ENBRIDGE

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March 16, 2021

BY RESS AND EMAIL

Ms. Christine Long
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Long:

Re: Enbridge Gas Inc. (Enbridge Gas)
Ontario Energy Board File No.: EB-2020-0091
Integrated Resource Planning Proposal
Undertaking Responses

Consistent with the Ontario Energy Board's ("OEB" or "Board") Procedural Order No. 9 (dated March 5, 2021), enclosed are the responses of Enbridge Gas to undertakings received during the Oral Hearing in the above noted proceeding held from March 1-4, 2021.

If you have any questions, please contact the undersigned.

Sincerely,

(Original Signed)

Adam Stiers
Technical Manager, Regulatory Applications

cc.: D. Stevens (Aird & Berlis)
M. Parkes (OEB Staff)
M. Millar (OEB Counsel)
EB-2020-0091 (Intervenors)

ENBRIDGE GAS INC.

Undertaking Response to Pollution Probe

To advise as to how many of the 2,114 projects in the AMP approximately, the approximate number of those that relate to pipeline projects.

Response:

Please see Figure 1, Figure 2, Table 1, and Table 2 below, which together clarify the investments and associated capital expenditure that Enbridge Gas believes are most appropriate for IRP Planning purposes. Figure 1 outlines the various asset classes set out within the 2021-2025 Asset Management Plan ("AMP"). Figure 2 provides an illustrative example of the decision-making process to exclude certain ineligible projects within the AMP from IRP consideration. Table 1 provides an accompanying assessment of projects identified within the Company's AMP compared to the steps set out in Figure 2.[1] Table 2 provides an estimate of the percentage of projects identified within the Company's 2021-2025 AMP, consistent with Table 1, that would qualify for IRP consideration.

Figure 2 begins with the investments in the AMP organized by Asset Classes and then identifies and excludes specific Asset Classes and Asset Class Programs that are not appropriate for IRP Planning.

In order to be representative of the capital spend and number of investments that are expected to flow through to IRP Planning, the Company has not removed additional projects at the Timing stage. Note that all of the capital spend and investments that relate to annual replacement of leaking mains, services, and valves have been removed as part of the Safety Criteria. It is not reasonably possible to retroactively establish when each of the reinforcements, relocations, and replacements in the 2021-2025 AMP were initially identified. As such, the Company cannot establish how many of them were identified three or more years ago. It is expected that as the Company develops experience with IRP Planning that most reinforcements would be identified with sufficient time to allow for IRP Planning. Similarly, it is also anticipated that a significant number of the larger replacements and relocations would be identified with more than three years lead time, making them eligible for IRP Planning.

For additional information on the projects that are in the AMP with spend in 2021-2023 and 2024-2025 please see the response at Exhibit J1.9.

It is Enbridge Gas's intention that all projects with a component of Growth flow through to the IRP Planning Stage described at Figure 2.

[1] EB-2020-0181 Exhibit C, Tab 2, Schedule 1.

Given that there was some confusion among intervenors during the oral hearing regarding the appropriate use of the terms Safety, Integrity, and Reliability Enbridge Gas offers the following clarifications:

- Although projects will often be described as addressing the needs of safety and reliability (or operational reliability) the intention of the proposed Safety Binary Screening Criteria is to exclude identified constraints/needs for which related safety and operational reliability risks are emergent and thus need to be addressed within a shorter time frame – making it impossible to deploy and test IRPA's.

- Although it is common to refer to projects as addressing integrity concerns (equivalent to condition) the capital spend in the AMP that is identified as Integrity refers to investments in launchers and receivers to support inline inspection of pipelines, integrity digs that arise from the inline inspection, programs to apply high performance coatings and other measures to extend the life of existing assets.

Figure 1

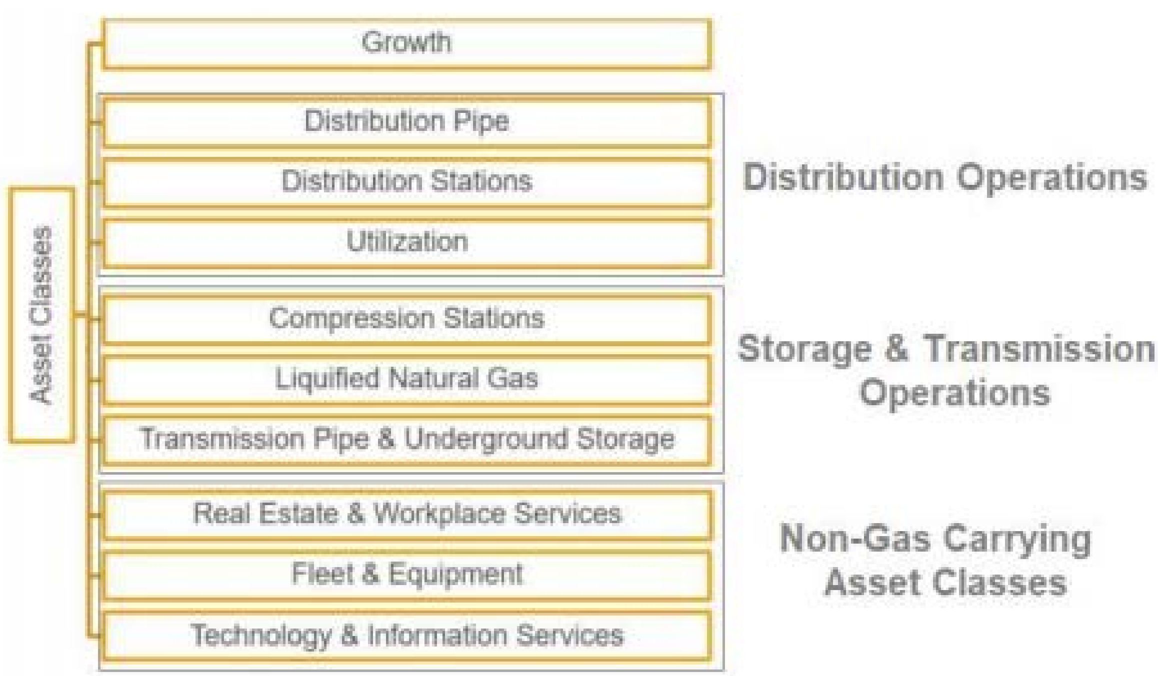
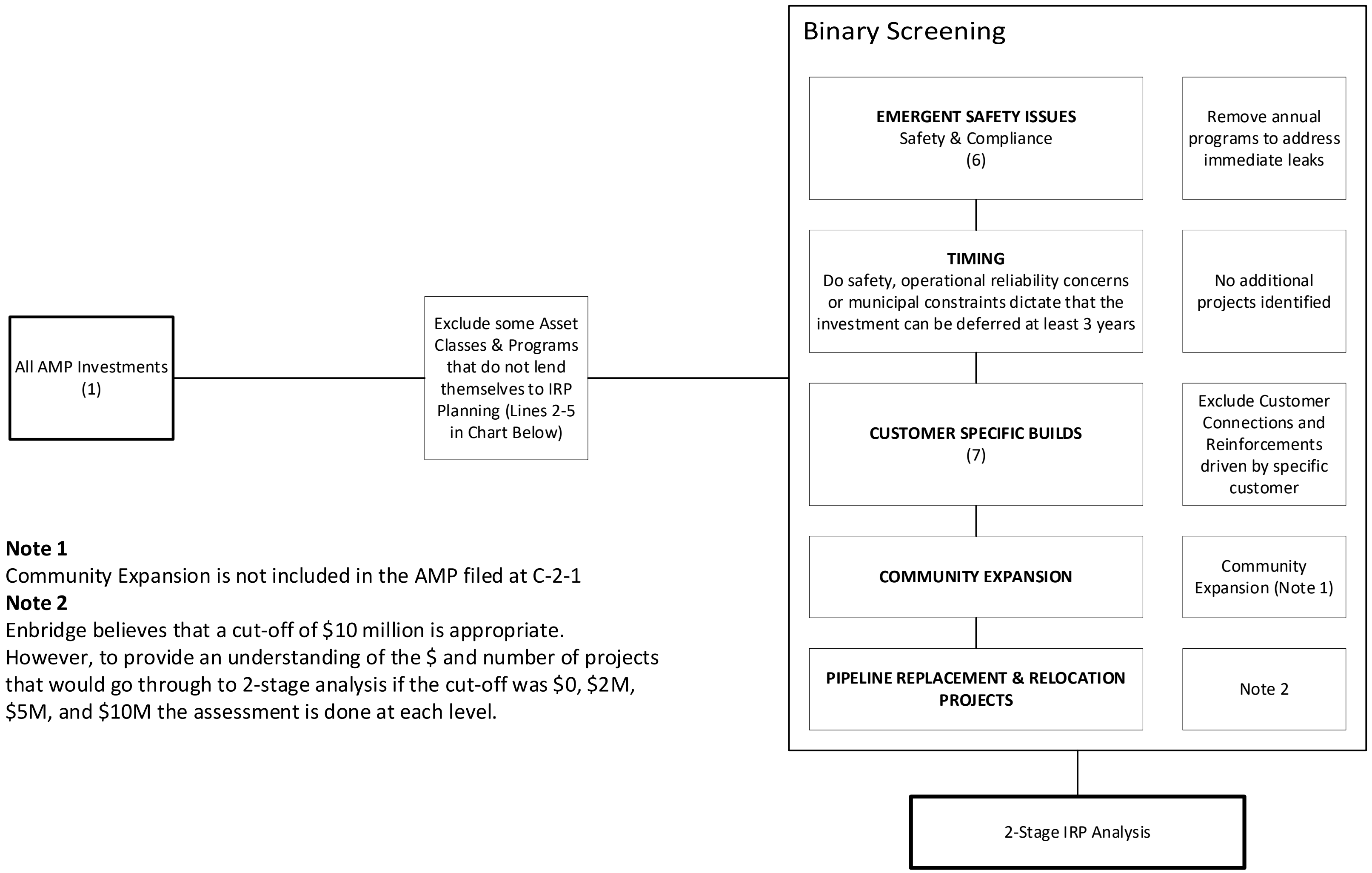


Figure 2



Note 1
Community Expansion is not included in the AMP filed at C-2-1
Note 2
Enbridge believes that a cut-off of $10 million is appropriate. However, to provide an understanding of the $ and number of projects that would go through to 2-stage analysis if the cut-off was $0, $2M, $5M, and $10M the assessment is done at each level.

Table 1

Category of Investment	Capital Spend	# Investments
1 - Full AMP	$ 6,304,004,942	2,114
2 - Exclude Fleet, TIS, REWS & Administrative Investments	$ 823,294,335	675
3 - Exclude Meters	$ 586,858,883	44
4 - Exclude Maintenance on Compression, LNG & Distribution Stations and site improvements (laneways, lighting)	$ 731,368,895	623
5 - Exclude Integrity and Corrosion Management (anode & rectifier bed replacements)	$ 363,506,987	123
6 - Emergent Safety Issues	$ 342,882,785	53
7 - Is the project a Customer Specific Build (Customer Connections)	$ 1,078,923,480	48
IRP Potential	**$ 2,377,169,577**	**548**
(A) IRP Planning - System Reinforcement	$ 978,323,070	164
(B) IRP Planning - Replacement & Relocation - Cost < $2M	$ 136,456,054	303
(C) IRP Planning - Replacement & Relocation - Cost > $2M	$ 119,612,000	40
(D) IRP Planning - Replacement & Relocation - Cost > $5M	$ 116,775,377	16
(E) IRP Planning - Replacement & Relocation - Cost > $10M	$ 1,026,003,077	25
Total	**$ 2,377,169,577**	**548**

Table 2

	Capital Spend	# Investments	As % of Gas Carrying Asset	
Capital Budget excluding Non-Gas Carrying & Administrative (Item 1 - Item 2)	$ 5,480,710,607	1,439	% Spend	% Investments
All System Reinforcement and Replacement & Relocation that come through the Binary Screening **(IRP Potential)**	$ 2,377,169,577	548	43%	38%
All System Reinforcement and Replacement & Relocation > $2M **(A + C + D + E)**	$ 2,240,713,524	245	41%	17%
All System Reinforcement and Replacement & Relocation > $5M **(A + D + E)**	$ 2,121,101,524	205	39%	14%
All System Reinforcement and Replacement & Relocation > $10M **(A + E)**	$ 2,004,326,146	189	37%	13%

ENBRIDGE GAS INC.

Undertaking Response to Pollution Probe

For a recent leave-to-construct project included in rate base where ICM treatment has been requested, to provide the total capital cost to that project and the rate impact is on an annual basis in dollars and as a percent increase a typical bill.

Response:

Enbridge Gas received ICM funding approval for the Windsor Line Replacement Project as part of the OEB decision in 2020 Rates (EB-2019-0194).[1] The total capital cost of the project approved for 2020 ICM funding was $82.9 million and the average annual revenue requirement of the project for the years 2020 to 2023 was $6.840 million. The associated bill increase for a residential customer consuming 2,200 m^3 annually in the Union South rate zone was $2.55 a year which represents 0.6% of annual delivery charges and 0.3% of annual total bill charges.

A certain level of annual capital expenditure is funded through existing rates and does not result in a rate impact for customers. Enbridge Gas's ICM materiality threshold value for 2020 was $490.4 million for the EGD rate zone and $447.9 million for the Union rate zones. Capital expenditures up to the ICM materiality threshold value are considered to be funded through existing rates.

[1] EB-2019-0194, Decision and Order dated May 14, 2020, pp. 11-12.

ENBRIDGE GAS INC.

Undertaking Response to ED

To advise if there were to be adjudication of decisions and discovery on decisions to not to pursue an IRPA prior to the leave-to-construct application, how often would they occur; and to give some thought as to what kind of proceeding they should occur in if that's not an annual rates case.

Response:

Similar to its decisions to resolve identified system constraints through the construction of facilities, Enbridge Gas does not accept that any additional adjudicative process of its decisions to pursue or to not pursue investments in IRPA(s) in advance of an associated application to the Board for leave-to-construct is necessary. The Company's IRP Proposal seeks to mitigate the need for adjudication by establishing Guiding Principles, Binary Screening Criteria and a 2-Stage Evaluation process. Further, Enbridge Gas has sought to eliminate any bias towards investment in facility alternatives by seeking the Board's approval to capitalize the costs of investment in IRPA(s) in a similar manner to facility alternatives. Finally, the Company has proposed an extensive Stakeholder Outreach and Engagement process in order to identify, record and address any stakeholder concerns early in the IRP assessment process, which includes:

(i) leveraging existing customer feedback;
(ii) conducting regional annual stakeholder events designed specifically for the purposes of explaining such decisions and receiving additional feedback from stakeholders (all of which it intends to record, make publicly available and file with the Board as appropriate); and
(iii) conducting geographically-specific stakeholder engagement regarding selected IRPA(s).

However, if the Board were to ultimately determine that some form of adjudicative process was appropriate to establish as part of an IRP Framework then the Company believes that, because its annual updates to the Asset Management Plan are proposed to be filed as part of its annual rates setting proceedings, it would be most appropriate for the Board to expand the scope of those annual rate setting proceedings to include a third phase (Phase 3) dedicated specifically to IRP related adjudication. To ensure that it maintains regulatory efficiency, the Board should limit the expanded scope of Phase 3 to those IRP decisions not to pursue investment in IRPA(s) raised by intervenors that cannot be resolved through the Company's proposed stakeholder engagement process (Component 2). The Board should ensure that the scope established for Phase 3 adjudication does not allow re-hearing of the elements of the IRP Framework previously decided upon by the Board.

ENBRIDGE GAS INC.

Undertaking Response to ED

To provide the list of screening criteria with additional specificity to address further details that may be helpful and issues that may have been discussed during the hearing.

Response:

Please also see response at Exhibit J1.1, for an illustrative example and accompanying discussion of the application of Enbridge Gas's proposed Binary Screening Criteria to identified system constraints/needs. What follows is a more detailed description of the Company's proposed Binary Screening Criteria that reflects their respective evolution over the course of the IRP Framework proceeding.

1. Emergent Safety Issues

If an identified system constraint/need is determined to require a facility project in order for Enbridge Gas to ensure its continued ability to offer safe and reliable service or to meet an applicable law, it would not be a candidate for IRP analysis. An example of such a system constraint/need, and an emergent safety issue, would be if an existing pipeline sustained unanticipated damage and needed to be replaced as quickly as possible to ensure the safety of local communities and the Company's broader transmission and distribution systems.

Enbridge Gas has acknowledged that longer-term safety related system constraints/needs may be appropriate for an IRPA solution and would be considered on a case-by-case basis.

2. Timing[1]

If an identified system constraint/need must be met in under 3 years, an IRPA cannot be implemented and its ability to resolve the identified system constraint/need cannot be verified in time. Therefore, an IRP analysis is not prudent.

Exceptions to this criterion, could include:
(i) Supply-side solutions like CNG;
(ii) Bridging or market-based alternatives in combination with other IRPAs.
Where such exceptions/IRPAs can address a more imminent constraint/need.

[1] Enbridge Gas has reflected upon the feedback received through the Technical Conference and Oral Hearing and agrees that its previous Project Specific Considerations criterion can be subsumed within the Timing and Pipeline Replacement and Relocation Project criteria. The Company believes that where pipeline relocation is required and/or where municipal infrastructure development can be leveraged, the cost savings that would result from downsizing pipeline size will not be significant enough to support consideration of IRPAs.

3. Customer-Specific Builds[2]

If an identified system constraint/need has been underpinned by a specific customer's (or group of customers') clear determination for a facility option and either the choice to pay a Contribution in Aid of Construction ("CIAC"), or to contract for long-term firm services delivered by such facilities (including new subdivision or small main extensions) then it is not appropriate to conduct IRP analysis for those projects.

4. Community Expansion[2]

If a facility project has been driven by policy and related funding to explicitly deliver natural gas into communities to help bring heating costs down, then it is not appropriate to conduct an IRP analysis.[3]

Where Government grants are not identified for the specific purpose of growing natural gas access, then IRP could be considered for community expansion provided IRPAs such as district energy systems were included in scope.

5. Pipeline Replacement and Relocation Projects[1]

If a facility project is being advanced for replacement or relocation of a pipeline and the cost is less than $10 million, then that project is not a candidate for IRP analysis.

Enbridge Gas acknowledges that for large pipeline replacement and relocation projects, there may be opportunities to reduce their size through consideration of IRPA's in the future. Accordingly, the Company would investigate such opportunities in the future on a case-by-case basis, taking into account the broader impacts of downsizing (e.g. creation of system bottlenecks or integrity and inspection concerns). The Company does not believe that IRP will be appropriate for smaller scale pipeline replacement projects (less than $10 million cost), as the cost savings that would result from downsizing pipeline size will not be significant enough to support consideration of IRPAs.[4]

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[2] Enbridge Gas has reflected upon the feedback received through the Technical Conference and Oral Hearing and believes that its previous Economic Development criterion can be subsumed within the Customer-Specific Builds criterion.

[3] Community expansion pertains to the expansion of natural gas to existing communities that do not currently have access to natural gas. These types of projects are governed by the Final Guidelines for Potential Projects to Expand Access to Natural Gas Distribution that were issued on March 5, 2020 (https://www.oeb.ca/sites/default/files/ltr-final-guidelines-gas-expansion-20200305.pdf).

[4] Enbridge Gas has provided in the response at Exhibit J1.1 the impact with respect to capital spend and number of investments if, instead of $10 million, the threshold was set at $5 million or $2 million. Exhibit J1.1 also shows the capital spend and the number of projects if there was no threshold imposed and all replacements and relocations were considered for IRP Planning.

ENBRIDGE GAS INC.

Undertaking Response to ED

To provide a further breakdown of the table from JT2.11 based on the categories in the Utility System Plan.

Response:

The spend categories identified in JT2.11 are Replacements, Relocations, and Reinforcements. They are associated to Utility System Plan ("USP") categories as shown in Table 1 below:

Table 1

Asset Class Program	**USP Category**
Main Replacements	System Renewal
System Reinforcements	System Service
Main Relocations	System Access

The mapping of all asset class programs to USP categories can be found in the 2021-2025 USP filed as part of Phase 2 of Enbridge Gas's 2021 Rates evidence.[1]

[1] EB-2020-0181 Exhibit C, Tab 1, Schedule 1, p. 43.

ENBRIDGE GAS INC.

Undertaking Response to SEC

To advise what time periods Enbridge does economic forecasting of GDP, inflation, interest rates, labour market trends, and market prices of competitive energy options.

Response:

Enbridge Gas uses consensus forecast for the economic indicators and commodity prices that are used in its normalized average consumption forecast with forecast horizons of 5-10 years. The forecasters for the economic indicators are a mix of financial institutes, Canada Mortgage and Housing Corporation (CHMC) and Conference Board of Canada (CBoC). Most financial institutions only produce 2-year provincial economic indicators forecasts while the CBoC produces 5 and 20 year provincial forecasts for the key economic indicators.[1] Consensus commodity price forecast is created by combining several energy consultants' forecasts and is available for a 30 year forecast period.

Enbridge Gas uses the latest available forecast information from these sources to complete its economic forecasts annually. When, as described above, certain long-term forecast information is not available/or is outdated, growth from the most recently available short-term forecasts is held constant in order to extend the forecast for a longer period.

[1] CBoC's 20 year provincial forecast is updated less frequently than annually.

ENBRIDGE GAS INC.

Undertaking Response to SEC

To provide the 20-year demand forecast, and to include uncertainty bands.

Response:

Two distinct categories of Design Day Demand growth are developed annually, as discussed below. Neither category includes uncertainty bands, as the forecasts underpinning them do not. Historically, Enbridge Gas has timed facility projects as closely as possible to the realization of identified system constraints/needs to mitigate as much remaining forecast uncertainty/risk as possible.

i. 20-year General Service Design Day Demand Growth

The 20-year general service design day demand growth is summarized in Table 1 below (organized according to the legacy Enbridge Gas Distribution Inc. ("EGD") and Union Gas Limited ("Union") delivery areas). It includes incremental residential and small commercial/industrial demand growth.

This forecast relies upon customer count information included in the Company's annual Revenue Forecast and other factors to inform more localized infrastructure needs such as:

- regional intelligence on general service demand growth gathered from the Company's Operations teams;
- municipal information on development projections; and
- historical regional growth rates.

ii. 10-year Firm Contract Rate Design Day Demand Growth

The 10-year firm contract rate design day demand growth is summarized in Table 2 below. It is produced annually for the Union South delivery area and reflects incremental large volume customer demand growth (or reduction). Forecasting beyond 10 years for this customer type is challenging due to the size of their demand and the need to understand the specific location on the system to inform infrastructure needs.

Table 1

Year	EGD Rate Zone	Union North Rate Zone	Union South Rate Zone	Total
	Incremental Peak Load (m3/hr)	Incremental Peak Load (m3/hr)	Incremental Peak Load (m3/hr)	Incremental Peak Load (m3/hr)
2018	106,281	10,859	22,726	139,866
2019	69,804	10,770	23,663	104,237
2020	61,380	9,365	23,212	93,957
2021	60,217	9,012	22,586	91,815
2022	54,995	8,836	22,612	86,443
2023	51,474	8,681	22,362	82,517
2024	50,339	8,554	22,028	80,921
2025	48,504	8,551	22,396	79,451
2026	46,361	8,622	22,051	77,034
2027	44,106	8,321	21,734	74,161
2028	41,744	8,321	21,626	71,691
2029	41,442	8,320	21,881	71,643
2030	41,351	8,320	21,694	71,365
2031	40,962	8,320	21,885	71,167
2032	40,401	8,320	21,578	70,299
2033	40,034	8,320	21,965	70,319
2034	39,360	8,321	21,626	69,307
2035	38,734	8,320	21,696	68,750
2036	38,030	8,320	21,757	68,107
2037		7,890	21,757	29,647
Grand Total	955,521	174,343	442,835	1,572,699

NOTE: Enbridge Gas has completed Table 1 using best available information. At the time that EGD completed its last forecast it did so for 2018-2036, whereas, Union did so for 2018-2037.

Table 2

Year	Incremental Firm Contract Rate Design Day Demand
	$10^3 m^3$/day
2020	-1223
2021	3413
2022	1014
2023	245
2024	4382
2025	250
2026	525
2027	245
2028	514
2029	265

ENBRIDGE GAS INC.

Undertaking Response to SEC

To provide an org chart of EGI, just down to the director level, not below that, with the various types of forecasting and planning and where they happen indicated, to understand how they work together, how they fit within the organization, and how they're separate from each other within the organization.

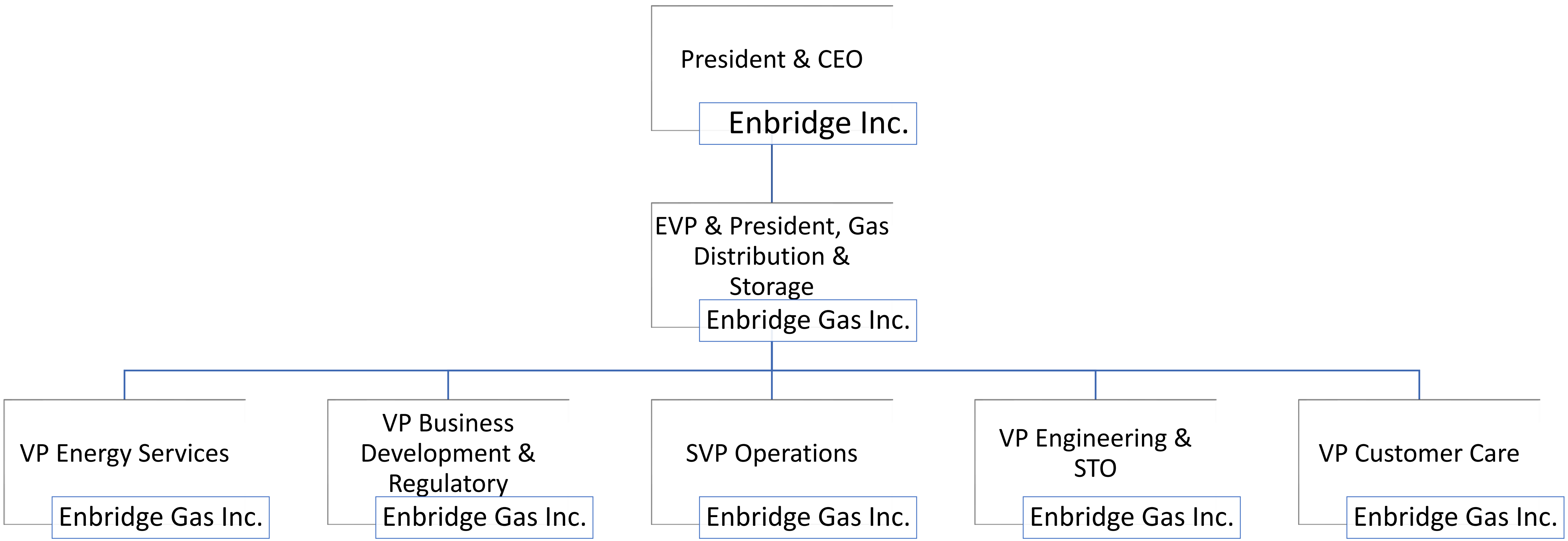
Response:

Please see Attachment 1 for organizational charts, down to the director level, of the areas of the organization that contribute to and/or are accountable for the forecasting and planning processes and outputs discussed by SEC during the Oral Hearing.

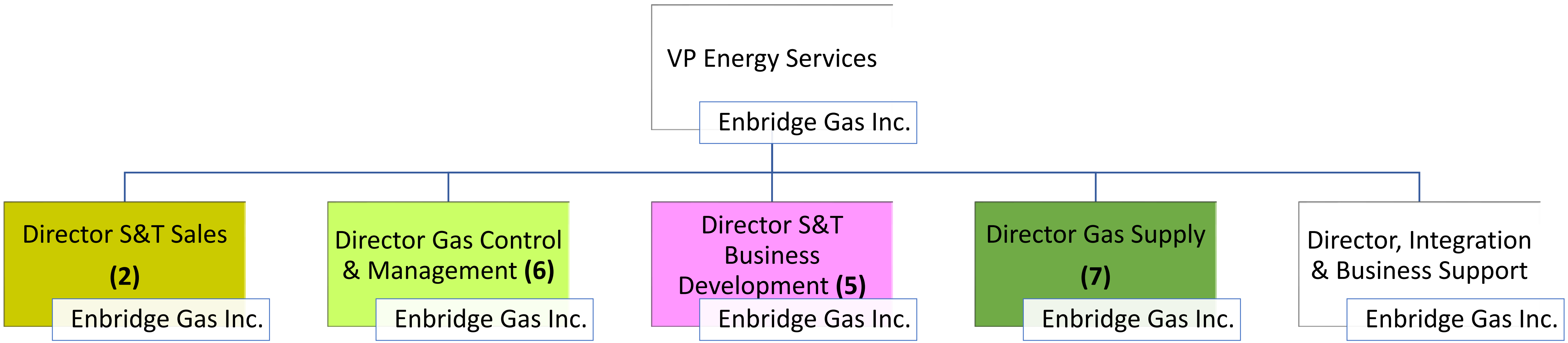
Please also see Attachment 2 for a high-level process diagram, designed to be a companion document to Attachment 1, that outlines how the various areas of the organization contribute to forecasting and planning processes and outputs.

The colour coding and numbering applied to director-level positions in Attachment 1 is aligned with the colour coding and numbering applied to areas of the organization identified in Attachment 2.

Gas Distribution and Storage Organizational Structure



Gas Distribution and Storage Organizational Structure



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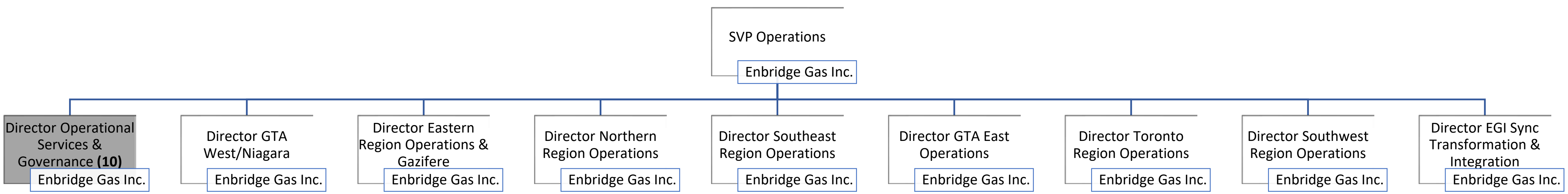

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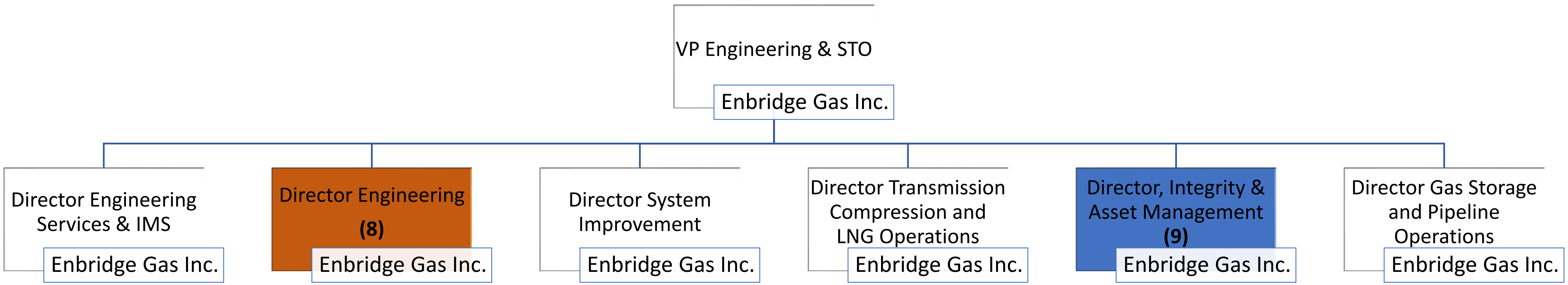
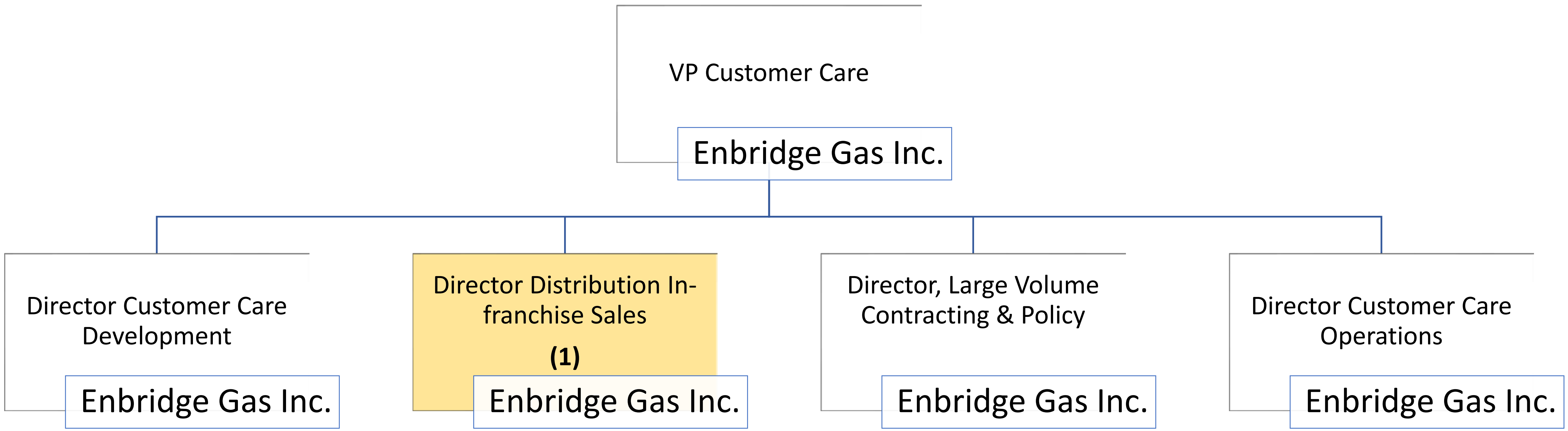
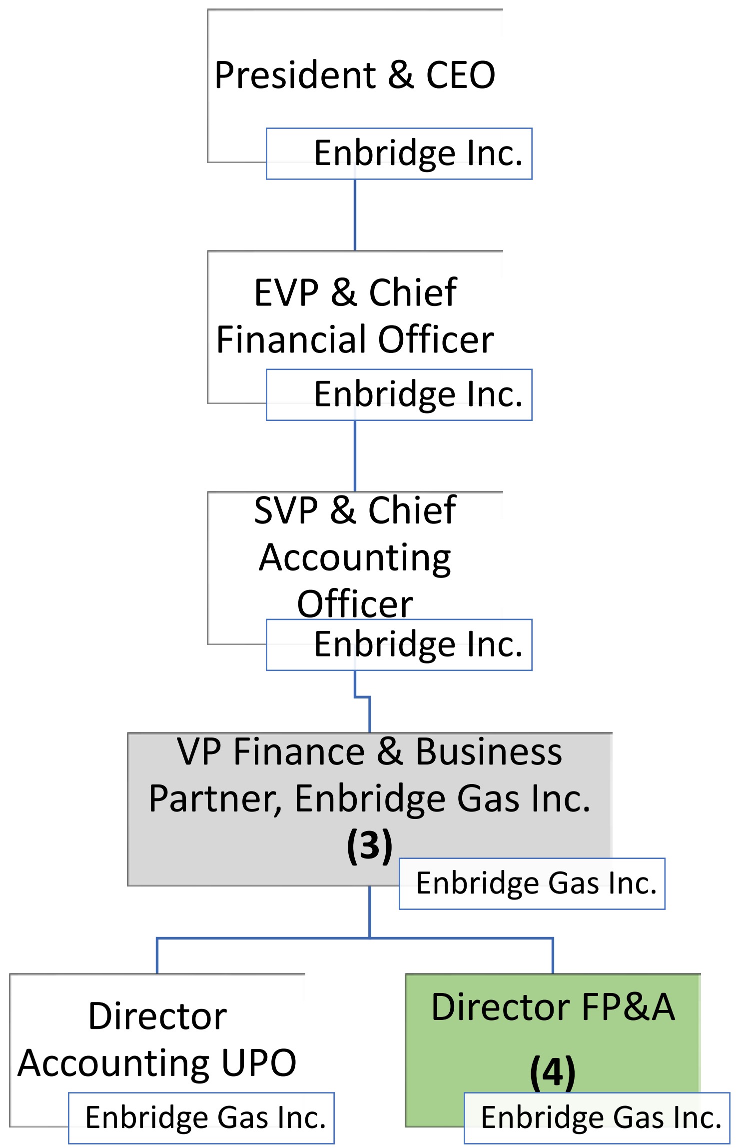
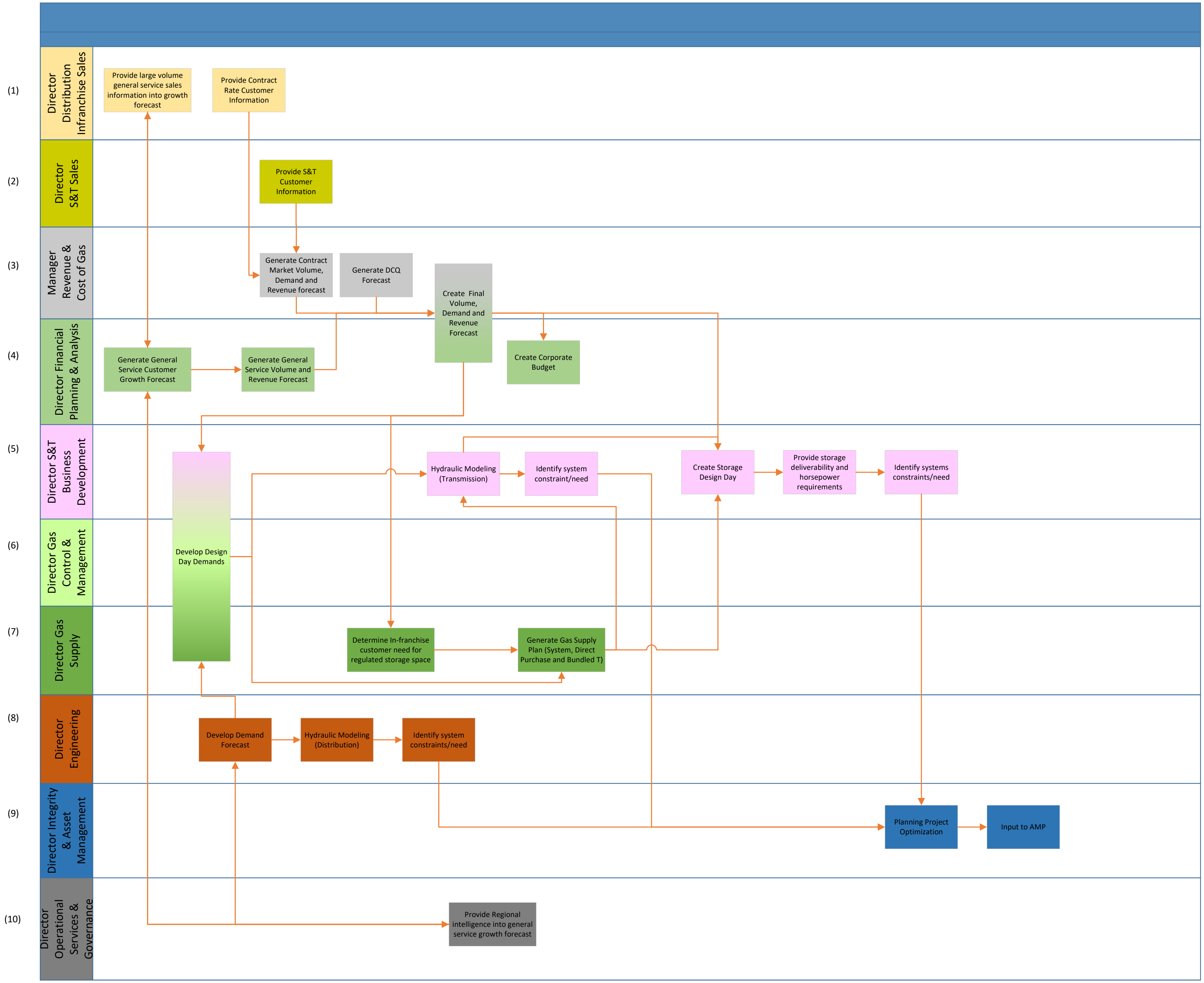


Gas Distribution and Storage Organizational Structure



Finance and Business Partner Organizational Structure





(1)
Director Distribution Infranchise Sales
Provide large volume general service sales information into growth forecast
Provide Contract Rate Customer Information
(2)
Director S&T Sales
Provide S&T Customer Information
(3)
Manager Revenue & Cost of Gas
Generate Contract Market Volume, Demand and Revenue forecast
Generate DCQ Forecast
Create Final Volume, Demand and Revenue Forecast
(4)
Director Financial Planning & Analysis
Generate General Service Customer Growth Forecast
Generate General Service Volume and Revenue Forecast
Create Corporate Budget
(5)
Director S&T Business Development
Hydraulic Modeling (Transmission)
Identify system constraint/need
Create Storage Design Day
Provide storage deliverability and horsepower requirements
Identify systems constraints/need
(6)
Director Gas Control & Management
Develop Design Day Demands
(7)
Director Gas Supply
Determine In-franchise customer need for regulated storage space
Generate Gas Supply Plan (System, Direct Purchase and Bundled T)
(8)
Director Engineering
Develop Demand Forecast
Hydraulic Modeling (Distribution)
Identify system constraints/need
(9)
Director Integrity & Asset Management
Planning Project Optimization
Input to AMP
(10)
Director Operational Services & Governance
Provide Regional intelligence into general service growth forecast

ENBRIDGE GAS INC.

Undertaking Response to Anwaatin

To indicate what proportion of the projects that are shown in Table 2 are more than three years away.

Response:

In the undertaking response at Exhibit J1.1 the Company has more clearly defined the investments that would be expected to go through IRP Assessment. As per Anwaatin's request, Table 1 below reflects the percentage of capital spend and the percentage of investments that are scheduled for 2021-2023 (within the three years) and the percentage of capital spend and investments that are scheduled for 2024-2025. The Company notes that Table 1 does not reflect the IRP opportunity envisioned by its IRP Proposal (identification of constraints/needs that would qualify for IRP consideration up to 10 years in advance within its annual updates to its 10-year Asset Management Plan) but rather a snapshot today based on its 5-year 2021-2025 Asset Management Plan ("AMP").

Table 1 below commences with those projects identified in the Company's AMP that would qualify for IRP consideration after having passed the proposed Binary Screening process (as discussed in the response at Exhibit J1.4). Table 1 goes on to organize projects according to the following categories:

- System Reinforcement;
- Replacement & Relocation < $2M;
- Replacement & Relocation > $2M;
- Replacement & Relocation > $5M; and
- Replacement & Relocation > $10M.

Table 1

Category	Capital Spend	# Investments	% Capital	% Investments
IRP Potential	$ 2,377,169,577	548		
No - Capital Spend 2021-3	$ 1,233,809,502	372	52%	68%
Yes - 2024 +	$ 1,143,360,075	176	48%	48%
IRP Planning - System Reinforcment	$ 978,323,070	164		
No - Capital Spend 2021-3	$ 482,638,580	100	49%	61%
Yes - 2024 +	$ 495,684,490	64	51%	39%
IRP Planning - Replacement & Relocation - Cost < $2M	$ 136,456,054	303		
No - Capital Spend 2021-3	$ 109,817,896	221	80%	73%
Yes - 2024 +	$ 26,638,158	82	20%	27%
IRP Planning - Replacement & Relocation - Cost > $2M	$ 119,612,000	40		
No - Capital Spend 2021-3	$ 82,518,977	28	69%	70%
Yes - 2024 +	$ 37,093,022	12	31%	30%
IRP Planning - Replacement & Relocation - Cost > $5M	$ 116,775,377	16		
No - Capital Spend 2021-3	$ 88,178,069	12	76%	75%
Yes - 2024 +	$ 28,597,308	4	24%	25%
IRP Planning - Replacement & Relocation - Cost > $10M	$ 1,026,003,077	25		
No - Capital Spend 2021-3	$ 470,655,980	11	46%	44%
Yes - 2024 +	$ 555,347,096	14	54%	56%
Grand Total	$ 2,377,169,577	548		

Note: For 2 investments, the spend has been split across the No and Yes categories as these investments represent projects that are yet to be defined but are anticipated to be identified with 3-5 years of lead time. They are divided as follows which represents the split of the yet to be identified projects.

MOP Verification Replacement Program	**$**	**19,375,000**
No - Capital Spend 2021-3	$	6,420,000
Yes - 2024 +	$	12,955,000
Relocation Program	**$**	**122,208,000**
No - Capital Spend 2021-3	$	60,024,000
Yes - 2024 +	$	62,184,000

ENBRIDGE GAS INC.

Undertaking Response to ED

To provide the calculation underpinning the 8 cents per kilowatt hour.

Response:

This undertaking response supports the following assertion made by Ms. Giridhar in response to page 8 of ED's compendium:

> "I will just note that if you were to convert this into cents per kilowatt hour, it's about 8 cents per kilowatt hour. So it's actually still cheaper than the rate of average cost of electricity in Ontario."[1]

1 Joule = 1 Watt applied for 1 Second

Therefore,
1 kWh = 1000 Watts/kW × 60 min/hour × 60 seconds/hour
= 3,600,000 W.sec
= 3,600,000 Joules
= 3.6 MJ or 0.0036 GJ

-or-

1 GJ = 1,000,000,000 Joules
= 1,000,000,000 Watt.sec
= 1,000,000 kW.sec
= 16,668 kW.min
= 277.78 kWh

Therefore, if electricity is $0.10/kWh, then electricity is $27.78/GJ.

According to the IESO's website the following TOU prices became effective February 23, 2021, and their equivalent cost in $/GJ are:[2]

Off Peak	$0.085/kWh	= $23.61/GJ
Mid	$0.119/kWh	= $33.06/GJ
Peak	$0.176/kWh	= $48.89/GJ

On page 8 of its Compendium, ED asserts that the price of RNG is $0.78/m^3 or $21/GJ.[3] Therefore, based on the calculations above, the cost of RNG is less expensive than the average cost of electricity in Ontario.

[1] EB-2020-0091, Final Transcript Enbridge IRP Vol 2, March 2, 2021, p. 45 (emphasis added); EB-2020-0091, ED Compendium Panel 2, February 26, 2021, p. 8.
[2] https://www.ieso.ca/en/Learn/Electricity-Pricing/For-Residents-and-Small-Businesses
[3] EB-2020-0066, Exhibit I.STAFF.4, p. 2.

ENBRIDGE GAS INC.

Undertaking Response to ED

To provide a list of what studies are saying regarding the price of green hydrogen as a cost per cubic metre of equivalent natural gas. To include the calculations used to get from the cost per kilogram to the cost per equivalent natural gas cubic metre in the underlying studies.

Response:

The most appropriate means to complete this response is via comparison on the basis of units of energy for each fuel. Therefore, GJ and kwh have been used.

The government of Canada's (Natural Resources Canada) Hydrogen Strategy For Canada, released in December 2020 (the "Hydrogen Strategy") reflects a forecast to have an,

> …[e]stablished supply base of low carbon intensity hydrogen with delivered prices of **$1.50 - $3.50/kg** [1]

Based on the numbers set out within the Hydrogen Strategy forecast:

1kg of H_2 at 1 atm and 0^0C	= ~11.126Nm^3
1m^3 of H_2	= 0.012GJ
1GJ	= 278.8kwh

At $1.50/kg:
Conversion to $/$m^3$ = $1.5/kg x 1kg/11.126$m^3$ = **$0.135/$m^3$**
Conversion to $/GJ = $0.135/$m^3$ x 1m^3/0.012GJ = **$11.13/GJ**
Conversion to $/kwh = $11.25/GJ x 1GJ/278.8kwh = **$0.0404/kwh**

At $3.50/kg:
Conversion to $/$m^3$ = $3.5/kg x 1kg/11.126$m^3$ = **$0.315/$m^3$**
Conversion to $/GJ = $0.315/$m^3$ x 1m^3/0.012GJ = **$26.21/GJ**
Conversion to $/kwh = $26.21/GJ x 1GJ/278.8kwh = **$0.094/kwh**

Therefore, the equivalent cost per cubic meter of hydrogen is $0.135/$m^3$ - $0.315/$m^3$ or in energy units $11.23/GJ - $26.21/GJ or $0.040/kwh to $0.094/kwh. In comparison,

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[1] NRCan, HYDROGEN STRATEGY FOR CANADA – Seizing the Opportunities for Hydrogen – A Call to Action, December, 2020, p. XVIII **[emphasis added]**; https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf

natural gas trades in Ontario at approximately \$3/GJ or \$0.117/m^3, subject to market conditions at any specific point in time.

Canada's Hydrogen Strategy indicates that the future cost of hydrogen will be lower than that of electric air source heat pumps (ASHP) and electric resistive heating based on the assumption that cost will be reflective of the cost of natural gas today which is lower than that of ASHP.[2]

> For both hydrogen and the alternative fuels, the costs shown reflect the total cost to the customer including production and distribution. The values are presented in \$/GJ-equivalent, which takes into account the efficiencies of FCEVs and BEVs relative to ICE vehicles and air source heat pumps (ASHP) relative to electric resistive. As a heating fuel, hydrogen is more expensive than natural gas, but this value does not account for the increased costs of natural gas due to carbon. Over time, the delivered costs of all of the available fuels are likely to change. As a point of comparison, the figure shows the expected cost of natural gas used for heating for which the carbon emissions have been offset through direct air capture (DAC)…[3]

Similar estimates have also been made by The Hydrogen Council,[4] and the International Energy Agency.[5]

[2] NRCan, HYDROGEN STRATEGY FOR CANADA – Seizing the Opportunities for Hydrogen – A Call to Action, December, 2020, p. 100; https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf.

[3] NRCan, HYDROGEN STRATEGY FOR CANADA – Seizing the Opportunities for Hydrogen – A Call to Action, December, 2020, pp. 76-77; https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf

[4] Hydrogen Council, Path to Hydrogen Competitiveness – A cost perspective, January 20, 2020, p. 21; https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf

[5] https://www.iea.org/data-and-statistics/charts/global-average-levelised-cost-of-hydrogen-production-by-energy-source-and-technology-2019-and-2050

ENBRIDGE GAS INC.

Undertaking Response to ED

To confirm whether all or almost all of Enbridge's pipelines would need to be replaced to transport 100 percent hydrogen safely and reliably.

Response:

Historically, certain of Enbridge Gas's natural gas pipeline systems were capable of carrying up to 50% hydrogen in the form of manufactured natural gas ("Town Gas"). While a number of natural gas utilities around the world still transport Town Gas, Enbridge Gas no longer does. Over time, Enbridge Gas's pipeline system has become increasingly integrated into other systems with newer, and improved infrastructure elements (e.g. steel and plastic pipelines and fittings). This evolution of pipeline systems makes the determination of maximum allowable hydrogen blending (%) a complicated endeavor.

With the above system complexity in mind, and due to various factors including system-related and customer-specific constraints, Enbridge Gas is not currently considering replacement of its natural gas distribution and/or transmission systems to blend or transport 100% hydrogen gas. Instead, natural gas utilities like Enbridge Gas are investigating the maximum hydrogen blend (%) that is appropriate for their respective systems and may choose to complement their existing systems with pipelines designed to carry 100% hydrogen (as is being contemplated in other jurisdictions such as the UK and Germany). It would not be accurate to conclude that natural gas utilities in other jurisdictions are considering conversion of their existing systems to solely carry 100% hydrogen, as this is not the case, see for example page 11 of the report *Hydrogen Europe Vision on the Role of Hydrogen and Gas Infrastructure on the Road Toward a Climate Neutral Economy A Contribution to the Transition of the Gas Market,* where this transitional approach is laid out,[1] and page 34 of the *Hydrogen Road Map Europe Report* which speaks to hydrogen pathways for decarbonization.[2]

As the Company's investigation into hydrogen blending and transmission/distribution advances, Enbridge Gas expects its focus upon maintaining the reliability and safety of its systems to remain steadfast.

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[1] https://ec.europa.eu/info/sites/info/files/hydrogen_europe_-_vision_on_the_role_of_hydrogen_and_gas_infrastructure.pdf
[2] https://www.fch.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf

ENBRIDGE GAS INC.

Undertaking Response to ED

To confirm whether the TRC or another society cost test was used in the OEB Mac curve analysis.

Response:

The OEB's *Marginal Abatement Cost Curve for Assessment of Natural Gas Utilities' Cap and Trade Activities* (the "MACC Study") which was commissioned in 2016 and submitted in July 2017, focused on utility costs, rather than costs to society or to customers. The analysis included the avoided cost of carbon as a benefit and assessed the impact of three long-term carbon price forecast scenarios. This approach was used because the MACC Study was intended to inform the development of Enbridge Gas Distribution Inc.'s and Union Gas Limited's annual Cap-and-Trade system Compliance Plans and to assist the OEB in evaluating the cost impacts of these plans. As such, the OEB MACC Study did not employ either a total resource cost ("TRC") test or another society cost test ("SCT"). Given the MACC Study's limited scope, the fact that it was intended to support the first compliance period (2017-2020) of Ontario's former Cap-and-Trade system and the fact that it was based on the now outdated 2016 Conservation Potential Study, it is not appropriate to rely upon it to draw conclusions regarding the current IRP Framework or future IRPA investments.

ENBRIDGE GAS INC.

Undertaking Response to ED

To confirm that there is a subsidy of 60,000 dollars per customer being paid for by existing ratepayers in the north bay community expansion project, and if not, to explain why not.

Response:

Enbridge Gas received funding of $8,670,000 for the North Bay (Northshore and Peninsula Roads) Community Expansion Project (the "Project") under the Government of Ontario's Regulation 24/19 for Expansion of Natural Gas Distribution Systems. The forecasted number of Project customers used in the economic analysis is 134. The funding per Project customer is $64,701.

Each natural gas customer in the Province of Ontario is charged $1.00 per month to fund the Expansion of Natural Gas Distribution Systems program.

ENBRIDGE GAS INC.

Undertaking Response to ED

To advise whether the gist of this quote is that the annual costs of a heat pump would be 150 to 250 dollars less than natural gas once the 23 cents per cubic metre system access surcharge is accounted for.

Response:

The quote referenced is specific to the North Bay (Northshore and Peninsula Roads) Community Expansion Project (EB-2019-0188) and refers to annual operating costs associated with electric air source heat pump ("EASHP") technology as compared to natural gas equipment. The estimate of $150-$250 dollars was based on several variables including electricity costs, natural gas rates, equipment efficiency, building heating requirements and local weather conditions at the time of submission.

At the time the analysis cited was completed using then current energy rates, EASHP systems were found to provide a lower annual operating cost compared to natural gas systems subjected to a 23-cent surcharge per cubic meter. Of course, any cost differential calculated in this manner will vary based on the specific variables included at the time and so this finding cannot be assumed to apply across Enbridge Gas's franchise area in perpetuity.

ENBRIDGE GAS INC.

Undertaking Response to ED

To review the amp to confirm the total cost of the projects that would no longer be necessary without the demand from fossil fuel electricity generation.

Response:

There are no projects in the 2021-2025 Asset Management Plan ("AMP") that are supporting electricity generation for Ontario's electricity distribution network. However, as outlined in Table 1 below, there is one investment in the current AMP that will allow a mine to generate its own electricity. The investment summary for this investment is contained in the AMP (the amount in Table 1 includes overheads while the amount in the investment summary report excludes overheads).[1]

Table 1

Investment ID	Investment Name	2021	2022	2023	2024	2025
49925	Greenstone	4,166,080	-	-	-	-

[1] EB 2020-0181 Exhibit C, Tab 2, Schedule 1, p. 381.

ENBRIDGE GAS INC.

Undertaking Response to ED

To respond to the question: if we see a trend towards decarbonization and it reduces gas demand in-franchise and ex-franchise, and your ex-franchise transportation customers choose not to renew commitments, who in Canada will bear the portion of capital costs that were being picked up by those ex-franchise customers? Assuming you cannot utilize that capacity because demand is falling here and in New York and elsewhere.

Response:

Based on the current rate-making approach, the Dawn Parkway System costs are allocated, based on the principles of cost causation, to ex-franchise and in-franchise rate classes at the time of a cost of service rate proceeding. Ex-franchise rate classes do not contribute in a significant way to other components of the Company's revenue requirement.

To the extent there is no ex-franchise demand forecast at the time of a cost of service rate proceeding, the Dawn Parkway System costs would be allocated to and recovered from in-franchise rate classes. Dawn Parkway System costs allocated to ex-franchise rate classes are approximately 3% of the Company's total revenue requirement.

ENBRIDGE GAS INC.

Undertaking Response to ED

To determine whether there are any associated methane regulation costs with respect to Enbridge distribution company.

Response:

The Federal *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)*[1] (the "Methane Regulations") does not cover natural gas transportation for the purpose of local distribution, therefore, Enbridge Gas's distribution activities are exempt.

However, Enbridge Gas's natural gas storage and transmission facilities are subject to the Methane Regulations and do incur costs of compliance. See Table 1 below for all 2020 Methane Regulation costs of compliance.

Table 1

Cost Type	
Repair Costs*	$65,308
STO Labour (inspection)	$21,764
Contractor Costs (inspection)	$277,893
Taxes	$35,202
Total	$400,167

*includes estimate of Tecumseh repair costs

[1] SOR/2018-66.

ENBRIDGE GAS INC.

Undertaking Response to APPrO

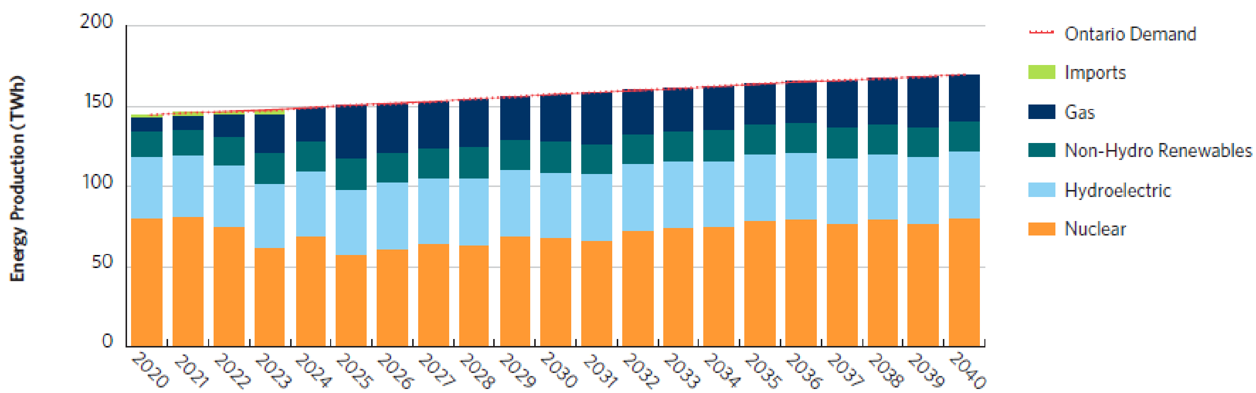
To file the IESO's most recent annual planning outlook for 2020; to discuss how this information relates to or otherwise supports Enbridge's forecasted demand from natural gas-fired electricity generation, and how this information may impact the likelihood of this speculative scenario proposed by Mr. Elson in respect of undertaking no. J2.7.

Response:

Figure 10 within the IESO's January 2020 Annual Planning Outlook ("APO") (see Attachment 1) shows installed capacity by resource type from 2020 to 2040. Figure 10 indicates that natural gas represents roughly 24% of installed capacity in 2019 and is anticipated to stay roughly the same to 2040.

Further, in section 4.2 Energy Resource Adequacy of the APO (the ability for Ontario to meet its own electricity needs) the IESO states that Ontario is expected to have an adequate supply of energy to 2040 with production from gas-fired generators ramping up to meet growing demand[1] as illustrated in Figure 20 included below.

Figure 20: Reference Case – Energy Adequacy Outlook, with Continued Availability of Existing Resources



Lastly, on page 21 of its APO, the IESO concludes that natural gas will play an important and increasing role in the production of electricity:

[1] Ontario is expected to have an adequate supply of energy, provided existing resources continue to be available post-contract expiry. In this scenario, current amounts of renewable generation continue and production from gas-fired generators ramps up to meet growing demand.

> Following the Pickering NGS retirement and during the nuclear refurbishment period, incremental energy needs will be met primarily through the increased use of the gas fleet. Given the important role of gas-fired generation in Ontario's supply mix and the potential for pipeline constraints during peak periods, the IESO monitors fuel security as part of its long-term planning.

The IESO's conclusions within the APO are consistent with Enbridge Gas's forecast of natural gas usage by power producers in the years ahead.

Annual Planning Outlook

A view of Ontario's electricity system needs

JANUARY 2020

ieso
Connecting Today.
Powering Tomorrow.

Executive Summary

The Independent Electricity System Operator (IESO) ensures the reliability and cost-effectiveness of Ontario's power system. The IESO plans and prepares for Ontario's electricity needs by assessing requirements to ensure electricity will be available when and where it is needed. It is an ongoing process that must consider near-, medium- and long-term electricity needs, as well as impacts on cost and reliability. Balancing electricity supply and demand depends on comprehensive planning that enables the IESO to meet reliability requirements, while giving market participants the data and insights they need to make informed operational and investment decisions.

Planning for Ontario's future electricity needs comprises two processes: bulk system planning and regional planning. Bulk system planning addresses the provincial electricity system while regional planning considers local electricity priorities within each of the province's 21 electricity planning regions. The IESO develops the *Annual Planning Outlook* (APO) as part of the bulk system planning process.

A 20-year forecast for Ontario's electricity system, the APO includes electricity demand projections, a resource adequacy assessment, transmission considerations, and performance indicators, such as an emissions outlook, and identifies the province's energy and capacity needs. By providing timely and transparent information about future electricity needs on a regular basis, the Outlook is intended to guide investment decisions and market development. That being said, forecasts of electricity supply and demand are, by definition, inexact. The uncertainties associated with any forecast will increase with the length of the planning horizon, and reflect dependencies.

Overall, Ontario is in a strong position, with sufficient resources to meet its needs under most circumstances, provided the majority of existing resources remain available.

The demand forecast serves as the basis from which Ontario's resource needs are assessed. The forecast informs system adequacy needs by anticipating future requirements, which are affected by many factors, including consumer behaviour, demographics, the economy, energy prices, transportation policy, and energy-efficiency measures.

Although energy efficiency is an important resource to meet system needs, one of the most significant variables affecting the forecast concerns the long-term future for energy-efficiency investment in Ontario. In light of uncertainty surrounding the future of existing programming beyond the end of 2020, the APO includes two demand scenarios or "cases" that reflect different assumptions related to future energy-efficiency initiatives:

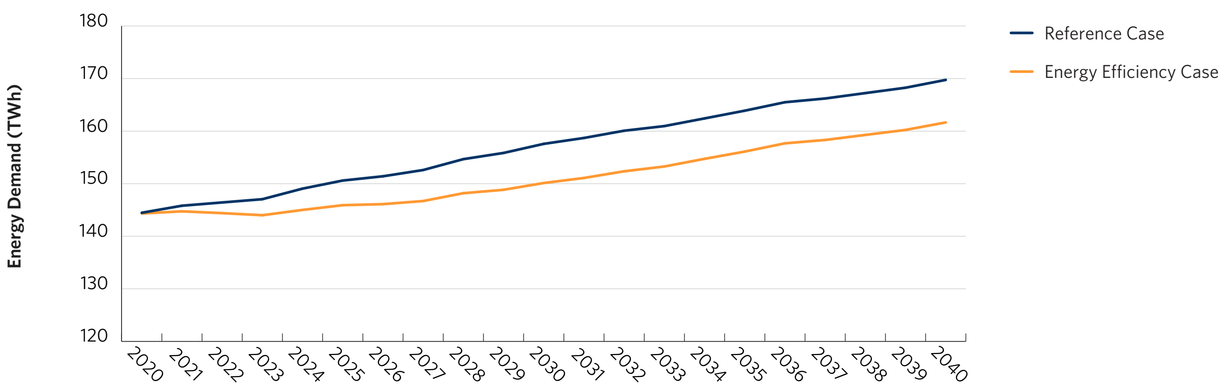
- **Reference Case:** existing IESO-delivered energy-efficiency programs cease at the end of 2020
- **Energy Efficiency Case:** existing energy-efficiency programs continue beyond 2020, for the duration of the outlook period

These two cases were used throughout the report to assess and compare Ontario's future resource adequacy needs.

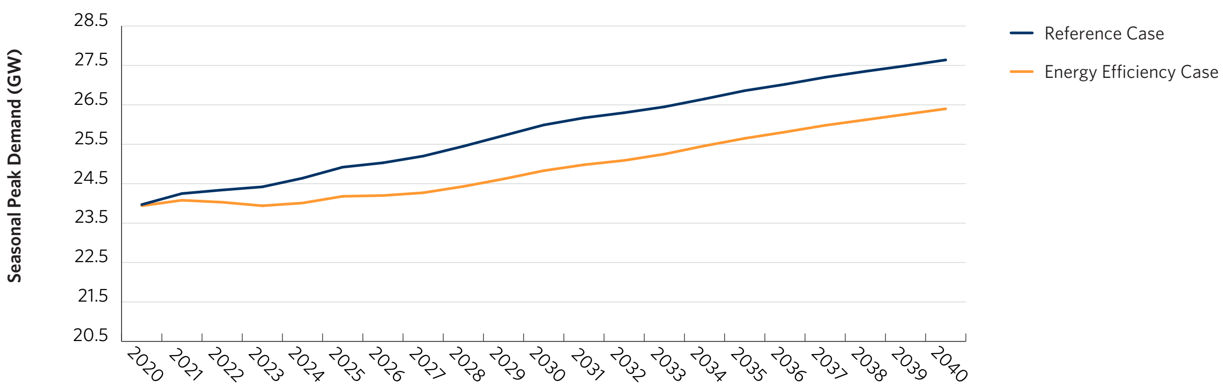
Overall demand growth over the next 20 years will be largely driven by modest growth in the residential, commercial and agricultural sectors, as well as the increased electrification of transportation. As a result, energy demand is expected to grow between 0.4 per cent and 1.4 per cent each year over the forecast period.

The Reference Case suggests total energy consumption is expected to grow from 144 terawatt-hours (TWh) in 2020 to 170 TWh in 2040. In the Energy Efficiency Case, overall energy demand is expected to increase from 144 TWh in 2020 to 162 TWh in 2040 – or 8 TWh less than the Reference Case.

Total Ontario Demand



Summer Peak Demand



Ontario's diverse supply mix means the province is well positioned to meet future resource adequacy needs. The APO forecasts that Ontario is generally expected to have enough energy to supply demand over the next 20 years. Having reliable baseload facilities like nuclear and hydroelectric, along with the combined cycle gas fleet, means there should be ample energy available to meet expected needs under most circumstances.

Although Ontario's energy requirements can largely be met with existing and available resources, a summer capacity need does arise in the 2020s. Assuming existing resources remain available, a capacity need of approximately 2,000 megawatts (MW) emerges in 2023 and grows slowly through 2040. This need is limited, occurring for a few short hours of peak demand each year, meaning future resource requirements are peaking in nature. The capacity need through the mid-2020s can primarily be met by acquiring capacity from existing and available resources, including demand response, imports, merchant generators, enhancements of current facilities (uprates), distributed energy resources (DERs) and, potentially, energy efficiency.

Major planned generator outages can also affect the need for capacity. The period during which nuclear refurbishments are scheduled is particularly important to monitor, since two to four nuclear units are anticipated to be out of service each summer until 2029. Peak refurbishment activity occurs in summer 2023, when four nuclear units (totalling 3,364 installed MW) will be out of service.

Going forward, capacity auctions will be an important mechanism for efficiently and competitively acquiring resources to meet Ontario's capacity needs. Introducing the capacity auction in advance of periods with significant system need will allow both the IESO and participants to learn and adjust early. At the same time, the increased competition fostered by the auction is expected to put downward pressure on pricing, which will benefit ratepayers.

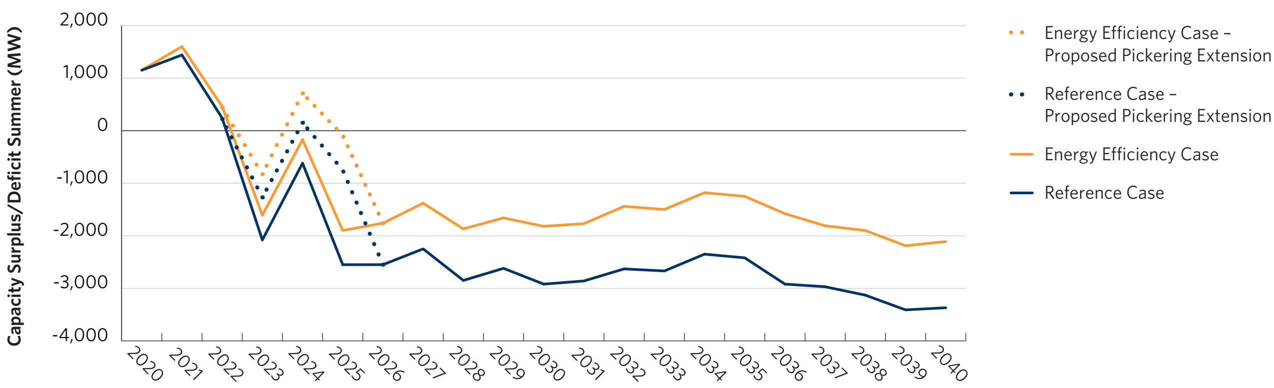
The IESO recognizes that a capacity auction, while a valuable tool, may not work for all resources. As a result, an engagement was announced in 2019 to work with stakeholders in anticipation of future capacity shortfalls and to consider complementary acquisition approaches. As there is no "one-size-fits-all" solution that works for all resources, the IESO intends to have a suite of procurement tools that enable competition.

Although the vast majority of Ontario's electricity resources are connected to the high-voltage transmission system, a growing number of smaller units are connecting at the distribution level as customers see the benefits of having greater control of their electricity supply. DERs may provide an opportunity for the IESO to address future energy and capacity needs if they are effectively integrated into the markets. Currently, there are approximately 33,000 DERs under contract with the IESO, the majority of which are small-scale solar projects. With the potential for further deployment of DERs in the province, an opportunity exists to harness their capabilities to reduce system costs, improve reliability and enhance resilience.

Planning Ontario's electricity system involves more than just ensuring adequate supply to meet demand. It also requires consideration of how electricity will be delivered to end users, including analysis of the expected state of the province's transmission system. Although the IESO has been carrying out bulk transmission planning for a number of years, the process was never standardized. Instead, individual studies have been initiated on an as-needed basis.

The IESO has been working to develop a formal, integrated bulk system planning process to ensure solutions are identified transparently as needs materialize. To meet Ontario's electricity needs most efficiently and cost-effectively, the IESO regularly assesses its planning assumptions and reliability criteria. Over the coming year, the IESO intends to conduct a formal review of its reliability criteria.

Summer Capacity Surplus/Deficit
with continued availability of existing resources



The IESO is also exploring competitive transmission procurement as a way to reduce the cost of transmission projects by leveraging market forces and competition. Stakeholder input will inform decisions on the development of a competitive process, including the types of transmission facilities suitable for competition, facility design standards, and potential opportunities for Indigenous communities to participate.

Greenhouse gas emissions from the electricity sector have declined by more than 90 per cent since 2005, and Ontario now has one of the cleanest electricity systems in North America. About 93 per cent of the electricity produced in 2018 was from non-carbon-emitting resources. Emissions are expected to increase in the 2020s as a result of increased production from gas-fired generation during the nuclear refurbishment period and the retirement of the Pickering Nuclear Generating Station. Electricity sector emissions are forecast to increase to 11 megatonnes CO_2e by 2030, still remaining well below 2005 levels.

Over the next 10 years, a number of variables could impact emission levels, leading to lower certainty in emission forecasts. These include advances in generation technology for non-emitting resources, the ongoing role of energy efficiency, carbon policies, and what types of resources are acquired to meet future electricity system needs.

Stakeholder input and feedback are priorities for the IESO and support effective sector-wide decision-making. Ensuring the reliability and cost-effectiveness of Ontario's power system is a collaborative activity that requires close coordination within the organization, and between the IESO and the sector as a whole. This approach brings together experts from all corners of the electricity industry to reconcile views, assumptions, requirements and solutions. Driven by the need to enhance planning transparency, the IESO will continue to investigate improvements to its long-term planning process with stakeholders, with a particular emphasis on regular sharing of information.

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A List of Abbreviations can be found on page 34.

1. Demand Forecast

1.1 Introduction

Satisfying consumer demand for electricity is the IESO's highest priority. The long-term demand forecast sets the context for the *Annual Planning Outlook* (APO) and the bulk power system planning process. That said, electricity demand forecasts are, by definition, inexact. They display inherent uncertainty and reflect dependencies such as the state of the economy, demographics, policy and other considerations. The IESO has developed its demand forecast from the bottom up to consider individual end-uses, building or business types, load profiles and analysis of seven different market sectors.

The demand forecast informs system adequacy and investment decisions by anticipating future needs, which are affected by many factors, including technology, equipment purchasing decisions, consumer behaviour, population, the economy, energy prices, transportation policy, and conservation.

Energy efficiency can have a significant impact on demand for electricity. In light of pending policy decisions with respect to the future of existing energy-efficiency programming beyond the end of 2020, when the current funding framework expires, the IESO has modelled two different cases to develop this demand forecast.

The Reference Case is considered a committed resource case that anticipates no major changes in its drivers over the outlook period, with existing IESO-delivered energy-efficiency programs coming to an end at the end of 2020. The Energy Efficiency Case, by contrast, reflects the continuation of current energy-efficiency programs, and projected benefit and cost outcomes beyond 2020.

This demand forecast is presented on a weather-normalized basis and at the net level, as opposed to actual weather-affected and grid or gross level. Gross-level demand is the total demand for electricity services in Ontario prior to the impact of conservation programs but including the effects of naturally occurring conservation. Net-level demand is gross-level demand minus the impact of conservation. Grid-level demand is net-level demand minus the demand met by embedded resources. It is equal to the energy supplied by the bulk power system to wholesale customers and local distribution companies.

To provide context for the long-term demand forecast, it is informative to understand historical electricity demand trends. Grid-level demand has been declining for the past five years, mainly driven by changes in the economy, conservation program savings, and embedded generation, which reduces the need for grid-supplied energy. Grid-level demand is 2 terawatt-hours (TWh) less (approximately 2%) than five years ago.

Figure 1: Historical Energy Demand

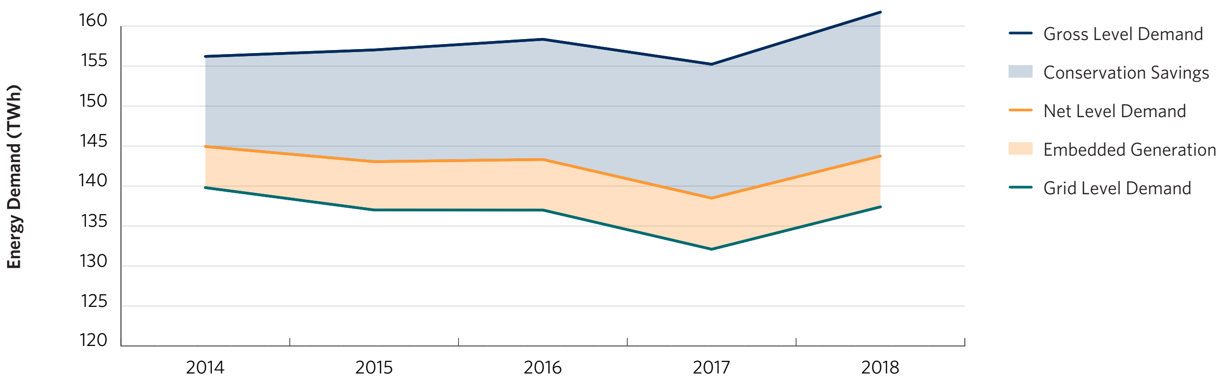


Figure 2: Reference Case – Energy Demand

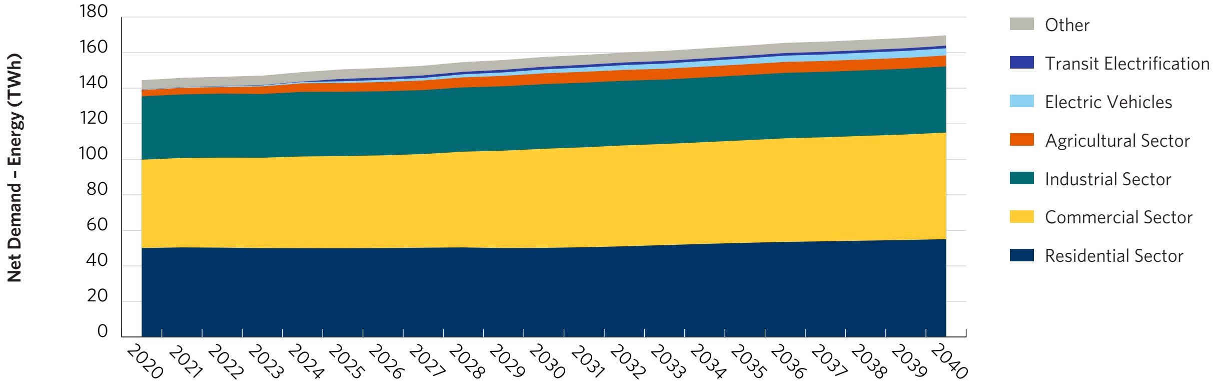
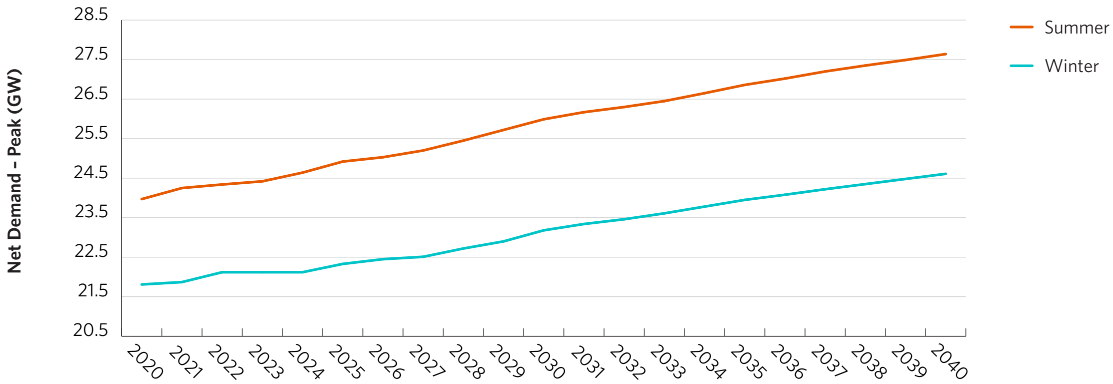


Figure 3: Reference Case – Seasonal Peak Demand



1.2 Reference Case

The demand forecast Reference Case projects annual net energy demand to be 144 TWh in 2020, and to increase an average of approximately 1 per cent per year over the outlook period to 170 TWh in 2040, an overall increase of 26 TWh.

Summer and winter peak demands are expected to experience an average growth rate of approximately 1 per cent, which is similar to the energy demand growth rate. Summer peak demand is projected to be approximately 23,970 megawatts (MW) in 2020, increasing to 27,640 MW in 2040, while winter peak demand is projected to be 21,810 MW in 2020, and 24,610 MW in 2040.

1.3 Energy Efficiency Case

The demand forecast Energy Efficiency Case is an illustrative forecast based on the Reference Case. The only variable that distinguishes it from the Reference Case is the inclusion of possible load modifiers consisting of:

- The continued delivery of the current 2019-2020 Energy Efficiency Interim Framework past its committed end date of December 31, 2020 at currently forecasted savings and approved budget rates, for the duration of the outlook period; and
- The delivery of federally or municipally funded programs affecting electricity demand, including the Green Municipal Fund, and the Climate Action Incentive Fund.

Figure 4: Energy Efficiency Case – Energy Demand

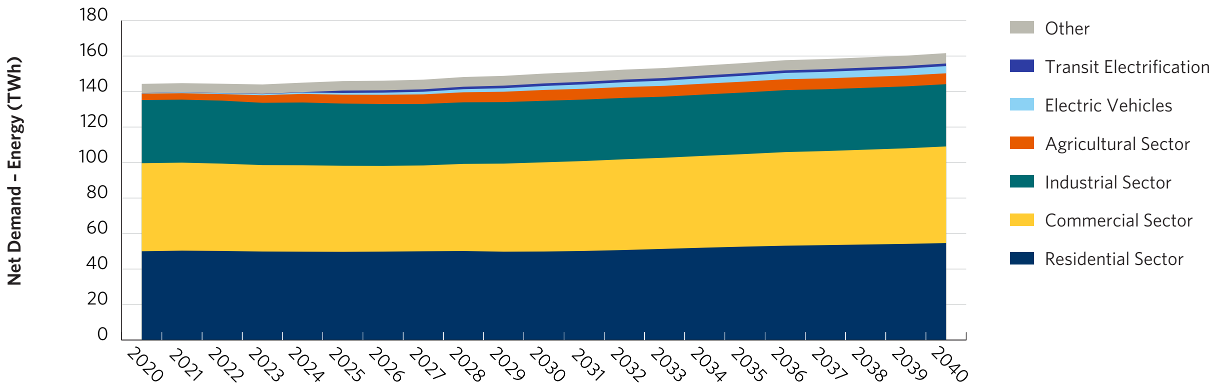
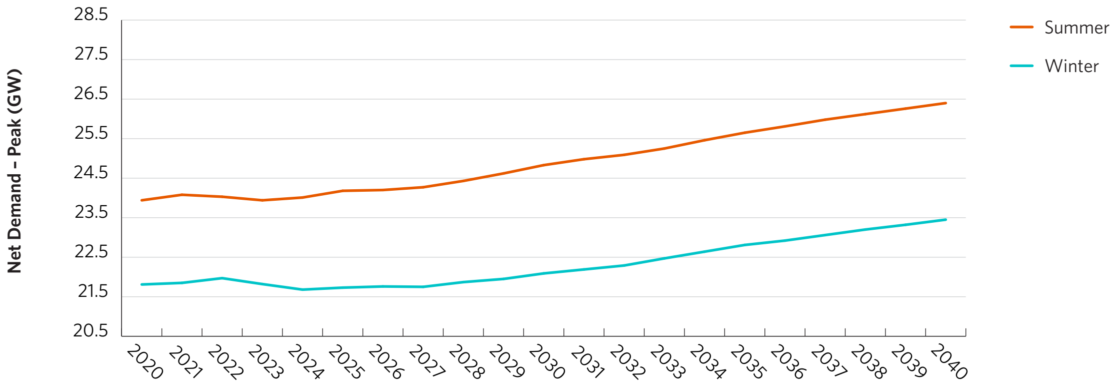


Figure 5: Energy Efficiency Case – Seasonal Peak Demand



The two government programs have recently been announced and are currently in development. Due to the absence of specific program details and associated forecasts of potential energy savings, the impacts on projected electricity demand remain uncertain; as a result, they have been included in the Energy Efficiency Case.

The Energy Efficiency Case projects annual net-level energy demand to be 144 TWh in 2020, and to grow an average of approximately 0.5 per cent per year (between -0.3% and 1.0%) over the outlook period to 162 TWh in 2040.

The difference in energy demand between the Reference Case and Energy Efficiency Case is roughly 1 TWh per year in 2021. This difference is expected to grow by an incremental 1 TWh per year in each year through 2024 to 4 TWh per year, then increase by about 0.6 TWh per year in each year through 2030 to 7.5 TWh per year before stabilizing at about 8 TWh per year from 2031 to 2040.

Summer peak demand is projected to be 23,940 MW in 2020 and grow an average of approximately 0.5 per cent per year (between 0.4% and 0.8%) to 26,400 MW in 2040, while winter peak demand is projected to be 21,810 MW in 2020 and grow an average of approximately 0.3 per cent per year (between –0.7% and +1.2%) to 23,450 MW in 2040.

The annual differences between the Reference and Energy Efficiency Cases for both summer and winter peak demand are roughly 150 MW in 2021, 700 MW in 2024, 1,000 MW in 2029, and 1,200 MW from 2035 to 2040.

1.4 Drivers of Demand

All electricity users – residential, commercial, institutional, industrial and others – contribute to province-wide energy demand. This demand forecast has been developed using sector-level segmentation and corresponding individual assessments. Overall, an expected increase in demand over the outlook period will be largely driven by mild demand growth in the commercial sector and emerging growth in the agricultural and transportation sectors. This increase in consumption may be compounded by the absence of future committed energy-efficiency programs.

1.4.1 Residential Sector

Electricity demand from the residential sector is expected to be flat over the outlook period as a result of offsetting trends. Household growth is forecast to be especially high in the Toronto and Ottawa zones, offset by the shift toward multi-residential high-rise buildings with lower unit energy intensity rates. Increased saturation of small appliances and other consumer electronics is expected to be offset by a decrease in electricity required for water and space heating attributable to mild fuel switching. Overall, total residential sector demand is forecast to grow minimally from 50 TWh in 2020 to 55 TWh in 2040, an average annual growth rate of 0.5 per cent.

1.4.2 Commercial Sector

Commercial sector electricity demand growth is expected to be slow over the outlook period. As is the case with the residential sector, multiple trends offset each other in terms of impacts on electricity demand. Emerging trends in the commercial sector include:

- **Urban construction boom:** Significant residential growth in urban areas, including downtown Toronto and Ottawa, is forecast to continue, which will increase demand for local services (e.g., education, health care, recreation and culture), and put additional pressure on existing facilities to expand their current locations.
- **Shrinking office space needs:** Many businesses are reducing their space – and energy – requirements through alternative workplace strategies and more efficient building design.
- **Declining growth in retail and restaurant businesses:** Shifts in consumer behaviour toward e-commerce and online food delivery services have resulted in softening growth in demand for bricks-and-mortar floor space, which is expected to continue in the future.
- **Supply chain warehouse business growth:** This shift in retail channel preferences is having a domino effect in the commercial real estate market, with increasing demand for large warehousing and logistics distribution hubs to support online shopping and declining demand for storefronts and malls.

Overall, commercial sector total floor space is forecast to grow from 3.4 billion square feet in 2020 to 4.1 billion square feet in 2040, a 19-per-cent increase. The proportion of demand from various end-uses and business types is forecast to be largely consistent over the outlook period. Total commercial sector energy demand, by contrast, is forecast to grow minimally from 50 TWh in 2020 to 60 TWh in 2040, an average annual growth rate of only 0.9 per cent.

1.4.3 Industrial Sector

Ontario's industrial sector has experienced a significant transition over the past 20 years. World economic conditions, particularly in the United States and China, coupled with foreign exchange rate variations, have resulted in a declining market for Ontario exports. Industry has responded to the reduced demand for Ontario products with plant closures and production cutbacks. Electricity demand from industrial wholesale customers has been flat at approximately 17 TWh per year for the past seven years. Five segments, each with geographic concentrations, currently dominate the Ontario industrial sector:

1. Mining (including smelting, in northern Ontario);
2. Primary metal (Hamilton, Cambridge, Nanticoke, and Sault Ste. Marie);
3. Chemical (Sarnia and Nanticoke);
4. Pulp and paper (northern Ontario); and
5. Automobile manufacturing (Windsor, Ingersoll, Cambridge, and the Toronto area).

Mining is the only top-five industrial sector segment to recover from the recession of 2008-2009 in terms of electricity demand. It is also forecast to continue to show the highest growth among all the industrial sector segments. Further, the northwestern Ontario area known as the "Ring of Fire" has been found to contain high quality rare earth metal ores, including chromite (used in the production of stainless steel). Conversely, the recent transition of the General Motors Canada automobile assembly plant in Oshawa, Ontario will have consequences on the supply chain throughout the industry segment in Ontario.

Overall, given current known economic indicators, energy demand from Ontario's industrial sector is forecast to stay flat, at roughly 36 TWh per year over the outlook period.

1.4.4 Agricultural Sector

Demand for electricity from Ontario's agricultural sector continues to grow, driven primarily by greenhouse expansion, as well as the proliferation of artificial lighting in greenhouses. Grow lights enhance production and crop yields of various fruits, vegetables, flowers and cannabis.

One area with significant agricultural sector growth is Kingsville-Leamington where a considerable number of requests to connect to the power system have materialized. Such loads primarily increase winter electricity energy and peak demand. The area's winter electricity demand is projected to increase by approximately 600 MW between 2020 and 2030 as identified in the conservative forecast of the Windsor-Essex Integrated Regional Resource Plan. The annual electricity energy demand for the agricultural sector is projected to increase to 6 TWh by 2030.

1.4.5 Electric Vehicles

Electric vehicle (EV) numbers and their electricity charging requirements are currently relatively small but are projected to increase significantly. In recent years, government policy has been a key driver for increased near-term EV adoption. The federal government has set a long-term target to sell 100 per cent zero-emission vehicles by 2040, with interim sales goals of 10 per cent by 2025 and 30 per cent by 2030. The federal government's 2019 budget included several measures to support EV adoption, including purchase incentives; tax benefits for business vehicles; and support for EV charging infrastructure, automobile manufacturers, and automobile parts suppliers.

A wide range of EV adoption forecasts are available from various organizations, including industry consultants, academic institutions, government agencies and market research companies, with annual sales market share estimates ranging from 1 per cent to 70 per cent in 2030. Actual EV adoption is affected by many factors, including policy, technology and consumer behaviour. The IESO's EV adoption forecast is based on historical trends and available information, such as industry sales data, government vehicle registration data, and forecasts from other reputable organizations.

The IESO projects Ontario's new EV sales will increase 20 per cent year over year over the next 10 years and then stabilize, and Ontario's EV stock will reach about 1.2 million vehicles by 2040 with an annual electricity charging demand of 4 TWh.

1.4.6 Transit Electrification

Broad transit electrification is underway in Ontario, including the GO commuter rail system serving the Greater Toronto Area, local light rail transit (LRT) systems throughout the province and multiple Toronto Transit Commission (TTC) subway line extensions.

Metrolinx, the Crown agency responsible for public transportation for the province, is building an integrated transit network which promotes transit electrification. Electrifying GO rail corridors is a multi-year project with completion expected in 2025. Built on previous environmental assessments and public engagement, the first step to electrify Metrolinx-owned corridors, the Transit Project Assessment Process, was completed in 2017.

Nine local LRT projects and multiple subway line extensions are being built or planned across the province. The ION project connecting Kitchener and Waterloo came into service in June 2019 and the Confederation Line in Ottawa opened in September 2019. New TTC subway projects, including the planned Ontario Line and several subway line extensions in the GTA, have been announced and early preparations are underway.

Demand projected for new transit electrification is based on most recent plans and schedules. This demand forecast predicts that annual electricity demand for public transit will be about 1.5 TWh when all the planned transit projects are in operation.

1.4.7 Other Electricity Demand

This demand forecast accounts for all electricity energy and peak demand in the province, which is generally categorized and evaluated according to established market sectors. However, certain loads do not fall under any one sector and are classified as "other." These include:

1. Remote communities;
2. Electricity generators;
3. Street lighting; and
4. Municipal water treatment.

The demand forecast projects these four segments to consume 5.2 TWh in 2020. A number of small remote communities in northern Ontario are not currently connected to the provincial electricity grid but will be within the next few years. Connecting these communities to the grid is expected to add approximately 0.2 TWh of annual energy demand by 2040. Collectively these four "other" load categories are expected to grow minimally but consistently over the course of the outlook to 5.9 TWh in 2040, an annual increase of 35 GWh or 0.6 per cent per year, for a total increase of 0.7 TWh or 14 per cent.

1.4.8 Energy-Efficiency Programs

On March 21, 2019 the 2015-2020 Conservation First Framework (CFF) and Industrial Accelerator Program (IAP) Framework were discontinued and replaced with an Interim Framework to be delivered through December 31, 2020.

The CFF and IAP Frameworks wind-down phase allows projects initiated prior to March 2019 to be completed where electricity savings can be achieved. These wind-down activities are expected to achieve annual electricity savings of 0.8 TWh in 2020.

The Interim Framework came into effect on April 1, 2019. The IESO's Program Plan for the delivery of the Interim Framework was released on June 5, 2019, with programs offered in Ontario from April 1, 2019 to December 31, 2020. The Program Plan aims to achieve annual energy savings of 1.4 TWh and peak demand reductions of 189 MW, funded with a total budget of $353 million.

Collectively, all energy-efficiency programs from the CFF, IAP and Interim Framework implemented in 2019 and 2020 are expected to realize annual electricity savings in 2020 of 2.2 TWh. These savings are accounted for in the Reference Case.

Demand Forecast Energy Efficiency Case

Beyond energy-efficiency program savings included in the demand forecast Reference Case, there are potential opportunities to achieve greater electricity savings. Based on the information available to date, there are at least three such opportunities as summarized in Table 1 and forecast to achieve the savings illustrated in Figure 6.

Given that these three potential energy-efficiency initiatives are not currently committed or are at an early stage of development, estimates of corresponding energy savings reflect a high degree of uncertainty.

1.4.9 Codes and Standards

Building codes and equipment standards are an effective energy-efficiency tool as they have no ratepayer cost, broad reach, and a relatively high level of certainty when forecasting results. Codes

Table 1: Demand Forecast - Energy Efficiency Case (Summary)

#	Program & Delivery Agent	Details, Funding & Target	Governance & Funding	Policy, Fuel Type & Support	Period	Incremental Annual Savings & Savings in 2040
1	**Post-2020 Save on Energy Programs** • Delivered by the IESO	• Not committed, assumes continued delivery of Interim Framework at current funding and energy-savings rates • Funding of $177 million/year • Focused on business and industrial customers, with ongoing commitment to low-income and First Nations communities	• Provincial • Ontario electricity rates or tax	• Energy efficiency • Electricity • Incentives	2021-2040	• 0.7 TWh incremental annual energy savings • 8 TWh annual energy savings in 2040
2	**Climate Action Incentive Fund** • Funded by the federal government	• Announced May 30, 2019, subject to the passage of the Budget Implementation Act. Program development underway • Ontario's allocation about $975 million from 2020-2024 • Available to small businesses, municipalities, universities, schools, hospitals and not-for-profit organizations	• Federal • Funded from proceeds of the federal carbon pollution pricing system	• Carbon emission reduction • All fuels • Rebates	2020-2024	• Maximum incremental annual energy savings of 0.34 TWh in 2023 • 0.16 TWh annual energy savings in 2040
3	**Green Municipal Fund** • Delivered by Federation of Canadian Municipalities via: 1. Collaboration on Community Climate Action 2. Community EcoEfficiency Acceleration 3. Sustainable Affordable Housing Innovation 4. Municipal Asset Management Program	• Ongoing development • Investment of $1 billion in 2018-2019 • Residential, commercial and multi-unit buildings	• Federal • Federal tax	• Energy efficiency • All fuels • Primarily financing, some grants	2021-2040	• Estimated incremental annual energy savings of 0.01 TWh • 0.11 TWh annual energy savings in 2040

Figure 6: Energy Efficiency Case - Incremental Energy-Efficiency Savings

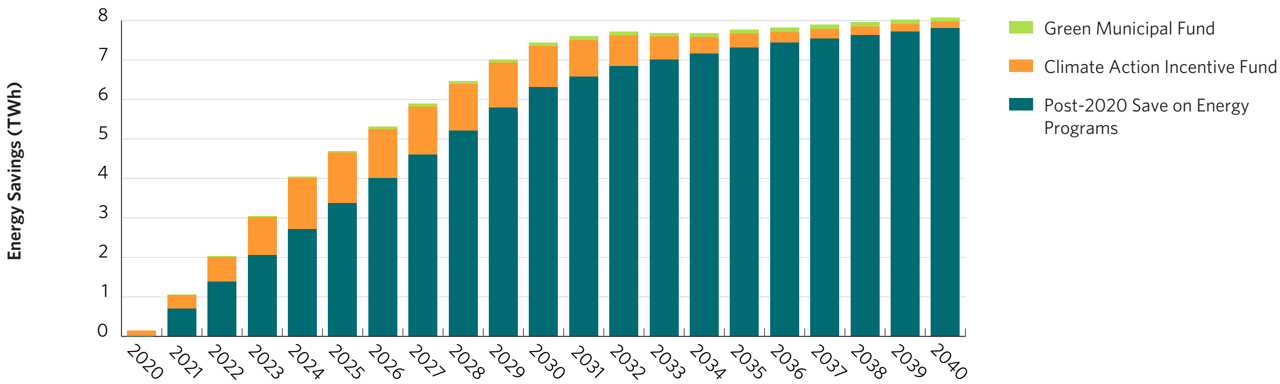
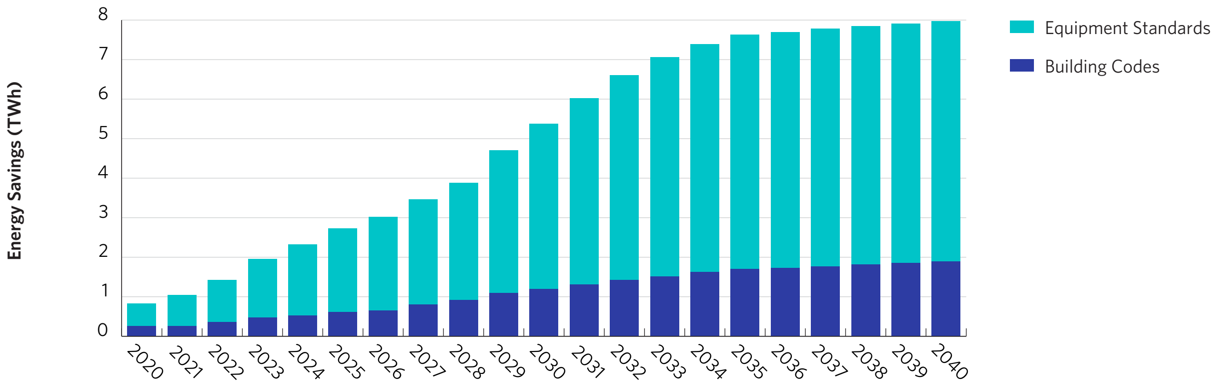


Figure 7: Codes and Standards Savings



and standards savings estimates are based on the expected improvement in the codes for new and renovated buildings and for specified end-uses through the regulation of minimum efficiency standards for equipment. The IESO estimates savings attributable to codes and standards by comparing the demand forecast at the gross level to the demand forecast adjusted for the impacts of regulations. Most savings from improved codes and standards will come from the residential and commercial sectors and are estimated to reduce demand by an additional 8 TWh by 2040.

1.4.10 Industrial Conservation Initiative

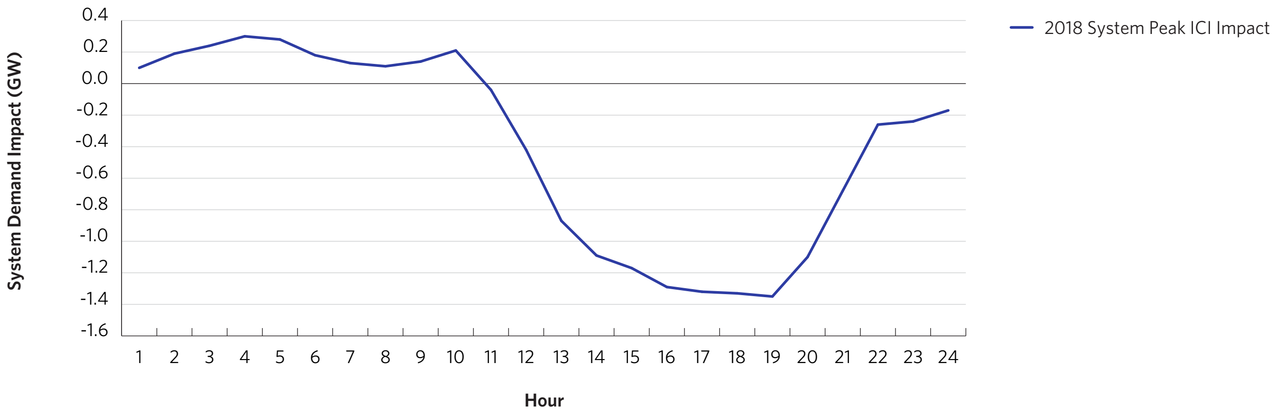
The Industrial Conservation Initiative (ICI) is a form of demand response that provides reduced electricity costs to program participants that reduce their electricity consumption during periods of peak electricity demand. Participant eligibility has been unchanged for two years and provides a reasonable sample set from which to assess and project the program's long-term impacts. The IESO projects ICI system peak-demand reduction impacts to remain at 2018 levels. ICI drivers, including customer ICI program investment and Global Adjustment levels, will inevitably change over the course of the outlook period and the ICI impacts on the demand forecast methodology will be reassessed on an annual basis.

In 2018, the ICI delivered an average demand reduction of approximately 1,600 MW[1] in the top 10 demand hours, and a maximum ICI reduction of 1,717 MW. The maximum ICI reduction on the peak demand day, and during the peak demand hour, was 1,347 MW and 1,330 MW, respectively.

The aggregate impact from all ICI participants on the 2018 system peak day is shown in Figure 8.

[1] All ICI figures based on reported estimates.

Figure 8: Industrial Conservation Initiative – Peak System Day Hourly Demand Impact



1.5 Conclusion

The IESO continues to monitor and interpret electricity demand drivers and other factors to develop and continuously improve demand forecasts. Demand forecasts are the basis of integrated planning. The demand forecast has been thoroughly developed, refined and reviewed by stakeholders as part of the IESO's commitment to transparency, consistency and engagement.

Key uncertainties over the next few years will include the extent and pace of industrial sector growth, potential changes to ICI program rules, the success of the Interim Framework on Energy Efficiency, agricultural sector load growth in southern Ontario, electric vehicle adoption and the potential growth of embedded generation in Ontario. Uncertainties in the longer term also reflect technological advances, changing customer preferences/choices and the potential for further economic fluctuations.

Demand Forecast: Key Highlights

- The IESO developed two demand cases, one that reflects the planned expiration of existing energy-efficiency programs at the end of 2020 (the Reference Case) and one that reflects the continuation of these programs beyond 2020 (the Energy Efficiency Case).
- Under the Reference Case, annual net energy demand will be 144 TWh in 2020 and will increase an average of approximately 1 per cent per year over the outlook period to 170 TWh in 2040, an overall increase of 26 TWh.
- Under the Energy Efficiency Case, annual net energy demand will be 144 TWh in 2020 and will increase an average of approximately 0.5 per cent per year (between –0.3% and 1.0%) over the outlook period to 162 TWh in 2040, an overall increase of 18 TWh.
- Under the Reference Case, summer peak demand is projected to be 23,970 MW in 2020 and will increase to 27,640 MW in 2040. Winter peak demand is projected to be 21,810 MW in 2020 and will increase to 24,610 MW in 2040.

2. Supply Outlook

2.1 Ontario's Installed Capacity in 2019

2.1.1 Fuel Type

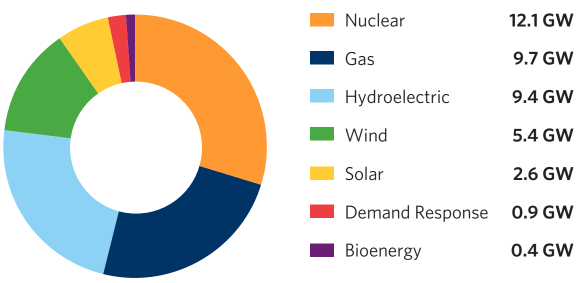
Ontario has 40.5 gigawatts (GW) of installed capacity comprising a diverse mix of resources.

The majority of Ontario's installed capacity comes from nuclear (30%), gas (24%), and hydroelectric (23%) resources, with the remainder from wind (13%), solar (6%), demand response (2%) and bioenergy (1%). The IESO has also procured 111 MW of energy storage for various reliability services. Most of Ontario's capacity is supplied by transmission-connected market participants (91%); the rest is supplied by embedded generators (9%). Both types of resources are included in the capacity assessment.

2.1.2 Seasonal Capacity

There is a fundamental difference between installed capacity and effective capacity. No resource is capable of producing energy at maximum output levels at all times, making effective capacity a more meaningful value for planning purposes. A resource's summer and winter effective capacity is an estimate of its contribution to meeting seasonal capacity needs. The effective capacity calculation takes into consideration expected ambient temperature, forced (i.e., unplanned) outages and fuel availability risks. Total installed capacity for the entire fleet is 40.5 GW, while summer and winter effective capacities are 28.0 GW and 29.6 GW respectively. More detail by fuel type is provided in the data tables at www.ieso.ca/apo.

Figure 9: 2019 Installed Capacity by Fuel Type



2.2 Ontario's Installed Capacity Supply Outlook: 2020-2040

Figure 10 shows the installed capacity (GW) by fuel type for the outlook period (2020-2040). Due to the refurbishment and/or retirement of the nuclear fleet, total installed capacity varies between 37 and 41 GW during the 2020s, before levelling off at 40 GW in the 2030s. The supply mix, over the course of the outlook, generally reflects the supply mix shown in Figure 9.

Figure 10: Installed Capacity 2020-2040

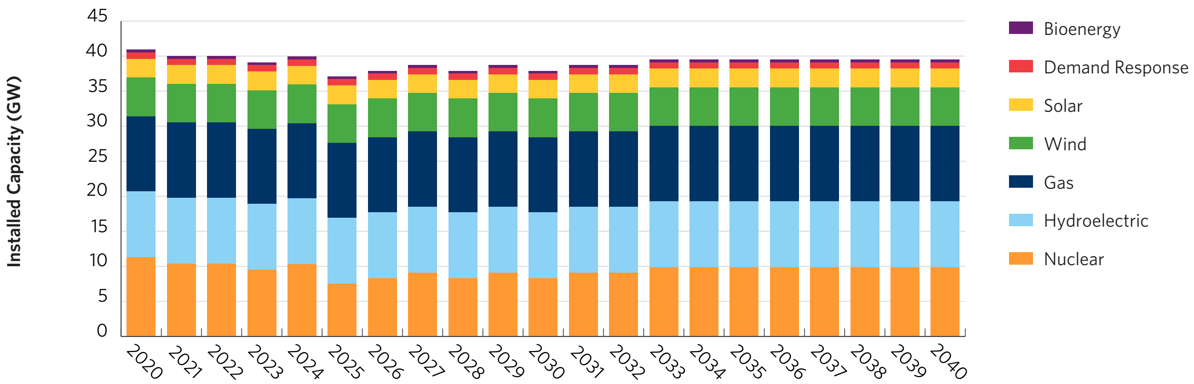


Figure 11: Summer Effective Capacity 2020-2040

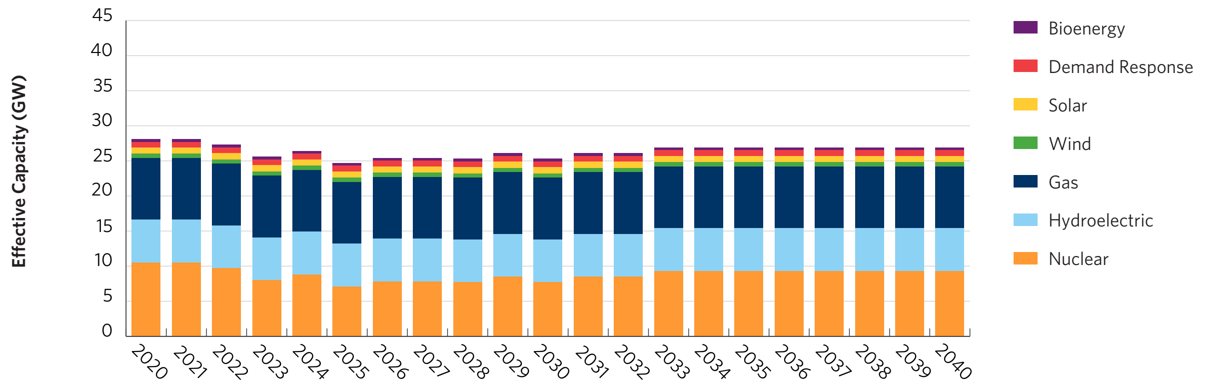
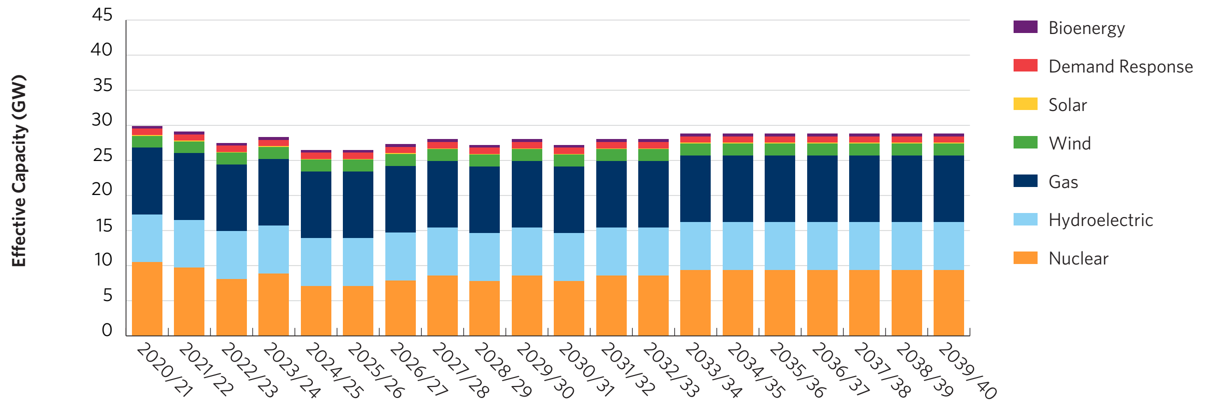


Figure 12: Winter Effective Capacity 2020-2040



Figures 11 and 12 show the summer effective and winter effective capacities, by fuel type, for the outlook period 2020-2040. Summer effective capacity varies between 25 and 28 GW during the 2020s, due to the refurbishment of the nuclear fleet, and then levels off at 27 GW in the 2030s.

2.3 Nuclear Resources

Throughout the 2020s, Ontario's electricity system will see significant turnover in its nuclear fleet, driven by nuclear refurbishments and retirements.

Long-term refurbishment outages at the Darlington and Bruce stations will increase resource needs and introduce greater uncertainty in the resource outlook. By 2033, a total of 8.4 GW of nuclear capacity will undergo refurbishment. The first Darlington unit went offline for refurbishment in 2016 and is expected to return to service in 2020.[2] Refurbishment activity will increase in the 2020s, with between two and four nuclear units out of service each summer until 2029. Darlington and Bruce refurbishments are expected to be complete in 2026 and 2033, respectively.

Pickering Nuclear Generating Station (NGS) is expected to retire in the mid-2020s, reducing Ontario's installed nuclear capacity by 3.1 GW. With the two Pickering A units scheduled to go out of service at the end of 2022, and the remaining four units at Pickering B following in 2024, the Pickering NGS retirement is a major contributor to upcoming resource needs. If approved, a proposal by Ontario Power Generation would see Pickering NGS units continuing to operate beyond their scheduled shutdown dates.

[2] Resource assessments in the APO were completed before Ontario Power Generation announced a four-month extension to the Darlington G2 refurbishment outage. This change is not expected to impact the overall nuclear refurbishment schedule.

Figure 13: Base Case Nuclear Refurbishment and Retirement Schedule

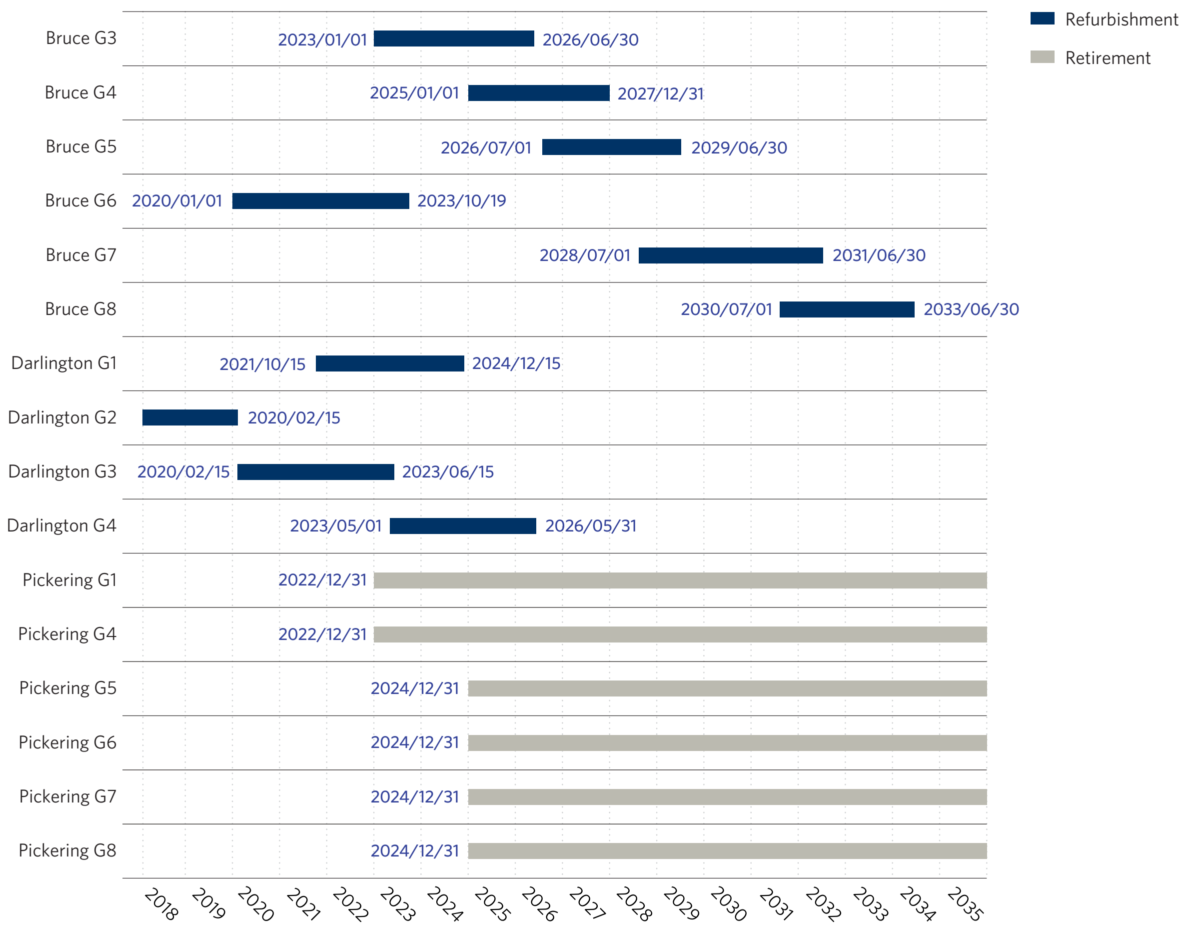


Figure 14: Nuclear Refurbishment Outages – Number of Units and Installed Capacity at Summer Peak

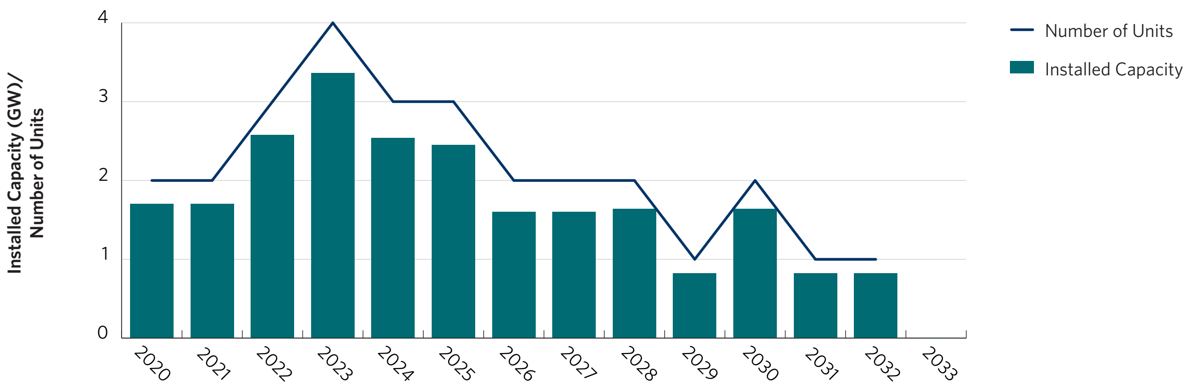


Figure 15: Existing Resources Post-Contract Expiry 2020-2040 by Fuel Type

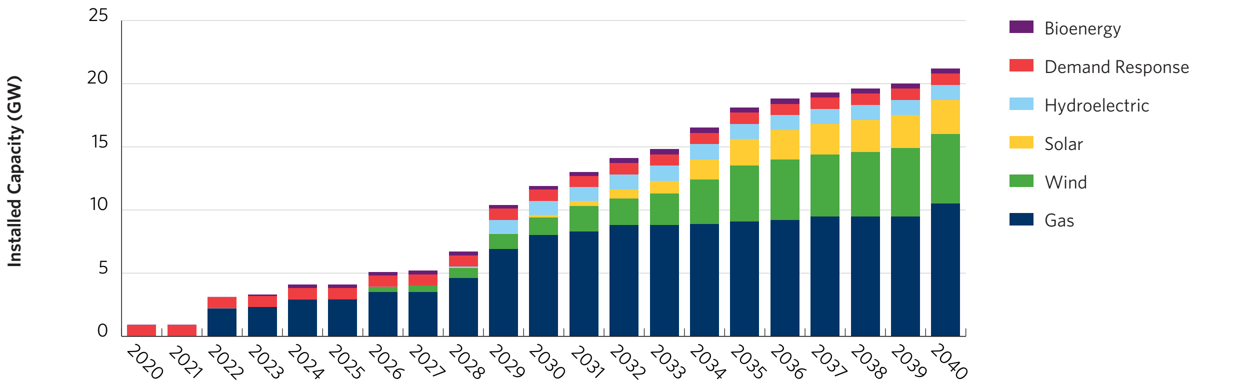
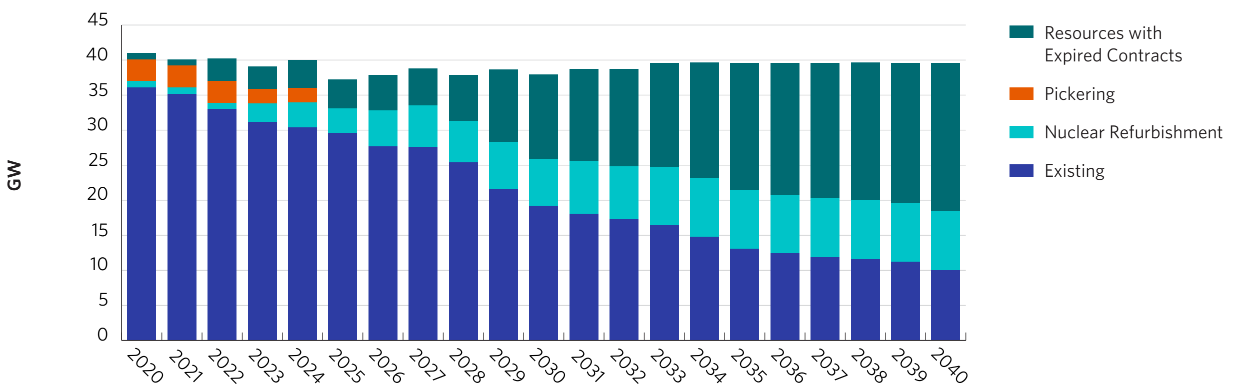


Figure 16: Installed Capacity by Commitment Type 2020-2040



2.4 Commitments Ending 2020-2040

Over the course of the outlook period, many generation contracts held by the IESO or the Ontario Electricity Financial Corporation will expire. In addition, the 2018 demand response (DR) auction committed capacity only until April 2020.[3] Contracted generators and existing DR capacity could continue to meet the IESO's capacity needs if these resources are successful in future acquisition mechanisms.

Material contract turnover begins in the 2020s and becomes significant by the end of the decade. Contracts and commitments that expire in the 2020s are primarily gas and DR resources, while wind, hydroelectric and solar contracts begin to expire in the 2030s.

Later in this report, scenarios with and without existing resources post-contact expiry will be examined.

The resource outlook includes considerable change through the 2020s and early 2030s due to the combined effect of nuclear retirement, refurbishment outages and contract expiry. The installed capacity outlook by commitment type illustrates the growing role of resources with expired contracts and units expected to complete nuclear refurbishment.

[3] The 2019 DR auction, which was held in December 2019, committed capacity for the summer 2020 and winter 2020/2021 periods; the results of that auction were not available at the time of this analysis and are, therefore, not included.

Supply Outlook: Key Highlights

- The majority of Ontario's installed capacity comes from nuclear (30%), gas (24%), and hydroelectric (23%) resources, with the remainder derived from wind (13%), solar (6%), demand response (2%), and bioenergy (1%). The IESO has also procured 111 MW of energy storage for various reliability services.
- Most of Ontario's capacity is supplied by transmission-connected market participants (91%), with the rest being supplied by embedded resources (9%).
- Turnover in nuclear resources continues through the 2020s as refurbishments proceed. The retirement of Pickering NGS in the mid-2020s is one of the drivers for incremental capacity needs looking ahead.
- Over the course of the outlook period, many contracts held by existing resources with the IESO or the Ontario Electricity Financial Corporation will expire. Contracts that expire in the 2020s are primarily gas; wind, hydroelectric and solar contracts begin to expire in the 2030s.

3. Resource Adequacy

3.1 Overview

A key aspect of power system reliability is resource adequacy, which describes the balance of supply and demand in the system. While risks to power systems, such as extreme weather and generator outages, could cause situations in which supply is unable to meet demand for a period of time, an adequate system has enough capacity to mitigate these risks. The IESO calculates capacity requirements by performing a resource adequacy assessment.

The probabilistic risk assessment compares the demand forecast with anticipated resource performance to simulate the range of possible future system conditions. Loss of load expectation (LOLE) is a measurement of resource adequacy, defined as the average number of days per year during which supply is expected to be insufficient to meet demand. Reliability standards[4] require that the IESO maintain enough capacity such that the LOLE is no greater than 0.1 days/year. As resources enter and exit the market, the IESO's capacity requirements will change.

The same standards set out the risks the IESO should consider in adequacy assessments. For example, actual demand may be higher or lower than forecast depending on weather conditions. Resources may be unavailable in real time due to planned maintenance or equipment failures. Variable generators – like wind and solar – provide relatively low levels of firm capacity since they are sensitive to environmental conditions and cannot always produce energy when required. Finally, major projects, such as the ongoing nuclear refurbishments, may not be completed on time and generators could potentially experience a higher failure rate afterward.

Resources are assessed in terms of effective capacity, which is typically lower than installed capacity, as was discussed in Chapter 2. The capacity requirements in this section are in the same units (MW). The total resource requirement is the amount of effective capacity needed to meet resource adequacy standards, and the reserve margin requirement is the amount by which the total resource requirement exceeds peak demand under normal weather conditions.

Summer capacity needs are generally much higher than winter capacity needs. The main driver of this difference is demand, with summer peaks tending to be higher and more variable than winter peaks. Existing resources, particularly gas, hydroelectric and wind, also provide less capacity value in the summer season compared to the winter season. If existing resources continue to be available, nearly all remaining capacity needs occur in the summer season.

3.2 Reserve Margin

The IESO maintains an adequate reserve margin to ensure there is enough electricity available to compensate for volatility in factors that impact supply and demand.

In accordance with Section 8.2 of the Ontario Resource and Transmission Assessment Criteria (ORTAC), the IESO annually publishes a five-year forecast of reserve margin requirements at the time of projected annual peak.[5] Requirements are compared to the amount of effective capacity available from existing resources.

Table 2: Five-Year Reserve Margin

	2020	2021	2022	2023	2024
Reference Case Summer Peak Demand (MW)	23,970	24,250	24,340	24,420	24,640
Summer Effective Capacity (MW)	28,100	28,120	27,300	25,660	26,460
Total Resource Requirement (MW)	26,950	26,680	27,060	27,740	27,070
Reserve Margin Available (MW)	4,130	3,870	2,960	1,240	1,810
Reserve Margin Requirement (MW)	2,980	2,430	2,720	3,320	2,430
Capacity Surplus (MW)	1,150	1,440	240	-2,080	-620
Reserve Margin Available (%)	17%	16%	12%	5%	7%
Reserve Margin Requirement (%)	12%	10%	11%	14%	10%

[4] NPCC's Regional Reliability Reference Directory # 1 Design and Operation of the Bulk Power System, available at www.npcc.org
IESO's Ontario Resource and Transmission Assessment Criteria, Section 8, available at www.ieso.ca

[5] Historically, the IESO has published this forecast as a standalone document, the Ontario Reserve Margin Report. Going forward, the APO will satisfy this requirement.

Figure 17: Reserve Margin Requirement 2020-2040

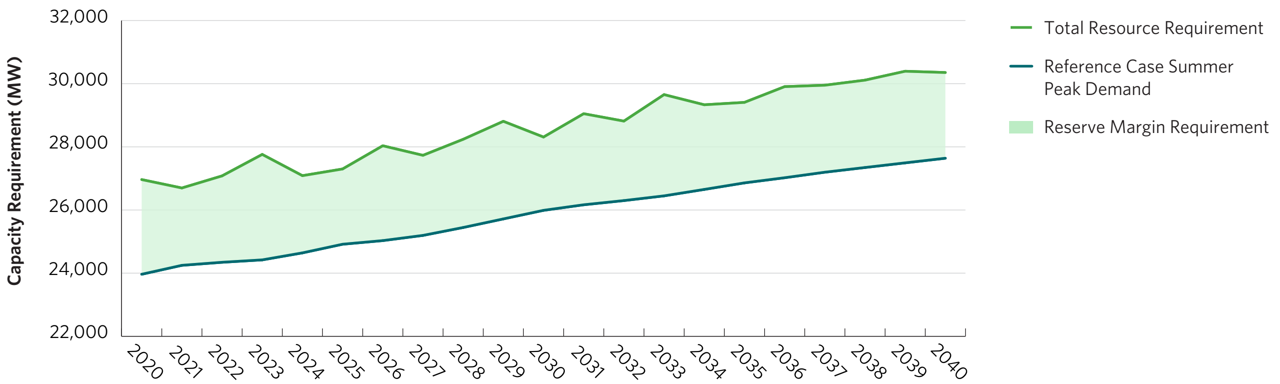


Figure 18: Summer Capacity Surplus/Deficit, with Continued Availability of Existing Resources

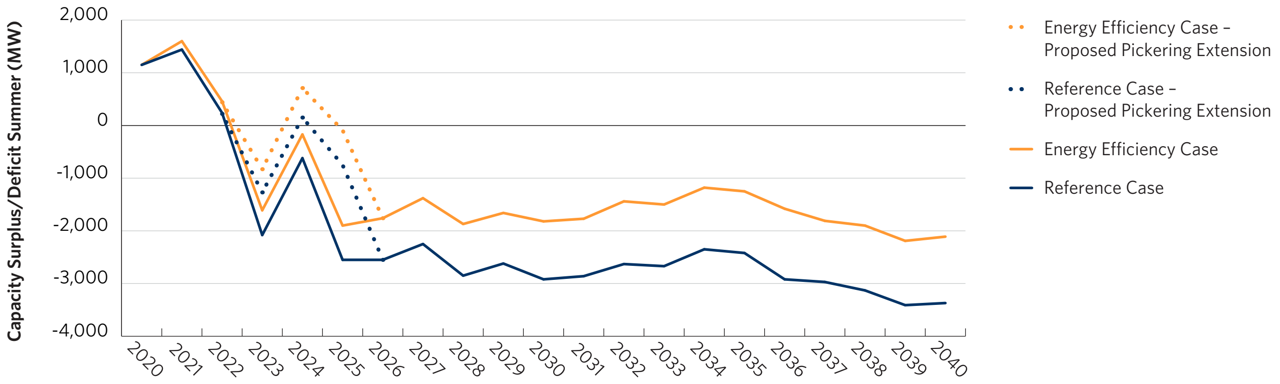
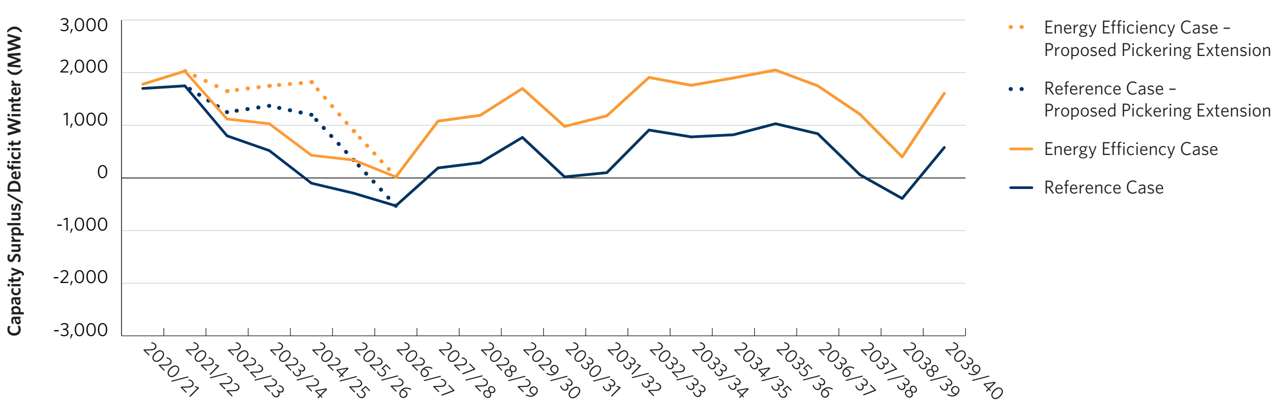


Figure 19: Winter Capacity Surplus/Deficit, with Continued Availability of Existing Resources



There are many reasons why the reserve margin requirement will vary from year to year. The IESO includes additional reserve to account for risks associated with nuclear refurbishments, with the amount varying depending on the refurbishment schedule. A year with higher-than-average planned outages will also have a higher reserve margin requirement. Finally, the methodology to calculate effective capacity for each resource type also affects the reserve margin.

3.3 Capacity/Surplus Deficit

An intuitive way to understand future capacity needs is in terms of surplus or deficit, relative to a set of resource assumptions. Results in this chapter assume the continued availability of existing resources post-contract expiry. In this resource scenario, the capacity deficit, or need, represents the minimum amount of new capacity that must be acquired from resources not currently registered in the IESO market or otherwise providing capacity to the IESO. A discussion of capacity needs without the continued availability of existing resources past contract expiry, as well as options for meeting those needs, is presented in Chapter 5.

The resource adequacy assessment was performed for the summer and winter seasons using the two demand forecasts outlined in Chapter 1.

In the next decade, up to 3,000 MW of new summer capacity will be needed in the Reference Case, with just over 2,000 MW required by 2023. If the proposed extension of Pickering NGS is approved, the capacity need would become 1,200 MW. In the Energy Efficiency Case, no more than 2,000 MW is needed over the same period.

Major planned generator outages affect the capacity need. The nuclear refurbishment program is particularly important, with between two and four nuclear units out of service each summer until 2029. Peak refurbishment activity occurs in summer 2023, when four nuclear units (totalling 3,364 installed MW) are out of service. The capacity need is lower in summer 2024 because there are fewer major outages planned for that season.

3.4 Locational Considerations

The capacity requirements presented in this chapter are the total amount needed to reliably meet provincial demand for electricity. However, the location of resources on the system also affects resource adequacy. Transmission limitations can prevent capacity from being delivered to where it is needed. To manage major transmission limitations that impact capacity acquisition, the IESO will continue to apply minimum or maximum capacity limits to certain regions of the province, as required.

Transmission constraints in the resource adequacy assessment are modelled using major transmission interfaces and the 10 IESO electrical zones. The process for setting zonal limits is under development as part of the work related to the IESO's capacity auction.

Current studies indicate that summer capacity needs in the mid-2020s will occur mainly in the GTA and eastern Ontario (i.e., Toronto, Essa, East and Ottawa zones). With the retirement of Pickering NGS and the Darlington refurbishment, this area will have much less generation capacity available than it has today.

Capacity constraints on the Flow South interface will limit the amount of capacity that can be added in northern Ontario (i.e., Northwest and Northeast zones). The Flow East Toward Toronto interface is also a key consideration. There will likely be limits on the amount of capacity that can be accommodated in southwest Ontario (i.e., Southwest, West, Niagara and Bruce zones), requiring some portion of new summer capacity in the mid-2020s to be acquired in the Toronto, Essa, East, or Ottawa zones. Further discussion of key transmission system considerations can be found in Chapter 6.

Resource Adequacy: Key Highlights

- In the next decade, up to 3,000 MW of new summer capacity will be needed in the Reference Case, with just over 2,000 MW required by 2023. In the Energy Efficiency Case, the summer capacity need decreases to just over 1,600 MW in 2023, and less than 2,000 MW in 2030. This assumes all existing generation resources continue to have an obligation to supply capacity. Should these generators exit the market, the need would be higher.
- Major planned generator outages affect the need for capacity. The nuclear refurbishment program is particularly important, with between two and four nuclear units out of service each summer until 2029. Peak refurbishment activity occurs in summer 2023, when four nuclear units (totaling 3,364 installed MW) will be out of service.
- Assuming all existing resources remain available and compete to provide capacity, nearly all remaining capacity is required for the summer season only.
- Transmission limitations can prevent capacity from being delivered to where it is needed. To manage major transmission limitations that impact capacity acquisition, the IESO will continue to apply minimum or maximum capacity limits to certain regions of the province, as required. Current studies indicate that summer capacity in the mid-2020s is required mainly in the GTA and eastern Ontario (i.e., Toronto, Essa, East and Ottawa zones).

4. Energy Outlook

4.1 Overview

Energy dispatch models allow the IESO to simulate how supply resources might participate in the energy market over the forecast period. Plant details such as startup times, ramp rates and marginal energy costs are used to replicate real-world scheduling, unit commitment and dispatch as closely as possible. It should be noted that all results are for a typical year. Variations in weather from one year to the next can cause large swings in energy demand and production from wind, solar and hydroelectric resources. Median conditions are assumed for weather-sensitive generators.

4.2 Energy Adequacy Outlook

The purpose of the energy adequacy outlook is to assess Ontario's ability to meet its own electricity needs and better characterize the nature of future needs. The simulation does not include any economic imports or exports across Ontario's interconnections. Contracted energy imports are included.

Ontario is expected to have an adequate supply of energy, provided existing resources continue to be available post-contract expiry. In this scenario, current amounts of renewable generation continue and production from gas-fired generators ramps up to meet growing demand.

The energy adequacy outlook indicates that Ontario's supply needs over the next decade are principally for managing risk. Existing resources can meet energy demands in most circumstances. The capacity requirement will be for only a few hours each year, and to help the system handle unlikely events.

Although existing resources are sufficient to meet future energy needs, new resources will have the opportunity to compete with existing resources in the energy and ancillary services markets. Any resource can earn revenue by offering energy at a lower price than the marginal resource (see Section 7.1). Flexible, dispatchable resources can also quickly react to short-term energy price spikes or sell operating reserve.

Another way to understand how often new capacity will be needed is through duration curves. The curve displays a year's hourly electricity demand from highest to lowest. For Ontario, the leftmost part of the curve represents the annual peak on a hot summer day, while the rightmost part of the curve is minimum demand overnight in the fall and spring.

Figure 20: Reference Case – Energy Adequacy Outlook, with Continued Availability of Existing Resources

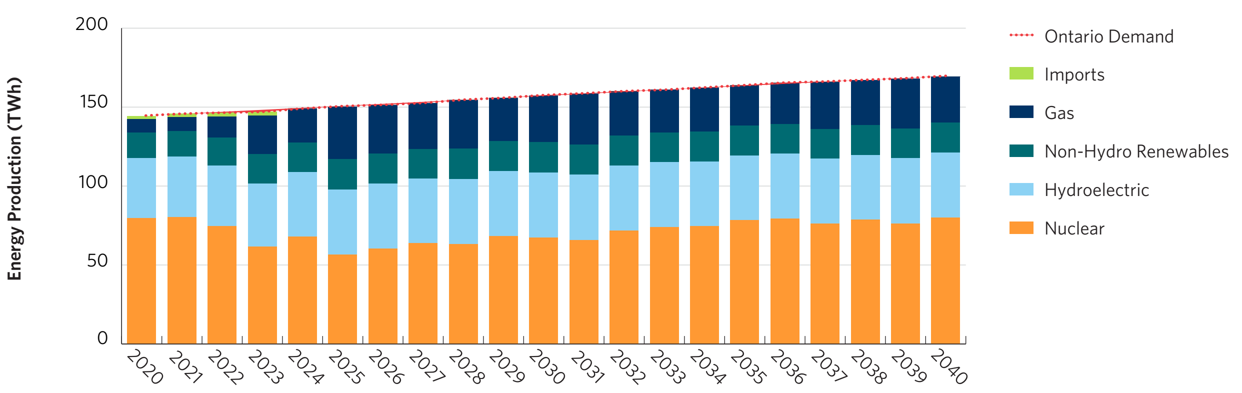


Figure 21: Duration Curves, with Continued Availability of Existing Resources

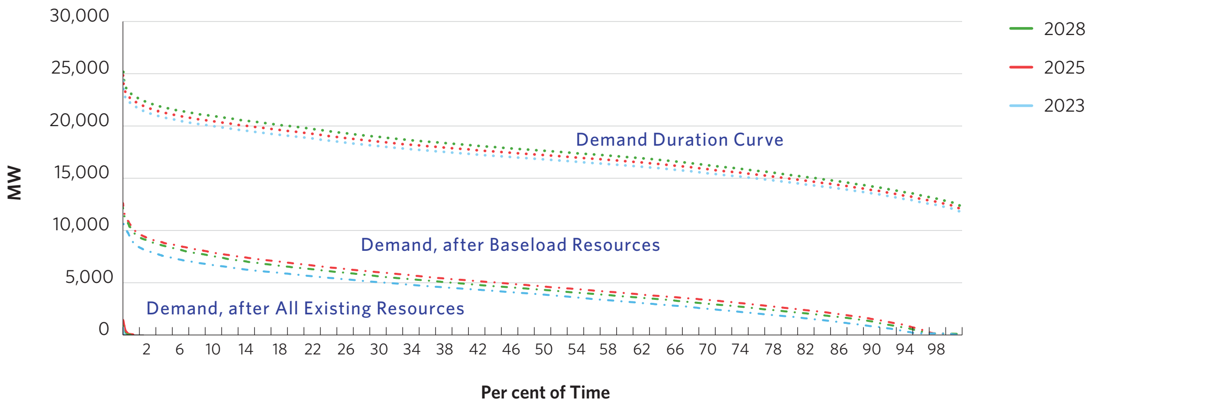
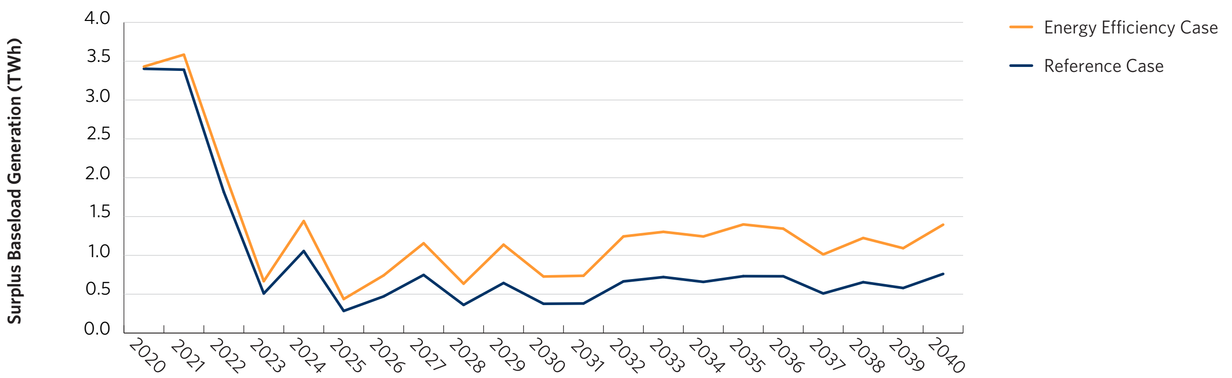


Figure 22: Surplus Baseload Generation, with Continued Availability of Existing Resources



The forecast duration curves for several years in the mid-2020s are shown in Figure 21. Directly below is another set of curves representing the remaining demand after the contribution from baseload resources – nuclear, run-of-river hydroelectric, wind, solar, and combined heat and power. This remaining demand is supplied by dispatchable resources like gas, peaking hydroelectric, storage and imports. The lowest curve at the lower left of the figure represents the residual requirement after dispatchable generation. Resources beyond what the existing fleet can provide would be required to meet this need.

Surplus baseload generation (SBG) occurs when output from baseload resources exceeds demand. It is a normal outcome of electricity markets with high shares of non-dispatchable (i.e., baseload and intermittent) resources. Periods of SBG require the IESO to use market mechanisms, such as exports, variable generation curtailment, and nuclear curtailment, to correct the imbalance. Curtailing generation can be costly to ratepayers because contracted generators still receive payments for energy that would otherwise have been produced, increasing the effective cost of this resource compared to its value in meeting system needs. In the APO study period, SBG is expected to continue to be managed using existing market tools.

SBG is forecast to decrease due to rising demand and the retirement of Pickering NGS (3,102 MW installed capacity, with output of 19-21 TWh/year). There are many uncertainties in the outlook for SBG. The energy adequacy outlook represents typical weather conditions, but high hydroelectric production or milder weather could lead to higher SBG.

Figure 23: Reference Case – Energy Production Outlook

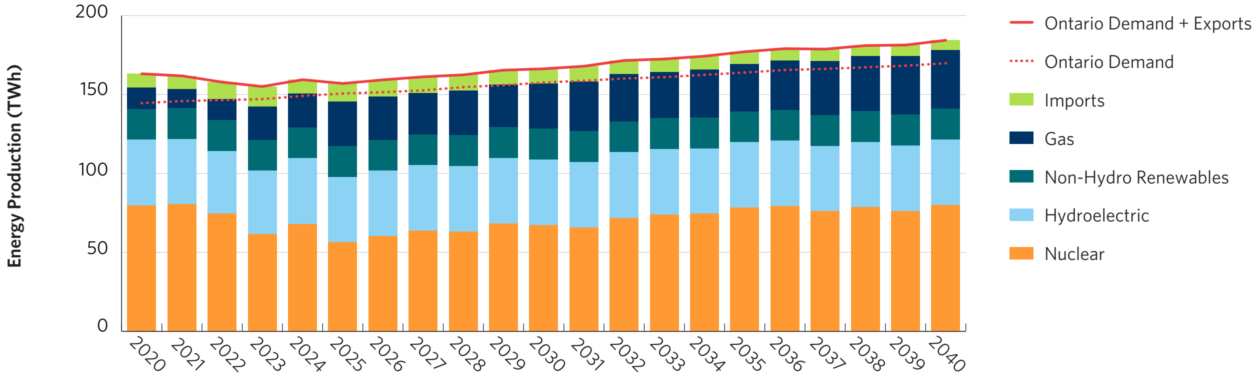
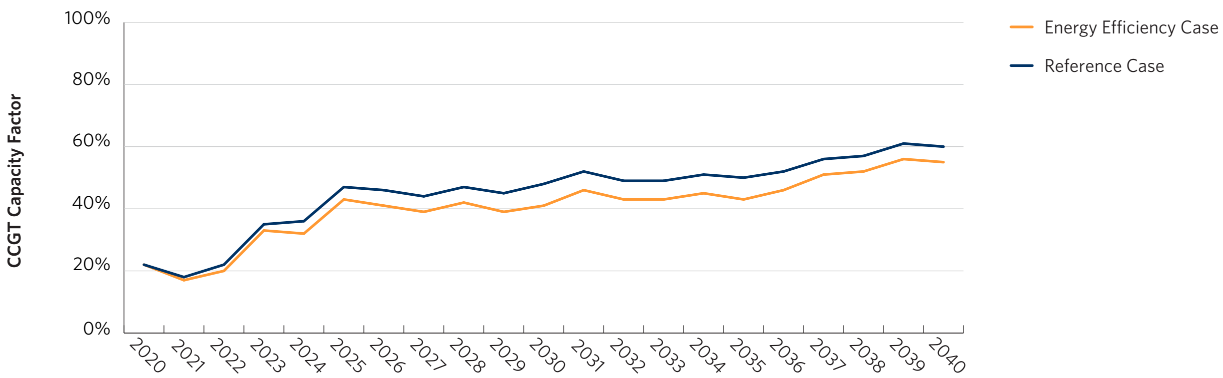


Figure 24: Energy Production Outlook, CCGT Capacity Factor with Continued Availability of Existing Resources



4.3 Energy Production Outlook

The IESO-administered energy markets are connected to Ontario's neighbours through interconnections. Imports and exports are scheduled in the real-time energy market to take advantage of price differences between jurisdictions. In 2018, Ontario imported 8.4 TWh of energy and exported 18.6 TWh. The model used to produce this energy production outlook includes detailed representations of Ontario's trading partners in order to more closely represent expected conditions and market outcomes. While the energy adequacy outlook is useful for characterizing resource needs, the energy production outlook is needed to forecast market outcomes.

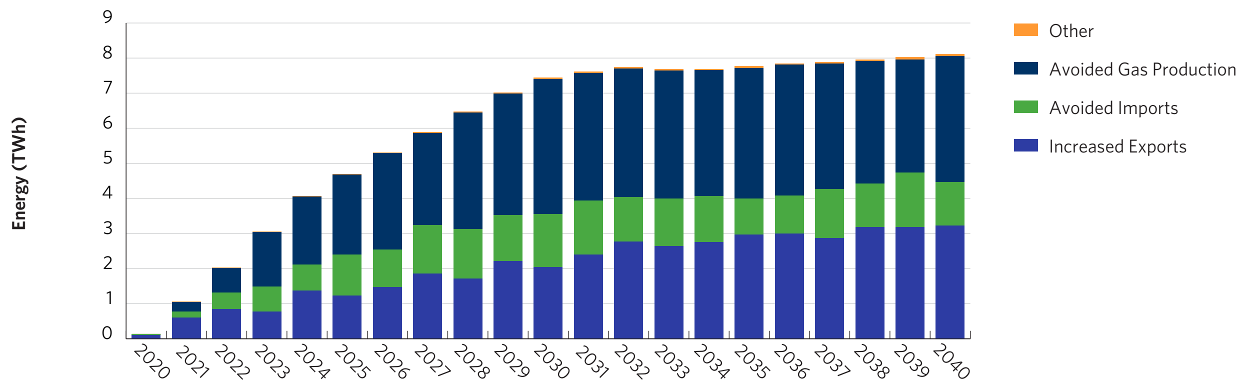
Production by fuel type is similar to the energy adequacy outlook because production from baseload resources is generally insensitive to market prices. Gas production is higher on average as these generators take advantage of export opportunities. Capacity factors[6] for combined cycle gas generators, which make up the majority of Ontario's gas-fired capacity, increase to between 40 and 60 per cent by the mid-2020s. Higher-priced peaking generators – such as Lennox and York Energy Centre – are needed for operability, but are expected to provide little energy.

Energy exports decrease sharply in the early 2020s with the retirement of Pickering NGS and more nuclear generators on refurbishment outage. Coincidentally, imports increase slightly from historical levels. The balance of trade is expected to shift back toward exports in the 2030s, when the nuclear refurbishment program concludes.

[6] A capacity factor is the ratio of a generator's average power output to its installed capacity.

Figure 25: Energy Production Outlook, Imports and Exports

Figure 26: Energy Efficiency Case – Change in Energy Production Outlook



The Energy Efficiency Case includes continued investment in energy-efficiency programs. Compared to the Reference Case, demand is up to 8 TWh lower over the outlook period. This reduced demand leads to differences in the energy production outlook between the two cases. Primarily, the Energy Efficiency Case sees reduced production from Ontario-based gas-fired generators, as well as fewer imports and more exports. Production from nuclear, hydroelectric, wind and solar resources is unchanged.

Cost and emission outcomes from the energy production outlook, including the avoided costs and emissions resulting from energy efficiency, are discussed in Chapter 7.

4.4 Fuel Security Considerations

Ontario has a diverse fuel mix, with nuclear and hydroelectric resources providing the majority of energy through the planning horizon. During the 2020s, nuclear refurbishments and the Pickering NGS retirement are projected to increase capacity factors of the combined cycle gas fleet to the 40 to 60 per cent range. As the fuel mix evolves through this period, the interdependencies between the gas and electric systems will need to be monitored.

Fuel-security risk reflects the possibility that thermal units will not have or be able to get the fuel (primarily natural gas) required to run. This could be due to either the season (i.e., during winter, generating capacity may become unavailable due to priority demand for natural gas from space heating), unexpected pipeline outages, or because increased utilization of the gas fleet creates uncertainty about whether power plants can arrange for fuel when needed.

Natural gas pipelines can become constrained during peak pipeline conditions, potentially limiting the use of natural gas-fired generation to meet Ontario's supply needs. Gas-fired generation is typically fuelled using just-in-time transportation and delivery with limited storage, and might be subject to interruption, depending on the gas delivery product. In constrained natural gas markets, these units may not be served during peak pipeline conditions. Natural gas pipeline constraints have serious implications for reliability and price volatility. Power generation facilities can mitigate these risks through the use of adequate firm transportation and storage capacity.

Fuel deliverability is of concern relative to the operating reliability of the infrastructure that delivers natural gas to the generating stations. In some areas, deliverability to the generation fleet is limited during winter months due to higher demand from space heating. As such, the risk of unavailability needs to be factored into the evaluation of the overall operational and planning reliability of the electricity system. This risk is mitigated through deemed dispatch contract structures that incent generators to mitigate the risk that their marginal economics would diverge from pricing at the Dawn Day Ahead Index. Further, certain gas-fired generators in areas with potential winter transportation issues have Gas Delivery and Management Committees that mitigate fuel availability risks.

Following the Pickering NGS retirement and during the nuclear refurbishment period, incremental energy needs will be met primarily by the increased utilization of the gas fleet. With the increasing reliance on natural gas-fired electricity generation in combination with the potential for constrained natural gas pipelines during peak pipeline conditions, important considerations around fuel security need to be incorporated into long-term planning.

Ontario is fortunate to be home to the Dawn storage hub – Canada's largest integrated underground natural gas storage facility. The risk of winter fuel unavailability in Ontario is further reduced with a large portion of the gas fleet located in close proximity to the Dawn hub.

Energy Outlook: Key Highlights

- Ontario is generally expected to have an adequate supply of energy, provided existing resources continue to be available post-contract expiry. In this outlook, current amounts of renewable generation continue and production from gas-fired generators ramps up to meet growing demand. As a result, capacity will only be required for a few hours each year, generally to help the system handle unlikely events.
- Although existing resources are sufficient to meet future energy needs, new resources will continue to have the opportunity to compete with existing resources in the energy and ancillary services markets.
- Surplus baseload generation (SBG), which occurs when output from baseload resources exceeds demand, is forecast to decrease due to nuclear refurbishments and retirements, as well as rising demand. Over the next 20 years, SBG is expected to be managed using existing market tools.
- Energy exports will decrease sharply in the early 2020s with the retirement of Pickering NGS and more nuclear generators on refurbishment outage. The balance of trade is expected to shift back toward exports in the 2030s, as the nuclear refurbishment program concludes.
- Following the Pickering NGS retirement and during the nuclear refurbishment period, incremental energy needs will be met primarily through the increased use of the gas fleet. Given the important role of gas-fired generation in Ontario's supply mix and the potential for pipeline constraints during peak periods, the IESO monitors fuel security as part of its long-term planning.

5. Meeting Ontario's Electricity Needs

As discussed earlier, the *Annual Planning Outlook* is not intended to recommend how the province should address potential needs at the bulk supply level. Instead, the APO is a technical document that describes the current demand and supply outlook, identifies future system needs, and highlights any areas that may require greater attention.

The resource adequacy assessment that underpins this report identifies a capacity need emerging in the mid-2020s and growing over the outlook period. This chapter presents a qualitative discussion of existing and available resources that may compete to meet this need, while remaining agnostic as to the specific mix of resources. Future editions of the APO will begin to explore the resources available to meet Ontario's future capacity needs more quantitatively.

5.1 Capacity Needs, Uncertainty and Planning Criteria

It is important to recall that the capacity need identified in Chapter 4 is the result of a probabilistic risk assessment. This accounts for a fair degree of uncertainty in the key parameters of this outlook. However, any forecast of this type is based on a range of assumptions for which all uncertainty cannot be accounted.

One such variable is the set of planning assumptions and reliability criteria used in this analysis. The IESO has identified certain aspects of these assumptions and criteria which, if revised, may change the results of this analysis. Over the coming year, the IESO intends to conduct a review of its reliability criteria.

5.2 Future Electricity System Needs

5.2.1 Capacity Need

Chapter 3 presented the resource scenario assuming all existing resources remain available post-contract expiry, which represents the minimum amount of new capacity that will have to be acquired to maintain adequacy. Capacity deficits are also calculated without existing resources post-contract expiry. In this scenario, the capacity deficit represents the total amount of capacity that the IESO must acquire to have adequate capacity. In other words, the capacity that will meet this need has not yet been committed. Capacity needs calculated in this manner, and other system inputs, will inform target capacity in future acquisition processes.

There is a small surplus in the first two years of the forecast. In the mid-2020s, the Pickering NGS retirement and the expiry of two major contracts will cause the summer need to increase to 6,000 MW. The capacity need increases again in the late 2020s and through the 2030s with contracts expiring for most of the remaining gas plants and many wind and solar generators.

5.2.2 Energy Need

If existing resources decide to exit the market post-contract expiry and the capacity shortfall grows, the amount of unserved energy would increase sharply after 2029, exceeding 40 TWh by the late 2030s. With a capacity need exceeding 10,000 MW, this resource scenario has considerable energy shortfalls through the 2030s, as gas and renewable contracts expire.

As discussed in Chapter 4, however, if existing resources continue to be available, Ontario is generally expected to have enough energy to meet demand throughout the forecast period.

5.3 Meeting Capacity Needs

As seen in Chapter 3, much of the need identified above can be met by the continued availability of existing Ontario resources once their contracts expire. Further, if existing resources remain in the market to provide capacity, the remaining capacity need exists only for a few hours each year and is primarily required to meet reliability standards and manage risk. New capacity may be acquired from:

- Demand response
- Capacity imports
- Enhancements of current facilities (including, for example, uprates to conventional generation at Bruce NGS as per the terms of its contract)
- Energy efficiency
- Distributed energy resources

5.3.1 Capacity Auctions

The transition of the demand response (DR) auction to a capacity auction will, over time, enable competition between additional resource types, such as non-committed dispatchable generators, transmission-connected storage facilities and firm imports. Introducing the capacity auction in advance of periods with significant system need will allow both the IESO and participants to learn and adjust early. At the same time, the increased competition fostered by the auction is expected to put downward pressure on pricing, which will benefit ratepayers.

The DR auction has proven successful in driving down capacity costs and increasing liquidity and competition. Enhancing the IESO's approach to capacity auctions by opening participation to other resources is another step toward a more competitive electricity marketplace.

Figure 27: Summer Capacity Surplus/Deficit, without Continued Availability of Existing Resources

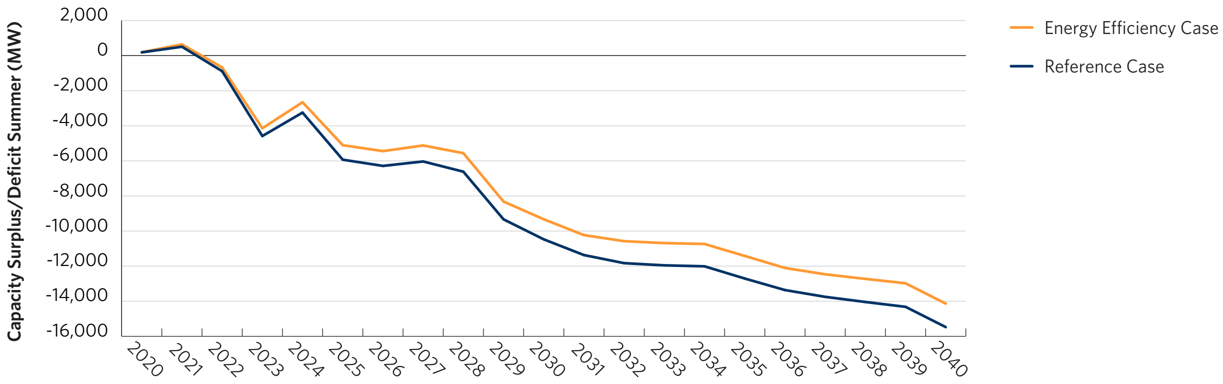


Figure 28: Winter Capacity Surplus/Deficit, without Continued Availability of Existing Resources

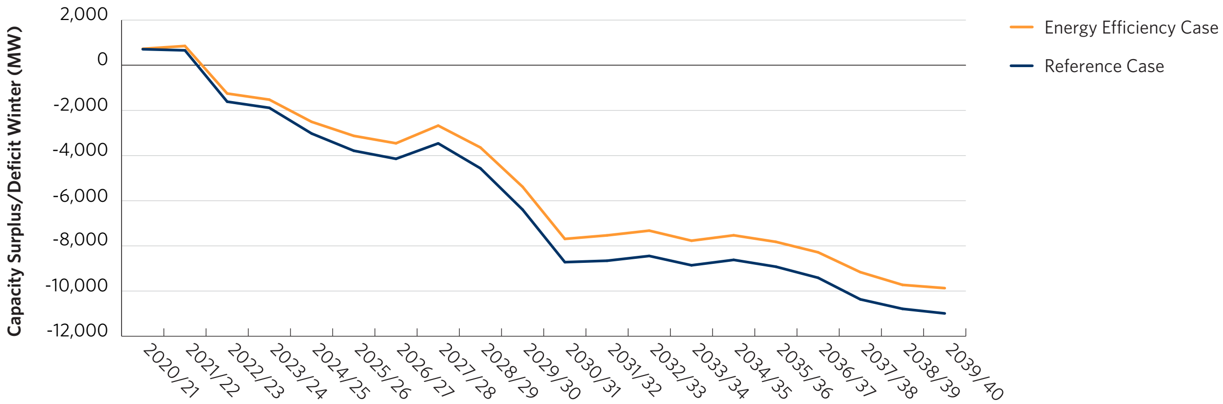
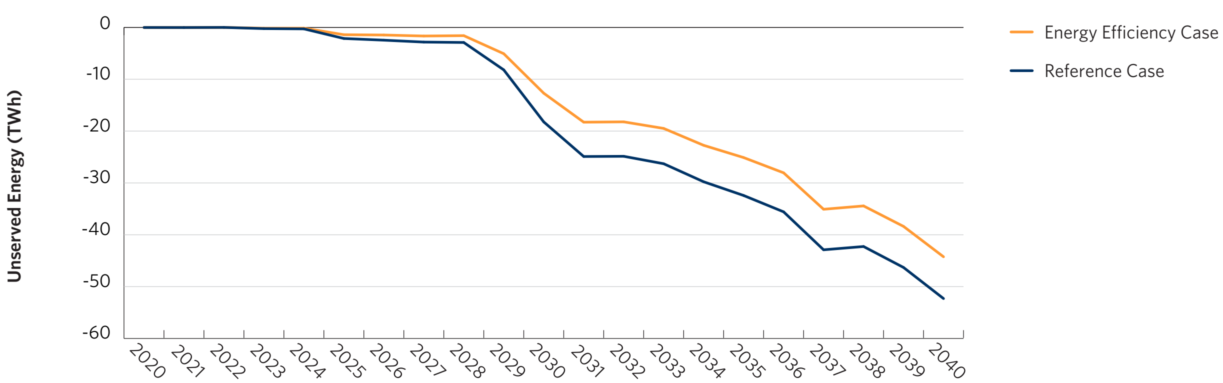


Figure 29: Unserved Energy, without Continued Availability of Existing Resources



The IESO remains committed to capacity auctions that will enable competition between non-committed dispatchable generators, transmission-connected storage facilities, demand response and firm imports. The IESO will also work with stakeholders in anticipation of future capacity shortfalls to consider complementary mechanisms to meet the province's adequacy needs.

5.3.2 Imports

Electricity imports can impact the need for capacity. Imports can be considered as either firm or non-firm:

- Firm Imports: contractual agreement guaranteeing a reliable amount of imports when needed. There is currently a firm import agreement with Quebec, with 500 MW of summer capacity to be delivered in a future year, when requested by the IESO, before 2030.
- Non-Firm Imports: Non-firm imports would assume a certain level of likely imports when needed, based on conditions in neighbouring jurisdictions.

Enabling capacity imports from neighbouring jurisdictions will provide access to non-domestic resources that would reduce the need for additional capacity in Ontario. Non-firm imports are currently not considered in the capacity assessment, in order to model the system for a self-sufficient Ontario as per ORTAC requirements.

Firm imports can take two forms: system-backed, where the capacity is ensured by an entire power system (e.g., a province or state); and resource-backed, where the capacity is being provided by a specific resource in another jurisdiction.

The IESO is enabling firm imports for system-backed and resource-backed resources through the evolution of its capacity auction.

5.3.3 Conservation and Demand Management

Conservation and demand management (CDM) is an important resource in Ontario's electricity markets, reducing the need to build new infrastructure, and secure electricity from less economic resources. CDM, however, is dependent on continued policy commitment. Programs require investment for administration and customer incentives on an annual basis, but provide benefits for years to come. The IESO has included varying levels of CDM based on different investment levels in this Outlook.

Reference Case Demand Forecast

The Reference Case demand forecast is presented as a business-as-usual case and considers expected shifts in market forces and known changes to policy. It includes only firm policy commitments and does not hypothesize about future energy-efficiency frameworks.

Incorporated in the Reference Case demand forecast are forecasted energy savings from committed, existing energy-efficiency programs, which expire on December 31, 2020. These include savings from:

1. Ongoing commitments from the Conservation First Framework (CFF) and Industrial Accelerator Program (IAP); and
2. The 2019-2020 Interim Framework.

These frameworks reinforce a commitment to energy efficiency through IESO-delivered programs. The Interim Framework is projected to achieve 1.4 TWh in annual energy savings in 2020 funded with a budget of $353 million from 2019-2020. The remaining commitments from the CFF and IAP are projected to achieve an additional 0.7 TWh, bringing total 2019-2020 incremental energy-efficiency program savings to 2.2 TWh.

Energy Efficiency Case

The alternative case and sensitivity analysis regarding energy efficiency in Section 1.3 included assumptions for energy-efficiency savings from provincial, federal and municipal programs:

- Provincial - the continued delivery of the 2019-2020 Interim Framework past December 31, 2020 to the end of the outlook period on December 31, 2040 at the current forecasted energy efficiency achievement and budget spending rates; and
- Federal and municipal programs, including the Green Municipal Fund and the Climate Action Incentive Fund.

This Energy Efficiency Case illustrates potential opportunities for electricity savings in the absence of committed CDM frameworks in the post-2020 era, and highlights uncertainties in forecasted electricity savings from early-stage or in-development CDM programs.

The net impact of the Energy Efficiency Case is incremental annual energy savings that increase to about 8 TWh per year by 2028 and are maintained through 2040, as well as a reduction in annual peak demand that grows from roughly 150 MW in 2021 to roughly 1,200 MW in 2035 and is maintained through 2040.

IESO and OEB CDM Achievable Potential Study

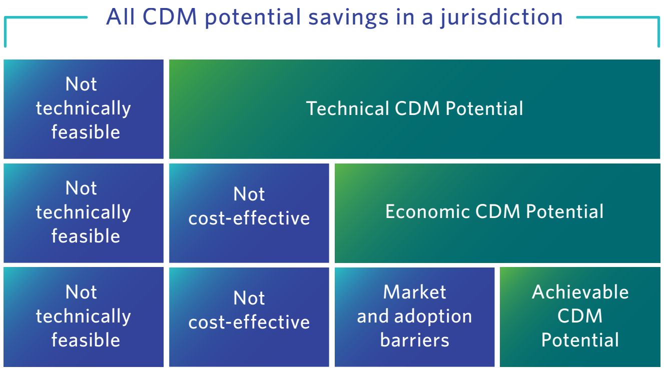
The IESO worked with the Ontario Energy Board (OEB) to consider future opportunities for energy efficiency through the *2019 Achievable Potential Study* (APS). This study identified and quantified electric and natural gas potential energy and demand savings, greenhouse gas emission reductions, and the associated cost of CDM program implementation for the period 2019-2038. The APS aimed to inform:

1. The development of future conservation policy and/or frameworks;
2. Program design, implementation and evaluation; and
3. Long-term resource planning and system operations.

The culmination of thorough investigation, research and analysis, as well as engagement and feedback since early 2018, the APS identifies and evaluates different levels of CDM potential based on standard industry practice:

1. **Technical CDM Potential:** the upper bound of the energy and demand savings from CDM technologies that are technically feasible, and unconstrained by considerations of cost, market acceptability or consumer adoption;
2. **Economic CDM Potential:** a subset of Technical CDM Potential that excludes CDM technologies that are not cost-effective based on specific societal and program administrator cost-effectiveness tests and also unconstrained by considerations of market acceptability or consumer adoption; and
3. **Achievable CDM Potential:** a subset of Economic CDM Potential that accounts for practical constraints, including market or programmatic barriers, incentive programs and specific incentive rates, and reflects the expected actual adoption of CDM technologies and practices by homes and businesses.

Figure 30: Various CDM Potential Subsets



The APS identifies four unique achievable potential scenarios based on varying levels of customer incentives. The incentive amounts and structure drive the estimates of customer adoption of the CDM technologies and the amount of energy and demand savings achievable from future CDM activities.

5.3.4 Distributed Energy Resources (DERs)

Exploring Options for Integrating DERs

The vast majority of Ontario's energy-producing resources are connected to the high-voltage transmission system, but a growing number of smaller units are connecting at the distribution level as customers see the benefits of having their own source of power. DERs can provide an opportunity for the IESO to address future energy and capacity needs if they are effectively integrated into the IESO-administered markets (IAMs). Currently, there are approximately 33,000 DERs under contract with the IESO, the majority of which are small-scale solar projects. With the potential for further deployment of DERs in the province, an opportunity exists to harness their capabilities to reduce system costs, improve reliability, and enhance resilience. However, DERs can also present some challenges to operability, as outlined in the IESO's *2019 Operability Assessment*.

In order to understand the potential for DERs to participate in the markets, the IESO included several DER-focused initiatives in its first Innovation Roadmap. These projects will examine potential models for DER participation in the IAMs and identify challenges and next steps to implementation.

The Innovation Roadmap identifies and assesses key challenges and opportunities to advancing innovation in Ontario's electricity sector and includes a multi-year work plan to help support the IESO's reliability and cost-effectiveness goals. The Roadmap projects include research and white papers, demonstration/evaluation projects, capital projects, process improvements, partnerships and capability building. Through the Innovation Roadmap projects, the IESO will gain a better understanding of the capabilities and limitations of DERs, which will allow these resources to be leveraged more effectively.

Addressing Barriers to Energy Storage

In April 2018, the IESO established the Energy Storage Advisory Group to assist in evolving policies, rules, processes, and tools to better enable the integration of energy storage resources within the current structure of the IAMs. Building on the work of this group, the IESO published *Removing Obstacles for Storage Resources in Ontario* in December 2018. The report detailed strategies to address the primary barriers preventing the fair competition of energy storage resources in the markets. As is the case with other types of DERs, addressing barriers to energy storage will provide more options for meeting future system needs in a cost-effective and reliable manner.

The IESO is committed to pursuing solutions to the barriers that are within its purview, and to working with government and the OEB to address those outside its jurisdiction.

Opportunities to Coordinate Bulk and Regional Needs with Non-Wires Alternatives

As outlined in numerous integrated regional resource plans, communities and customers have been exploring opportunities to meet their own regional electricity system needs with DERs and community-based solutions. The IESO is conducting a review of the regional planning process to identify and propose options to overcoming potential barriers to implementing non-wires solutions in regional planning. The barriers relate to any issues that would limit the consideration, acquisition and operationalization of DERs and energy-efficiency options to address identified regional needs. These could include a combination of emerging technologies and conservation programs, such as targeted demand response, distributed generation and advanced storage technologies, microgrid and smart-grid technologies, and more efficient and integrated systems combining heat and power. As barriers begin to be mitigated, more energy resources are expected to be available in the electricity system, increasing competition in the IAMs.

Through this initiative, the IESO will address barriers related to regional planning and continue to work with industry partners to address barriers downstream of regional planning and advance broader sector changes. The IESO will publish a Regional Planning Review straw man report in early 2020 and is aiming to release the final report in 2020.

Meeting Ontario's Electricity Needs: Key Highlights

- If existing resources continue to operate, Ontario is generally expected to have enough energy to meet demand throughout the forecast period.
- If existing resources decide to exit the market after contract expiry and the capacity shortfall grows, the amount of unserved energy would increase sharply after 2029, exceeding 40 TWh by the late 2030s. With a capacity need exceeding 10,000 MW, this resource scenario shows considerable energy shortfalls through the 2030s, when gas and renewable contracts expire.
- The transition of the demand response (DR) auction to a capacity auction will enable competition between additional resource types. Introducing the capacity auction in advance of periods with significant system need will allow both the IESO and participants to learn and adjust early. At the same time, the increased competition fostered by the auction is expected to put downward pressure on pricing, which will benefit ratepayers.
- In anticipation of future capacity shortfalls, the IESO will work with stakeholders to consider complementary approaches to enable more dynamic market-based approaches to maintain resource adequacy.
- Conservation and demand management is an important resource in Ontario’s electricity market and reduces the need to build new infrastructure for output from more expensive generation.
- The vast majority of Ontario’s energy-producing resources are connected to the high-voltage transmission system, but a growing number of smaller units are connecting at the distribution level as customers see the benefits of having their own source of power. Provided they are effectively integrated into the IESO-administered markets, distributed energy resources can provide an opportunity for the IESO to address future energy and capacity needs.

6. Transmission Planning

6.1 Development of an Integrated Planning Framework

The IESO has been working to develop an integrated planning framework that will bring together an annual resource planning process, a bulk transmission planning process, and a regional planning process. The framework will align the three individual processes and their respective cycles, to facilitate information sharing and to create opportunities to consider common solutions.

The annual resource planning process will provide an overview of the province's current and anticipated near-term resource requirements. This information is required before initiating resource procurement activities, which are expected to occur on an annual basis.

The new bulk transmission planning process will formalize the IESO's bulk transmission planning activities. In recent years, individual bulk transmission studies have been initiated on an as-needed basis, typically either in response to government direction or as a result of the IESO becoming aware of a need through routine planning and system operator functions. The new formalized bulk transmission planning process will ensure solutions are identified transparently as needs materialize.

The bulk transmission planning process will be structured around a provincial bulk system screening assessment that will take place on a regular cycle, notionally every three years. This screening stage will identify the need to initiate bulk transmission studies, which will then be completed on individualized timelines, depending on the scale and nature of the planning issues involved. Detailed design of this process is expected to begin in 2020. The IESO's ongoing bulk transmission planning activities are expected to begin transitioning to the new formalized process in 2021. In the future, regular updates on bulk transmission planning activities will be provided in the *Annual Planning Outlook* (APO), as well as through a periodic provincial bulk study report.

The IESO has been conducting a formalized regional planning process for a number of years, ensuring each of the province's 21 planning regions is reviewed at least once every five years. Future issues of this Outlook may include updates on regional resource topics, such as the integration of distributed energy resources (DERs).

6.2 Development of a Competitive Transmission Procurement Process

One possible outcome of the planning processes described in Section 6.1 is a recommendation for a new transmission facility. In addition to developing the planning processes described in the previous section, the IESO is also developing a new process to competitively procure transmission.

In 2016, the Government of Ontario amended the *Electricity Act, 1998* to give the IESO authority to enter into contracts for the development of transmission systems. This means that, where it makes sense to do so, the IESO could run a competitive process to select a transmitter to build transmission in Ontario, as opposed to deferring to an established transmitter. This move from established or incumbent transmitters having sole rights to build transmission facilities in their service area to a more competitive approach also aligns with trends in North America and globally. To prepare to undertake future competitive transmission procurements, the IESO is developing a transmission procurement process.

With this process, the IESO aims to reduce the cost of transmission projects by leveraging market forces and competition, and provide opportunities for transmitters to innovate in the development or operation of transmission facilities. The IESO will be seeking stakeholder input on the development of a competitive process, including the types of transmission facilities suitable for competition, facility design standards, transaction structure and Indigenous involvement. More information on how to participate in this engagement is available on the IESO's website.

6.3 Active Transmission Projects

This section highlights some active, ongoing or recently completed transmission planning activities. These projects are highlighted because they focus on broader system issues, such as locational considerations (Section 3.4), addressing new load growth while maintaining reliability of the bulk system (Section 1.4), or enhancing Ontario's ability to import electricity from neighbouring jurisdictions (Section 5.3.2).

Transfer Capability Across the Flow East Toward Toronto (FETT) Interface: The FETT interface consists of the four 500 kV circuits and six 230 kV circuits that transfer power from the West, Southwest, Bruce and Niagara zones to the rest of Ontario. The 230 kV transmission lines between Richview TS and Trafalgar TS are the limiting path for the FETT interface. Coincident with the planned shutdown of Pickering NGS and the major refurbishment of other nuclear generating units and changes to the status of contracted generation, the transmission lines between Trafalgar TS and Richview TS may reach their limits by 2023. To help mitigate potential future constraints on the FETT interface, the IESO has requested that Hydro One study various upgrade options for the Richview x Trafalgar 230 kV transmission lines. This will increase the transfer capability of the FETT interface to ensure planned changes to generation patterns can be accommodated by the transmission system. If these upgrades are not completed, a number of resources would have to be located east of the FETT interface.

East-West Tie Reinforcement: Additional electrical capacity is required to maintain reliable supply to northwest Ontario under a wide range of possible system conditions. Northwest Ontario is connected to the rest of the Ontario system by a 230 kV double-circuit line known as the East-West Tie. The expansion of the East-West Tie with the addition of a new 230 kV double-circuit transmission line will provide the necessary transfer capability to meet capacity needs in northwest Ontario. Following expected completion of the project in Q4 2021, the transfer capability of the East-West Transfer East and West interfaces will increase, providing the required supply to and removing one constraint on generation in the Northwest.

West of Chatham Area Reinforcement: Growth in the agricultural sector is one of the main drivers of increasing demand in Ontario, as discussed in Section 1.4.4. This growth has not been uniform across the province but, instead, is occurring in specific regions. For example, growth in the agriculture sector in the Windsor-Essex region has resulted in the need for additional electrical supply capacity to serve the area. As a result, the IESO requested that Hydro One proceed with development of a new switching station (SS) at Leamington Junction to improve load-meeting capability in the local area and to enable future bulk system improvements to reinforce the transmission path west from Chatham SS. The expected in-service date is Q4 2022. The IESO has also requested Hydro One to develop and construct a new, double-circuit, 230 kV transmission line, approximately 50 km in length, to bring additional supply to the area. This line will connect from Chatham SS to the proposed switching station north of Leamington, and is expected to be completed by Q4 2025. This project will increase the overall transfer capability of the bulk transmission system to reliably supply the forecasted load growth in the Kingsville-Leamington area and the broader Windsor-Essex region, permit resources and bulk facilities to operate efficiently and maintain existing interchange capability on the Michigan interconnection between Windsor and Detroit.

West Ottawa Area Reinforcement: The IESO requested that Hydro One proceed with upgrading circuits between Merivale TS and Hawthorne TS with a planned in-service date of December 2022. This project will address supply capacity constraints to west Ottawa, and enhance the ability to import electricity from Quebec. Additional information on how imports are considered in the planning process is included in Section 5.3.2.

6.4 Outlook for Future Transmission

To address emerging system issues and challenges, such as facility end of life, changes to the generation resource fleet, and preservation of utility corridor space to accommodate future transmission needs, expansion or reconfiguration of the transmission system may be required.

Some of these new transmission projects could be candidates for competitive procurement.

Transmission facility end of life: As major transmission facilities reach the end of their expected life, resizing or reconfiguring the assets could be considered to better align with the needs of a changing system. The process by which these opportunities are identified and evaluated going forward is being formalized, and will be part of the integrated planning framework introduced in Section 6.1.

An example of this work is the end of life of the Clarington to Chats Falls 230 kV transmission line, a 300-km transmission corridor that runs from the Chats Falls generating station west of Ottawa to the GTA. The four 230 kV transmission lines that run this corridor were built almost 90 years ago, and while some sections have been refurbished, the majority of the lines are at or nearing their end of life. The IESO is undertaking a planning study to assess alternatives to like-for-like replacement of these circuits.

Accommodating changes to the generation resource fleet and to demand: Many generation facilities, including gas plants, are located in areas where they provide critical supply to address regional or local needs, in addition to supplying provincial demand. As major changes to generation resources occur, electricity flows on the transmission network can change and trigger the need for transmission reinforcements. Similarly, changes to electricity demand can alter flows on the transmission network and trigger the need for investment.

An example of this is the planned retirement of Pickering NGS in the mid-2020s. The retirement of this major source of electricity in the east GTA, combined with increased demand in the area and other factors, may result in flows on the bulk transmission facilities in the western GTA that exceed their capacity.

One potential option to address this need involves installing new 500-230 kV transformers at the existing Milton SS and reinforcing the 230 kV transmission network in the West GTA. The 230 kV reinforcement would involve building two new transmission line sections totalling 13 km on the existing Parkway Belt Transmission Corridor. As noted, the need for these facilities is based on several factors, which are being monitored closely given the lead time required for installation.

Preserving corridor space for future transmission: Accommodating sustained growth and development can produce unique challenges when the growth materializes far from the existing transmission grid. Waiting for load to materialize before expanding grid infrastructure can sometimes mean that land suitable for transmission is no longer available. This could require either expropriation or use of underground facilities, both of which are costly and potentially disruptive alternatives.

Figure 31: Transmission Zones and Active Projects

*A transmission interface is not a single physical element; it is a conceptual representation of the flow of electricity from one zone to another. This map is for illustrative purposes only. All locations are approximate.

Planning work to identify and preserve future transmission corridor space is currently underway along a proposed GTA West highway corridor. The IESO has identified a long-term need for new supply capacity to meet future growth in northern Brampton and southern Caledon – locations where urban development is expanding into areas where there is currently limited transmission capability to supply new electrical demand. If this projected urban development materializes, new transmission will be needed to supply growth in the area.

The IESO and the Ministry of Energy, Northern Development and Mines are currently undertaking a joint study to identify land suitable for a transmission corridor and maintain the option of preserving this land for future transmission infrastructure. The areas of focus for this joint study are adjacent to a planned 400-series highway (the GTA West highway corridor) that is currently undergoing an Environmental Assessment (EA). In accordance with the Provincial Policy Statement and good planning practice, opportunities for colocation of linear infrastructure should be sought where practical.

The pace and location of growth will dictate the dates when new transmission infrastructure is required. Development would not occur until closer to the time that transmission is needed, and would still require an EA, including community engagement and evaluation of potential alternatives.

Transmission Planning: Key Highlights

- The IESO is developing a formalized integrated planning framework to ensure that needs and solutions are identified transparently and according to a regular cycle. This is being carried out through the formalization of a process for bulk system planning, a review of the regional planning process, and integration of other planning processes and products.
- The IESO is implementing its new accountability under the *Electricity Act, 1998*, by developing a process to guide future competitive transmission procurements.
- Several active, ongoing or recently completed transmission planning activities focus on broader system issues, such as improving bulk system transfer capability, addressing new load growth considerations, or enhancing Ontario's ability to import electricity from neighbouring jurisdictions.
- Planning is underway to assess a number of emerging system issues, including standardizing the approach to transmission assets at their end of life, accommodating changes in the generation resource fleet, and identifying corridors for future transmission. These initiatives and their outcomes could result in a need for new transmission facilities, which may be potential candidates for a future competitive transmission procurement.

7. Outcomes and Additional Considerations

7.1 Marginal Resources and their Importance

Long-term power system plans use an economic dispatch model that schedules resources to meet system needs based on least cost. This considers each resource's production or variable costs, which typically include fuel costs and variable operating and maintenance costs. The most expensive resource scheduled is the marginal resource. This is important because costs associated with the marginal resource provide an indication of market price. This model is not meant to forecast prices but, given future conditions, the marginal resources scheduled indicate trends in energy production from different resources.

Supply resources are categorized as baseload (operating essentially constantly, e.g., nuclear), dispatchable (operating as needed, e.g., gas), or intermittent (operating when fuel is available, e.g., wind). The variable cost required to produce a unit of energy is referred to as the production cost and typically consists of fuel costs, carbon costs, and variable operating and maintenance costs. Typically, baseload and intermittent resources have lower marginal energy costs than dispatchable resources.

The IESO strives to ensure Ontario's energy needs are met at the lowest possible cost. Resources are generally dispatched from lowest production cost baseload resources to higher production cost dispatchable resources that are able to adjust their output according to fluctuations in demand or supply of baseload and intermittent resources.

Marginal resources provide the next unit of energy needed on the system. For example, during the peak demand hours of hot summer days, the marginal resource is usually a natural gas-fired generator; overnight during autumn it is less likely that gas-fired generation would be the marginal resource.

7.2 Marginal Cost

The data underpinning this Outlook are based on an economic dispatch model that simulates each hour of the 20-year outlook period. This model dispatches units in order of their production costs and identifies the marginal resource in each hour. The marginal cost in each hour is the production cost of the marginal resource.

Marginal costs are not intended to be a forecast of market prices, such as the Hourly Ontario Energy Price or locational marginal prices. Market prices are the wholesale prices for electricity and can differ widely due to market participant behaviour, congestion and other factors.

Marginal costs provide an indication of the direction of market prices. When a fundamental change to the supply mix occurs – such as the retirement of Pickering NGS – marginal costs illustrate the expected impact on the factors underpinning market prices. They also provide an indication of the change in production costs due to changes in supply and demand.

With the retirement of Pickering NGS and demand increases in the long term, marginal costs are expected to increase as gas-fired generation becomes the marginal resource more often.

The average marginal costs can be found in the data tables at www.ieso.ca/apo.

7.3 Carbon Pricing

Ontario imports from and exports to its five neighbours every day of the year. To forecast the impact of imports and exports, the IESO models the demand and supply in neighbouring jurisdictions and develops regional commodity and carbon price forecasts for fuels used to produce electricity.

Currently, the electricity sectors in Ontario and in neighbouring jurisdictions are subject to carbon pricing. This section details the carbon pricing policies currently in effect within the northeastern portion of the Eastern Interconnect, and how the carbon pricing was modelled for the *Annual Planning Outlook*.

7.3.1 Carbon Pricing in Ontario and Neighbouring Jurisdictions

The federal carbon pricing backstop in Ontario was effective January 1, 2019. This backstop has two components: the carbon levy applied to fossil fuels (effective April 1, 2019) and the output-based pricing system (OBPS) for industrial facilities (effective January 1, 2019).

The OBPS applies a regulatory charge above an industry-specific benchmark emission rate for emission-intensive, trade-exposed (EITE) industry. The federal government considers the electricity sector as EITE and, as such, applies a benchmark emission rate to the sector for large emitters (those exceeding the threshold, with voluntary opt-in).

Having a benchmark applied to the electricity sector means that there will be no charge associated with emissions up to a specific rate based on fuel type (e.g., 370 t CO_2e/GWh for natural gas). As such, the carbon pricing applied with the OBPS acts as a pro-rated carbon price. As different gas-fired generation facilities have different emission rates, each facility will be charged an amount based on its facility emissions and electricity production, leading to facility-specific carbon pricing.

The IESO has modelled the carbon pricing policies applied in neighbouring jurisdictions where there is a material impact on electricity sector emissions,[7] including Nova Scotia,[8] New Brunswick,[9] and parts of the United States through the Regional Greenhouse Gas Initiative.[10]

7.4 Greenhouse Gas (GHG) Emissions

Electricity sector emissions are forecast to increase to 11 megatonnes CO_2e by 2030, still well below 2005 levels. This expected increase is due to reduced nuclear production and increasing demand, resulting in increased production from gas-fired generation.

An increase in electricity sector emissions does not necessarily mean an increase in economy-wide emissions. The carbon intensity of electricity remains far below that of other fuels such as gasoline for automotive transportation or fuel oil for space heating. Switching from higher-emission fuels to low-carbon electricity could increase electricity sector emissions while reducing province-wide emissions. As electricity consumption increases and emissions rise, opportunities exist for emission reduction through non-emitting resources.

7.5 Avoided Costs

The IESO's avoided cost analysis considers the avoided energy and capacity costs from a reduction in demand. These avoided costs are considered benefits, and can be compared to the cost of other measures that would reduce demand. Any measures that are implemented should be cost-effective and lead to lower overall customer costs.

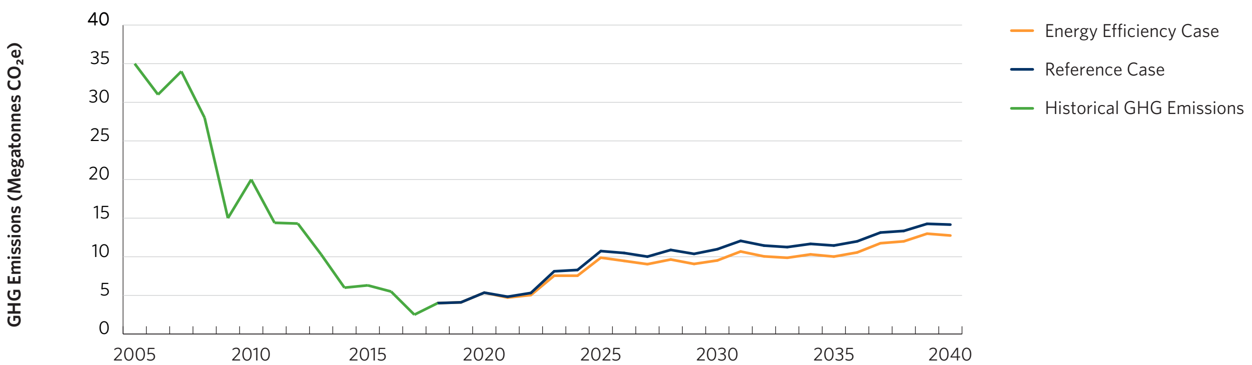
Marginal costs are used to estimate the avoided costs associated with changes in electricity consumption. The hourly profile of the measures being considered is compared to the hourly profile of marginal costs to understand the impact of avoided generation.

In the near term, Ontario will have an abundance of resources with low production costs, meaning few system costs can be avoided.

In the medium and long terms, however, increased system costs can be avoided due to increased demand, decreased nuclear generation, and increased gas-fired generation.

The avoided energy costs change as demand and supply changes. Energy data are provided to show the changes during the day, during the seasons, and from year to year covering the 20-year outlook.

Figure 32: Electricity Sector GHG Emissions, Historical and Forecast



[7] Although carbon pricing is in effect in Manitoba and Quebec, these jurisdictions are considered essentially non-emitting in terms of electricity sector emissions.

[8] Nova Scotia's cap-and-trade program took effect January 1, 2019. climatechange.novascotia.ca/nova-scotias-cap-trade-program

[9] The federal output-based pricing system was also in effect in New Brunswick as of January 1, 2019. www.gazette.gc.ca/rp-pr/p2/2019/2019-04-03/html/sor-dors79-eng.html

[10] The Regional Greenhouse Gas Initiative is currently in effect in nine northeastern states, with New Jersey and Virginia anticipated to join in the near future. www.rggi.org

The avoided capacity costs reflect the cost of capacity in years where there is a capacity deficit, plus the avoided cost of additional resources to meet reserve margin requirements.

The current energy-efficiency framework in Ontario will conclude in 2020. If the existing energy-efficiency framework were to continue to 2040 with rigorous cost-effectiveness testing, there would be less gas-fired generation operating, with associated system cost savings.

The avoided cost data can be found in the data tables at www.ieso.ca/apo.

7.6 Avoided Emissions

Similar to the avoided costs, the avoided emission factors consider the avoided emissions associated with a reduction in demand for electricity.

In order to estimate the avoided GHG emissions associated with lower consumption levels, the IESO considers emissions reflective of the marginal resource. Based on the hour and year being considered, a different mix of generators with different emission rates will represent the incremental increase or decrease in generation.

Similar to the avoided costs, there are fewer emissions to be avoided in the near term, when more non-emitting resources will be operating, and greater opportunities for emission reductions in the medium and long term due to increased demand, decreased nuclear generation and increased gas-fired generation.

The current energy-efficiency framework in Ontario will conclude at the end of 2020. If the existing energy-efficiency framework were to continue to 2040, there would be less gas-fired generation operating, and therefore lower system emissions, as shown in Figure 32.

Outcomes and Additional Considerations: Key Highlights

- Since gas-fired generators are expected to increasingly be the marginal resource as Pickering NGS retires and long-term demand increases, emissions and the marginal cost of electricity production are expected to increase over time.
- An increase in electricity sector emissions does not necessarily mean an increase in economy-wide emissions. Switching from higher-emission fuels to low-carbon electricity has tremendous potential to reduce total provincial emissions.

LIST OF ABBREVIATIONS

Abbreviation	Description
APO	Annual Planning Outlook
CCGT	Combined cycle gas turbine
CDM	Conservation & demand management
CFF	Conservation First Framework
CO_2e	Carbon dioxide equivalent
DER	Distributed energy resource
DR	Demand response
EA	Environmental assessment
EITE	Energy-intensive, trade-exposed (as in sector)
EV	Electric vehicle
FETT	Flow East Toward Toronto
GHG	Greenhouse gas
GTA	Greater Toronto Area
GW	Gigawatt
GWh	Gigawatt-hour
Hydro One	Hydro One Networks Inc.
IAM	IESO-administered markets
IAP	Industrial Accelerator Program
ICI	Industrial Conservation Initiative
IESO	Independent Electricity System Operator
kV	Kilovolt
LOLE	Loss of load expectation
LRT	Light rail transit

Abbreviation	Description
MW	Megawatt
MWh	Megawatt-hour
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council
OBPS	Output-based pricing system
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
SBG	Surplus baseload generation
SS	Switching station
TTC	Toronto Transit Commission
TS	Transmission station or transformer station
TWh	Terawatt-hour

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ENBRIDGE GAS INC.

Undertaking Response to EP

To advise whether the JT1.16 metrics will be used for considering pipe and non-pipe IRPA's in the asset management plan.

Response:

Based on the Transcript for Day 3 of the Oral Hearing at pages 70-71, Enbridge Gas has made the assumption that the question posed by EP was whether the matrix (not metrics) shown in JT2.16 (not JT1.16) will be used for considering pipe and non-pipe alternatives in the asset management plan (AMP).

The intention of the illustrative matrix in JT2.16, is to compare each risk category for an IRPA deployment relative to other alternatives (i.e. other IRPA(s), baseline facility alternatives, or combinations of the two). The matrix will not be included in the body of the AMP as its primary purpose is to assist Enbridge Gas in comparing the risk of IRPA(s) to other alternatives, and to help determine the appropriate targeted reduction needed as a result of the incremental risk of an IRPA. However, the matrix and related analysis would be reflected in an Appendix to the AMP if it was used to support the Company's decisions to pursue a particular alternative.

ENBRIDGE GAS INC.

Undertaking Response to EP

To explain why in the illustrative example the demand response is shown as significantly worse than PIP on financial, operational, and reputational factors.

Response:

Based on the Transcript for Day 3 of the Oral Hearing at page 71, Enbridge Gas has made the assumption that the question posed by EP was to clarify why demand response was shown as worse than pipe (not PIP).

The matrix provided in the response at Exhibit JT2.16, is intended to be illustrative and the analysis has not been completed to establish the relative risk of various IRPA's compared to baseline facilities. At this time, Enbridge Gas has not determined the degree to which Demand Response without AMI will impact peak hour load. Further, without AMI, there is no way to confirm that the peak demand reductions achieved by a Demand Response program are sustainable. For example, both customers' habits and home ownership could change over time, eroding the reductions in peak hour demand initially achieved via investment in a Demand Response IRPA, without any advanced notice to Enbridge Gas.

This uncertainty could result in a scenario where Enbridge Gas has invested in one or more IRPA's in order to defer or avoid a facility alternative and the conditions underlying the peak load/demand reductions forecasted to result from such IRPA(s) investments changes. In such a scenario, in the absence of AMI, this change in peak hour demand could go undetected by Enbridge Gas, resulting in a capacity shortfall and/or unplanned system outages.

ENBRIDGE GAS INC.

Undertaking Response to EP

To advise as to why the EAHSP example shows good results.

Response:

The matrix provided at Exhibit JT2.16 is intended to be illustrative and the analysis has not been completed to establish the relative risk of various IRPAs compared to baseline facilities. At this time, Enbridge Gas has not determined the degree to which Electric Air Source Heat Pumps (EASHPs) will impact peak hour load.

The colour coding in the matrix indicates that EASHPs will have a positive Environmental Risk impact when compared to natural gas baseline facilities as a result of less natural gas being used and therefore less potential for leaks and their associated negative environmental consequences. No assumptions are made about the source of the electricity in drawing this illustrative conclusion.

Similarly, assuming that Enbridge Gas does not own or operate them EASHPs would result in less natural gas equipment requiring inspection, therefore the Health & Safety Risks are reduced. In addition, with less natural gas equipment to suffer an outage there is a lower Financial Risk related to same (this illustrative conclusion does not consider any increased risk of outage on the electricity system).

It should be noted that this tool will be used in comparing IRPAs in conjunction with a full benefit/cost analysis which Enbridge Gas expects will include more detailed information for a specific IRP Plan.

ENBRIDGE GAS INC.

Undertaking Response to EP

To advise as to why the ETEE column shows worse results for the final three values.

Response:

As noted in the response at Exhibit J3.4, the matrix provided at Exhibit JT2.16 is intended to be illustrative and the analysis has not been completed to establish the relative risk of various IRPAs compared to baseline facilities. In the response at Exhibit J3.3, Enbridge Gas describes how, in the absence of AMI, it is possible that forecasted peak load/demand reductions associated with an IRPA(s) investment could change without being detected by the Company resulting in a capacity shortfall and/or unplanned system outages. This concept applies similarly to ETEE. AMI is an important tool to confirm the amount of peak hour reduction achieved and to confirm the relative permanence of such reductions.

This uncertainty could result in a scenario where Enbridge Gas has invested in one or more IRPA's in order to defer or avoid a facility alternative and the conditions underlying the peak load/demand reductions forecasted to result from such IRPA(s) investments changes. In such a scenario, in the absence of AMI, this change in peak hour demand could go undetected by Enbridge Gas, resulting in a capacity shortfall and/or unplanned system outages.

ENBRIDGE GAS INC.

Undertaking Response to OGVG

To confirm the consultative process that goes on between Enbridge and large customers that are responding to an expression of interest with respect to future capacity projects.

Response:

Following the launch of an expression of interest ("EOI"), Enbridge Gas Account Managers contact all contract market customers in the geographic area proposed to be served by Enbridge Gas and other market participants including gas marketers to explain the process and to answer any questions they may have. As part of the communication accompanying the bid form, Enbridge Gas is clear that the process has been designed to consider all changes in future demand, both increasing and decreasing:[1]

> Concurrent with this process to express interest in new capacity, all existing contract rate class customers in the Area of Benefit (see attached map on page 4) will be offered the opportunity to "turn back" or de-contract their capacity via a concurrent Reverse Open Season using the same bid form. Bids under the Reverse Open Season will be subject to other customers contracting to take on that "turned back" capacity. In this way, Enbridge will minimize the facilities required to serve incremental demand while optimizing any unwanted existing capacity.

Ultimately, customers choosing to bid into the EOI process are in the best position to evaluate their natural gas requirements based on their assessment of future business opportunities, economic factors, new technologies and opportunities for incremental energy conservation. The EOI bid form is structured to clearly allow for customers to fully consider their future needs for incremental firm or interruptible demands, conversion between firm and interruptible services and allows customers to turn back capacity.

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[1] Enbridge Gas EOI Bid Form: https://www.enbridgegas.com/PanhandleRegionalExpansion

ENBRIDGE GAS INC.

Undertaking Response to OGVG

To comment on the question if a pipeline alternative did not meet E.B.O. 188 guidelines for the purpose of serving new customers, but an IRPA proposal could meet those guidelines of PI and volume portfolio, whether Enbridge would consider the IRPA.

Response:

An IRPA that meets the guidelines of E.B.O. 188 as calculated in DCF+ Stage 1 would be considered as an alternative to a pipeline alternative that does not meet E.B.O. 188 guidelines.

ENBRIDGE GAS INC.

Undertaking Response to OEB Commissioners

Enbridge to provide the implications of different treatment of IRPA's between regulatory accounting and financial accounting, specifically with respect to something that's rate base, but not an asset on the financial statements.

Response:

As noted by Presiding Commissioner Anderson (EB-2020-0091 Hearing Transcript Vol. 3, March 3, 2021, page 145), several utilities regulated by the OEB follow IFRS. There are scenarios under IFRS where something is capitalized and added to rate base for regulatory accounting purposes but is not permitted to be capitalized on the audited financial statements for financial accounting purposes, creating differences between the two. These differences could result in two sets of "books" (general ledgers) needing to be maintained which would cause higher administrative costs and regulatory financial statements that could differ substantially from audited financial statements.

However, Enbridge Gas follows U.S. GAAP, which is significantly different from IFRS with respect to recognition and measurement of regulatory assets in that US GAAP, ASC 980, allows qualifying regulated entities to capitalize costs that would otherwise be expensed. *ASC 980-340-25-1*:

> *Rate actions of a regulator can provide reasonable assurance of the existence of an asset. An entity shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met:*
>
> *a) It is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes; and*
>
> *b) Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost.*

Therefore, Enbridge Gas's IRPA costs that might otherwise be expensed, could be capitalized if Enbridge Gas can demonstrate that the costs are probable of being recovered through future revenues derived from rates approved by the Board. The best evidence for this is an OEB Rate Order specifying the nature of the costs and the timing and manner of recovery. This would keep regulatory rate base and the audited financial statements aligned and avoid the need to maintain two sets of "books" (general ledgers) as might otherwise be required under IFRS.

ENBRIDGE GAS INC.

Undertaking Response to GEC

To provide comparable figures to those for Toronto dollars per gigajoule for gas and electricity as they appear on page 48 of the updated report from ICF, to update those figures assuming 170 dollars per tonne cost of carbon.

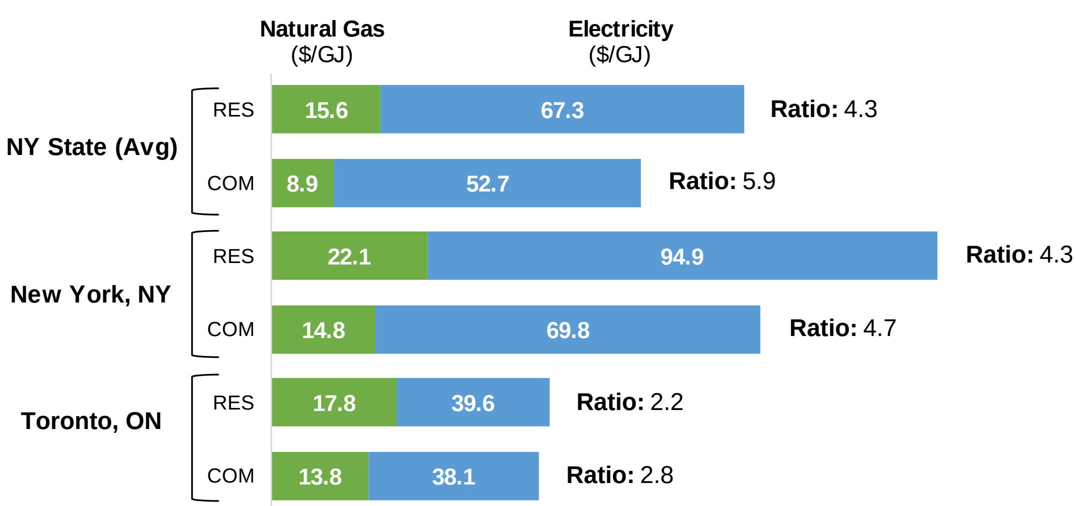
Response:

Figure 1 below reflects a carbon cost of $170/tonne CO_2e for both natural gas and electricity rates for Toronto, ON.[1] This represents an incremental addition of $140/tonne CO_2e to the $30/tonne CO_2e cost of carbon that was already included in the original figure for this jurisdiction. The impact on natural gas rates is based on an extrapolation of rate impacts from Enbridge Gas's website,[2] and the impact on electricity rates is based on the latest available Ontario electricity consumption carbon intensity of 30 g CO_2e/kWh, which is reflective of the 2018 average for Ontario.[3]

For more details on the sources of these values and relevant caveats, please refer to the original figure.

Figure 1

Exhibit 1: Comparison of Natural Gas and Electricity Retail Rates ($CAD) in Terms of Delivered Energy, Including a $170/tonne Carbon Cost for Toronto, ON



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[1] The values for New York State and New York City have not been revised.
[2] Enbridge, "Federal Carbon Pricing Program", available at: https://www.enbridgegas.com/Natural-Gas-and-the-Environment/Enbridge-A-Green-Future/Federal-Carbon-Pricing-Program---Business
[3] Environment and Climate Change Canada, "National Inventory Report, 1990-2018: Greenhouse Gas Sources and Sinks in Canada, Part 3", Tables A13-7 (p 66), 2020, available at: http://publications.gc.ca/collections/collection_2020/eccc/En81-4-2018-3-eng.pdf