)	27.6	27.8	29.0	38.4	38.8	39.6	40.1	46.6	47.4	47.3	47.9
Cost to Load ($MM)	4004	3934	4013	4925	5286	4817	5139	6124	6271	6295	6356
Emissions (kiloton)	25	25	24	39	28	280	50	108	297	162	539
Emissions Cost ($MM)	1	1	1	1	1	10	2	4	10	6	19
FOM Cost ($MM)	1630	1574	1529	1362	1483	1174	1252	1250	1277	1271	1180
Generation Cost ($MM)	1319	1254	1205	1015	1154	912	984	987	1047	1041	1073
Total Fuel Cost ($MM)	796	758	728	614	699	561	597	600	643	635	668
Total Generation Cost ($MM)	1320	1255	1205	1016	1155	922	985	991	1057	1046	1091
VOM Cost ($MM)	523	497	477	401	456	351	387	387	404	406	404

2.11.9.4 Low Fuel Price Summary

Results for base case with energy storage and decrease in all fuel prices by 40% are summarized here. Table 100 shows the energy storage build by year and by bucket type under the low fuel price scenario and indicates a decrease in amount compared to base case.

Table 101 and Table 102 show the cost metrics along with average HOEP and emissions for low fuel price scenarios without and with Energy Storage.

Table 100. Storage Built by Year by Duration Type for Low Fuel Price Scenario

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
ES_L (MW)	0	0	0	0	0	0	0	0	0	0	0	0
ES_ML (MW)	0	0	0	0	0	350	0	0	0	0	447	797
ES_MS (MW)	113	0	0	0	0	262	0	0	0	0	125	500
ES_S (MW)	38	0	0	0	0	88	0	0	0	0	120	245

Grand Total (MW)	150	0	0	0	0	700	0	0	0	0	692	1542

Table 101. Sensitivity Metrics for Low Fuel Price Scenario without Energy Storage

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average HOEP ($/MWh)	26.8	27.2	28.6	36.7	36.5	38.1	38.5	43.5	43.6	43.6	44.3
Cost to Load ($MM)	4225	4116	4235	5714	6038	5673	6023	8044	8276	8126	8388
Emissions (kiloton)	5480	4719	4702	12942	12727	13511	14160	25100	26907	25104	27477
Emissions Cost ($MM)	113	130	162	445	438	465	487	863	926	864	945
FOM Cost ($MM)	1658	1602	1557	1390	1511	1274	1352	1351	1385	1388	1381
Generation Cost ($MM)	1150	1067	1035	1360	1450	1335	1437	2062	2187	2105	2234
Total Fuel Cost ($MM)	563	513	502	807	847	826	883	1374	1463	1401	1504
Total Generation Cost ($MM)	1263	1197	1197	1806	1888	1800	1924	2925	3113	2969	3179
VOM Cost ($MM)	587	554	533	553	603	508	554	687	725	705	730

Table 102. Sensitivity Metrics for Low Fuel Price Scenario with Energy Storage

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average HOEP ($/MWh)	27.6	27.8	29.0	38.4	38.8	39.6	40.1	46.6	47.4	47.3	47.9
Cost to Load ($MM)	4203	4113	4227	5736	6013	5679	6037	8070	8270	8131	8422
Emissions (kiloton)	5479	4719	4658	12944	12699	13511	14160	25100	26929	25101	27528
Emissions Cost ($MM)	113	130	160	445	437	465	487	863	926	863	947
FOM Cost ($MM)	1642	1586	1540	1374	1494	1223	1301	1299	1323	1327	1283
Generation Cost ($MM)	1150	1067	1034	1360	1449	1335	1437	2062	2189	2106	2237
Total Fuel Cost ($MM)	563	513	501	807	846	826	883	1374	1464	1401	1506
Total Generation Cost ($MM)	1262	1197	1194	1806	1885	1800	1924	2925	3116	2969	3184
VOM Cost ($MM)	587	554	533	553	603	508	554	688	725	705	731

2.11.9.5 High Carbon Tax Summary

Results for base case with energy storage and 25% increase in Carbon Tax are summarized here. Table 103 shows the energy storage build by year and by bucket type under the high carbon tax scenario and it indicates a slight change in amount compared to base case.

Table 104 and Table 105 show the cost metrics along with average HOEP and emissions for high carbon tax scenarios without and with Energy Storage.

Table 103. Storage Built by Year by Duration Type for High Carbon Tax Scenario

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
ES_L (MW)	0	0	0	0	0	0	0	0	0	0	0	0
ES_ML (MW)	0	0	0	0	0	844	0	0	0	0	1057	1902
ES_MS (MW)	113	0	0	0	0	263	0	0	0	0	125	500
ES_S (MW)	38	0	0	0	0	88	0	0	0	0	120	245
Grand Total (MW)	150	0	0	0	0	1194	0	0	0	0	1302	2646

Table 104. Sensitivity Metrics for High Carbon Tax Scenario without Energy Storage

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average HOEP ($/MWh)	27.7	27.8	29.1	38.5	38.8	39.6	40.2	47.1	47.8	47.7	48.2
Cost to Load ($MM)	4102	3986	4072	4955	5397	4743	5066	6324	6610	6550	6559
Emissions (kiloton)	1.0	0.9	0.9	1.1	1.0	1.0	0.9	2.3	3.3	2.3	2.9
Emissions Cost ($MM)	28698	34	41	50	48	46	42	108	158	110	140
FOM Cost ($MM)	1658	1602	1557	1390	1511	1274	1352	1351	1385	1388	1381
Generation Cost ($MM)	1178	1113	1070	930	1046	819	893	1025	1162	1071	1120
Total Fuel Cost ($MM)	645	607	584	520	580	461	496	614	722	642	689
Total Generation Cost ($MM)	1206	1147	1111	980	1094	865	934	1133	1321	1182	1259
VOM Cost ($MM)	533	506	486	411	466	358	396	411	441	430	430

Table 105. Sensitivity Metrics for High Carbon Tax Scenario with Energy Storage

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average HOEP ($/MWh)	27.6	27.8	29.0	38.4	38.8	39.6	40.1	46.6	47.4	47.3	47.9
Cost to Load ($MM)	4078	3984	4075	5001	5366	4759	5072	6331	6618	6488	6589
Emissions (kiloton)	1114	974	942	1156	1123	1073	919	2503	3651	2532	3179
Emissions Cost ($MM)	29	34	41	50	48	46	40	108	157	109	137
FOM Cost ($MM)	1630	1574	1529	1362	1483	1174	1252	1250	1277	1271	1180
Generation Cost ($MM)	1178	1113	1070	930	1046	819	889	1025	1159	1069	1113
Total Fuel Cost ($MM)	645	607	584	519	580	461	493	614	719	639	684
Total Generation Cost ($MM)	1206	1147	1111	979	1094	865	929	1133	1316	1178	1250
VOM Cost ($MM)	533	506	486	411	466	358	396	411	440	429	429

2.11.9.6 Low Carbon Tax Summary

Results for base case with energy storage and 25% decrease in Carbon Tax are shown in Table 109.

Table 106 shows the energy storage build by year and by bucket type under the low carbon tax scenario and indicates a decrease in amount compared to base case.

Table 107 and Table 108 show the cost metrics along with average HOEP and emissions for low carbon tax scenarios without and with Energy Storage.

Table 106. Storage Built by Year by Duration Type for Low Carbon Tax Scenario

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
ES_L (MW)	0	0	0	0	0	0	0	0	0	0	0	0
ES_ML (MW)	0	0	0	0	0	404	0	0	0	0	447	851
ES_MS (MW)	112	0	0	0	0	263	0	0	0	0	125	500
ES_S (MW)	38	0	0	0	0	88	0	0	0	0	120	245
Grand Total (MW)	150	0	0	0	0	754	0	0	0	0	692	1596

Table 107. Sensitivity Metrics for Low Carbon Tax Scenario without Energy Storage

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average HOEP ($/MWh)	27.4	27.8	29.1	38.0	38.6	39.2	39.7	45.8	46.4	46.3	46.9
Cost to Load ($MM)	4144	4025	4173	5329	5754	5042	5354	7149	7311	7298	7460
Emissions (kiloton)	2553	1859	2621	6219	5501	4933	5039	12416	12578	12047	13891
Emissions Cost ($MM)	39	38	68	160	142	127	130	320	325	311	358
FOM Cost ($MM)	1658	1602	1557	1390	1511	1274	1352	1351	1385	1388	1381
Generation Cost ($MM)	1283	1171	1195	1338	1400	1137	1226	1856	1893	1864	2015
Total Fuel Cost ($MM)	734	657	690	869	885	736	786	1329	1353	1326	1460
Total Generation Cost ($MM)	1323	1210	1262	1498	1542	1264	1356	2176	2217	2175	2373
VOM Cost ($MM)	550	514	505	468	515	401	440	526	540	538	555

Table 108. Sensitivity Metrics for Low Carbon Tax Scenario with Energy Storage

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average HOEP ($/MWh)	27.6	27.8	29.0	38.4	38.8	39.6	40.1	46.6	47.4	47.3	47.9
Cost to Load ($MM)	4121	4021	4174	5370	5725	5046	5361	7173	7326	7284	7483
Emissions (kiloton)	2553	1828	2594	6178	5482	4927	4929	12416	12550	12027	13861
Emissions Cost ($MM)	39	38	67	159	141	127	127	320	324	310	358

FOM Cost ($MM)	1640	1584	1539	1372	1493	1218	1295	1294	1318	1322	1278
Generation Cost ($MM)	1283	1169	1192	1334	1398	1136	1220	1856	1890	1863	2012
Total Fuel Cost ($MM)	734	655	688	867	883	735	781	1329	1351	1325	1458
Total Generation Cost ($MM)	1323	1206	1259	1494	1540	1264	1347	2176	2214	2173	2370
VOM Cost ($MM)	550	514	504	468	515	401	439	526	540	538	555

2.11.9.7 High Tech Cost Summary

Results for base case with energy storage and 140% multiplier for ES build cost are summarized here.

Table 109 shows the energy storage build by year and by bucket type under the high technology cost scenario and indicates a decrease in amount compared to the base case.

Table 110 shows the cost metrics along with average HOEP and emissions for high technology cost scenario with Energy Storage.

Table 109. Storage Built by Year by Duration Type for High Tech Cost Scenario

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
ES_L (MW)	0	0	0	0	0	0	0	0	0	0	0	0
ES_ML (MW)	0	0	0	0	0	0	0	0	0	0	0	0
ES_MS (MW)	112	0	0	0	0	262	0	0	0	0	125	500
ES_S (MW)	38	0	0	0	0	88	0	0	0	0	120	245
Grand Total (MW)	150	0	0	0	0	350	0	0	0	0	245	745

Table 110. Sensitivity Metrics for High Tech Cost Scenario with Energy Storage

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average HOEP ($/MWh)	27.6	27.8	29.0	38.4	38.8	39.6	40.1	46.6	47.4	47.3	47.9
Cost to Load ($MM)	4103	3991	4070	5088	5388	4806	5168	6604	7018	6826	7029
Emissions (kiloton)	1762	1081	1072	2386	1346	1886	1940	5678	7688	6131	7923
Emissions Cost ($MM)	36	30	37	82	46	65	67	195	264	211	273
FOM Cost ($MM)	1650	1594	1548	1382	1503	1258	1336	1334	1368	1372	1362
Generation Cost ($MM)	1217	1121	1080	1033	1062	878	974	1282	1488	1364	1498
Total Fuel Cost ($MM)	678	614	593	606	594	513	569	839	1007	899	1018
Total Generation Cost ($MM)	1253	1151	1116	1115	1108	943	1041	1477	1752	1575	1770
VOM Cost ($MM)	539	506	486	427	468	365	404	442	480	466	480

2.11.9.8 Low Tech Cost Summary

Results for base case with energy storage and 60% multiplier for ES build cost are summarized here.

Table 111 shows the energy storage build by year and by bucket type under the low technology cost scenario and indicates an increase in amount compared to base case.

Table 112 shows the cost metrics along with average HOEP and emissions for low technology cost scenario with Energy Storage.

Table 111. Storage Built by Year by Duration for Low Tech Cost Scenario

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
ES_L (MW)	0	0	0	0	0	0	0	302	0	619	1072	1993
ES_ML (MW)	2	8	200	200	0	1237	1352	0	0	0	0	3000
ES_MS (MW)	112	0	0	0	0	262	0	0	0	0	125	500
ES_S (MW)	38	0	0	0	88	0	0	0	0	125	0	250
Grand Total (MW)	152	8	200	200	88	1500	1352	302	0	744	1197	5743

Table 112. Sensitivity Metrics for Low Tech Cost Scenario with Energy Storage

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average HOEP ($/MWh)	27.6	27.8	29.0	38.4	38.8	39.6	40.1	46.6	47.4	47.3	47.9
Cost to Load ($MM)	4103	3990	4071	5081	5388	4804	5165	6594	6934	6824	6900
Emissions (kiloton)	1762	1081	1072	2356	1344	1872	1939	5582	6855	5915	6661
Emissions Cost ($MM)	36	30	37	81	46	64	67	192	236	203	229
FOM Cost ($MM)	1620	1563	1503	1321	1434	1097	1047	1020	1047	978	883
Generation Cost ($MM)	1217	1121	1080	1030	1062	877	974	1273	1412	1345	1381
Total Fuel Cost ($MM)	678	614	593	604	594	512	569	832	943	882	919
Total Generation Cost ($MM)	1253	1151	1116	1111	1108	941	1040	1465	1648	1548	1611
VOM Cost ($MM)	539	506	486	426	468	365	404	441	469	463	462

2.11.10 Energy Storage Deferral Value

The energy storage Deferral Value represents a $/kW-yr value offset by installing generation-like systems in distribution systems. The deferral value is not universal across GX, TX, and DX, therefore a range of $35/kW-yr to $55/kW-yr was used. D-Value is derived from Marginal Cost. The deferral value has 3 components including peaking plant deferral, transmission deferral, and distribution deferral. Sensitivity analysis was performed using five deferral values ranging from 35$/kW-yr to 55$/kW-yr to explore storage expansion scenarios in areas of the system where storage has the highest value. Table 113 below presents results for each deferral value sensitivity in the 10 IESO regions. As the deferral values increase, the amount of energy storage installations increase.

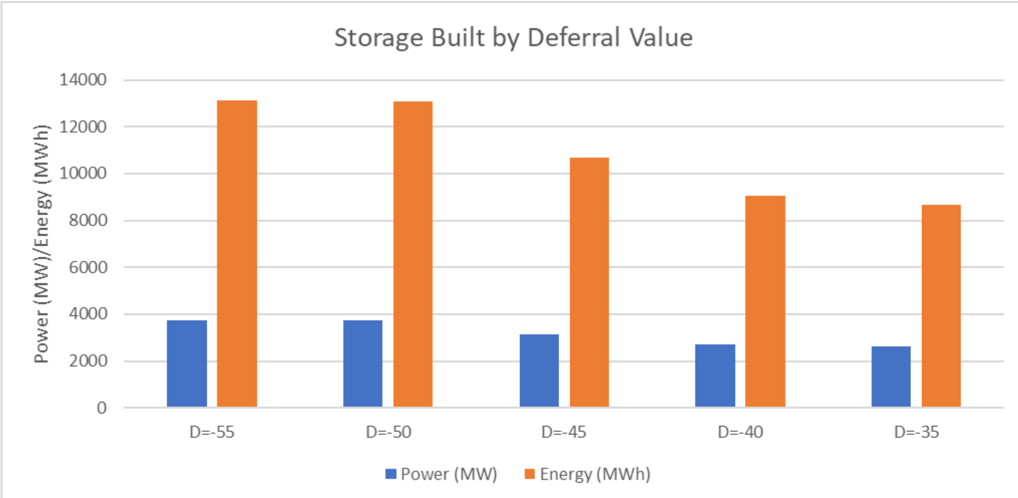

Table 113. Capacity Built by Region by Deferral Value

Zone	35 ($/kW-yr)	40 ($/kW-yr)	45 ($/kW-yr)	50 ($/kW-yr)	55 ($/kW-yr)
ONBRUCE ES Exp	375	165	165	375	375
ONEAST ES Exp	134	375	165	375	375
ONESSA ES Exp	165	375	375	375	375
ONNE ES Exp	375	134	375	375	375
ONNI ES Exp	375	375	375	375	375
ONNW ES Exp	375	375	375	375	375
ONOT ES Exp	132	132	375	375	375
ONSW ES Exp	134	165	375	375	375
ONTO ES Exp	324	375	370	370	370
ONWEST ES Exp	248	257	190	368	375

The total capacity built for each of the deferral value sensitivities in terms of MW and MWh is presented in Table 114. An additional 1109 MW of energy storage capacity was built in the highest case as compared to the lowest case.

Table 114. Energy Storage Power and Capacity Built by Deferral Value Sensitivity

D-Value	35	40	45	50	55
Capacity Built (MWh)	8688	9053	10698	13093	13122
Power Built (MW)	2636	2727	3139	3737	3745

The data from Table 114 is plotted and shown in Figure 49 below.

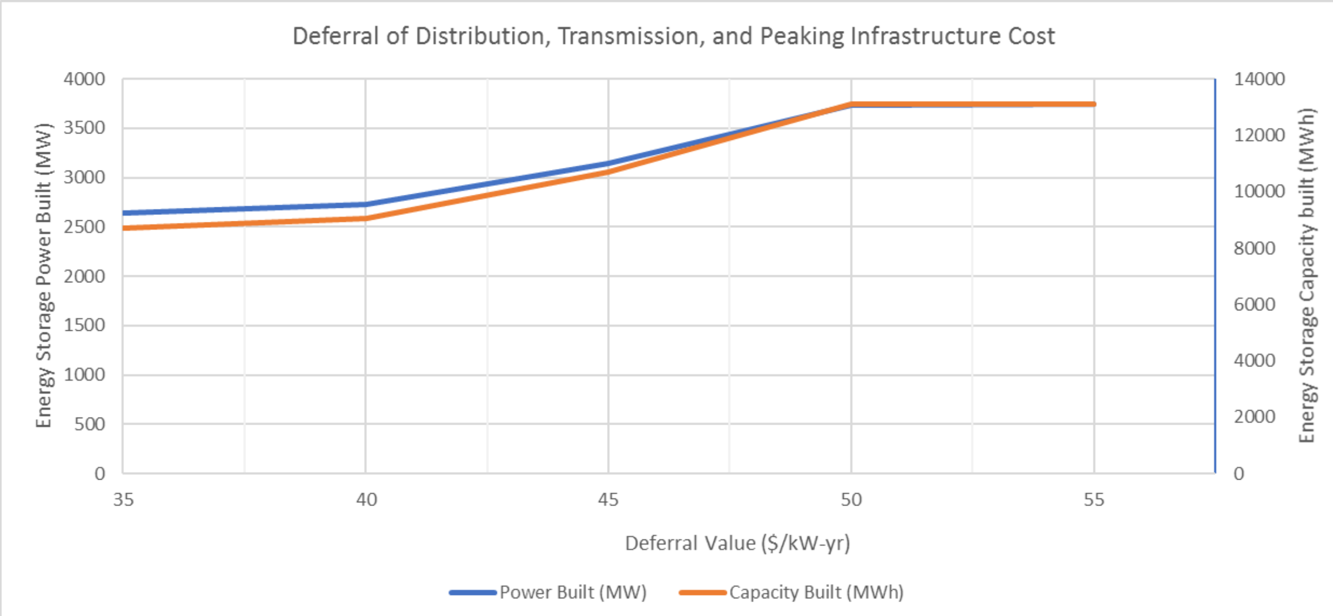

Figure 49. Deferral of Distribution, Transmission, and Peaking Infrastructure Cost

2.11.10.1 Scenario D=35 $/kW-yr Summary

Results for D=35$/kW-yr are summarized here. Table 115 shows the energy storage build by year and by bucket type under this scenario and is used as the base for base + storage case.

Table 116 shows the cost metrics along with average HOEP and emissions.

Table 115. Storage Built by Year by Duration Type for D=34 $/kW-yr Scenario

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
ES_L (MW)	0	0	0	0	0	0	0	0	0	0	0	0
ES_ML (MW)	0	0	0	0	0	834	0	0	0	0	1057	1892
ES_MS (MW)	112	0	0	0	0	263	0	0	0	0	125	500
ES_S (MW)	38	0	0	0	0	87	0	0	0	0	120	245
Grand Total (MW)	150	0	0	0	0	1184	0	0	0	0	1302	2636

Table 116. Sensitivity Metrics for D=35 $/kW-yr Scenario with Energy Storage

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average HOEP ($/MWh)	27.6	27.8	29.0	38.4	38.8	39.6	40.1	46.6	47.4	47.3	47.9
Cost to Load ($MM)	1630	1574	1529	1362	1483	1175	1253	1251	1278	1272	1181
Emissions (kiloton)	1762	1081	1072	2386	1346	1886	1939	5678	7561	6124	7847
Emissions Cost ($MM)	36	30	37	82	46	65	67	195	260	211	270
FOM Cost ($MM)	4103	3991	4070	5089	5388	4809	5165	6594	7002	6827	7027

Generation Cost ($MM)	1217	1121	1080	1033	1062	878	974	1282	1476	1364	1491
Total Fuel Cost ($MM)	678	614	593	606	594	513	569	839	998	898	1012
Total Generation Cost ($MM)	1253	1151	1116	1115	1108	943	1040	1477	1736	1574	1761
VOM Cost ($MM)	539	506	486	427	468	365	404	442	479	466	479

2.11.10.2 Scenario D=40 $/kW-yr Summary

Results for D=40$/kW-yr are summarized here. Table 117 shows the energy storage build by year and by bucket type under this scenario and it indicates an increase in energy storage build compared to base case.

Table 118 shows the cost metrics along with average HOEP and emissions.

Table 117. Storage Built by Year by Duration Type for D=40 $/kW-yr Scenario

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
ES_L (MW)	0	0	0	0	0	0	0	0	0	0	0	0
ES_ML (MW)	0	0	0	0	0	926	0	0	0	0	1057	1983
ES_MS (MW)	112	0	0	0	0	263	0	0	0	0	125	500
ES_S (MW)	38	0	0	0	0	88	0	0	0	0	120	245
Grand Total (MW)	150	0	0	0	0	1276	0	0	0	0	1302	2727

Table 118. Sensitivity Metrics for D=40 $/kW-yr Scenario with Energy Storage

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average HOEP ($/MWh)	27.6	27.8	29.0	38.4	38.8	39.6	40.1	46.6	47.4	47.3	47.9
Cost to Load ($MM)	4103	3991	4070	5088	5388	4809	5165	6594	6999	6827	7026
Emissions (kiloton)	1762	1081	1072	2386	1346	1886	1939	5678	7537	6121	7843
Emissions Cost ($MM)	36	30	37	82	46	65	67	195	259	211	270
FOM Cost ($MM)	1628	1572	1527	1360	1481	1161	1240	1238	1265	1259	1163
Generation Cost ($MM)	1217	1121	1080	1033	1062	878	974	1282	1474	1364	1490
Total Fuel Cost ($MM)	678	614	593	606	594	513	569	839	996	898	1012
Total Generation Cost ($MM)	1253	1151	1116	1115	1108	943	1040	1477	1733	1574	1760
VOM Cost ($MM)	539	506	486	427	468	365	404	442	478	466	479

2.11.10.3 Scenario D=45 $/kW-yr Summary

Results for D=45 $/kW-yr are summarized here. Table 119 shows the energy storage build by year and by bucket type under this scenario and indicates an increase in energy storage build compared to base case.

Table 120 shows the cost metrics along with average HOEP and emissions.

Table 119. Storage Built by Year by Duration Type for D=45 $/kW-yr Scenario

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
ES_L (MW)	0	0	0	0	0	0	0	0	0	0	0	0
ES_ML (MW)	0	0	0	0	0	926	0	0	0	0	1468	2394
ES_MS (MW)	112	0	0	0	0	262	0	0	0	0	125	500
ES_S (MW)	38	0	0	0	0	87	0	0	0	0	120	245
Grand Total (MW)	150	0	0	0	0	1276	0	0	0	0	1713	3139

Table 120. Sensitivity Metrics for D=45 $/kW-yr Scenario with Energy Storage

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average HOEP ($/MWh)	27.6	27.8	29.0	38.4	38.8	39.6	40.1	46.6	47.4	47.3	47.9
Cost to Load ($MM)	4103	3991	4070	5089	5388	4808	5165	6606	6999	6826	7034
Emissions (kiloton)	1762	1081	1072	2386	1346	1886	1939	5678	7537	6121	7796
Emissions Cost ($MM)	36	30	37	82	46	65	67	195	259	211	268
FOM Cost ($MM)	1628	1572	1527	1360	1481	1157	1235	1234	1260	1254	1111
Generation Cost ($MM)	1217	1121	1080	1033	1062	878	974	1282	1474	1364	1486
Total Fuel Cost ($MM)	678	614	593	606	594	513	569	839	996	898	1008
Total Generation Cost ($MM)	1253	1151	1116	1115	1108	943	1040	1477	1733	1574	1754
VOM Cost ($MM)	539	506	486	427	468	365	404	442	478	466	478

2.11.10.4 *Scenario D=50 $/kW-yr Summary*

Results for D=50 $/kW-yr are summarized here. Table 121 shows the energy storage build by year and by bucket type under this scenario and indicates an increase in energy storage build compared to base case.

Table 122 shows the cost metrics along with average HOEP and emissions.

Table 121. Storage Built by Year by Duration Type for D=50 $/kW-yr Scenario

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
ES_L (MW)	0	0	0	0	0	0	0	0	0	0	0	0
ES_ML (MW)	0	0	0	0	0	926	0	0	0	0	2067	2993
ES_MS (MW)	113	0	0	0	0	263	0	0	0	0	125	500
ES_S (MW)	38	0	0	0	0	88	0	0	0	0	120	245
Grand Total (MW)	150	0	0	0	0	1276	0	0	0	0	2312	3737

Table 122. Sensitivity Metrics for D=50 $/kW-yr for Scenario with Energy Storage

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average HOEP ($/MWh)	27.6	27.8	29.0	38.4	38.8	39.6	40.1	46.6	47.4	47.3	47.9
Cost to Load ($MM)	4103	3991	4070	5089	5388	4809	5165	6606	6999	6827	7010
Emissions (kiloton)	1762	1081	1072	2386	1346	1886	1939	5678	7537	6121	7612
Emissions Cost ($MM)	36	30	37	82	46	65	67	195	259	211	262
FOM Cost ($MM)	1628	1572	1527	1360	1481	1152	1230	1229	1255	1249	1034
Generation Cost ($MM)	1217	1121	1080	1033	1062	878	974	1282	1474	1364	1469
Total Fuel Cost ($MM)	678	614	593	606	594	513	569	839	996	898	994
Total Generation Cost ($MM)	1253	1151	1116	1115	1108	943	1040	1477	1733	1574	1731
VOM Cost ($MM)	539	506	486	427	468	365	404	442	478	466	476

2.11.10.5 Scenario D=55 $/kW-yr Summary

Results for D=55 $/kW-yr are summarized here. Table 123 shows the energy storage build by year and by bucket type under this scenario and indicates an increase in energy storage build compared to base case. Table 124 shows the cost metrics along with average HOEP and emissions.

Table 123. Storage Built by Year by Duration Type for D=55 $/kW-yr Scenario

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
ES_L (MW)	0	0	0	0	0	0	0	0	0	0	0	0
ES_ML (MW)	0	0	0	0	0	926	0	302	0	715	1057	3000
ES_MS (MW)	112	0	0	0	0	263	0	0	0	0	125	500
ES_S (MW)	38	0	0	0	0	88	0	0	0	0	120	245
Grand Total (MW)	150	0	0	0	0	1276	0	302	0	715	1302	3745

Table 124. Sensitivity Metrics for D=55 $/kW-yr Scenario with Energy Storage

Energy Storage Duration "Bucket"	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average HOEP ($/MWh)	27.6	27.8	29.0	38.4	38.8	39.6	40.1	46.6	47.4	47.3	47.9
Cost to Load ($MM)	4103	3991	4070	5088	5388	4808	5165	6594	6989	6827	7009
Emissions (kiloton)	1762	1081	1072	2386	1346	1886	1939	5678	7455	6095	7610
Emissions Cost ($MM)	36	30	37	82	46	65	67	195	256	210	262
FOM Cost ($MM)	1628	1572	1527	1360	1481	1147	1221	1190	1217	1130	1018
Generation Cost ($MM)	1217	1121	1080	1033	1062	878	974	1282	1467	1361	1469
Total Fuel Cost ($MM)	678	614	593	606	594	513	569	839	989	896	993

Total Generation Cost ($MM)	1253	1151	1116	1115	1108	943	1040	1477	1723	1571	1731
VOM Cost ($MM)	539	506	486	427	468	365	404	442	477	465	476

2.12 Cost Benefit Analysis

Benefits and cost analysis results for the base, low, and high cases are presented below. Benefits are represented as the combined value of the storage capacity value, ancillary services value, energy arbitrage value, difference in FOM costs between the base case without storage and the case with storage, and the difference in generation cost between the base case without storage and the case with storage. Present value of benefits is determined by summing up all benefits from 2020 through 2039 and applying a discount factor. Costs are represented by the annuity cost of the storage built. Present value costs are determined by summing up all costs from 2020 through 2039 and applying a discount factor. Net Present Value (NPV) is the difference between total present value benefits and total present value costs.

2.12.1 Benefits

Benefits to the grid are represented as the combined value of the storage capacity value, ancillary services value, energy arbitrage value, difference in FOM costs between the base case and storage case, and the difference in generation cost between the base case and storage case.

2.12.1.1 Fixed Operation and Maintenance (FOM) Delta ('$MM')

FOM delta is the difference in fixed operation and maintenance cost between the base case and storage case. FOM for the base case was determined for all generators. Storage FOM is calculated by multiplying the Storage FOM values in Table 125 with the cumulative storage built by bucket by year. The storage FOM is then added to all non-storage FOM costs to determine total FOM for the storage case. FOM delta results for the low, base and high cases are presented in Table 125 below.

Table 125. FOM Delta Results for Low, Base, and High Cases

Year	Low Case FOM Delta ('MM$')	Base Case FOM Delta ('MM$')	High Case FOM Delta ('MM$')
2020	1.7	21.1	21.1
2021	1.7	21.0	14.6
2022	1.7	21.0	8.3
2023	1.7	21.0	2.0
2024	1.7	21.1	-4.3
2025	-5.3	1.5	-10.7
2026	-5.3	1.2	-20.0
2027	-5.3	1.2	-29.0
2028	-4.7	8.9	-30.5
2029	-4.7	18.6	-29.8
2030	-9.6	-2.1	-38.8
2031	-6.6	0.3	-36.6
2032	-6.6	0.3	-33.8
2033	-6.6	0.3	-31.0
2034	-6.6	0.3	-29.8
2035	0.4	19.8	-8.9
2036	0.4	19.8	9.9

2037	0.4	19.8	14.1
2038	0.4	19.8	14.1
2039	0.4	19.8	24.5

2.12.1.2 Storage Capacity Value ('$MM')

Storage capacity value is the deferral value multiplied by the incremental storage built by bucket by year. For the base, low and high cases the deferral value is 35 $/kW-yr. In high case, the Energy Storage technology cost is 40% lower than the base case, and for low case the same technology cost is 40% higher than the base case. Total storage capacity values by year are represented as the sum of all capacity values of all storage duration buckets. Table 126 shows results of the total storage capacity value for the low, base, and high cases.

Table 126. Capacity Value Results for Low, Base and High Case Storage

Year	Low Case Storage Capacity Value ('MM$')	Base Case Storage Capacity Value ('MM$')	High Case Storage Capacity Value ('MM$')
2020	2.1	2.1	2.2
2021	2.1	2.1	2.5
2022	2.1	2.1	9.5
2023	2.1	2.1	16.5
2024	2.1	2.1	16.9
2025	7.1	36.3	64.8
2026	7.1	36.3	112.1
2027	7.1	36.3	122.7
2028	7.1	36.3	122.7
2029	7.1	36.3	144.9
2030	9.8	76.0	184.6
2031	7.7	73.9	182.1
2032	7.7	73.9	175.1
2033	7.7	73.9	168.1
2034	7.7	73.9	167.7
2035	2.7	39.7	119.8
2036	2.7	39.7	72.5
2037	2.7	39.7	61.9
2038	2.7	39.7	61.9
2039	2.7	39.7	39.7

2.12.1.3 Generation Cost Delta ('$MM')

Generation cost delta is determined by taking the difference in generation cost between the base case and the base storage case. Table 127 presents generation cost delta results for the low, base and high cases below.

Table 127. Generation Cost Delta Results for Low, Base and High Cases

Year	Low Case Gen Cost Delta (MM$)	Base Case Gen Cost Delta (MM$)	High Case Gen Cost Delta (MM$)
2020	0.0	0.0	0.0
2021	0.0	0.0	0.0

2022	0.0	0.0	0.0
2023	4.4	4.4	6.8
2024	0.0	0.0	0.1
2025	1.1	1.1	2.3
2026	0.0	0.1	0.1
2027	0.0	0.0	8.8
2028	0.0	11.6	75.8
2029	1.6	2.2	21.5
2030	2.6	9.5	118.8
2031	2.0	9.0	115.5
2032	2.0	9.0	111.3
2033	2.0	9.0	107.2
2034	2.0	9.0	105.4
2035	0.8	4.7	74.4
2036	0.8	4.7	46.4
2037	0.8	4.7	40.1
2038	0.8	4.7	40.1
2039	0.8	4.7	24.8

2.12.1.4 Ancillary Services (‘$MM’)

Ancillary Services results for the low, base, and high cases are presented in Table 128.

Table 128. Ancillary Services Results for Low, Base, and High Cases

Year	Low Case Ancillary Services ('MM$')	Base Case Ancillary Services ('MM$')	High Case Ancillary Services ('MM$')
2020	13.8	13.8	13.7
2021	13.8	13.8	13.7
2022	13.8	13.8	13.7
2023	13.8	13.8	13.7
2024	13.8	13.8	21.7
2025	46.0	46.0	45.7
2026	46.0	46.0	45.7
2027	46.0	46.0	45.7
2028	46.0	46.0	45.7
2029	46.0	46.0	57.1
2030	68.5	68.5	68.5
2031	54.7	54.7	54.8
2032	54.7	54.7	54.8
2033	54.7	54.7	54.8
2034	54.7	54.7	46.8
2035	22.5	22.5	22.8
2036	22.5	22.5	22.8
2037	22.5	22.5	22.8

2038	22.5	22.5	22.8
2039	22.5	22.5	11.4

2.12.1.5 Energy Arbitrage ('$MM')

Energy arbitrage is applied to long and medium long duration energy storage buckets by multiplying the cumulative storage built by year by the energy arbitrage value from Table 20. Energy Arbitrage Services results for the low, base, and high cases are presented in Table 129.

Table 129. Energy Arbitrage Results for Low, Base, and High Cases

Year	Low Case Energy Arbitrage Value ('$MM')	Base Case Energy Arbitrage Value ('$MM')	High Case Energy Arbitrage Value ($MM')
2020	0	0.0	0.1
2021	0	0.0	0.6
2022	0	0.0	11.9
2023	0	0.0	23.3
2024	0	0.0	23.3
2025	0	47.4	93.6
2026	0	47.4	170.4
2027	0	47.4	187.7
2028	0	47.4	187.7
2029	0	47.4	223.1
2030	0	107.4	284.4
2031	0	107.4	283.8
2032	0	107.4	272.4
2033	0	107.4	261.1
2034	0	107.4	261.1
2035	0	60.0	190.8
2036	0	60.0	114.0
2037	0	60.0	96.7
2038	0	60.0	96.7
2039	0	60.0	61.3

2.12.2 Storage Costs

Storage costs are represented by annuity payment for the storage units in the storage case.

2.12.2.1 Storage Cost Annuity ('$MM)

Annuity costs are calculated for the storage units built in the storage case using a discount rate of 7% over a 10 year period for all energy storage builds. Storage Cost Annuity results for the low, base, and high cases are presented in Table 130. The costs of ES are paid by the projects but then transitioned into fees and surcharges to the ratepayers. Table 130 shows the costs associated with the different ES technology "buckets" which vary as installed ES increases over time and the ES technology costs reduce.

Table 130. Storage Cost Annuity Results for Low, Base, and High Cases

Year	Low Case Storage Cost Annuity ('MM$')	Base Case Storage Cost Annuity ('MM$')	High Case Storage Cost Annuity ('MM$')
2020	18.9	13.5	8.3
2021	18.9	13.5	9.1
2022	18.9	13.5	26.4
2023	18.9	13.5	42.4
2024	18.9	13.5	44.5
2025	48.9	132.3	142.1
2026	48.9	132.3	232.1
2027	48.9	132.3	259.4
2028	48.9	132.3	259.4
2029	48.9	132.3	314.5
2030	45.4	232.6	399.1
2031	45.4	232.6	398.3
2032	45.4	232.6	381.0
2033	45.4	232.6	365.0
2034	45.4	232.6	362.9
2035	15.4	113.7	265.3
2036	15.4	113.7	175.3
2037	15.4	113.7	148.0
2038	15.4	113.7	148.0
2039	15.4	113.7	92.9

2.12.3 Free Cash Flow

Free cash flow (FCF) for the total benefits and total costs are presented below for the low, base, and high cases.

2.12.3.1 Total Benefits ('$MM')

Total Present Value Benefits are the sum of all Present Value Benefits from 2020 through 2039 with a 7% discount factor applied annually. Total present value benefits for the low, base, and high cases are presented in Table 131.

Table 131. Total Present Value Benefits for Low, Base, and High Cases

Case	Total Benefit to Grid, FCF ('$MM')
Low Case	771
Base Case	2859
High Case	6096

2.12.3.2 Total Cost ('$MM')

Total Present Value Costs are the sum of all Present Value Costs from 2020 through 2039 with a 7% discount factor applied annually. Total present value cost for the low, base, and high cases are presented in Table 132.

Table 132. Total Present Value Cost Results for Low, Base, and High Cases

Case	Total Cost FCF ('$MM')
Low Case	642
Base Case	2460
High Case	4074

2.12.4 Net Present Value

Net Present Value (NPV) is the difference between total present value benefits and total present value costs. Net present value results for the low, base, and high cases are presented in Table 133.

Table 133. Net Present Value Results for Low, Base, and High Cases

Case	NPV ('$MM')
Low Case	46
Base Case	200
High Case	903

2.13 Pillar 1 Conclusions

This study provides an analytically-driven process for examining the cost of energy storage and potential value streams for individual scenarios. Project economics and net benefits were modelled for policy futures with and without the addition of energy storage systems to the IESO system over the 2020-2030 horizon. Detailed scenarios were modelled to identify key cost-effective opportunities and analyze the value of energy storage systems.

The study determines the recommended size of the distributed energy storage deployment, for each of the evaluation sites including energy, power, location and timing, along with a full-range, stacked-services benefit assessment, including the potential operational benefits, financial savings and additional revenue opportunities that can be realized through the deployment of the energy storage in Ontario. It quantifies the size and location of energy storage systems that would provide maximum benefits to Ontario's system by examining 13 cases in the context of potential futures for the IESO region.

The economic benefits of adding energy storage systems into the Ontario footprint were analyzed for a base-case scenario, a low-case scenario, and a high-case scenario. The cases were analyzed against a "business-as-usual" scenario where energy storage was not built into the Ontario footprint. The following benefits were examined between the case without energy storage and the cases with energy storage:

- Low Case - 745 MW built resulting in $50 million of gross lifetime benefits to the grid (net benefits not analyzed)
- Base Case – 2,636 MW built resulting in $200 million of gross lifetime benefits
- High Case – 5,743 MW built resulting in $900 million of gross lifetime benefits

Benefits are analyzed as the combined value of the storage capacity value, ancillary services value, energy arbitrage value, and the difference in FOM and generation cost between the "business-as-usual" case and storage case.

In addition to economic advantages, energy storage also supports resource flexibility. This will become particularly valuable as the penetration of renewable resources such as wind and solar become more widespread in the Ontario footprint. Energy storage can provide steady power output over a desired time window allowing the energy storage systems to compensate for forecast uncertainty in renewable generation. Furthermore, ES systems can also mitigate rapid fluctuations in renewables output during periods of intermittency in order to smooth power output.

The addition of energy storage systems to the Ontario system can improve resiliency to the electric system by reducing the impact of outages during disturbances or natural disasters. When ES systems are within clearly defined electrical boundaries, they can act as a single controllable entity with respect to the main grid. This functionality allows energy storage systems to connect to and disconnect from the grid to enable it to operate in either grid-connected or island mode.

The overall impact of energy storage on greenhouse gas (GHG) emissions depends on two key factors: 1) carbon emissions from generators that charge the energy storage system from the grid, and 2) the efficiency losses associated with charging and discharging of an energy storage resource. As more renewables are added into the Ontario footprint, energy storage will play a larger role in off-peak time shifting and avoid renewable curtailment. Both these activities will have an impact on the overall GHG emissions.

Results from this study show that ES systems can increase the overall benefits of the Ontario system by improving efficiency, providing resiliency and reliability, and increasing system flexibility. Value stacking through participation in a combination of wholesale market services and distribution services is critical for maximizing system benefits and economic benefits.

3 Technology Assessment and Valuation Pillar

Pillar 2 is a micro-level analysis that simulates the profitability, technical performance, and dispatch of a single, grid-connected ES unit. The Pillar 2 analysis matches technology and application requirements, proposes valuation and performance frameworks, and evaluates individual ES profitability and dispatch on the electric grid. Details on Pillar 2 objectives, background, methodology, and results are provided in the sections below.

3.1 Introduction to Pillar 2

Despite the expectations of many regarding the potential benefits from grid-scale storage technologies[5], the complexity of markets, technologies, and integration at a project level often makes these benefits difficult to quantify appropriately. There are however several evaluation frameworks available that can aid in the decision to adopt energy storage technology and assist in the planning, installation, and demonstration of up to a full commercial operation level. Choosing the appropriate storage technology can be difficult as there are many factors to consider, such as the variety of technology choices available, the diverse application services along the electricity value chain, restrictions or adoption of specific business models at the utility and end user level, and complicated ownership or revenue structures.

Pillar 2 focuses on understanding how specific energy storage (ES) technologies can meet the operational and cost requirements for the nodes outlined in Pillar 1. This is accomplished in two successive evaluation processes: 1) rank the suitability of generic ES technology classes for a specific market and select the top ES technologies, and 2) simulate specific examples of ES installations at a project level in that market. The goal is to align the larger grid-scale market opportunity already outlined in Pillar 1 with an equipment operator and/or asset owner's point of view to determine the viability of selected ES technologies at individual projects. This is achieved by:

- Ranking several classes of ES technologies on how they fit the location, cost, grid applications, and technological maturity requirements of a market.
- Performing a project-level valuation analysis of specific examples of the top ranked ES technology classes to assess their investment potential through the benefit to cost evaluation for different use cases.
- Reviewing the multi-year performance of the potential ES projects given different market scenarios and analyzing typical financial or ownership structures to determine where benefits might accrue on potential ES projects given the constraints above.

A description of Pillar 2's methodology can be found in Section 3.3. It should be noted that while the analysis in Pillar 1 is technology-agnostic and takes a system level approach to ES on the Ontario electric system, the analysis in Pillar 2 is both project and technology-specific in order to meet the goals above. By simulating specific classes of ES technologies in individual examples that operate at a specific location on the Ontario electric system, it becomes possible to bring real world cost, performance, and market information into the analysis. This facilitates the determination of which technologies and grid benefits outlined in Pillar 1 are viable under current and proposed regulations and market structures. While not fully comprehensive, it provides a

[5] (Zhenguo, et al. 2013, Barnhart and Benson 2013)

starting point for a comparative discussion of potential policy or market options to pursue in order to achieve the “lowest cost” system outlined in Pillar 1.

3.1.1 Relation to Pillar 1

The valuation analysis in this section simulates several ES technology classes, and then a single ES unit at a time, thus all inputs are assumed to be static. This is inherent in the simulation tools’ designs. The simulations do not take into account the effect of ES on system-level price and load data because of the insignificant impact of a single ES unit operating on the Ontario electric system. The dynamic effect of aggregated ES units on pool price and load data could be significant and is already accounted for at the system level in Pillar 1’s production cost model. Pillar 2’s storage valuation instead uses only actual historical wholesale market electricity / pool prices, ancillary service price, and load data from IESO. There are two reasons for this latter decision: 1) in the grid scale energy storage analysis in Pillar 1, ES capacity is added at the system level at different time intervals over the 11 year study period with various pool prices, and 2) changing ES capacity and pool price also influences ancillary service price and load data. This requires similar price and load outputs from system level calculations (Pillar 1) that are too granular for the system level modelling. As a reasonable approximation, the Pillar 2 analysis involves calculating increases in pool prices as well as ancillary service price and load data using macroeconomic indicators like escalation of benefits, inflation and fuel escalation rate inputs shown in Table 138.

3.2 Background: Analysis, Market, and Technical Considerations

3.2.1 Overview of Analysis Objective

The goal of this section’s analysis is to evaluate which ES technology classes are best suited for the Ontario electric system and then how an individual ES system would perform over its lifetime as a grid asset operating in Ontario. The outcome could provide information for Ontario stakeholders to understand the viability of ES technologies in Ontario-specific use cases.

3.2.2 Market Considerations

Reductions in total cost, including capital and operating costs, of energy storage systems over the past decade have attracted interest from system operators, generators and technology vendors across customer-sited, transmission, and distribution-connected electric grids worldwide. Electricity systems face many challenges including how to analyze each proposed project on the grid, how to access the markets, and where the benefits might be accrued.

While each market has unique attributes, several markets and services common to Canadian and American Independent System Operators (ISO’s) and Regional Transmission Organizations (RTO’s) have been identified in other analyses[6]. These standard definitions could be customized to match Ontario’s markets and services for today and in the future; however, each of these require detailed information on market dynamics, pricing, and load data. Fortunately, given Ontario’s market, much of this information is available from the IESO and published literatures, including detailed descriptions of the overall market and the operation of submarkets. Table 134 provides a summary of the current Ontario markets and services.

[6] (Akhil, Huff and Currier 2015, Electric Power Research Institute 2014)

Looking at other electricity markets, in the United States, US FERC Order 841 was an important step allowing ES to access value in these wholesale energy markets, ancillary services and capacity markets[7]. This has impacted several ISO/RTO's, including PJM, CAISO, ERCOT, NYISO, ISONE, and MISO. PJM has rectified its market rules to allow fast ramping projects to participate in the Reg D service. PJM is also working on proposals to allow ES systems to participate in energy and capacity markets as dispatchable assets. Finally PJM is proposing a 5-minute real-time market settlement time interval, which allows ES to maximize revenue and allow smaller MW-rated ES systems to participate. PJM's capacity market requirements remain largely unchanged.

More recently, from Q1 2013 to Q4 2018, US ES growth came from large, long duration installations where capacity markets of at least 4 hours' duration were the key application[8]. In Arizona, ES is being used for long-term transmission deferral[9] and ES as a transmission asset is being considered by CAISO and MISO[10]. There is a significant upside for ES in ERCOT's first significant overhaul of its ancillary services market[11] which Ontario could monitor and learn from.

Table 134. Overview of IESO Markets and Services

Market	Submarket	Description
Real-time Markets	Real-time Energy Markets	Ontario participates in a real-time energy market process. The market clearing price (MCP) is set every five minutes based on the bids and offers settled in the wholesale market. For each five-minute interval, dispatch instructions are provided by the IESO based on accepted offers and bids. Non-dispatchable generators are paid the hourly Ontario energy price (HOEP) which is calculated using the average of the 12 five-minute market clear price during the hour. Non-dispatchable loads pay the HOEP. (Pillar 1) The day-ahead commitment process (DACP) commits certain dispatchable resources and the economics scheduling of imports. Dispatchable generators, dispatchable loads, importers, exporters, and linked wheels are all eligible for participation in the DACP. (Pillar 1) The DACP is not a 'day-ahead market' – however, the day-ahead commitment helps address reliability concerns. (Ontario IESO 2017)
	Real-time Operating Reserve Markets	Operating reserve is the replacement power that can be called upon in case of equipment failure or emergency. Ontario's IESO administers three separate Real-time Operating Reserve Markets to provide a market-based way for the IESO to quickly replace the supply of electricity for a short period of time until requirements can again be supplied from normal dispatch: • 10 minute synchronized reserve (also called 10 minute spinning) • 10 minute non-synchronized reserve (also called 10 minute non-spinning) • 30 minute reserve (synchronized or non-synchronized)

[7] (Ruiz, et al. 2018)

[8] (Simon, Finn-Foley and Gupta 2019)

[9] (Scottmadden Management Consultants 2018)

[10] (Simon, Finn-Foley and Gupta 2019)

[11] (Simon, Finn-Foley and Gupta 2019)

Procurement Markets	Ancillary Service Contracts	Ancillary services are services required to maintain the reliability of the IESO-controlled grid, including: • Frequency control • Voltage control • Reactive power
	Reliability Must-run Contracts	Reliability must-run contracts are also used to ensure the reliability of the IESO-controlled grid. A reliability must-run contract allows the IESO to call on the registered facility under contract to produce electricity if it is needed to maintain the reliability of the electricity system.
	Black-start Contracts	Black-start capability is a generator's ability to help restore the province's power system without relying on an external supply of electricity.
	Demand Response / Capacity Auction	The demand response (DR) capability refers to consumers (both aggregated and individual loads) who are capable of reducing their electricity consumption in response to prices and system needs. This DR auction is used as a way to meet Ontario's resource adequacy needs instead of planning new generator installations. These resources are considered in the IESO economic dispatch process alongside bids and offers from other resources, such as generators and imports, in the energy market in exchange for availability payments. Very recently, the DR Auction has further expanded into the Capacity Auction where distributed generators can also bid as generation resources; this is an alternative way to meet Ontario's resource adequacy needs instead of planning new generator installations.
Transmission Rights Market		Currently, this is the only IESO-administered financial market which involves the transfer of funds only but does not involve the transfer of energy. Through an auction process, the IESO sells transmission rights (TRs) that entitle the owner to a payment if the price of energy in Ontario is different from the price in an intertie zone. The transmission rights market allows market participants to reduce price risks associated with transmission congestion and price volatility.

3.2.3 Technical Considerations

ES technologies are being developed and commercialized by numerous companies and organizations around the world, and range in maturity from very early stage research and development (R&D) to fully commercial repeatedly deployed systems[12]. The maturity of an ES technology can be assessed by using Technology Readiness Level (TRL) and Manufacturing Readiness Level (MRL).[13]

In general, TRL1 refers to an innovation activity at the very basic R&D stage (proof of concept), while TRL9 represents the technology at a commercial stage and market-ready state. TRL and the risk associated with the

[12] (Viswanathan, et al. September 2013)

[13] (Engel, et al. October 2012).

maturity of ES systems have been used by the U.S. Department of Energy (USDOE) for providing support for scientific, R&D, and commercialization activities related to grid-scale ES systems. The highest TRL9 is assigned to technologies such as pumped hydro systems, which are widely deployed and have a long history of operation, whereas newer technologies, such as solid state lithium batteries, would currently be below TRL6. This study, consistent with other ES studies, evaluates technologies at TRL 8 and above - essentially, commercial at-scale technologies, that are readily available for purchase from a vendor by the owner/operator. These commercial systems usually have more data with respect to ES unit cost, performance and lifetime, including additional information on the full project costs required to build and operate a project including Balance of System (BoS) equipment and installation, and operational fixed and variable costs. The initial capital costs usually include manufacturing and material costs, but may not include commissioning, and end-of-life costs such as decommissioning, disposal or recycling / repurposing. These end of life costs are not included in analysis in Pillar 2 due to the varied approaches being taken by project proponents with respect to dealing with these eventual costs. They are however addressed in Pillar 3 as part of the full life-cycle assessment of technologies.

MRL is similarly assigned to each storage technology by many studies. The International Energy Agency's (IEA) 2014 Technology Roadmap[14] provided a development spectrum for maturity of ES technologies which closely resembles the TRL and MRL levels defined by Engel et al[15]. In a recent report, USDOE[16] evaluated the risk and technology readiness of ES technologies. Several valuation frameworks were recently proposed that integrate the technology outlook, storage performance matrix, and storage valuation models into a business opportunity assessment[17].

3.3 Methodologies and Analytical Tools

The viability of any energy storage project depends upon location, a market structure that enables the valuation of benefits, and the cost and performance of the energy storage technology[18]. At a project level, several tools have been developed to analyze the value of distributed storage technologies for various grid applications[19]. In many of these tools, the underlying assumption is that the operation of any single energy storage system will not significantly influence market conditions, and therefore the existing market prices are used as a fixed input[20]. This is one of the fundamental differences between project level valuation tools in this section and the system level electricity production cost models as used in Pillar 1. Pillar 2's study focuses on economic dispatch and understanding stackable benefits and costs, and allows for ranking ES technology classes on a level playing field and then discrete analyses at a project level which can clearly identify monetization and cost-benefit ratios of relevant grid services. It therefore allows an increased understanding of

[14] (International Energy Agency 2014)

[15] (Engel, et al. October 2012)

[16] (U.S. Department of Energy December 2013)

[17] (Malek and Nathwani, Typology of Business Models for Adopting Grid-Scale Emerging Storage Technologies 2016)

[18] (Kirby, Ma and O'Malley May 2013)

[19] (Zhenguo, et al. 2013)

[20] (Pearre and Swan 2014)

the value that an individual ES system creates for its owner, and thus builds up the acknowledgement of whether it is economically viable to build such a system.

The wide variety of technology choices and diverse applications along the electricity value chain makes the choice of appropriate ES technology difficult[21]. From a utility perspective, Southern California Edison (SCE) noted the lack of storage project parameters in the context of existing infrastructure. This lack of clarity from utilities around value propositions and technical needs makes it difficult for the manufacturer to improve ES cost effectiveness and performance. Therefore, an application-focused valuation methodology was introduced by SCE[22]. In addition, the NREL valuation analysis tool evaluates the operational benefit of commercial storage applications, including load-leveling, spinning reserves, and regulation reserves[23]. Finally, the Energy Storage Valuation Tool (ESVT), developed by the Electric Power Research Institute (EPRI)[24], proposes a methodology for separating and clarifying analytical stages for storage valuation. ESVT and its successors, including Storage VET, calculate the value of ES by considering the full scope of the electricity system including system/market, transmission, distribution, and customer services; and in ES-Select™, designed and developed by DNV-KEMA, the user must choose where ES is connected to an electric grid[25].

Lazard (now Roland Berger) provides a comprehensive technology assessment framework based on the levelized cost of storage LCOS[26]. One should note that LCOS only analyzes observed costs and revenue streams from the project and is generally an empirical indication for equipment costs and associated revenues. LCOS reported by Lazard is based on aggregating cost and operational data from original equipment manufacturers' technology developers and is only applicable to a select subset of use cases identified by Lazard [27].

A description of ES technologies and how the above mentioned tools were utilized is shown in the Appendix *'Treatment of ES Technology Options'***.**

3.3.1 Analysis Methodologies

Pillar 2 involves performing detailed project level techno-economic analysis (TEA) of specific ES systems for the properly selected technologies. The screening of ES technologies for particular markets and use cases was carried out prior to the detail dispatching analysis that is energy price dependent. This step is new to the analysis methodology when compared with the previous study on Alberta jurisdiction where the ES technologies were pre-determined beforehand (Regoui, et al. 2020).

This is accomplished by using evaluation frameworks in a two-stage, top-down or funnel approach. The first stage uses Ontario specific grid and technology data from a survey completed by the NRC as well as assumptions obtained from Pillar 1. The data and assumptions are used to rank several ES technology classes on a level playing field. The second stage must have actual hourly price and load data to perform more detailed dispatch and profitability analysis. Using that data, specific examples of top ES technology classes are simulated

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[21] (Denholm, Jorgenson, et al. May 2013, Kaun June 2013)

[22] (Rittershausen and McDonagh 2013)

[23] (Denholm, Jorgenson, et al. May 2013)

[24] (Kaun June 2013)

[25] (DNV KEMA Inc. December 31, 2012)

[26] (Lazard 2016, Lazard 2017)

[27] (Lazard 2016, Lazard 2017)

one at a time at the project level for its entire lifetime. This approach, from general to specific, provides a more granular snapshot of ES potential at a technology-specific and individual project-level basis. The analysis process is summarized in Figure 50.

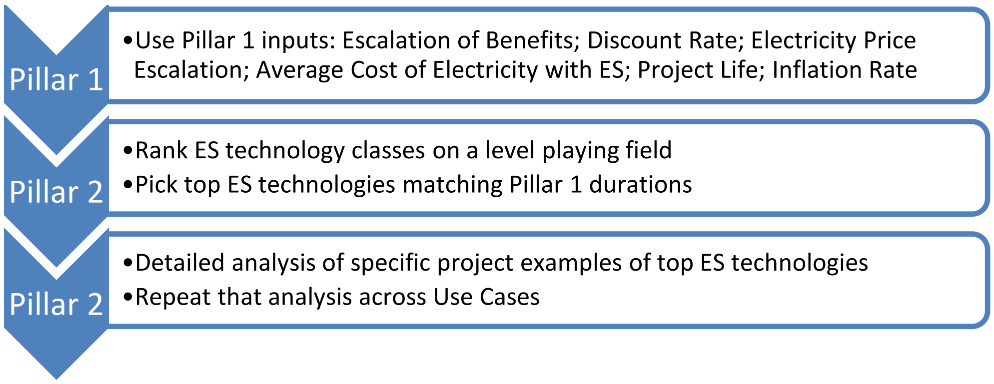

Figure 50. Funnel Model

First, nineteen ES technology classes are ranked on a level playing field, using IESO specific pricing for each market and service as well as Ontario-specific financial ownership structures. That ranking result enables the selection of top ES technology classes for a more detailed study. Second, the next level of a more granular analysis focuses on simulating specific examples of those top ES technologies one at a time as a single piece of equipment. An intensive time series dispatch simulation at an hourly resolution is performed for each individual piece of ES equipment to model its operation over the asset's lifetime, charging / discharging, along with bidding results into the Ontario markets according to a generic North American ISO dispatch order or hierarchy. The simulation combines price and load signals from actual IESO data with actual commercial, at-scale ES technology cost performance and lifetime data to create stackable, mutually exclusive costs and benefits based on each IESO market and service and typical financial inputs for Ontario. The outcome is both the financial and grid operation performance of an individual ES technology.

The overall expectations from this Pillar 2's analysis include:

1) Assess appropriate ES Technologies
   a) Evaluate the impact of specific ES technologies' performance, cost, and operational requirements on the viability of individual projects
2) Assess Benefits
   a) Align ES benefits between IESO markets and services to Pillar 2's valuation of storage for grid services
   b) Use IESO price and load data for those markets and services, and when unavailable internal estimates are provided
   c) Incorporate current and future IESO market mechanisms, and incorporate potential markets or specific applications based on Ontario stakeholder input
   d) Analyze dispatch of an ES technology operating on the Ontario electric system
3) Understand the Impact of Financial and Regulatory Structures
   a) Look at reasonable ownership structures, and assess the value which is attributed to each party in the proposed project

b) Account for macroeconomic factors like fuel escalation and understand project viability and risk
c) Incorporate assumptions on financial ratios such as debt to equity ratios, return on equity, and tax rates.

3.3.2 Analysis Tools

Following a review of the available tools as outlined above, for this study, DNV GL's ES-Select™ (DNV KEMA Inc. December 31, 2012) and EPRI's Energy Storage Valuation Tool (ESVT) 4.0 were used for techno-economic analyses of use cases (Electric Power Research Institute 2014). The former is used for ranking then selecting ES technology classes in the first stage, while the latter is used for detailed benefit to cost analysis of an individual ES project in specific Use Cases.

3.3.2.1 ES Select

In ES-Select, the user needs to choose where energy storage is connected to an electric grid (DNV KEMA Inc. December 31, 2012). Typical energy storage applications are characterized in view of different performance attributes. The ES market and its associated applications span a variety of locations along the electricity value chain (Rastler 2010). For instance, on the generation side, the addressable market for energy storage is improving power quality or usage of existing generation sources.

Several key steps are involved in creating and utilizing valuation tools. From various academic and business sources, detailed data-sets are gathered for several electrochemical energy storage solutions with potential applications in power grids. Each data-set contains a technology description and technology targets for various grid applications. The input data were developed on system and component levels, including prioritized technical parameters and market attributes. The data sets are updated on an ongoing basis and are used for storage valuation analysis. The benefit of storage is ultimately described by return on the total cost of capital for a specific period of time (asset lifetime) based on several financial outputs that include Net Present Value (NPV), Internal Rate of Return (IRR), the Total Cost of Ownership (TCO), and Cash Flow.

Tax rates will be included in all cost and benefit terms. One should notice that a single revenue stream (from a single application service) usually does not lead to a short (<10 years) payback time. Only multiple revenue streams could lead to net benefits in a reasonable payback period as illustrated by many studies (Mears, et al. 2003). Note that the effect of an electricity price increase is captured by electricity price escalation factors as an input parameter within the financial database in ES-Select (DNV KEMA Inc. December 31, 2012). Finally, internal rate of return (IRR) is calculated as the discounted rate under the assumption that the net cash flow is zero.

3.3.2.2 Energy Storage Valuation Tool (ESVT)

ESVT is a time-series dispatch simulation tool to analyze the cost-effectiveness of energy storage based on the Analytica™ Power Player with Optimizer software platform by Lumina Decision Systems. In this analysis, the value of energy storage is calculated for a specific use case by taking into account the full electricity system, including system-specific load and price data, financial and cost information, market structure (e.g. regulated or de-regulated), transmission and distribution capacity, and service applications. ESVT is a financial simulation model that allows the user to evaluate the cost-effectiveness of technically feasible grid-connected energy storage system use cases and multiple business cases. The model supports energy storage grid services covering the full scope of the electric system, from generation, transmission and distribution or "front of meter" down to end user consumption or "behind the meter." ESVT contains preloaded seed data based on actual historical data provided by EPRI partner ISO/RTO's for grid service requirements and values, as well as financial, and economic assumptions. Corresponding actual stakeholder data was then collected to build the Canadian jurisdiction-based database, and that jurisdiction-specific data is used to run TEA simulations.

ESVT simulates energy storage operation for achieving a combination of chosen grid service applications or benefits, called use cases, through a hierarchical dispatch order that prioritizes long-term commitments over shorter ones and optimizes for storage system value across services of equivalent priority. Outputs include financial, technical and service-specific dispatch results over the defined technology lifetime. ESVT is unique among energy storage cost-effectiveness tools, due to its specific focus on energy storage and its time-series simulation capability[28]. All underlying databases, models, financial and performance equations are identical to those embedded in ESVT 4.0 and can be found in Akhil et al[71].

Several studies[29] indicate that multiple revenue streams are required to result in net benefits with a reasonable payback period. ESVT can approximate profit maximizing decisions made by a grid asset owner/operator to obtain the total benefit of participating in multiple electricity markets, ancillary services and specific applications, while both considering the operational characteristics of the ES technology, and following a generic North American ISO/RTO dispatch hierarchy[30]. We use the term "stackable" to mean that the costs and benefits are mutually exclusive, which avoids double counting those costs and benefits.

3.4 Model Inputs and Assumptions

Benefits are defined in terms of what a single ES system operating on the Ontario electric system can provide in terms of IESO's current and planned markets and services. Market inputs, technology inputs, and financial inputs are key data to be used in both modelling tools.

3.4.1 General Assumptions

Effect of Installed ES on Price and Load Data. At the project level, the simulation does not take into account the effect of ES on system level price and load data as described in Section 3.1.1. The dynamic effect of aggregated ES units on pool price and load data could be significant and is accounted for at the system level in the production cost model performed in Pillar 1. Pillar 2 utilizes actual historical wholesale market electricity - pool prices, ancillary service price, and actual load data from IESO. This provides a constant baseline, and assumes that the presence of a single ES unit operating on the Ontario electric system is relatively insignificant. However, pool prices as well as ancillary service prices were increased based on load data and macroeconomic indicators such as escalation of benefits, inflation rate and fuel escalation rate inputs shown in Table 138 and Table 139.

3.4.2 Current Market Inputs

Market inputs are one of the key inputs to both ES-Select and ESVT valuation tools. While the characterizations of market services defined in the two tools are, in general consistent, there are still some differences in their capabilities regarding the description of market services. Therefore, below are some key inputs that differentiate in both tools that will be described separately where necessary.

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28 (Navigant May 2014)

29 (Kaun June 2013, Lazard 2016, Lazard 2017)

30 (Kaun June 2013, Electric Power Research Institute 2014)

3.4.2.1 ES-Select Model

Table 135 details the markets and services that ES Select can model, and how they align with those in the Ontario electric system. The column "ES Select Potential Benefits" lists markets and services modelled by the tool. For each benefit, the IESO market or ancillary service that is currently, or might be, available is shown in column "IESO." Services included in this study are indicated by a "Y" (Yes) in the column "Scope." Price and load data that were either provided by Ontario stakeholders (Malek and Skrivan, ES Select Canada BETA 2014) or are not applicable, indicated by "ON" or "n/a" respectively for the markets and services, are shown in the column "Data." If Ontario stakeholders indicated there was no expected annual benefit for a market and service that ES could capture, those are indicated by an asterisk or "ON*."

Table 135. Summary of Grid or Markets and Services Benefits Modelled by ES Select

ES Select Potential Benefits	IESO	Scope	Data
Energy Time Shift (Arbitrage)	Real-time Energy Market	Y	ON
	Day-Ahead Commitment Process	Y	ON
Supply Capacity	n/a	Y	ON
Load Following	n/a	Y	ON
Area Regulation	Ancillary Services Market: Regulation Service	Y	ON*
Fast Regulation	Ancillary Services Market: Regulation Service	Y	ON*
Supply Spinning Reserve	Operating Reserve Markets: Synchronized	Y	ON
	Operating Reserve Markets: Non-Synchronized and Reserve	Y	ON*
Voltage Support	Ancillary Services Market: Reactive Support and Voltage Control	Y	ON*
Transmission Support	Ancillary Services Market: Reactive Support and Voltage Control	Y	ON*
Transmission Congestion Relief	Transmission Rights Market	Y	ON*
Dist. Upgrade Deferral (top 10%)	n/a	Y	ON
Trans. Upgrade Deferral (top 10%)	n/a	Y	ON
Retail TOU Energy Charges	n/a	Y	ON*
Retail Demand Charges	Demand Response Auction	Y	ON
Service Reliability (Utility Backup)	n/a	Y	ON
Service Reliability (Customer Backup)	n/a	N	ON
Power Quality (Utility)	n/a	Y	ON
Power Quality (Customer)	n/a	N	ON
Wind Energy Time Shift (Arbitrage)	Real-time Energy Market	Y	ON
	Day-Ahead Commitment Process	Y	ON
Solar Energy Time Shift (Arbitrage)	Real-time Energy Market	Y	ON
	Day-Ahead Commitment Process	Y	ON
Renewable Capacity Firming	n/a	Y	ON*
Wind Energy Smoothing	n/a	Y	ON*
Solar Energy Smoothing	n/a	Y	ON*
Black Start	Ancillary Services Market	Y	ON
n/a	Physical Bilateral Contracts	Y	n/a

n/a	Capacity-Based Demand Response	Y	n/a
n/a	Demand Response Pilot	Y	n/a

Markets and services modelled were those available as “ES Select Potential Benefits”, in “Scope” for the Ontario Chapter, and for which Ontario stakeholders provided “Data”. At the time of this study, ES Select could not model Global Adjustment (GA) charges. The NRC has GA data and that could be modelled in a future version of the Ontario Chapter once ES Select has the capability to model GA. However GA can be modelled in Pillar 1’s tool and Pillar 2’s ESVT tool (in a customized route).

3.4.2.2 ESVT Model

Table 136 details the markets and services that the ESVT tool can model, and how they align with those in the Ontario electric system. The column “ESVT Grid Service” lists markets and services that can be modelled by the tool. For each benefit, the IESO market or ancillary service that is currently, or might be, available is shown in column “IESO Markets and Services”. According to the availability of data listed in column “IESO Data Availability”, three Use Cases are defined in the last three columns, where green checkmarks indicate that benefit stream will be included in the corresponding case study.

It is shown that Electric Energy Time Shift, or Energy Market, and the Operating Reserves services are modelled throughout all Use Cases, as shown in Table 136, since they all belong to current IESO market services. Black start services were modelled using the preloaded value in ESVT 4.0[31] because Black Start data from Ontario is not available at the time of this report. During the case studies, it turned out the value from providing black start is negligible when compared with other value streams, and therefore, in the rest of the report, the black start is omitted from all the ESVT result analysis.

It is also noted that there is no supply capacity service in existing Ontario markets during the time period of our study that could be comparable with this ESVT's function. On the other hand, there are two unique value streams of ES by providing for GA reduction and DR in existing Ontario markets, but they are missing from the ESVT model. However, an alternative way was found to be valid to include these two value streams (separately) in our study. The corresponding benefit calculations actually can be customized with the existing function - System Electric Supply Capacity, of the ESVT tool. The details can be found in Section 3.6.2.1.1.

Table 136. Summary of Grid or Markets and Services Benefits Modelled by ESVT. Mark ** Indicates No Direct Data Available but Derived Data can be Obtained from Accessible Data

[31] (Electric Power Research Institute 2014, Akhil, Huff and Currier 2015)

TEA - ESVT	IESO	IESO	ON Use Cases		
Grid Service	Markets and Services	Data Availability	1	2	3
System/Market Services					
System Electric Supply Capacity	**Global Adjustment (GA) reduction / Demand Response (DR) auction***			v (GA**)	v (DR**)
Local Electric Supply Capacity					
Electric Energy Time-Shift	**Real time Energy Market AND Day-Ahead Commitment Process**	**Partially**	v	v	v
Frequency Regulation	AS Markets: Regulation Service	No	(need data)	(need data	(need data)
Synchronous Reserve	**OR Markets: Synchronized (10 min)**	**Yes**	v	v	v
Asynchronous Reserve	**OR Markets: Non-Synchronized and Reserve (10 and 30 min)**	**Yes**	v	v	v
Black Start	AS Markets: Certified Black Start Facilities	No	(need data)	(need data	(need data)
Transmission Services					
Transmission Investment Deferral					
Transmission Voltage Support	AS Markets: Reactive Support and Voltage Control Service	No	(need data)	(need data	(need data)
Renewable Generation Shaping					
Distribution Services					
Distribution Investment Deferral					
Distribution Losses Reduction					
Distribution Voltage Support	AS Markets: Reactive Support and Voltage Control Service	No			
Distribution Voltage Support (PV Ramp)					
Customer Premise Services					
Power Quality	n/a		n/a	n/a	n/a
Power Reliability	n/a		n/a	n/a	n/a
Retail TOU Energy Time-Shift	n/a		n/a	n/a	n/a
Retail Demand Charge Management	n/a		n/a	n/a	n/a
Others					
	Demand Response (DR) auction*	**Yes****			see **System Electric Supply Capacity** function above
	Global Adjustment (GA) reduction (Class-A)*	**Yes****		see **System Electric Supply Capacity** function above	

At the time of preparation of this report, IESO is implementing a supply capacity service through Capacity Auction, which will replace the former Demand Response Auction. The impact of this new implementation on our study will be addressed in Use Case 3. Of note, RS/VCS was excluded from our study due to lack of data.

3.4.3 Technology Inputs

3.4.3.1 Treatment of Technology Options

A full list of all nineteen options of ES technology classes and their abbreviations available in ES Select can be found in Appendix 'ES Select Storage Options and Abbreviations'. In ESVT, in order to compare multiple ES technologies, the main technical attributes such as cost, performance, and lifetime data were obtained from actual suppliers with consistent multi-year reports. Pillar 2 analysis used technology data for commercial assets or equipment at a TRL of 8 or 9 that a typical owner operator could purchase from a vendor (Akhil, Huff and Currier 2015).

The selection of technology options for further analysis using the ESVT valuation tool is presented in Section 3.5. As seen in the selection results, CAES, NaS, and Li-ion Battery (LIB) are the top three ES technology classes from the ranking analysis for the Ontario electric system. In the current study, two specific LIB systems, 10MW 2hr and 10MW 4hr, are used in the ESVT Use Case studies. As an example, technology cost/performance considerations for LIB 10MW 2hr are shown in Table 137.

Based on Pillar 1 results, and available ES cost and performance data sets from the US DOE, a lithium-ion (Li-ion) battery electricity to electricity (E2E) storage technology was prioritized for analysis as summarized in Table 147[32].

Table 137. Technology Cost and Performance Data for LiB with Capacity of 10MW and Energy Duration of 2 hours. Source Data and Reference Details in the Appendix - Treatment of ES Technology Options

Technology	Li-ion Battery [33, 34]	
Configuration	Capacity (MW)	10
	Duration (hr)	2
	Technology Lifetime (yrs)	15
Performance	Battery Lifetime (yrs)	10
	Roundtrip Efficiency (%)	85%
	Max Depth of Discharge (DoD)	80%
Cost	Capital Cost ($/kWh) in 2016	869 CAD
	Variable O&M Cost ($/MWh)	2.70 CAD
	Fixed O&M Cost ($/kW-yr)	5.70 CAD
	Battery Replacement Cost in 2016 ($/kWh)	350 CAD
	Battery Replacement Cost (Reduction/yr)	9.67%

With respect to data from the US DOE Energy Storage Handbook, the vendor survey is from 2010 and 2011. The cost curve data from Lazard's LCOS 2.0 was used to discount and extrapolate the respective ES costs from either 2010 or 2011 to 2019, when the ES unit would be purchased and installed. Finally, those discounted ES costs were converted from 2019 USD to 2019 CAD.

3.4.3.2 ES Equipment Lifetime.

The number of years before stacks are replaced is used as an indication of ES lifetime and contains ES repair and maintenance. However, detailed battery degradation profiles were not included due to limited availability of the cycle life and durability data. For Li-ion, 10 years was the number of years before stack replacement was required, which is based on an average of the 5 and 15 year values[35]. For NaS, stack replacement was 15 years (Akhil, Huff and Currier 2015). Two other inputs include battery stack replacement costs in $/kWh and the decrease in replacement costs as a % reduction per year[36]. Annual kWh degradation estimates are an output of the simulation[37].

No lead time is assumed from the time the project is approved, financed, site prepared, equipment installed and connected to the grid to the time it becomes operational. All ES technologies considered have a technology lifetime at least equal to or greater than the 11-year horizon of the project. To account for different technology

[32] (Akhil, Huff and Currier 2015, Electric Power Research Institute 2014, Lazard 2016, Lazard 2017)

[33] Akhil, Huff and Currier 2015

[34] Lazard 2016, Lazard 2017

[35] (Akhil, Huff and Currier 2015)

[36](Lazard 2016)

[37](Electric Power Research Institute 2014)

lifetimes, the resulting NPV's are multiplied by a simple ratio of project time horizon to actual technology lifetime.

3.4.4 Financial Inputs

This class of inputs focuses on the economics and details such as debt to equity ratios, tax rates, and regulatory incentives. These financial inputs are keys to completing the cost benefit analysis, since the final results from valuation analysis are represented in the form of several financial and economic outputs, optimization and simulation dispatch outputs, and the conversion of those time-series outputs into a financial model.

3.4.4.1 ES-Select Model

ES Select uses simplified financial and macroeconomic inputs that are used across all markets and ancillary services as well as simulated ES technology classes. A summary of financial inputs for ES Select is shown in Table 138.

Table 138. Financial Inputs for ES Select Valuation Tool

Financial Parameters	Values		Source
Escalation of Benefits (%)		0.95%	<1% from Pillar 1
Discount Rate (%)		7.00%	from Pillar 1
Electricity Price Escalation (%/yr)		9.00%	Pilar 1 Base+Storage
Cost of Energy for Charge ($/MWh)	18.05	51.89	Pillar 1 Base+Storage average +/- two standard deviations
Project Life (years)		20	Aligns with Pillar 1
Inflation Rate (%)		1.90%	Average of 1.6% and 2.2% from Pillar 1

3.4.4.2 ESVT Model

The ESVT model incorporates key ownership and financing attributes, along with macroeconomic factors, to develop multiple project level outputs. Additionally, it performs a number of additional calculations for quick metrics and comparison that may be of interest to a user. The key inputs include ownership type, financing information, project term, inflation, discount rate, project cost information, and key outputs including benefit to cost ratios, NPV, net cost of capacity, breakeven CAPEX, and project pro forma financials. The financial inputs and an illustrative output from the financial calculations and consistency with the common ES financial parameters are provided in Table 139.

3.4.4.3 Treatment of Financial Ownership Structure

Possible ownership types include Investor Owned Utility (IOU), Publically Owned Utility / Municipality Owned (POU/Muni), Independent Power Producer (IPP), Co-Operative (Co-Op), Residential Customer, and so on.

Given that Ontario is a deregulated market, and the project scope is mainly in front of the meter, an Independent Power Producer (IPP) was chosen as the ownership structure. Details for the IPP ownership structure are shown in Table 139. Information was taken from public finance and tax data for Ontario and other published sources. Where applicable, economic inputs are aligned with assumptions in Pillar 1. Uniform IPP ownership structure and details were used for all ES simulations, although in the latter two Use Cases of this study, the ES asset is customer sited (behind-the-meter) but controlled front of the meter. This facilitates the horizontal comparison between Use Cases where different value streams are included and thus the impact of stacked services can be easily identified.

Table 139. Financial Inputs for ESVT Valuation Tool and IPP Ownership Structure

Financial Inputs	Ownership Type	IPP
Financing Inputs	% Debt (typical for IPP)	20%
	Debt Interest Rate [38]	5.17%
	% Equity (typical for IPP)	80%
	After Tax Nominal WACC (Pillar 1 Discount Rate)	7.00%
	Return on Equity	7.76%
Tax Inputs	Federal Income Tax Rate	15%
	Provincial Income Tax Rate, ON	10%
	Property Tax Rate, ON	1.25%
	Modified Accelerated Cost Recovery System (MACRS) Term (Years)	15
	% of Capital Cost Eligible for Tax Credit	0%
Economic Inputs	Inflation Rate (%/Year)	1.90%
	Fuel Escalation Rate (%/Year)	1.73%
Non-Tax Incentives	$/kW Province or Local Rebate ($/kW)	0.00
	$/kW Province or Local Rebate 2 ($/kW)	0.00

3.4.4.4 Taxes and Incentives

In order to represent Canadian taxes paid, three levels of taxes were interpreted from U.S. based taxation to a Canadian based tax model. They are federal, provincial and property taxes.

With respect to regulatory incentives, currently there are no Canadian federal or Ontario provincial regulatory incentives for ES. Federal tax credits and provincial local rebates could be modelled in the future once the data is available.

3.5 ES Technologies Ranking and Selection

In this ranking analysis of ES technology classes, the ES-Select valuation tool is customized with Canadian markets and services data for BC, AB and ON (Malek and Skrivan, ES Select Canada BETA 2014). The cost-benefit models were mapped to scenarios (or use cases) of services that are available on the Ontario electric system and are shown in Table 140 and Table 141.

3.5.1 Model Assumptions and Implications

ES Select simulates several ES technology classes simultaneously over the same user selected project lifetime and holds all inputs and selections constant. ES Select cannot account for different ES technology lifetimes or decreases in ES technology costs over time, nor can it account for the effect of ES deployment on the value of market and service benefits. ES Select is a “price taker” and assumes all inputs are fixed during the entire simulation.

[38] The Debt Interest Rate is back calculated based on WACC of 7% that is the discount rate used in Pillar 1, IPP debt to equity of 20:80, and so on.

Future versions of the Ontario Chapter could use similar valuation tools to ES Select, once available, that are more customizable and can be updated with the latest cost, performance, lifetime ES data, current market and service benefit values for Ontario, and finally add market and service benefits specific to Ontario.

3.5.2 Modelling Details

In ES Select, ES technology classes are modelled by installed capacity ranges (MW) depending on their location or placement on the grid in decreasing voltage from the system level on down to the end user or customer level. Of the five locations decreasing from Generation (> 50MW), Transmission (≤ 10MW), Distribution (≤ 2MW), Commercial & Industrial (≤ 1MW), and Residential (≤ 100kW), the Generation and Transmission levels were modelled for two reasons. The first is based on what market and service benefits are possible at each level or location in ES Select, and the second is based on both IESO's ESAG guidelines and this project's scope.

First, Pillar 2's valuation tools simulate ES based on profitability or maximum possible NPV. The highest value market and service benefit in the ES Select valuation tool survey of ES in Ontario was Load Following which in ES Select is available at three of five locations: Generation, Transmission and Distribution. Second, IESO's ESAG guidelines state ES can't participate in wholesale markets at the Distribution level, and customer-sited or behind-the-meter ES is out of scope for this project. So respectively the Distribution, Commercial & Industrial and Residential locations are excluded in ES Select.

In ES Select, up to six market and service benefits can be selected at each grid location or level, and their priority or dispatch order can be changed by the user to maximize the combined or bundled range of benefit values. This is shown for the Generation Level in Table 140 and at the Transmission Level in Table 141. Note "Load Following" is not a market or service benefit currently offered by IESO but was listed as the highest value service in the NRC's survey of Ontario stakeholders (Malek and Skrivan, ES Select Canada BETA 2014). All of ES Select's "…Energy Time Shift" are essentially variations on IESO's Real-time Energy Market and Day-Ahead Commitment Process. See Table 134 for detailed descriptions.

Table 140. Generation Level Over 50MW (Central or Bulk Storage) Grid Application Priority and Annual Benefit

Priority	Grid Application	Annual Benefit LO (CAD/kW)	Annual Benefit HI (CAD/kW)
1	Load Following	$450.00	$850.00
2	Supply Spinning Reserve	$12.00	$61.00
3	Solar Energy Time Shift (Arbitrage)	$33.00	$56.00
4	Energy Time Shift (Arbitrage)	$15.40	$28.00
5	Black Start	$4.60	$8.90
6	Wind Energy Time Shift (Arbitrage)	$14.00	$80.00

At the Generation Level, maximum bundle value is $554 to $958 CAD/kW. Neither Hot nor Cold Thermal Storage are available at the generation level. However both are available at the Commercial / Industrial level. Voltage Support services are not available at this level in ES Select.

Table 141. Transmission Level up to 10MW (Substation) Grid Application Priority and Annual Benefit

Priority	Grid Application	Annual Benefit

		LO (CAD/kW)	HI (CAD/kW)
1	Load Following	$450.00	$850.00
2	Supply Spinning Reserve	$12.00	$61.00
3	Solar Energy Time Shift (Arbitrage)	$33.00	$56.00
4	Energy Time Shift (Arbitrage)	$15.40	$28.00
5	Wind Energy Time Shift (Arbitrage)	$14.00	$80.00
6	Voltage Support	$0.00	$0.00

At the Transmission Level, maximum bundle value to the ES owner is $551 to $955 CAD/kW. Cold Thermal Storage is available at this location; however, Hot Thermal Storage is not. Both are available at the Commercial / Industrial level. Black Start services are not available at the Transmission level in ES Select; however, Voltage Support services are available. Ontario stakeholders surveyed put the value of Voltage Support that ES could capture at zero (Malek and Skrivan, ES Select Canada BETA 2014).

3.5.3 Modeling Results

Multiple ES Select output metrics are possible, and for the purpose of this study, results are shown that include the main output or ranking by Feasibility Score as well as financial metrics like Payback Time and NPV ranges (DNV KEMA Inc. December 31, 2012). Results are shown at the Generation Level in Table 142 and at the Transmission Level in Table 142.

Table 142. Generation Level Feasibility Score, Payback Time in Years and NPV in CAD/kW Listed in Descending Order

Storage Option	Feasibility	Payback Time (years)		NPV (CAD/kW)	
Abbreviation	Score	Min	Max	Min	Max
CAES-c	76%	2	3	$ 3,938	$ 8,954
Hybrid	38%	3	4	$ 2,928	$ 7,835
CAES-s	31%	6	7	$ 1,845	$ 6,825
P-Hydro	73%	5	6	$ 1,845	$ 6,247
NaNiCl	40%	6	7	$ 1,196	$ 6,247
VRLA	38%	6	9	$ (969)	$ 4,335
LIB-e	45%	8	12	$ (825)	$ 4,299
NaS	62%	9	11	$ (1,113)	$ 4,082
LA-adv	33%	14	15	$ (3,495)	$ 2,351

Table 143. Transmission Level Feasibility Score, Payback Time in Years and NPV in CAD/kW Listed in Descending Order

Storage Option	Feasibility	Payback Time (Years)		NPV (CAD/kW)	
Abbreviation	Score	Min	Max	Min	Max
CAES-c	56%	2	3	$ 3,550	$ 8,538
Hybrid	58%	4	5	$ 2,200	$ 7,263
A-VRFB	51%	5	6	$ 2,200	$ 7,000
CAES-s	51%	6	7	$ 1,375	$ 6,400

Ni-batt	47%	5	6	$ 1,225	$ 6,400
NaNiCl	57%	6	7	$ 1,120	$ 6,100
ZnBr	52%	6	9	$ 100	$ 5,500
VRFB	50%	8	12	$ (163)	$ 5,050
LIB-e	57%	11	20	$ (1,250)	$ 3,700
NaS	63%	10	20	$ (1,625)	$ 3,625
VRLA	54%	9	20	$ (1,813)	$ 3,550
LA-adv	49%	>20	>20	$ (4,400)	$ 1,600

A combined score used ES technology classes that were present in both Table 142 and Table 143 and multiplied their respective feasibility scores. Any ES technology class that wasn't in both tables was excluded from the ranking process. The combined feasibility scores were listed in descending order, with their overall ranking in increasing order shown in Table 144.

Table 144. Combined Feasibility Score for Generation and Transmission Levels and Ranking of ES Technology Classes in Descending Order

Storage Option Abbreviation	Feasibility Score Combined	Rank
CAES-c	43%	1
NaS	39%	2
LIB-e	26%	3
NaNiCl	23%	4
Hybrid	22%	5
VRLA	21%	6
LA-adv	16%	7
CAES-s	16%	8

Only eight of the initial nineteen ES technology classes of at least 10MW have a combined score greater than zero, and the top five are CAES-c, NaS, LIB-e, NaNiCl and Hybrid. Pillar 2 will take a deep dive on specific, project level examples of the top three: CAES-C, NaS, and LIB-e using the ESVT valuation tool.

In the ES Select and ESVT valuation tools, CAES-c data is for underground or cavern storage which constrains the location or siting of a potential project to specific geological formations. This study assumed either domal or bedded salt formations could site CAES-c (Akhil, Huff and Currier 2015), restricting possible locations to the Great Lakes region between Lake Huron and Lake Erie (Butler, et al. 2018).

Tying back the analysis to storage technology categories in Table 18 of Pillar 1, CAES-c is an example of Long duration (L), NaS is an example of a Medium-Long duration (ML), and LIB or Lithium-ion is an example of L, ML, Medium-Short (MS) and Short duration (S). Lithium-ion is the only ES technology class that cuts across all four ES durations modelled in Pillar 1. Thus in the next section, a detailed ESVT analysis will focus on a specific example of potential Lithium-ion ES projects in three Use Cases.

3.6 Case Studies

Table 145 lists a matrix depicting the combinations of wholesale market products that an ES system can participate in today, adapted from IESO's ESAG group meeting presentation held on February 18, 2020 (IESO's ESAG 2020). The columns represent what service ES is providing and the rows represent what other services ES can provide simultaneously. This forms the basis of what services can be "stacked" according to IESO market participation rules and regulations, and in turn, how Case Studies or Use Cases were created. However, as shown in Use Case #3, the services of "Real-time Energy" and "Demand Response auction" are still stacked for the same ES system, which is because the ES is assumed to be capable to provide Real-time Energy service only out of the commitment period for Demand Response auction. Here the product Demand Response (DR), which cannot be directly accessible by ES before, will be replaced by Capacity Auction, which ES can participate in. In some cases, when an ES is registered to participate in a given wholesale market, service product is mutually exclusive to providing another service, for example, Demand Response/ Capacity Auction precludes participation in energy and operating reserve markets. That means, in today's IESO-administered markets, not all market service products can be stacked for the most benefit of the ES owner.

Table 145. Possible Combinations of IESO Wholesale Market Products that ES can Participate in Today (IESO's ESAG 2020)

	Real-time Energy	Operating Reserve	Regulation Service	Reactive Support and Voltage Control	Demand Response /Capacity Auction
Real-time Energy		Yes	No	Yes	No
Operating Reserve	Yes		No	Yes	No
Regulation Service	No	No		Yes	No
Reactive Support and Voltage Control	Yes	Yes	Yes		No
Demand Response /Capacity Auction	No	No	No	No	

In Table 145 moving down a column, the green boxes marked 'Yes' indicate what other IESO market or service in each row ES can participate in simultaneously. The red boxes marked 'No' indicate ES cannot participate simultaneously in that row's market or service. Finally, the greyed out boxes are the diagonal of the matrix.

However, for those specific service products, such as DR/Capacity Auction, the commitment periods for these services can be chosen, and thus the ES system can still participate in multiple market service products only with a time restriction. In this section, two cases (#1 and #3) are studied for maximizing the profit of the asset owner by participating in the existing IESO wholesale market; one case (#2) includes an additional benefit stream (Global Adjustment savings) that does not belong to the market service products but proves to have a significant impact on the asset owner's profit based on the pre-existing policies/rules over GA in 2019. It is noted that Global Adjustment savings is a particular benefit to the customer. This generally requires the ES asset to be installed on a customer site that is neither transmission site nor the distribution site; however, it is still studied here as a unique case to the Ontario market assuming the ES asset is owned and operated by the IPP front of the meter. The three use case studies are summarized in Table 146, along with the identified Benefit-to-Cost ratios. Details of each case will be described below.

Table 146. Brief Summary of ES Use Cases Being Studied

	Use Case #1	Use Case #2	Use Case #3
Real-Time Energy	Y	Y	Y
Operating Reserve	Y	Y	Y
Regulation Service	n/a[1]	n/a[1]	n/a[1]
Reactive Support and Voltage Control	n/a[2]	n/a[2]	n/a[2]
Demand Response / Capacity Auction	N	n/a[3]	Y
Global Adjustment Reduction	N	Y	n/a[3]
Benefit-To-Cost Ratio	**0.61**	**0.98**	**0.59-0.63**

[1] ES can't participate in IESO's Regulation Service. Data was unavailable at the time of this report.

[2] Unclear if ES can participate in IESO's Reactive Support and Voltage Control. Data was unavailable at the time of this report.

[3] The valuation tool can't simultaneously model or stack Demand Response and Global Adjustment even if IESO market rules and regulations allowed ES to do so.

The simulation's benefit-to-cost ratios and NPV's are likely a lower bound for three reasons outlined in Table 146, and described in more detail here. First, in other US and Canadian jurisdictions, Frequency Regulation, Spinning Reserves and Non Spinning Reserves in decreasing order are what make ES projects profitable. So the fact that ES cannot participate in the Regulation Service (Frequency Regulation) decreases the benefit to cost ratio. The same goes for Reactive Support and Voltage Control, but to a lesser extent. Second, even if ES could participate in these services, the corresponding data was not available at the time of this report, and hence couldn't be modelled in the valuation tool. Third, IESO's Demand Response / Capacity Auction and non-market charges like Global Adjustment, respectively, either operate differently than, or aren't found in, the valuation tool's generic North American markets and services. The valuation tool's System Electric Supply Capacity (SESC) was customized to simulate either Demand Response or Global Adjustment. So even if the IESO market allowed ES to participate in both Demand Response and Global Adjustment, the valuation tool can't simulate both in a Use Case.

In summary, for these three reasons: IESO market constraints, data accessibility, and compatibility with the valuation tool, the Use Cases simulated tend to underestimate ES benefit to cost ratios.

3.6.1 Use Case #1: IPP Owned Transmission-sited Energy Storage for Market Services

The primary value driver of IPP-owned transmission-sited energy storage systems comes from maximizing the profit of the asset owner by participating in the existing IESO wholesale market. It assumes the storage units have the necessary equipment, metering, and software to communicate in a network with the utility and IESO. In this use case, the following potential benefit streams were modelled:

Market services

- Electric energy time-shift
- Spinning reserve, and
- Non-spinning reserve

It is noted that the ancillary service, Frequency Regulation (FR), is also in existing IESO Procurement Markets; however, it is excluded from this case study because: 1) currently the market is not open to any ES technologies, although some ES systems may exclusively provide the FR service through 2017 Request for Proposals (RFR) for incremental regulation capacity; a contract format, 2) the historical pricing data for FR market service is not accessible and prevents us from testing its impact by assuming the ES can participate in the FR procurement market. In addition, service of Black Start is included as one possible value stream but not shown in this report due to its negligible impact on all results.

3.6.1.1 Use Case Modelling Approach

3.6.1.1.1 Data resources

To evaluate the ES asset owner's best profit by participating in the above selected IESO market services in ESVT, we utilized historical 8760 Hourly Ontario Electricity Price (HOEP) data for electric energy time-shift purposes, and historical 8760 hourly prices awarded for 10-minute spinning reserve and 10-minute non-spinning reserve for operating reserve market services, respectively. These data are publicly accessible through IESO's website (http://www.ieso.ca/en/Power-Data/Data-Directory). Particularly for this study, the price data from the single year of 2018 were used due to their relative completeness in all types of required data.

3.6.1.1.2 Benefit calculations as modelled in Use Case #1

Energy time-shift value in the real-time energy market is modelled as the difference in the value of selling stored electricity minus the cost of lower price electricity that was stored, and accounting for the roundtrip losses of the energy storage system.

Spinning and non-spinning reserves are modelled as contingency reserve services, so ESVT awards this capacity-based service value to energy storage, as long as it has at least one hour of energy stored to supply operating reserve energy if called upon in a contingency scenario. The ES selected for providing this reserve energy is paid the market clearing price for that class, which is determined every five minutes based on offers in the market. When the operating reserve is activated, the ES owners are paid for the energy provided also.

3.6.1.1.3 Financial and technology inputs

This use case assumes that the ES installation is transmission-sited and the ownership structure is Independent Power Producer (IPP). The detailed financial inputs and technology cost/performance considerations can be found in Table 139 and Table 137, respectively.

3.6.1.2 ESVT Prioritization and Optimization

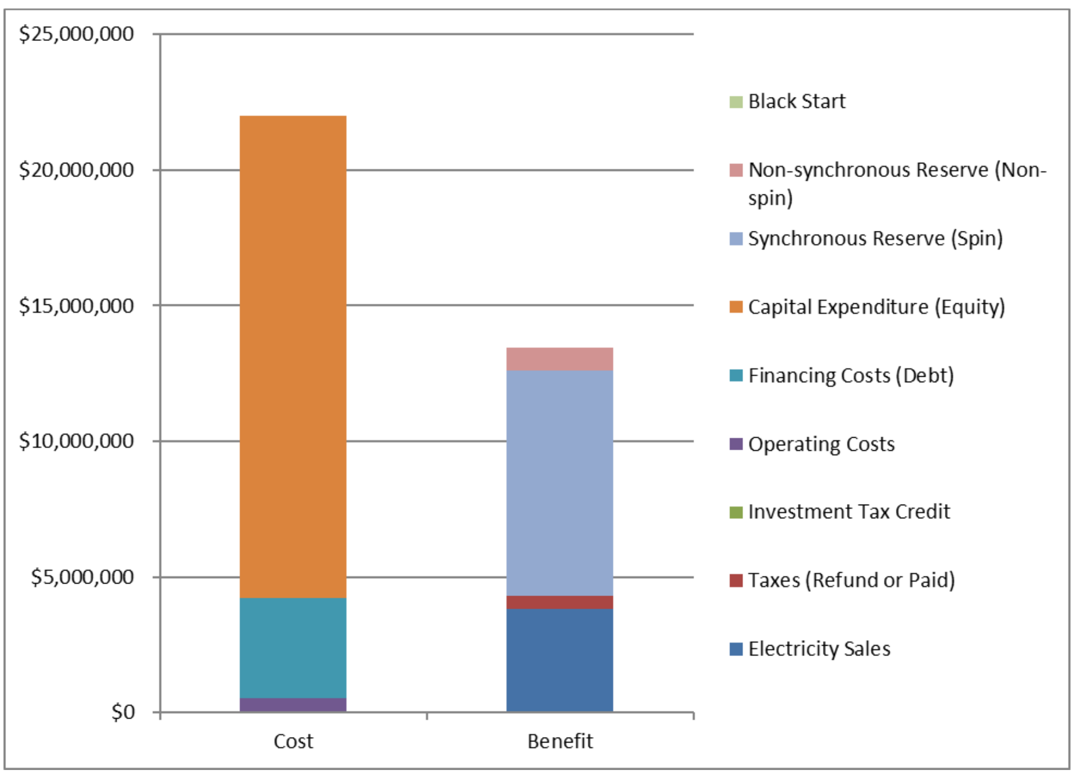
The scheduling of operating reserves and energy in the real-time energy markets are co-optimized, since they have equivalent priority in ESVT optimization architecture, to ensure the highest profit for the ES system owner. Combining the received payments from providing above services with the ES system cost and performance data, the benefit-to-cost ratios for each scenario were calculated using ESVT's prioritization and optimization algorithm. The benefit-to-cost result of this Use Case will be compared with other Use Cases, Storage Scenarios and Modelling Results.

In this case, the ES was modelled as one large LIB energy storage system of 10MW and 2 hours of energy duration, and its performance data can be found in Table 137. For this scenario assumption, the net present value (NPV) of the lifetime benefits and costs is illustrated in Table 147, where a cost-to-benefit ratio is also provided.

Table 147. Net Present Value over Project Life of Use Case #1

	Cost ($)	Benefit ($)
Electricity Sales	$0	3.80E+06
Taxes (Refund or Paid)	$0	4.82E+05
Operating Costs	5.15E+05	$0
Financing Costs (Debt)	3.69E+06	$0
Capital Expenditure (Equity)	1.78E+07	$0
Synchronous Reserve (Spin)	$0	8.31E+06
Non-synchronous Reserve (Non-spin)	$0	8.59E+05
Total	2.20E+07	1.35E+07
Benefit-to-Cost Ratio		**0.61**

Figure 51. Benefits and Costs over Project Life of Use Case #1 (only existing Market Services).



Use Case #1 is an illustration of one large LIB ES system; 10MW and 2 hours of energy duration accomplishing existing market services for Ontario's IESO with maximized benefits to the owner of the ES asset. While it only requires 1 hour's energy duration for the operating reserves in Ontario, an ES system with 2 hours' duration was used in this case study in order to have an appropriate comparison with other cases as studied in Cases #2 and #3, where 2 hours' energy duration is necessary.

As shown in Table 147 and Figure 51, when only three typical market services are provided, the benefit-to-cost ratio of the studied ES system is 0.61, which is less than the break-even value 1. This indicates the ES asset is losing money for this scenario study.

3.6.2 Use Case #2: IPP Owned, Customer-Sited ES, Shared Control by Customer and Utility for GA Reduction (Class-A) and Grid Market Services

This use case is built on top of Use Case #1, but the ES asset is relocated to the customer-side. The assumption is that the ES asset is owned and controlled front of the meter (externally) by the IPP. The primary value driver of putting the ES system to customer site is to lower the customers' global adjustment charge, since under the current IESO's policy (by October, 2019) the global adjustment charge could be a significant portion of a large customer's electricity bill.

The assumption for this case is that an ES asset is installed at the large customer's site, primarily aiming to reduce the customer's GA charge, but also to share in its operation with a utility to participate in the IESO's market services during hours when it is not utilized for GA reduction. The underlying reason for having this combined value stream is that the Class-A customer generally only needs the use of ES within a very limited time period to reduce the GA charge, and thus the unutilized availability of ES could provide services to the IESO market to earn additional value. Therefore, in this use case, in addition to reducing the customer's GA charge, ES will also be deployed for providing the same market services as stated in Use Case #1. Being able to provide the IESO's market services, we consider this use case is still within the scope of our study. The same transmission-sited ES, including capacity and energy duration, as used in Use Case #1 is deployed here at the customer site. The ES is assumed to be owned and controlled or operated front of the meter by a third-party, IPP. This assumption is done in order to simplify financial modelling comparisons from this Use Case to others for readers. We also assumed the IPP controls the scheduling of ES for each service on the basis of achieving the maximum overall benefit to the asset owner. This is consistent with the optimization principle as implemented in the evaluation tool ESVT.

It is noted that the rules are now under discussion on how the GA charge on a customers' bill in Ontario would be modified or adjusted; however, in this study the existing GA charge method is used to investigate its impact on deployment of ES technologies. The scenario where no GA charge is included as investigated in Use Case #1 is compared. No other GA charge scenarios were studied since no clear information about evolvement was obtained.

It is noted that the ESVT tool will optimize the scheduling of ES for various services/purposes automatically based on the maximization of the overall benefit of the asset owner. Therefore, in principle the final optimization result may or may not guarantee the customer's best GA reduction benefit. However, according to the existing GA charge policy (by October, 2019) and the recent historical prices for wholesale markets, the GA charge reduction was actually found to be the largest contribution to the overall benefit, as shown below. The assumed GA reduction calculation method was thus proven to be valid in this case.

3.6.2.1 Use Case Modelling Approach

Except for GA reduction, all other benefit streams are the same as used in Use Case #1. The same data sources and benefit calculation methods as used in Use Case #1 are also utilized here. Below the benefit calculation for GA reduction, which is a unique feature of Ontario jurisdiction and not a directly implemented benefit stream in ESVT 4.0, is introduced. Basically it is a re-routing way to calculate the GA reduction through the existing *System Electric Supply Capacity* benefit function as implemented in ESVT 4.0.

3.6.2.1.1 Benefit calculation for GA reduction and data sources

As stated in Appendix 'Benefit Calculation Methodology', Class-A customers have the ability to reduce their GA fees by reducing their own demand during those hours when Ontario's electricity system is experiencing its top five coincident demand peaks in a given year. An installed ES behind the meter of a Class-A customer may be able to achieve this goal. In particular, this use case studied the impact of the ES system on the reduction of the Global Adjustment charge for Class-A customers.

To evaluate GA charge reduction in ESVT, mostly through the demand reduction at the top five coincident demand peaks Ontario-wide in a given year, we utilized the publicly accessible Ontario total demand 8760 hourly profile for 2018 , the annual total GA costs in 2018 , the total electricity consumption of the top 5 peak demand hours for 2017-2018, and customized the ESVT tool's function of "system electric supply capacity" benefit calculation into the "global adjustment charge reduction" calculation. This customization process is validated through comparison of the need with the provided benefit calculation function "system electric supply capacity" as shown in Appendix 'Benefit Calculation Methodology'.

According to the GA charge calculation for Class-A customers (IESO 2019a), GA reduction is calculated to be the percentage contribution of the consumption reduction (due to the use of ES) to the top 5 peak Ontario demand hours over a 12-month period. In analogy, when applied in ESVT, the benefit of ES application to GA reduction is calculated to be:

$$GA\ charge\ reduction(\$) = GA\ Payment\ rate\ \left(\frac{\$}{kW}\right) \times Capacity\ Derate \times Storage\ Capacity\ (kW) \qquad (1)$$

Where GA Payment rate is the same as the GA charge rate ($/kW) that can be calculated through the Capacity reduced during the top 5 peak Ontario demand hours and the total GA charge over the past 12-month period, Storage Capacity (kW) is the nameplate capacity of the ES system that is assumed to be fully discharged for demand reduction as scheduled, and the Capacity Derate is a factor that accounts for the non-performance penalty due to the unavailable capacity or short energy duration.

GA Payment rate is assumed to be constant along the project years, staying the same as the GA charge rate ($/kW) calculated for the reference year. The detailed calculation of GA charge reduction is described in Appendix 'Benefit Calculation Methodology'. The minimum capacity duration is 1 hour, since only the top demand hour is available (at most one top demand hour is counted each day, according to IESO's GA payment calculation method (IESO 2019a)). We assume the probability to dispatch ES in defined top 5 demand hours per year is 100%, which indicates the Capacity Derate is 1, meaning there is no non-performance when being dispatched. This value for ES is derated proportionally to the number of peak hours when it is unavailable to provide its discharge capacity. See Appendix 'Benefit Calculation Methodology' for further information.

3.6.2.2 ESVT Prioritization and Optimization

Figure 52 illustrates the modelled service prioritization and co-optimization in this Use Case as applied by ESVT 4.0. High priority modelled grid services are displayed above lower priority modelled grid services. Services that are at the same priority are shown at the same level and optimized economically in the simulation.

It is seen that in this Use Case, the grid service "System Capacity" has the highest model priority, and the others are at the equivalent priority level. Note that here "System Capacity" actually represents the "GA reduction" value stream for a large customer, which means that the "GA reduction" is firstly prioritized over any other modelled market services when scheduling the ES's usage. This is consistent with the original setup of the Use Case. The commitment to provide GA reduction for the customer is only within a few short time periods according to the peak demand hour prediction. Ideally, when the predicted top five peak demand hours are coincidentally consistent with the real case, only the top 5 peak demand hours would need ES's discharge to reduce the demand from the grid (a possible future study could simulate the impact of the top 25 peak hours scenario for comparison). To account for the penalty of non-performance due to the mis-predicted top 5 peak demand hours, the benefit value ESVT assigns to GA reduction (system capacity) is de-rated based on how well the storage system has met its peak demand hours in reality. Beyond those specified 5 hours, which are a very short commitment time period, the remaining capacity of ES will be scheduled to provide other specified market services.

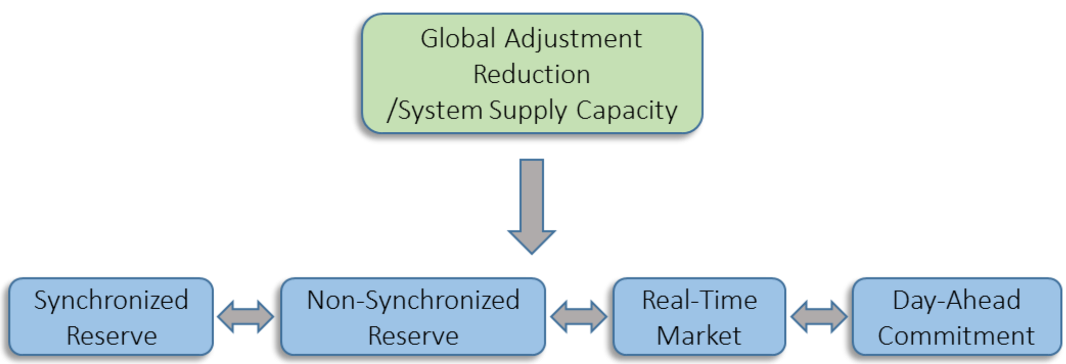


Figure 52. Modelled Services Prioritization in Use Case #2

3.6.2.3 Storage Scenarios and Modelling Results

In this case, the same ES type and size LIB of 10MW and 2 hours of energy duration, was firstly modelled as that used in Use Case #1. We assume the ES is installed on the site of a Class-A customer whose general electricity consumption is quite large, with peak demand larger than 10MW, and thus the entire capacity 10MW of the ES was assumed to be able to be fully discharged when being dispatched for GA reduction. It is reasonably assumed that even after the compensation of the ES usage on specified hours, the customer is still qualified for the participation of ICI, as a Class-A customer, so that the benefits of GA reduction could be practically realized.

Using the historical GA calculation matrix for the base period 2017-2018, and assuming all five top demand peak hours were exactly captured by the ES's energy substitution, the GA reduction rate that was used in ESVT was calculated to be \$104.3/kW-year (See Appendix 'Benefit Calculation Methodology'). We assume ES would be available for providing other grid services during all time windows other than those five top demand peak hours.[39] For this scenario assumption, the net present value of the lifetime benefits and costs is illustrated in Table 148 with a cost-to-benefit ratio provided.

Table 148. Net Present Value over Project Life of Use Case #2

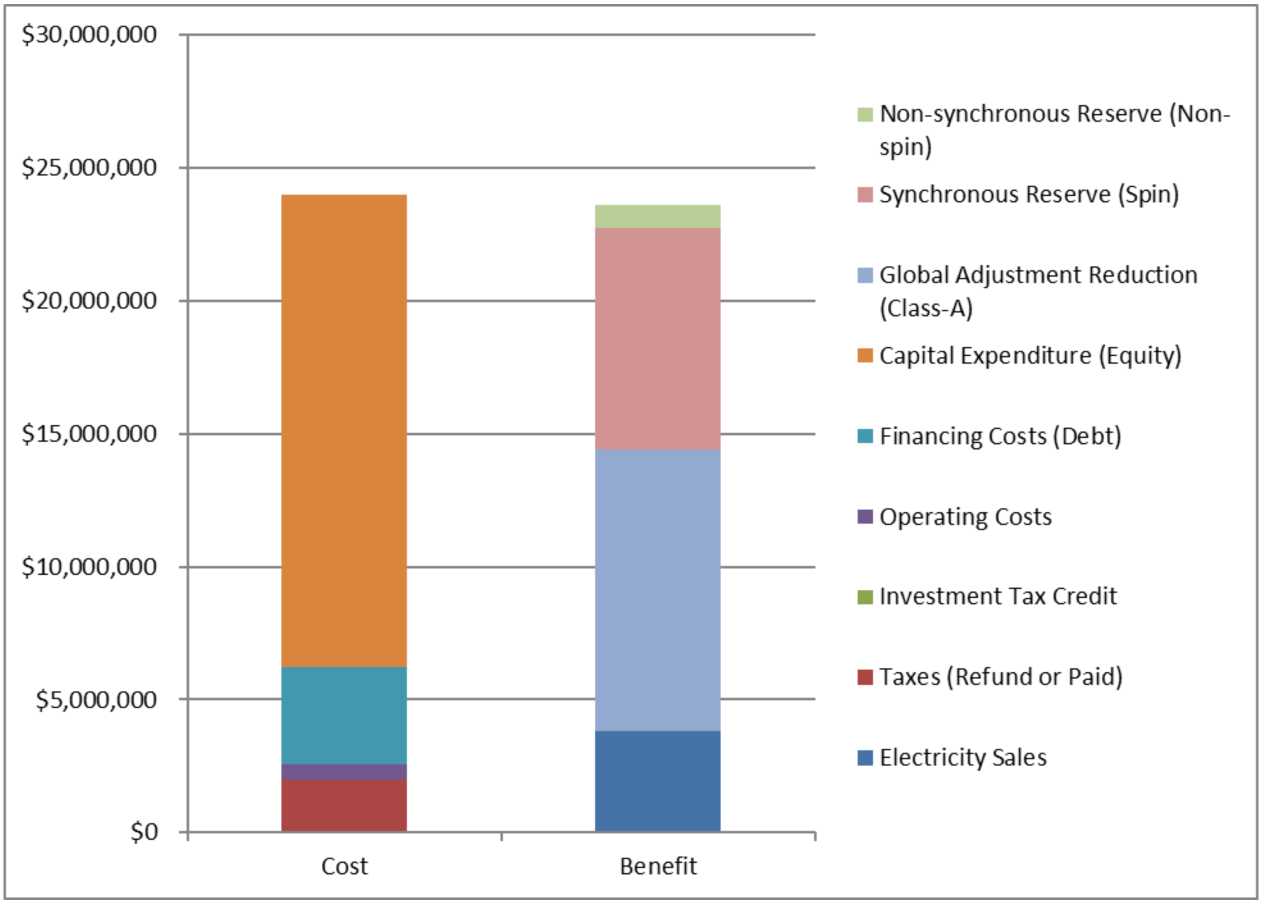
	Cost ($)	Benefit ($)
Electricity Sales	$0	3.80E+06
Taxes (Refund or Paid)	$2,005,839	0.00E+00
Operating Costs	5.34E+05	$0
Financing Costs (Debt)	3.69E+06	$0
Capital Expenditure (Equity)	1.78E+07	$0
Global Adjustment Reduction (Class-A)	$0	1.06E+07
Synchronous Reserve (Spin)	$0	8.30E+06
Non-synchronous Reserve (Non-spin)	$0	$860,220
Total	$24,010,664	2.36E+07
Benefit-to-Cost Ratio		**0.98**

The cost-to-benefit ratio is increased to 0.98 when compared with the 0.61 of Use Case #1. Basically the only difference between Use Case #2 and Use #1 is the inclusion of GA reduction in Use Case #2. Although the location of the installed ES is changed from the transmission site to the customer site, the ownership data and the ES technology data are kept the same. Therefore, from this comparison, we can see that the impact of the inclusion of GA reduction benefit is dramatic, increasing the cost-to-benefit ratio from 0.61 to 0.98. Now in this case, the ES technology's benefit and cost nearly reach the break-even point.

As shown in Figure 53, the value stream from GA reduction counts the largest contribution that is 45% of the overall benefit, even larger than the Synchronous Reserve's contribution that takes 35%.

Figure 53. Benefits and Costs over Project Life of Use Case #2 (GA Reduction along with Existing Market Services).

[39] In the current study, the historical IESO demand data were used so the top 5 peaks are known, and so only the 5 top demand hours were exactly captured for the GA reduction purpose. However, in reality this wouldn't be the case. More (e.g., 20-25 hrs) demand peaks from the historical data may need to be allocated to the use for GA reduction in order to capture the actual 5 top demand peaks. A future study could examine this effect.



3.6.3 Use Case #3: IPP Owned ES for Demand Response Auction (to be replaced by Capacity Auction) and Grid Market Services

This case is also built on top of the Use Case #1, with the additional value of having the Demand Response (DR) Auction included. The energy storage asset is located at the site of a large customer, belonging to behind-the-meter instead of in-front-of-the-meter, but it is able to participate in the IESO-administered market and thus is regarded to be within the scope of our study. The primary value driver of putting the ES system to customer site now is to allow the customer who installed the ES asset to participate in the Demand Response Auction.

In this Use Case, ES can make the time-shift of the grid electricity use by charging during low electricity demand periods and discharging during high demand periods. When participating in the DR Auction set by IESO, the ES should be ready to be called upon for discharging during the commitment periods that cover high demand hours, and the owner of the ES will receive the corresponding availability payment for the participation aside from the cost/benefit incurred in participating in the energy market. Outside those commitment periods, ES can participate in any other preferred market services to add to its value.

It is noted that, similar to the GA reduction value stream as described in Use Case #2, the DR Auction value stream is also quite unique to the Ontario jurisdiction, and the ESVT 4.0 tool does not have its value calculation implemented directly. Instead, we built upon an existing value calculation function, which is the "*system electric supply capacity*" from the ESVT 4.0, and adapted it to the need for the DR Auction value calculation to meet our goal. Therefore, we understand that due to the limitation of the utilized ESVT tool, we can only simulate either the GA reduction or DR Auction value stream in a specified use case, although theoretically both value streams can be stacked together to a large extent. This limitation may restrict the ES owner from achieving the maximum profit.

While there are extra potential benefits from time of use (TOU) energy charge shifting from peak to off-peak, it is excluded from this study because we focus only on the impact of the participation of DR Auction on the ES owner's profit.

In this use case, it is highly possible that the ES is owned by the customer where the ES is installed. While the ownership of ES could be the customer, the IPP ownership structure with the same inputs as in previous Use Cases is utilized to make it consistent and easy for comparison for the readers' benefit.

It is noted that, at the time of writing this report, IESO has announced that starting December 2019, the Capacity Auction will replace the existing DR Auction to enable competition between additional resource types (IESO 2019). Although there is no clear published policy yet on how ES can participate in the new Capacity Auction, from the released information through very recent ES Canada's Webinar (Energy Storage Canada 2019), we were informed that only the ES registered as dispatchable generator is permitted to participate in the Capacity Auction, whereas the behind-the-meter ES will continue to participate in the Auction as a DR resource. IESO and ES Canada are putting efforts into rolling out the first Capacity Auction in June 2020 for the 2021 – 2022 commitment periods (Energy Storage Canada 2019).

In this Use Case, we will firstly continue presenting our original study result with the ES on the customer site, participating in the Auction as a DR resource. To accommodate the policy change occurring in the coming Capacity Auction (CA), a second scenario will be discussed separately later where ES will be located on a transmission site and will participate in the Capacity Auction as the generator resource. It is noted that the goal of the Capacity Auction program to be implemented by IESO is by definition differentiated from that of the *System Electric Supply Capacity* value stream built in the ESVT 4.0; therefore we would not use the *System Electric Supply Capacity* benefit calculation directly. Instead, we customized it in a similar way to the scenario of the DRA benefit calculation for the CA benefit calculation.

3.6.3.1 Use Case Modelling Approach

For those market services, the same data sources and benefit calculation methods as used in Use Case #1 are also utilized here. While DR Auction is not a common feature in jurisdictions in North America, and thus is not a directly implemented benefit stream in ESVT 4.0, similar to the GA reduction calculation used in Use Case #2 we use a re-routing way to calculate the DR Auction benefit through the existing *System Electric Supply Capacity* benefit function as implemented in ESVT 4.0. Details of the calculation are introduced below.

3.6.3.1.1 Benefit calculation for Demand Response Auction (DRA)

Similar to the case of GA reduction value stream described in Use Case #2, the DR Auction value stream is not implemented in ESVT directly. The function of "*system electric supply capacity*" from the ESVT 4.0 will be adapted for the DR value calculation. Details can be found in Appendix 'Benefit Calculation Methodology'.

According to IESO, benefit from DR Auction participation is calculated based on the availability payment the ES receives that is associated with the committed capacity within the committed time period. In analogy with the "system electric supply capacity" function implemented in ESVT, this availability payment calculation is translated as:

$$Availability\ Payment = Storage\ Capacity \times Capacity\ Value \times Capacity\ Derate \quad (2)$$

Where Storage Capacity is the DR Capacity Obligation (MW), Capacity Value is the same as the DR Auction Clearing Price ($/MW-day) determined by IESO but transformed into the unit of $/kW-yr for the usage in ESVT, and Capacity Derate is a factor that is based on the actual system capacity service hours provided as the probability to dispatch in committed capacity hours. This derating method is used as an approximation for penalty for non-performance when providing this DR service under contract.

The DR Auction Clearing Price is also assumed to be constant along the project years, keeping the same rate as adopted for the reference year. To ensure this assumption is valid, in ESVT we set up the CONE (cost of New Entry) value, which is meaningless in this case study, to be the same as the DR Auction Clearing Price at the reference year.

3.6.3.1.2 Data sources

According to the payment made to existing DR Auction's participants, the historical DR Auction Clearing Price, $200/kW-day as established in 2018, is used for the benefit calculation for providing DR service in this Case study.

3.6.3.2 ESVT Prioritization and Optimization

Figure 54 illustrates the modelled service prioritization and co-optimization in this Use Case as applied by ESVT 4.0. Similar to what is modelled in Use Case #2, Demand Response, once committed through the auction, has the highest model priority, and the other models are at the equivalent priority level, which is optimized economically in the simulation.

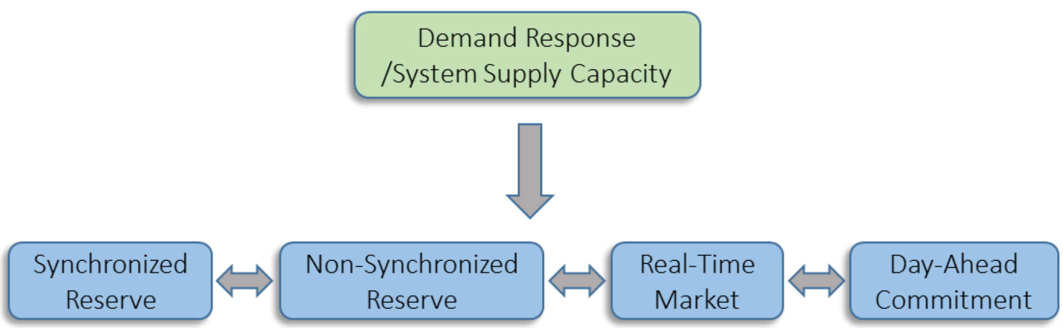


Figure 54. Modelled Services Prioritization in Use Case #3

3.6.3.3 Modelling Results

While there are two separate commitment periods, Summer and Winter, that could be bid for in the Auction, in this Case Study, DR service is assumed to be provided by ES only in the Winter commitment period (Nov. 1-April 30). The other scenarios, by providing the DR service for the Summer period or for both periods, could be studied later as the sensitivity analysis.

During the winter commitment period, the commitment hours should be within the window between the ending hour 17 and 21 (IESO 2019). Within this 5-hour time period, we assume the minimum discharge duration is 4 hours for the ES to meet the DR Auction requirement (Energy Storage Canada 2019)[40]. In other words, 4 or 5 hours per day during the winter commitment period will be reserved from the ES for DR service. Outside this time frame, the ES will be utilized to provide other market services to maximize its value to the asset owner.

In this case, the same ES type and size as that used in Use Case #1, LIB of 10 MW and 2 hours of energy duration, was firstly modelled. We assume the ES is installed on the site of a sufficiently large customer. To meet the minimum duration of 4 hours to qualify for this DR service, the ES has its discharge capacity reduced to meet the requirement. For example, the 2 hour storage system cannot fully meet the 4 hours commitment period for the winter time, so ESVT would assign half of the capacity value to that ES system in the simulation. This derating method accounts for the penalty of non-performance due to other commitments or insufficient energy duration. This capacity allocation method is also consistent with the requirements from the IESO when bidding for the auction. We also assume that the probability to dispatch ES in the commitment period is 100% in this study.

Using the historical DR Auction Clearing Price ($200 / MW-day) for the base period 2017-2018, the DR payment rate that is used in ESVT for calculation is to be $36.6/kW-year (see Appendix 'Benefit Calculation Methodology'). The load data is based on the total Ontario Demand profile of 2018. We assume the ES would be available for providing other grid market services during all time windows other than the committed four hours for DR service. For this scenario assumption, the net present value of the lifetime benefits and costs are illustrated in the Table 149 with a cost-to-benefit ratio provided.

Table 149. Net Present Value over Project Life of Use Case #3

	Cost ($)	Benefit ($)
Electricity Sales	$0	4.24E+06
Taxes (Refund or Paid)	$0	5.13E+05
Operating Costs	1.56E+06	$0
Financing Costs (Debt)	3.69E+06	$0
Capital Expenditure (Equity)	1.78E+07	$0
Demand Response Reduction	$0	1.47E+06
Synchronous Reserve (Spin)	$0	7.19E+06
Non-synchronous Reserve (Non-spin)	$0	9.85E+05
Total	$23,028,821	1.44E+07
Benefit-to-Cost Ratio		**0.63**

The cost-to-benefit ratio is barely improved when compared with the 0.61 of Use Case #1. This means that by stacking the value from providing the DR service for the winter period, the 10MW 2hr LIB could not improve

[40] At the time of preparing this document, no related information was found through the IESO website; however, it was suggested in the ESC webinar 2019 (Energy Storage Canada 2019).

the overall profit for the asset owner at all. This is totally different from the Use Case #2 which increases the benefit-to-cost ratio significantly by adding the ES's service to GA reduction.

The limited improvement of the overall benefit by including the DR service through the auction is also shown in Figure 55. The benefit from DR only takes 10% of the total, while the value stream from Synchronous OR still counts for the largest contribution that is 50% of the overall benefit. The unfavorable impact from the inclusion of DR service can also be identified from the total capacity performance that the ES is dispatched for, as shown in Figure 55. For each of the 5 hours between the hours 16 to 21, the total qualifying capacity in each year for DR is 90.5 MW (red color); however, the storage is not dispatched to fill the full capacity room (blue color) for any of them. Therefore the ESVT's optimization tells us that the full use of the ES for the entire 5 hour time window is not optimal. In fact, the detailed analysis shows that for each qualified day, the ES is only dispatched for 4 continuous hours instead of 5 hours to meet both criteria of the minimum DR auction requirement and the best profitable scheduling at the same time.

Figure 55. Benefits and Costs over Project Life of Use Case #3 (DR Auction along with Existing Market Services).

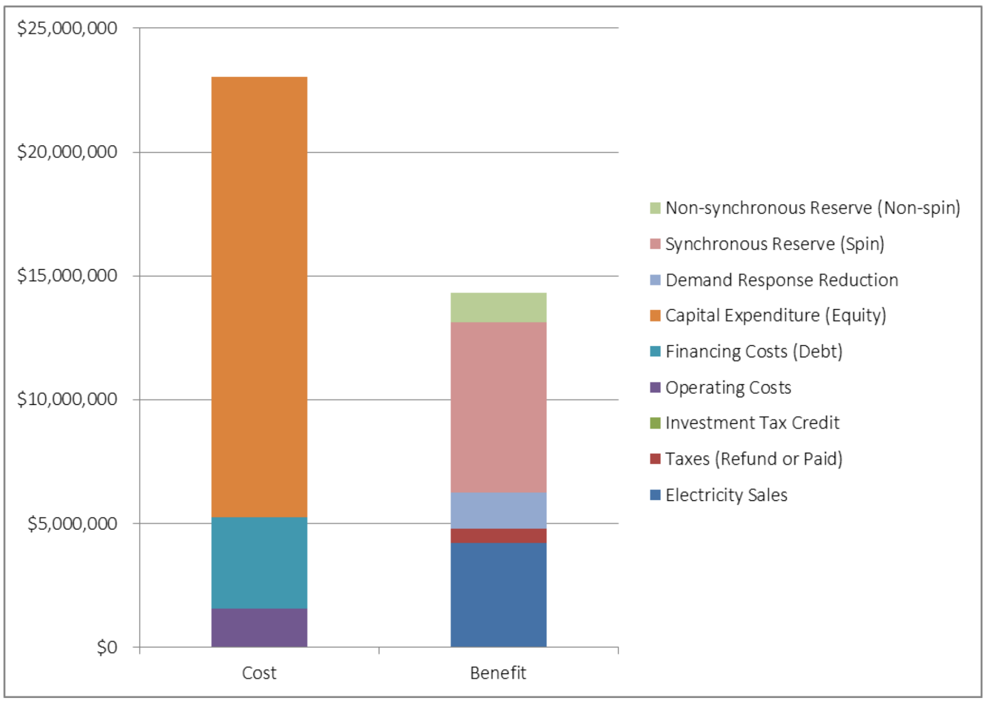
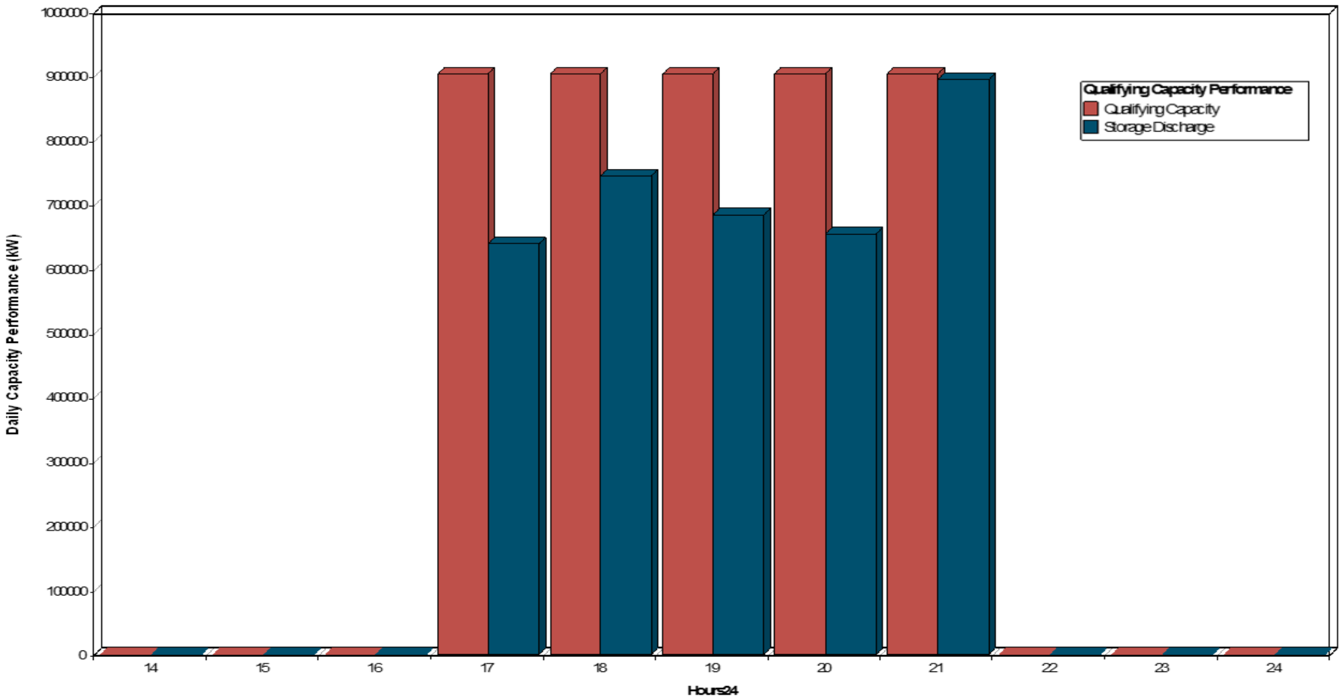


Figure 56. Qualifying Capacity Performance for Demand Response Service, Winter Commitment Period Only.



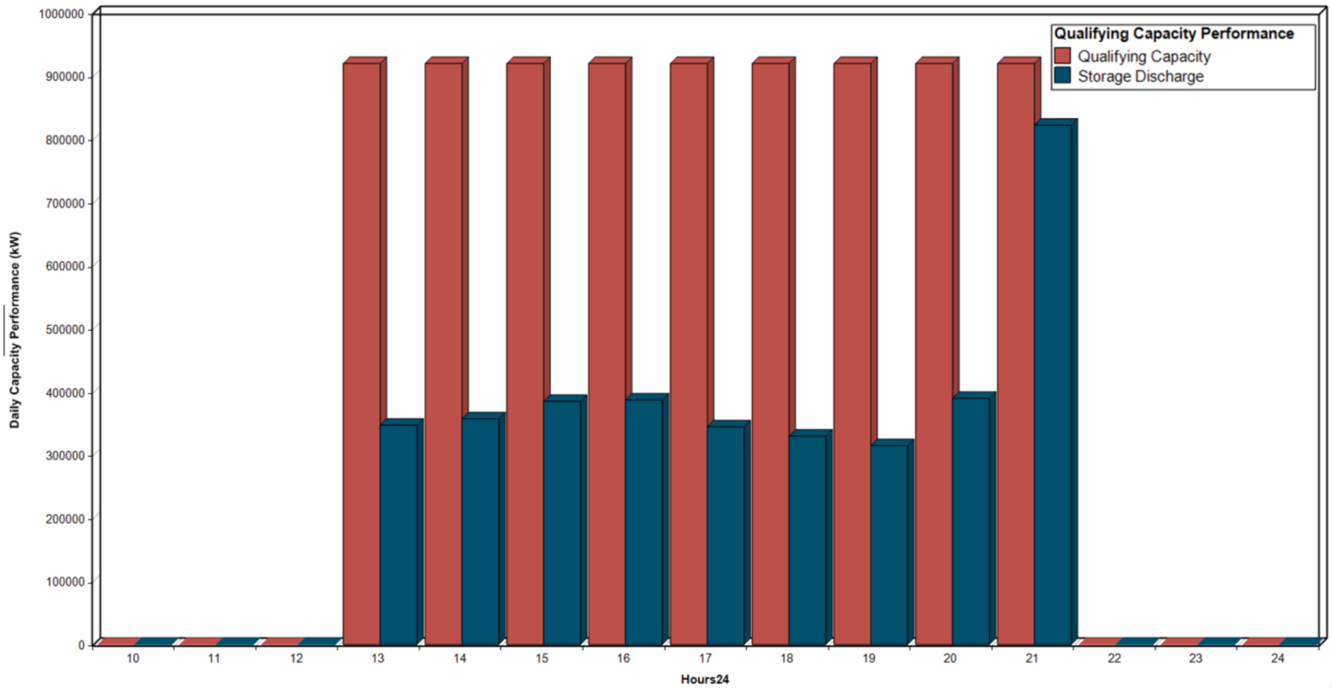
3.6.3.4 Scenarios and Sensitivity Studies

a) Scenarios on different DRA commitment periods

The base scenario studied above is the DR Auction applied to the Winter Commitment period only. Here the other two scenarios were studied as well, for the Summer Commitment period only and for year round (both Summer and Winter Commitment periods), respectively.

When DR service is applied to the Summer Commitment period, longer service hours are reserved. However, again, not all of the capacity room in each hour is fulfilled with the discharge of the ES facility, as seen from Figure 57 below.

Figure 57. Qualifying Capacity Performance for Demand Response Service, Summer Commitment Period Only.



Comparison of the benefit-to-cost ratio from different scenarios in commitment periods is listed in Table 150. It shows that the scenario where ES is reserved for the DR service during the Winter commitment period only has the highest benefit-to-cost ratio, which is 0.63. Commitment to the Summer Commitment period, in either way, will reduce the ratio value to 0.59 to 0.60 however.

Table 150. Comparison with Different DR Commitment Period Scenarios

Commitment Period	DR Auction Clearing Price ($/MW-day)	Capacity Payment ($/kW-yr)	Benefit-to-Cost Ratio
Winter (Nov. 1 - April 30)	200	36.2	0.63
Summer (May 1 - Oct. 31)	200	36.8	0.59
Winter & Summer	200	73.0	0.60

b) Scenarios of Capacity Auction

As stated at the beginning of this Use Case section, it has been determined that the DR Auction will be replaced by the Capacity Auction (CA) soon (IESO 2019). Although the details of the CA procedure, as well as the payment method, are not yet available, it is highly possible most of the existing DR Auction process is applicable; however, the ES must register as a generator resource to participate in the CA (Energy Storage Canada 2019). Accordingly, the impact on the Use Case design would be the location of the ES asset. To participate in the CA, the ES does not necessarily need to be located at the customer site. Instead, it would be in a location belonging to the front-of-the-meter, such as a transmission site.

Generally, as a capacity supply, ES would be paid based on the number of weekdays that it is committed. While the details of the CA are not yet available, we study the CA service, which is assumed to be paid based on the number of weekdays within the commitment period(s), which will affect the used Capacity Payment ($/kW-yr) value in the ESVT.

Two scenarios with the Capacity Auction are studied, both with participation in the Winter Commitment Period, where the number of weekdays is 130 days in the year of 2018. These are compared to the base scenario where DR Auction is based on the total number of days included in the Winter Commitment Period, i.e. 180 days in the year of 2018. The sensitivity to the auction clearing price and thus the capacity payment is also studied for comparison. The results are compared in Table 151, where the same LIB 10MW 2hr system is committed for the Winter Period (Nov. 1 - April 30). It turns out that based on the same DR auction clearing price, $200/MW-day, where the number of committed days per year drops from 181 days to 130 days, the Benefit-to-Cost ratio is reduced marginally from 0.63 to 0.62. However, assuming the auction clearing price is doubled to $400/MW-day, the use scenario is more profitable with the Benefit-to-Cost ratio increased to 0.66.

Table 151. Comparison between Scenarios of Different Auction Clearing Prices and/or Different Auction Types

Auction Type	DR Auction Clearing Price ($/MW-day)	# of Committed Days per Year	Capacity Payment ($/kW-yr)	Benefit-to-Cost Ratio
Demand Response	200	181	36.2	0.63
Capacity	200	130	26.0	0.62
Capacity	400	130	52.0	0.66

c) Scenarios of different LIB energy durations

Previously, the LIB 10MW with duration of 2 hours was used for studies. It is noted that 2 hours is shorter than the minimum duration requirements from the ES to participate in the DR/Capacity Auction, and thus the capacity is accordingly compromised/reduced for the commitment period. Here, a new LIB system was tested which has a longer energy duration, 4 hours instead of 2 hours. The result shows, as given in Table 152, when the LIB energy duration is doubled to 4 hours, the Benefit-to-Cost ratio is reduced from 0.66 to 0.53. It indicates that the LIB 10MW 4hr is less profitable than the LIB 10MW 2hr for this Use Case.

Table 152. Comparison between Scenarios of Different LIB Energy Durations

Auction Type	Capacity Auction Result Assumptions	LIB System	Benefit-to-Cost Ratio
Capacity Auction	Winter commitment period only # of committed days: 130 days per year DR auction clearing price: $400/MW-day Equivalent Capacity Payment: $52/kW-yr	10MW 2hr	0.66
		10MW 4hr	0.53

3.7 Conclusions

The Energy Storage (ES) valuation analysis performed in this section evaluated the profitability and dispatch of classes of ES technologies, and then individual project level examples operating at a typical node on the Ontario electric system. This may differ from the analysis in Pillar 1. Although at the system level operation of the Ontario electric system can be optimally designed to accept ES systems at certain nodes, with certain technology attributes and costs, it is not guaranteed that these deployments of individual storage technologies are equally economically or technically optimized at a project level. Therefore, several classes of ES technologies and then specific project level examples were evaluated to identify the benefits, to assess the overall economics of the ES deployment evaluated using project level metrics such as Net Present Value (NPV), and to analyze dispatch to the grid. Pillar 2 considered the economic benefits that were available for classes of ES technologies and then individual project level examples operating on the Ontario electric system, as well as the potential for each individual ES project to be dispatched to meet grid needs.

This was accomplished by using evaluation frameworks in a two-stage, top-down or funnel approach. The first stage used Ontario specific grid and technology data from a survey completed by the NRC as well as assumptions obtained from Pillar 1. The second stage used actual hourly, public price and load data obtained from IESO to perform more detailed dispatch and profitability analysis. This approach, from general to specific, provided a more granular snapshot of ES potential at a technology-specific and then individual project level basis.

First, nineteen ES technology classes were simulated at the Generation and Transmission levels, using pricing for each market and service from a survey of Ontario electric system stakeholders as well as Ontario specific financial ownership structures. From that survey, Use Cases used Load Following (not presently part of IESO's markets or services) as the top or anchor service to maximize potential profitability or potential Net Present Value (NPV). The top three ES technology classes in descending order were Compressed Air Energy Storage in salt Caverns (CAES-c), Sodium Sulfur battery energy storage (NaS), and Lithium-ion battery energy storage (Li-ion). From Pillar 1's analysis, Li-ion is found in all four energy storage duration classes, and so was selected for a more detailed study.

Second, a more granular analysis focused on simulating specific examples of Li-ion battery ES, as a single piece of equipment in three Ontario specific use cases. Where the first stage of the valuation analysis includes all potential services from the survey at the Generation and Transmission levels, the second stage only includes those that ES is allowed to participate in according to IESO market rules and regulations and using actual historical data. An intensive time series dispatch simulation at an hourly resolution was performed for an individual Li-ion ES project to model operation over its lifetime, charging / discharging, along with bidding results into the Ontario markets according to a generic North American ISO dispatch order or hierarchy. The 10MW 2hr Li-ion battery simulated was IPP owned and controlled over its 15 year lifetime.

1. In Use Case #1, the Li-ion battery is transmission-sited, front of the meter, and providing Real Time Energy and Operating Reserves (Spinning and Non-Spinning reserves) with a benefit-to-cost ratio of 0.61. This indicates the ES project would have a negative NPV or net loss for the IPP. Although ES is capable of providing Regulation Services (Frequency Regulation), in Ontario ES is not yet allowed to participate in that market.

2. In Use Case #2, the Li-ion battery is hypothetically customer-sited, behind the meter, so it can reduce Global Adjustment Class-A charges. The assumption was that this customer-sited Li-ion battery is IPP owned and operated front of meter so it could both participate in the markets from Use Case #1 and benefit from reduced Global Adjustment charges. This increased the benefit-to-cost ratio considerably to 0.98 and indicated that the added benefit from reducing Global Adjustment charges can make ES NPV close to break even for the IPP. In reality, customer-sited ES in Ontario is usually owned by the customer, and hence not allowed to also participate in IESO market services.
3. In Use Case #3, the Li-ion battery is again customer-sited, behind the meter, and now provides Demand Reduction/Capacity Auction (in several sub scenarios) in addition to the markets in Use Case #1. The same assumptions for Global Adjustment were made for Demand Reduction. However, the new Capacity Auction that will replace Demand Reduction doesn't require ES to be customer-sited. Participating in Demand Reduction/Capacity Auction does exclude simultaneous participation in any other IESO market. So for the hours when ES is scheduled to provide Demand Reduction/Capacity Auction, no other services are provided. Outside of those hours, ES can participate in Real Time Energy and Operating Reserves. Furthermore, ES can participate in either the winter or summer Demand Reduction commitment periods. So sub scenarios were run for summer, winter and combined. Sub scenarios were also run for two estimates of the Capacity Auction. The Li-ion battery simulations show that by participating in Demand Reduction/Capacity Auction, the benefit-to-cost ratios are all in the range of 0.59 to 0.63, comparable to that in Use Case #1. This means that although ES can provide Demand Response/Capacity Auction, the overall benefit of the ES installation will not increase significantly over providing Real Time Energy and Operating Reserves alone.

Combining both ES valuation stages, although CAES-c, NaS, and Li-ion ES technologies are potentially profitable or could have benefit-to-cost ratios greater than 1, the more detailed analysis of a single 10MW 2hr Li-ion battery participating in actual IESO markets and services in three use cases shows benefit-to-cost ratios of less than 1. Only the hypothetical use case of Global Adjustment, Class-A, with Real Time Energy and Operating Reserves has a benefit to cost ratio of nearly 1.

The benefit-to-cost ratio results in this analysis should be taken as a lower bound. Overall, potential ES benefits or revenue streams in Ontario are constrained, decreasing benefit-to-cost ratios for three reasons. First, ES is not allowed to participate in all IESO markets and services, and in particular Regulation Service or Frequency Regulation. Additionally, if a new IESO market for Load Following or Ramping is both needed and ES is allowed to participate, then ES profitability or benefit-to-cost ratio would increase further. Second, some Ontario data was unavailable at the time of this report meaning a hypothetical use case with Regulation Service could not be simulated. Third, the valuation tools have limits, and in particular, the second stage cannot model a hypothetical use case providing both Global Adjustment and Demand Reduction/Capacity Auction.

4 Environmental and Socio-Economic Impact Assessment Pillar

As described in the Introduction section, the overall purpose of Pillar 3 is to evaluate the environmental and socio-economic impact of ES deployment in the Ontario electricity system by estimating the greenhouse gas (GHG) emissions and the number of jobs generated from 2020 to 2030 with and without ES.

4.1 Introduction to Pillar 3

A primary objective of Pillar 3 is to develop a systematic framework for the life cycle assessment (LCA) of stationary and large-scale ES systems. Following the same methodology described in the Alberta chapter, the first part of this section evaluates the environmental impact of ES technologies. The evaluation aims at providing a comprehensive environmental understanding of ES systems by identifying the major parameters that can improve their environmental sustainability, and provides detailed LCA data with updated life cycle emissions intensities for ES systems, thereby increasing the robustness of the LCA results. Under this environmental life cycle analysis approach, this section quantifies the GHG emissions generated along the whole life cycle processes involved to manufacture, operate, and recycle Li-ion and Vanadium Redox Flow Battery (VRFB) energy storage systems. These were the two ES technologies that were analyzed because they represent approximately 82% of current storage development in Ontario based on the energy storage procurement process at the IESO[41].

Two approaches to evaluate the environmental impacts of ES deployment in the Ontario electricity grid were utilized: overall GHG emissions at the grid level, and life cycle impact comparability between selected ES technologies, i.e. Li-ion and VRFBs. The aggregated GHG emissions for ES usage at the grid-level and the life cycle GHG emissions from manufacturing of ES technologies together comprised the system-level GHG emissions. The aggregated GHG emissions are based on changes in natural gas consumption over time as a result of ES integration in the grid and are obtained from Pillar 1’s simulation results. The life cycle GHG emissions from ES manufacturing uses a “cradle-to-gate” LCA approach and assumes that only these two technologies are deployed in the Ontario electricity system over the study horizon. For the ES technology GHG comparison, a “cradle-to-grave” LCA is used to calculate the environmental life cycle impact per technology where the GHG emissions from the operation phase are based on both time-of-the-day grid marginal grid emission factors and round trip efficiencies.

The second part of this section evaluates the socio-economic impact in the province of Ontario as a result of ES project implementation. Input-output economic models (IOM) were used to evaluate the economic impact of ES deployment. They track the changes of industrial outputs in the supply chain according to a shock (change) in the final demand of a given industry. The increase in the final output of a particular industry increases the demand on industries that supply goods and services, creating ripple effects throughout the economy. These effects are measured by input-output multipliers, which are estimated using the coefficients of IOM.

The socio-economic impact of ES deployment in Ontario is measured by quantifying the direct and indirect impact through the number of jobs created during the three main phases of typical ES projects: planning and development, construction, and operation and maintenance. The direct impacts associated with the ES projects are also compared to those of renewable energy projects.

[41] http://www.ieso.ca/en/Sector-Participants/Energy-Procurement-Programs-and-Contracts/Energy-Storage

4.2 GHG Emissions Analysis

There has been debate on the value of ES with respect to GHG reduction. Due to round trip efficiencies, any individual ES project may have a negative GHG impact as measured on a project specific basis. Additionally, some critique the installation of new technology as having an overall negative impact on GHG emissions if the full life-cycle emissions are not considered. Therefore, the following section of the study aims to understand these overall impacts, and what potential benefits might accrue to the Ontario Interconnected Electricity System with the introduction of ES.

4.2.1 Background

Both the current GHG regulatory system and the technology choices themselves necessarily impact the outcome of any GHG analysis. Therefore, the detailed treatment of the current Ontario GHG regulatory system is outlined below, and the overall environmental impact of ES technologies is discussed in Section 3.2.1.2 of the Alberta report.

4.2.1.1 Ontario's GHG Regulatory System

Ontario is already on a transition to a low carbon electricity system and currently has more than 93% of its electricity generation from low-carbon resources. As a consequence, the GHG reductions from the electricity system have fallen by 80% since Ontario committed to phasing out coal and the GHG emissions made up only 3% of the province's total emissions in mid-2017.

GHG emissions reductions from Ontario's electricity system are aligned with the province's GHG reduction targets according to the Climate Change Mitigation and Low-carbon Economy Act, 2016 (no longer law) and the new Made-in-Ontario Environment Plan released in January 2019, which reset the Ontario emissions reduction target to a 30% decrease in GHG emissions from 2005 levels by 2030 (the same as Canada's Paris Agreement targets, but lower than Ontario's prior target of 37%). In order to reach its 2030 target, Ontario must reduce GHG emissions by an additional 18Mt by 2030. The estimated reductions in 2030 are reflected in the following policies (Ministry of the Environment, Conservation, and Parks 2018):

- Low carbon vehicles uptake (16%)
- Industry performance standards (15%)
- Clean fuels (ethanol gasoline, renewable natural gas) (19%)
- Federal clean fuel standard (7%)
- Natural gas conservation, including existing Demand Side Management (18%)
- Innovation, including energy storage (15%)
- Ontario Carbon Trust (4%)
- Other policies (organic waste, transit) (6%)

A summary of Ontario's Climate Change Framework is shown in the Appendix, Table A-1, page 169.

4.2.2 Objectives

The two primary objectives of the Pillar 3 study are to evaluate the environmental impact of ES systems at the grid level and perform a comparative life cycle GHG impact analysis on ES technologies. The system level environmental impact is evaluated by quantifying the overall GHG emissions generated by ES technologies in the Ontario electricity system. Grid-level GHG emissions are calculated by adding GHG emissions from the ES manufacturing phase and net system GHG emissions from ES operation in the grid. The latter is obtained from

Pillar 1's capacity optimization simulation model for the base case + storage scenario. Given that Pillar 1's simulation model outputs are based on an ES technology agnostic approach, the ES operations phase GHG emissions are aggregated values without a breakdown of GHG emissions by ES grid services. Moreover, it is assumed that two technology types, Li-ion battery and VRFB systems, are deployed in the Ontario electricity system over the period of study. For the ES technologies comparison, a 'cradle-to-grave' LCA is used to calculate the environmental life cycle impact per technology while the GHG emissions from the operation phase are based on both time-of-day marginal grid emissions factors and round trip efficiencies.

4.2.3 Methodology

The net system emissions from the ES operations phase are the sum of the increased and displaced emissions from the grid as a result of overall ES charge/discharge cycles. The operations phase at the grid level is calculated by taking the difference of natural gas usage for the base case scenario compared to ES Capacity Scenario as evaluated in Pillar 1.

The overall methodology of GHG evaluation through the Life Cycle Assessment method is discussed in detail in Section 3.2.2 in the Alberta Chapter. The cradle-to-gate emissions include emissions from raw material production, components production, and ES product manufacturing. Further emissions occur during the ES product operations phase (charging and discharging) at the grid level and ES product recycling.

Pillar 3 also incorporates the differential charging and discharging for each ES technology by considering time-of -day marginal emission factors depending upon current and prospective generation mixes to perform a comparative LCA of different ES technology types.

The cradle-to-gate LCA study of Pillar 3 was performed using the LCA software SimaPro version 8.3.

4.2.4 Application of the Methodology

With regard to the LCA methodology, it will be applied to assess the potential environmental impacts and benefits of two ES technologies, Li-ion and Vanadium Redox Flow Batteries in the Ontario Electricity grid. Only these two technologies were analyzed since they represent approximately 82% of current storage development in Ontario based on the energy storage procurement process at IESO[42]. This process has procured 50MW of storage in total, 33.54MW in 2014 and 16.75MW in 2015. Figure 58 shows the share of participation of ES technologies, Li-ion, VRFB, and others, in the IESO storage procurement process[43]. In addition, there are a few LCA studies of ES technologies with complete and open LCI data to be modelled.

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[42] http://www.ieso.ca/en/Sector-Participants/Energy-Procurement-Programs-and-Contracts/Energy-Storage

[43] (IESO 2016)

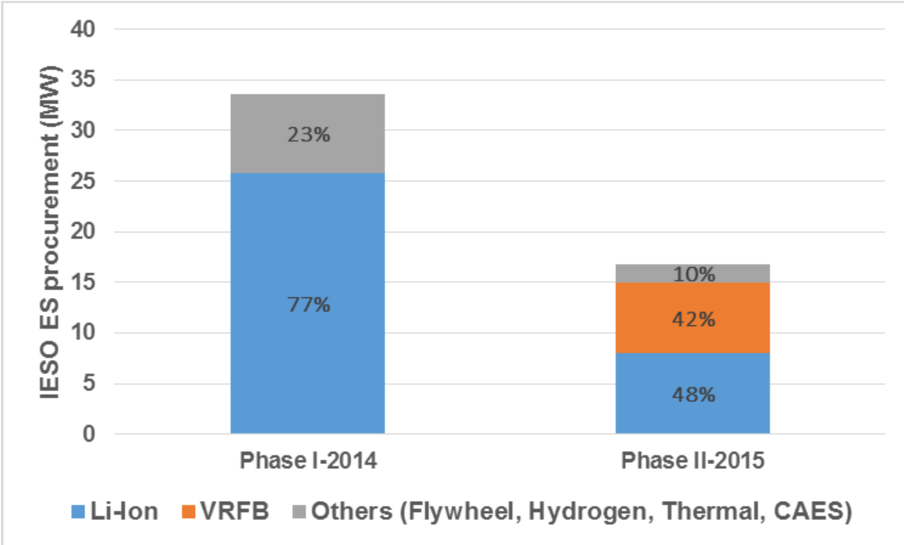

Figure 58. ES Technology Share in the IESO ES Procurement Process

4.2.4.1 *Goal of LCA Study*

The goal of the LCA study was to assess and quantify the GHG emissions of the selected ES technologies, Li-ion and VRFB ES systems during their life cycle stages, including raw material production, manufacturing, use in the electric grid, and recycling (end of life). In this LCA study, the LCI data for Li-ion battery and VRFB systems were obtained from very detailed open inventories in literature.[44, 45]

4.2.4.2 *Scope of the Study*

According to ISO 14044, the scope of an LCA study should define the studied product system, the function of the product system, the functional unit, allocation procedures (if any), types of impacts and life cycle impact assessment (LCIA) methodology, interpretation, data requirements, data quality requirements, limitations, and assumptions.

In this section, the LCA methodology is presented with application to Li-ion and Vanadium Redox Flow Battery ES systems.

4.2.4.2.1 Product Systems

The product systems of this LCA case study are a Li-ion and a Vanadium Redox Flow Battery ES system used for stationary grid applications, i.e. to store and deliver electricity to the grid.

For the Li-ion battery ES system, a cell chemistry of $LiFePO_4$ (LFP)/graphite was utilized as it was used in the LCA study in the Alberta study.

The mass ratios of the positive and negative electrodes, separator, substrates, cell container, module and battery packing, battery management system (BMS), as well as the electrolyte, are based on values reported by Majeau-Bettez, Hawkins, and Stromman (2011) in an LCA study on Li-ion batteries for electric vehicle batteries. Those values are used in Pillar 3 as a reference for battery ES systems due to the lack of information available for

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[44] (Hiremath, Derendorf, and Vogt 2015, Majeau-Bettez, Hawkins, and Stromman 2011)
[45] (Weber et al. 2018, Peters and Weil 2017)

stationary applications. It is assumed that the production of LFP material is conducted by hydrothermal synthesis routed through the reaction of iron sulfate, phosphoric acid and lithium hydroxide. Mass breakdown of other components such as inverter, transformer, and cooling system are adapted from Weber et al. (2018) and Peters and Weil (2017). The main components and electrochemical characteristics of the modelled battery system are provided in Table 153.

Table 153. Component Mass Breakdown and Performance of the Modelled Battery (LFP) System (Majeau-Bettez, Hawkins, and Stromman 2011, Peters and Weil, 2017, Weber et al. 2018)

Main Components	Li-ion Battery System (LFP) Details	Approximate Quantities (%)
Battery System Mass Composition (%)	Positive electrode paste	17
	Negative electrode paste	6
	Separator	2
	Substrates, positive and negative electrodes	8
	Electrolyte	8
	Cell container, tab and terminals	14
	Module and battery packaging	12
	Inverter	13
	Transformer	18
	Battery management system (BMS) and cooling system	2

With regard to the VRFB system, this comprises the power and energy subsystems, where the cell components are related to the power, and the electrolyte volume is related to the energy capacity. Remaining components are considered as balance of system (BOS) components. The mass breakdown of the VRFB components for this LCA study is based on the values reported in Weber et al. (2018) and is presented in Table 154.

Table 154. Component Mass Breakdown and Performance of the Modelled Battery (VRFB) System (Weber et al. 2018)

Main Components	Vanadium Redox Flow Battery System (VRFB) Details	Approximate Quantities (%)
Battery System Mass Composition (%)	**Power Subsystem**	
	Membrane, Electrode, Bipolar plate, Current collector, Cell frame, Gaskets, Stack frame	3.1
	Energy Subsystem	
	Electrolyte	84.0
	Tanks	10.1
	Balance of System (BOS)	
	Pumps, pipes and cables, process control system (PCS), including battery management system (BMS)	0.3
	Inverter and transformer	2.2
	Heat exchanger	0.3

4.2.4.2.2 Functional Unit

The functional unit measures the function of the studied system. A clearly defined and measurable functional unit needs to be consistent with the goal and scope of the study. The functional unit allows for making valid comparisons between products. It offers a reference to which the inputs and outputs of the product system are related. Provided that the main function of the product system is delivery of electrical power to the grid, the selected functional units for this study were (1) one MWh delivered to the grid by a Li-ion battery system and (2) one MWh delivered to the grid by a VRFB system.

4.2.4.2.3 System Boundary and Process Flowchart

According to ISO 14044, a system boundary of an LCA study is defined as a set of criteria specifying which unit processes are part of a product system[46]. For Li-ion and VRFB, the system boundary of this LCA study contains the entire material production and manufacturing sequence (cradle-to-gate), operations phase, and recycling as the end of life scenario of a Li-ion battery and VRFB systems, respectively. For the use/operation phase emissions calculation, the methodology is explained in Section 4.2.4.5.

As shown in Figure 59 and Figure 60, these primary flow diagrams represent the phases included in the system boundary of each LCA study. It is assumed that the geographical system boundary is the province of Ontario for all life cycle stages in order to exclude transportation to the project site. By contrast, the vanadium pentoxide (V_2O_5) for the electrolyte is assumed to be produced in Quebec; this being one of Canada's largest known vanadium deposits and having important project development to produce vanadium electrolyte for VRFB stationary systems[47]. The 2020 forecasted Ontario electric grid mix from Pillar 1 results was assumed to provide energy requirements of life cycle stages.

Additionally, Figure 59 and Figure 60 provide some details on unit processes related to the Li-ion battery and VRFB ES systems, respectively. Four main steps are defined in these system boundaries including raw material production, battery manufacturing, battery operation, and end of life, including recycling. The Life Cycle Inventory data is required for all the cradle-to-gate processes. Although the battery operations phase and recycling phase are included in Figure 59 and Figure 60 to highlight the significance of the environmental performance of end-of-life operations, the operations phase emissions calculations are detailed in Section 4.2.5.2.

[46] (ISO 2006b)

[47] https://www.northernminer.com/news/spotlight-on-vanadium/1000403529/

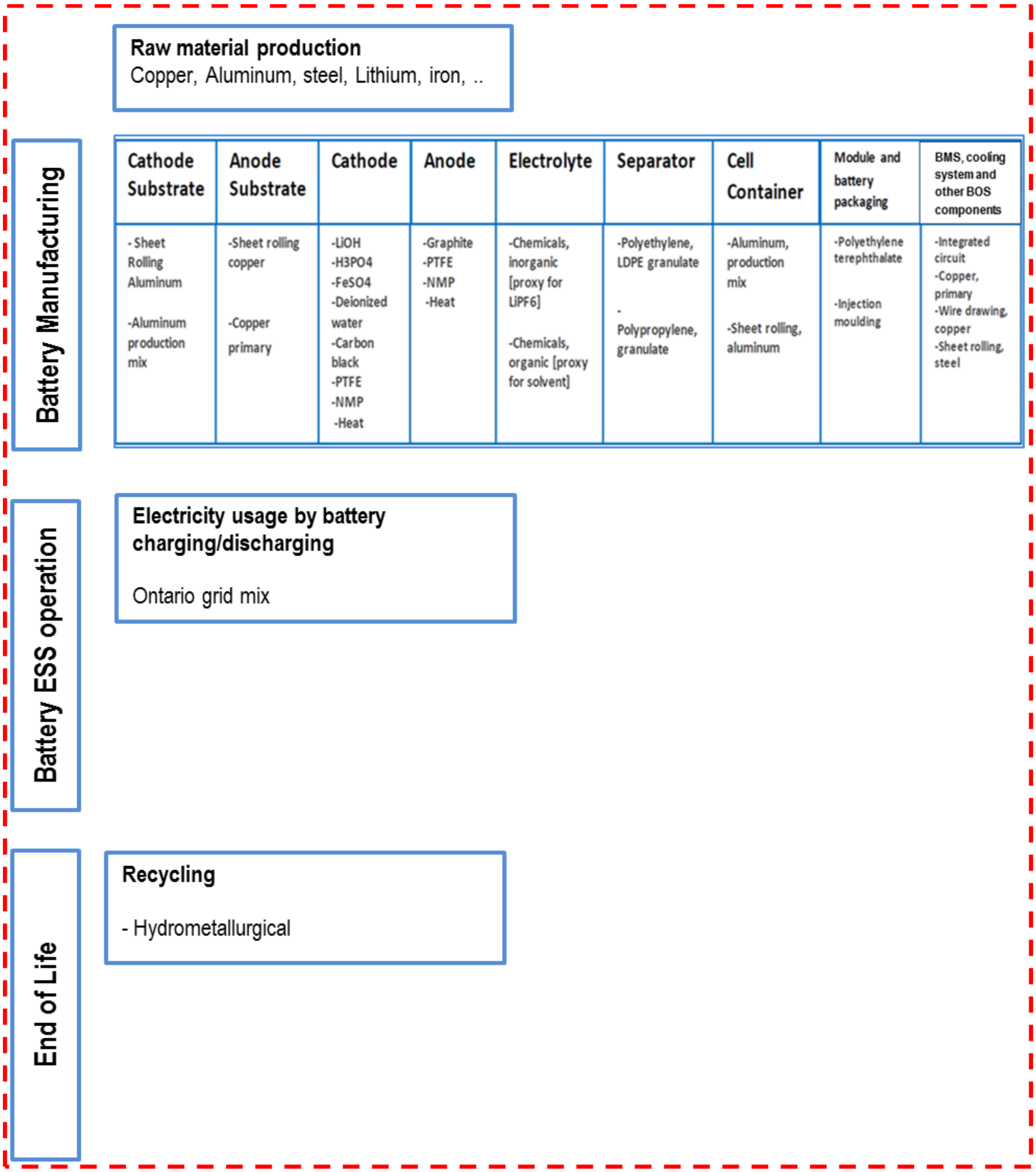

Figure 59. Flow-diagram of the System Function and Related Unit Processes of Li-ion Battery ES System

Raw material production
Magnetite, steel, Vanadium pentoxide, iron, ..

Battery Manufacturing

Power subsystem							Energy System		BOS	
Membrane	Electrode	Bipolar plate	Current collector	Cell frame	Gaskets	Stack frame	Electrolyte	Tanks	Pumps, pipes, cables, and PCS	Inverter, Transformer, Heat exchanger
PTFE	Carbon felt	Graphite	Copper	PVC	FKM	Steel	Vanadium pentoxide	Resin	Plastic-coated steel	Stainless steel
SO_3	Heat	Polypropilene					Sulfuric acid	Glass fiber	Steel, Teflon lining	Hot rolling, steel
C_3F_6		Particle board					Phosphoric acid	PVC	Cooper	Various
NaOCl		Core board					Water		Various	
NaOH		Bleached board								
Na_2CO_3										

Battery ESS operation

Electricity usage by battery charging/discharging

Ontario grid mix

End of Life

Recycling

- Mechanical separation (disassembly)

Figure 60. Flow-diagram of the System Function and Related Unit Processes of VRFB ES System

4.2.4.2.4 Impact Category and Impact Assessment Method

The results of the inventory analysis are assessed in the impact assessment phase, in which selection of impact categories has significant implications on the results. The selected method to weigh and model the results is classification and characterization following the Dutch method ReCiPe 08 Midpoint (H) which is employed in the SimaPro LCA software tool[48]. ReCiPe Midpoint (H) version 1.12 includes 18 impact categories given the availability of LCI data[49].

Based on the data sources used in this LCA study and their related limitations, as well as scope of this LCA study, only a global warming potential (GWP) indicator (kg CO2 eq.) is represented in the final environmental LCIA category results. The selected impact category covers the main issues relevant to Li-ion batteries and VRFB systems related to air, water and energy resources.

4.2.4.3 Life Cycle Inventory (LCI) Analysis

Most of the recent LCA studies on batteries focus on their application in the automotive industry; however, there is a significant lack of specific LCI data for battery energy storage systems for stationary applications. Hence the life cycle inventory of an electric vehicle Li-ion battery pack and the BMS components are scaled up to the energy resources and materials required for upstream processes to support and manufacture a large scale Li-ion battery pack to be used as an element of an energy storage system. Figure 61 shows a schematic setup of a utility-scale Li-ion battery energy storage system (BESS) and indicates the system components that are included in the primary Li-ion LCA system boundary such as the battery pack, the BMS components, the battery thermal management (cooling system), and the other BOS components like the power conversion system-PCS (inverters) and transformers.

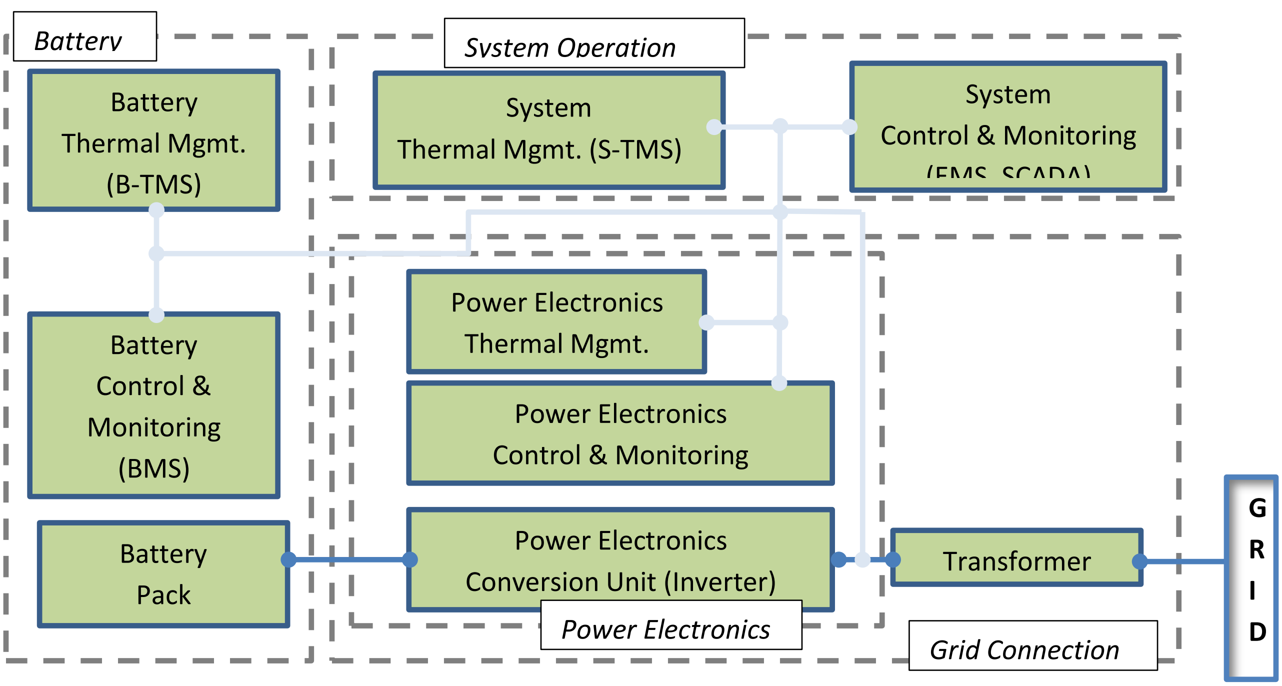

Figure 61. Utility-scale Battery Energy Storage System Topology adapted from (Holger, et al. 2017)

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[48] (Goedkoop et al. 2009)

[49] (Frischknecht et al. 2007)

Note that for clarity in the figure above, light blue lines indicate auxiliary power supply; blue lines indicate main energy storage power flow.

In order to model the inventory of a Li-ion battery and VRFB ES system life cycle during their life span, data was collected from previous studies[50]. The Appendix section, Table A-2 and Table A-3, pages 169 and 170, respectively, show summaries of the LCI for Li-ion battery and VRFB ES systems.

The manufacturing of LFP battery pack components was modelled using the primary LCI database from Majeau-Bettez et al. (2011) and Ecoinvent data sources. Majeau-Bettez et al.(2011)'s study provides the most updated and comprehensive inventory for LFP batteries[51], however the cooling system is excluded from their inventory. Peters and Weil (2017) provide LCI data related to the cooling system of an LFP battery for ES stationary systems. Note that a battery energy storage system also includes additional balance of system (BOS) components apart from BMS and cooling systems such as an inverter and transformer, which are modelled in this LCI as no reliable data on composition and manufacturing are available for a battery ESS-specific inverter and transformer. Thus standard Ecoinvent datasets are used (inverter production, 500kW and transformer production, high voltage use) and scaled to the corresponding power rating.

With regard to the manufacturing process of VRFB ES system components, i.e. power, energy and BOS subsystems, currently there is a lack of reliable data on large-scale VRFB production processes. In this LCA study the VRFB ES system is modelled based on published literature, thus the VRFB manufacturing processes were modelled using the LCI data from Weber et al. (2018). In the case of the inverter and transformer components, these were modelled using standard Ecoinvent datasets as in the LCI of Li-ion battery aforementioned.

The end of life batteries are dismantled and recycled, and recycled Li-ion battery cells are modelled on Ecoinvent, assuming 100% hydrothermal recycling. Note that due to the very limited data availability, a cut-off approach is used for the end-of-life model of the batteries, based on an adaptation of existing Ecoinvent datasets. Therefore, all impacts associated with the recycling process are allocated to the battery ES system, while the recovered products are available free of burden[52].

4.2.4.4 Major Assumptions and Limitations

A summary of major assumptions applied in this LCA study of Li-ion and VRFB ES systems is provided in Table 155 and Table 156, respectively.

In Table 155, one of the main assumptions is about mass fraction for Li-ion battery packs based on the study by Majeau-Bettez et al. (2011). It is assumed that 67% of the battery ESS mass corresponds to the battery pack, and 33% is for the battery balance of systems (BOS) components such as BMS, cooling system, inverter, and transformer.

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[50] (Ellingsen et al. 2013, Hiremath, Derendorf, and Vogt 2015, Majeau-Bettez, Hawkins, and Stromman 2011, Notter et al. 2010, Peters and Weil 2017, Sullivan and Gaines 2012, Ziemann et al. 2016, Weber et al. 2018)
[51] (Hawkins, Gausen, and Stromman 2012, Hiremath, Derendorf, and Vogt 2015)
[52] (Weber et al. 2018)

According to[53], there is an uncertainty around the conceptual border between “manufacturing” and “material production,” and it is believed that “material production” means being limited to pure metals, simple plastics, or raw chemicals. Additionally, it is assumed that the applied infrastructure onsite at the battery assembly plant has negligible material loss or emissions in the system. Note that the transportation of materials to the project site is not included in the assessment.

The Li-ion ES battery is assumed to have 90% round trip efficiency and a cycle life of 6,000 charging/discharging cycles (average value of total number of cycles to failure at 80% depth-of-discharge (DOD)). These battery technical characteristics assumptions are average values from literature based on the Majeau-Bettez, Hawkins, and Stromman (2011) and Peters and Weil (2017) LCA studies on LFP batteries. Note that the ES round trip efficiency assumed in Pillar 1 is an average value for all the ES technologies categories modelled.

Due to the limited calendric lifetime of the battery cells[54], a certain amount of cells needs to be replaced during the operation and maintenance of the battery required for a service life of 10 years. For this reason, it is assumed that the battery is monitored frequently and battery trays with major performance loss are repaired. Thus, only weak cells are substituted instead of a bulk exchange of battery cells altogether, and only the replacement of the corresponding fraction of cells is accounted for[55]. Additionally, it was assumed that virgin materials were used for the production from cradle-to-gate[56].

Table 155. Major Assumptions Made for Cradle-to-Gate and Recycling Phases for the Li-ion Battery used in Stationary Application

Field of Assumption	Assumed
Battery type	Li-ion battery
Chemistry of applied Li-ion battery	LiFePO4/Graphite
Nominal battery capacity	1.4 MWh
Round trip efficiency	90%
Life time of ES system	10 years
Battery cycle life (total number of cycles in battery lifetime)	6,000
Lifetime capacity@80%DoD	6,048 MWh

[53] (Rydh and Sandén 2005)
[54] (Hiremath, Derendorf, and Vogt 2015)
[55] (Weber et al. 2018)
[56] (Majeau-Bettez, Hawkins, and Stromman 2011)

Contribution of the battery pack mass	Table 153
Transportation of all phases	Omitted
Infrastructure at the battery assembly plant	All assumed to be negligible in comparison to other stages.
Electricity generation	2020 Ontario grid mix. Used for manufacturing of Li-ion battery pack.

In Table 156, one of the main assumptions is about mass fraction for VRFB ESS based on the study by Weber et al. (2018). It is assumed that 71% of the VRFB ESS mass corresponds to the electrolyte related components, including raw materials production, 19% is for the stack components, and 10% is related to the balance of systems (BOS) components such as BMS, heat exchanger, inverter, and transformer.

The VRFB battery is assumed to have 75% round trip efficiency and a cycle life of 10,000 charging/discharging cycles (average value of total number of cycles to failure at 80% depth-of-discharge (DoD)). These battery technical characteristics assumptions are average values from literature based on the Weber et al. (2018) LCA study on VRFB for ES stationary applications. Note that the ES round trip efficiency assumed in Pillar 1 is an average value for all the ES technologies categories modelled.

Regarding the stack replacement in VRFB, a lifetime of 10 years is assumed for the stack, while the electrolyte and BOS components are assumed not to be replaced over the lifetime of the ES system. Due to corrosion and degradation of membranes and gaskets, whole stack is replaced completely after 10 years. VRFB's electrolyte does not degrade and only requires re-balancing with electrify input[57].

Table 156. Major Assumptions Made for Cradle-to-Gate and Recycling Phases for VRFB used in Stationary Application

Field of Assumption	Assumed
Battery type	Vanadium Redox Flow Battery
Nominal battery capacity	8.3 MWh
Discharge time	8.3 hours
Round trip efficiency	75%
Life time of ES system	20 years

[57] (Weber et al. 2018)

Battery cycle life (total number of cycles in battery lifetime)	10,000
Contribution of the battery mass	Table 154
Transportation of all phases	Omitted
Infrastructure at the battery assembly plant	All assumed to be negligible in comparison to other stages.
Electricity generation	2020 Ontario grid mix. Used for manufacturing of VRFB.

4.2.4.5 Operations Phase

As mentioned previously, the grid-level GHG emissions resulting from the usage of ES systems are evaluated considering changes in the grid electricity generation sources over time as a result of ES integration. The following methods were utilized to calculate operations phase emissions at the system level and for technology comparisons.

4.2.4.5.1 System Level GHG Emissions Based on Changes in Natural Gas Consumption

The production cost analysis described in Pillar 1 performs grid simulations for case studies with no storage in the grid and with installed storage in the grid from 2020 to 2030. The annual consumption of natural gas was calculated for each case and the difference (ΔGHG) was calculated according to Eq.1.

$$\Delta GHG = (-)\ \sum_{i=1}^{n}(F_{NS,i} - F_{WS,i}) \times EI_{F,i} \qquad (1)$$

Where $F_{NS,i}$ is the consumption of fuel type i for no storage case, $F_{WS,i}$ is the consumption of fuel type i with storage case and $EI_{F,i}$ is the emission intensity of fuel type i (obtained from a national inventory report) (Canada 2019).

As the case studies include the capacity reductions of natural gas generation as well as nuclear planned retirements for refurbishments, the fuel consumption values reflect the prospective changes in the Ontario electricity grid which include the effect of increasing levels of ES integration. Hence, the ΔGHG values indicate the net emissions from grid over the period of study as a result of differentials of fuel consumption during the benchmark scenario and the ES capacity scenario with complete charging/discharging cycles.

Overall, the ES environmental impact on the Ontario electric grid is calculated considering the total GHG emissions from manufacturing (cradle-to-gate) of ES technologies in addition to the grid level GHG emission reductions from usage of ES technologies based on changes in natural gas consumption.

4.2.4.5.2 GHG Emissions Based on Time-of-the-day Marginal Emission Factors for Technology Comparisons

As it is explained in Section 3.2.3.6.2 of the Alberta study, the operations phase impact for each ES technology is considered a function of the quantity and type of energy consumed and dispatched during overall ES operation. In the Alberta study, the operations phase impact for each ES technology under this technology comparison approach only considers the electric grid losses from the overall usage of each ES technology. The charging and discharging emissions are annual average values estimated by using grid marginal emission factors and round trip efficiencies of the specific technologies.

Despite the methodology used in the Alberta study, the GHG emissions during operation phase for each ES technology in Ontario are calculated as both (i) net GHG emissions from storage, i.e. sum of increased and displaced emissions when storage is charging or discharging, which are calculated using marginal emissions factors (MEFs) and life cycle emission intensities, and (ii) normalized to the delivered energy from the storage device.

Emission factors, which describe the GHG emissions associated with the generation of a unit of electricity (e.g. kgCO_2e/ MWh), can be used to evaluate the emissions from ES systems considering different ES technologies during their usage in the grid.

The MEF approach is relatively simple, data-driven, and provides time variant estimates of the emissions of marginal generators. MEF is calculated as the β of the linear regression of the changes in GHG emissions of generation on the changes in generation on the margin between one hour and the next. Time-of-the-day MEFs allow identifying energy and emissions displacement from generators on the margin, since the GHG impact from storage operation is affected by the variations of the emission intensities in the power-grid mix when the energy storage system is charged and discharged according to a specific grid service. Different operation patterns for storage could realize higher carbon reductions.

System level GHG emissions are calculated as net GHG emissions of ES in the grid (kg$CO_{2\text{-eq}}$) and normalized net GHG emissions (kg$CO_{2\text{-eq}}$/$MWh_{\text{ES delivered}}$), which are calculated using marginal emissions factors (MEFs) and life cycle emission intensities. According to (Hawkes 2010) and (Siler-Evans, Azevedo, and Morgan 2012)'s MEF method, MEFs reflect the emissions intensities of the marginal generators in the system - the last generators needed to meet demand at a given time, and the first to respond given an intervention.

$$MEF = \beta \ of \ the \ linear \ regresion \ of \ \Delta E_h \left(CO_{2-eq}\right) on \ \Delta G_h \quad \text{Eq.1}$$

$\Delta G_h = G_h - G_{h+1}$ (MWh) is the change in generation on the margin between one hour and the next. The hourly generation on the margin is calculated as follows: $G_h = \sum_f G_{f,h}$, where $G_{f,h}$ is the net generated electricity by technology type f on the margin at given time.

$\Delta E_h = E_h - E_{h+1}$ (kgCO_{2eq}) is the change in GHG emissions of generation on the margin between one hour and the next. The hourly GHG emissions on the margin is calculated as follows: $E_h = \sum_f \left(G_{f,h} * EI_f\right)$, where EI_f is the technology specific life cycle emission intensity for technology type f on the margin at given time.

- ***Identify marginal generation source.*** Using a variation of the MEF method, the generation source contribution on the margin is estimated as the β value of the linear regression of the change in total generation between one hour and the next (ΔX) and the corresponding change in each generation source (ΔY). Separate regressions of ΔX on ΔY approximate the share of marginal generation for each generation source type (G_f).

$$Contribution\ (\%G_f) = \beta\ of\ the\ linear\ regression\ of\ \Delta Y_h\ (MWh) on\ \Delta X_h \qquad \text{Eq.2}$$

- ***Annual MEFs (kgCO$_{2\text{-}eq}$/MWh).*** These reflect the changes in Emissions (E) on marginal generation (G) between one hour and the next for the optimized grid with ES case and during each year of the period of study.

- ***Time-of-the-day (TOD) MEFs (kgCO$_{2\text{-}eq}$/MWh).*** Hourly variations of marginal GHG emission for the optimized grid with ES case are calculated using 24 separate regressions for all observations at a given time interval during each day of the year. MEF_{TOD} is calculated as follows:

$$MEF_{TOD,i} = \beta\ of\ the\ linear\ regression\ of\ \Delta E_{h,i}\ \left(CO_{2-eq}\right) on\ \Delta G_{h,i} \qquad \text{Eq.3}$$

$i = \langle h\ to\ h+1 \rangle$, where i = 1 to 24 intervals and h = 1 to 24 hours. ΔE_h and ΔG_h are calculated at each time interval during each day of the year.

- ***ES charging - GHG emissions (kgCO$_{2\text{-}eq}$).*** In hours when the storage is charging, this increased demand requires an increase in electricity generation and emissions from a marginal generator. Using the hourly ES charge time series, which is generated from the grid optimization model, and the TOD MEFs values, the total annual GHG emissions generated from ES charging is calculated as follows:

$$E_{ch} = \sum_i (G_{ch,i} * MEF_{TOD,i}) \qquad \text{Eq.4}$$

$G_{ch,i}$ is the energy charged by storage at time interval i during each day of the year and $MEF_{TOD,i}$ is the marginal emissions factor at each time interval i for each year.

- ***ES discharging – GHG emissions (displaced) (kgCO$_{2\text{-}eq}$).*** While discharge of storage results in reduced generation and GHG emissions. Using the hourly ES discharge time series, which is generated from the grid optimization model, and the TOD MEFs values, the total annual GHG emissions displaced by ES discharging is calculated as follows:

$$E_{disch} = -\sum_i (G_{disch,i} * MEF_{TOD,i}) \qquad \text{Eq.5}$$

$G_{disch,i}$ is the energy delivered from storage at time interval i during each day of the year and $MEF_{TOD,i}$ is the marginal emissions factor at each time interval i for each year.

System level GHG emissions are reported as both total emissions from storage and normalized to the delivered energy from the storage device.

  - ***Net GHG emissions (kgCO$_{2\text{-}eq}$).*** The net GHG emissions are the sum of these increased and displaced emissions during storage operation over the year. This is calculated for each ES technology under this study.

  - ***Normalized net GHG emissions (kgCO$_{2\text{-}eq}$/MWh $_{ES\ delivered}$),*** which are the net GHG emissions calculated previously for each ES technology divided by its total energy delivered to the grid in a year.

The MEFs calculated in this report represent time-of-the-day marginal emission factors on a yearly basis.

4.2.5 Evaluation of Environmental Impact of Energy Storage Systems

Overall GHG emissions from the Ontario electricity grid as a result of ES systems deployment during the period of study are calculated by adding overall cradle-to-gate GHG emissions of ES, i.e. GHG emissions from manufacturing of ES systems, and aggregated grid-level GHG emissions (reductions/increments) from ES operation in the grid.

A life cycle impact comparative assessment for two ES technologies (Li-ion and VRFB) is also presented in this section. More granularity and sensitivities can be added when LCA results of more ES technologies become available.

4.2.5.1 Manufacturing (Cradle-to-Gate) and End-of-life Phase Emissions of ES Technologies

GHG emissions of Li-ion battery and VRFB ES systems from their respective cradle-to-gate and recycling stages were calculated according to the application of the LCA methodology explained in Section 4.2.4 by using the SimaPro LCA software 8.3 Developer version to model the cradle-to-gate and recycling processes for each ES technology. Table 157 shows the GHG emission results for Li-ion and VRFB ES systems manufacturing and end-of-life phases.

The functional unit of the cradle-to-gate and end-of-life phases for both types of ES systems evaluated in this LCA section are related to the energy delivered to the grid based on average values of their complete utilization over their cycle lives or lifetime and expressed in MWh. Pillar 3 therefore performs the comparative cradle-to-gate impact assessment of both ES technologies assuming that the energy discharged to the grid is delivered during their respective complete lifetime utilizations regardless of the type of service provided to the grid. These ‘cradle-to-gate’ emission values are then normalized to a service lifetime of 10 years. This is the basis of comparison with the report’s overall period of study in order to get direct cradle-to-gate impact comparisons between these ES technologies.

The manufacturing (cradle-to-gate) and end-of-life GHG emissions are relative values expressed in $kgCO_{2e}$ per MWh delivered to the grid considering an average complete lifetime utilization for each ES technology. Note that VRFB ES systems can deliver larger amounts of energy to the grid than Li-ion systems. For the Li-ion ES battery system, the cradle-to-gate impact comprises the GHG emissions from the manufacturing of the battery pack and BOS components (cooling system, transformer, and inverter). ES operations phase emissions for the Li-ion battery and VRFB ES systems are calculated in Section 4.2.5.4.1.

Table 157. GHG Emissions during Manufacturing and Recycling for Li-ion and VRFB ES Systems

GHG emissions ($kgCO_{2eq}$/MWh)	**Li-Ion**	**VRFB**
Manufacturing (cradle-to-gate)	**110**	**17**
Battery components	*94*	*15*
BOS	*16*	*2*
Stack replacement	**3**	**3**
End-of-Life	**2**	**1**

4.2.5.2 ES operations phase impact at Grid Level

The natural gas CO2 emissions reductions as a result of ES operation in the Ontario electricity grid for the benchmark scenario are calculated by taking the difference of natural gas yearly consumptions for the benchmark compared to ES capacity scenario according to Eq.1 in Section 4.2.4.5.1. Thus, grid-level GHG emissions are estimated based on annual fuel consumption of each generation unit and $CO_{2\text{-eq}}$ emission rates of each fuel type. Carbon emissions from the Ontario electricity system come primarily from natural gas-fired generation.

Overall, Figure 62 shows that emissions are expected to increase from 2020 to 2030, with a CAGR of 14% for the benchmark scenario and a CAGR of 12% for the ES capacity scenario. Total grid-level GHG emissions for the benchmark scenario and ES capacity scenario from 2020 to 2030 represent 40.3 and 35.8 $MTCO_{2\text{-eq.}}$, respectively. The expected increment of grid level GHG emissions is due to nuclear unit's refurbishments that lead to increased reliance on natural powered units, and opportunities for natural gas avoidance by storage. Storage deployment can reduce grid-level $CO_{2\text{-eq}}$ emissions by 11% by 2030 that represent an accumulated grid-level GHG emissions reduction of 4.5 $MTCO_{2\text{-eq.}}$ As well, annual carbon emissions reduction due to storage is increasing by more storage deployment over time.

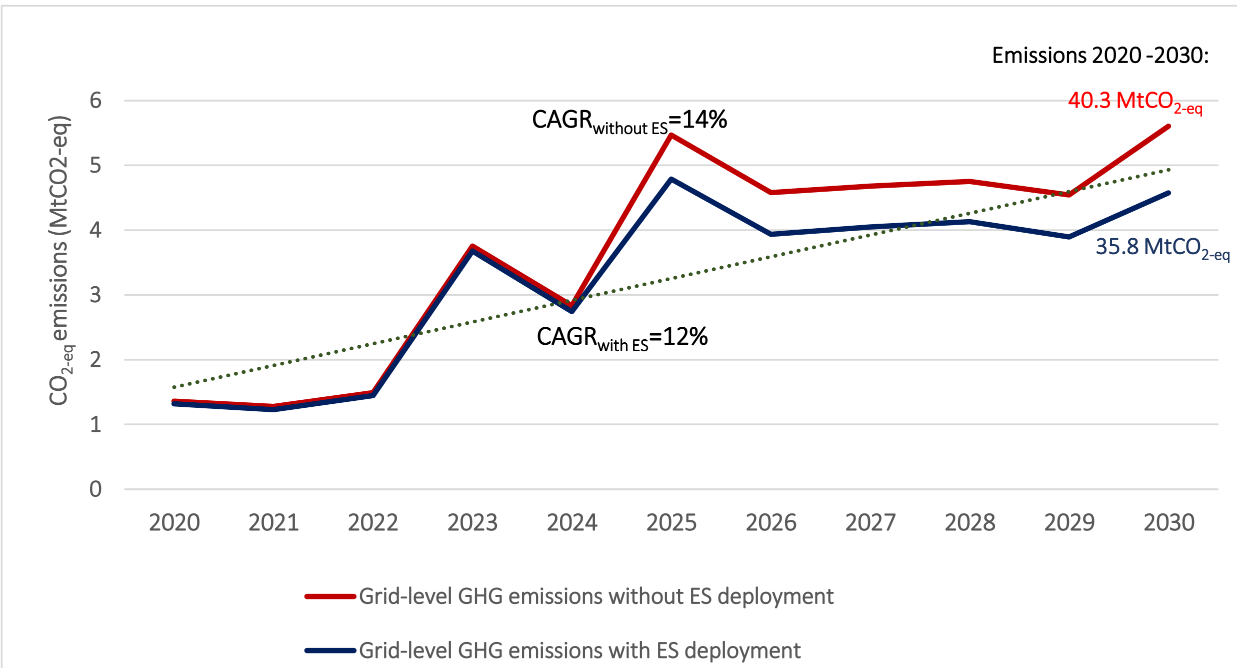

Figure 62. System Level GHG Emissions Outlook in the Ontario Electricity Grid (2020-2030)

The net grid-level GHG emissions reductions from ES usage are shown in Figure 62 expressed in $MtCO_{2\text{-eq}}$. The GHG emissions resulted from the difference between $CO_{2\text{-eq}}$ emitted during charging and displaced emissions during discharging. Consequently, the aggregated natural gas GHG emission reductions are 4.5 Mt of CO_{2e} due to the increasing displacement of natural gas powered units when ES discharges to the grid from 2020 to 2030. *Therefore, there is an important difference between Ontario electricity grid-level GHG emissions with and without ES over the period of study.*

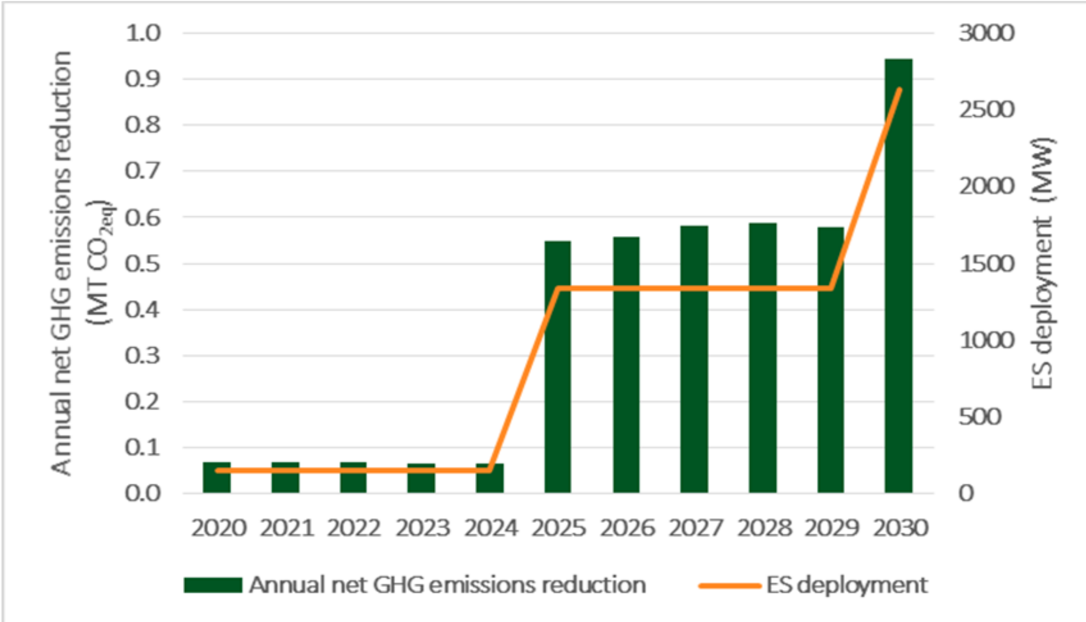

Figure 63. Net Natural Gas GHG Emission Reductions due to Energy Storage Operation in the Ontario Electricity Grid (2020-2030)

4.2.5.3 Overall GHG Emissions of Energy Storage at Grid Level

Given that cradle-to-gate life cycle impact results from Table 157 are only for individual Li-ion and VRFB systems, they were aggregated, re-scaled, and considered as part of a whole ES system to calculate total cradle-to-gate life cycle emissions at grid level for the Ontario electricity system over the base case simulation period, and expressed in absolute terms ($MTCO_{2\text{-eq}}$). Pillar 3 assumes that the value of the cradle-to-gate life cycle emissions of an aggregated ES system of 2,636MW, which is the total ES deployment in the Ontario electricity system according to the ES Capacity scenario, is calculated by extrapolating the cradle-to-gate LCA results for individual systems (Li-ion and VRFB). It is also assumed that ES deployment begins in 2020 (although at minimal levels initially) according to the Pillar 1 simulation results in Section 2.11.7.1. Taking into account the distribution of ES within the four storage categories used in Pillar 1, the ES capacity result suggests that Li-ion storage may be deployed during all the suggested deployment years and VRFB may only be deployed in 2025 and 2030.

With regards to the annual capacity (MW) to be deployed for each ES technology (Li-ion battery and VRFB) from 2020 to 2030, Pillar 3 assumed five allocation scenarios of Li-ion and VRFB systems for the total ES deployment in 2020, 2025, and 2030. Figure 64 shows the annual capacity distribution among Li-ion battery and VRFB systems per scenario that is estimated by applying assumed allocation factors for each technology to the annual ES deployment for the ES Capacity scenario. Details are shown in the Appendix, Table A-4, page 170.

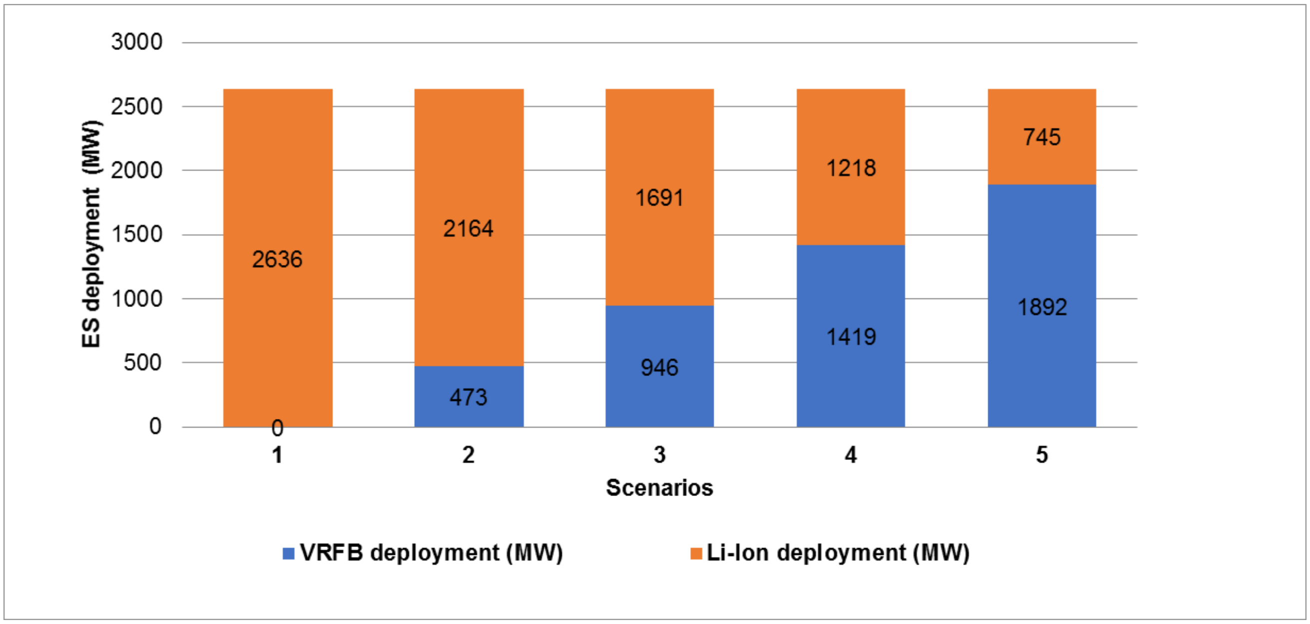

Figure 64. ES Allocation Scenarios by Technology

Figure 65 shows the net ES GHG emissions reductions at the grid level for different ES deployment scenarios, expressed in $MTCO_{2\text{-}eq}$ (positive values). Each environmental impact scenario is obtained by adding the overall ES cradle-to-gate emissions estimated for each scenario (negative values) and the grid-level GHG emissions reductions from ES usage (positive values) over the period of the study of the ES capacity scenario. The cradle-to-gate emissions from ES systems for each ES deployment scenario are discussed in detail in the Appendix, Table A-5, page 171.

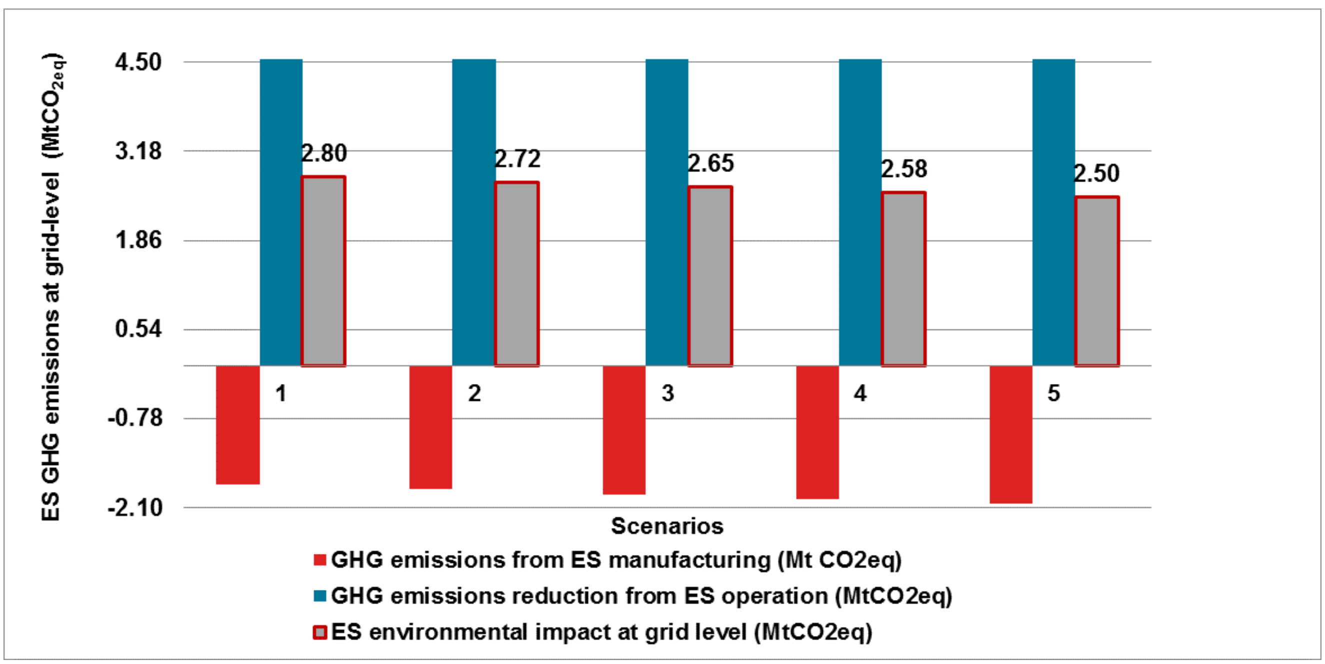

Figure 65. ES Environmental Impact at Grid Level for Different ES Deployment Scenarios

Scenario 1 indicates that the highest quantity of GHG emissions reduction from ES systems deployment is generated if only Li-ion battery ES systems are deployed by 2030, while scenario 5 shows that the lowest ES environmental positive impact expressed in GHG emissions is produced if 72% of the total ES systems deployment corresponds to VRFB deployment by 2030 since GHG emissions from VRFB manufacturing are higher than Li-ion batteries if these are expressed in $MTCO_{2\text{-eq}}$/MW deployed (see Appendix, Table A-5, page 171). For scenario 4, the total ES system's deployment by 2030 is equally distributed among Li-ion battery and VRFB systems. Note that overall GHG emissions from ES systems manufacturing (cradle-to-gate) do not surpass grid-level GHG emissions reductions from ES usage in all the assumed ES systems deployment scenarios.

As was pointed out in Section 4.2.5.2, the comparison between GHG emissions generated from the base case scenario without ES and ES capacity scenario in the Ontario electricity grid presents a moderate decrement over the period of study. Figure 66 shows that overall grid-level GHG emissions with ES usage decrease by 11% from 2020 to 2030, primarily due to nuclear refurbishment that leads to increased reliance on natural gas, and opportunities for natural gas avoidance by storage. If the annual cradle-to-grate GHG emissions of ES systems is included, this overall GHG emissions reduction drops to 6%. Therefore, GHG emissions from ES manufacturing (cradle-to-gate) generate an impact of 5% increment on the overall GHG emissions in the Ontario electricity grid with ES over the period of study and the majority is in the years 2025 and 2030 with the deployment of large scale VRFB. Note that annual GHG emissions values from ES manufacturing (cradle-to-gate) in Figure 66 correspond to scenario 4 in which the proportion of Li-ion to VRFB systems is equal.

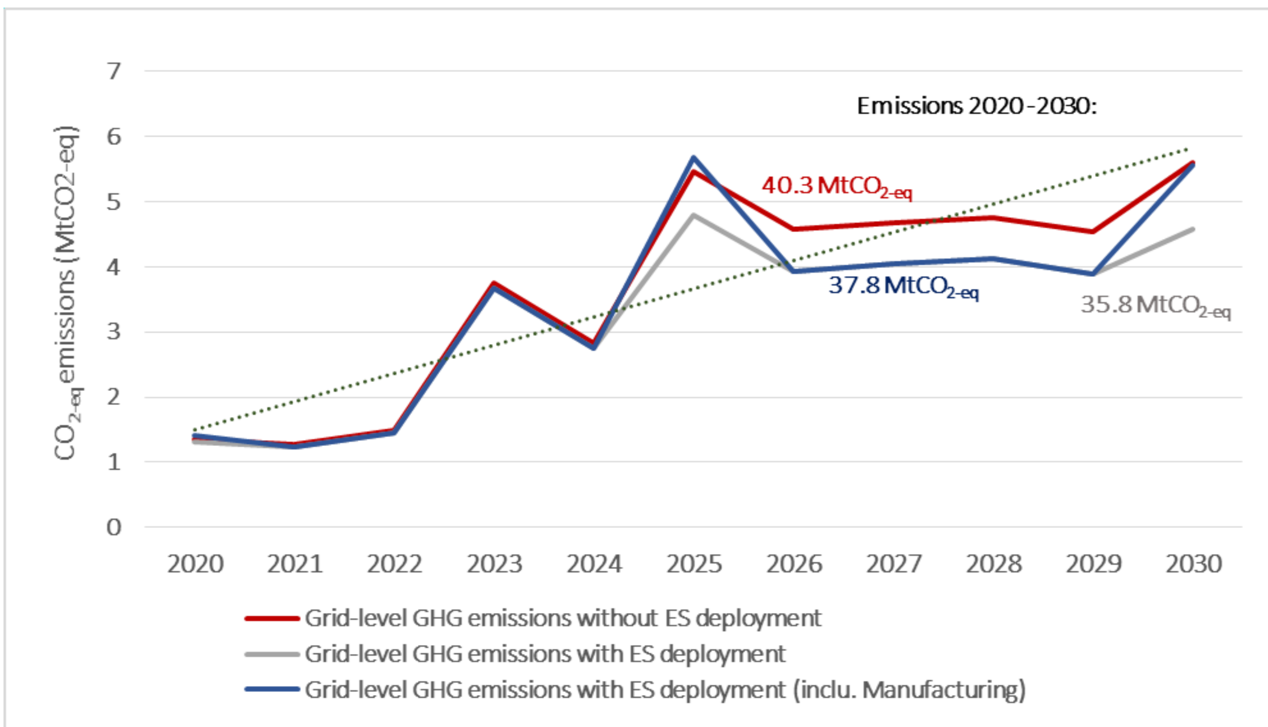

Figure 66. Comparison of Grid-level GHG Emissions without ES and with ES Capacity Scenarios in the Ontario Electricity Grid (2020-2030)

4.2.5.4 Technology Comparisons

In order to compare the life cycle impact of Li-ion battery and VRFB ES systems in terms of emission intensity, i.e. amount of total GHG emissions per MWh delivered to the Ontario electricity grid, the cradle-to-gate and end-of-life impacts of these two ES technologies in Table 157 are normalized to a 10-year service lifetime, which is assumed as a basis of a life cycle impact comparison. The operations phase emission intensity for this comparative life cycle impact assessment of ES technologies is calculated below.

4.2.5.4.1 Operations Phase Emissions for ES Technology Comparison

The functional unit of the operations phase for each ES technology is defined as normalized net GHG emissions, which are net GHG emissions for each ES technology divided by its total energy delivered to the grid in a 10 year-service lifetime (economic life) and expressed as $kgCO_{2\text{-}eq}/MWh$. The net GHG emissions are calculated using time-of-the-day grid marginal emission factors and hourly energy charging/discharging dispatch of ES technologies from Pillar 1's production cost optimization model.

Overall, the time-of-the-day marginal emission factors for Ontario's grid electricity system are calculated according to Eq.2 and Eq.3 in Section 4.2.4.5.2 using the hourly energy generated by fuel type over the study period modelled by Pillar 1 and the emission intensities of generation types. Figure **67** shows the hourly marginal emission factors for the period of study, the hourly natural gas-fired generation unit's dispatch, and the average daily power output from storage at the Ontario electricity grid. The latter shows the average daily charge/discharge patterns. Positive values represent discharge and negative values represent charging of the storage. Lower hourly marginal emissions factors correspond to the time range between 1 am to 3 pm when storage is charging, meanwhile higher marginal emission factors occur between 3 pm to 12 am when storage is discharging. Each data point is the average for that hour over the period of study from 2020 to 2030. Furthermore, Figure 67 shows that the time range when there are minimum MEF values concurs with the ES charging peak hours between 2 am to 5 am and it is the same period of time when the natural gas-fired generation minimum average capacity is dispatched to the electricity system. Maximum MEF values occur between 4 pm to 11 pm at ES discharging peak hours and correspond with the time period when the natural gas-fired generation maximum average capacity is dispatched to the electricity system.

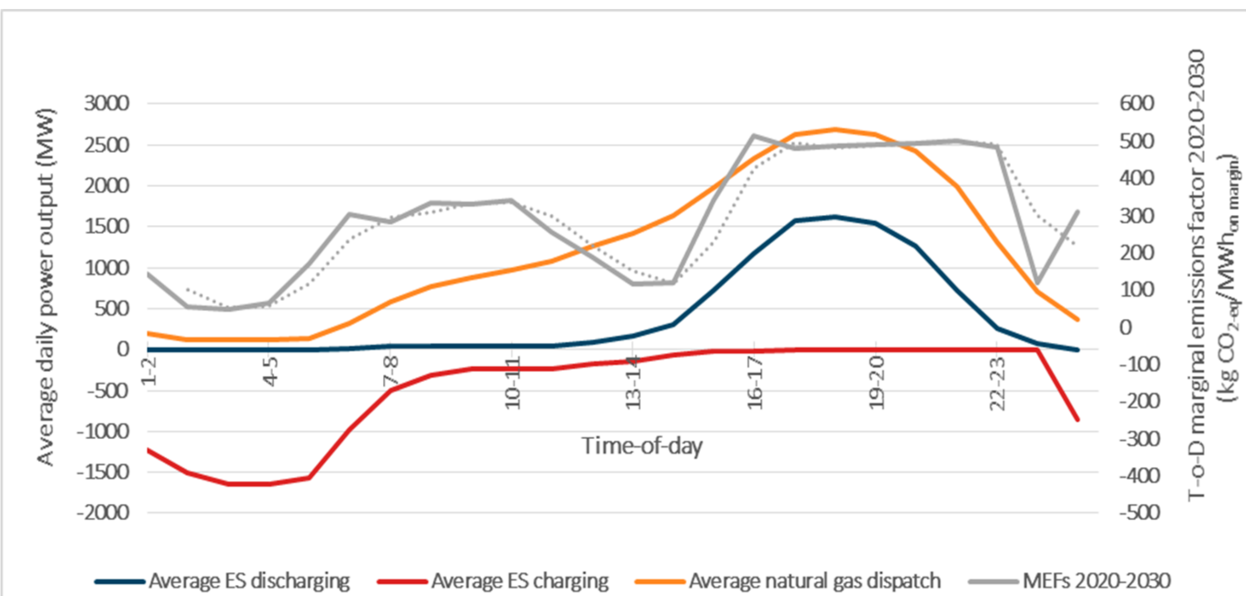

Figure 67. Time-of-the-day Marginal Emission Factors 2020-2030, ES Capacity Scenario

(*) MEF= marginal emission factor: T-o-D= Time-o-f-the-day

The net GHG emissions are calculated according to Eq.4 and Eq.5 in Section 4.2.4.5.2 as the sum of ES charging emissions (negative values) and ES discharging emissions (positive values). It is noted that ES discharging emissions are considered as displaced emissions in the grid.

Due to the evaluation of the operations phase, GHG emissions for technology comparison are over the Pillar 1's period of study, the energy delivery to the grid by each ES technology is normalized to a 10-year service lifetime. Table 158 shows the operations phase GHG emissions per specific ES technology, which are considered as the net GHG emissions resulting from the differential of charge/discharge cycle emissions per MWh delivered to the electric grid. The charging and discharging emissions are accumulated values from 2020 to 2030 calculated by using the respective hourly MEF and the hourly charging/discharging dispatch of the specific technology. The ES operations phase emissions for Li-ion batteries and VRFBs are 16 kg CO2-eq/MWh and 9 kg CO2-eq/MWh displaced emissions from 2020 to 2030, respectively.

Table 158. Operations Phase GHG Emissions for ES Technology Comparisons

ES operation phase GHG emissions (kg$CO_{2\text{-}eq}$/MWh)- (2020-2030)	LFP-C	VRFB
Normalized net displaced emissions (kgCO_{2eq}/MWh)	16	9
Net displaced emissions (kgCO2eq)	91,778	235,648
Energy delivered to the grid (MWh)	5,890	25,254

4.2.5.4.2 Technology Comparisons

A comparative life cycle GHG impact analysis for Li-ion battery and VRFB systems is performed at predictive power-grid mix scenarios from Pillar 1's cost production optimization model assuming ES deployment of these two technologies between 2020 and 2030. The cradle-to-grave (cradle-to-gate and stack replacement, operations phase, and end-of-life) impact of Li-ion battery and VRFB systems are based on results presented in previous sections. Note that the Li-on battery and VRFB systems cradle-to-gate and stack replacement life cycle impact of 113 and 20 kg CO_{2e}/$MWh_{delivered}$ respectively from Table 157, which are based on their complete lifetime utilization over their respective cycle lives or lifetime assumed in Table 155 and Table 156, are normalized to a 10-year service lifetime based on the ES charging/discharging dispatch from Pillar 1's results, and re-scale to 117 and 33 kg CO_{2e}/$MWh_{delivered}$ respectively in order to make direct comparisons between technologies. Note that there is no GHG emissions related to VRFB's stack replacement for 10-year service lifetime. The life cycle GHG impact of each ES technology is shown in Figure 68, where Li-ion has more cradle-to-grave emissions than VRFB systems during operation in the Ontario electricity grid from 2020 to 2030. Although VRFB manufacturing is less emission intensive than Li-ion based on the results from Table 157, with regard to the operations phase emissions, Li-ion is less emission intensive than VRFB by taking into account the differential of charging and displaced emissions, which are determined by the time-of-the-day marginal emissions factors and the charging/discharging dispatch profile of each technology.

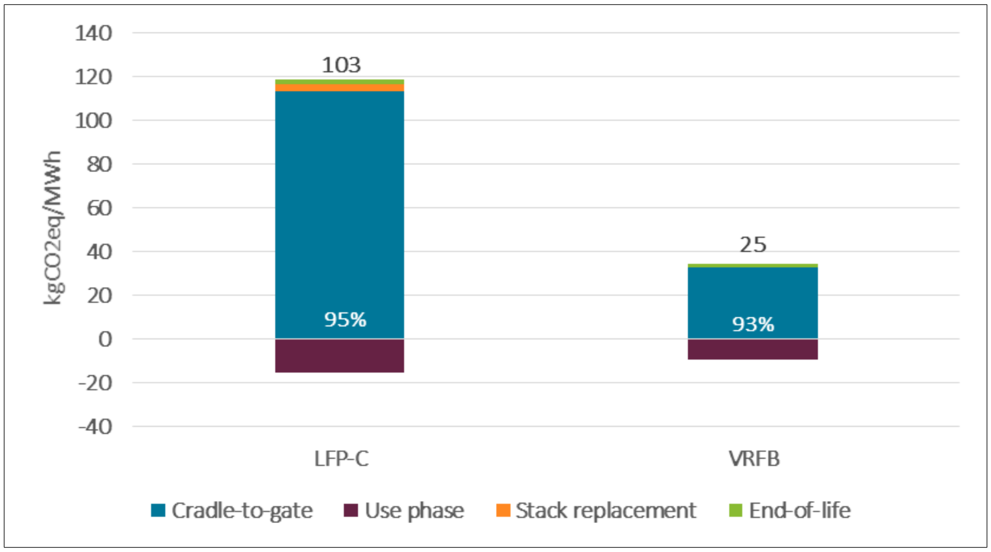

Figure 68. Life Cycle GHG Impact Comparison for ES Technologies

4.2.5.5 *Life Cycle GHG Emission Intensity for ES Technologies*

Table 159 shows the life cycle GHG emission intensity values expressed in GHG emissions per electricity delivered to the Ontario electric grid ($kgCO_{2e}/MWh_d$) for the two ES technology types analyzed in this section, Li-ion batteries and VRFB, based on the cradle-to-gate and stack replacement, operations phase and end-of-life LCA results presented above. Note that cradle-to-gate, stack replacement, and end-of-life GHG emissions are evaluated on a per technology basis considering their energy delivered to the grid during their respective complete lifetime utilization periods assumed in this study. The energy delivered to the grid from Table 158 is adjusted to the respective lifetime periods. The GHG emissions related to VRFB's stack replacement are included assuming 20 years of complete lifetime utilization for VRFB systems. The operations phase life cycle GHG emission values correspond to those calculated in Section 4.2.5.4.1.

Table 158. Life Cycle GHG Emission Intensities of ES Technology Types

ES Technology Type	Life Cycle GHG Emission Intensity (kg CO_{2e}/MWh)
Li-ion battery	103
VRFB	11

4.3 Socio-Economic Impact Assessment

In Pillar 3, input-output economic models (IOM) were used to evaluate the economic impact of ES deployment in Alberta. IOM models track the changes of industrial outputs in the supply chain according to a shock (change) in the final demand of a given industry. The increase in the final output of a particular industry increases the demand on industries that supply goods and services, creating ripple effects throughout the economy. These effects are measured by input-output multipliers, which are estimated using the coefficients of IOM. Statistics Canada collects national and provincial data and creates and maintains national and provincial accounts and IOMs for Canada. Industries are combined into 233 aggregates at the most detailed level of the Canadian input-output tables available.

4.3.1 Methodology for Economic Impact Assessment of ES Projects

The bill-of-goods approach is most appropriate when analyzing a new industry or an industry without a lot of granular data. This approach relies on an accurate description for the first round of purchases for a particular industry (BEA 2013). In the context of this socio-economic impact study, this involves the accounting of direct purchases by the ES industry from other industry categories. It requires identifying the front-end goods and services requirements of the project supply chain and quantifying the incremental spending on those goods and services. Once relevant supply chain industries are determined, the provincially-bought goods and services are identified. The calculated expenditure values are assigned to appropriate input-output model categories. This overall methodology of evaluating socio-economic values is shown in Figure 69.

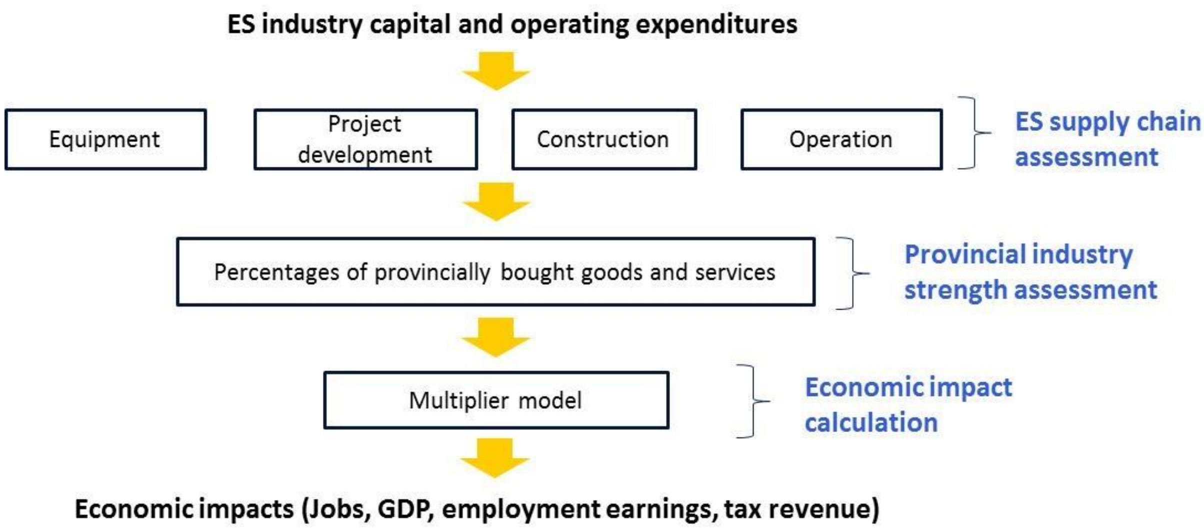

Figure 69. Methodology of Estimating Socio-economic Impact

Once the capital and operating expenditures are assigned to relevant industry categories, those increases in the demand can be entered into the IOM. The following types of impacts can be calculated using IOMs.

Direct Impacts – Result from expenditures associated with construction and operation of the project (1st round of spending), e.g. compensation for employees, taxes paid, capital formation, and profits.

Indirect Impacts – Involve the 2nd round of spending, which is the economic benefits of industries in the supply chain by hiring more workers and improving capacities to increase their output. Direct + indirect impacts represent the minimum value of economic impacts.

Induced Impacts - Result from the increased employment earnings of the workers in the project and supply chain industries causing more spending in the economy. Direct + Indirect + Induced impacts represent the maximum value of economic impacts. This is because workers may choose to spend their earnings outside the considered region (e.g. another province or country).

Total Impact - Represents the sum of direct, indirect and induced impacts.

The socio-economic impacts can be evaluated using the following indicators:

- GDP

- Number of jobs
- Employment earnings
- Tax revenue

The main assumptions of socio-economic impact assessment are shown in Table 160 below.

Table 159. Main Assumptions of Socio-economic Impact Assessment

Field of Assumption	Assumed Value or Input
Jurisdiction boundary for economic expenditures	Ontario
Economic structure	Current Ontario economic structure as given by Input-Output tables was assumed to be valid for project horizon.
Spending of the economic benefits (employment income)	All the spending occurs inside Ontario.
ES supply chain inputs	- Electrical power engineering construction - Electrical power transmission and distribution - Electrical equipment manufacturing - Battery and related devices manufacturing - Consulting and financial services - Government services

4.3.2 Socio-Economic Impact of Deploying ES in Ontario

The socio economic impact of deploying ES in Ontario from 2020 to 2030 is estimated by evaluating the socio-economic indicators: number of jobs created and the increase of the GDP. The total impact represents the sum of direct, indirect and induced impacts. The scope of direct impacts is the province of Ontario. However, the indirect and induced impacts are calculated for both Ontario and Canada.

Figure 70 shows the potential economic impact of ES projects in terms of number of jobs created during construction and operation stages in the province of Ontario. The number of jobs are calculated based on the average capital cost of the ES technology deployed during the period of study, taking into account the decreasing cost of ES technology over time. As can be seen, most local jobs are created (direct impact) as more ES projects are deployed, i.e. 507 jobs are created as a result of deployment of 150MW of ES systems in 2020 as opposed to 2,709 and 2,565 jobs created for the deployment of 1,184MW and 1,320MW of ES systems in 2025 and 2030, respectively. Regarding the total impact, including induced jobs, the number of jobs created during the project construction and operation stages is 1,119, 6,004, and 5,791 in 2020, 2025, and 2030, respectively.

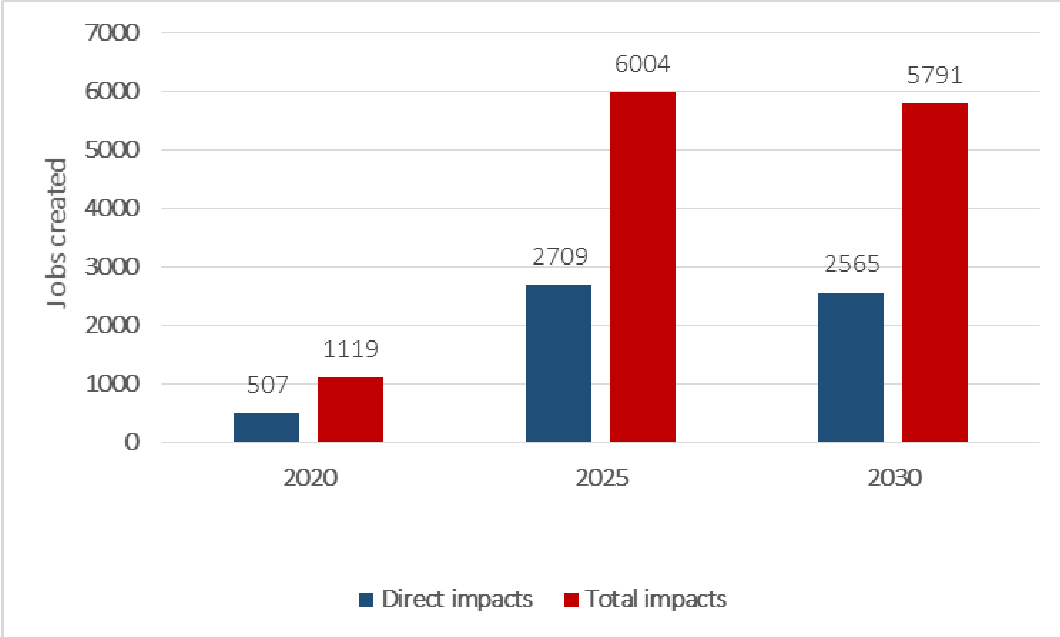

Figure 70. GDP Impact of Deploying Energy Storage Systems in the Province of Ontario

Figure 70 shows the potential economic impact of ES projects in terms of GDP added during construction and operation stages in the province of Ontario. The GDP is calculated based on the average capital cost of the ES technology deployed during the period of study, taking into account the decreasing cost of ES technology over time. As can be seen, most GDP is added (direct impact) as more ES projects are deployed, i.e. 65 M$ are added to the Ontario economy as a result of deployment of 150MW of ES systems in 2020 as opposed to 351 and 352 M$ of GDP added for the deployment of 1,184MW and 1,320MW of ES systems in 2025 and 2030, respectively. Regarding the total impact, including induced GDP, the increment of GDP during the project construction and operation stages is 129, 629, and 686 M$ in 2020, 2025, and 2030, respectively.

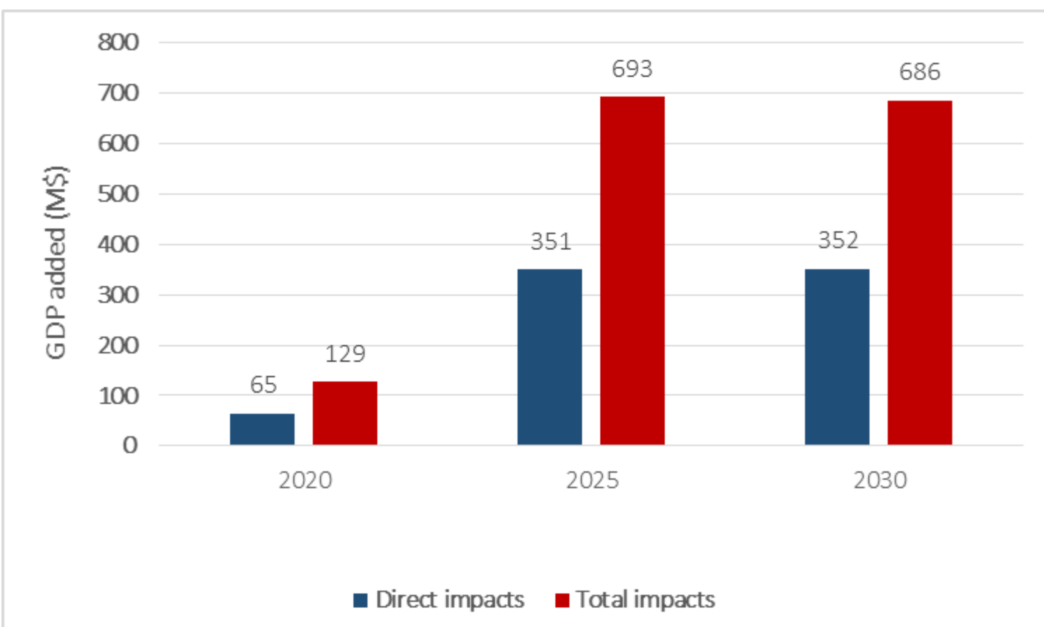

Figure 71. Number of Jobs Impact of Deploying Energy Storage Systems in the Province of Ontario

Table 161 shows a comparison of the reported direct impact of renewable energy and ES projects during the construction and operation stages (direct impact) in Ontario. The direct impact of ES projects is estimated using a job factor that is expressed as the total number of jobs created per total MW installed during each project stage.

Table 160. Direct Impact Comparison to Renewable Technologies

Project Type	Jobs/MW (Direct Impact)
Wind	1.1*
Solar	12.8*
Energy Storage	**2.19**

(*) Jeyakumar (2016)(2016)(2016)

The total direct impact GDP added to Ontario's economy and the number of jobs created due to the construction and operation of storage are 768 M$ and 5,781 jobs, respectively by 2030.

4.4 Conclusions: Environmental and Socio-Economic Impact

Overall, in this environmental and socio-economic impact assessment, three environmental and socio-economic impact indicators were identified to analyze the sustainability aspect of ES deployment in the Ontario electricity grid, including GHG emissions, number of jobs created, and GDP added. The analyses of these impact indicators were completed using the environmental life cycle approach and the input-output economic model (IOM) method, respectively. Based on these analyses, several important results of the overall environmental and socio-economic impact relative to the prospective deployment of ES systems in the Ontario electricity grid from 2020 to 2030 were obtained.

Overall, at the grid level, the GHG emission calculation, which is evaluated for 2,636MW of ES deployment (as determined by the analysis in Pillar 1), considered two aspects: GHG emissions reductions due to the operation of ES, which is based on changes in natural gas consumption, and GHG emissions from ES implementation, which is calculated by extrapolating cradle-to-gate life cycle results for individual systems (Li-ion and VRFB).

The resulting GHG impact of installing 2,636MW of ES leads to the following conclusions:

There are important displaced GHG emissions that are attributable to ES deployment; these GHG emission reductions surpass GHG emissions from ES systems manufacturing over the study period.

Large GHG emission reductions are likely to happen; hence, energy storage can be justified solely from the GHG reduction perspective or by achieving GHG reduction targets. Storage operation can reduce grid-level $CO_{2\text{-eq}}$ emissions by 11% by 2030 with a grid-level GHG emissions reduction of 4.5 $MtCO_{2\text{-eq}}$.

Even the system level GHG emissions reductions from ES usage can alone justify developing ES infrastructure. The environmental life cycle impact from ES deployment, taking into account GHG emissions from ES manufacturing and operation in the grid, is still important in comparison to the overall anticipated GHG emissions in the Ontario electricity system from 2020 to 2030. Storage deployment can reduce grid-level CO2-eq emissions by 6.4% by 2030 when storage life cycle carbon emissions are taken into account to estimate overall storage environmental impact on the grid.

An LCA approach was used to perform a comparative life cycle GHG impact analysis of Li-ion battery ES and VRFB systems operating in the Ontario electricity system from 2020 to 2030. Furthermore, considering the operations phase, GHG impact is affected by the variations of the emission intensities in the power-grid mix when the ES system is charged and discharged on an hourly basis; hourly MEFs is used to calculate operations phase GHG emissions using hourly generation data and charge/discharge dispatch from simulation model.

- The environmental performance of Li-ion batteries indicates that this ES technology generates more GHG emissions than VRFB systems from 2020 to 2030. The cradle-to-grave LCA results indicate that the life cycle GHG impact of Li-ion battery ES systems are mostly affected by the emissions during manufacturing (cradle-to-gate stage) of the ES systems components, specifically the battery pack. In the case of VRFB systems, they displaced less emissions during the operations phase, originating from the time-of-the day marginal emissions factors when it is dispatched, exacerbated by low VRFB system round-trip efficiency.
- The life cycle GHG impact of Li-ion battery ES and VRFB systems indicates that the overall contribution of the operations phase to the overall life cycle impact depends upon hourly marginal emissions factors that reflect the changes on power-grid mix and the round-trip efficiency. Time dependent marginal emission factors accurately capture the effects of different charging and discharging times subject to hourly dispatch of ES technologies instead of using average emissions intensities of provincial electricity grids to calculate the emissions related to grid electricity losses depending on technology specific round trip efficiencies.
- Our methodology for grid-level GHG emission calculations of ES operation is based on changes to natural gas consumption, where the system GHG emissions are based on results from Pillar 1. The GHG emission intensity is initially calculated for each technology based on the use case assumptions. Independently, life cycle emissions for different technologies have also been calculated and compared.
- Life cycle emissions for VRFB and Li-ion batteries are estimated based on the functional unit of 1 kg $CO_{2\text{-}eq}$/MWh delivered to the grid. In order to compare these two technologies with different expected project lifetimes, the LCAs for Li-ion battery and VRFB were normalized to the energy generated during the 10-year study period. Initially, each cradle-to-gate is calculated for its expected project lifetime (Li-ion 10 years and VRFB 20 years) based on their lifetime capacity at 80% DoD. For normalization, cradle-to-gate is calculated based on the energy delivered to the grid using the hourly charge/discharge dispatch for each ES technology from 2020 to 2030 obtained from Pillar 1's simulation results. In the case of operations phase GHG emissions, net displaced GHG emissions are calculated using hourly marginal emissions factors.

With regard to the socio-economic impact for ES deployment, it is evaluated through the number of jobs created and GDP added by ES deployment in Ontario during ES project stages. Direct economic impacts are estimated and resulted from local activities in the supply chain of the project, meanwhile the total economic impacts include the indirect and induced activities inside and outside Ontario.

- Most economic impacts are generated during the construction and operation phases in a similar way to that in renewable energy projects. The economic impact is likely to be lower than, for example, in solar projects, as ES systems are usually modular and implemented with lower construction phase costs.
- Overall, direct jobs that would be generated in Ontario represent 45% of total jobs generated in Canada as a result of ES deployment in Ontario, meanwhile GDP added to Ontario's economy represent 50% of total GDP added.

Further study is recommended to perform a comparative analysis of life cycle GHG impacts on ES systems for different stationary grid applications, as the cradle-to-gate and operation phase GHG impact would be affected by lifetime utilization of a specific application.

5 References

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Appendices

This section includes all the supplemental report data and data of all the figures included in the report.

Capacity Forecast Data by Fuel Type

Table A 1. Year-end Installed Capacity by Fuel Type Forecast [7]

Fuel	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Nuclear	12,133	12,133	12,133	11,311	10,430	10,430	8,619	10,322	7,485	8,325	8,325	8,276	9,098	8,276
Gas	10,221	10,940	10,818	10,899	10,899	10,899	10,857	10,857	10,857	10,857	10,857	10,857	10,857	10,857
Hydroelectric	8,863	8,914	8,959	8,961	8,962	8,997	8,997	9,012	9,012	9,012	9,012	9,012	9,012	9,012
Biomass	596	597	598	598	598	598	598	598	598	598	598	598	598	598
Solar	2,485	2,636	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,977
Wind	5,159	5,459	5,462	5,716	5,714	5,714	5,714	5,714	5,714	5,714	5,713	5,713	5,713	5,713
Demand Response	847	847	847	847	847	847	847	847	847	847	847	847	847	847
Storage	34	50	50	50	50	50	50	50	50	50	50	50	50	50
Total	40,338	41,577	41,846	41,361	40,480	40,515	38,661	40,379	37,542	38,382	38,380	38,331	39,153	38,330

Fuel Price Forecast Data

Table A 2. Fuel Price Forecast in 2016 CAD$/GJ [11], [12]

CAD/GJ	Natural Gas	Fuel Oil (Distillate)	Fuel Oil (Residual)	Coal	Uranium
2016	3.66	15.14	10.36	2.74	0.80
2017	4.32	17.59	13.13	2.67	0.81
2018	4.45	18.25	12.73	2.69	0.81
2019	4.89	19.18	14.28	2.75	0.81
2020	5.18	23.11	17.27	2.79	0.81
2021	5.10	24.79	18.32	2.79	0.81
2022	5.15	25.37	18.51	2.78	0.81
2023	5.30	25.75	18.56	2.79	0.82
2024	5.43	25.98	18.64	2.82	0.82
2025	5.58	26.08	18.74	2.84	0.82
2026	5.62	26.05	19.06	2.85	0.82
2027	5.68	26.24	19.28	2.85	0.82
2028	5.69	26.47	19.36	2.85	0.83
2029	5.76	26.87	19.70	2.86	0.83
2030	5.76	27.07	19.94	2.87	0.83
2031	5.75	27.41	20.34	2.88	0.83
2032	5.77	27.67	20.48	2.88	0.83
2033	5.75	28.00	20.68	2.90	0.84
2034	5.76	28.33	20.85	2.91	0.84
2035	5.75	28.51	21.05	2.93	0.84

Peak Demand Forecast

Table A 3. Forecast Peak Demand by Year, MW [3]

Datetime	Bruce	East	Essa	Niagara	North East	North West	Ottawa	South West	Toronto	West	Ontario Peak
2018	445	1807	2073	881	1914	803	1668	4792	9699	3364	**24,041**
2019	425	1828	2042	882	2108	852	1650	4924	9486	3444	**23,993**
2020	421	1849	2103	845	2067	844	1663	4985	9642	2746	**23,916**
2021	421	1819	2076	881	2232	818	1694	4811	9636	3610	**23,890**
2022	408	1796	2086	885	2053	771	1658	5128	9748	3270	**23,887**
2023	426	1751	2082	874	1780	766	1645	4820	9698	3310	**23,901**
2024	442	1795	2033	878	1952	848	1643	4903	9444	3429	**23,888**
2025	421	1851	2091	870	2069	853	1633	4962	9501	2992	**23,950**
2026	434	1840	2104	850	2167	824	1664	4850	9637	3494	**23,931**
2027	423	1826	2085	885	2241	821	1701	4831	9676	3625	**23,988**
2028	410	1807	2094	879	2067	771	1654	4847	9753	3332	**24,036**
2029	448	1816	2083	885	1926	807	1676	4815	9746	3385	**24,156**
2030	430	1848	2064	891	2136	861	1668	4976	9585	3491	**24,243**
2031	430	1881	2125	883	2111	867	1660	5041	9653	3069	**24,332**
2032	443	1878	2123	900	2217	838	1732	4916	9847	3694	**24,411**
2033	423	1854	2154	913	2133	800	1712	5292	10059	3397	**24,650**
2034	444	1824	2169	911	1857	798	1714	5020	10099	3472	**24,889**
2035	468	1893	2170	922	2016	841	1746	5014	10149	3545	**25,152**

Energy Forecast

Table A 4. Forecast Energy Demand by Year, GWh

Datetime	Bruce	East	Essa	Niagara	North East	North West	Ottawa	South West	Toronto	West	Ontario Energy
2018	718	8,907	8,317	3,962	10,504	3,974	8,311	29,744	54,105	14,116	**142,659**
2019	715	8,881	8,293	3,950	10,474	3,963	8,286	29,658	53,948	14,075	**142,243**
2020	715	8,880	8,292	3,950	10,472	3,962	8,285	29,654	53,940	14,073	**142,224**
2021	713	8,850	8,265	3,937	10,438	3,949	8,258	29,556	53,762	14,027	**141,754**
2022	713	8,846	8,261	3,935	10,433	3,947	8,254	29,542	53,737	14,020	**141,689**
2023	713	8,845	8,259	3,934	10,431	3,946	8,252	29,536	53,727	14,017	**141,660**
2024	714	8,866	8,279	3,943	10,456	3,956	8,272	29,607	53,855	14,051	**142,000**
2025	714	8,863	8,276	3,942	10,452	3,954	8,269	29,596	53,836	14,046	**141,948**
2026	714	8,859	8,272	3,940	10,447	3,953	8,265	29,583	53,812	14,039	**141,884**
2027	716	8,890	8,301	3,954	10,484	3,967	8,294	29,687	54,001	14,089	**142,383**
2028	721	8,948	8,355	3,980	10,552	3,992	8,348	29,880	54,352	14,181	**143,310**
2029	724	8,991	8,396	3,999	10,603	4,012	8,389	30,024	54,614	14,249	**144,000**
2030	729	9,050	8,451	4,025	10,673	4,038	8,444	30,222	54,974	14,343	**144,948**
2031	734	9,108	8,506	4,051	10,742	4,064	8,498	30,417	55,329	14,435	**145,885**
2032	740	9,189	8,581	4,087	10,837	4,100	8,574	30,687	55,820	14,563	**147,179**
2033	748	9,281	8,666	4,128	10,945	4,141	8,659	30,992	56,375	14,708	**148,643**
2034	757	9,398	8,776	4,180	11,084	4,194	8,769	31,386	57,091	14,895	**150,531**
2035	767	9,524	8,894	4,236	11,232	4,250	8,886	31,805	57,854	15,094	**152,543**

Solar and Wind Capacity

Table A 5. Solar and Wind Firm Capacity [15]

Month	Wind Capacity Contribution (% of Installed Capacity)	Solar Capacity Contribution (% of Installed Capacity)
Jan	37.8%	0.0%
Feb	37.8%	0.0%
Mar	33.6%	0.0%
Apr	35.4%	1.3%
May	22.8%	2.9%
Jun	13.6%	10.1%
Jul	13.6%	10.1%
Aug	13.6%	10.1%
Sep	14.8%	8.6%
Oct	29.8%	0.0%
Nov	36.5%	0.0%
Dec	37.8%	0.0%

Capacity by Fuel Type Benchmark Values

Table A 6. Capacity by Fuel Type Benchmark

Fuel Type	Data	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Hydro	Acelerex Model	8905	8905	8905	8905	8905	8905	8905	8905	8905	8905	8905
	Annual Planning Outlook 2020	8961	8962	8997	8997	9012	9012	9012	9012	9012	9012	9012
Natural Gas	Acelerex Model	10961	10961	10961	10961	10961	10961	10961	10961	10961	10961	10961
	Annual Planning Outlook 2020	10899	10899	10899	10857	10857	10857	10857	10857	10857	10857	10857
Wind	Acelerex Model	5697	5697	5697	5697	5697	5697	5697	5697	5697	5697	5697
	Annual Planning Outlook 2020	5716	5714	5714	5714	5714	5714	5714	5713	5713	5713	5713
Solar	Acelerex Model	2950	2950	2950	2950	2950	2950	2950	2950	2950	2950	2950
	Annual Planning Outlook 2020	2978	2978	2978	2978	2978	2978	2978	2978	2978	2978	2977
Nuclear	Acelerex Model	11322	10441	10441	8627	10325	7469	8317	8317	8284	9101	8284
	Annual Planning Outlook 2020	11311	10430	10430	8619	10322	7485	8325	8325	8276	9098	8276

Fuel Type	Data	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Biomass	Acelerex Model	587	587	587	587	587	587	587	587	587	587	587
	Annual Planning Outlook 2020	596	597	598	598	598	598	598	598	598	598	598

Demand and Capacity with Reserve Margin

Table A 7. Summer Peak Demand and Total Capacity Requirement Forecast [9]

Year	Summer Peak Demand (MW)	Reserve Margin	Reserve Requirement (MW)	Total Capacity Requirement (MW)
2017	24,083	18%	4,290	28,373
2018	24,041	21%	5,131	29,172
2019	23,993	21%	4,923	28,916
2020	23,916	23%	5,609	29,525
2021	23,890	23%	5,539	29,429
2022	23,887	24%	5,665	29,552
2023	23,901	23%	5,419	29,320
2024	23,888	20%	4,873	28,761
2025	23,950	22%	5,187	29,137
2026	23,931	22%	5,341	29,272
2027	23,988	22%	5,284	29,272
2028	24,036	22%	5,393	29,429
2029	24,156	22%	5,379	29,535
2030	24,243	22%	5,375	29,618
2031	24,332	23%	5,703	30,035
2032	24,411	23%	5,505	29,915
2033	24,650	24%	5,859	30,509
2034	24,889	19%	4,614	29,503
2035	25,152	18%	4,606	29,758

Energy Storage Nodes

Table A 8. List of Energy Storage Nodes

ONBRUCE L ES PC	159338_SAMSUCOLLB_34.5	ONBRUCE
ONBRUCE L ES PC	159502_CEDAR_CL_34.5	ONBRUCE
ONBRUCE L ES PC	159658_JERICHO_WTG4_34.5	ONBRUCE
ONBRUCE L ES PC	159509_CEDAR_C4_34.5	ONBRUCE
ONBRUCE L ES PC	159610_BHWP_B_TS_A_13.8	ONBRUCE
ONBRUCE ML ES PC	159318_SAMFEED10_34.5	ONBRUCE

ONBRUCE ML ES PC	159654_JERICHO_COL_34.5	ONBRUCE
ONBRUCE ML ES PC	159618_BRUCE_B_GS-6_24	ONBRUCE
ONBRUCE ML ES PC	159626_BRUACE_S21A_13.8	ONBRUCE
ONBRUCE ML ES PC	159633_BRUCE_B_S61B_13.8	ONBRUCE
ONBRUCE MS ES PC	159314_SAMFEED6_34.5	ONBRUCE
ONBRUCE MS ES PC	159316_SAMFEED8_34.5	ONBRUCE
ONBRUCE MS ES PC	159636_BRUCE_B_S71A_13.8	ONBRUCE
ONBRUCE MS ES PC	159649_ADELAIDE_WF2_34.5	ONBRUCE
ONBRUCE MS ES PC	159643_BORNISH_WTG3_34.5	ONBRUCE
ONBRUCE S ES PC	159647_ADELAIDE_COL_34.5	ONBRUCE
ONBRUCE S ES PC	159505_CEDAR_C2_34.5	ONBRUCE
ONBRUCE S ES PC	159640_BORNISH_COL_34.5	ONBRUCE
ONBRUCE S ES PC	159322_SAMFEED3_34.5	ONBRUCE
ONBRUCE S ES PC	159660_JERICHO_WTG6_34.5	ONBRUCE
ONEAST L ES PC	155601_ALMONTE_Q_44	ONEAST
ONEAST L ES PC	155612_PEMBROKE_BY_44	ONEAST
ONEAST L ES PC	155627_BAR_CHUT_GS4_13.8	ONEAST
ONEAST L ES PC	155648_WOLF_ISL_CG2_34.5	ONEAST
ONEAST L ES PC	155750_WHITE_PINESW_34.5	ONEAST
ONEAST ML ES PC	155602_ARNPRIOR_BJ_44	ONEAST
ONEAST ML ES PC	155618_TIMMINCO_CTS_13.8	ONEAST
ONEAST ML ES PC	155637_MT_CHUTE_GS2_13.8	ONEAST
ONEAST ML ES PC	155668_CHESTERVILLE_44	ONEAST
ONEAST ML ES PC	155755_KINGSTONSLAR_34.5	ONEAST
ONEAST MS ES PC	155758_KINGSTONSOF3_34.5	ONEAST
ONEAST MS ES PC	155749_WHITE_PINES_69	ONEAST
ONEAST MS ES PC	155633_CHENAUX_GS34_13.8	ONEAST
ONEAST MS ES PC	155608_COBDEN_TS_M2_44	ONEAST
ONEAST MS ES PC	155617_CHAT_FL_GS4_13.8	ONEAST
ONEAST S ES PC	155622_ARNPRIOR_GS1_13.8	ONEAST
ONEAST S ES PC	155629_CHAT_FL_GS5_13.8	ONEAST
ONEAST S ES PC	155641_STEWARTVL_G4_13.8	ONEAST
ONEAST S ES PC	155652_WOLF_ISL_CG6_34.5	ONEAST
ONEAST S ES PC	155687_LAFARGE_BATH_13.8	ONEAST
ONESSA L ES PC	153615_WALLACE_TS_Y_44	ONESSA
ONESSA L ES PC	153619_D_JOACH_GS-1_13.8	ONESSA
ONESSA L ES PC	153630_BROWN_HL_BY_44	ONESSA
ONESSA L ES PC	153644_MINDEN_TS_T2_13.8	ONESSA
ONESSA L ES PC	153651_MIDHURST_JQ_44	ONESSA
ONESSA ML ES PC	153616_WALLACE_TS_Q_44	ONESSA
ONESSA ML ES PC	153645_MUSKOKA_BY_44	ONESSA
ONESSA ML ES PC	153621_D_JOACH_GS-3_13.8	ONESSA
ONESSA ML ES PC	153629_BEAVERTON_JQ_44	ONESSA

ONESSA ML ES PC	153638_ESSA_TS_T3_27.6	ONESSA
ONESSA MS ES PC	153647_PARRY_SND_BY_44	ONESSA
ONESSA MS ES PC	153623_D_JOACH_GS-5_13.8	ONESSA
ONESSA MS ES PC	153631_LINDSAYTS_BY_44	ONESSA
ONESSA MS ES PC	153654_HOLLAND_TS_44	ONESSA
ONESSA MS ES PC	153648_WAUBAUSHN_JQ_44	ONESSA
ONESSA S ES PC	153627_ARMITAGE_JQ_44	ONESSA
ONESSA S ES PC	153650_BRACEBRIDGE_44	ONESSA
ONESSA S ES PC	153640_MIDHURST_BY_44	ONESSA
ONESSA S ES PC	153642_MINDEN_TS_Y_44	ONESSA
ONESSA S ES PC	153635_BARRIE_TS_BY_44	ONESSA
ONNE L ES PC	152552_XENECA_LV_69	ONNE
ONNE L ES PC	152558_CHUTE_HV_69	ONNE
ONNE L ES PC	152649_INCO_#4_L2_69	ONNE
ONNE L ES PC	152842_TARENTORUS12_34.5	ONNE
ONNE L ES PC	152867_NORTH_BAY_TS_44	ONNE
ONNE ML ES PC	152556_JCT_4_69	ONNE
ONNE ML ES PC	152563_OUT_KAP_HV_69	ONNE
ONNE ML ES PC	152838_YOUNG-DAVDSN_13.8	ONNE
ONNE ML ES PC	152899_BOWL_LAKE_W4_34.5	ONNE
ONNE ML ES PC	152930_GOULAIS_WTG_34.5	ONNE
ONNE MS ES PC	152666_INCO_#4_L1_69	ONNE
ONNE MS ES PC	152562_LAP_RAP_HV_69	ONNE
ONNE MS ES PC	152851_LAKESUPER_T2_13.8	ONNE
ONNE MS ES PC	152885_MCLEANSFD2_34.5	ONNE
ONNE MS ES PC	152822_NORTHERN_AVE_34.5	ONNE
ONNE S ES PC	152560_N_NORTH_HV_69	ONNE
ONNE S ES PC	152857_PRINCE_WF_C1_34.5	ONNE
ONNE S ES PC	152924_SMOKY_FL2_G2_13.8	ONNE
ONNE S ES PC	152806_WAWA_SUB1_34.5	ONNE
ONNE S ES PC	152788_ALGOMA_ST313_34.5	ONNE
ONNI L ES PC	157600_TREI-BACHER_13.8	ONNI
ONNI L ES PC	157614_CARLTON_HK_13.8	ONNI
ONNI L ES PC	157626_KALAR_MTSID2_13.8	ONNI
ONNI L ES PC	157635_ABIT_NAN2801_13.8	ONNI
ONNI L ES PC	157653_CNP_#18_CTS_34.5	ONNI
ONNI ML ES PC	157601_ALLAN_DSN_BY_27.6	ONNI
ONNI ML ES PC	157621_GLENDALE_DQ_13.8	ONNI
ONNI ML ES PC	157641_STANLEY_JQ_13.8	ONNI
ONNI ML ES PC	157667_BECK_#2_GS21_13.8	ONNI
ONNI ML ES PC	157686_THOROLD_CTG1_13.8	ONNI
ONNI MS ES PC	157608_BEAMSVIL_BY_27.6	ONNI
ONNI MS ES PC	157679_BECK1_NM_69	ONNI

ONNI MS ES PC	157645_VINELAND_B1_27.6	ONNI
ONNI MS ES PC	157632_PAN_ABRASIVE_13.8	ONNI
ONNI MS ES PC	157611_BUNTING_J1J2_13.8	ONNI
ONNI S ES PC	157617_CROWLAND_QY_27.6	ONNI
ONNI S ES PC	157630_MURRAY_TS_K_13.8	ONNI
ONNI S ES PC	157642_STEVENSVILLE_34.5	ONNI
ONNI S ES PC	157660_BECK_#1_GS10_13.8	ONNI
ONNI S ES PC	157707_JBL_N_L1_13.8	ONNI
ONNW L ES PC	151600_UMBATA_FLS_G_13.8	ONNW
ONNW L ES PC	151619_BOWAT_KRAFT4_13.8	ONNW
ONNW L ES PC	151651_MACKENZIE_T3_13.8	ONNW
ONNW L ES PC	151747_PINE_PORT_G3_13.8	ONNW
ONNW L ES PC	151782_LONG_RPDS_LO_34.5	ONNW
ONNW ML ES PC	151780_NAMEWAMINIKN_34.5	ONNW
ONNW ML ES PC	151721_THUN_BAY_GS1_13.8	ONNW
ONNW ML ES PC	151645_LAKEHEAD_T7_13.8	ONNW
ONNW ML ES PC	151626_DRYDEN_TST22_13.8	ONNW
ONNW ML ES PC	151657_MARATHON_T12_13.8	ONNW
ONNW MS ES PC	151772_GREENWITCHT1_34.5	ONNW
ONNW MS ES PC	151739_WESTCOAST_G2_13.8	ONNW
ONNW MS ES PC	151698_GRNW_LK_B2_34.5	ONNW
ONNW MS ES PC	151633_FT_FRANCS_T2_13.8	ONNW
ONNW MS ES PC	151604_FT_FRANCS_L5_13.8	ONNW
ONNW S ES PC	151749_SILVER_FALLS_13.8	ONNW
ONNW S ES PC	151728_AGUASABON_GS_13.8	ONNW
ONNW S ES PC	151638_GRIFFIN_MINE_13.8	ONNW
ONNW S ES PC	151613_AINSWORTH_13.8	ONNW
ONNW S ES PC	151622_RESFP_TB_LT_13.8	ONNW
ONOT L ES PC	154351_LIMEBANK_B_1_27.6	ONOT
ONOT L ES PC	154644_NAVAN_DS_NL2_27.6	ONOT
ONOT L ES PC	154676_KANATA_MTS#1_27.6	ONOT
ONOT L ES PC	154684_GREELY_DS_B1_27.6	ONOT
ONOT L ES PC	154696_CYRV_RD_JQ_27.6	ONOT
ONOT ML ES PC	154602_BILBERRY_BY_27.6	ONOT
ONOT ML ES PC	154614_HAWTHORNE_T1_27.6	ONOT
ONOT ML ES PC	154671_WILHAVEN_B1_27.6	ONOT
ONOT ML ES PC	154682_OHSC_CGS_13.8	ONOT
ONOT ML ES PC	154698_TERRY_FOX_L2_27.6	ONOT
ONOT MS ES PC	154611_FALLOWFIELD_27.6	ONOT
ONOT MS ES PC	154669_WENDOVER_B2_27.6	ONOT
ONOT MS ES PC	154680_WILHAVEN_B2_27.6	ONOT
ONOT MS ES PC	154689_MARIONVILLE_27.6	ONOT
ONOT MS ES PC	154703_ORLEANS-LV1_27.6	ONOT

ONOT S ES PC	154626_LIMEBANK_B1_27.6	ONOT
ONOT S ES PC	154640_MOULTON_MTS_27.6	ONOT
ONOT S ES PC	154674_BRIDLEWOOD_27.6	ONOT
ONOT S ES PC	154686_IVACO_ROD_Q_13.8	ONOT
ONOT S ES PC	154677_UPLANDS_Z_27.6	ONOT
ONSW L ES PC	158699_NEWTON_TS_B_13.8	ONSW
ONSW L ES PC	158771_AMARANTH_S1_34.5	ONSW
ONSW L ES PC	158837_SEAFORTH_TS_27.6	ONSW
ONSW L ES PC	158909_DUFFERIN_WT1_34.5	ONSW
ONSW L ES PC	158949_GRANDBEND_C2_34.5	ONSW
ONSW ML ES PC	158716_SCHEIFELE_HJ_13.8	ONSW
ONSW ML ES PC	158807_RIPLEYSOUTHC_34.5	ONSW
ONSW ML ES PC	158868_SUMERHAVENF3_34.5	ONSW
ONSW ML ES PC	158922_GRANDENRGYW5_34.5	ONSW
ONSW ML ES PC	158957_GRANDVALLYF2_34.5	ONSW
ONSW MS ES PC	158721_US_STL_A1A2_13.8	ONSW
ONSW MS ES PC	158816_KARN_TS_T2_13.8	ONSW
ONSW MS ES PC	158881_PORTDOVERFD5_34.5	ONSW
ONSW MS ES PC	158932_GRANDENRGYS2_34.5	ONSW
ONSW MS ES PC	158980_ARMOW_WG_F3_34.5	ONSW
ONSW S ES PC	158723_STIRTON_BY_13.8	ONSW
ONSW S ES PC	158835_GRD_BEND_EB2_27.6	ONSW
ONSW S ES PC	158890_BLUEWATR_WT1_34.5	ONSW
ONSW S ES PC	158941_GOSHEN_WF_F2_34.5	ONSW
ONSW S ES PC	158984_ARMOW_WG_F7_34.5	ONSW
ONTO L ES PC	156605_AGINCOURT_Y_27.6	ONTO
ONTO L ES PC	156622_IBM_CTS_BY_13.8	ONTO
ONTO L ES PC	156637_MARKHAM_#3JY_27.6	ONTO
ONTO L ES PC	156703_BRIDGMAN_R11_13.8	ONTO
ONTO L ES PC	156758_MAIN_TS_A3A4_13.8	ONTO
ONTO ML ES PC	156608_ATLANT_PK_BY_13.8	ONTO
ONTO ML ES PC	156644_SCARBORO_B_27.6	ONTO
ONTO ML ES PC	156716_CECIL_TS_A56_13.8	ONTO
ONTO ML ES PC	156772_STRACHAN_A78_13.8	ONTO
ONTO ML ES PC	156626_GERDAU_AW_C_33	ONTO
ONTO MS ES PC	156612_BERMONDSY_Q_27.6	ONTO
ONTO MS ES PC	156648_SHEPPARD_IDL_27.6	ONTO
ONTO MS ES PC	156617_CHERRYWD_T17_27.6	ONTO
ONTO MS ES PC	156629_LESLIE_TS_J_27.6	ONTO
ONTO MS ES PC	156722_DUFFERIN_A12_13.8	ONTO
ONTO S ES PC	156630_LESLIE_TS_H1_13.8	ONTO
ONTO S ES PC	156654_WHITBY_TS_BY_27.6	ONTO
ONTO S ES PC	156697_JOHN_TS_AB_13.8	ONTO

ONTO S ES PC	156735_GERRARD_A1A2_13.8	ONTO
ONTO S ES PC	156747_JOHN_TSA1516_13.8	ONTO
ONWEST L ES PC	160547_ADEL-WPP_CL1_34.5	ONWEST
ONWEST L ES PC	160627_FORD_ESSEX_13.8	ONWEST
ONWEST L ES PC	160680_WALKER_MTS#2_27.6	ONWEST
ONWEST L ES PC	160716_W_WIND_PWRG1_13.8	ONWEST
ONWEST L ES PC	160760_RALEIGH_WCL2_34.5	ONWEST
ONWEST ML ES PC	160563_GN_ELEC_G2_13.8	ONWEST
ONWEST ML ES PC	160694_SUNCOR_CTS_B_13.8	ONWEST
ONWEST ML ES PC	160655_NOVA_CORUNNA_13.8	ONWEST
ONWEST ML ES PC	160733_PORTALMA_CLC_34.5	ONWEST
ONWEST ML ES PC	160774_AUXROCHES_F2_34.5	ONWEST
ONWEST MS ES PC	160605_PORT_BURWELL_34.5	ONWEST
ONWEST MS ES PC	160688_FORD_WINDSOR_27.6	ONWEST
ONWEST MS ES PC	160658_NELSON_TS_BQ_13.8	ONWEST
ONWEST MS ES PC	160755_FORT_CHICAGT_13.8	ONWEST
ONWEST MS ES PC	160765_PORTALMA_CLG_34.5	ONWEST
ONWEST S ES PC	160609_BUCHANAN_T3_13.8	ONWEST
ONWEST S ES PC	160667_ST_THOMAS_QZ_13.8	ONWEST
ONWEST S ES PC	160672_SUNCOR_CTS_A_13.8	ONWEST
ONWEST S ES PC	160698_F_TALBOTVL_B_13.8	ONWEST
ONWEST S ES PC	160720_TR_ENERG_871_13.8	ONWEST

Appendix: ES Select Storage Options and Abbreviations

ES technology classes available in ES-Select are shown in the Table below (DNV KEMA Inc. December 31, 2012).

Table A 9. ES Select Storage Options and Abbreviations in Alphabetical Order

No.	Storage Options	Abbreviation
1	Adv. Vanadium Red. Flow Batt.	A-VRFB
2	Compressed-Air ES, cavern	CAES-c
3	Compressed-Air ES, small	CAES-s
4	Double Layer Capacitors	DL-CAP
5	Flywheel	FlyWl
6	Thermal Storage (Hot)	Heat
7	Hybrid LA & DL-CAP	Hybrid
8	Thermal Storage (Cold)	Ice
9	Advanced Lead Acid	LA-adv
10	Lithium-ion - High Energy	LIB-e
11	Lithium-ion - High Power	LIB-p
12	Sodium Nickel Chloride	NaNiCl
13	Sodium Sulfur	NaS
14	Ni batt. (NiCd, NiZn, NiMH)	Ni-batt
15	Pumped Hydro	P-Hydro
16	Vanadium Redox Battery	VRFB
17	Valve Regulated Lead Acid	VRLA
18	Zinc-Air Battery	ZnAir
19	Zinc Bromide	ZnBr

Appendix: Treatment of ES Technology Options

There are several ES technology types in the form of heat or electricity. Within the scope of this project the primary focus has been on Electricity to Electricity (E2E) ES, which can be further broken down into:

- Electrochemical (e.g., battery, flow battery, etc.)
- Electromechanical (e.g., flywheel, compressed air ES, pumped hydro, etc.)
- Electrical (e.g., superconducting electromagnetic ES, capacitors, etc.)

Of these three types of E2E, electrochemical and electromechanical were chosen based on available input data and Ontario Stakeholder feedback. The table below shows examples of possible electrochemical and electromechanical ES technologies for evaluation. The broad power to duration categories from Table 115 in Section 2.11.10.1 are shown here. They include long duration of 6 hrs or greater (L), medium long duration of 4 hrs (ML), medium-short duration of 2 hrs (MS), and short duration of 0.5 hrs (S). The corresponding color-coded bars indicate ES technologies that fall into the categories of L, S, or some combination thereof (Mass Department of Energy Resources, Mass Clean Energy Center 2016). The dash ('-') indicates that the ES technology does not fall in that duration category. In summary, these categories are useful for the system level analysis shown in Pillar 1. In Pillar 2, however, at the level of an individual ES technology it is more practical to state the actual power-to-duration or respective maximum MW and hrs.

Table A 10. Examples of Electrochemical and Mechanical ES Technologies

	Electrochemical								Electromechanical			
	Battery					Flow Cell						
PWR:Dur	SuperCap	AdvPbAcid	Li ion	NaS	…	V Red	ZnBr	…	CAES	P-Hydro	Flywheel	…
L	-	-									-	
ML	-								-	-	-	
MS	-			-		-	-		-	-	-	
S		-		-		-	-		-	-		

SuperCap: Super Capacitor or Ultra Capacitor
AdvPbAcid: Advanced Lead Acid
Li-ion: Lithium-ion
NaS: Sodium Sulphur
V Red: Vanadium Redox
ZnBr: Zinc Bromide
CAES: Compressed Air Energy Storage
P-Hydro: Pumped Hydro Electric

ES technology and cost and performance data used in ESVT 4.0 were custom inputs based on commercial vendor data supplied to the US DOE in Appendix B of the peer reviewed public report SAND2015-1002 from February 2015 (Akhil, Huff and Currier 2015). It should be noted that the other ES technologies listed in Appendix B, or any commercial at-scale ES cost and performance data, can be used as custom inputs for ESVT 4.0.

Table A 11. Sources from SAND2015-1002 for ES Technology Cost and Performance Data **(Akhil, Huff and Currier 2015)**

Electrochemical
Battery
Li-ion: 10 MW 2Hr
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If an ES technology requires replacement or rebuild during the study period or technology lifetime, those costs were included as well. For instance, a Li-ion stack lifetime is assumed to be ten years, and thus the simulation takes into account both the cost decline over ten years and the stack replacement costs assumed at year ten (Lazard 2016). Detailed tables for cost, performance and lifetime data are available upon request.

Appendix: Benefit Calculation Methodology

Assumptions for all calculations (ESSEXENERGY):

- Where benefit values are clearly linked to the Ontario energy sector, Ontario market data as well as other regional sources were used to derive Ontario-specific ranges. Where benefit values are more universal, multiple sources across multiple jurisdictions were cross-checked and used to derive ranges.
- All dollars are expressed as $/MWh Canadian for services delivered to the grid.
- Canadian exchange rate was assumed to be $1.30 from US currency where applicable.

Benefit calculation for "System Electric Supply Capacity"

The benefit stream of "system electric supply capacity" is not explored directly in this TEA study. Its benefit calculation is described here in order to illustrate how the GA charge reduction benefit and the DR service benefit is calculated through this implemented function in ESVT.

In ESVT 4.1, "system electric supply capacity" is modelled as the requirement for energy storage to avoid or defer building a new generation asset. This is estimated as the difference between the conventional generations fixed cost and net revenues, a metric known as net Cost of New Entry (CONE). This value for energy storage is derated proportional to the number of peak hours when it is unavailable to provide its discharge capacity.

"System electric supply capacity" is defined as the use of energy storage in place of combustion turbine (CT) to provide the system with peak generation capacity, and its benefit is calculated to be:

$$Benefit\ (\$) = Capacity\ Payment\ \left(\frac{\$}{kW}\right) \times Capacity\ Derate \times Storage\ Capacity\ (kW)$$

Capacity value escalates from the Capacity Payment at reference year to the cost of CT (as the planned New Entry) in the resource balance year. The capacity value is derated as a factor, based on the actual system capacity service provided as a percentage of the number of hours requested for dispatch (based on probability). The derating method is used as a proxy for penalty for non-performance when providing this service under contract.

Benefit calculation for Global Adjustment charge reduction (Class-A)

Class-A customers pay GA based on their percentage contribution to the top five peak Ontario demand hours over a 12-month period. "After the IESO establishes the final top five Ontario demand peaks using adjusted AQEW (allocated quantity of energy withdrawn) for a base period, the IESO and LDCs then look at each Class-A customer's consumption during those five hours (coincident peaks) to calculate their corresponding portion of peak demand. This portion is called a peak demand factor and is used to determine a customer's allocation of costs for the adjustment or billing period.

While not implemented in the ESVT directly, the benefit calculation for the ES by providing GA charge reduction can be customized through the analogy with the "system electric supply capacity" function, whose calculation method is explained above. In analogy, in ESVT the benefit of ES application to GA reduction is calculated to be:

$$GA\ charge\ reduction(\$) = GA\ Payment\ rate\ \left(\frac{\$}{kW}\right) \times Capacity\ Derate \times Storage\ Capacity\ (kW) \qquad (1)$$

Where GA Payment rate is the same as the GA charge rate ($/kW) that can be calculated through the Capacity reduced during the top 5 peak Ontario demand hours and the total GA charge over the past 12-month period; Storage Capacity (kW) is the nameplate capacity of the ES system that is assumed to be fully discharged for demand reduction as scheduled, and the Capacity Derate is a factor that accounts for the non-performance penalty due to the unavailable capacity or short energy duration.

- Step 1: Identify the top five system-wide consumption peaks (MW). According to the provided Ontario total demand profile, ESVT identifies the top five peak demand hours automatically; however, two or three of the picked top 5 hours could be from the same day, according to the ESVT's self-identification results, which is not consistent with the original meaning that was defined by IESO. Based on the historical information of demand peaks during the base period May 2017 – April 2018, as shown in the Table below, each of the top 5 peak demand hours should be one from the highest electricity demand hours of a single day. Therefore, to accommodate the difference in the IESO's definition and the calculation algorithm used in ESVT, the original Ontario total demand profile was slightly adjusted manually [the shoulder demand peaks of the highest peak hour of those 5 days are artificially reduced to a level that is lower than the real 5th top peak hour's demand, and the reduced amount was randomly distributed to the neighboring hours in order to keep the total amount of the demand if the entire base period is not changed, and the shape of the demand profile is not changed] so that the right peak demand hours would be identified by ESVT. After all, the provided demand profile is only used for identification of these top 5 peak demand hours in this study, so it is concluded that the simulation results will not be affected at all due to this modification. The table below shows the identified and established final top five Ontario demand peaks using adjusted AQEW for (May 1, 2017 to April 30, 2018).

Table: Top 5 Ontario Demand Peaks for Base Period: May 1, 2017 to April 30, 2018

Date	Hour Ending	Allocated Quantity of Energy Withdrawn (MW)	Embedded Generation (MW)	Total (MW)*
25-Sep-17	17	21,170	641	21,812
26-Sep-17	17	21,039	626	21,665
12-Jun-17	17	20,702	1297	21,999
5-Jan-18	18	20,238	647	20,885
19-Jul-17	18	20,122	862	20,984

*The value in this column is the number used to calculate a customer's Peak Demand Factor.

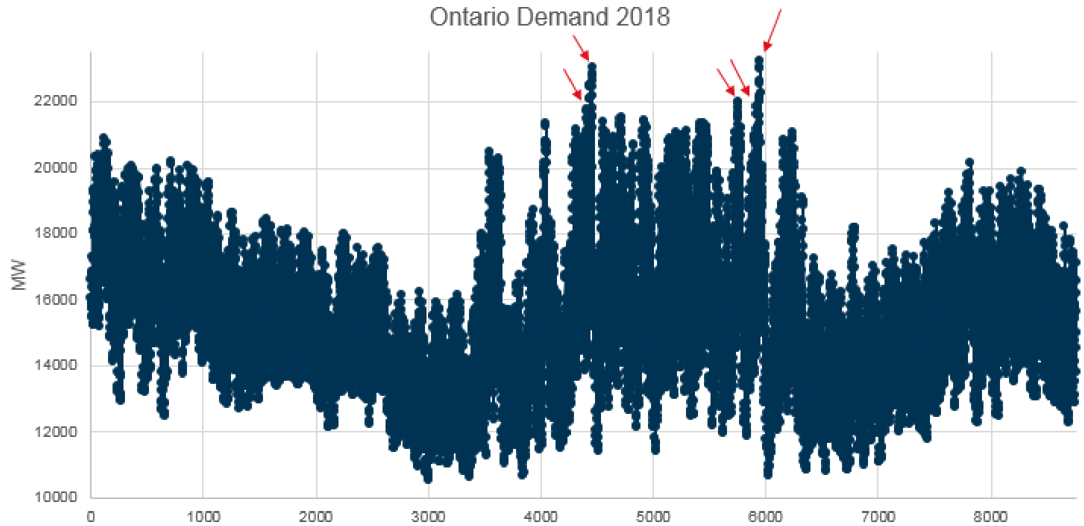

Figure 72. Identified Top 5 Demand Peak Hours (see arrows) through ESVT, Consistent with IESO Released Top 5 Demand Peak Hours (2018) as Shown in the Table Above

- Step 2: Identify the customer's consumption reduction during the top five peak demand hours (MWh). Assume the 10MW ES system is dispatched for GA reduction for all top five demand peak hours, then the customer's consumption reduction is 50MW/year.
- Step 3: Calculate the reduced peak demand factor (r-PDF).
  - Sum of top five system-wide consumption peaks (MW) from the base year, for example see Table above, the sum of the last column is 107,345MW (=A).
  - Sum of yearly customer's consumption reduction (from step 2) is 50MW (=B).
  - Reduced peak demand factor: *r-PDF* = B/A = 50/107,345 = 4.65789E-4
- Step 4: Calculate the yearly GA charge rate.
  - System-wide GA cost for a given year 2018 (M$): 11,196.2 M$ (IESO data).
  - Yearly GA charge reduction rate: 11,196.2 M$ * *r-PDF* / 50MW = 104.3 $/kW-year
- The obtained GA reduction rate **104.3** $/kW-year will be used accordingly in ESVT as the input value for "System Capacity Value".
- To disable the function of "Cost of New Entry" the same value 104.3 $/kW-year as the GA reduction rate was used in ESVT. In this way, the GA reduction rate is kept constant throughout the project years. Accordingly, the "Years until Resource Balance Year" becomes irrelevant and could be randomly chosen.
- The minimum capacity duration requirement is set as 1 hour, which meets the IESO's definition of top five peak demand hours (at most 1 hour per day).
- The service hours of ES for GA charge reduction are defined according to the top 5 load hours per year (at most one hour per day).

Benefit calculation for DR service

Similar to the case of GA reduction value stream as described in Use Case #2, the DR Auction value stream is not implemented in ESVT directly. The function of "*system electric supply capacity*" from the ESVT 4.1 will be adapted for the DR value calculation.

According to IESO, benefit from DR Auction participation is calculated based on the availability payment the ES receives that is associated with the committed capacity within the committed time period. The Availability payment is calculated to be as follows:

$$Availability\ Payment = \sum_{d=1}^{n} Capacity_d \times Clearing\ Price \qquad (1)$$

Where, *d* is a business day in the month, *n* is the number of applicable business days in the month, $Capacity_d$ is the DR Capacity Obligation (MW) on day *d*, and *Clearing Price* is the DR Auction Clearing Price. In analogy with the “system electric supply capacity” function as implemented in ESVT, this availability payment calculation is translated as:

$$Availability\ Payment = Storage\ Capacity \times Capacity\ Value \times Capacity\ Derate \qquad (2)$$

Where Storage Capacity is the DR Capacity Obligation (MW), Capacity Value is the same as the DR Auction Clearing Price ($/MW-day) as determined by IESO but transformed into the unit of $/kW-yr for the usage in ESVT, and Capacity Derate is a factor that is based on the actual system capacity service hours providing as the probability to dispatch in committed capacity hours. This derating method is used as an approximation for penalty for non-performance when providing this DR service under contract.

- Step 1. DR Auction clearing price for the winter in 2017-2018 is $200 /MW-day, which is used as the payment rate for providing the DR service.
- Step 2. Take the Winter commitment period as the example, which is between November 1 to the next April 30, the number of days included in this time period is on average 181 days, and it will be used for the annual payment calculation for the usage in ESVT tool. The *Capacity Value* in Eq.(2) will become:

$$Payment\ Rate = Capacity\ Value = \frac{\$200}{MW\cdot day} = \frac{\$200\times 181\ day/yr}{1000\ kW} = \$36.2/kW\cdot yr \qquad (3)$$

- Step 3. Set the CONE value in ESVT the same as the payment rate as derived above. This keeps the payment rate constant along the project years.

Data References

#	Data Category	Reference
1	Demand – historical	IESO Power Data, 2017 Hourly Zonal Demand
2	Demand – forecast	IESO, 2017 Long-Term Energy Plan Demand Module
3	Peak demand forecast	IESO, 2017 Long-Term Energy Plan Module 3 Supply
4	Intertie flow limits and connection types	IESO, Ontario Transmission System, 2017
5	Intertie flow – historical	IESO Power Data, 2017 Hourly Intertie Flow
6	Imports and exports – forecast	IESO, 2017 Long-Term Energy Plan Module 3 Supply
7	Generation capacity by fuel type – historical and forecast	IESO, 2017 Long-Term Energy Plan Module 3 Supply
8	Generation capacity by unit	IESO, Active Contracted Generation List 2018
9	Reserve requirement and capacity requirement forecast	IESO, 2017 Long-Term Energy Plan Module 3 Supply
10	Nuclear refurbishment schedule	IESO, Ontario Planning Outlook Module 4: Supply
11	Fuel price forecast	IESO Fuels Technical Report, 2016
12	Uranium price forecast	EIA, 2018 Annual Energy Outlook *converted to 2016 CAD$
13	CO2 pricing	Government of Canada, Greenhouse Gas Pollution Pricing Act (S.C. 2018, C. 12, s. 186)
14	Demand sensitivities	IESO, 2017 Long-Term Energy Plan
15	Solar and Wind Firm Capacity	IESO 18-month Outlook Tables (Figure 4.1 and 4.2)
16	Ontario System Map	http://www.ieso.ca/Power-Data/Supply-Overview/Ontario-System-Maps
17	Operating Reserve Prices	IESO Price Data, 2018 Yearly Hourly HOEP Report
18	Ancillary Services Cost	IESO Ancillary Market Data, 2017 annual cost and quantity
19	Base Case Capacity Optimization Results	Excel Sheet Base_CO-ES_v6
20	Base + Storage Case Capacity Optimization Results	Excel Sheet Base+Storage_CO_ES_v2
21	Base Case Production Cost Results	Excel Sheet Base_PC_ES_v11
22	Base + Storage Case Production Cost Results	Excel Sheet Base+Storage_PC-ES_v3
23	Sensitivities Metrics	Excel Sheet ES Build Sensitivities_v8
24	Sensitivities Energy Storage Built	Excel Sheet Base_CO-ES_Sensitivities_v5
25	Base + Storage High Case Production Cost Results	Excel Sheet Base+Storage_PC-ESH_v0
26	Base + Storage Low Case	Excel Sheet Base+Storage_PC-ESL_v0

	Production Cost Results	

Terminology

#	Acronym	Full Terminology
1	DRV	Demand Reduction Value
2	VDER	Value of Distributed Energy Resources
3	FOM	Fixed Operating and Maintenance Cost
4	VOM	Variable Operating and Maintenance Cost
5	LGH	Load Growth High Sensitivity
6	LGL	Load Growth Low Sensitivity
7	FPH	Fuel Price High Sensitivity
8	FPL	Fuel Price Low Sensitivity
9	CTH	Carbon Tax High Sensitivity
10	CTL	Carbon Tax Low Sensitivity
11	TCH	Energy Storage Technology Cost High Sensitivity
12	TCL	Energy Storage Technology Cost Low Sensitivity
13	PS	Pump Storage
14	D value	Deferral Value

Appendix: Summary of Ontario's Climate Change Framework

Ontario's Climate Change Acts and Regulations	***Key Policy Documents***	***Emissions Reduction Targets***	***Mandatory GHG Requirements***	***Carbon Pricing Mechanism***
-Environmental Protection Act (1990). - Climate Change Mitigation and Low-Carbon Economy Act (2016) (not law) -Greenhouse Gas Emissions: Quantification, Reporting and Verification (2018) under Environmental Protection Act.	- Ontario's 2015 Climate Change Strategy (not government policy) - Made-in-Ontario Environment Plan (2018), which sets out the province's specific priorities, challenges and opportunities, and commits to reducing our emissions to 30% below 2005 levels by 2030, a target that aligns with the Federal Government's Paris commitments.	- Under the 2018 Ontario's Environment Plan, the following target is set: 2030: 18 Mt $CO_{2\text{-}eq}$ reduction to achieve 30% emissions reduction relative to 2005 according to Paris Agreement.	- Greenhouse Gas Emissions Reporting requires Ontario facilities emitting ⩾ 10,000 tonnes of $CO_{2e\text{-}eq}$ to annually report GHG emissions. Electricity importers emitting greater than zero tonnes of GHG emissions and facility generating greater than 25,000 tonnes per year must be third party verified. - Large industrial emitters also required to report under federal GHGRP. - Ontario participates in Environment Canada's Single Window GHG reporting system.	-N/A

Table A 12. Summary of Ontario's Climate Change Framework (Lee-Andersen 2017)

Appendix: Summary of Life Cycle Inventory – Li-ion Battery and VRFB

	Sub-assemblies	Quantity	Unit
Positive electrode paste	Lithium hydroxide (LiOH)	0.4	kg
	Phosphoric acid (H3PO4)	0.6	kg
	Iron Sulphate (FeSO4)	0.9	kg
	Deionized water	40.0	kg
	Carbon black	0.1	kg
	Poly tetra fluoroethylene (PTFE)	0.1	kg
	N-methyl-2-pyrrolidone (NMP)	0.3	kg
Negative electrode paste	Graphite	1.0	kg
	Poly tetra fluoroethylene (PTFE)	0.1	kg
	Nmethyl2pyrrolidone (NMP)	0.3	kg
Separator	Polyethylene, LDPE granulate	0.5	kg
	Polypropylene, granulate	0.5	kg
Substrate, positive electrode	Positive electrode:Sheet rolling, Aluminium	1.0	kg
	Positive electrode: Aluminium, production mix	1.0	kg
Substrate, negative electrode	Negative electrode:Sheet rolling, copper	1.0	kg
	Negative electrode: Copper, primary	1.0	kg
Electrolyte	Chemicals, inorganic [proxy for LiPF6]	0.1	kg
	Chemicals, organic [proxy for solvent]	0.9	kg
Cell container, tab and terminals	Aluminium, production mix	1.0	kg
	Sheet rolling, aluminum	1.0	kg
Module and battery packaging	Polyethylene terephthalate	1.0	kg
	Injection moulding	1.0	kg
Battery management system (BMS)	Integrated circuit, logic type	0.1	kg
	Copper, primary	0.5	kg
	Chromium steel 18/8	0.4	kg
	Wire drawing, copper	0.5	kg
	Sheet rolling, steel	0.4	kg

Table A 13. Life Cycle Inventory Summary for 1 kg of Li-ion Battery Pack System (Majeau-Bettez, Hawkins, and Stromman 2011)

Main components	Sub-assemblies	Quantity	Unit
Stack	Membrane	0.0005	kg
	Electrode	0.0013	kg
	Bipolar plate	0.0169	kg
	Current collector	0.0061	kg
	Cell frame	0.0009	kg
	Gaskets	0.0013	kg
	Stack frame	0.0039	kg
Energy	Electrolyte	0.8401	kg
	Tank	0.1006	kg
Balance of system	Pumps	0.0018	kg
	Pipes	0.0010	kg
	Inverter	0.0093	kg
	Cables	0.0005	kg
	PCS	0.0000	kg
	Transformer	0.0126	kg
	Heat exchanger	0.0032	kg

Table A 14. Life Cycle Inventory Summary for 1 kg of VRFB ES System (Weber et al. 2018)

Appendix: ES Deployment Scenarios by Technology

The annual ES deployment for the base case + storage scenario is shown in Table 60, thus Pillar 3 analyzed the total annual ES deployment as a whole to be distributed among Li-ion battery and CAES systems. Table 0-4 shows 5 ES allocations scenarios considering combinations of assumed ES capacity distribution for Li-ion and VRFB energy storage systems by 2030. Note that Li-ion battery ES systems are deployed in all the suggested deployment years, i.e. 2020, 2025, and 2030, while VRFB ES systems are deployed only in 2025 and 2030 when medium long buckets of ES are deployed.

ESS allocation scenarios	2020 (150 MW)		2025 (1184 MW)		2030 (1302 MW)		Total deployment (MW) scenario	
	VRFB	Li-Ion	VRFB	Li-Ion	VRFB	Li-Ion	VRFB	Li-Ion
1	0	150	0	1185	0	1302	0	2636
2	0	150	209	976	264	1038	473	2163
3	0	150	417	767	529	773	946	1691
4	0	150	626	559	793	509	1419	1218
5	0	150	835	350	1057	245	1892	745

Table A 15. ES Allocation Scenarios by Technology for the ES Capacity Case

Where variations in total ES deployment:
Scenario 1: 100% Li-ion deployment
Scenario 2: 18% VRFB and 82% Li-ion deployment
Scenario 3: 36% VRFB and 64% Li-ion deployment
Scenario 4: 54% VRFB and 46% Li-ion deployment
Scenario 5: 72% VRFB and 28% Li-ion deployment

Appendix: ES Environmental Impact at Grid Level for Different ES Deployment Scenarios

Cradle-to-gate emissions generated per type of ES system deployed for each allocated scenario are expressed in absolute values ($MtCO_{2e}$) and calculated by:

(i) Rescaling the cradle-to-gate emissions per energy delivered during complete lifetime utilization expressed in kg CO_{2e}/MWh_d and shown in Table 157 to cradle-to-gate emissions per MW deployed expressed in $MtCO_{2e}/MW$.

(ii) Applying the rescaled cradle-to-gate emissions per type of ES technology expressed in $MtCO_{2e}/MW$ (deployed) to the respective annual ES capacity deployment in MW from Table 0-4 for each scenario. Annual cradle-to-gate emissions in absolute values are then added to obtain the total cradle-to-gate emissions per type of ES system for each scenario.

The table below shows the ES environmental impact at grid level for different ES deployment scenarios. Each environmental impact scenario is obtained by adding the overall ES cradle-to-gate emissions from Li-ion battery and VRFB systems for each ES deployment scenario and the grid-level GHG emissions reductions from ES usage, i.e. 4.55 MT of CO_{2e}, as a result of total natural gas emissions reductions from ES usage at the grid level.

ESS allocation scenarios	VRFB		Li-Ion		GHG emissions from ES manufacturing (Mt CO_{2eq})	GHG emissions reduction from ES operation ($MtCO_{2eq}$)	ES environmental impact at grid level ($MtCO_{2eq}$)
	ESS deployment (MW)	Cradle-to-gate GHG emissions (Mt CO_{2eq})	ESS deployment (MW)	Cradle-to-gate GHG emissions (Mt CO_{2eq})			
1	0	0.00	2636	1.76	-1.76	4.55	2.80
2	473	0.39	2164	1.44	-1.83	4.55	2.72
3	946	0.78	1691	1.13	-1.90	4.55	2.65
4	1419	1.17	1218	0.81	-1.98	4.55	2.58
5	1892	1.56	745	0.50	-2.05	4.55	2.50

Table A 16. ES Environmental Impact at Grid Level for Different ES Deployment Scenarios

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