LEI Semi-Annual Regional Market Update and 10-year Energy Price Forecast

Ontario

3rd Quarter 2018

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Description of Report

London Economics International LLC ("LEI") provides semi-annual regional market updates and 10-year energy price forecasts for major markets in North America and around the world. In addition to providing price projections, the reports highlight major developments in each of the regions as well as the underlying structural dynamics. LEI also provides more detailed regional market price forecasts tailored to a client's individual needs, including longer time horizons and forecasting of plant-specific revenues or the impact of structural or market design changes.

Disclaimer

1 Executive summary

This report presents the results of a 10-year price forecast (2019-2028) for the Ontario wholesale electricity market, underlying assumptions, and a brief market overview. Often characterized as a "hybrid" market, Ontario's electricity industry structure contains elements of both a centrally planned and competitive market. The primary competitive elements are: (i) generators that bid into and receive "dispatch instructions" from a wholesale market administered by the Independent Electricity System Operator ("IESO") and (ii) retail choice at the consumer level.

The Ontario government is responsible for developing the long-term energy plans for the province. The IESO, at the government's direction, supports the implementation of the long-term plan and makes decisions regarding new generation procurement, contracting decisions with existing assets, and conservation and demand management ("CDM") programs. Power generators have open access to the transmission network and can theoretically operate without some form of guaranteed revenue. However, in practice the majority of Ontario's electricity generation receives full cost recovery through either a long-term contract with the IESO or regulation by the Ontario Energy Board ("OEB").

Highlights:

- Ontario Progressive Conservative party won the provincial election, ending over a decade of Liberal leadership and making further policy-driven renewable procurements highly unlikely;
- Ontario ends cap-and-trade program, making the province subject to the federal carbon pricing backstop
- Global Adjustment forecast values to decline at a CAGR of -0.6%, from $80.3/MWh to $75.9/MWh in 2028; and
- IRM is expected to hit its lowest level of 15.3% in 2025 primarily due to the refurbishment of Bruce and Darlington units and retirement of Pickering nuclear facilities.

The Hourly Ontario Energy Price ("HOEP") is a single zone wholesale electricity price. Over the forecast horizon (2019-2028), it is projected to increase at a compound annual growth rate ("CAGR") of 8.5% per annum, rising from $20.2/MWh in 2019 to $42.2/MWh by 2028.[1] HOEP growth is primarily due to the refurbishment and retirement of nuclear generation units across the province (leading to increased dispatch from higher marginal cost gas units), and increasing fuel prices. The final Pickering nuclear units are retired at the end of 2024, and prices peak at $42.8/MWh in 2027.

Internal reserve margins ("IRM") remain above 15% over the outlook horizon - averaging 22% across the period, and peaking at 32% in 2019. The IRM decreases to its lowest level of 15.3% in 2025 when the combination of nuclear retirements and refurbishment schedules yields the lowest available nuclear supply capacity. Wholesale electricity prices in Ontario in the long term will continue to be influenced by natural gas prices, nuclear refurbishment schedules, and conservation and demand management.

[1] Unless otherwise stated, all prices in this report are in nominal Canadian dollars. Where input sources were based in USD, an exchange rate of CAD $1.3 / USD $1 was applied.

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Figure 1. Acronyms

AEO	Annual Energy Outlook
CAGR	Compound Annual Growth Rate
CCGT	Combined Cycle Gas Turbine
CDM	Conservation and Demand Management
CfD	Contracts for Differences
CMI	Continuous Modeling Initiative
DR	Demand Response
EIA	US Energy Information Administration
ERUC	Enhanced Real-Time Unit Commitment
FIT	Feed-In Tariff
FOM	Fixed Operations & Maintenance
GA	Global Adjustment
ICA	Incremental Capacity Auction
IESO	Independent Electricity System Operator
IPP	Independent Power Producer
IRM	Internal Reserve Margin
HOEP	Hourly Ontario Energy Price
HQ	Hydro Quebec
LCOP	Levelized Cost of Pipeline
LEI	London Economics International LLC
LRP	Large Renewable Procurement
LTEP	Long-Term Energy Plan
MOE	Ministry of Energy
MOU	Memorandum of Understanding
NERSC	Non-Emitting Resources Subcommittee
NETP	New Entry Trigger Price
NUG	Non-Utility Generators
NYISO	New York Independent System Operator
O&M	Operations and Management
OBPS	Output-Based Pricing System
OEB	Ontario Energy Board
OEFC	Ontario Electricity Financial Corporation
OPA	Ontario Power Authority
OPG	Ontario Power Generation
OPO	IESO's 'Ontario Planning Outlook'
OTCGH	OTC Global Holdings
PBR	Performance-Based Regulation
PC	Progressive Conservative
RFP	Request for Proposal
RFQ	Request for Qualifications
RTO	Regional Transmission Organization
SCGT	Simple Cycle Gas Turbine
SSM	Single Schedule Market

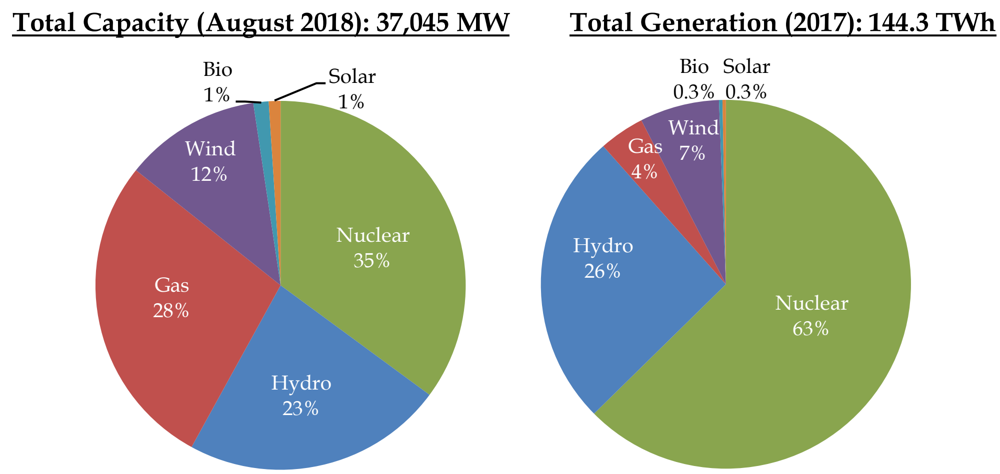
2 Market overview and recent developments

2.1 Market overview

Ontario has operated an energy-only wholesale electricity market since May 2002, following the restructuring of the vertically integrated Ontario Hydro.[2] There are two components of electricity commodity charges in Ontario: the HOEP and the Global Adjustment ("GA"). The HOEP is the wholesale market price and is based on supply and demand, as balanced in real-time for each hour. Our forecasts are meant to represent future HOEP or its equivalent. The GA reflects the difference between market prices/revenues and: 1) the regulated rate paid to Ontario Power Generation's ("OPG") baseload generating stations; 2) payments made to suppliers under contract with the IESO; and 3) contracted rates paid to non-utility and other resources.

The GA is also the mechanism used to recover the cost of a number of other IESO-administered programs, including demand response and conservation initiatives. Taken together, the HOEP and the GA reflect the "consumer price" of electricity in Ontario. For each contract class, the GA amount is determined by the difference between the contract/regulated price and price received in the market.

Figure 2. Installed capacity and generation by fuel type for transmission-connected resources



Sources: IESO 18-month outlook (September 2018) and IESO year-end data for 2017
Note: As of Q3 2018, Ontario also has an additional 3,387 MW of distribution-connected generation under IESO contract

The province's installed capacity consists primarily of nuclear (35%), natural gas (28%), hydroelectric (23%), and wind (12%). This supply mix is heavily weighted towards baseload resources such as nuclear and hydroelectric, which together accounted for approximately 89% of the total output in calendar year 2017 as shown in Figure 2.

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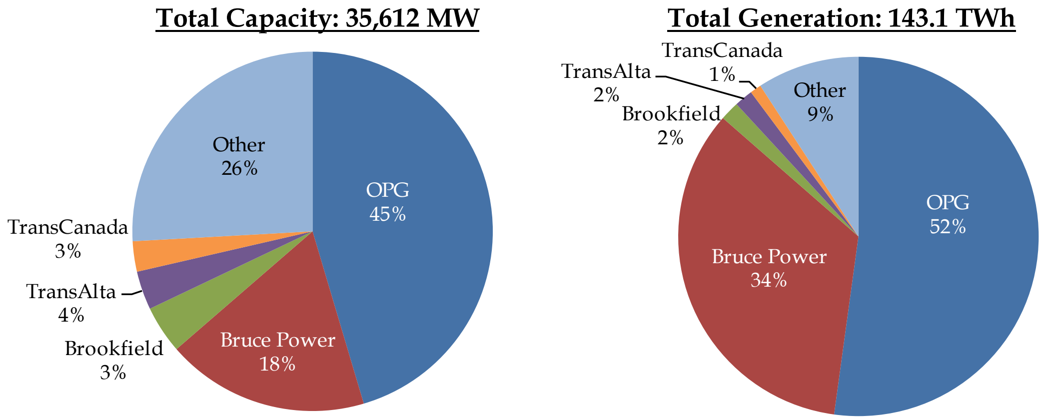
[22] The IESO is currently engaged in the development of an incremental capacity auction as part of its market renewal program. The market renewal program is covered in Section 2.2.3.

Figure 3 shows the installed capacity and annual generation by owner for calendar year 2017. The market is dominated by OPG and Bruce Power who together control approximately 63% of the total installed capacity. OPG is fully-owned by the province of Ontario and controls approximately 45% of total market capacity, comprising predominately of hydroelectric and nuclear facilities. OPG's share of total generation output during the calendar year 2017 was 52%. Bruce Power is the second largest generator in terms of capacity (18% of total market capacity) and generation output (34% of total output), and is responsible for the operation of the Bruce A and Bruce B nuclear facilities.

Figure 3. Installed capacity and generation by market participant (2017)



Source: IESO 'generator and output capability' data for 2017
Note: Data in IESO 'generator and output capability' reports only show transmission-connected generating facilities with a maximum output capability of 20 MW or more

2.2 Recent developments

In June 2018 the Ontario Progressive Conservative ("PC") party won the Ontario provincial election, ending over a decade of Liberal leadership. Since winning the election, the PC government has taken a number of high-profile actions aimed at reducing the overall cost of electricity, including repealing the Green Energy Act, cancelling renewable energy contracts, and ending Ontario's cap-and-trade program. By cancelling Ontario's cap-and-trade program, Ontario became subject to the Canadian federal government's carbon pricing backstop.

Despite the governmental change, the IESO continues to make progress on its Market Renewal initiative with the goal of enabling a more competitive, efficient, and transparent system, which may eventually lead to the development of an incremental capacity auction.

These updates are discussed in further details in the sub-sections below, and the potential impacts to HOEP and GA forecasts are summarized in Figure 4.

Figure 4. HOEP and GA price impacts

Recent Development	Potential Price Impact (ceteris paribus)
Renewable Contract Cancellations	Marginally higher HOEP, marginally lower GA
Federal Carbon Pricing Backstop	Marginally higher HOEP
Demand Response Auction	Lower HOEP
Capacity Exports	Mixed impact depending on direction of flow

2.2.1 Renewable contract cancellations

In July 2018, the newly elected PC government announced plans to cancel 748 FIT and 10 Large Renewable Procurement ("LRP") contracts for upcoming projects (a total of around 444 MW), asserting the LRP projects had not achieved their key development milestones and the FIT contracts had not received a Notice To Proceed.[3] According to the PC government, the decision to cancel these contracts will lead to $790 million in savings in the long term.

The Ontario PC government also later announced its plan to repeal the Green Energy Act, which was enacted in 2009 to promote renewable energy development in the province. The Green Energy Act established the Feed-in Tariff ("FIT") and microFIT programs, which offered long-term contracts at above-market rates for new renewable generation, almost entirely from wind and solar generators. The FIT and microFIT programs obligated the IESO to contract with qualifying projects, consistent with the procurement targets established by the Ministry of Energy. However, per ministerial directives from the previous Liberal government, the final FIT application period was held in 2016, and the final microFIT application period was held in 2017.[4] Therefore, the repeal of the act was largely symbolic, but did reinforce the notion that any future procurements of new resources are more likely to be driven by system needs and project economics.

Finally, in July 2018 OPG announced it had reached an agreement to shut its 153 MW Thunder Bay Biomass Station, ahead of its contracted end date of January 2020. According to OPG, the decision would save ratepayers a total of $40 million.[5]

These changes were reflected in LEI's modeling.

2.2.2 Federal carbon pricing policy

In 2016, the Canadian federal government introduced a carbon pricing backstop for jurisdictions that either do not have a pricing system that meets the federal benchmark or jurisdictions that request it. The backstop is comprised of the carbon levy for fuel producers or distributors which will take effect in April of 2019, and an Output-Based Pricing System ("OBPS") for certain

[3] Ministry of Energy, Northern Development and Mines. *Backgrounder: Large Renewable Procurement and Feed-In Tariff Contracts*. July 13, 2018.

[4] IESO. Website. *Feed in Tariff Program Overview* and *microFIT News and Overview*.

[5] OPG. *Second Quarter 2018 Results Report*.

industrial facilities which will take effect in January 2019.[6] Ontario's cap-and-trade program met the federal government's benchmark, but in July 2018 the recently elected Ontario PC government introduced legislation to end Ontario's cap-and-trade program. Due to the removal of the provincial system, Ontario became subject to the federal carbon pricing backstop.[7]

Under the federal carbon pricing plan, carbon prices will begin at $20 per tonne in 2019, and increase by $10 per tonne each year until they hit $50 per tonne in 2022. Generators that use fossil fuels to produce electricity and emit 50,000 tonnes of CO_2e or more per year have a direct compliance obligation under the OBPS.[8, 9] Facilities that emit more than their predefined annual limit (based on an industry benchmark) will effectively pay the carbon price on any additional emission above the limit, while facilities that emit less receive a credit for their emissions below the limit.[10] The plan also includes a commitment in early 2022 to review the overall approach and path forward for post-2022 carbon pricing.

2.2.3 IESO's Market Renewal process

In early 2016, the IESO launched its Market Renewal stakeholder engagement process, providing a venue for market players to discuss and provide feedback on the IESO's market design renewal workplan. The overall objective of Market Renewal is to "enable a more efficient, stable marketplace with competitive and transparent mechanisms that meets system and participant needs at lowest cost".[11] According to the IESO, a fundamental market redesign is required to accomplish this, taking place under the umbrella of the Market Renewal process. The IESO's market renewal process was launched to focus on three workstreams broken down into seven separate initiatives. At a high level, these initiatives are:

Energy Workstream:

1) **Single Schedule Market ("SSM"):** Move from the current system where prices and dispatch are determined through different unconstrained and constrained systems, to prices following the same constrained scheduling system as dispatch (leading to prices being determined on a locational basis).

2) **Day-Ahead Market ("DAM"):** Move from the current 'voluntary' Day Ahead Commitment process to a financially binding Day-Ahead Market.

[6] Environment and Climate Change Canada. *Pan-Canadian Framework on Clean Growth and Climate Change*. December 2018.

[7] The Ontario government for its part has been vocally opposed to the federal plan, and has challenged the constitutionality of the federal plan.

[8] Government of Canada. Ontario and pollution pricing.

[9] Government of Canada. Pricing pollution: how it will work.

[10] Government of Canada. Update on the output-based pricing system: technical backgrounder.

[11] IESO. Market Renewal Working Group. March 10, 2017.

3) **Enhanced Real-Time Unit Commitment ("ERUC"):** Enhancements to the current Real-Time Unit Commitment process, to include items such as start-up costs and speed-no-load costs, and optimization over multiple hours, when choosing which units to commit.

Capacity Workstream:

4) **Capacity Exports:** Allow Ontario market players to export excess capacity to neighbouring jurisdictions.

5) **Incremental Capacity Auction ("ICA"):** Auction to secure incremental capacity (i.e. capacity not currently under contract and not rate-regulated). The ICA will provide uncontracted generating assets with an additional source of revenue on top of energy market revenues.

Operability Workstream:

6) **More Frequent Intertie Scheduling** to increase the efficiency of managing unexpected short-term system changes.

7) **Enabling System Flexibility** to more optimally manage scheduling of quick-response resources and manage real-time energy market uncertainty.

In addition to the market renewal initiative, the IESO also launched the Non-Emitting Resources Subcommittee ("NERSC"), where the IESO is exploring issues that include additional incentives for non-emitting resources, and the potential development of new revenue streams to compensate uncontracted generation resources with clean attributes.

From a modeling perspective, the two most important initiatives are arguably the SSM and the ICA. However, both initiatives are still in their design phase. Given that actual final market rules have not been promulgated, LEI has modeled the Ontario market as an unconstrained single zone energy-only market for this report. As the framework for the Market Renewal initiatives becomes more established, later iterations of LEI's CMI will likely incorporate constrained locational marginal prices and an incremental capacity market.[12]

2.2.4 Capacity exports

In February 2015, the IESO launched a stakeholder engagement process regarding the provision of capacity exports in the market. The IESO recognised capacity exports:

- provide Ontario-based resources an opportunity to monetize capacity not required for Ontario reliability;
- offer an alternative to facilities that would otherwise choose to idle or shut down due to Ontario market conditions; and

[12] LEI has a working preliminary Ontario ICA model which can provide capacity market prices as an add-on to this report.

- improve the efficient utilization of assets regionally.[13]

In February 2016, the IESO invited interested parties to particpate in one-on-one meetings in order to identify capacity export opportunities.[14] From these meetings, one participant identified a specific near-term opportunity in the New York Independent System Operator ("NYISO") capacity auction. As a result, a Memorandum of Understanding ("MOU") was signed between the IESO and NYSIO in August 2016, providing for participation by Ontario-based generators in the NYISO capacity auction.[15] The most recent NYISO Winter 2018/19 auction was held at the end of September 2018, and a total of 355 MW of Ontario resources were committed.

In addition, the IESO has been in contact with MISO and PJM about the possibility of exporting capacity to those markets. The most recent information from the IESO indicates it is working towards enabling capacity exports to MISO by 2019 or later. Potential exports to PJM depend on many factors including the status of the Lake Erie Connector.[16]

2.2.5 Trade with Quebec

In September 2015, the governments of Ontario and Quebec signed an MOU to engage in the exploration of capacity trade between the two provinces. This resulted in the signing of a bundled electricity trade agreement between the IESO and Hydro Quebec in November 2016. Based on this agreement, Hydro Quebec ("HQ") will provide the IESO between 2-2.3 TWh of energy per year from January 2017 to December 2023, while the IESO will provide HQ with 500 MW of capacity between December 2016 and March 2023 (as Quebec is winter-short on capacity). [17,18] In addition, Quebec will return a *one-time* 500 MW summer capacity commitment before September 2030 upon request from the IESO, which may be required as reserve margins tighten around 2025.

In addition to this direct agreement, the IESO and HQ-TransEnergie have also been involved in discussions on reliability-based capacity exports, following a similar format to the discussions between the IESO and neighbouring US RTOs (covered in Section 2.2.4). In November 2017, HQ released an RFP for up to 200 MW of capacity commitments for January to February 2018, and one 125 MW Ontario participant was committed as a result of this RFP.[19]

2.2.6 Demand response auction

In December 2015, the IESO held its first Demand Response ("DR") auction, procuring 391.5 MW for the 2016 summer period and 403.7 MW for the 2016-17 winter period.[20] The DR auction

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13 Independent Electricity System Operator. Presentation Capacity Exports: Stakeholder Meeting 3. February 4, 2016.

14 This followed an early invitation to interested participants between March and May of 2015 in which no qualified resources came forward.

15 Independent Electricity System Operator. Capacity Exports Update. October 12, 2016. Available here: <http://www.ieso.ca/Documents/consult/ce/CE-20161012-Communication.pdf>

16 IESO. Incremental Capacity Auction, Stakeholder Engagement Phase 2 – Options. December 4, 2017.

17 IESO. Overview of Electricity Trade Agreement between Quebec and Ontario. May 10, 2017.

18 IESO. 18-month Outlook, Jan 2018 – June 2019. December 2017.

19 IESO. Incremental Capacity Auction, Meeting 4. December 4, 2017.

20 Independent Electricity System Operator. 18 Month Outlook. March 22, 2016.

followed the successful completion of the DR pilot program during which 80 MW of DR was procured from five participants across 20 projects.[21]

The IESO's most recent demand response auction for the 2018-2019 commitment period procured 571 MW for the 2018 summer period with an auction clearing price of $318.01/MW-day, and 712.4 MW for the 2018-19 winter period with an auction clearing price of $317.46/MW-day.[22]

The IESO has stated its intention to eventually procure demand response through its incremental capacity auction as opposed to having a standalone DR auction as is the case presently. The ICA is still in its design stage.

LEI's analysis incorporates the revised long-term demand, conservation and demand response outlook published by the IESO in the OPO (for a more detailed discussion, see Section 3.7). This provides for a demand response target of 10% of peak demand in 2025 (or approximately 2,400 MW) and conservation target of 30 TWh by 2032.[23]

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[21] Independent Electricity System Operator. Website. Demand Response Pilot. Last accessed: October 15, 2016.

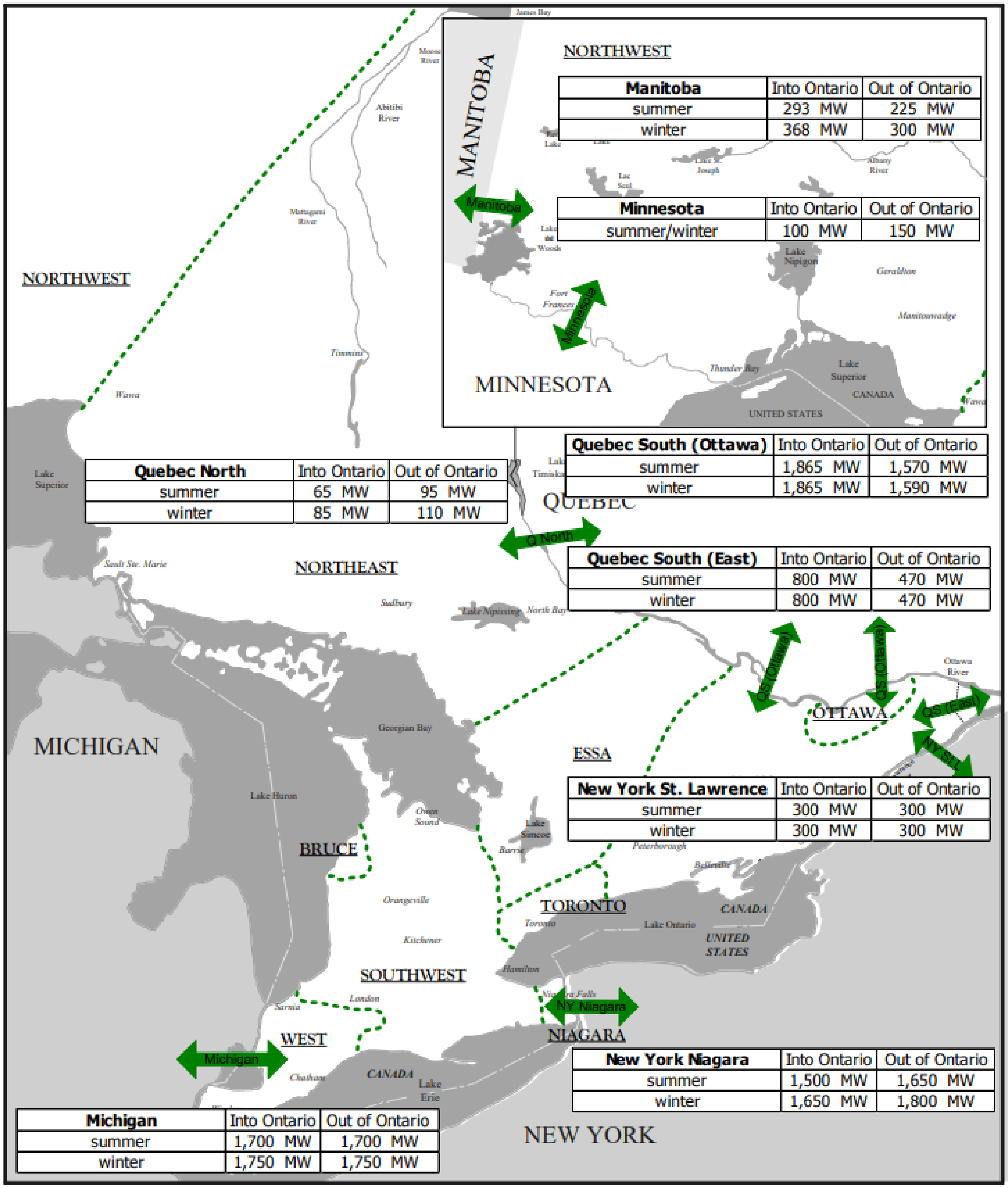
[22] With the exception of the sparsely populated Northeast zone, which cleared at $200/MW-day for both commitment periods.

[23] Total demand response procured, including forecast targets, are routinely incorporated into LEI's station database as announced by the IESO. LEI utilizes demand response procured as a supply side resource to service scheduled demand.

3 Modeling assumptions

3.1 Market topology

Figure 5. Regional transmission interface limits



Source: IESO. *Ontario Transmission System*. June 20, 2018.

Ontario's market is modeled as a single zone with interties to Manitoba, Minnesota, Michigan, New York, and Quebec, with no internal transmission constraints. All generators are paid on the basis of a single wholesale hourly price. The internal Ontario transmission system consists of nine major interfaces and ten internal zones. The 10 internal zones are as follows: Northwest, Northeast, Bruce, West, Southwest, Toronto, Niagara, Essa, East, and Ottawa. However, wholesale electricity prices are not settled on a zonal basis as Ontario's internal zones are mainly relied upon for planning purposes.

3.2 Natural gas price projections

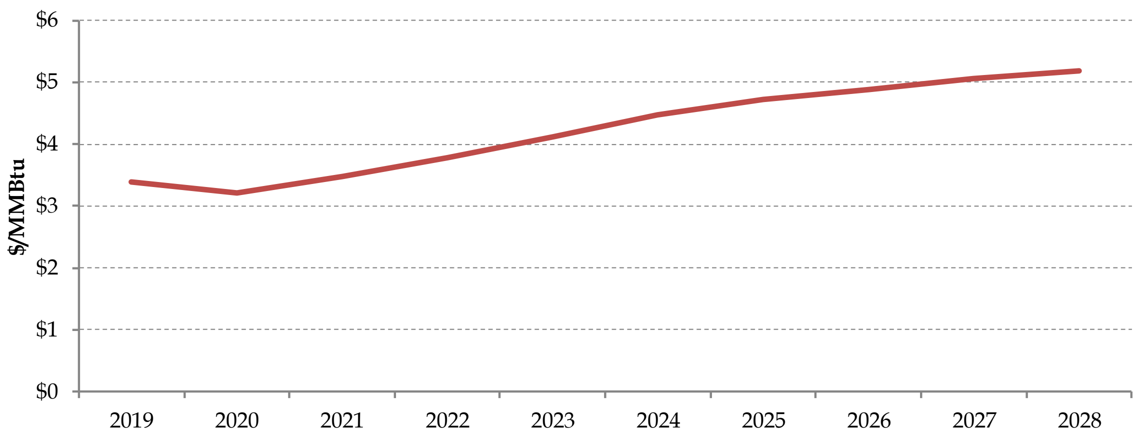
Natural gas price projections in the short term (2019-2021) are based on average forward prices for Dawn Hub as reported by OTC Global Holdings ("OTCGH") between July 1 and September 30, 2018. From 2022 onwards, due to reduced liquidity in the forwards market, LEI relied on fundamental analysis to project natural gas prices, using a reference point plus a transportation adder and local distribution charges.

Traditionally, Henry Hub has been the reference point for the North American gas market. However, due to the relatively low-cost shale gas production from Marcellus and Utica, Dominion South is becoming an important source of supply to Eastern hubs. LEI therefore chose Dominion South as the reference point for all Eastern gas hubs it models, including Dawn. Furthermore, Dawn Ontario and Henry Hub prices are not expected to diverge widely; therefore, LEI increased the Dawn Ontario gas prices at the same rate as Henry Hub's, based on the 2018 EIA Annual Energy Outlook ("AEO").

Finally, the delivered gas price is determined by LEI's proprietary Levelized Cost of Pipeline ("LCOP") model that observes market dynamics between gas price basis and cost of building new gas pipelines. The model calculates distances between 30 gas pricing hubs in North America and the 20-year levelized cost of building new pipeline between each hub, based on actual and proposed new gas pipeline projects filed to the Federal Energy Regulatory Commission ("FERC"). In the long run, the gas price spread between two pricing hubs is assumed not to exceed the levelized cost of building a new pipeline between the two hubs. This levelized cost therefore effectively sets a long-term price cap between two pricing points. For Ontario, the primary gas pricing point is Dawn Hub.

Figure 6 below shows LEI's forecast for Dawn Hub gas prices over the next ten years. Dawn Hub gas prices are projected to increase from $3.4/MMBtu in 2019 to $5.2/MMBtu in 2028, a CAGR of 4.8% per annum.

Figure 6. Gas price projections for Dawn Hub (nominal $/MMBtu)



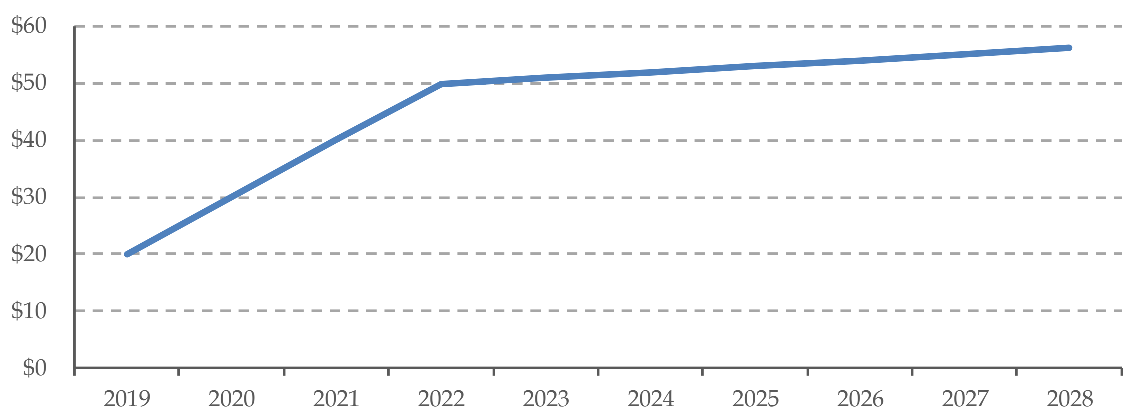
CAD$/MMBtu	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	CAGR
Dawn Hub forecasts	$ 3.4	$ 3.2	$ 3.5	$ 3.8	$ 4.1	$ 4.5	$ 4.7	$ 4.9	$ 5.1	$ 5.2	4.8%

Sources: OTCGH; EIA AEO 2018

3.3 Emissions costs

As noted in Section 2.2.2, in July 2018 the recently elected Ontario PC government introduced legislation to end Ontario's cap-and-trade program. Due to the removal of the provincial system, Ontario became subject to the federal carbon pricing backstop. LEI therefore assumed carbon prices in line with the federal backstop, beginning at $20/tonne in 2019, and increasing at $10/tonne annually until it hits $50/tonne in 2022. From 2022 onwards, LEI assumed carbon prices would continue to increase annually at inflation. As the industry benchmark that determines the limit above which emitting generators will need to pay for their emissions has not yet been set, LEI assumed the industry benchmark for gas-fired generators would be 0.37 tonnes/MWh, in line with the current benchmark being used in Alberta. The impact of carbon pricing on LEI's price forecasts is minimal, as the current system would likely only impact a small portion of Ontario's least efficient thermal generation, which are not dispatched frequently.

Figure 7. Forecast carbon price ($/tonne)



Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Carbon price ($/tonne)	$ 20.0	$ 30.0	$ 40.0	$ 50.0	$ 51.0	$ 52.0	$ 53.1	$ 54.1	$ 55.2	$ 56.3

3.4 Cost of generic new entry

Theoretically, new generation may enter the market when price levels signal that it is economic to do so. The new entry trigger price ("NETP") as shown in Figure 8, or the all-in levelized unit electricity cost for a new "generic" generation plant, is dependent upon a range of factors, including the capital costs, leverage ratio, return on equity, tax rates, debt terms, fixed and variable operations and maintenance ("O&M") expenses, expected production level, and fuel cost. For Ontario, we do not assume the need for new entry based on market dynamics because most plants seek contracts – therefore, no new resources were modeled aside from those already in the pipeline.

Figure 8. NETP – CCGT 2021

Year	2021
Nominal Capital Cost ($/kW)	$1,548
Leverage	60%
Debt interest rate	6%
After-tax Return on Equity	11%
Corporate income tax rate	27%
Debt financing term	20
Equity contribution capital recovery term	20
Construction time	36
Heat rate (Btu/kWh)	6,700
Fuel Costs ($/MMBtu)	$3.5
Nominal fixed O&M, $/kW/year	$30.2
Nominal variable O&M ($/MWh)	$2.7
CO2 allowance cost ($/tonne)	$40
CO2 content for gas-fired CCGT (lb/MMBtu)	120
CO2 adder ($/MWh)	$0
Capacity factor	60%
All-in break-even for new CCGT ($/MWh)	**$61.1**

Note: NETP provided for illustrative purposes. In reality, a new CCGT without a contract in 2021 would most likely operate at significantly lower capacity factors.

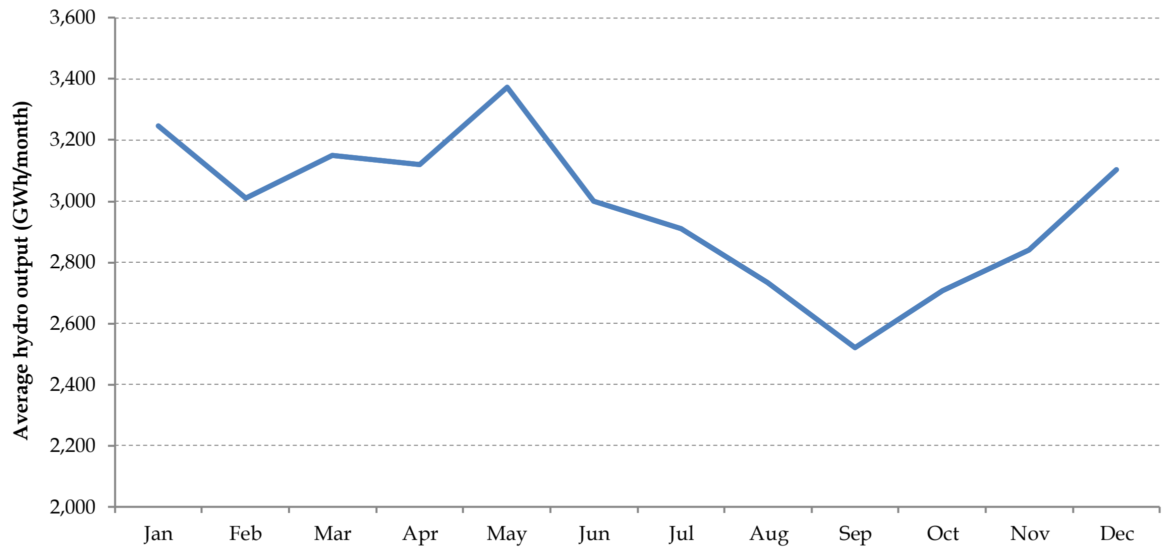
3.5 Hydrology

Hydroelectric production is seasonal. In Ontario, the pattern historically has shown an increase during the spring, a decrease during the summer and the early fall months before rebounding again in mid-late fall and early winter, and a slight decrease again in late winter. This pattern is primarily driven by climatological patterns in the region; the spring is characterized by high precipitation and melting of frozen water resources, the fall also receives more precipitation, while the summer tends to be drier.

Run-of-river hydroelectric plants will produce more energy during high water availability months and less during the dry summer months, but specific generation levels in any given month may nevertheless vary from plant to plant.

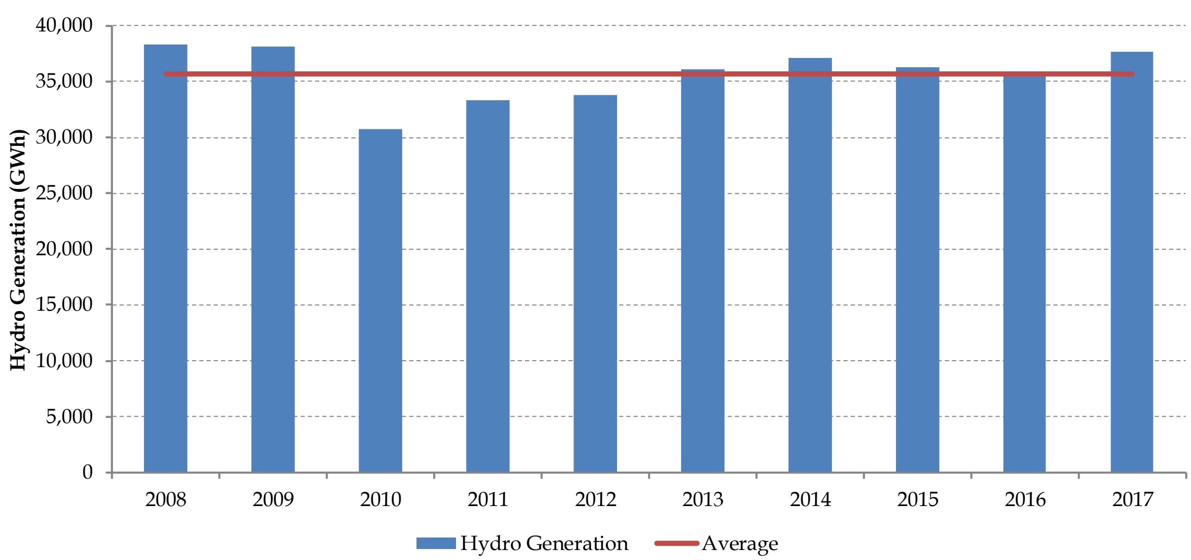
Our hydroelectric generation is based on "weather-normalized" conditions. To determine a schedule of energy production for the hydroelectric plants in our model, we use Ontario's historical hydroelectric monthly production data over the long term (2008-2017) for individual plants to create typical monthly energy production targets for each plant in our database. Figure 9 below presents the monthly energy budgets developed for all existing hydroelectric plants in the system based on historical hydrology.

Figure 9. Average monthly hydro output for transmission-connected facilities (2008-2017)



GWh	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Monthly hydro output	3,246	3,010	3,151	3,119	3,372	3,000	2,910	2,733	2,521	2,707	2,840	3,102

Figure 10. Annual hydroelectric generation for transmission-connected facilities (2008-2017)



Sources: IESO, third party commercial database

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3.6 Import and export flows

Externally, Ontario has interconnections (consisting of several transmission interfaces) with Quebec, New York, Manitoba, Minnesota, and Michigan (illustrated in Figure 5, along with their interface limits). Together, the province has approximately 13 GW of simultaneous import/export capability via these interties.[24] Through these interconnections, the market participants are able to import/export power from/to Ontario, as well as to wheel power through Ontario to other jurisdictions. External resources available for imports are modeled on an aggregate for Quebec, NYISO, Manitoba, and MISO interconnections.

As a result of Ontario's supply mix, Ontario is assumed to be a net exporter of electricity over the forecast period. This is consistent with recent historical data. To model the interchange between Ontario and external regions, we reviewed historical interchange data reported by the IESO. The modeling considers seasonality of net exports during summer, winter and shoulder periods using average profiles developed based on historical data.

While Ontario is assumed to be a net exporter of electricity over the forecast period, the amount of net exports are expected to decline over time as a result of significant amounts of nuclear generation being taken offline for refurbishment and retirement (discussed further in Section 3.8.2) as well as the completion of large hydroelectric projects specifically designed for export of hydroelectric power from Quebec (La Romaine Complex consisting of four generating stations totaling 1,550 MW, is under construction and expected to be fully operational by 2021).[25]

Modeled net exports in 2019 are assumed to be 13.0 TWh, decreasing to 10.4 TWh in 2021 reflecting nuclear unit refurbishments, declining to their lowest point of 4.7 TWh in 2025 as the Pickering nuclear facility is fully retired, then increasing slightly in 2026 and holding steady until 2028.

Figure 11. Projected net exports

Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
TWh	13.0	11.4	10.4	10.4	7.4	8.3	4.7	5.1	5.1	5.5

3.7 Demand

LEI's demand forecast is based on the IESO's long term demand and conservation outlooks as presented in the 2016 report titled *Ontario Planning Outlook: A technical report on the electricity system prepared by the IESO*.[26] The report included four different planning scenarios (one low, one flat, and two high-growth) that provide a range of demand outlooks for the period 2016 to 2035.

[24] Non-coincident transfer capability may be lower than coincident capability due to internal transmission constraints in Ontario.

[25] Romaine-2 the first of the generating stations with a capacity of 640 MW was successfully commissioned in December 2014. Hydro-Québec. Mise en service commerciale de la centrale de la Romaine-2. Last accessed: January 2015 <http://nouvelles.hydroquebec.com/fr/communiques-de-presse/692/mise-en-service-commerciale-centrale-romaine-2/>. <http://www.hydroquebec.com/projects/romaine.html>

[26] IESO. Ontario Planning Outlook. September 1, 2016.

The OPO remains the most recent long-term demand outlook published by the IESO, and the 'flat demand' outlook continues to be used by the IESO in current planning and stakeholdering sessions as the reference case. Therefore, for the purposes of producing a 10-year price forecast LEI has used the 'flat demand' outlook, which LEI considers to represent the best baseline forecast for provincial demand.

Gross peak demand in 2019 is assumed to be 26,219 MW, and to increase at 0.3% per year CAGR. Gross peak demand excludes the mitigating effect of conservation and demand response, and the effect of embedded generation. By 2028, gross peak demand is estimated to reach 26,874 MW. Net peak demand, which is net of conservation, is projected to decrease negligibly at -0.02% per year CAGR over the forecast period.

Figure 12: Gross and net peak demand projections

MW	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	CAGR
Gross Peak Demand	26,219	26,279	26,275	26,290	26,344	26,345	26,464	26,565	26,726	26,874	0.3%
Net Peak Demand	23,993	23,916	23,889	23,881	23,890	23,868	23,918	23,882	23,918	23,940	0.0%

Source: IESO Ontario Planning Outlook. Module 2 – Demand Outlook.

Net energy consumption in 2019 is projected to be 142.2 TWh, decreasing to 142.1 TWh by 2028. This is equivalent to -0.01% CAGR and is consistent with the flat demand outlook provided by the IESO as part of the OPO.

Figure 13. Annual net energy consumption projection

TWh	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	CAGR
Net Energy Consumption	142.2	142.2	141.7	141.6	141.5	141.7	141.5	141.2	141.5	142.1	0.0%

Source: IESO Ontario Planning Outlook. Module 2 – Demand Outlook.

3.8 Supply

3.8.1 New entry

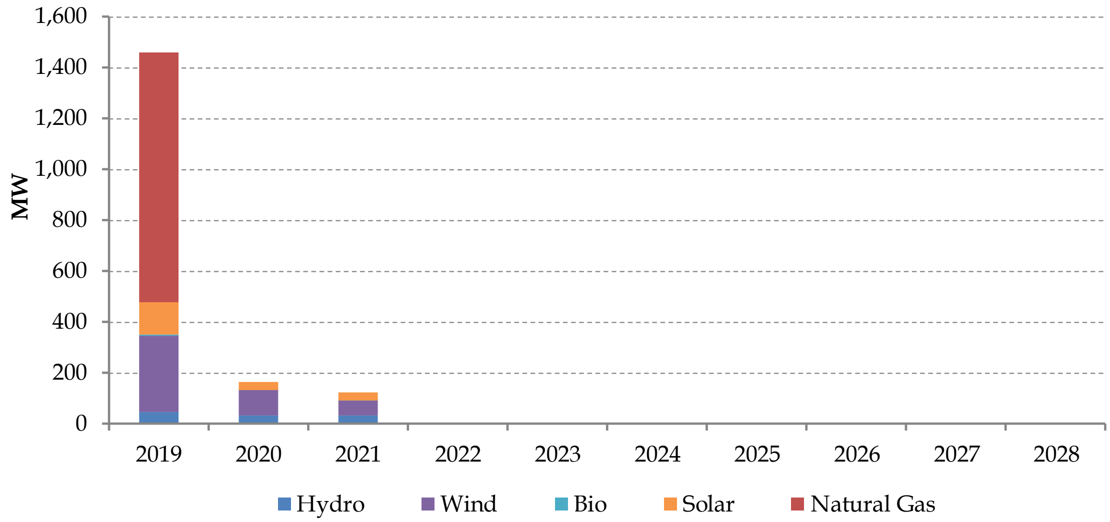
As shown in Figure 14, a total of approximately 1.8 GW of new generation resources are expected to come online between 2019 and 2028. Approximately 1.5 GW of there are transmission-connected IESO-contracted facilities due to come online between Q1 2019 and Q1 2020:

- Q1 2019 – Nanticoke Solar Project (44 MW);
- Q1 2019 – Yellow Falls Generating Station (16 MW);
- Q2 2019 – Napanee Generating Station (985 MW);
- Q2 2019 – Loyalist Solar Project (54 MW);
- Q3 2019 – Henvey Inlet Wind Farm (300 MW); and
- Q1 2020 – Nation Rise Wind (100 MW).[27]

[27] IESO website. *Supply Overview*.

For the remaining 313 MW of smaller scale transmission or distribution-connected generation that is still under development, LEI spread the entry years over the 2019-2021 timeframe as their specific entry dates were not available. As discussed in Section 3.4, current market economics do not support the need for additional resources, therefore no additional new entry was modeled outside of the IESO-contracted resources currently under development.

Figure 14. New entry (nameplate capacity) assumed in the Ontario modeling



Source: IESO Progress Report on Contracted Electricity Supply – Q3 2018; IESO website

In addition, the following IESO-contracted facilities have come offline since Q2 2018 or are due to come offline by 2019:

- Q2 2018 – Thunder Bay Biomass Generating Station (47 MW);
- Q4 2018 – Douglas Generating Station (122 MW); and
- Q2 2019 – Whitby Generating Station (56 MW).[28]

3.8.2 Nuclear refurbishment and retirement

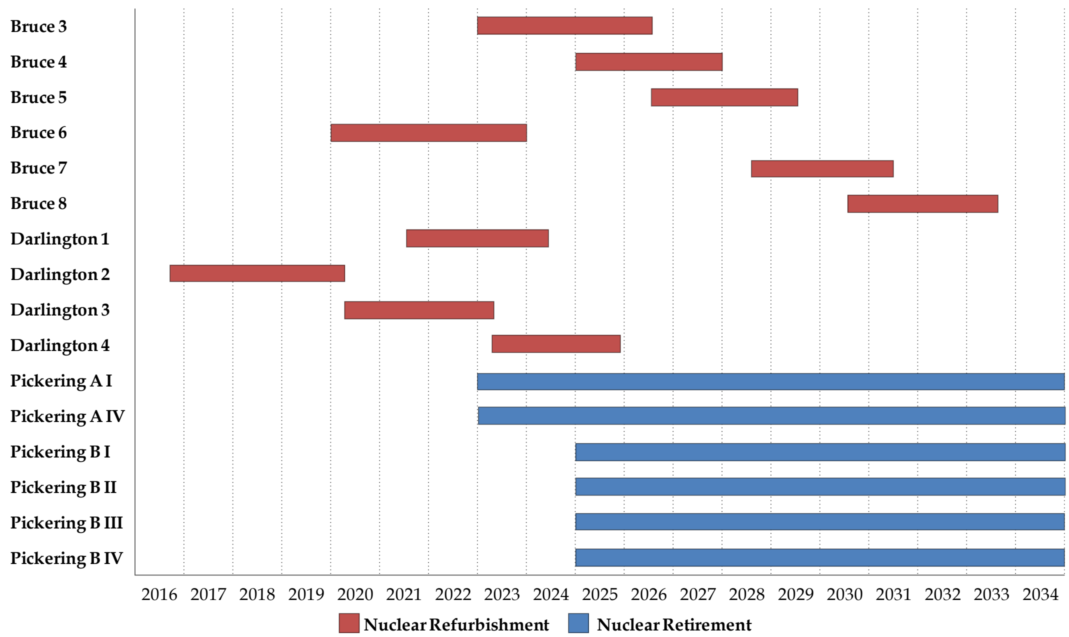
In December 2015 Bruce Power and the IESO announced an amended, long-term agreement had been reached between the two parties allowing Bruce Power to make incremental life extension investments, including refurbishment, to six of eight nuclear units.[29] The refurbishment program is set to commence from 2020 and will see the final unit return to service in 2033.[30] As part of the agreement, Bruce Power will invest approximately $13 billion.[31] Further, in January 2016, the Ontario government announced its plans to proceed with the refurbishment of four nuclear units at the Darlington nuclear facility. Refurbishment commenced in 2016 and is scheduled for

[28] IESO. *18-Month Outlook from October 2018 to March 2020*. September 2018.
[29] Ontario Ministry of Energy. News Release: Ontario commits to future in nuclear energy. December 3, 2015.
[30] Ibid.
[31] Ibid.

completion by 2026 at a cost of $12.8 billion.[32] The Ontario government also announced its approval for the continued operation of Pickering nuclear station beyond its previously scheduled retirement date. As part of the approval, two Pickering units will be retired at the end of 2022 and the remaining four units retired at the end of 2024.[33]

The IESO as part of its 2016 OPO, and the Ministry of Energy in its 2017 Long Term Energy Plan, have provided for minor revisions to the planned schedule for the nuclear refurbishment and retirement of Bruce, Darlington, and Pickering stations as shown in Figure 15. Once nuclear units are refurbished, it is assumed that they will continue to operate beyond the end of the modeling horizon in 2028.

Figure 15. Assumed nuclear refurbishment and retirement schedule



Source: Ontario LTEP 2017, IESO OPO 2016, OPG Pickering retirement schedule

3.8.3 Supply-demand balance and internal reserve margins

Figure 16 below summarizes our projected supply-demand balance for Ontario. Modeled supply is sufficient to meet projected demand and internal reserve margins over the forecast period.

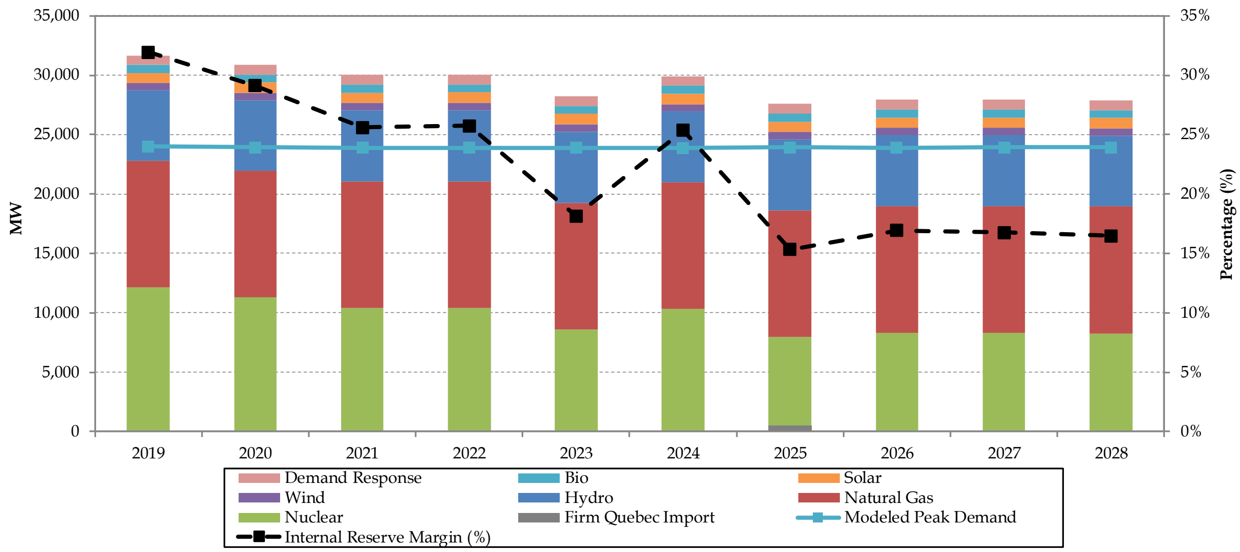
The internal reserve margin ("IRM") is forecast to decrease from a high of 32% in 2019 to a low of 15% in 2025, before rising to 18% by 2028. This decrease in IRM from 2019 to 2028, and the year-over-year fluctuations, reflects the combination of various nuclear units being taken offline temporarily for refurbishment or permanently for retirement, as well as nuclear units eventually returning online after refurbishment. To meet LEI's reserve margin target of 15%, LEI assumed

[32] Ontario Ministry of Energy. News Release: Ontario moving forward with nuclear refurbishment at Darlington and pursuing continued operations at Pickering to 2024. January 11, 2016.

[33] Ibid.

the IESO would request in 2025 the one-time 500 MW Quebec summer capacity commitment (discussed in Section 2.2.5).

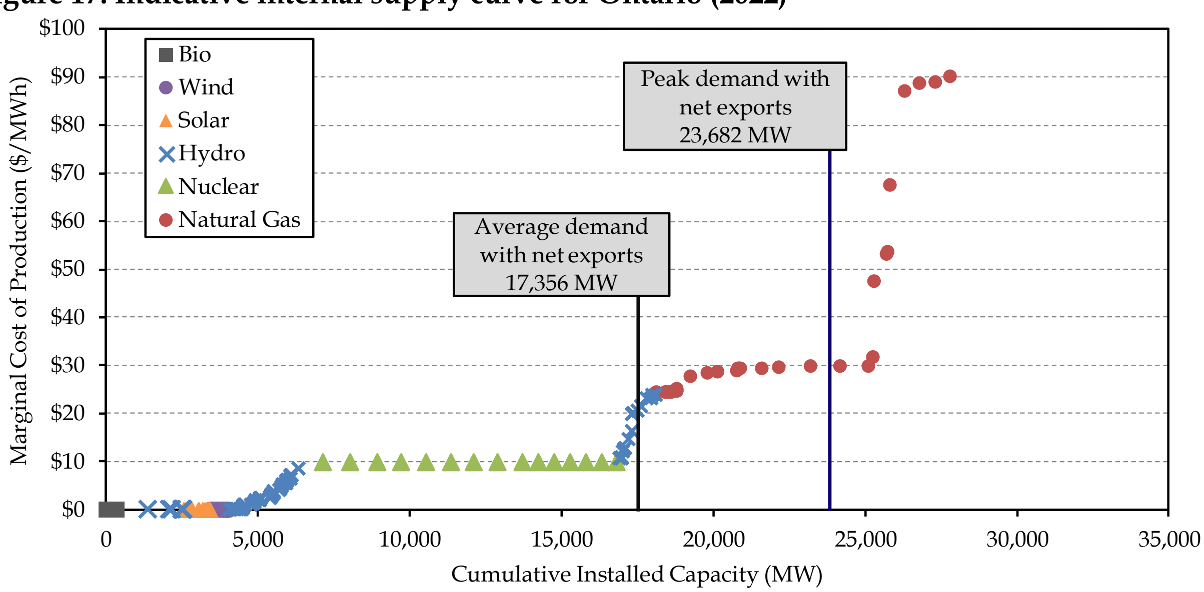
Figure 16. Region-wide supply-demand balance



Notes: Wind is de-rated to 11%, solar to 33%, and hydroelectric to 68%. These numbers are based on available capacity for these technology types at summer peak from the IESO.

Figure 17 illustrates Ontario's forecasted supply curve in 2022, showing the marginal cost and available capacity of generation resources. In 2022, natural gas facilities are expected to be the marginal units for higher-demand hours, with hydro and nuclear units being marginal units in lower demand hours. However, with the retirement of Pickering (starting in 2023), gas is expected to be the marginal unit for the majority of hours.

Figure 17. Indicative internal supply curve for Ontario (2022)



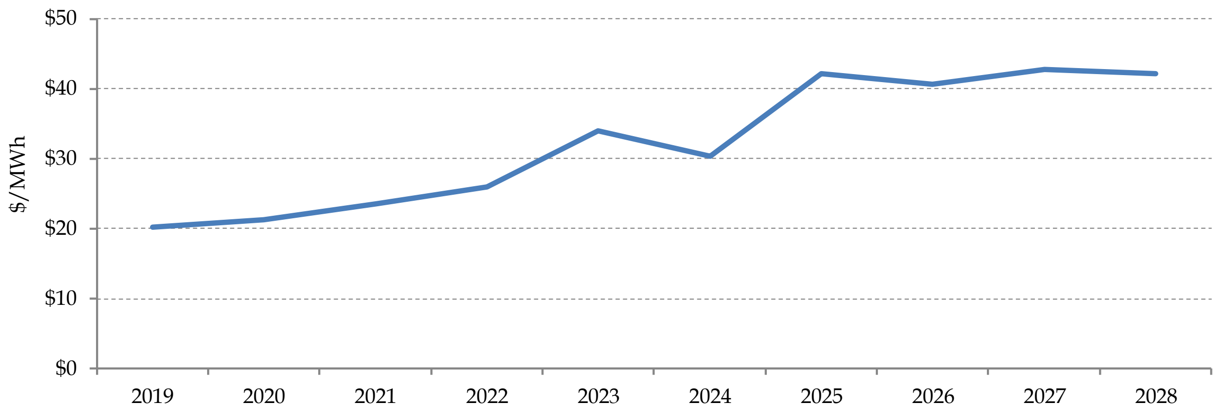
Note: Wind, solar, and hydro-electric resources are treated the same as in Figure 16.

4 10-year price forecast

4.1 Energy market prices

Figure 18 presents the forecast of wholesale energy market prices over the 2019 to 2028 period, during which time the average HOEP is forecast to increase at a CAGR of 8.5% from $20.2/MWh in 2019 to $42.2/MWh in 2028.

Figure 18. 10-year forecast Hourly Ontario Energy Prices ($/MWh)



HOEP ($/MWh)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	CAGR
Average (7x24)	$ 20.2	$ 21.3	$ 23.5	$ 25.9	$ 33.9	$ 30.3	$ 42.2	$ 40.6	$ 42.8	$ 42.2	8.5%

Modest increases in the HOEP are shown across the first few years (2019-2022) of the forecast horizon following the beginning of the nuclear refurbishment schedule, changes in net exports, and growth in Dawn Hub gas prices. These increases are offset by negative peak demand growth over the 2019-2022 period.

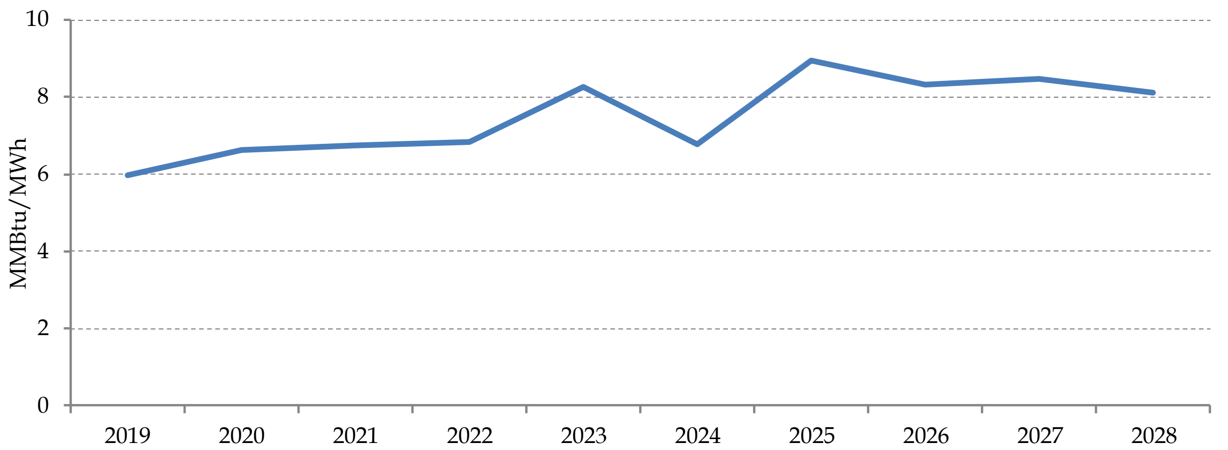
From 2022 energy prices are forecast to increase to higher levels through to 2028. This period covers the retirement of the Pickering nuclear units, as well as the beginning of most Bruce Power unit refurbishment programs (along with continued refurbishment of the Darlington units) resulting in more than 4,000 MW of capacity removed from the market. Nuclear refurbishments and retirements are the biggest driver of overall price increases and year-on-year fluctuations over the forecast horizon. Retirements of Pickering units by the end of 2022 and 2024 lead to noticeable price increases in 2023 and 2025, while relief is provided in the following years as refurbished nuclear units return to operation.

Increasing forecasted natural gas prices, along with increasing dispatch from natural gas facilities due to nuclear refurbishments and retirements, also play a role in driving up forecasted HOEP over the 2019 to 2028 timeframe. As noted in Section 3.8, gas facilities are forecast to be the marginal units for the majority hours from 2023 onwards.

4.2 Implied market heat rate

Implied market heat rates are projected to increase at a 3.5% CAGR over the forecast period. Market heat rates over the 2019-2022 period average 6.5 MMBtu/MWh, below the forecasted 10-year average of 7.5 MMBtu/MWh. Implied heat rates visibly increase in 2023 to 8.3 MMBtu/MWh and from 2025-2028 at an average of 8.5 MMBtu/MWh as a result of contracting internal reserve margins, as nuclear capacity decreases with the retirement of Pickering and continued refurbishments at Bruce.

Figure 19. Implied market heat rates



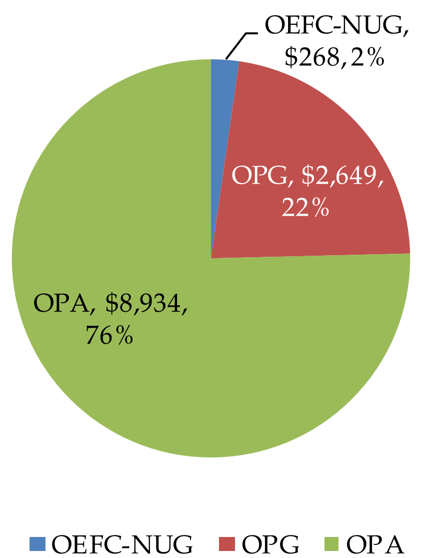
Heat Rate (MMBtu/MWh)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	CAGR
Average	6.0	6.6	6.7	6.8	8.3	6.8	8.9	8.3	8.5	8.1	3.5%

5 Global Adjustment

5.1 Global Adjustment overview

The GA was established with the creation of the OPA[34] as a so-called "Provincial Benefit" (from January 1st, 2005); it was renamed effective January 1st, 2011.[35] The GA represents the difference between the HOEP and the rates paid to regulated and contracted generators and for conservation and demand management programs.[36] Figure 20 highlights the payments made to individual contract providers over 2017.

Figure 20. GA composition by contract provider (2017, $ millions)



Source: IESO website. Global Adjustment. <http://www.ieso.ca/Pages/Ontario%27s-Power-System/Electricity-Pricing-in-Ontario/Global-Adjustment.aspx>

Changes in IESO HOEP prices and the level of the GA are largely symmetrical (as seen in Figure 21); under the contracts for differences ("CfD") structure adopted in many fossil-fuel contracts, IESO payments to generators fall or become negative (generators pay the IESO) as IESO prices approach or exceed the contract price. Even where a CfD structure is not explicitly deployed, the impact is similar as contracted power under take or pay contracts is effectively resold at market rates.

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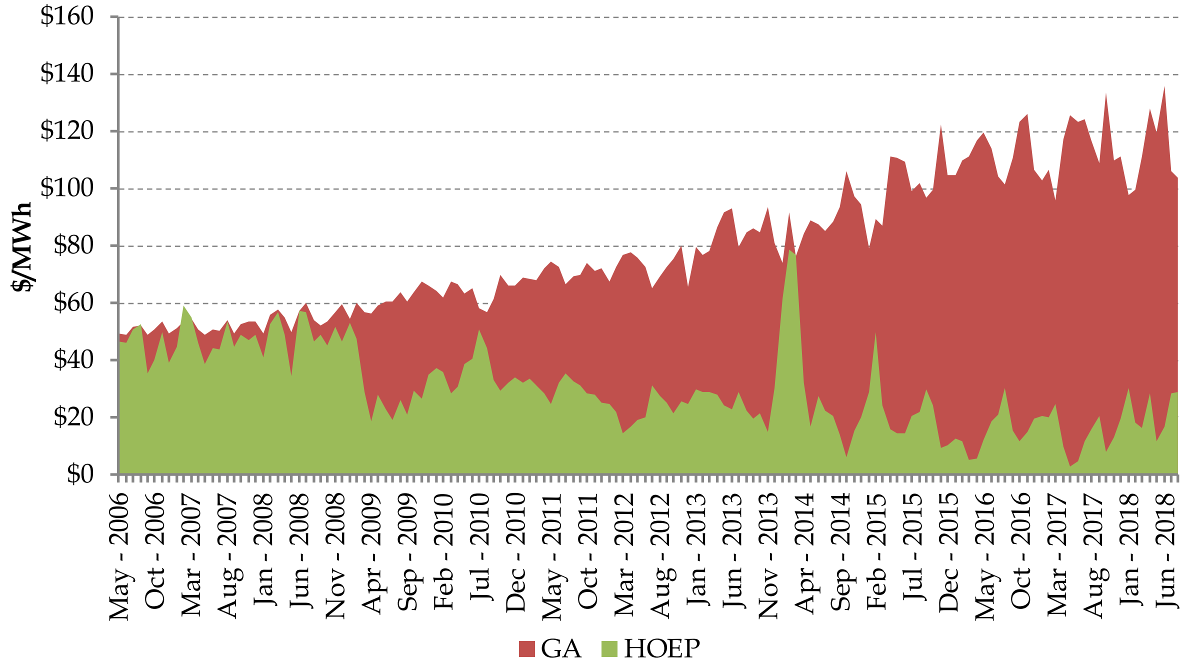
[34] The OPA was established by The Electricity Restructuring Act, 2004 (Bill 100). Source: OPA website. Mandate and Organization. <http://www.powerauthority.on.ca/about-us/management-mandate-and-organization/corporate-documents>

[35] Independent Electricity System Operator. Website. Global Adjustment. <http://www.ieso.ca/Pages/Ontario%27s-Power-System/Electricity-Pricing-in-Ontario/Global-Adjustment.aspx>

[36] Independent Electricity System Operator. Website. Price Overview < http://www.ieso.ca/Pages/Power-Data/Price.aspx>

With the recent change in government, policy-driven renewable supply additions which led to the large increase in non-hydro renewable entry in the recent past (such as renewable new entry through FIT and RESOP programs) are unlikely to occur again over the forecast horizon.

Figure 21. Historical Global Adjustment, May 2006 – Aug 2018 ($/MWh)



Source*:* IESO

5.2 LEI proprietary Global Adjustment simulation model

The LEI Global Adjustment forecast model estimates the out-of-market payments or receipts made to or received from generators and demand-side resources. The majority of supply-side resources are either (i) under contract with the IESO or the OEFC, or (ii) regulated by the OEB.[37]

The GA is divided into three categories:

- Payments made to OPG's prescribed nuclear and hydro-electric assets;[38]
- Payments made to generators and demand-side resources under contract with the IESO; and
- Payments made to non-utility generators.

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[37] OEB. Regulated Price Plan – Price Report, May 1, 2013 to April 30, 2014. April 5th, 2013. <http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2004-0205/RPP_Price_Report_May2013_20130405.pdf>

[38] As of July 1, 2014 an additional 48 hydroelectric generation facilities owned and operated by OPG were defined as prescribed for the purposes of section 78.1 of the Ontario Energy Board Act 1998. <https://www.canlii.org/en/on/laws/regu/o-reg-53-05/latest/o-reg-53-05.html>

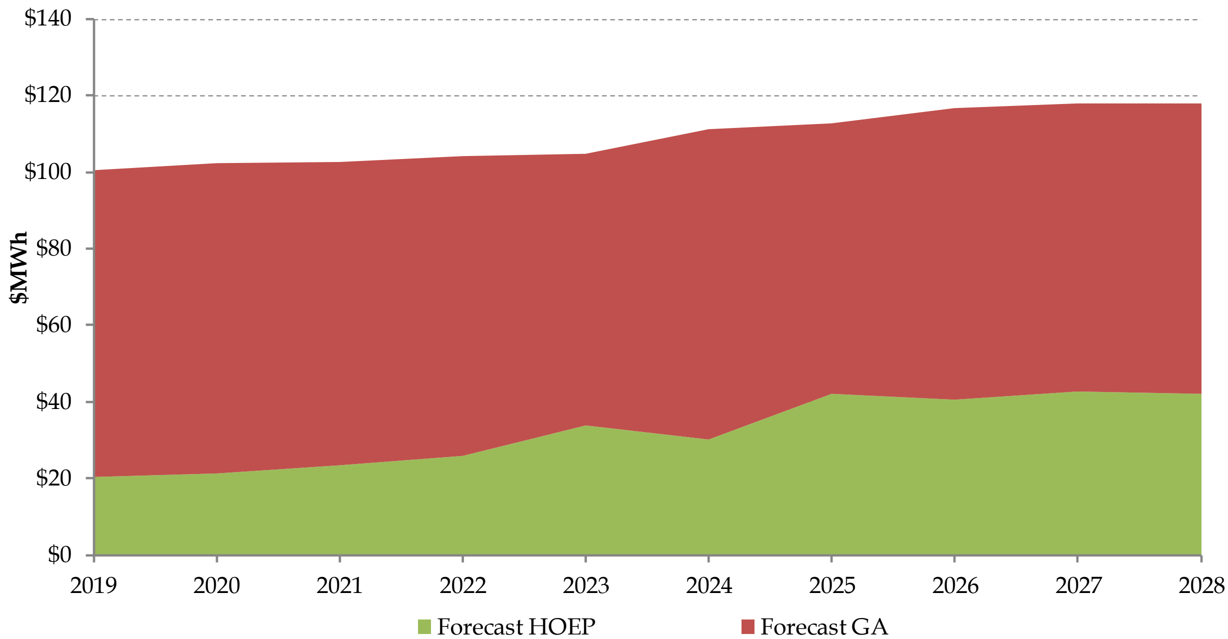
LEI's estimate of the GA is based on publicly available information regarding regulated and contractual rates for classes of generation assets as well as forecast market revenue derived from its wholesale market modeling.

5.3 Consumer price 10-year forecasting results

The HOEP is the wholesale market price, and is based on supply and demand, as balanced in real-time for each hour. Taken together, the HOEP and the GA reflect the total cost of electricity supply in Ontario.

Figure 22 presents LEI's combined forecast for the HOEP and GA components over the 2019-2028 period. GA growth between years fluctuates from positive to negative subject to the timing of key market events including the nuclear refurbishment/retirement schedule. The GA values are projected to decline across the period 2019 to 2028 at a CAGR of -0.6%, and as discussed in Section 4.1 the HOEP is forecast to increase at a CAGR of 8.5%, meaning the combined HOEP and GA values are projected to grow at a CAGR of 1.8% over the forecast horizon.

Figure 22. Forecasted Ontario Price $/MWh (HOEP plus GA)



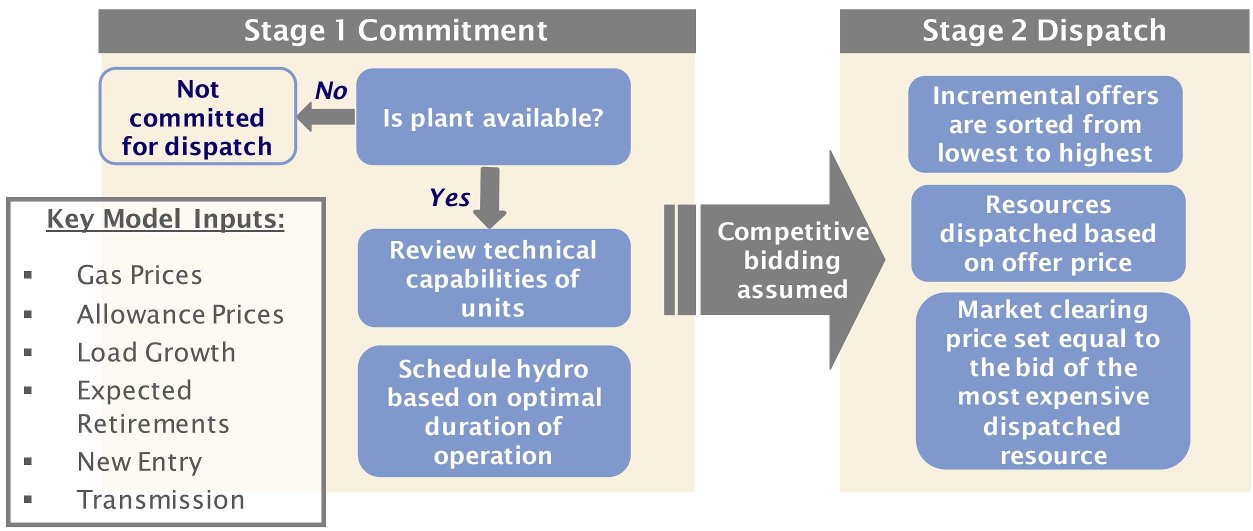
$/MWh	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	CAGR
Forecast HOEP	$ 20.2	$ 21.3	$ 23.5	$ 25.9	$ 33.9	$ 30.3	$ 42.2	$ 40.6	$ 42.8	$ 42.2	8.5%
Forecast GA	$ 80.3	$ 81.0	$ 79.3	$ 78.2	$ 70.8	$ 81.0	$ 70.5	$ 76.2	$ 75.2	$ 75.9	-0.6%

6 Appendix A: Overview of forecasting methodology

For the wholesale energy prices outlook, we employed our proprietary simulation model, POOLMod, as the foundation for our electricity price forecast. POOLMod simulates the dispatch of generating resources in the market subject to least cost dispatch principles to meet projected hourly load and technical assumptions on generation operating capacity and availability of transmission.

POOLMod consists of a number of key algorithms, such as maintenance scheduling, assignment of stochastic forced outages, hydro shadow pricing, commitment, and dispatch. The first stage of analysis requires the development of an availability schedule for system resources. First, POOLMod determines a 'near optimal' maintenance schedule on an annual basis, accounting for the need to preserve regional reserve margins across the year and a reasonable baseload, mid-merit, and peaking capacity mix. Then, POOLMod allocates forced (unplanned) outages randomly across the year based on the forced outage rate specified for each resource.

Figure 23. POOLMod's two-stage process



Source: LEI

POOLMod next commits and dispatches plants on a daily basis. Commitment is based on the schedule of available plants net of maintenance, and takes into consideration the technical requirements of the units (such as start/stop capabilities, start costs (if any), and minimum on and off times). During the commitment procedure, hydro resources are scheduled according to the optimal duration of operation in the scheduled day. They are then given a shadow price just below the commitment price of the resource that would otherwise operate at that same schedule (i.e., the resource they are displacing).

In addition, POOLMod is a transportation-based model, giving it the ability to take into account thermal limits on the transmission network.

7 Appendix B: About LEI and its Ontario experience

LEI is a global economic, financial, and strategic advisory professional services firm specializing in energy, water, and infrastructure. The firm combines detailed understanding of specific network and commodity industries, such as electricity generation and distribution, with sophisticated analysis and a suite of proprietary quantitative models to produce reliable and comprehensible results.

The firm also has in-depth expertise in many economic and financial issues related to the electricity sector, such as asset valuation, procurement, regulatory economics, and market design and analysis (see Figure 24). LEI has performed extensive work with electricity markets in North America, Europe, Asia, South America, Africa and the Middle East, and has a comprehensive understanding of the issues faced by the utilities and regulators alike.

Figure 24. LEI economic, financial and strategic management advisory expertise

Source: LEI

The following attributes make LEI unique:

- *clear, readable deliverables* grounded in substantial topical and quantitative evidence;

- *internally developed proprietary models* for electricity price forecasting incorporating game theory, real options valuation, Monte Carlo simulation, and sophisticated statistical techniques;

- *balance of private sector and governmental clients* enables LEI to effectively advise both regarding the impact of regulatory initiatives on private investment and the extent of possible regulatory responses to individual firm actions;

- *ability to estimate relative efficiency levels* and efficiency frontiers provides expertise to advise on network tariffs and design rates under performance-based ratemaking; and

- *worldwide experience* backed by multilingual and multicultural staff.

Over the past 20 years LEI has had **significant experience in the Ontario market**, including previous engagements with the market regulator, crown corporations, various local electric and gas distribution companies ("LDCs"), private equity firms, and a number of Ontario-based independent power producers ("IPPs"), market players, and stakeholders. A sample of this experience includes:

- ***Review of environment for gas plants in Ontario:*** On behalf of a private equity fund, LEI conducted an assessment of the re-contracting environment for gas plants in Ontario over the next 15 years. The engagement focused on reviewing the historic contracting of gas/thermal assets, the relevant political and regulatory context and outlook with respect to carbon targets and emissions performance standards, the need for gas plants as part of the supply mix, locational value in alleviating congestion and valuation of energy, capacity, and export revenue streams.

- ***Analysis and modeling related to the IESO's market renewal:*** For an Ontario IPP, LEI conducted a qualitative and quantitative assessment of the various components of the IESO's Market Renewal initiative, as well as a 20-year ahead energy and preliminary capacity market modeling exercise for the Ontario market.

- ***Market price impacts of incremental imports from Quebec:*** LEI was retained by one of Ontario's largest independent power generators to complete a briefing report quantifying the contract costs and market price impacts (including both an assessment of the Hourly Ontario Energy Price and Global Adjustment) of incremental imports from Quebec relative to deployment of local baseload generation in Ontario.

- ***Paper assessing Ontario electricity market:*** On behalf of a respected Canadian think tank, LEI provided an assessment of the ways in which the Ontario electricity sector could be improved to increase economic efficiency and reduce costs for consumers over the long run. Paper included extensive discussion of how a capacity market would work in Ontario.

- ***Submission to Ontario LTEP 2013 consultations regarding value of capacity imports:*** On behalf of a large Canadian hydropower generator, LEI analyzed the potential economic benefits of the export of capacity and energy from Quebec to Ontario. The engagement included a review of the treatment of imports in capacity markets in the Northeast, an examination of the impact on capacity prices of imports, and a discussion of the reliability benefits that long-term contracts for capacity imports provide. In addition, LEI discussed how Ontario can create a level playing field for clean energy imports relative to other potential future sources of supply in Ontario.

- ***OPG total factor productivity study:*** LEI assisted OPG in performing a productivity study on OPG's regulated hydroelectric assets to fulfill the mandate of the OEB. LEI proposed a structured approach which would address how productivity should be measured, what methods are available, identify a relevant peer group, and ultimately provide OPG with a productivity study for filing with the OEB. Data for this study covered an eleven-year period from 2002-2012. LEI subsequently updated this study for newly available data (encompassing operating costs and other statistics for calendar years 2013 and 2014).

- ***Review of equity component for gas distribution utility:*** LEI was engaged by a Canadian gas distribution company to conduct an independent capital structure review to assess the reasonableness of its current common equity component. The project included: (i) completing an assessment of the company's business and financial risk profile compared to the last assessment that was reviewed by the provincial regulatory board; (ii) completing an assessment of the company's business and financial risk compared to other comparable Canadian and US utilities; (iii) estimating the cost of equity for groups of comparable risk utilities; (iv) examining information on average utility actual and allowed capital structures; (v) comparing cost of equity estimates and information on average utility capital structures to the company's proposed cost of equity and capital structure; and; (vi) providing recommendations on the appropriate common equity level.

- ***Testimony on using building blocks approach in PBR frameworks***: LEI was engaged by Enbridge Gas Distribution to provide an analysis of building block incentive ratemaking approaches used in Australia and the UK, and how they would apply to Enbridge's circumstances in Ontario. LEI's report supported Enbridge's distribution tariff proposal submission to the Ontario Energy Board for a second-generation Customized IR plan for the period of five years (2014-2018). The testimony set out the theory behind as well as the practical experience of using the building blocks approach in incentive regulation regimes. LEI supported Enbridge throughout the regulatory proceeding, including providing additional reports to respond to interrogatories, attending technical conferences, and testifying before the Board in an oral hearing.