EB-2022-0157

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998,* S.O. 1998, c. 15, Sched. B, as amended (the "**Act");** and in particular section 90(1) and section 97 thereof;

AND IN THE MATTER OF an application by Enbridge Gas Inc. for an order granting leave to construct natural gas pipelines in the Municipality of Chatham Kent and Essex County.

CROSS-EXAMINATION COMPENDIUM

ATURA POWER

November 13, 2023

INDEX

TAB 1

PROJECT COSTS AND ECONOMICS

1. The purpose of this Exhibit is to provide an overview of the costs of the Project and the economic analysis that was completed to demonstrate that the Project is economically feasible and in the public interest.

2. This Exhibit is organized as follows:
   A. Project Cost
   B. Project Economics
      i. Stage 1 – Project Specific Discounted Cash Flow Analysis
      ii. Stage 2 – Benefit/Cost Analysis
      iii. Stage 3 – Other Public Interest Considerations
      iv. Summary of Stages 1 to 3 Analyses

A. Project Cost

1. The total estimated cost of the Project is $358.0 million, as shown in Exhibit E, Tab 1, Schedule 2. This cost includes: (i) materials; (ii) labour; (iii) external permitting and land; (iv) outside services; (v) contingencies; (vi) interest during construction; and (vii) indirect overheads. Excluding indirect overheads, the total estimated cost of the Project is $289.2 million. /U

2. The costs are based upon a class 3 estimate prepared in Q1 2023, updated to reflect market conditions based on Q4 2022 contractor responses to RFP, as per American Association of Cost Engineers standards, and include a contingency of approximately 8% applied to all direct capital costs reflecting the detailed engineering design stage of the Project and materials received to date. This contingency amount has been calculated based on the risk profile of the Project and is consistent with contingency amounts calculated for projects in similar stages of design and complexity completed by Enbridge Gas. /U

3. Table 1 below provide a comparison of Project pipeline costs to other recent Enbridge Gas pipeline projects in close proximity to the Project area. Table 1 compares the estimated cost of the current Project (Panhandle Loop) to the latest estimated cost of the Dawn to Corunna Replacement Project (EB-2022-0086). A high-level explanation of significant variances is provided in the notes to the table. /U

Table 1: Project Cost Comparison – Pipeline Costs ($ Millions) /U

Item No.	**Description**	**(a)** **Proposed Project** Panhandle Loop (EB-2022-0157)	**(b)** **Current Forecast** Dawn to Corunna (EB-2022-0086)	**(c) = (a) - (b) Variance to Actual**
	Pipeline Diameter	***NPS 36***	***NPS 36***	
	Length	***19 km***	***20 km***	
	Pipeline Material	***Steel***	***Steel***	
1	Materials	28.3	26.1	2.2
2	Labour	150.8	123.1	27.7
3	Contingency	13.9	2.6	11.3
4	Interest During	6.4	3.7	2.7
5	**Total Direct Capital Cost**	**199.5**	**155.5**	**44.0**
6	Indirect Overheads	48.0	33.4	14.6
7	**Total Project Cost**	**247.5**	**188.9**	**58.6**
8	Total Cost per km	13.0	9.4	3.6
9	Material Cost per km	1.5	1.3	0.2
10	Labour, External permitting and land, and Outside Services per km	7.9	6.2	1.7
11	**Total Ancillary Facilities Direct Capital Cost**	**89.7**	**127.1**	**(37.4)**
12	Ancillary Facilities Indirect Overheads	20.8	23.3	(2.5)
13	**Total Ancillary Facilities Project Cost**	**110.5**	**150.4**	**(39.9)**
14	**Total Project Cost (Mainline and Ancillary Facilities) $ Millions**	**358.0**	**339.3**	**18.7**

NOTES:

- The proposed Project mainline estimate is inclusive of the Richardson Sideroad end point valve site.
- The proposed Project has a more complex mainline scope with eight (8) trenchless crossings compared to one (1) trenchless crossing for the Dawn to Corunna Replacement Project.
- Reduced contingency for the Dawn to Corunna Replacement Project due to its current stage of development/execution.

/U

B. Project Economics

4. The purpose of this section of evidence is to discuss the economic analysis of the Project, completed in accordance with the OEB's recommendations in E.B.O. 134 Report of the Board ("E.B.O. 134"). E.B.O. 134 is the appropriate economic test to apply to the Project, as the Project consists entirely of transmission pipeline infrastructure to which distribution customers do not directly connect. The use of E.B.O. 134 for the Project is also consistent with recent expansions to Enbridge Gas's Panhandle System approved by the OEB.[1]

5. To provide the OEB with supporting information, a Discounted Cash Flow ("DCF") analysis, consistent with E.B.O. 134, has been completed.

6. Stage 1 consists of a DCF analysis specific to Enbridge Gas. All incremental cash inflows and outflows resulting from the Project are identified. The NPV of the cash inflows is divided by the NPV of the cash outflows to arrive at a profitability index ("PI"). If the NPV of the cash inflows is equal to or greater than the NPV of the cash outflows, PI is equal to or greater than 1.0 and the Project is considered economic based on current approved rates. If the Project NPV is less than $0 or the PI is less than 1.0, Stage 2 and 3 benefit/cost analysis must be undertaken.

7. Stage 2 consists of discounting the quantified benefits to customers resulting from the Project at a social discount rate and the results are added to the Project NPV from Stage 1 to calculate the direct net benefit of the Project to Enbridge Gas customers.

   The Project is considered to be in the public interest if the net benefit is greater than $0.

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[1] Union Gas Panhandle Reinforcement Project: EB-2016-0186, Union Gas Kingsville Transmission Reinforcement Project: EB-2018-0013.

8. Stage 3 analysis considers other quantifiable benefits and costs related to the construction of the Project, not included in the Stage 2 analysis, and other non-quantifiable public interest considerations.

i. Stage 1 – Project Specific Discounted Cash Flow Analysis /U

9. The Stage 1 DCF analysis for the Project can be found at Exhibit E, Tab 1, Schedule 5. This schedule indicates that the Project has a NPV of negative $150 million and a PI of 0.48.

10. A summary of the key input parameters, values and assumptions used in the Stage 1 DCF analysis can be found at Exhibit E, Tab 1, Schedule 3.

11. Incremental cash inflows are estimated based on the transmission portion ("transmission margin") of 2023 OEB-approved rates.[2] The revenue calculation for the transmission margin can be found at Exhibit E, Tab 1, Schedule 4. /U

12. Incremental cash outflows, in accordance with E.B.O. 134, include all estimated incremental Project costs. Indirect overhead is not included within cash outflows.

13. The total estimated incremental cost of $289.2 million can be found at Exhibit E,Tab 1, Schedule 2, Line 7.

ii. Stage 2 – Benefit/Cost Analysis

14. A Stage 2 analysis was undertaken as the Stage 1 NPV is less than zero (negative $150 million). The Stage 2 analysis considers the estimated energy cost savings that accrue directly to Enbridge Gas in-franchise customers as a result of using natural /U

[2] EB-2022-0133

gas instead of another fuel to meet their energy requirements. The difference in fuel cost is derived as:

[Weighted Average Alternative Fuel Cost - Cost of Natural Gas] × Energy Use

15. The Stage 2 NPV of energy cost savings are estimated to be in the range of approximately $226 million over a period of 20 years to $353 million over 40 years. A range is provided as the outcome can vary depending upon the assumptions for alternative fuel mix, energy use, fuel prices, and term. /U

16. The Stage 2 energy cost savings have only been calculated for the general service customer class. It is assumed that contract rate customers will not choose an alternative fuel if natural gas is not available to them. The non-availability of natural gas will cause contract rate customers to expand or move their operations to other jurisdictions, likely outside of Ontario, where their natural gas needs can be served. The resulting impacts to the Ontario economy are addressed in Stage 3.

17. The results and assumptions associated with this analysis can be found at Exhibit E, Tab 1, Schedule 6.

iii. Stage 3 – Other Public Interest Considerations

18. There are several other public interest factors for consideration as a result of the Project. Some are quantifiable and others are not readily quantifiable. Quantifiable factors include GDP, taxes, and employment impacts. Applicable other public interest factors are discussed below:

/U

<u>Economic Benefits for Ontario</u>

19. The construction of the Project will provide direct and indirect economic benefits to

Ontario estimated at approximately $257 million, as detailed at Exhibit E, Tab 1, Schedule 7. This figure is related only to the construction of the Project and does not include the similar direct and indirect economic benefits to Ontario when natural gas customers receiving this incremental supply invest and grow their operations. Customers who submitted EOI bids in 2021 were requested to provide economic development impacts related to their incremental natural gas needs. In the EOI bid responses, customers indicated that total direct capital investment into their business operations in Southern Ontario would exceed $6.37 billion. These figures were updated via the 2023 EOI bid forms. Although, the Company only received relevant feedback from 75% of customers who bid in 2023 (relative to 100% in 2021) the Project is still anticipated to result in total direct capital investment in Southwestern Ontario exceeding $4.5 billion.[3]

Employment

20. The construction of this Project will result in additional direct and indirect employment. There will be additional employment of persons directly involved in the construction of the Project. In addition, there will be a trickledown effect on employment as the Project is estimated to create approximately 1,093 jobs as referenced at Exhibit E, Tab 1, Schedule 7. /U

21. Customers who submitted EOI bids in 2021 indicated that a total of 11,526 jobs could be created through the investment into their business operations enabled by the incremental capacity of the proposed Project. These figures were updated via the 2023 EOI bid forms. Although, the Company only received relevant feedback from 75% of customers who bid in 2023 (relative to 100% in 2021) the Project is still anticipated to result in the creation of 6,900 jobs.[4] /U

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[3] Implying a comparable result to 2021, since $4.5 billion is 75% of $6 billion total potential.
[4] Implying a comparable result to 2021, since 6,900 jobs is 75% of 9,200 total potential.

Utility Taxes

22. A decision to proceed with this Project will result in Enbridge Gas paying taxes directly to various levels of government. These taxes include Ontario income taxes and municipal taxes paid by Enbridge Gas as a direct result of the Project and are included as costs in the Stage 1 DCF analysis. These taxes are not true economic costs of the Project since they represent transfer payments within the economy that are available for redistribution by federal, provincial, and municipal governments. The NPV of Ontario income taxes and municipal taxes payable by Enbridge Gas related to the Project over the Project life is approximately $45 million with a further $22 million paid to the federal government. These figures are further detailed at Exhibit E, Tab 1, Schedule 7.

Employer Health Taxes

23. The additional employment resulting from construction of the Project will generate additional employer health tax payments to aid in covering the cost of providing health services in Ontario.

iv. Summary of Stages 1 to 3 Analyses

24. Table 3 below shows the NPV calculated for the 3-Stage economic analysis completed for the Project.

Table 3: NPV Calculation /U

Stage	NPV ($millions)
1	($150)
2	$226 to $353
3	$257
Total	$333 to $460

25. As set out above, the Project is in the public interest and the tests set out in E.B.O. /U
134 are appropriate for the purposes of evaluating the Project. Based on these tests,

the Project has a net present value of $333 million to $460 million and is economically feasible.

26. On Februry 21, 2013, the Board issued a new requirement to the Filing Guidelines on the Economic Tests for Transmission Pipeline Applications with respect to E.B.O. 134 (EB-2012-0092):[5]

> Any project brought before the Board for approval should be supported by an assessment of the potential impacts of the proposed natural gas pipeline(s) on the existing transportation pipeline infrastructure in Ontario, including an assessment of the impacts on Ontario consumers in terms of cost, rates, reliability and access to supplies.

27. These impacts have been addressed throughout this application and evidence. Table 4 below summarizes these impacts and provides references to additional detail.

Table 4: Project Impact to Customers

Entity Impacted		**Summary of Impact**	**Reference**
Existing Infrastructure	Enbridge Gas	Enbridge Gas is proposing to construct: i) 19 km of NPS 36 pipeline that will parallel the existing NPS 20 pipeline from the Dover Transmission Station to a new valve site at Richardson Sideroad	Exhibit D, Tab 1, Schedule 1
Impacts to Ontario consumers	Costs and Rates	Enbridge Gas is not seeking cost recovery of the Project as part of this application. Enbridge Gas expects that, upon rebasing, the capital costs associated with the Project will be included within rate base. Enbridge Gas will allocate Project costs to rate classes according to the applicable OEB-approved cost allocation methodology in place at the time the Company applies for such rate recovery.	N/A
	Reliability and Access to Supplies	In response to increased forecast of demand growth, the Project will create incremental reliable firm transportation assets on the Panhandle System. Project also supports increased access to the Dawn Hub for the Panhandle Market, providing lower cost and greater reliability.	Exhibit B, Tab 3, Schedule 1 Exhibit C, Tab 1, Schedule 1

/U

[5] EB-2012-0092, Filing Guidelines on the Economic Tests for Transmission Pipeline Applications, February 21, 2013, P. 3.

Panhandle Regional Expansion Project
Economic Benefits from Infrastructure Spending
Figures in $ Millions

Line No	Description	Capex Spend Out of Country (a)	Capex Spend within Ontario (b)		Capex Spend within Canada Excluding Ontario (c)	Capex Total (d)= sum (a-c)	
1	Proposed Facilities	$ 47	$ 232		$ 10	$ 289	
2							
3	% of Total Spend	16%	80%		4%	100%	Line 1 /Total Line 1 Col (d)
4							
5	GDP						
6	GDP Factor		0.91	*			
7	GDP Impact $ Millions		$ 212				Line 1 * Line 6
8							
9	Employment (Jobs)						
10	Jobs Factor		4.7	*			
11	Jobs Created		1,093				Line 1 * Line 10
12							
13	Taxes Paid by Union Gas						
14	Property Tax		$ 17				Source: NPV DCF
15	Provincial Income Tax		$ 28				Source: NPV DCF
16	Total Provincial Taxes		$ 45				
17	Federal Income Tax		$ 22				Source: NPV DCF
18	Total Taxes Paid		$ 67				
19							
20	Total Value to Ontario						
21	GDP Impact $ Millions		$ 212				Line 7
22	Total Provincial Taxes		$ 45				Line 16
23	NPV Total Value to Ontario		$ 257				

Notes:
* The Economic Benefits of Public Infrastructure Spending in Ontario, Prepared for Ministry of Economic Development and Growth, Ministry of Finance, Ministry of Infrastructure. Prepared by The Centre For Spatial Economics, March 2017.

TAB 2

Table 3: NPV Calculation[1]

Stage	NPV ($millions)
1	($150)
2	$226 to $353
3	$257
Total	$333 to $460

[1] Application, Exhibit E – 1-1 – page 7 of 8.

TAB 3

Comparison of Economic Test Results: Tx Expansions

Project	**Cost ($M)**	**Capacity (TJ/d)**	**Net Present Value ($M)**	**Profitability Index**[1]	**Economic Feasibility Test**
Panhandle Regional Expansion Project (current)	$358.0	168 TJ/d	Stage 1: (150) Stage 2: 226-353 Stage 3: 257 Overall: 333-460	0.48	EBO 134
2018 Union Gas Kingsville Transmission Reinforcement[2]	$105.7	71 TJ/d	Stage 1: (59.2) Stage 2: 283-472 Stage 3: not discussed	0.44	EBO 134
2016 Union Gas Panhandle Reinforcement[3]	$264.5	106 TJ/d	Stage 1: (212)-(207) Stage 2: 805 Stage 3: not discussed	Not provided but < 1 given NPV	EBO 134

[1] The NPV of the cash inflows divided by the NPV of the cash outflows
[2] Union Gas Kingsville Transmission Reinforcement Project (EB-2018-0013) (September 20, 2018)
[3] Union Gas Panhandle Reinforcement Project (EB-2016-0186) (February 23, 2017)

TAB 4

Ontario

Executive Council of Ontario
Order in Council

On the recommendation of the undersigned, the Lieutenant Governor of Ontario, by and with the advice and concurrence of the Executive Council of Ontario, orders that:

Conseil exécutif de l'Ontario
Décret

Sur la recommandation de la personne soussignée, le lieutenant-gouverneur de l'Ontario, sur l'avis et avec le consentement du Conseil exécutif de l'Ontario, décrète ce qui suit :

WHEREAS the Minister of Energy ("Minister") is committed to ensuring that Ontario has a reliable and affordable electricity system, while continuing to find further cost efficiencies in the system;

AND WHEREAS it is desirable that the Independent Electricity System Operator ("IESO") assist the Government to ensure that Ontario continues to have a reliable and affordable electricity system;

AND WHEREAS the Minister may, with the approval of the Lieutenant Governor in Council, issue directives under subsection 25.32(5) of the *Electricity Act, 1998* that require IESO to undertake requests for proposals and any other initiative or activity that relates to, amongst other matters, electricity supply or capacity.

NOW THEREFORE the Directive attached hereto is approved as of the date hereof.

ATTENDU QUE le ministre de l'Énergie (ministre) est résolu à s'assurer que l'Ontario dispose d'un réseau d'électricité fiable et abordable, tout en continuant de réaliser d'autres économies de coûts dans ce réseau;

ATTENDU QU'il est souhaitable que la Société indépendante d'exploitation du réseau d'électricité (SIERE) aide le gouvernement à s'assurer que l'Ontario dispose d'un réseau d'électricité fiable et abordable;

ET ATTENDU QUE, sous réserve de l'approbation de la lieutenante-gouverneure en conseil, le ministre peut, par directive, en vertu du paragraphe 25.32(5) *de la Loi de 1998 sur l'électricité* (Loi), ordonner à la SIERE de lancer des demandes de propositions et toute autre initiative ou activité portant, entre autres choses, sur l'approvisionnement en électricité ou la capacité de production ou de stockage d'électricité;

PAR CONSÉQUENT, la directive ci-jointe est approuvée à la date des présentes.

Recommended: Minister of Energy
Recommandé par : Le ministre de l'Énergie

Concurred: Chair of Cabinet
Appuyé par : Le président | la présidente du Conseil des ministres

Approved and Ordered:
Approuvé et décrété le : APR 2 7 2023

Lieutenant Governor
La lieutenante-gouverneure

MINISTER'S DIRECTIVE

TO: THE INDEPENDENT ELECTRICITY SYSTEM OPERATOR

I, Todd Smith, Minister of Energy (Minister), hereby direct the Independent Electricity System Operator (IESO) pursuant to section 25.32 of the *Electricity Act, 1998* (the Act) in regard to the procurement of electricity resources to ensure the reliable operation of Ontario's electricity system in response to ongoing and growing electricity needs expected in the future, as follows:

BACKGROUND

After more than a decade of stable electricity supply, and at times, a surplus, IESO has forecasted that Ontario will see a capacity need emerging in 2025 and growing through the latter part of the decade. This is a result of increased demand due to expanding electrification and increasing business investment in the province, refurbishment schedules at the Bruce and Darlington nuclear facilities and expiring contracts.

Southwestern Ontario, especially the Windsor-Essex region is experiencing rapid growth in electricity demand from greenhouses as well as investments in the lithium-ion battery and automotive sectors.

According to IESO, peak electricity demand in the Windsor-Essex and Chatham areas is forecast to grow from roughly 500 megawatts in 2022 to about 2,100 megawatts in 2035, equivalent to adding cities the size of Ottawa and London to the grid.

Fulfilling this forecasted supply need, at the provincial as well as regional level, will require IESO to procure electricity products and services from both existing and new resources.

The government is committed to a procurement framework that ensures Ontario has a reliable, affordable and clean electricity system. The IESO's Resource Adequacy Framework sets out a long-term strategy to acquire products and services from resources while balancing ratepayer and supplier risks and recognizing the unique characteristics and contributions of different resource types.

The framework consists of competitive procurement mechanisms, as well as special programs and bilateral negotiations with resource providers that are essential to meeting reliability needs or broader government objectives.

In April 2022, the government issued an Order in Council and a Minister's Directive to the Ontario Energy Board (OEB) that was approved by the Lieutenant Governor in Council to accelerate the development of new electricity transmission infrastructure projects in Southwestern Ontario. This new transmission infrastructure will bring power to the region to support economic development in the region, especially the expansion of the electric vehicle supply chain.

Brighton Beach Generating Station (GS) is a natural gas-fired combined cycle power station located in Windsor, Ontario. The IESO's 2021 and 2022 Annual Acquisition Reports (AARs) have identified that while the transmission infrastructure projects are being developed there is a need for re-contracting Brighton Beach GS as it is uniquely positioned to meet reliability needs in the Windsor-Essex region. This includes ensuring the region has the power it needs during demand peaks and supporting the integration of intermittent renewable generation already in place.

Once the transmission infrastructure projects have been completed, IESO believes capacity for the region could be competitively procured.

The government recognizes that Ontario's electricity system is evolving and must continue to move towards flexible and non-emitting sources of supply. In keeping with the goals of the "Made-in-Ontario Environment Plan", the government continues to advance new technologies and opportunities for emission reductions in the electricity sector.

At the same time, IESO's "Pathways to Decarbonization" study conducted in 2022 concluded that while most of the province's increasing electricity demand by 2035 can be met by non-emitting resources, eliminating natural gas-fired generation in the near term from Ontario's electricity system would not only result in rotating blackouts but would also hamper efforts to electrify and reduce emissions in the province by making electrification significantly more costly.

Ontario must have a reliable supply of affordable and clean energy to ensure that we can meet the needs of an electrifying economy, including transportation, steel and other industries.

The government recognizes that further actions will be required beyond those outlined in this Directive. The IESO and the Ministry of Energy will continue to work together to ensure Ontario's electricity system continues to be ready to meet the needs of Ontario's residents and businesses.

DIRECTIVE

Therefore, in accordance with the authority under section 25.32 of the Act, IESO is hereby directed as follows:

1. IESO shall enter into a procurement contract with Brighton Beach Power L.P., doing business as Atura Power for Brighton Beach GS, on terms that are materially consistent with the draft term sheet dated October 12, 2022, with such subsequent changes outlined in the memo submitted to me on April 14, 2023 which shall be incorporated into the final contract.

2. The procurement contract described in paragraph 1 shall include the following:

    a. A contract term that begins on July 16, 2024 and ends on July 15, 2034; and

    b. Provisions that require Atura Power to upgrade the facility to increase its average capacity by approximately 42.5 megawatts.

GENERAL

This Directive takes effect on the date it is issued.

DIRECTIVE DU MINISTRE

DESTINATAIRE : LA SOCIÉTÉ INDÉPENDANTE D'EXPLOITATION DU RÉSEAU D'ÉLECTRICITÉ

Je soussigné, Todd Smith, ministre de l'Énergie (ministre), ordonne par la présente directive à la Société indépendante d'exploitation du réseau d'électricité (SIERE), conformément à l'article 25.32 de la *Loi de 1998 sur l'électricité* (Loi), concernant l'acquisition de ressources en électricité, de garantir l'exploitation fiable du réseau d'électricité de l'Ontario en réponse aux besoins courants et croissants en électricité escomptés, comme suit :

CONTEXTE

Après plus d'une décennie d'approvisionnement stable en électricité, et parfois d'excédent, la SIERE prévoit que l'Ontario verra un besoin en capacité émerger en 2025 et croître jusqu'à la fin de la décennie. Cette situation est le résultat d'une demande accrue qui est attribuable à l'augmentation de l'électrification et à l'accroissement des investissements des entreprises dans la province, aux calendriers de remise en état des centrales nucléaires de Bruce et de Darlington et aux contrats arrivant à échéance.

Le sud-ouest de l'Ontario, en particulier la région de Windsor-Essex, connaît une croissance rapide de la demande en électricité provenant des serres et découlant des investissements dans les secteurs des batteries au lithium-ion et de l'automobile.

Selon la SIERE, la demande de pointe en électricité dans les régions de Windsor-Essex et de Chatham devrait passer d'environ 500 mégawatts en 2022 à environ 2 100 mégawatts en 2035, ce qui équivaut à l'ajout au réseau de villes de la taille d'Ottawa et de London.

Afin de répondre à ce besoin prévu d'approvisionnement tant à l'échelle provinciale qu'à l'échelle régionale, la SIERE devra acquérir des services et produits d'électricité auprès de ressources existantes et de nouvelles ressources.

Le gouvernement est résolu à mettre en place un cadre d'approvisionnement qui garantit que l'Ontario dispose d'un réseau d'électricité fiable, abordable et propre. Le Cadre de suffisance des ressources de la SIERE établit une stratégie à long terme d'acquisition de produits et de services auprès de ressources tout en équilibrant les risques pour les consommateurs et les fournisseurs et en prenant en compte les caractéristiques et les contributions uniques des différents types de ressources.

Le cadre comprend des mécanismes d'approvisionnement en mode concurrentiel ainsi que des programmes spéciaux et des négociations bilatérales avec des fournisseurs de ressources qui sont essentiels pour répondre aux besoins en matière de fiabilité ou aux objectifs plus larges du gouvernement.

En avril 2022, le gouvernement a pris un décret et publié une directive ministérielle à l'intention de la Commission de l'énergie de l'Ontario (CEO), qui ont été approuvés par la lieutenante-gouverneure en conseil, afin d'accélérer la création de nouveaux projets d'infrastructure de transport d'électricité dans le sud-ouest de l'Ontario. Cette nouvelle infrastructure de transport apportera de l'électricité à la région afin de soutenir son développement économique, en particulier l'expansion de la chaîne d'approvisionnement des véhicules électriques.

La centrale électrique de Brighton Beach est une centrale à cycle combiné au gaz naturel située à Windsor, en Ontario. Les rapports annuels d'acquisitions (RAA) de 2021 et de 2022 de la SIERE ont révélé que même si les projets d'infrastructure de transport sont en cours d'élaboration, il est nécessaire de passer un nouveau contrat avec la centrale de Brighton Beach, car elle est particulièrement bien placée pour répondre aux besoins en matière de fiabilité dans la région de Windsor-Essex. Il s'agit notamment de s'assurer que la région dispose de l'électricité dont elle a besoin pendant les périodes de pointe et de soutenir l'intégration de la production d'énergie renouvelable intermittente déjà en place.

La SIERE estime qu'une fois les projets d'infrastructure de transport terminés, la capacité de la région pourrait faire l'objet d'un processus d'approvisionnement en mode concurrentiel.

Le gouvernement réalise que le réseau d'électricité de l'Ontario évolue et qu'il doit continuer de se tourner vers des sources d'approvisionnement souples et non émettrices. Conformément aux objectifs du Plan environnemental pour l'Ontario, le gouvernement continue de proposer de nouvelles technologies et des possibilités de réduction des émissions dans le secteur de l'électricité.

Parallèlement, dans l'étude sur les voies de la décarbonisation menée en 2022, la SIERE a conclu que même si la majeure partie de la demande croissante en électricité de la province d'ici 2035 peut être satisfaite grâce à l'utilisation de ressources non émettrices, l'élimination à court terme de la production d'électricité au gaz naturel du réseau d'électricité de l'Ontario non seulement entraînerait des pannes rotatives, mais nuirait également aux efforts d'électrification et de réduction des émissions dans la province en rendant l'électrification beaucoup plus coûteuse.

L'Ontario doit disposer d'un approvisionnement fiable en énergie propre et abordable pour pouvoir répondre aux besoins d'une économie qui s'électrifie, y compris dans les secteurs des transports, de l'acier et autres.

Le gouvernement est conscient du fait que d'autres mesures devront s'ajouter à celles qui sont décrites dans la présente directive. La SIERE et le ministère de l'Énergie continueront de collaborer pour veiller à ce que le réseau d'électricité de l'Ontario demeure prêt à répondre aux besoins des résidents et des entreprises de la province.

DIRECTIVE

Par conséquent, en application des pouvoirs qui lui sont conférés par l'article 25.32 de la Loi, le ministre ordonne par les présentes à la SIERE ce qui suit :

1. La SIERE conclura un contrat d'approvisionnement avec Brighton Beach Power L.P., faisant affaire sous le nom d'Atura Power, pour la centrale de Brighton Beach, selon des modalités qui sont sensiblement conformes à l'ébauche de la liste de modalités datée du 12 octobre 2022, avec les changements subséquents décrits dans la note de service qui m'a été soumise le 14 avril 2023 et qui seront intégrés au texte définitif du contrat.

2. Le contrat d'approvisionnement décrit au paragraphe 1 doit comprendre ce qui suit :

    a. Une durée de validité du contrat qui va du 16 juillet 2024 au 15 juillet 2034.

    b. Des dispositions exigeant qu'Atura Power modernise la centrale afin de hausser sa capacité moyenne d'environ 42,5 mégawatts.

RENSEIGNEMENTS GÉNÉRAUX

La présente directive prend effet à la date de sa publication.

TAB 5

Annual Planning Outlook

Ontario's electricity system needs: 2024-2043

December 2022

ieso
Connecting Today.
Powering Tomorrow.

2 Demand Forecast

In this year's APO, electricity demand is ramping up more quickly and growing at a slightly quicker pace than the 2021 forecast, driven primarily by economic development and government policy on climate change. Notable updates include emerging electrification in the building, transportation and industrial sectors, with planned changes in new buildings in the City of Toronto; accelerated federal targets for EVs; and industrial sector electrification projects.

Continuing trends highlighted in prior outlooks include steady growth in the residential and commercial sectors, industrial mining sub-sector growth, the electrification of rail transit and the assumed continued delivery of conservation programs beyond the existing conservation framework period.

Forecasting electricity demand is a challenging exercise as it incorporates uncertainties about future events, including economic growth, changing customer preferences and a rapidly evolving policy environment. The uncertainties associated with any forecast will naturally increase with the length of the outlook period and reflect the interdependencies of underlying assumptions. The demand forecast presented here therefore includes the most current economic and demographic projections, as well as announced projects and policy known of at the time of forecast modeling.

2.1 Overview

The long-term demand forecast informs system reliability and investment decisions and sets the context for the APO, AAR and the bulk power system planning process.

Future electricity demand is affected by many factors, including but not limited to the state of the economy, population, demographics, technology, energy prices, input fuel choices, equipment-purchasing decisions, consumer behaviour, government policy and conservation.

Since 2020, Ontario has experienced significant fluctuations in electricity demand as a result of the COVID-19 pandemic and resulting economic recession and recovery, including potential permanent and structural changes to the economy, which were reflected in the 2020 and 2021 APOs.

In this year's APO, the demand forecast continues to reflect the economic recovery and emerging electrification initiatives begun in 2021, leading to higher electricity demand in the short, medium and long term relative to today's levels.

The forecast exhibits strong and steady growth through the end of the 2030s, fueled primarily by industrial sector development in the mid-2020s in mining, steel, EV battery and hydrogen production; agricultural sector greenhouse construction; and transportation sector electrification, before moderating in the early 2040s. Although the exact magnitude and timing of these demands are uncertain, it is clear that the province has entered a period of demand growth. The system is forecast to transition to a winter peak in 2036 from overnight EV charging demand coinciding with the winter system peak, and reduced overall summer peaks from slowing summer demand growth in the agricultural sector.

Overall net energy demand is projected to be 147 terawatt-hours (TWh) in 2024, increasing by an average of almost 2 per cent per year over the outlook period to 208 TWh in 2043, for a total increase of 60 TWh.

Summer and winter peak demands are expected to experience an average growth rate of approximately 1.2 and 1.8 per cent, respectively. Summer peak demand is projected to be 24.6 gigawatts (GW) in 2024, increasing to 30.7 GW in 2043, while winter peak demand is projected to be 22.6 GW in 2024, increasing to 31.5 GW in 2043.

Figure 1 illustrates the forecasted changes in energy demand over the planning horizon. Figure 2 shows summer and winter peak demand.

Figure 1 | Annual Energy Demand

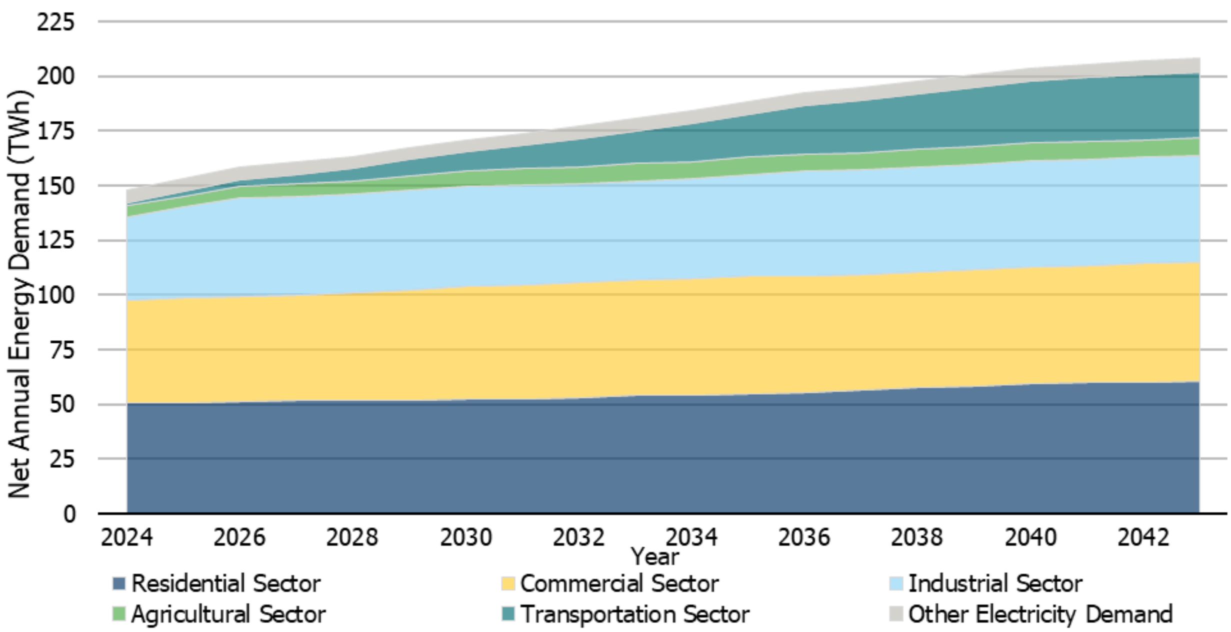
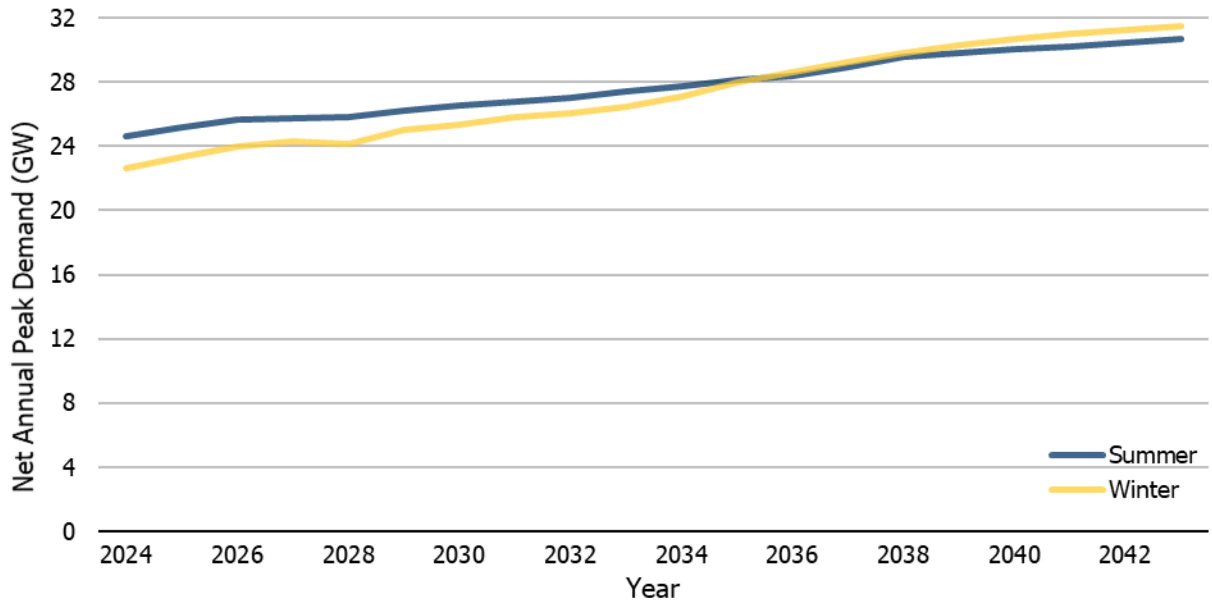


Figure 2 | Seasonal Peak Demand



A significant change in system demand forecasted over the course of the outlook period is the change in daily system load profiles attributed to substantial differences in electricity-consumption patterns expected over the course of the next 20 years. A variety of forecasted changes will influence the shape of the daily demand curve – including year-round battery EV charging and an increase in winter-season electric space heating in the City of Toronto – that each result in heightened demand in the evening-to-dawn periods.

Increased agricultural greenhouse consumption will also impact the daily demand profile, as its consumption is greatest between late evening and late morning, with lower consumption in the afternoon and early evening. Additionally, the connection of multiple large industrial facilities will cause the profile to shift upward significantly.

Figure 3 and Figure 4 illustrate the forecasted changes in hourly energy demand in a typical mid-winter and mid-summer business day over the planning horizon.

TAB 6

Decarbonization and Ontario's Electricity System

Assessing the impacts of phasing out natural gas generation by 2030

OCTOBER 7, 2021

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The Fundamentals of Reliability

Ontario's electricity system is a large, dynamic and interconnected machine with many factors working together to ensure the reliable operation of the grid.

To ensure that the right amount of electricity is available when and where it is needed, the IESO forecasts supply and demand, plans for future system needs, acquires supply resources, procures various electricity services to support reliability, and recommends the development of transmission infrastructure. On a real-time basis, the IESO's control room operators administer the wholesale market to efficiently match supply to demand to keep the grid reliable.

In Ontario, gas generation plays a crucial role in the reliability of the electricity grid. It provides a range of services that no other resource today can provide on its own, including producing large amounts of power to meet high demand, and running for extended periods when other resources are not available.

Elements of a Reliable Electricity System

Some of the most important elements of a reliable electricity system are capacity, energy, other ancillary (or reliability) services, and transmission infrastructure. As a result, a supply mix must be able to provide for all these specific needs:

- **Capacity** is the ability of a supply resource to deliver energy – either a generator that increases its output or businesses, institutions or aggregated homeowners that can reduce consumption when needed. To plan a reliable electricity system, the IESO must ensure that adequate capacity is available to supply demand throughout the year, including during peak times.
- **Energy** refers to actual electricity output over a specific period of time.
- **Ancillary Services** – also known as reliability services – are critical to the reliable operation of the grid, and include things like frequency regulation and voltage control.
- **Transmission Infrastructure** delivers electricity from generators along high-voltage power lines to consumers – a key consideration as supply is often limited by where it can be located.

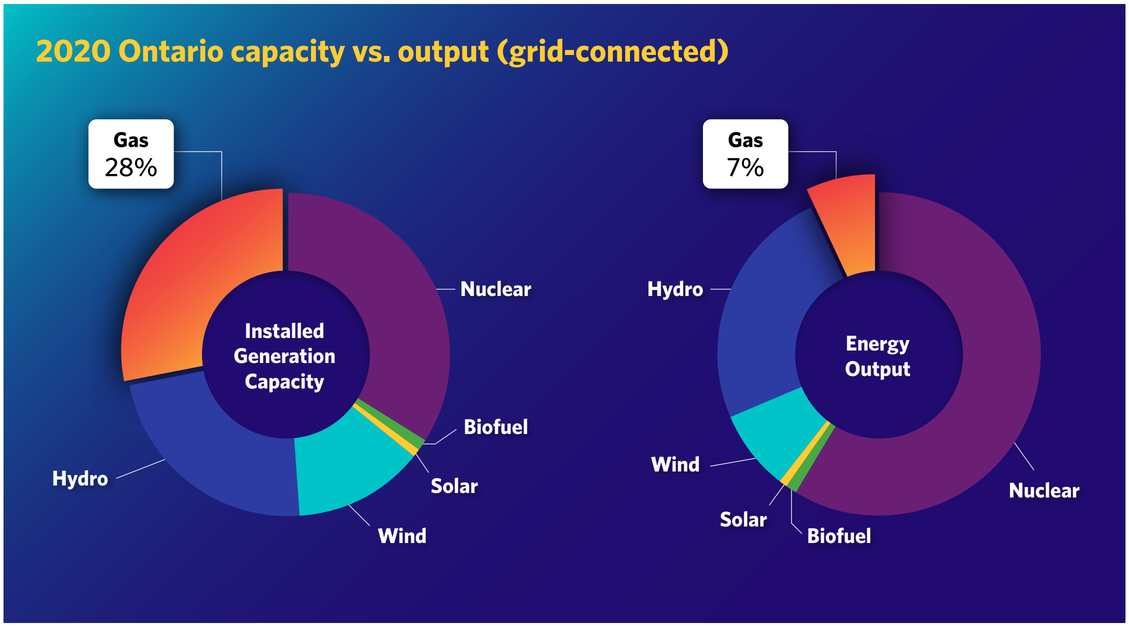
Long-Term Planning

Planning for electricity needs 10 or 20 years into the future requires careful consideration of many different factors that influence both supply and demand. Building new transmission infrastructure and new generation takes many years, with time needed to plan, obtain necessary regulatory and environmental approvals, engage with affected communities, and then build and integrate the resources into the provincial grid.

The IESO's Annual Planning Outlook (APO) provides a 20-year forecast for Ontario's electricity system. The outlook includes projected electricity demand, a resource adequacy assessment, transmission considerations, and performance indicators, such as an emissions outlook. It also identifies the province's energy and capacity needs.

A Diverse and Flexible Supply Mix

Diversity in energy supply strengthens the reliability and resilience of Ontario's power system, as different types serve different functions in order to meet needs. No single energy option can meet all system needs at all times. Maintaining a diverse supply mix, where the different forms of supply complement each other, is an effective way to balance supply and demand to maintain the reliability of Ontario's power system.



The province's demand for energy can fluctuate throughout the day by as much as 10,000 MW from low to peak times – requiring different energy resources to perform different roles. Some sources are needed to produce a constant supply of energy, while others increase or decrease in step with second-by-second changes on the system.

In Ontario, different forms of supply offer different operating characteristics.

- Nuclear and "run-of-the-river" hydroelectric generation provide constant, steady power 24 hours a day.
- Wind and solar offer variable output depending on the wind and the sun, but can provide some flexibility by reducing production when active.
- "Peaking" hydro generators are able to store water and are very flexible, increasing and decreasing their energy output as needed to match fluctuating demand.
- Imports from neighbouring jurisdictions also play a critical role in maintaining reliability, bringing in power when supply conditions are tight.
- Demand response – energy consumers who reduce energy use when needed – can help reduce peaks on short notice.
- Gas generation has a unique range of operating characteristics needed for the reliable operation of the power system.
- Storage provides the ability to capture excess energy and reinject it into the system when supply is low.

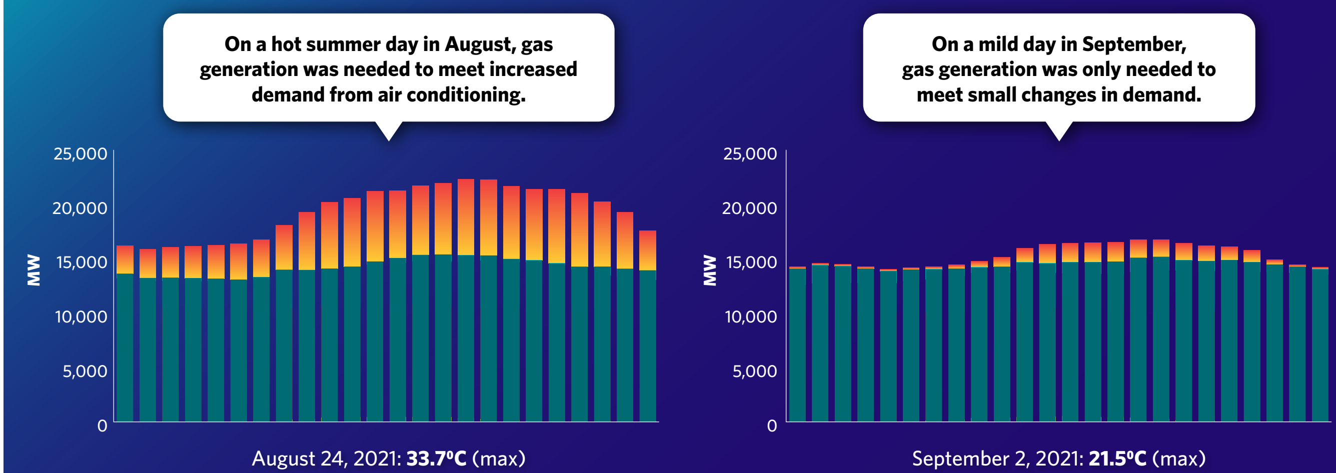
Standards for safety and reliability

As system operator, the IESO is the Reliability Co-ordinator for the province. It is accountable for following reliability standards for planning and operating within the interconnected North American bulk electric system.

The Role of Natural Gas in Ontario

While gas generation comprised roughly 28 per cent of the province's production capacity in 2020, it generated just seven per cent of energy used. As a readily available fuel source in Ontario, it provides energy consistently and confidently when it is needed most. As a result, it provides almost three quarters of the system's ability to match supply and demand under all conditions, a reliability service known as flexibility.

Gas generation helps meet peaks on hot summer days

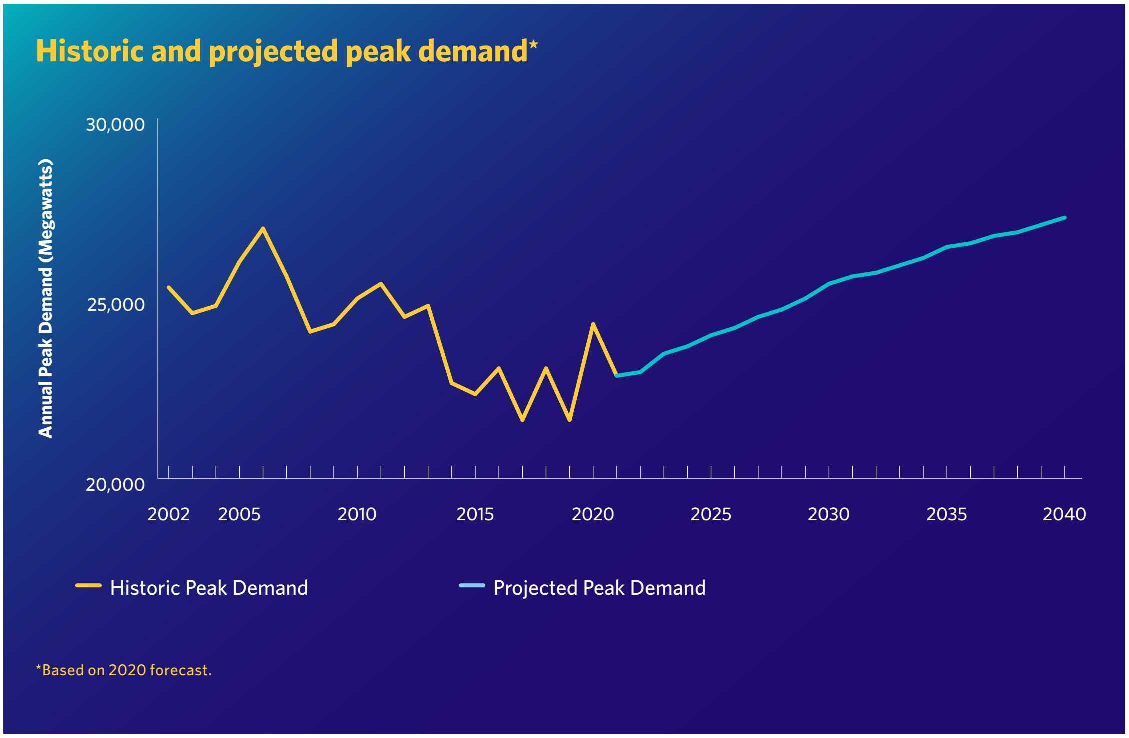


Here are the ways gas generation supports grid reliability:

- With Ontario's robust gas supply infrastructure, gas generation can provide continuous energy when needed as it is generally available at all times of the day throughout the year, under all weather conditions.
- Given its flexibility, gas generation can be ramped up or down within minutes to follow sudden or unexpected changes in demand or in the availability of other generators. This is important when managing the ebb and flow of wind and solar generation and the constant demand changes in the system.
- Gas plants are generally located near large population centres to support local power needs, avoiding the need for potentially expensive or disruptive transmission projects.
- Gas also provides reliability services that help stabilize voltages and frequencies on the transmission grid. Often, these services are also needed close to population centres.

Ontario’s Future Supply Needs

After years of strong supply, Ontario is now entering a period of growing electricity needs – most immediately and significantly to meet the need for capacity at times of peak demand, but also to satisfy overall energy requirements towards the end of the decade.



On the demand side, needs are driven by economic growth and electrification. Supply shortfalls arise out of expiring contracts with existing facilities, the retirement of Pickering Nuclear Generating Station and refurbishments to extend the life of other nuclear units in the system.

As electricity demand increases and nuclear production decreases, the IESO expects production from existing gas-fired generation to increase in future, depending on the pace of economic growth.

The Results

IESO modelling and simulations show that a reliable electricity service cannot be maintained, nor can the system support further electrification or accelerated economic growth if gas generation is phased out by 2030. Even under the most optimistic scenario, the IESO would frequently need to resort to emergency actions such as rotating blackouts to manage energy shortfalls.

Despite Ontario's extensive experience with various supply resources – including renewable generation – developing and building a mix of clean and cost-effective technologies at the scale needed to replace gas generation by 2030 would not be feasible. This would exclude using significant quantities of new hydro and nuclear capability that require more time to build, something to be considered for longer-term zero-emission targets.

A 2030 phase out would require incorporating much larger amounts of established resources, such as wind, solar and demand response, onto the grid. Higher amounts will present more risk, as solar and wind are variable and cannot always produce electricity when needed.

It would mean assuming the availability of certain emerging resources that are not fully tested in the Ontario context, such as a fully operational small nuclear reactor and new storage technologies. Once proven at a commercial level, these technologies can become integral components of the power system of the future.

Ontario would also need to lock in far greater amounts of year-round imports from Quebec that the province currently cannot supply, requiring both Ontario and Quebec to undertake lengthy and expensive transmission expansions specifically to meet Ontario's needs.

There is also the challenge of managing multiple infrastructure projects at the same time. Whether all these projects could be completed by 2030 would depend on the availability of capital, skilled workers, supplies and equipment.

And finally, the minimum amount of investment required to accomplish this effort as it is currently laid out is estimated to be more than $27 billion, increasing residential bills by 60 per cent.

All this would need to be considered as the IESO projects the need for further electricity supply that will grow throughout this decade and beyond, driven by increasing electricity demand, the expiration of generation contracts, and nuclear refurbishments and retirement.

The Replacement Supply Mix

In assessing the impact of a complete phase-out of gas generation, the IESO constructed a portfolio of replacement supply resources taking into account the varying operating characteristics of each.

In this scenario, new wind, solar, nuclear and imports would provide the bulk of the province's incremental energy needs. Storage and demand response could provide further additional capacity and help balance periods of excess baseload generation or insufficient supply. Energy efficiency would help reduce growing energy consumption.

Given the short timeline associated with a 2030 phase out, the scenario excluded significant quantities of new hydro and nuclear capability that require more time to build, something to be considered for longer-term net-zero targets.

Provincial wind capacity on the grid would double from existing levels, while solar capacity would also increase by an additional 843 MW. While the IESO has experience with these resources, higher amounts will present more risk, as solar and wind are variable and cannot be counted on to produce electricity when needed. This will also present administrative and operational challenges that would be very difficult to overcome.

This supply mix also assumes the availability of certain emerging resources that are currently untested. For example, a limited amount of new nuclear capacity would come in the form of a small modular reactor, which is currently in development in Ontario and expected to be in service by 2028. Once proven at a commercial level, these technologies can become integral components of the power system of the future.

The scenario also considers energy-efficiency savings beyond those identified in the 2020 APO. Enhanced programs with higher incentive levels could tap into the greater conservation potential in the province, delivering an additional 9 TWh in reduced demand by 2030.

Firm energy imports from Quebec with significant hydroelectric portfolios would provide 3,300 MW of capacity year round. While Ontario already imports and exports electricity on an economic basis with its neighbours, "firm" imports would lock in this capacity so that it could not be offered to other jurisdictions.

Establishing additional firm imports from Quebec will be particularly challenging. Quebec is currently an importer of electricity in winter, where the majority of residents use electricity for home heating, and will require additional capacity to meet future domestic demand. Quebec would need to expand its hydroelectric and transmission system to meet Ontario needs. Similarly, Ontario would need to build out its transmission system to deliver imports to major centres of consumption across the province – at a cost of $1 to $1.5 billion.

This portfolio of resources, along with the assumptions presented, satisfied high-level reliability requirements for basic capacity and energy needs and cost effectiveness. This portfolio was then simulated to operate on an hourly basis to determine if it could reliably supply all energy needs at different times of the day, and different seasons, under changing operating conditions.

To address the need for more flexibility, the IESO looked at how storage and demand response could be scaled up to respond to changing system needs. Both supply options currently provide capacity to the system and offer great promise for the future. For example, at the request of the Ministry of Energy, the IESO is currently in negotiations to develop a 250 MW battery storage facility in Haldimand County – which, if successful, would result in one of the largest facilities in the world, providing valuable insights on operating grid-scale storage for the future.

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The challenge, however, is that storage does not actually produce energy and is limited by how long or how often it can support system needs. Storage – whether it's pumped storage or batteries – cannot inject energy into the system on a continuous basis as it needs to be replenished once depleted. The scenario calls for up to 47 hours of continuous output from storage. This amount of energy could only be provided by exceptionally large facilities – far beyond what could be available over the coming years.

From a high level, the scenario also assumes demand response capacity of 2,000 MW. This amount of capacity would require participating businesses to reduce their energy use during peak hours approximately four times a week – a level of disruption that would not be sustainable. Indeed, some activations would need to last tens of hours.

While the portfolio can provide enough capacity and energy to meet system needs in its totality, it would not be able to deliver energy precisely when it is needed if stressed by sustained extreme weather and equipment failures.

As a result, IESO system operators would need to activate emergency actions such as conservation appeals, voltage reductions and rotating blackouts to maintain overall reliability. These periodic shortfalls would total 500 GWh, roughly the same amount of energy needed by a city the size of Stratford over the space of a year.

Other Supply Needs

Not all electricity services are about providing large amounts of energy. The IESO also requires specific types of grid support to ensure a reliable service.

Many energy suppliers – including gas generators – step in on short notice to supply energy for unforeseen events like extreme weather conditions and equipment failures. These suppliers provide operating reserve and are available on call to ramp up production, often within minutes, to meet changing system needs. Storage technology is well-suited to provide this service.

Reliability also depends on a number of finely-tuned services that are critical to maintaining voltages, the force that drives current along transmission lines, and frequencies, which keep voltages stable. Gas generators provide frequency support and are particularly well suited to providing active and reactive power to support voltages. Without these services, the system would collapse. The model was not able to adequately provide for these needs, and would require further analysis to determine how to maintain system stability.

Transmission Requirements

Where replacement supply is located is just as important as how much is built. As electricity planners, the IESO looks at how electricity supply is delivered to load centres to assess the maximum amount of power that can be safely delivered along transmission lines.

Much of the 11,000 MW of existing natural gas-fired generation is located in or around the GTA, with the balance primarily in western Ontario. Given the replacement supply mix, it would not be practical to site large wind and solar facilities in large urban or suburban areas given the amount of land they require. Imports from Quebec would necessitate additional pathways throughout the province.

Some natural gas plants are strategically located to supply specific local needs. Any transition of the system to other forms of supply must also take these regional needs into account, including:

- Portlands Generating Station (GS) provides critical support to Toronto's downtown core. Without it, a new transmission corridor may be required.
- The retirement of Pickering Nuclear Generating Station will increase overloading of the transmission infrastructure in the area. Without support from Goreway GS and Halton Hills GS, other transmission enhancements would be needed to address this risk.
- The York Energy Centre plays a critical role in local reliability. New supply will likely be required in the area by 2030, even with this facility in service; without equivalent local generation, a new transmission corridor would be needed.
- Brighton Beach GS, East Windsor GS and West Windsor GS play a critical role in local reliability in Southwest Ontario, an area already experiencing significant load growth and the focus of ongoing transmission expansion.

Most importantly, transmission development takes time. It involves developing the designs and specifications, identifying appropriate sites and routes, extensive consultation, and finally constructing new assets. The lead time for the development of a new transmission project can be at least seven to 10 years.

Costs

Even though this supply mix could not be built within a 2030 timeline, and would not perform reliably, the IESO looked at a potential range of costs to acquire, build and connect this replacement supply in order to learn more about how future evolutions of the system would impact energy bills.

Overall, the capital investment required is estimated to be more than $27 billion – this includes the cost of constructing new supply, upgrades to transmission infrastructure and increasing investment in conservation programs.

This investment in supply mix, together with associated operating costs, will result in an annual system cost increase of $5.7 billion by 2030. As a result, this gas phase-out scenario would increase residential bills by 60 per cent – almost $100 a month for the average residential consumer.

These costs are significant, yet the best way to evaluate the effectiveness of the scenario might be to look at the net cost of carbon reduction. In this case, removing all gas generation from the electricity system would cut carbon emissions in Ontario by 12.2 Mt per year by 2030, and result in Ontario ratepayers paying $464 per tonne of carbon. For comparison, the cost of carbon reduction in the steel sector, based on publicly announced funding, is roughly $14 a tonne.

Indeed, Save on Energy conservation programs are also more cost effective at reducing GHG emissions than phasing out gas generation from Ontario's electricity grid. For commercial and industrial businesses looking to upgrade to more efficient lighting and equipment, reducing carbon emissions will save money.

From this lens, a gas phase-out strategy by 2030 provides a very poor return on investment, and suggests that it would be more cost-effective to direct spending into broader carbon reduction strategies that produce much greater impacts.

TAB 7

IESO Resource Adequacy Update – May 16, 2023

Overview

To meet the significant electricity system needs expected over the next decade, the IESO is moving forward with the largest procurement of energy storage in Canada – with 739 MW of new capacity slated to connect to the grid by 2026. These storage projects will be accompanied by 586 MW of expansions and upgrades at existing natural gas facilities – providing a cost-effective and timely solution to secure operational flexibility.

Together these procurements have been designed to strike a balance between ensuring system reliability as nuclear refurbishments take place and setting the stage for a robust storage fleet that will underpin the ongoing energy transformation.

The results of these competitive procurements have secured the first 1,325 MW of long-term capacity out of the 4,000 MW indicated as being needed in the 2022 Annual Acquisition Report. Coupled with the IESO's other resource acquisition initiatives, they demonstrate the important progress being made to meet Ontario's reliability requirements.

As outlined in the most recent Annual Planning Outlook, this capacity is needed to help meet shortfalls mid-decade that will arise as a result of nuclear retirements and refurbishments. It will also help address longer-term needs driven by electrification and economic growth, largely as a result of increasing electric vehicle adoption and investments in battery and automobile manufacturing facilities as well as mining operations.

The IESO's recent resource acquisition activities put Ontario on track to meet needs through 2028, including:

- The first 739 MW of new battery storage from seven facilities - ranging from 5 to 300 MW in size and representing significant economic interest from Indigenous communities. This procurement is still active with the potential for more projects to be announced later this summer;
- A 250 MW agreement for Oneida Energy Storage, slated to come into service in 2025;
- The acquisition of 295 MW through expansions at existing natural gas facilities, with contracts designed to align with proposed federal emissions regulations;
- Up to 291 MW in efficiency upgrades at existing natural gas facilities coupled with contract extensions to provide cost-effective reliability up to spring 2035;

- The highest capacity to date (roughly 1,400 MW) through the annual capacity auction, including a significant contribution from demand response, to meet system needs over the next year; and
- A new agreement for Brighton Beach Generating Station to continue operations and provide incremental capacity through an efficiency upgrade, addressing urgent regional reliability needs in the fast-growing Windsor area.

By taking a competitive and flexible approach, the current procurement has attracted considerable interest from storage developers, securing supply at cost-effective rates. Future competitive procurements will be informed by evolving market conditions, demand forecasts and how these projects progress.

To ensure that supply is available where it is needed most, the IESO is working with communities to understand and develop plans to meet local energy needs. The Province is also currently consulting with Ontarians on the IESO's Pathways to Decarbonization report, released last December, which explored options to develop a moratorium on new gas generation and move towards a decarbonized electricity system by 2050.

Securing new supply

With electricity demand forecast to grow at an average rate of two per cent a year for the next 20 years, the IESO is securing new capacity to meet those needs, taking into account the operating characteristics of each form of supply. Energy storage, for example, can react quickly to sudden changes in the system, providing some flexibility while reducing the need for emitting generation when demand is high.

- **Expedited Process**: Successful proponents to date are expected to provide 739 MW of non-emitting capacity from seven electricity storage facilities varying from 5 to 300 MW in size and to be in service no later than 2026. There are remaining storage proposals in the Expedited Process, which have the potential to receive financing from the Canada Infrastructure Bank. Any remaining successful projects will be announced early this summer. More than 25 communities have provided their support for storage proposals that have been submitted, and five of the successful proponents have 50 per cent or more economic interest from Indigenous communities.
- **Oneida Energy Storage facility**: The IESO has finalized a 20-year agreement for the 250 MW Oneida facility after direction from the Minister of Energy. The project also received support from the federal government and the facility is scheduled to be in service in 2025.
- **Long-Term RFP**: The engagement for the Long-Term RFP has begun and the procurement is expected to launch this fall, providing development time to build new resources or undertake expansions that can be in service no later than 2027.
- **Additional Future Needs**: Needs for capacity, energy and the characteristics that allow for the reliable operation of the system are expected to grow. Additional long-term procurements will address needs emerging in the early 2030s. The upcoming Annual Acquisition Report will outline the IESO's plans for the ongoing acquisition of supply for Ontario.

Leveraging Existing Assets

Leveraging existing facilities by providing new or extended contracts, as well as upgrading and expanding capacity, will be critical for reliability over the medium term. For example, natural gas generation will be essential to meeting summer peaks over this period, as emerging technologies mature to offset the role played by gas. Looking forward, it is expected that reliance on natural gas facilities will decrease over time and that they would eventually act as back-up supply.

Existing infrastructure will be used to help meet near and medium-term needs in the following ways:

- **Natural Gas Facility Upgrades**: Ontario is securing up to 291 MW of natural gas capacity from efficiency upgrades at existing facilities through the Same Technology Upgrades procurement. These facilities will upgrade existing equipment to provide additional capacity more efficiently to meet growing demand. Contracts with expiry dates prior to 2032 have been extended to 2035 to provide continued flexibility to the broader system and to meet local needs. Upgrades are a cost-effective, efficient and reliable way to prepare for coming needs, as they use a known technology with a long-established track record and provide significant ratepayer value.
- **Expedited Process**: 295 MW of natural gas capacity has also been acquired in the non-storage category of the Expedited Process through the addition of on-site expansions at the East Windsor and Greenfield South generation facilities. Municipal support has been provided for these projects. The expansion facilities will be eligible for contracts up to 2040 and will align with proposed federal regulations that allow for natural gas to operate as back up generation.
- **Brighton Beach Contract**: The IESO has also finalized a 10-year agreement for the continued operation of the Brighton Beach Generation Station, including a 42.5 MW efficiency upgrade for the facility, which will provide about 580 MW of urgently needed capacity in the Windsor area. The IESO expects that going forward, capacity for the region will be procured competitively.
- **Annual Capacity Auction**: The December 2022 auction secured 1,430 MW of supply for summer 2023 and 1,160 MW for winter 2023-2024. While the majority of the supply secured was from demand response from businesses, this year's auction secured capacity from a greater number of organizations and resources than in previous years, including imports from Quebec. Enrolments equalled more than double the megawatts needed, demonstrating the flexibility of the auction and the diversity of options available to meet short-term electricity system needs.
- **Small Hydro**: A new program to secure the capacity of existing small hydroelectric facilities is expected to launch this fall. The program is focused on ensuring these existing facilities can continue to operate, and provide value to the electricity system.
- **Biomass Facilities**: To address the needs of the forestry sector in northern Ontario and support a longer-term transition to alternative uses for waste biomass, a contract has been signed with Chapleau Cogeneration Facility until December 2027. The IESO is exploring possible options for signing new contracts for the Thunder Bay Resolute, Hornepayne, and Atikokan biomass plants.

Complementary Supply Options

Many of the IESO's ongoing activities focus on reliably advancing the transformation of the electricity grid. Significant investments in expanded conservation programs, hydrogen projects and other emerging technologies are complementing the IESO's ongoing work to pilot and enable new solutions for generation, demand response and energy management.

- **Energy Efficiency**: Ontarians continued to reduce their energy use in 2022 by over 850 GWh by implementing energy-efficient improvements through Save on Energy programs. As conservation will continue to play an important role in managing demand, the Ontario government announced last year a $342 million increase in funding. Four new and expanded SOE programs will deliver additional peak electricity demand savings of 285 MW by 2025 – including new and expanded incentives – many of which are targeted to consumers in areas where the system is constrained.
- **Hydrogen Innovation Fund**: Hydrogen resources have the potential to support Ontario's growing reliability needs in several ways, including with capacity and energy. Earlier this year, the Minister of Energy directed IESO to establish a $15 million Hydrogen Innovation Fund to support new and existing hydrogen projects as well as research studies that advance decarbonization and help drive broad emissions reductions. Through the fund, the IESO will be able to investigate, evaluate and demonstrate how these technologies can be integrated into Ontario's electricity grid for the purposes of balancing and strengthening the system.

TAB 8

Need for Bulk System Reinforcements West of London

September 2021

1. Executive Summary

This report documents the results of a planning study the IESO has undertaken to assess the reliability of the bulk transmission system in the West of London (WOL) area. The WOL area encompasses a 230 kV and 115 kV high voltage network in southwest Ontario, stretching from outside the western edge of the City of London, to the City of Sarnia in the northwest, and to the City of Windsor in the west. This system interconnects large generators in the Lambton-Sarnia and Windsor areas, with existing load centres and encompasses the growing Kingsville-Leamington and Chatham-Kent areas. It provides four interconnection points with Michigan's power system via Windsor and Lambton-Sarnia. The area is also connected to the 500 kV system at Longwood TS, within the Municipality of Strathroy-Catadoc near the City of London, providing a strong path between the WOL area and the rest of the province.

Electricity demand in Windsor-Essex and the Chatham-Kent area (referred to as the "Focus Area") within WOL is growing at a rapid pace. This growth has been driven by strong indoor agricultural growth, mainly vegetable greenhouses, as well as in part, cannabis, specifically through existing greenhouses switching to lit indoor facilities, expansion of greenhouse facilities, and supplemental load to support the agricultural sector. The agricultural sector demand in the Focus Area is expected to increase from a winter peak of roughly 500 MW today to 2,300 MW in 2035 – this is the electrical equivalent of adding a city the size of Ottawa. Due to this rapid growth, planning in southwestern Ontario has been occurring on a continuum over the last five years. In 2019, the IESO released the 2019 Windsor-Essex bulk study, which made recommendations for supplying this growing demand. This report is the latest in a line of ongoing analysis at the bulk system and regional level.

Based on the reference forecast, and assuming the transmission recommendations from the 2019 Windsor-Essex bulk study come into service as planned, there will still be a winter need for additional supply to the Focus Area starting in 2024 that reaches 2,050 MW by 2035. This supply need assumes that when generation contracts expire, the resources are not reacquired, and export capability on the Ontario-Michigan intertie, J5D, is maintained with all transmission elements in-service. Typically, the system is planned to maintain export capability when all transmission elements are in service, not when transmission elements are out of service. The supply need is specified assuming resources are not reacquired since reacquisition is a decision that should be made as per the IESO's Resource Adequacy Framework and should not be presupposed. Hence, the statement of supply need should not assume resources are reacquired.

In response to this growing need, the IESO has adopted a multi-pronged approach using a combination of transmission reinforcements, resources, and targeted energy efficiency programs.

Due to the lead time required to implement solutions to provide the additional supply required and support the economic growth in the near-term (2021-2027) and mid-term (2028-2029), the IESO recommended actions ahead of the publication of this report. This report will provide the need and rationale for the actions taken by the IESO, which were:

- On March 26, 2021, the IESO sent a letter to the lead transmitter in the region, Hydro One Networks Inc. ("Hydro One"), in order to inform them of the need for a new 230 kV double circuit line from Lambton TS southwards to Chatham SS (Lambton South line) and associated station facility expansions or upgrades required at the terminal stations. While Hydro One will initiate the work, engagement and related activities, it will be subject to all required Environmental Assessment, regulatory (e.g., Leave-to-Construct), and other approvals and permits; and
- On July 19, 2021, the IESO indicated, through the Annual Acquisition Report (AAR), an intention to begin bilateral negotiations for Brighton Beach Generating Station. This is an existing facility supporting the area's needs today, that has been identified as required to continue supporting this immediate localized need in the near-term until the transmission line recommended in the March 26, 2021 letter is in-service.

These actions will provide the required supply to the domestic load up to the year 2030. With these actions taken, the winter supply requirement for the Focus Area reduces from 2,050 to 1,100 MW in the year 2035.

To deliver the 1,100 MW of required supply, this plan recommends a single circuit 500 kV transmission line from Longwood TS to Lakeshore TS, as well as 550 MW of local resources. The transmission line is required to be in service by 2030. The 550 MW of local resources is the total amount required by 2035, where the requirement progressively increases up to this level starting in 2030. It can be met by reacquiring resources that exist today whose contracts have expired between now and 2035, and/or by acquiring new resources.

The IESO is committed to transitioning to the long-term use of competitive resource acquisition mechanisms to meet Ontario's reliability needs. As such, the long-term resource requirement for 550 MW will be met by using the mechanisms outlined in the IESO's Resource Adequacy Framework, which will be outlined in future AARs.

The IESO will work with entities applying to the Ontario Energy Board (OEB) to become the transmitter for this project as well as stakeholders and communities, to implement the recommended 500 kV transmission line.

This planning report also identifies interdependencies between this provincial/bulk level plan and the regional electricity plan being developed in parallel with local distribution companies (LDCs) in the area – through the on-going Windsor-Essex Regional Addendum study and Chatham-Kent/Lambton/Sarnia regional planning cycle. In particular, depending on where the 550 MW of recommended capacity is located within the Focus Area, a double circuit 230 kV transmission line between Windsor and Lakeshore may be needed to address local reliability issues and maintain interchange capability with Michigan under all elements in-service. Furthermore, the IESO will continue to monitor and explore opportunities for conservation efforts targeted to the Focus Area, including cost-effective energy efficiency measures and pilot projects that help mitigate needs and manage reliability issues until bulk reinforcements are in-service.

Finally, in addition to the reliability of the supply to the Focus Area, this report also explores the reliability of the supply to the larger WOL area, which encompasses the Focus Area. A review of the supply to WOL area was necessary not only because of the forecast load growth in the Focus Area, but also because 85% of the nearly 5,000 MW of supply resources within WOL have contracts expiring by the end of the decade.

The study of the supply to the broader WOL area concluded, that 1,425 MW of local resources must be acquired in the WOL area to reliably supply the region in 2035, where the requirement progressively increases up to that level starting in 2030. This is in addition to what was recommended in this report to supply the Focus Area. Similar to the recommendations made for the Focus Area, the need for 1,425 MW in WOL will be included in future AARs, can be met by reacquiring resources that exist today whose contracts have expired between now and 2035 and/or by acquiring new resources, and will be addressed using the IESO’s Resource Adequacy Framework.

7. Near- to Mid-Term Solutions

Section 6 indicated that additional supply to the Focus Area was needed to supply the forecast electricity demand from the agricultural sector. Section 6 also indicated that there is sufficient supply to the larger WOL area, if some the existing resources were reacquired and interchange capability is not maintained. Hence, this Section and Section 8 recommends the most effective solution to supplying the load in the Focus Area and then given that solution, Section 9 presents the amount of resources (existing resources that must be reacquired or new equivalent capacity) that is needed) to ensure adequate supply to the broader WOL area.

Due to the lead time required to implement solutions to meet the Focus Area's supply requirements in the near-term (2021-2027) and mid-term (2028-2029), the IESO recommended actions ahead of the publication of this report. This section provides the rationale for the actions taken by the IESO, which were:

- **Mid-Term Recommendation:** On March 26, 2021, the IESO sent a letter to the lead transmitter in the region, Hydro One, in order to inform them of the need for a new 230 kV double circuit line from Lambton TS southwards to Chatham SS (Lambton South line) and associated station facility expansions or upgrades required at the terminal stations. While Hydro One will initiate the work, engagement and related activities, it will be subject to all required Environmental Assessment, regulatory (e.g., Leave-to-Construct), and other approvals and permits; and
- **Near-Term Recommendation:** On July 19, 2021, the IESO indicated through the AAR an intention to begin bilateral negotiations for Brighton Beach Generating Station. This is an existing facility supporting the area's needs today, that has been identified as required to continue supporting this immediate localized need in the near-term until the transmission line recommended in the March 26, 2021 letter is in-service.

7.1 Near-term Options Analysis

As outlined in Section 6.1.1, a 640 MW supply need into the Focus Area emerges in 2024 based on the Reference Need – which considered resources reaching contract expiry and maintaining full interchange capability. Even if the need to maintain interchange capability is relaxed (Reference, Sensitivity B), and remedial action schemes continued to be relied on, a 240 MW supply need still emerges in 2024.

The need is immediate, triggered by a single contract expiry, and is large in magnitude due to the ongoing and forecast load connections in the Focus Area. The lead time would significantly limit potential cost-effective options (i.e. insufficient time for large transmission reinforcement or for initiating a competitive procurement). The initial magnitude of the need when it emerges and impacts of forecast growth in the area, limit the pool of technically feasible options, even if lead time were not an issue.

Reference, Sensitivity B (considering resources reaching contract expiry but not maintaining full interchange capability) illustrates the minimum capacity and energy requirements in order to defer the need from 2024 to early 2028, when transmission enhancements or other long lead time solutions could be implemented, is 525 MW of capacity and 340 GWh of energy.

In order to determine the most cost-effective way to defer the need, the following options were considered:

1. **Load transfer** – This option considers the ability to transfer load outside the Focus Area.
2. **Local resources** – In this option, the identified capacity and energy needs are met through local resources, either through existing resources whose contracts are expiring between 2024-2027 and/or an equivalent amount of new capacity located within the Focus Area.

As discussed, new transmission would not be implemented in time to meet the 2024 need date. However, load transfers would be a low cost option that could be implemented by 2024. Typically load transfers occur between adjacent or proximate supply stations via the local distribution system, or in some cases by reconfiguring the transmission system (i.e. creation or removal of normally open points (switches) on the lines which could transfer load between pockets of the transmission system). In this case, the supply need extends across the entire Focus Area (Windsor-Essex and Chatham-Kent). Currently, there is the ability to transfer up to 50 MW of the 115 kV load in the Focus Area to an existing 115 kV circuit connected to Scott TS in the Lambton-Sarnia area. However, this creates operability and low voltage concerns connecting load radially along this distance. It is preferable to retain the capability to transfer load during outage conditions for the purpose of load supply. Load transfer of any significant amount of capacity is not technically feasible, based on the lack of available transmission infrastructure to support such a long-distance transfer.

For a resource to meet the need, it must be located in the Focus Area, ideally close to the greenhouse loads and directly connected to an integrated transmission station. They must also be capable of providing a significant energy component along with the required capacity since, until further transmission reinforcements are in place, energy availability within the Focus Area will be limited and worsen as resource contracts expire. Combined with insufficient lead time to carry out a competitive procurement, reacquiring existing resources with expiring contracts presents a cost-effective and least risk solution to ensuring the area's existing and growing needs will continue to be met in 2024.

Considering existing resources supporting the Focus Area's needs today that would be coming off contract between 2024-2027, it was identified that Brighton Beach GS could address the local need while system reinforcements are being constructed to meet the identified deferred 2028 need date. Like Lennox GS, it represents the only supplier in the local area with requisite scale to address this immediate need, offering 588 MW of capacity (approximately 500 MW of unforced capacity[27]) to support the growing loads in the Focus Area. This is an existing facility supporting the area's needs today, which will come to the end of its contract in 2024, but has been identified as being needed to ensure the reliability of the area as an interim solution to address the near-term needs.

[27] Unforced capacity, or UCAP is defined in the AAR as a resource's installed capacity that accounts for seasonal and ambient weather conditions, further reduced by forced outages.

As a result, it is recommended that the IESO plan to begin bilateral negotiations for Brighton Beach GS, until the mid-term recommendation is in-place. By this time, it is likely that competitive mechanisms will help address this growth, offering an opportunity for a wider range of suppliers to contribute through a medium-term or long-term mechanism to meet the mid- to long-term needs.

7.2 Mid-term Option Analysis

Similar to the near-term, the options identified to meet the mid-term needs prioritized the supply of Ontario loads, given known resource constraints – i.e., considering resources reaching contract expiry, but not maintaining interchange capability (Reference, Sensitivity B). As per the near-term options analysis, it was then assumed that resources reaching contract expiry (i.e. Brighton Beach GS) continue to operate until 2028. Thus as outlined in Section 6.1, a supply need into the Focus Area re-emerges in 2028 and grows to approximately 930 MW by 2029. This need is driven by the limitation of the FIC interface.

Thus options considered to address the mid-term needs involve improving the FIC interface limit by addressing the most restrictive path – Lambton to Chatham, or new local generation within the FIC boundary. These options are described below:

1. **Reinforce the existing Flow into Chatham interface (the Lambton South Line)** – In this option, a new 230 kV double circuit transmission line from Lambton TS to Chatham SS forms the next stage of transmission development in the area. The approximately 60-km transmission line would increase the FIC transfer capability to 2,300 MW (a 950 MW increase from 1,350 MW) and increase the deliverability of Lambton-Sarnia resources.
2. **No transmission expansion** – In this option, the identified capacity and energy needs are met through the addition of the least-cost resource alternative, located between Chatham SS and Lakeshore TS. This analysis included 950 MW of additional resources staged in as needs grow, corresponding to the increased capability achieved by the transmission reinforcement in option 1.

Both options increase the supply capability in the Focus Area by 950 MW, which more than addresses the 2029 Reference Need, Sensitivity B.

Note that in option 1, the Lambton South line addresses the upstream FIC constraint and enables the full transfer capability of the previously recommended Chatham west lines and Lakeshore TS, resulting in a WOC limit of 1,950 MW (winter capability).

Note that option 2 was evaluated considering two cost benchmarks based on resource types capable of supplying the magnitude of energy and capacity required - a new natural gas-fired simple cycle gas turbine (SCGT), and an energy storage facility.[28] However, the ultimate resource type could be a combination of various generation and/or storage technologies, depending on a variety of factors including the profile of energy required to meet this need, impact of demand response on greenhouse crop growth cycles, and ratepayer value.

Other options, including wind, solar, and renewables in combination with storage were considered as potential cost benchmarks for the analysis but would be more expensive than the resource options

[28] Refer to Appendix D for details on the resource cost assumptions.

TAB 9

Reliability Outlook

An adequacy assessment of Ontario's electricity system

April 2023 to September 2024

Connecting Today.
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5. Transmission Reliability Assessment

Ontario's transmission system is expected to continue to reliably supply province-wide demand for the next 18 months. However, electricity demand is growing significantly in certain parts of the province and, as such, a large number of outages will be needed to implement the bulk transmission system reinforcements and build the load stations needed to supply this increase in demand. Until this work is completed, managing the outages in these parts of the province will be challenging.

The IESO assesses transmission adequacy using a methodology based on conformance to established criteria, including the Ontario Resource and Transmission Assessment Criteria (ORTAC), NERC transmission planning standard TPL 001-4 and NPCC Directory #1, as applicable. Planned system enhancements and projects, and known transmission outages are also considered in the studies.

5.1 Transmission Projects

This section considers the information transmitters have provided with respect to transmission projects that are planned for completion within the next 18 months. The list of transmission projects can be found in Appendix B1. Note that the planned in-service dates in this table and throughout this document are as of January 2023. These dates are subject to change as the COVID-19 pandemic may impact project logistics. Any changes will be communicated through subsequent Reliability Outlooks.

5.2 Transmission Outages

The IESO's assessment of transmission outage plans is shown in Appendix C, Tables C1 to C11. The methodology used to assess the transmission outage plans is described in the Methodology to Perform the Reliability Outlook. This Outlook reflects transmission outage plans submitted to the IESO as of February 14, 2023.

5.3 Transmission Considerations

The purpose of this section of the report is to highlight projects and outages that may affect reliability and/or the scheduling of other outages, and to consolidate these considerations by zone. For more information about the IESO's transmission zones and interfaces, please see the Transfer Capability Assessment Methodology.

Bruce, Southwest, and West Zones

Significant growth in the Windsor-Essex region has led to the capacity of the existing transmission system in the area being exceeded. Market rule exemptions are in place, acknowledging this exceedance. Until system reinforcements are completed, operating the area requires exceptional operational plans and control actions, which can include customer load shedding in certain situations.

The new switching station Lakeshore TS at the Leamington Junction has been installed and all four of the existing circuits have been cut over. All new loads connected to the first South Middle Rd. load station by radial circuits from Lakeshore TS, are now being supplied. The Lakeshore Remedial Action Scheme (RAS), one of the largest in the province, is also in-service. Work is on-going for for the connection of Mastron II CTS, expected to be in-service by Q3 2023, at which point the area will be required to operate to more stringent contingencies to meet NPCC security requirements.

The following outages will impact the flow out of the Bruce zone:

- A planned five-week outage starting April 27, 2023, on circuit B501M
- A planned one-week outage starting June 23, 2023, on circuit B561M
- A planned three-week outage starting August 1, 2023, on circuit B502M, followed by another planned four-week outage starting August 21, 2023
- A planned five-week outage starting August 18, 2023, on circuit B560V

Toronto, East, and Ottawa Zones

Operational challenges due to high voltages in eastern Ontario and the Greater Toronto Area continue to occur during low-demand periods. High voltages are the result of lower minimum demand for electricity. The IESO and Hydro One have been managing this situation by removing from service certain 500 kV circuits, mainly in eastern Ontario and occasionally in the Bruce area during those periods. To address this issue on a longer-term basis, two 500 kV line-connected shunt reactors are being installed at Lennox TS. The first reactor has been installed and is in-service. The second reactor is expected to go into service in Q2 2023.

There are upcoming nuclear refurbishments of multiple units at Darlington with overlapping timelines. As a result, it will be increasingly challenging for market participants to take outages impacting the Flow East Towards Toronto (FETT) interface. Future planned outages, specifically those associated with the FETT upgrade project and the Bruce B station re-build, will necessitate enhanced coordination between transmitters and generators. Planned outages for certain windows may need to be rescheduled or rejected to ensure reliability.

Of particular note, the FETT Capacity Upgrade (i.e., Richview-Trafalgar Reinforcement) project to address future needs is underway; the project is expected to be in-service by Q1 2026.

The Hawthorne-Merivale transmission path supplies load in western Ottawa and delivers eastern Ontario resources, and imports from Quebec, to southern Ontario load centres. The reinforcement consists of upgrading the two 230 kV circuits between Merivale TS and Hawthorne TS, a length of 12 km. Hydro One began the project in 2022, with an expected in-service date of Q4 2023.

TAB 10

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

INTERROGATORY

Reference:

Procedural Order No. 4, December 14, 2022, page 3; Updated Application Exhibit E, Tab 1, Schedule 1, B. Project Economics, paragraph 4, page 3

Preamble:
In Procedural Order No. 4, which placed the proceeding in abeyance as of December 5, 2022, the OEB confirmed that the issue of the applicability of E.B.O. 134 and E.B.O. 188 is within the scope of the proceeding. The OEB stated:

"...the OEB is of the view that the economics of the project, the applicability of EBO 134 and EBO 188, and the extent to which contributions in aid of construction should be required are issues that are in scope for this proceeding. Enbridge may wish to consider whether to provide additional evidence on those issues as part of its proposed update to its application. Enbridge may also wish to consider whether it should be communicating with potentially affected customers regarding the position of some parties that contributions in aid of construction should be required."

In the updated application filed on June 16, 2023, Enbridge Gas addressed the issue of applicability of the E.B.O. 134 and E.B.O. 188 by stating that E.B.O. 134 is the appropriate economic test as the Project is entirely a transmission project.

As part of the EOI 2023, Enbridge Gas conducted outreach to customers who indicated their intention to submit an EOI bid to obtain customer's position on paying CIAC. Enbridge Gas asked these customers how a requirement for a CIAC may impact their demands for new/incremental service.

Enbridge Gas stated that the customers feedback was as follows:

• Customers submitting EOI bids for new/incremental service were generally doing so under the assumption that the OEB would apply the established regulatory framework for transmission system expansion projects, which does not require CIAC, consistent with similar projects constructed in the past. Customers generally indicated opposition to being required to provide CIAC to support transmission system expansion in this instance.

•No customer indicated that they would be willing to provide CIAC for a transmission system expansion project without understanding the magnitude of the CIAC and the unique justification for its selective application in this instance.

Question(s):

a) Please provide details on Enbridge Gas's customer outreach activities regarding the requirement for a CIAC including dates, method of communication, and information provided to customers.

b) Please advise whether any customers will be directly connected to the Project.

c) Please advise whether Enbridge Gas agrees that the Project almost entirely benefits identifiable contract customers.

Response:

a) As part of the 2023 EOI, Enbridge Gas conducted outreach to customers who indicated their intention to submit an EOI bid to obtain their position on paying a CIAC. Enbridge Gas asked these customers how a requirement for a CIAC may impact their demands for new/incremental service. This outreach was a result of the OEB's Procedural Order No. 4 dated December 14, 2022, which stated:[1]

> "Enbridge may also wish to consider whether it should be communicating with potentially affected customers regarding the position of some parties that contributions in aid of construction should be required."

Outreach occurred between February 15, 2023 and April 6, 2023.

There was no information sent to customers regarding the matter, and Enbridge Gas account managers were not provided with a script to deliver to customers. Rather, Enbridge Gas account managers sought customer feedback via verbal communication and recorded any feedback from customers. The customer feedback collected by Enbridge Gas account managers can be found at Attachment 1 to this response. Please note that Enbridge Gas is requesting confidential treatment of the names of customers in Attachment 1. A summary of the feedback back can be found at Exhibit A, Tab 4, Schedule 1, Paragraph 21.

Please also see the response at Exhibit I.SEC.5, part b) for instructions/guidance provided to Enbridge Gas account managers regarding the matter.

[1] OEB Procedural Order No. 4 (December 14, 2022), p. 3.

b) No customers will be directly connected to the Project.[2]

c) No, Enbridge Gas does not agree that the transmission Project almost entirely benefits identifiable contract customers. The very nature of a transmission pipeline is that it provides natural gas to a broad geographic region comprised of multiple distribution systems of which a large number of both contract and general service customers are served. Whereas distribution pipelines benefit a very specific customer or set of customers, a transmission pipeline provides benefits to a broad region. The proposed Project will enable the transportation of natural gas for the benefit of all natural gas customers within the Panhandle Market (including the Municipalities of Chatham-Kent, Lakeshore, Tecumseh, Windsor, LaSalle, Amherstburg, Essex, Kingsville and Leamington, St. Clair, and Dawn-Euphemia).

   The proposed Project partially alleviates the largest Panhandle System bottleneck (see Exhibit B, Tab 2, Schedule 1, pp. 13 - 14). Partial alleviation of the bottleneck improves the reliability of natural gas service for existing customers and will allow for growth among both existing and new customers on the Panhandle System. All customers benefit from alleviation of Panhandle System bottlenecks.

   Although the demand forecast is based on contract customers who responded to the EOI, these are not the only customers that will benefit from the capacity created. Customers that did not respond to the EOI will have the ability to connect to the system using any capacity that is available at the time of their request. The timing of when commercial, industrial, and power generation customers are in a position to express their needs for natural gas service do not always align with the timing of Enbridge Gas's EOI process. As a result, the EOI results are only a point-in-time snapshot of customer demand. As has been demonstrated over the last decade, both expected and unexpected growth in the Panhandle Market area has continued to materialize as new customers attach to the natural gas system. As these new customers request natural gas service, it is important that Enbridge Gas has the ability to accommodate them in a timely and economic manner.

   Transmission system capacity is available on a "first come, first served" basis. Once in service, the proposed Project will serve all existing and future customers whether or not they participated in the EOI.

   The capacity created by the proposed Project will also benefit new general service customers. The timing for the attachment of general service customers is dependent upon the planning and development of new residential and commercial buildings as undertaken by cities, municipalities, and developers. Since the Project will provide

[2] For clarity, the Project consists of the Panhandle Loop (i.e., 19 km of NPS 36 natural gas pipeline) and ancillary measurement, pressure regulation, and station facilities within the Township of Dawn Euphemia and in the Municipality of Chatham-Kent.

incremental capacity across a broad geographic region, it will benefit all new general service customers in that area by allowing Enbridge Gas to attach these new customers as they emerge.

Existing contract and general service customers will also benefit from the capacity created by the Project. These customers, which are already attached to the system, will have the ability to grow their natural gas use (and in some cases their businesses) by leveraging the capacity that is available after the Project is placed into service.

From an operational standpoint, the proposed Project also provides enhanced system reliability and redundancy to existing customers during non-peak times of the year. Once the proposed pipeline facilities are placed into service, they become a functional loop of the overall Panhandle System. Enbridge Gas cannot differentiate natural gas molecules as they flow through the transmission system, and as a result both new and existing customers will be served by both the new and existing transmission facilities. The proposed Project increases operational flexibility in the event of maintenance, in-line inspections or unplanned outage on the Panhandle System, including interruption of Ojibway supply.

From a broader economic perspective, as outlined at Exhibit E, Tab 1, Schedule 1, Paragraph 19, the transmission Project will also provide direct and indirect economic benefits to Ontario estimated at approximately $257 million. This figure does not include the similar direct and indirect economic benefits to Ontario when both existing and new natural gas customers invest and grow their operations. Within EOI bid responses, customers indicated that total direct capital investments into their business operations in Southern Ontario related to their incremental natural gas needs would exceed $4.5 billion.

Enbridge Gas is aware of an increased demand for natural gas in the Panhandle Market via local economic development organizations and recent publications:

- March 2023: “Drawings, details of new hospital revealed during virtual town hall” – https://windsorstar.com/news/local-news/drawings-details-of-new-hospital-revealed-during-virtual-town-hall
- April 2023: “Windsor-Essex being eyed for billions in new industrial investment” – https://windsorstar.com/news/Windsor-essex-being-eyed-for-billions-in-new-industrial-investment
- June 2023: “New Interchange Connecting Lauzon Parkway To 401 'Highest Priority' Says Ford” – https://www.iheartradio.ca/am800/news/new-interchange-connecting-lauzon-parkway-to-401-highest-priority-says-ford-1.19736147

- July 2023: "Windsor lands another big EV auto supply chain company" – https://windsorstar.com/news/Windsor-lands-another-big-ev-auto-supply-chain-company
- August 2023: "Windsor inching closer to landing another major foreign investment" – https://windsorstar.com/news/Windsor-inching-closer-to-landing-another-major-foreign-investment

Please also see a recent Globe and Mail article which includes commentary from the greenhouse industry:

- August 2023: "Southern Ontario's greenhouse operators warn lack of infrastructure is slowing growth in booming sector" – https://www.theglobeandmail.com/business/article-windsor-greenhouse-growers-infrastructure/

The IESO has similarly recognized the significant and exceptional demand the Panhandle Market area will experience as part of their Southwest Ontario Bulk Planning initiatives[3].

> *"Electricity demand in Southwest Ontario is growing at a rapid pace. This growth is primarily driven by economic development in the agriculture and manufacturing sectors. The Windsor-Essex and Chatham-Kent areas are the primary drivers of the agriculture growth, which is projected to reach a demand of 2,300 MW by 2035 - the equivalent of adding a city the size of Ottawa to the electricity grid."*

The IESO has forecasted that Ontario will see a capacity need emerging in 2025 and growing through the latter part of the decade. Peak electricity demand in the Windsor-Essex and Chatham areas is forecast to grow from roughly 500 megawatts in 2022 to about 2,100 megawatts in 2035, equivalent to adding cities the size of Ottawa and London to the grid. The IESO was directed by the Minister of Energy to procure certain natural gas generation to respond to this demand.

Enbridge Gas understands that replacing the generation capacity that the IESO has been directed by the Minister of Energy to procure will be significantly more expensive to meet the demand and reliability needs of the Panhandle region. Furthermore, it is not clear at this time what other generation technology has the ability to be deployed in the timeframe and scale required to respond to system needs. More specifically:[4]

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[3] https://www.ieso.ca/en/Get-Involved/Regional-Planning/Southwest-Ontario/Southwest-Ontario-Bulk-Planning-Initiatives

[4] https://www.ontario.ca/files/2023-07/energy-powering-ontarios-growth-report-en-2023-07-07.pdf, p. 49.

“Ontario’s natural gas generators can be turned on and ramped up quickly to ensure the province does not need to be reliant on emergency actions such as conservation appeals and rotating blackouts to stabilize the grid, according to the IESO.

While during most hours throughout the year Ontario can meet its electricity generation needs with nuclear, hydroelectric, bioenergy, wind and solar power, natural gas generation also acts as the province’s insurance policy that can be turned on if the wind is not blowing or sun is not shining, or another generator is offline for repairs. There is currently no like-for-like replacement for natural gas and the IESO has concluded it is needed to maintain system reliability until nuclear refurbishments are complete and new non-emitting technologies such as storage mature.”