
Pathways to Decarbonization: Appendix B

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1. Capacity Expansion Model – Methodology

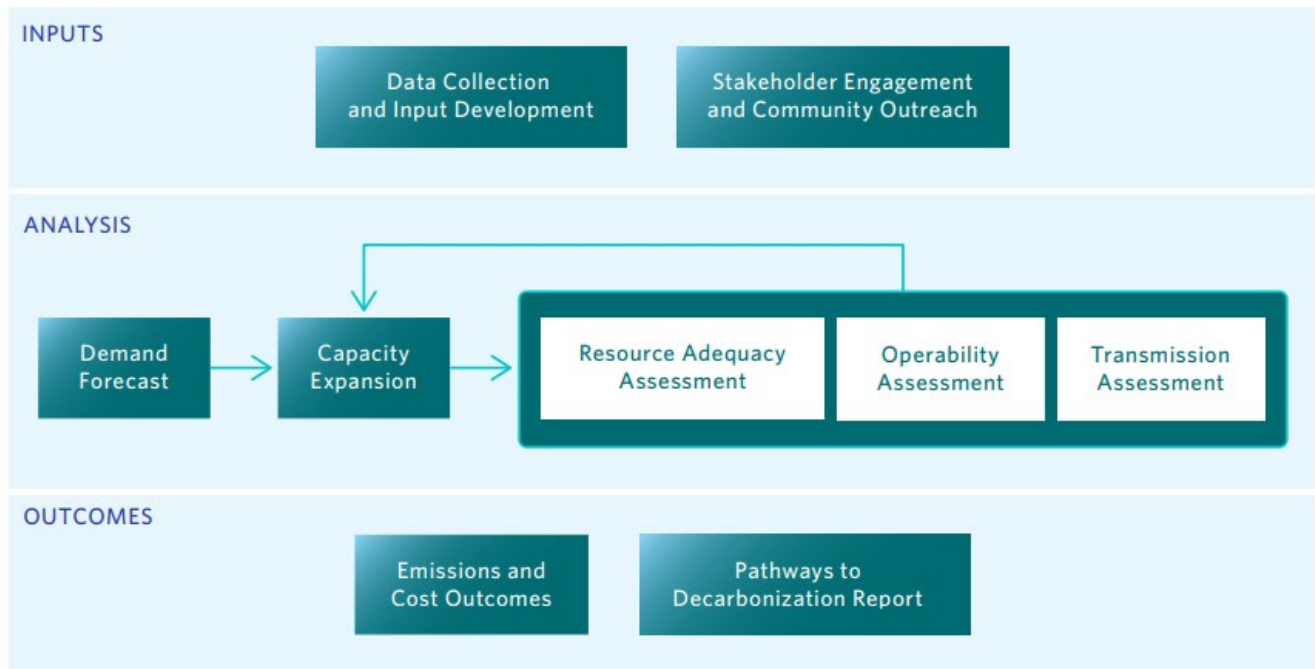
Introduction

Capacity Expansion Model (CapEx) is a general term for a mathematical model that takes user-defined inputs about projected future conditions (e.g., demand forecast), and suggests a least-cost supply mix to serve future energy needs. CapEx models can consider different factors such as data granularity, temporal resolution, or transmission considerations, to name a few. Electricity system modellers must weigh the trade-offs carefully in terms of computation time, accuracy, data granularity, etc. For the purposes of P2D, Energy Exemplar's PLEXOS LT-Plan CapEx model was used for the Capacity Expansion step in both the Moratorium and Pathways scenarios. The supply mix modelling and analysis process comprises a number of steps (see Figure 1).

PLEXOS is a widely used electricity energy modelling software platform. The LT-Plan phase is the long-term expansion planning function, and is the name of their CapEx module. The model takes user defined inputs and determines a least-cost supply mix to meet future demand. This is a mixed-integer linear programming optimization model, where the objective function seeks to minimize the net present value of build costs plus fixed operations and maintenance costs plus production costs over the entire planning horizon. This is where the trade-offs are most apparent: the finer the granularity, the greater the accuracy on the model's estimates of production and maintenance costs. However, the finer the granularity, the greater the computational expense. One can imagine the computational complexity of modeling multiple decades at an hourly or sub-hourly level in a single optimization problem. No such model exists that would be able to do this.

PLEXOS LT-Plan maintains a realistic level of detail while still being able to run a full simulation within a reasonable amount of time. Many studies simply stop here and assume that the supply mix generated by the CapEx model is sufficient. As the system operator, the IESO's role is to also ensure that the portfolio is reliable and operable. Different tools are built to meet different objectives and no single tool can assess all aspect of the performance of the portfolio. For example, the LT-Plan cannot assess chronological unit commitment, and another modelling tool is used for this assessment.

Figure 1 | Supply mix modelling and analysis process steps



As such, the approach taken is to run several modules in sequence. From a high level, the approach is as follows:

1. Based on the demand forecast, resource inputs and constraints, the LT-Plan determines a least-cost supply mix.
2. The supply mix is assessed to ensure resource capacity adequacy is met. This determines if the least-cost supply mix satisfies NPCC resource adequacy requirements. Further information can be found in the [IESO's Annual Planning Outlook Resource Adequacy and Energy Assessment Methodology](#).
3. The supply mix is assessed in a production cost model to ensure resource energy adequacy is met. Further information can be found in the IESO's Annual Planning Outlook Resource Adequacy and Energy Assessment Methodology.
4. A screening of the supply mix is conducted for operability to understand the ability of the mix to manage a variety of conditions as they occur in real-time on durability, diversity and flexibility.
5. The supply mix is assessed to understand the ability of the system to maintain supply within established transmission planning standards.
6. If the supply mix is deemed insufficient in Steps 2 to 5 to meet the projected demand, the inputs and constraints to the LT-Plan are modified in Step 1 and the process starts again at Step 2.
7. When a supply mix is deemed sufficient, it is then post-processed for reporting on metrics such as cost and emissions. Examples of model outputs include how much, when and what technology to build, as well as estimates of new-build cost and energy production cost.

A high-level summary of the model inputs are as follows:

- Planning horizon of interest (number of years into the future being considered).
- Demand forecast (could be a single forecast for an entire region or more granular such as zonal or nodal).
- Details of the existing and committed resources (resources that are steel on the ground and/or have been secured and are available during the planning horizon).
- Comprehensive suite of resource candidates. This includes: wind, solar, nuclear, hydroelectric, storage, firm imports, low-carbon fueled thermal, and DR.
- Detailed parameters of all candidate resources. This includes: build costs, lead-times, capacity factors, fuel availability profile (e.g., for wind, solar, hydroelectric), fixed O&M cost, variable O&M cost, start-up time, minimum loading point, etc.
- Fuel and carbon cost forecast.
- Discount rate/relevant financial parameters.

2. Transmission Assessment Additional Detail for Moratorium and Pathways

This section presents additional details on the findings of the transmission assessments for the moratorium and pathways scenarios.

Transmission Assessment – Moratorium

The moratorium scenario requires additional transmission infrastructure in Toronto, York Region, east of the Greater Toronto Areas, west of Barrie and in both northwestern and northeastern Ontario. Overall, this results in up to \$2.1 B of incremental transmission investments by 2035, beyond what is currently planned or underway. These reinforcements are required to ensure the new resources in the supply mix can connect to the system and be delivered to the load centers, or to ensure load supply needs are met, particularly for areas that currently rely on existing gas facilities to ensure a reliable local supply.

In addition to these transmission reinforcements, the analysis also identified that for Toronto and York Region, Portlands Energy Centre and York Energy Centre will be needed post-contract to continue to provide reliable local supply to existing and forecast load in these communities out to 2035.

To relieve the need for York Energy Centre, two new transmission lines would be required, one between Buttonville TS and Armitage TS and another between Kleinburg TS and Vaughan #4 MTS, before the end of the facility's contract. These new lines would need to be accompanied by additional reinforcement to the area such as a new switching station and/or additional autotransformers. All of these together would not be feasible to implement by the early 2030s; hence the need for York Energy Centre in 2035. With York Energy Centre remaining in-service out to 2035, one new transmission line supplying the region will still be required in the early 2030s, either the Buttonville TS to Armitage TS or the Kleinburg TS to Vaughan #4 MTS line, each ~\$100 M, as detailed in 2020 York Region IRRP. The next cycle of regional planning for York Region will make a recommendation around the scope of the preferred reinforcement.

Similarly, if Portlands is removed from service at the end of its contract, a ~\$100 M transmission reinforcement from Cherrywood TS to Leaside TS, through eastern Toronto, would be required to increase supply to the downtown before the end of the facility's contract. This would not be feasible by the early 2030s. With Portlands remaining in-service out to 2035, new or upgraded autotransformers at Leaside TS in eastern Toronto will still be required to meet forecast load growth. However, future cycles of regional planning would examine if approximately 150 MW of local resources, such as targeted energy efficiency or DERs, could cost-effectively defer this need.

Both Toronto and York Region will be starting new regional planning cycles in the near-term. These plans should consider options to address the reliability needs that arise without York Energy Centre and Portlands Energy Centre in-service, including those identified above. Those planning processes

should then make a determination if development work needs to begin on any transmission facilities to ensure there is no local reliability need for those facilities beyond 2035.

Table 1 details the scope of the bulk transmission reinforcements required for the moratorium scenario and their associated drivers. In addition to these facilities, smaller, non-dynamic voltage support devices were required at a number of locations throughout the province. It should be noted that several simplifying assumptions were made to arrive at this list of transmission projects and a robust planning analysis was not completed for this report. Hence, this list of transmission enhancements is an indication of the scope and costs of the bulk transmission enhancements that may be needed to enable the moratorium scenario. These enhancements are indicative of the changes that would be necessary to support a moratorium on new gas; the IESO is not recommending pursuing these transmission enhancements at this time. Upcoming regional and bulk planning processes may further review these needs and options and make recommendations if appropriate.

Table 1: Transmission Upgrade for Moratorium Scenario

Reinforcement Type	From Station	To Station	Description	Driver & Key Assumptions
New Station Asset/ Expansion	Leaside TS	N/A	Autotransformer	Load growth in Toronto; timing dependent on forecast uncertainty and potential/cost-effectiveness of local solutions (i.e., distribution connected)
New Station Asset/ Expansion	Essa TS	N/A	New Autotransformer	Load growth in Essa zone and maintaining deliverability of resources located in Northern Ontario
Reconductoring	Clarington TS	Cherrywood TS	Refurbish and upgrade T28C	Resource connection; assumes SMR at Darlington
Reconductoring	Clarington TS	Cherrywood TS	Reconductor portions of existing 230 kV lines T26C, T24C, T29C, T23C	Resource connection; assumes SMR at Darlington
New Line	Pinard TS	Porcupine TS	New 500 kV single circuit line	Load growth and resource retirement in northern Ontario; timing dependent on potential/cost-effectiveness of local generation in the north (i.e., transmission connected)

Reinforcement Type	From Station	To Station	Description	Driver & Key Assumptions
New Line	Porcupine TS	Hanmer TS	New 500 kV single circuit line	Load growth & resource retirement in northern Ontario; timing dependent on potential/cost-effectiveness of local generation in the north (i.e., transmission connected)
New Station Asset/ Expansion	Various station sites in Northwest and Northeast	N/A	4-5 New Static Var Compensators	Maintain deliverability of resources located in Northern Ontario
New Line	Buttonville or Kleinburg	Armitage or Vaughan #4 (respectively)	New double circuit 230 kV line for York Region	Load growth in York Region

These findings relied on implementation of the East-West Tie Reinforcement, Northeast Bulk Plan, Waasigan Transmission Project and Wataynikaneyap Transmission Project to allow the projected additional generation in the northeast and northwest contribute to meeting provincial needs. The existing transmission plans for the West of London and Ottawa areas, including local generation requirements, were assessed to be sufficient to ensure supply in these areas under the moratorium scenario. Since these plans are already committed to meet existing needs, they form part of the 2021 APO base case.

Additionally, any existing gas resources which were picked up by the capacity expansion model were assumed to be available for the transmission assessments, so the assessments do not identify if any additional reinforcements would have been required if those facilities were also retired.

Transmission Assessment – Pathways

The incremental customer demand and corresponding resources in the supply mix are significant, with a number of resources, primarily nuclear and hydro, that will be limited in terms of locational siting and, particularly in the case of nuclear, likely to be sited in large increments. This has important implications for the build out of the transmission network to support the supply mix and ensure it can be delivered to growing load centres.

Several simplifying assumptions were made to be able to begin to define the transmission reinforcements that might be needed to support such a massive change in load and generation on the system over a relatively short time period. A robust planning analysis was not completed for this report, as significantly more accurate assumptions regarding future demand and the resource mix would be required before this type of analysis could be undertaken. The resource and time requirements for this type of analysis also exceed what was available for carrying out the moratorium and pathways work.

In order to achieve a starting point for a system that is capable of incorporating the resources identified and reliably supplying the forecast demand, a substantial build out of Ontario’s existing 500 kV network had to be assumed, focusing on paralleling the existing network where possible.

The range of 500 kV reinforcements reviewed was developed based on an initial set of assumptions on where the new resources identified in the supply mix would be located. Two sensitivities were then reviewed to determine how the level of reinforcement on the different 500 kV paths may be impacted by the location of the supply mix. These assumptions are detailed in Table 2.

Table 2: Locational assumptions for incremental resources to inform review

Locational Assumption	Description
Reference Assumption	<p>Assumes that solar and wind are scaled based on their existing distribution.</p> <p>New nuclear is assumed at or near existing sites or at former sites of large centralized resources. For simplicity of modelling, new hydrogen generation was located proportionally to the existing gas fleet, however, it was assumed there would no longer be local gas in Toronto or York Region. Assumes new interconnection with Quebec would be located at Chat Falls.</p>
Sensitivity 1	<p>Designed to stress the supply into western Toronto by replacing supply that was assumed to be located in eastern Ontario from the reference case (for simplicity, Quebec imports were curtailed) with incremental generation in the west, i.e., located in the Lambton area.</p>
Sensitivity 2	<p>Designed to stress the transmission into western Ontario by making more conservative assumptions about how much additional generation could be located there. Adopted minimum generation requirements from the West of London bulk plan, while allowing for renewables to still scale to up to twice the existing amount. The majority of the additional resources required to make up for this change were then assumed to come from the Northeast.</p>

The number of 500 kV reinforcements reviewed ranged from 25 new circuits (3100 circuit-km), which is the low scenario in Table 3, to 39 new circuits (4400 circuit-km), which is the high scenario in Table 3, with the assumption that some circuits will share a tower structure, depending on the configuration of the existing network in that location. Table 3 details the circuits assumptions, which are in addition to the existing plans included in the 2021 APO. The review focused on confirming if the range identified was sufficient under the scenarios in Table 2. Additional 500 kV reinforcement through the Northwest out to Manitoba was also considered (incremental 12 circuits, 2200 circuit-km), but the need for this would be highly dependent on specific locational assumptions for load and resources in the northwest. Without this additional detail, which is outside the scope of this assessment, no meaningful conclusions could be made.

Table 2: Range of 500KV reinforcements reviewed

From Station	To Station	#Of New Circuits Included in Low	#Of New Circuits Included in High	Considerations from Modelling Results
Lakeshore TS	Keith TS	1	2	Need would depend heavily on use of intertie and location of generation within the west zone.
Lambton TS	Longwood TS	1	2	Well utilized when assuming resources will remain located in the Lambton-Sarnia area, scaled with the overall incremental resource requirements. For scenarios with an even larger proportional amount of generation in the west zone relative to today, to stress the westward flow into the Toronto area, more than 2 circuits would be required between Lambton TS and Longwood TS.
Longwood TS	Lakeshore TS	2	3	Need would depend heavily on use of intertie and location of generation within the west zone. For scenarios with lower generation requirements in the west zone, this path is more heavily utilized.
Longwood TS	Nanticoke TS	1	2	Assessment showed that the number of circuits required would fall within the identified range.
Huron TS*	Middleport TS	1	2	Well utilized when assuming load centres throughout the southwest would use the line as a new load supply point.
Middleport TS	Beck TS	1	2	Appears to have low utilization, need would likely depend heavily on the use of the intertie.
Huron TS*	Bruce TS	1	2	Need would depend on relative location of new resources in Bruce versus Lambton-Sarnia.
Essa TS	Claireville TS	2	2	Assessment showed that the number of circuits required would fall within the identified range.

From Station	To Station	#Of New Circuits Included in Low	#Of New Circuits Included in High	Considerations from Modelling Results
Kleinburg TS	Claireville TS	0	2	Assessment showed that the number of circuits required would fall within the identified range.
Essa TS	Armitage TS	1	1	Assessment showed that the number of circuits required would fall within the identified range.
Cherrywood TS	Claireville TS	1	2	Need would depend on source for future supply points to Toronto.
Cherrywood TS	Clarington TS	1	2	Corridor is heavily loaded when assuming significant resources are sited in eastern Ontario. For scenarios with high imports from Quebec and large centralized resources located along the 500 kV corridor, more than 2 additional circuits may be required.
Bowmanville TS	Clarington TS	1	2	Corridor is heavily loaded when assuming significant resources are sited in eastern Ontario. For scenarios with high imports from Quebec and large centralized resources located along the 500 kV corridor, more than 2 additional circuits may be required.
Lennox TS	Bowmanville TS	1	2	Assessment showed that the number of circuits required would fall within the identified range.
Westcott TS*	Lennox TS	1	1	Need depends on the balance of load growth in Ottawa and new supply from Quebec (as well as location of new supply point).
Westcott TS*	Chat Falls TS	2	2	Depends on location of new intertie with Quebec.
Essa TS	Hanmer TS	2	2	Assessment showed that the number of circuits required would fall within the identified range.

From Station	To Station	#Of New Circuits Included in Low	#Of New Circuits Included in High	Considerations from Modelling Results
Hanmer TS	Mississagi TS	1	2	Assessment showed that the number of circuits required would fall within the identified range.
Hanmer TS	Porcupine TS	2	2	Assessment showed that the number of circuits required would fall within the identified range.
Porcupine TS	Pinard TS	1	1	Assessment showed that the number of circuits required would fall within the identified range.
Porcupine TS	Wawa TS	1	1	Assessment showed that the number of circuits required would fall within the identified range.

***Refers to a new station**

The review of the model also showed that if significant new resources were to be located in the Nanticoke area, 1-2 additional 500 kV circuits from Nanticoke TS to Middleport TS would be required. As well, for scenarios where incremental resources were not heavily focused in the west zone, additional 500 kV circuits from Huron TS to Longwood TS would be required.

For York and Toronto, which rely on local gas today, and Ottawa, which interfaces with the path of new interties required for firm imports, the details of bulk reinforcements beyond the 500 kV system were considered in further detail. This provides an illustration of the magnitude of reinforcements required not only for these areas, but across the province. However, the scope of analysis did not include local supply needs at the 115 kV level.

For supply to the City of Toronto, reinforcement to the existing 230 kV/115 kV station in Leaside from Cherrywood TS in the Pickering area was assumed as a starting point, along with the creation of a new supply point via underwater cable from Pickering to a new 230 kV/115 kV station in the Portlands area. These reinforcements serve as a critical starting point for ensuring sufficient bulk supply for Toronto without Portlands Energy Centre in-service. Beyond these investments in new and expanded 230 kV/115 kV supply points, reinforcements to the 230 kV system in the west portion of Toronto, from Trafalgar to Richview and from Parkway to Richview, and a new 500 kV to 230 kV autotransformer at Claireville TS were also identified as needed. With all these facilities in place, however, winter 2050 demand could still not be met. Out to the 2050 timeframe, there may be opportunities to convert existing 115 kV stations in the city to 230 kV supply, or supply new loads from the 230 kV system directly, that could help manage the need for a fourth supply point into Toronto's downtown (e.g., additional underwater cable from Niagara or Darlington) before the 2050 timeframe. Demand side options, including additional conservation, or local generation would also require further investigation.

For supply to York Region, new double circuit lines from Buttonville to Armitage and from Kleinburg to Vaughan #4, along with the conversion of the existing Holland Junction into a full switching station, were assumed as a starting point for examining the bulk supply to York Region without York

Energy Centre in service. It was found necessary to extend the double circuit 230 kV Buttonville to Armitage line all the way back to Essa TS, with four circuits required between Innisfil and Essa TS, along with reinforcing the 500 kV path from Porcupine in northeastern Ontario all the way down to Essa, to ensure sufficient support from Essa TS to supply the load increase in York Region. A new double circuit 230 kV line from Milton to Kleinburg was also required to improve transfers into York Region from the west. New autotransformers were required at Essa, Milton, Parkway and Kleinburg stations. Assumptions on the siting of the supply mix can impact the overall needs in York Region and western Toronto, as continuing to encounter limitations on flows east towards Toronto may be alleviated based on how much supply is available from sources in eastern Ontario.

To provide a strong interconnection point into Ontario's 500 kV system for a new intertie with Quebec and provide an additional supply point for reliably supporting forecast demand growth in Ottawa, a new 500/230 kV station was assumed to be required in west Ottawa, ideally situated on or close to the existing 500 kV corridor and connected to new and existing 500 kV circuits from Lennox TS. It was assumed that the new interconnection with Quebec would come via Chat Falls and connect via new 500kV circuits into the new 500 kV/230 kV station in west Ottawa to join with the broader 500 kV network. Two new 230 kV circuits from St Lawrence, near Cornwall, to west Ottawa were also assumed to be required as an initial improvement to load supply in the Ottawa area and to improve deliverability of existing Quebec imports and hydro generation in the St Lawrence area. While these circuits may be initially terminated at the existing Merivale TS it may make sense to re-terminate the circuits at the future 500 kV/230 kV station in west Ottawa depending on how new loads connect in the Ottawa area over the coming decades.

Overall, the cost for building out the bulk 500 kV and 230 kV system to meet the pathways scenario is estimated to be between \$17 billion and \$40 billion. This estimate includes new 500 kV and 230 kV network lines and terminations, and new 500/230 kV and 230/115 kV auto-transformation. The costs for 500 kV lines and terminations are directly informed by the 500 kV reinforcements modelled. The low-end range of auto-transformation is based on the what was modelled to support the assumed 500 kV network, and the high-end range was based on unit costs per MW of load growth assuming typical equipment capabilities. If 500 kV reinforcement through northwestern Ontario to Manitoba were also needed due to load growth or constraints on resource siting, this could result in an additional \$7 billion to \$16 billion in costs. The 230 kV lines and terminations were calculated based on unit costs per MW of load growth assuming typical equipment capabilities. Table 4 details the asset counts assumed for the purpose of constructing the range of transmission costs.

Table 4: Incremental Bulk Transmission Asset Count Estimates

Asset Type	Low Number of Units/cct-kms	High Number of Units/cct-kms
New 500 kV line (cct-km)	3100	4400
New 230 kV line (cct-km)	3000	4700
Number of New 500 kV Circuits*	25	39
Number of New 230 kV Circuits*	100	156
New 500 kV/230 kV Autos	30	50
New 230 kV/115 kV Autos	10	45

***Number of circuits is utilized for estimating associated station costs for terminating the new circuits.**

The reviewed bulk transmission enhancements and the estimates of asset units based on load growth are an indication of the scope and costs that may be needed to enable the pathways scenario; the IESO is not recommending pursuing these transmission enhancements at this time. More certainty on the location of future resources and timing of demand growth would be required for future studies to make recommendations and/or prioritize the facilities that may be required.

Many of the needed investments will be challenging to implement given their location within major load centres and populations (making land more challenging to acquire, constructability costlier (i.e., to underground infrastructure) and approvals often disputed). Aside from bulk reinforcements needed to support growth in the load centre, the pathways scenario also necessitates major investments in the local distribution system, including step down stations required between the transmission and distribution network, and distribution infrastructure for final connection to the customer. The cost and siting challenge for the required stations and distribution infrastructure will also be substantial.

3. Operability Services

Introduction

A reliable system is one that is both adequate and operable, with an operable system having the attributes of flexibility, durability and diversity. To assess these attributes as the electricity system transitions a number of detailed assessments will need to be conducted. These assessments focus on ensuring that future resource mixes possess sufficient additional services that are essential to ensuring the reliable operation of the system (Essential Reliability Services). Today, Ontario’s power system consists of resources that provide energy and capacity, as well as the essential reliability services needed to support reliable grid operations and respond to the inherent variability and uncertainty of electricity supply and demand.

Figure 2 | Components of Operability



What are Essential Reliability Services (ERSs)

The [NERC Essential Reliability Services Task Force](#) defines ERSs as operational attributes that are necessary to reliably operate the power system. Example of ERSs are reactive power to maintain system voltages and physical inertia to maintain system frequency.

ERSs have traditionally been provided by conventional resources such as large nuclear, hydroelectric and fossil-fueled generators. With an evolving resource mix that includes retirements of conventional resources coupled with increasing amounts of variable generation, ensuring a sufficient amount of ERSs is critical to maintaining an adequate level of reliability through the energy transition.

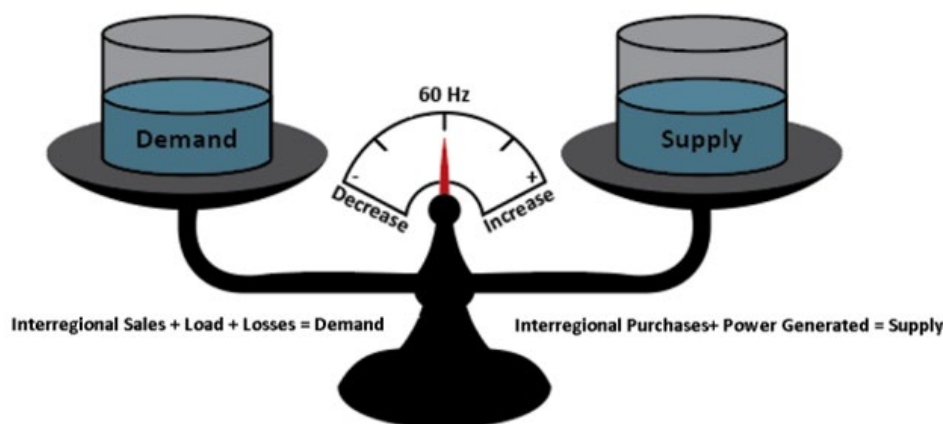
The NERC Essential Reliability Services Task Force indicated that the key attributes of a reliable grid can be categorized into **frequency support** and **voltage support**. This appendix discusses both topics, including an overview of the frequency support and the essential reliability services that help ensure that supply and demand are balanced.

Frequency Support and Balancing

What is it?

Rotating electrical equipment on the power system operates at a continuously varying rate (i.e., frequency) of 60 cycles per second, or 60 Hertz (Hz). Frequency will be constant on the system when there is a balance between supply and demand. When supply exceeds demand, frequency increases beyond the scheduled value of 60 Hz until energy balance is achieved. Conversely, when there is a temporary supply deficiency, frequency declines until the balance between supply and demand is restored.

Figure 3 | Frequency Balancing



Why is it Important?

The IESO is required by NERC Reliability Standards to continuously match supply and demand so as to maintain the system in a state of readiness for disturbances that inevitably occur. During normal operations, it is typical for small mismatches between total demand and total supply to occur. Typically, the system is designed to automatically respond to these small mismatches by making continuous adjustments that maintain the delicate balance. However, significant mismatches between supply and demand for a prolonged period of time put the power system at risk of losing generation and/or load, and potentially causing local or widespread blackouts.

How is frequency support and balancing achieved today?

In real-time operations demand and supply are constantly changing, with resources providing a range of balancing mechanisms to respond to changes as they occur, effectively maintaining system frequency under all conditions. As shown in Table 5, balancing occurs over a continuum of time on the power system (with some overlap in timeframes of occurrence).

Table 5: Mechanisms of Achieving Balance

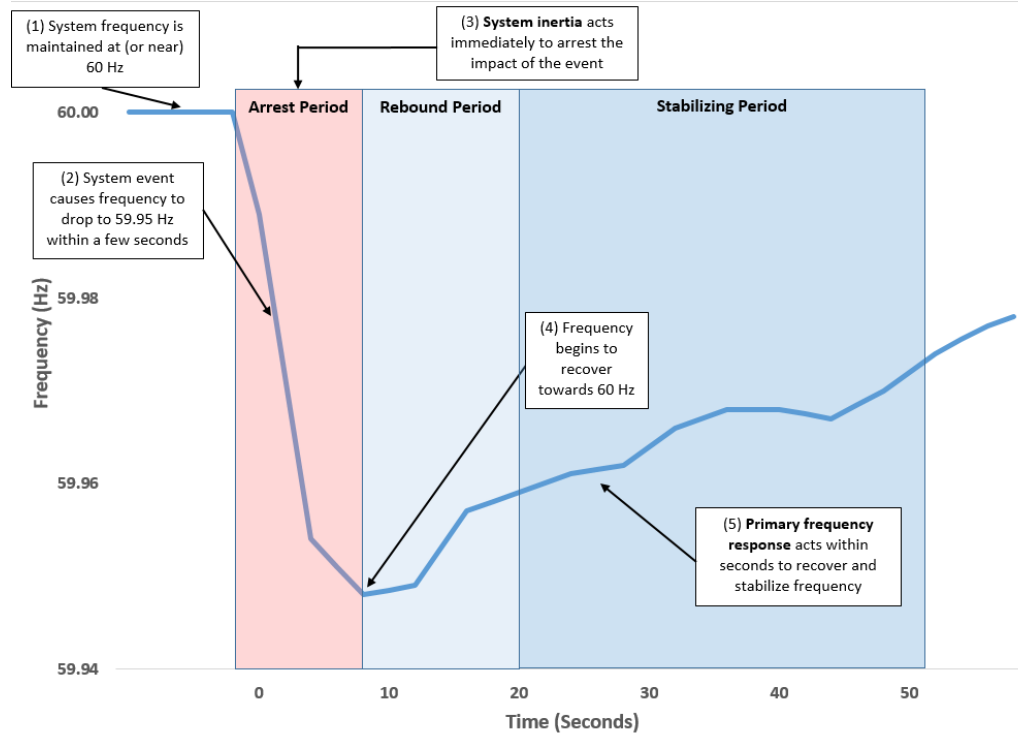
Mechanism for achieving balance	Inertial Response	Primary Frequency Response	Regulation	Operating Reserve	Ramping Capability
What is the response time?	Immediately following a system event	Within the first few seconds following a system event	Within minutes of a mismatch between supply and demand	Within 10 minutes or 30 minutes of a system event	Five minutes to hours
How is balancing currently achieved?	Drawn from the stored kinetic energy of rotating equipment	Automatic adjustment of energy output by generators	Signal from IESO tools to a resource to adjust energy output	Activated by the IESO	Scheduled by the IESO's dispatch scheduling engine

Inertial and Primary Frequency Response

What is it?

Synchronous resources are electrically synchronised to the grid, that is, they rotate at the same speed as other resources and are able to quickly respond to conditions that arise on the system.

Figure 4 | Frequency Response



Frequency support is required to restore system frequency to the scheduled value of 60 Hz after an event such as the sudden loss of a large generator that results in an imbalance between load and generation. Such an event initially causes frequency to drop, as stored kinetic/rotational energy is released in an attempt to arrest the electrical imbalance (inertial response), as shown in Figure 4. Arresting further decline in system frequency requires an immediate response from resources connected to the grid. That response slows the rate at which frequency declines by increasing the power output of generators within seconds to stop the fall and stabilize frequency (this is the primary frequency response).

Inertial response and primary frequency response are essential reliability services that are provided by synchronous resources. These resources have large rotating masses that provide inertia to immediately arrest the impact of the event, and governors that sense changes in local system frequency to automatically adjust the energy output of the resource to recover and stabilize system frequency.

Together, inertial response and primary frequency response act to maintain the stability and reliability of Ontario's power system and the broader Eastern Interconnection¹, of which Ontario is a part. These reliability services are essential to preventing power system equipment damage, automatic load shedding and ultimately a widespread blackout.

How are these services provided?

Ontario's large hydroelectric and natural-gas fired generators provide both inertial and primary frequency response to maintain balance during system events. Baseload resources (such as nuclear and run-of-river hydroelectric) also provide inertia but are unable to provide primary frequency response, as they typically operate at full output power and therefore cannot adjust energy output to counteract changes in frequency.

Ontario is also strongly connected with the broader Eastern interconnection through interties with New York and Michigan, which can provide supplementary frequency support to Ontario if needed.

Energy sources such as wind and solar, and storage units such as batteries and flywheels, are known as **inverter-based resources (IBRs)**. These resources are connected to the grid through electronic inverters, and either have no rotating masses, or the effects of their rotating masses are isolated from the grid by their inverters. As a result, the IBRs do not naturally contribute to the inertial response of the system; however, the control systems of IBRs are increasingly being outfitted with the capability to simulate this type of response.

What are potential challenges and considerations for the future?

A decarbonized resource mix is anticipated to have an increased number of inverter-based resources and potentially fewer conventional resources connected to the grid. At the same time, higher system demands in the future may increase the amount of frequency response that Ontario is required by NERC Reliability Standards to provide to help maintain the stability of the Eastern Interconnection. As a consequence of these expected changes, recovery from system events may become more challenging in the future, specifically during periods of outages to those remaining resources that provide frequency support.

While existing hydroelectric resources can provide a portion of the frequency support required, other sources of frequency support will also be needed to respond to system events. Inverter-based resources already have some capability to provide primary frequency response and inertia through control systems, but are not currently required to do so in Ontario.

Fast frequency response is an emerging product that can be provided by multiple generator types and demand response, and may replace a portion of traditional frequency support. As technological capability advances, there is potential for frequency support to also be provided by resources such as small modular reactors and natural gas resources retrofitted to use hydrogen as a fuel.

A considerable amount of further technical study will be required to determine the ability of a future resource mix to provide sufficient frequency response during system events, and the minimum amount of synchronous generation capacity that is required on the system to ensure that there is sufficient frequency response as the resource mix is decarbonized.

Regulation Service, Operating Reserve and Ramping Capability

Table 6 describes three additional essential reliability services that are required to ensure that balance on the power system is maintained. These are regulation service, operating reserve and ramping capability.

Table 6: Reliability Services

Requirement	Regulation Service	Operating Reserve	Ramping Capability
What is it?	Balances normal fluctuations in supply and demand, and helps restore frequency after a system event, and following the primary frequency response	Stand-by power or demand reduction that can be called upon in short notice	The ability to follow changes in Ontario demand
When is it needed?	On a minute-to-minute basis	Following a system event (e.g., loss of a large generator)	Many times, a day: on a five-minute basis in real-time and to meet demand forecast for future hours
Why is it important?	Regulation compensates for the normal variations between what is forecast (for demand and variable generation output) and what actually materializes, and is necessary to help maintain system frequency at the scheduled value	Operating reserve helps to restore system frequency to the scheduled value, and maintain reliability following an unexpected event that creates a mismatch between supply and demand	Ramping capability is essential to ensuring that online resources are able to respond to increases or decreases in demand within an hour and in future hours (e.g., during evening pick-up)
How are needs met today?	Mainly by hydroelectric resources that also provide energy to the system	Mainly by hydroelectric and natural gas-fired resources that are scheduled in the IESO's operating reserve markets	Some hydroelectric resources; natural gas-fired resources (combined-cycle units for longer duration ramps and simple-cycle combustion turbines for shorter duration ramps); and the scheduling of interchange with other jurisdictions

What are potential challenges and considerations for the future?

As the resource mix evolves and system needs change as a result of the broader energy transition, ensuring a sufficient amount of regulation service, operating reserve and ramping capability may be challenged. Further considerations that will be required are discussed below.

Other resources may be able to satisfy the system's balancing requirements provided they have the demonstrated capability to respond to system needs as described above. These resources may include storage resources, flexible demand products, and combustion turbines that have been

retrofitted to utilize cleaner sources of fuel such as hydrogen. Further assessments will be required as technological capability advances and these types of resources are integrated into the power system.

Regulation Service

An increased penetration of variable generation resources on the system, such as wind and solar, may result in more and/or higher magnitude variations between the forecast and actual output of these resources. Further studies will be required to determine the amount of regulation service needed to enable the system to respond to the inherent uncertainty that arises with the output of variable generation resources. In addition to assessing regulation service needs, potential methods of enhancing the IESO's forecasts of demand and variable generation may be explored.

Operating Reserve

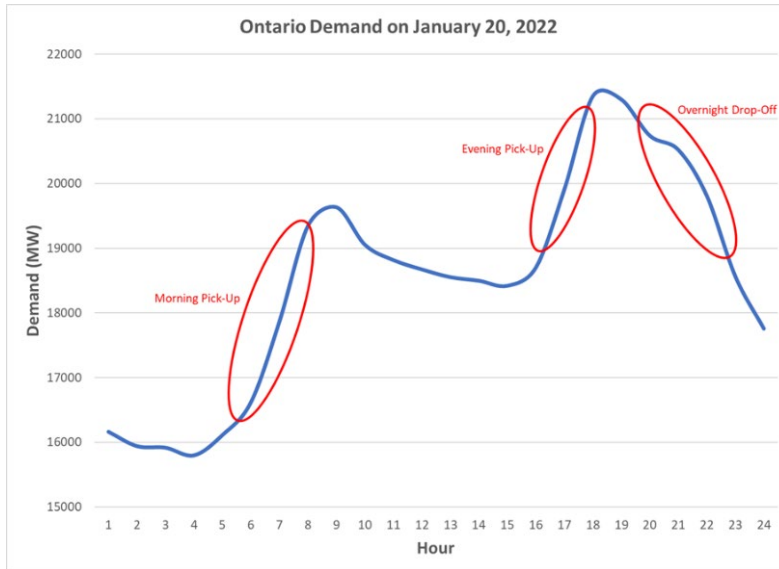
Meeting operating reserve requirements today is already a challenge during certain periods of the year, such as the spring or fall seasons when demand is typically lower and very few natural gas-fired resources are online and providing energy. This is further exacerbated when these periods coincide with periods of freshet and the hydroelectric resources are utilized to maximize energy production and are not available to provide operating reserve to help respond to system events.

With natural gas resources providing a significant amount of Ontario's operating reserve requirements today, in-depth analysis must be conducted to determine the ability of a decarbonized resource mix to meet provincial operating reserve requirements² at all times of the year and under various system conditions. For example, battery storage resources are anticipated to play a role in providing operating reserve in the future. However, their limited energy capability will mean that once activated to produce energy, they will be available for a finite amount of time after which they will need to be recharged. Replenishing battery charge will impose additional load on the system, which may not be feasible during periods of high demand (such as on peak summer or winter days) or days when output from variable generation resources is low.

Ramping Capability

As other sectors of the economy decarbonize to meet broader emissions targets, and reliance on the electricity system grows, a change in today's demand profiles is anticipated (the demand profile from a typical winter day is shown in Figure 5). This may create an additional need for system ramping capability as periods of load pick-up and drop-off occur more often and/or become steeper during the day. In addition, steeper changes in load pick-up could be exacerbated by an increased number of solar resources on the distribution system, particularly over the evening period; as the output of these resources decreases, this will have the effect of adding to system demand.

Figure 5 | Ramping



With natural gas resources meeting a significant amount of system ramping needs today, a resource mix with fewer natural gas resources will pose challenges to meeting daily ramps in demand as they occur in real-time or are anticipated to occur in future hours. This can also be further exacerbated during periods of freshet when hydroelectric resources are unavailable to provide ramping capability. Here again, in-depth analysis will be required to assure the decarbonized resource mix is capable of responding to potentially more frequent and steeper daily ramps in the future.

Reactive Support and Voltage Control

What is it?

Reactive support and voltage control service is required to maintain acceptable reactive power and voltage levels on the power system.

Why is it important?

Acceptable voltage levels are required to move power through the transmission and distribution system from generators to end consumers. Maintaining adequate voltage profiles across the power system is critical to reliably operating the system, both during normal operations and following a system event. Power sags (dips) and prolonged low-voltage events can affect large areas and create more widespread events, while high-voltage events can result in equipment damage and potentially the loss of life.

How are reactive support and voltage control needs met today?

All generating resources injecting energy into the system are required to provide a certain level of reactive support and voltage control service in accordance with the Market Rules. The IESO also

contracts some resources to provide additional amounts of this service in order to meet system needs.

What are potential challenges and considerations for the future?

Synchronous resources provide the system with a significant amount of reactive power and voltage control today, which may be challenged in the future by a resource mix with a decreased proportion of synchronous resources. In-depth analysis will be required to determine the ability of a future resource mix with an increased amount of inverter-based resources to maintain acceptable voltage levels on the system.

Considerations to ensure a system with a sufficient amount of reactive support and voltage control may include:

- Enhancing the capability of conventional power electronic inverter-based resources to exhibit similar characteristics as synchronous resources, and
- Integrating technologies such as synchronous compensators (rotating machines that contribute to reactive power and voltage control but do not produce power) on the power system.

Additional Considerations

In addition to the essential reliability services discussed above, other areas of study will be required as the resource mix evolves to ensure reliable operation of the power system.

Black Start Capability

Black start capability is critical to restoring the power system in a timely manner following a power system blackout. This service is provided through certified black start resources that have the ability to start without drawing power from the grid or other sources of generation. Once started, these resources can in turn support the energization of transmission elements, other generation units and load in a defined area of Ontario.

Today, hydroelectric and natural gas resources provide black start capability in Ontario. In-depth analysis will be required as the resource mix evolves to ensure that the system has sufficient black start capability; this will include a transmission analysis that incorporates the location of black start resources. As technologies advance, other types of resources may also be able to provide this service in the future.

Ability to Manage Resources

Significant effort will be required to maintain reliability of the power system during the energy transition. Another system attribute and key focus area for the IESO is manageability, which is a critical aspect of reliable operations. Manageability is the attribute that enables the IESO to have visibility of, monitor and direct the operation of the majority of resources across the system.

The [2021 Electric Reliability Organization Reliability Risk Priorities Report](#) indicated that the risk posed by human error will increase as power systems become more complex as a result of the energy transition. To manage this risk, updates will be required to the IESO's internal models, tools and processes to effectively integrate and operate new resource types and technologies. Changes may

also be required to current planning, operating and market approaches to optimize existing resources and enable new resources to support the transition.

Seasonal and Extreme Event Analysis

Seasonal weather changes and extreme events such as a heat wave or cold snap can impact power system equipment and the performance of resources. For example, extreme heat conditions typically result in higher forced outages on the system, as well as low water conditions that can reduce hydroelectric output and impact the ability of these resources to provide energy and operating reserve. In-depth analysis will be required to ensure that the electricity system is resilient through a variety of conditions, and that the resource mix possesses the characteristics necessary to withstand these conditions. In addition, a changing climate that results in more periods of drought may not only limit the ability of hydroelectric resources to provide operating reserve, but also energy.

Conclusion

Assessing these attributes and ensuring that a future resource mix possesses the essential reliability services that are necessary for reliable operations will require significant in-depth analysis that includes the topics discussed in this appendix. With natural gas providing many of the essential reliability services required on the system today, developing a strategy to shut down natural gas facilities will be necessary to ensure that the system has the reliability services that are needed through the energy transition.

4. Storage Summary

This table details out the types of storage and corresponding functioning of the grid storage technologies.

Table 7: Storage Type and Technology

Storage type	Grid Storage Technology	Description
Chemical	Batteries	Electrochemical energy storage systems charges and discharges electricity in the form of chemical redox reactions. An electrochemical battery is made of cells consisting of a positive and negative electrode separated by an electrolyte. Varying the materials for the electrodes and electrolyte give rise to many different variations of battery storage technologies. Established and commercialized electrochemical storage technologies include lead-acid and lithium-ion batteries while emerging technologies include sodium ion batteries and metal-air batteries.
Mechanical	Flywheels	Stores energy in the form of rotational kinetic energy. When charging, a motor accelerates the spin of a large mass in a vacuum. When discharging the generator converts kinetic energy into electrical energy, decelerating the rotation of the mass.
Chemical	Flow	Similar to batteries, flow batteries charges and discharges electricity in the form of chemical redox reactions. However, in flow batteries, the electroactive elements are stored externally and pumped into the cell to generate electricity. Types of flow batteries include Zinc Bromine, Polysulphide Bromine and Vanadium Redox flow batteries.
Mechanical	Gravity Energy Storage	Involves storing energy in the form of gravitational potential energy by raising a large mass of material (solid/liquid) and recovering the stored energy by lowering the mass to power a turbine that converts kinetic energy back into electricity. This includes established storage technology such as pumped hydro storage in hydro reservoirs and emerging technologies such as Lifted Weight Storage (LWS).

Storage type	Grid Storage Technology	Description
Thermo-Mechanical	Compressed Air Energy Storage	Uses a compressor to store pressurized air in a cavern. When discharging, the heat captured by the thermal energy system during the compression process is integrated back into the pressurized air and decompressed in an expansion turbine coupled with a generator.
Chemical	Hydrogen Storage	Hydrogen gas is generated either through electrolysis, pyrolysis or steam methane reforming which can then be compressed or liquefied and stored either in tanks or underground salt caverns. When discharging, the stored hydrogen can generate electricity by combustion using a hydrogen turbine or reverse electrolysis using a fuel cell.
Thermal	Pumped Thermal Energy Storage	Electricity is used to generate heat using a heat pump and then stored as thermal energy in a hot store. Thermal energy storage mediums could include molten salt, molten aluminum, molten silicon etc. When discharging, the temperature differential between the cold and hot stores is used to convert thermal energy back into electricity. Pumped thermal energy storage systems consist of a hot and cold store, compressors, turbines and generators.
Thermo-Mechanical	Liquid Air Energy Storage	Electricity is used to clean, compress and cool to liquefy air/nitrogen and stores energy in the form of liquid air in a tank. When discharging, the liquid air is pumped, evaporated and the expansion of air is used to drive a turbine.

5. Proposed Federal Clean Electricity Regulation

Summary

The Federal government's proposed Clean Electricity Regulation (CER) will have implications for Ontario's existing natural gas fleet, decarbonization pathway and future reliability. The IESO provided comments to Environment and Climate Change Canada (ECCC) on the CER Framework regarding the need for policy certainty, the transitional role of natural gas, and the criticality of affordability so the electricity system can enable overall emissions reductions through electrification of other sectors.

Background

In July, the Federal government released the framework for the proposed CER, with quantitative details to be shared later (not yet released). In developing the Framework, ECCC heard from stakeholders that the CER needs to balance sustainability, reliability and affordability. The key elements of the framework are summarized below:

- Plants will be covered by the CER if they 1) combust fossil fuels; 2) are over a threshold size; and 3) sell power to the grid.
- The regulated entity will be the entity that manages the plant. They will be subject to two requirements:
 - Performance standard; and
 - Financial compliance for any permitted emissions.
- The penalty for failure to comply with the performance standard will be a criminal penalty.
- Financial compensation will be equal to the carbon tax or offsets. The government commits to no double counting.
- The performance standard will be an intensity standard, likely set to be equivalent to a natural gas combined cycle plant with carbon capture.
- All "new units" must come into compliance by 2035. A "new unit" is any unit commissioned (i.e., offering electricity for sale to the grid) in 2025 or later. In order for a new unit to continue to run in or after 2035 it must meet the performance standard.
- An "existing unit" can operate unabated until the end of potential life (EOPL). An existing unit is one commissioned in 2024 or earlier. EOPL has not yet been defined, but is not expected to be longer than 25 years. After the EOPL, these plants must either retire, meet the performance standard or run only for back up or ramping within a set annual emissions budget. These plants must pay financial compensation for all emissions.
- The following units are exempted from the CER:
 - Industrial units used entirely for own consumption
 - Very small units

- Remote units
- Emergencies – “extraordinary, unforeseen and irresistible”, i.e., where human life or safety are at risk – these are expected to be very rare, and no examples exist in the last decade.

P2D Study Assumptions

The input assumptions used in the Pathways scenario were informed by the draft CER framework. In particular, existing gas units were limited to a 25-year life. We also made the assumption that natural gas acquired in the current procurements, much of which is expected to be from upgrades and expansions, would be able to stay online until 2040.

P2D Insights

Our analysis found that Ontario will need about 8,000 MW of natural gas in 2035 to maintain reliability. If the CER were to define the EOPL as 25 years, then Ontario would only have approximately 2,000 MW of natural gas available; most existing facilities will reach the 25-year mark on or before 2035, except for York Energy Centre (2037), Green Electron (2042), and Napanee (2045). This would be insufficient to maintain reliability. In addition, an EOPL of 25 years or less would force the retirement of Portland’s Energy Center and York Energy Center, which are vital to reliability in Toronto and York region. These plants can only be retired if they are replaced by some combination of new generation or transmission. Our analysis finds that sufficient new transmission could not be built in the region by 2035.

Our research led us to conclude that there are limited compliance options for gas plants in Ontario. Carbon capture and storage CCS was considered unlikely given the technical and economic challenges of using it on peaking plants. RNG is considered unlikely because of the scarcity of RNG resources in Ontario; the potential RNG in the province is about 2.5% of the total amount of natural gas used. With technology or market innovation this situation could change, however it is risky to assume that it will. Low-carbon hydrogen is a theoretical compliance path, but requires the development of a source of low carbon hydrogen (made in Ontario and/or imported), a transportation system across Ontario, and turbines that can combust 100% hydrogen. Our research suggested that retrofitting existing natural gas plants to 100% hydrogen will not be feasible, as such existing plants will likely need to be replaced. This is possible by 2035, but it does not exist at this time at the necessary scale. Concerted effort by government and the private sector would be needed to open up compliance paths.

6. Further Context on Scale: Land and Labour

Introduction

One of the key findings of this report is the scale of the effort that will be required to decarbonize Ontario's electricity system. The Pathways scenario, in examining the decarbonization of electricity, is also looking at moving a significant portion of Ontario's economy onto a clean system. This report has so far discussed the scale of the solutions in terms of how many new MWs of resources would be required, how many MWs of new transmission would be required, and the cost of all these upgrades/additions. This section will discuss the physical requirements, such as land and labour, to be able to build-out the supply mix projected in this study. This discussion is based on a literature review and does not reflect independent analysis performed by the IESO.

Land and Labour Requirements

Land

Quantifying the land-use associated with electricity generation assets is an active area of research, with many opinions on best practices. Some resource types, such as nuclear, are somewhat easier to quantify as their footprint represents the amount of physical space the plant occupies. A resource such as a wind farm, however, will have usable land (often for farming purposes) between the physical wind turbine locations, forcing the analyst to decide whether this should be counted as part of the land requirements or not. In addition, the breadth of the analysis is also hotly debated: should the analysis include the land impacts of mining all the raw materials, land requirement of the physical plant, and any land required for decommissioning, or a subset of these?

The following graphic is an excerpt from [Land-use intensity of electricity production and tomorrow's energy landscape](#)¹. A peer reviewed paper with contributions from several prominent universities, it calculates the land-use intensity of electricity (LUIE) for several generation technologies. Broadly speaking, the analysis in this paper spans electricity systems in 45 US states and 73 additional countries. The analysis also includes land impacts of mining for raw materials. See the paper for greater detail on the methodology used.

¹ [Land-use intensity of electricity production and tomorrow's energy landscape | PLOS ONE](#)

Figure 6 | Land use intensity of Electricity

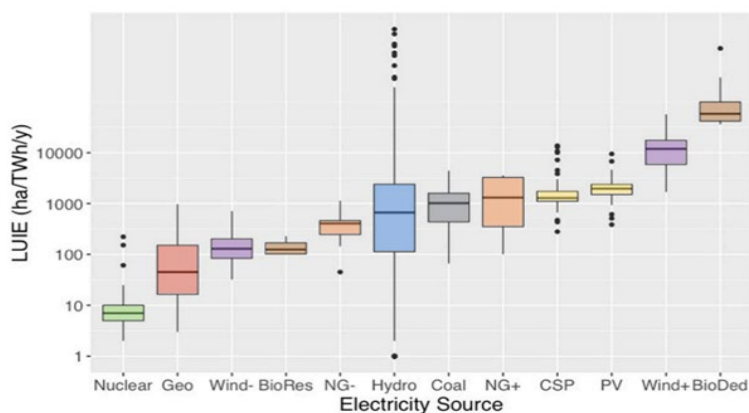


Fig 1. Land use intensity of electricity (LUIE: ha/TWh/yr), shown on log scale. Boxes represent the inter-quartile range with the median as the middle bar. Whiskers extend to the highest or lowest data point that is within 1.5 times the inter-quartile range; points outside this range represent outliers. Electricity sources: nuclear energy (Nuclear), geothermal energy (Geo), wind energy with footprint only, (Wind-), natural gas footprint only (NG-) and including spacing (NG+), hydroelectric power for single purpose dams (Hydro), coal (Coal), concentrating solar power (CSP), ground-mounted photovoltaic solar energy (PV), wind energy with footprint (Wind-) and spacing (Wind+), and residual biomass (BioRes) and dedicated biomass (BioDed).

This plot demonstrates the vastly different land requirements for different electricity generation technologies. On the low end is nuclear, with a median LUIE of around 7.1 ha/TWh/yr while on the higher end a thermal unit burning biodiesel would require up to 58,000 ha/TWh/yr. This massive difference can be attributed to the land required to grow the feedstock for the biodiesel. The following table summarizes the land requirements for the Pathways scenario, estimated using the Land analysis in the cited paper.

Table 8: Land Requirements for the Pathways Scenario

Resource	Incremental Resources by 2050 (MW)	Average Capacity Factor Percentage	Median LUIE (ha/TWh/yr)	Land Required (km ²)
Hydrogen (SCGT)	14,000	10	410	50
Hydro	657	60	650	22
Solar	6,000	25	2,000	263
Onshore Wind	15,100	45	12,000	7,064
Offshore Wind*	2,500	50	12,000	1,314
Nuclear	17,800	93	7	10

***Note: Offshore wind estimate is based on the same LUIE as onshore wind as there was no differentiation in the paper**

The above table does not include the land required for new hydro/wind being developed in Quebec to support the firm capacity/energy imports, nor does it include the land required for the pumped-hydro storage options. Based on the land use estimates above, approximately 8,700 km² would be needed to accommodate all of these new resources, as well as the amount of land that is impacted

for raw materials and construction. To put this in context, the city of Toronto has a land area of 630 km²; meaning that an area of almost 14 times the size of Toronto would be needed for all of these incremental resources. This would be equivalent to less than 1% of Ontario’s land mass, which is 1.076 million km².

Labour

Another important factor to consider is the amount of labour required to build this new generation. As presented in the input assumptions, our capacity expansion modelling included an “Annual Build Limit” per resource type. Without these limits, the model would be free to build any amount of any resource each year. With the aggressive demand increase, the modeling showed that there are years where it would be likely that all resource categories would have to be built at their annual maximum limits. To get a sense of the labour force required to be able to build all resource categories at their maximum annual build limit, estimates of Construction, Installation and Manufacturing (CIM) of each resource type was taken from an Energy Policy Study².

Table 9: Labour Requirements for the Pathways Scenario

Resource	Annual-Build Limit (MW)	CIM (job-years/MW-inst)	Total (job-years/MW-inst)
Hydrogen (SCGT)	1,000	1.02	1,020
Hydro	1,000	5.7	5,700
Solar	600	25.5	15,300
Onshore Wind	1,000	6.96	6,960
Nuclear	3,300	15.2	50,160
Total	-	-	79,140

To put this in context, in 2021 the Ontario workforce had approximately 600,000 construction workers, with approximately 14,000 working on electricity related projects. This would represent an almost 6-fold increase in the number of workers focused on electricity projects up to almost 14 per cent of all construction labour in the province in 2021. Also note that the P2D scenario requires a significant transmission build-out that has not been quantified here, meaning that the labour requirements would likely be larger than what is presented here.

² [Putting renewables and energy efficiency to work How many jobs can the clean energy industry generate in the US? \(berkeley.edu\)](#)

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