Ontario Wholesale Electricity Market Price Forecast

For the Period May 1, 2019 through October 31, 2020

Prepared for:

Ontario Energy Board

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Submitted by:

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EXECUTIVE SUMMARY

Power Advisory LLC (Power Advisory) was engaged by the Ontario Energy Board (OEB) to produce a forecast of wholesale electricity market prices in Ontario for the May 1, 2019 to October 31, 2020 period. This wholesale electricity price forecast will be used by the OEB as an input to the calculation of the "Global Adjustment Modifier", which is used to reduce the Global Adjustment charges that certain consumers would otherwise pay, as required under the *Ontario Fair Hydro Plan Act, 2017*.

Power Advisory used a complex model of Ontario's electricity market to forecast the Hourly Ontario Electricity Price (HOEP). The model combines regression analysis and dispatch modeling to generate hourly price curves that are consistent with historical market behaviour and reflective of forward-looking analysis that predicts market changes. Amongst other data, the model reflects Ontario's electricity demand and hourly load shape, all committed new entrant generation, all planned generation retirements, the operating profiles of Ontario's hydroelectric generation (including both baseload and peaking resources), the operating characteristics of Ontario's thermal generation, and expected fuel and carbon prices. The assumptions used by Power Advisory and their sources are discussed in detail in Chapter 3 of this report.

Table ES-1 presents the results of the base case market price forecast resulting from Power Advisory's modeling. The on-peak and off-peak prices presented are simple averages (i.e., not load weighted).

Table ES-1: HOEP Forecast ($ CAD per MWh)

Quarter	Calendar Period	On-Peak	Off-Peak	Average
Q1	May 2019 - Jul 2019	$20.83	$9.78	$14.85
Q2	Aug 2019 - Oct 2019	$22.13	$12.09	$16.69
Q3	Nov 2019 - Jan 2020	$26.75	$12.92	$19.23
Q4	Feb 2020 - Apr 2020	$28.38	$20.94	$24.26
Q1	May 2020 - Jul 2020	$23.22	$12.33	$17.33
Q2	Aug 2020 - Oct 2020	$24.37	$14.68	$19.13
Average	**May 2019 - Oct 2020**	**$24.26**	**$13.76**	**$18.56**

Source: Power Advisory
Notes:
1) Assumes natural gas prices that reflect the exchange rate forecast reported in the Bank of Montreal's "Canadian Economic Outlook" issued April 5, 2019. For the May 2019 to October 2020 HOEP forecast period the average exchange rate is US$1 = C$1.32.
2) On-peak hours are between 7 a.m. and 11 p.m. Eastern Standard Time (EST) on non-holiday weekdays. Off-peak hours are all other hours (weekends, holidays, and overnight). The times for the calculation of on-peak and off-peak hours are not adjusted for Daylight Savings Time (DST).

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1. INTRODUCTION

Power Advisory LLC (Power Advisory) was engaged by the Ontario Energy Board (OEB) to produce a forecast of wholesale electricity market prices in Ontario for the May 1, 2019 to October 31, 2020 period (forecast period). This wholesale electricity price forecast will be used by the OEB as an input to the calculation of the "Global Adjustment Modifier" (GA Modifier), which is used to reduce the Global Adjustment charges that certain consumers would otherwise pay, as required under the *Ontario Fair Hydro Plan Act, 2017*. The GA Modifier applies to two types of customers:

- customers that are eligible for the Regulated Price Plan (RPP), but have opted out for a retail contract or for market-based pricing; and,
- customers that are not eligible for the RPP but are qualified for an 8% discount through the *Ontario Rebate for Electricity Consumers Act, 2016* (ORECA).

The GA Modifier is subtracted from the Global Adjustment (GA) line item of the above customers' bills. By subtracting the GA Modifier, these customers receive a benefit that corresponds with that provided to RPP customers through periodic adjustments to time-of-use electricity rates. As well, the forecast is used to fulfil the OEB's requirement to calculate what time-of-use (TOU) and tiered RPP prices would have been without the Fair Hydro Plan.[1]

This report presents the results of Power Advisory's forecast, the key assumptions driving this forecast, and the information sources on which these assumptions were based.

1.1 Contents of This Report

This report is organized into four chapters, starting with this introduction. Chapter 2 outlines the price forecasting methodology and identifies the key forecast drivers. Chapter 3 reviews the forecast assumptions and identifies the information sources on which these assumptions are based. Chapter 4 presents the Ontario wholesale electricity market price forecast results.

[1] O. Reg. 195/17, as amended by O.Reg. 46/19, Section 5.1 (5): "The Board shall calculate the time-of-use and tiered rates that would have been effective on May 1, 2019 if they had been determined using the method prescribed by the regulations made under clause 79.16 (1) (b) of the *Ontario Energy Board Act, 1998* and without taking into account any forecasted impact of any provisions of the Act."

2. PRICE FORECASTING METHODOLOGY

2.1 Overview of Ontario's Wholesale Electricity Market

Wholesale prices in Ontario are determined by the Independent Electricity System Operator (IESO) based on provincial electricity demand and the monies paid to generators to supply it. Generators supplying electricity to the Ontario market must offer their output to the IESO as a series of hourly price and quantity pairs. Based on these offers, the IESO uses a dispatch algorithm to choose the least-cost combination of generation resources which can meet forecast demand in each five-minute interval of each hour. The selection of resources based on cost is subject to technical factors such as ramp rates for gas-fired generation, transmission constraints, and other physical limitations.

For each five-minute interval, the offer price of the most expensive generation selected becomes the Market Clearing Price (MCP) for that period. Each generator in Ontario receives the MCP for its energy output, regardless of what price it offered to the IESO. For each hour, the twelve five-minute MCPs are averaged to determine the Hourly Ontario Electricity Price (HOEP). Thus, the interaction of hourly supply and demand determines Ontario's wholesale electricity market price.

2.2 Overview of the Forecasting Model

The major factors known to drive the equilibrium between electricity supply and demand in Ontario are reflected in Power Advisory's HOEP Forecast Model. Accordingly, the model reflects the history of the Ontario electricity market and specifically the relationship between the drivers of market prices and the resulting market prices. This relationship is then extrapolated forward to produce a forecast of expected wholesale electricity prices.

However, no model can accurately simulate all of the factors and interactions that affect prices in an electricity market the size of Ontario's. In order to retain as much historical information as possible regarding the nuances of market operation, the starting point for Power Advisory's model is hourly prices over the past five years (2014-2018). For each forecast year, the model takes the hourly prices for the first historical base year (2014), reflecting supply, demand, fuel prices, weather, etc. in that year, and adjusts each of these 8,760 prices based on expected changes in supply, demand, and fuel prices in each forecast year. For example, if the amount of nuclear capacity in-service in the forecast year is expected to be less than what was available in the base year, supply will be reduced, and prices correspondingly increased to reflect the revised supply mix, in all hours of the forecast year. If more wind capacity is expected to be in service, supply in the forecast year is increased, but with a greater impact on prices in hours which experienced greater wind in the base year. The relationship between supply, demand, and price is established through regression analysis as part of the modelling process. Prices are further adjusted to reflect market rules on curtailment of wind, solar, and nuclear generation, as appropriate. The process is repeated for the same forecast year using each of the remaining four historical base years (2015, 2016, 2017 and 2018), and the results using all five base years are averaged to produce the forecasts shown in this report.

2.3 Key Forecast Drivers

Although other influences exist, forecast price changes are driven by three primary factors:

- **Hourly demand for electricity**, including both changes in total monthly or annual demand, and changes in the time of day when consumers use electricity.
- **Generation in service**, taking into account capacity additions (such as wind, solar, hydro, gas and other facilities coming into service), retirement of older capacity, the expiration of generation contracts and temporary shut-downs; especially for the refurbishment of the Bruce and Darlington nuclear plants.
- **Cost of burning natural gas**, including both the market price of natural gas and the cost of the greenhouse gas (GHG) emissions. The marginal cost of generating electricity from natural gas is an important determinant of electricity prices in Ontario in many hours during the forecast period. When Ontario demand is high relative to supply, the marginal source of supply (which either sets or strongly affects the MCP) is usually either domestic gas generation, or imports from other markets where the price is often set by natural gas generation. When supply is high relative to Ontario demand, the province exports electricity to neighbouring markets, and the price received is often set by the cost of natural gas generation in those markets.

3. KEY FORECAST ASSUMPTIONS

The major assumptions used in the HOEP forecast model, as well as their sources, are presented below.

3.1 Demand Forecast

The basis for Power Advisory's energy demand forecast is the IESO's *Reliability Outlook: An adequacy assessment of Ontario's electricity system from April 2019 to September 2020* (released March 20, 2019) (*Reliability Outlook)*. The IESO's forecast contained in this report takes conservation and demand management (CDM) programs into account.[2] It assumes "normal weather" – i.e., the energy forecast is based on daily weather conditions that are representative of typical weather conditions for that time of year.

The IESO forecasts demand at the transmission grid level. However, Ontario has a significant and growing supply of generation "embedded" in the distribution network, which supplies a corresponding volume of consumer demand that does not pass through the transmission system. Therefore, the IESO adjusts its forecast of grid-level demand to exclude embedded generation (technically, to exclude the demand that it supplies). Power Advisory's HOEP forecast model takes into account both grid-level demand, and the demand supplied by embedded generation.

The forecast period for this report (May 1, 2019 - October 31, 2020) extends slightly beyond the energy forecast period covered by the IESO's *Reliability Outlook* and therefore Power Advisory has extrapolated the IESO's forecast to cover the entire forecast period. Table 1 shows the forecast of monthly energy consumption used in the model.

[2] On March 21, 2019, the Conservation First Framework was discontinued by Ministerial directive, and replaced with a new Interim Framework effective April 1, 2019. These changes will substantially reduce CDM spending. As these changes were announced after the *Reliability Outlook* was released, it is unlikely that the *Reliability Outlook*'s demand forecasts take them into account. However, conservation measures usually take years to have their full effect, so the impact of these changes on demand during the forecast period is likely to be minimal.

Table 1: Forecast Monthly Energy Consumption and Peak Demand

Month	Grid-Level Demand (GWh)	Embedded Demand (GWh)	Total Demand (GWh)	Peak Demand (MW)
May 2019	10.41	0.69	**11.10**	**18,663**
Jun 2019	10.94	0.66	**11.60**	**21,623**
Jul 2019	11.91	0.65	**12.56**	**22,105**
Aug 2019	11.67	0.55	**12.22**	**21,550**
Sep 2019	10.16	0.57	**10.73**	**18,920**
Oct 2019	10.72	0.57	**11.29**	**17,621**
Nov 2019	11.09	0.53	**11.62**	**19,701**
Dec 2019	12.03	0.48	**12.51**	**20,367**
Jan 2020	12.61	0.58	**13.19**	**21,104**
Feb 2020	11.44	0.56	**12.00**	**19,819**
Mar 2020	11.36	0.64	**12.00**	**19,476**
Apr 2020	10.04	0.76	**10.80**	**17,369**
May 2020	10.24	0.73	**10.97**	**18,519**
Jun 2020	11.01	0.69	**11.70**	**21,404**
Jul 2020	11.72	0.69	**12.41**	**21,902**
Aug 2020	11.53	0.58	**12.12**	**21,028**
Sep 2020	10.19	0.60	**10.78**	**18,773**
Oct 2020	10.72	0.60	**11.32**	**17,706**
Total/Maximum	**199.81**	**11.11**	**210.92**	**22,105**

Source: IESO, Reliability Outlook: An adequacy assessment of Ontario's electricity system from April 2019 to September 2020 (released March 20, 2019), Tables 3.1.1 and 3.3; Power Advisory

3.2 Supply Resources

Power Advisory's generation capacity assumptions are consistent with the IESO's *Reliability Outlook*. Assumptions regarding expected generation capacity additions, available nuclear capacity and hydro generation, and Ontario's interconnection limits are detailed below.

3.2.1 *Generation Capacity Additions*

In addition to the existing supply resources, several major projects are expected to come on-line during the forecast horizon, as listed in Table 2. These have been included in the model specification. The IESO capacity additions include the Napanee generating station, a 985-MW gas-fired combined-cycle plant, and 574 MW of hydro, wind and solar generation. The supply contracts of one gas generator (Whitby Cogeneration) and one biomass generator (Calstock) will expire during the forecast period.

Table 2: Major Generation Capacity Changes

Project Name	Resource Type	Capacity (MW)	In-Service Date
Nanticoke Solar	Solar	44	2019-Q1
Yellow Falls	Hydro	16	2019-Q1
Loyalist Solar	Solar	54	2019-Q2
Whitby Cogeneration	Gas	-56	2019-Q2
Napanee Generating Station	Gas	985	2019-Q2
Henvey Inlet Wind Farm	Wind	300	2019-Q3
Romney Wind Energy Center	Wind	60	2019-Q4
Nation Rise	Wind	100	2020-Q1
Calstock	Biomass	-38	2020-Q2

Source: IESO, Reliability Outlook: An adequacy assessment of Ontario's electricity system from April 2019 to September 2020 (released March 20, 2019), Table 4.2

In addition to the transmission-connected projects shown in Table 2, the IESO's *Reliability Outlook* forecasts the addition of 200 MW of distribution-connected bioenergy, hydro, solar and wind projects during the forecast period. Including the above additions, the model assumes that 2,800 MW of solar capacity and 5,500 MW of wind capacity will be in service by October 2020, capable of generating enough electricity to meet approximately 12% of Ontario's demand. Increases in wind and solar generation put downward pressure on Ontario's wholesale electricity prices.

3.2.2 Nuclear Capacity

Unit 2 of the Darlington Nuclear Generating Station has been out of service for refurbishment since October 2016 and is expected to return to service in March 2020. Unit B6 of the Bruce Nuclear Generating Station is planned to be taken out of service for refurbishment in January 2020, and Darlington Unit 3 in February. The other two Darlington units, and five of the eight Bruce units, are also scheduled to undergo refurbishment, but not before the end of the forecast period, according to the IESO's *Reliability Outlook*.

Based on this, and historical generation patterns, the HOEP forecast model assumes total nuclear generation of 127 TWh over the forecast period, as shown in Table 3 below. This implies a capacity factor of 82.5%, which is calculated as the average power generated over the rated peak power available through the nuclear fleet, excluding the units which are out of service. It takes into account expected curtailment of some of the Bruce units during times when domestic supply exceeds demand. All plants show higher capacity factors during summer and winter and lower capacity factors during the shoulder seasons (spring and fall), indicative of the planned maintenance that tends to be scheduled for the shoulder seasons when demand is lower.

Table 3: Forecast Nuclear Generation

Month	Nuclear Generation (TWh)
May 2019	6.73
Jun 2019	7.21
Jul 2019	7.86
Aug 2019	7.81
Sep 2019	7.09
Oct 2019	7.21
Nov 2019	7.51
Dec 2019	7.83
Jan 2020	7.37
Feb 2020	5.84
Mar 2020	6.99
Apr 2020	6.22
May 2020	6.27
Jun 2020	6.72
Jul 2020	7.31
Aug 2020	7.26
Sep 2020	6.60
Oct 2020	6.71
Total	**126.56**

Source: Power Advisory

3.2.3 Hydro Generation

Hydroelectric generation can vary significantly from year to year depending on the level of precipitation in the province. The starting point for Power Advisory's HOEP forecast model is historical supply and demand for the five base years (2014-2018). During these years, annual output of transmission-connected hydro ranged from a low of 35.0 TWh in 2016 to a high of 36.9 TWh in 2017. This range is reflected in the forecast, which is based on an average of the forecast developed using each of the five base years. The forecasts of hydro output are adjusted for changes in installed hydro capacity between the forecast year and the base year (such as the addition of the 16 MW Yellow Falls Hydroelectric Generating Station in 2019).

3.2.4 Transmission Capabilities and Constraints

Unlike many electricity systems which have different electricity prices in different areas, Ontario has a uniform electricity price that applies across the entire province. HOEP therefore does not directly reflect transmission constraints within Ontario. The forecast model reflects this, and does not model internal transmission constraints. To the extent that transmission constraints have indirect impacts on wholesale market prices, these are implicitly factored into the model through the use of historic price curves.

External transfer limits can also affect Ontario prices. Limited transfer capability can mean higher prices when demand exceeds supply, because less expensive imports cannot be brought in, and lower prices when supply exceeds demand, because suppliers cannot sell their surplus in other markets. The transfer capabilities of transmission interconnections with adjacent markets are shown in the IESO's *Reliability Outlook*, differentiated by season and direction of flow. Table 4 shows the ratings of Ontario's interconnections with adjacent markets based on the information presented in this report.

Table 4: Ontario Interconnection Limits

(MW)	Flows Out of ON		Flows Into ON	
	Summer	Winter	Summer	Winter
Manitoba	225	300	293	368
Minnesota	150	150	100	100
Michigan	1,700	1,750	1,700	1,750
New York	1,950	2,100	1,800	1,950
Québec	2,135	2,170	2,730	2,750

Source: IESO, Reliability Outlook: An adequacy assessment of Ontario's electricity system from April 2019 to September 2020 (released March 20, 2019), Table B3

3.3 Natural Gas Prices

Given the uncertainty associated with fuel price forecasts, Power Advisory typically relies on liquid financial and physical markets to specify natural gas market price forecasts. For Ontario electricity prices, the most relevant pricing hub is the Dawn/Union hub in Southwestern Ontario. While trade volumes at this hub are lower, and therefore less widely reported than at other gas hubs, S&P Global Market Intelligence reports forward prices for up to ten years into the future, based on trades brokered by OTC Global Holdings. Power Advisory uses these prices in its forecasts.

Future prices based on trading over a single day may be pushed up or down by very short-term factors that do not reflect long-term trends. To reduce the impact of such volatility on forecast prices, an average of settlement prices over the most recent 21 days is used.

These forward prices are reported in US dollars and therefore must be converted into Canadian dollars. The price forecast reflects an average exchange rate of $1.32 CAD between May 2019 and October 2020. The monthly exchange rate forecast is taken from the Bank of Montreal's "Canadian Economic Outlook" issued April 5, 2019. As well as affecting the forecast of the natural gas price in Ontario, the forecast exchange rate affects the price of electricity imports from, and exports to, neighbouring markets.

3.3.1 GHG Emission Allowance Price Forecast

Effective January 1, 2019, gas-fired generation in Ontario (as well as in some other provinces) is subject to Part II of the federal government's *Greenhouse Gas Pollution Pricing Act*, which introduces an output-based pricing system (OBPS). Participants in the OBPS are required to report and manage their own carbon-related compliance obligations, and have the following options to satisfy annual emissions that exceed their sector-based emission intensity benchmark: (i) pay the carbon price; (ii) submit surplus credits issued by the federal government; or (iii) submit eligible offset credits.

For purposes of this forecast, Power Advisory has assumed that gas-fired generators will satisfy their OBPS obligations by paying the carbon price, as this is likely to represent the marginal cost of complying with the legislation for most generators. These generators are therefore assumed to pay a per tonne excess emissions charge on their actual emissions above the sector-based emission intensity benchmark of 370 tonnes per GWh.[3] The excess emissions charges that apply during the forecast period are $20 per tonne of CO_2e emissions in 2019 and $30 per tonne of CO_2e in 2020.

The following example illustrates how the excess emissions charge payable by Ontario's gas-fired generators is calculated: a combined-cycle plant that emitted 430 tonnes of CO_2e in the process of generating 1 GWh of electricity would pay $1,200 in excess emissions charges in 2019. The $1,200 charge is determined based on a CO_2e emission level of 60 tonnes (being the difference between the 430 tonnes of CO_2e emitted and the 370 tonnes of CO_2e per GWh benchmark) x $20/tonne. Less efficient gas-fired plants will pay more, and extremely efficient gas-fired plants could theoretically receive a rebate. Electricity imported from neighbouring areas is not subject to carbon charges.

The HOEP forecast takes into account the cost of GHG emission allowances incurred when burning natural gas to generate electricity.

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[3] https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/output-based-pricing-system/complete-text-for-proposal-regulations.html#toc22 .

3.3.2 Natural Gas Price Forecast

Natural gas price assumptions are presented in Table 5 below. The forecast average Dawn/Union hub natural gas market price for the forecast period is C$3.55/MMBtu, and the forecast effective price, including the impact of excess emissions charges, is C$3.75/MMBtu.[4]

Table 5: Natural Gas and GHG Allowance Price Forecasts

Month	Forward Price @ Dawn Hub US$/MMBtu	Forward Price @ Dawn Hub C$/MMBtu	Excess Emission Charges C$/tonne	Effective Gas Price C$/MMBtu
May 2019	$2.59	$3.46	$20.00	**$3.61**
Jun 2019	$2.62	$3.49	$20.00	**$3.65**
Jul 2019	$2.63	$3.50	$20.00	**$3.66**
Aug 2019	$2.66	$3.53	$20.00	**$3.69**
Sep 2019	$2.62	$3.48	$20.00	**$3.63**
Oct 2019	$2.62	$3.48	$20.00	**$3.64**
Nov 2019	$2.85	$3.78	$20.00	**$3.94**
Dec 2019	$3.07	$4.06	$20.00	**$4.22**
Jan 2020	$3.22	$4.25	$30.00	**$4.49**
Feb 2020	$3.19	$4.22	$30.00	**$4.45**
Mar 2020	$3.07	$4.05	$30.00	**$4.28**
Apr 2020	$2.57	$3.39	$30.00	**$3.62**
May 2020	$2.47	$3.25	$30.00	**$3.48**
Jun 2020	$2.47	$3.24	$30.00	**$3.48**
Jul 2020	$2.49	$3.26	$30.00	**$3.49**
Aug 2020	$2.45	$3.21	$30.00	**$3.44**
Sep 2020	$2.44	$3.19	$30.00	**$3.42**
Oct 2020	$2.43	$3.17	$30.00	**$3.40**
Average	**$2.69**	**$3.55**	**$25.55**	**$3.75**

Source: S&P Global Market Intelligence, Power Advisory

[4] The effective price assumes a heat rate of 8 MMBtu/MWh (typical for a combined cycle plant including starts) and an emissions factor of 54 kg of CO_2e per MMBtu of natural gas.

4. REVIEW OF FORECAST RESULTS

The results of Power Advisory's base case market price forecast are shown in Table 6. Consistent with previous editions of this report to the OEB, these prices are presented as simple averages, with high-demand and low-demand hours having equal weight.

The forecast prices show a distinct seasonal pattern (higher in summer and winter, lower in spring and fall) which reflects natural gas prices, Ontario's load shape, typical hydroelectric generation output profiles, and the timing of maintenance outages. Natural gas prices tend to be higher in winter because of heating demand. Electricity demand in Ontario tends to be higher in summer (due to air conditioning) and in winter (due to heating) than in spring and fall. Hydroelectric generation tends to be highest in May and June due to the downstream effects of snowmelt (called the spring freshet). Maintenance outages, particularly at nuclear and gas generation facilities, are most often scheduled in the shoulder seasons. The effect of these planned outages is to mitigate the downward price impact of reduced load in the shoulder seasons and increased hydroelectric generation in the spring.

Table 6: HOEP Forecast (C$/MWh)

Quarter	Calendar Period	On-Peak	Off-Peak	Average
Q1	May 2019 - Jul 2019	$20.83	$9.78	$14.85
Q2	Aug 2019 - Oct 2019	$22.13	$12.09	$16.69
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Notes:
1) Assumes natural gas prices that reflect the exchange rate forecast reported in the Bank of Montreal's "Canadian Economic Outlook" issued April 5, 2019. For the May 2019 to October 2020 HOEP forecast period the average exchange rate is US$1 = C$1.32.
2) On-peak hours are between 7 a.m. and 11 p.m. Eastern Standard Time (EST) on non-holiday weekdays. Off-peak hours are all other hours (weekends, holidays, and overnight). The times for the calculation of on-peak and off-peak hours are not adjusted for Daylight Savings Time (DST).

Power Advisory's forecast is based on a set of assumptions related to supply and demand that have been derived from best available information. Although Power Advisory has taken great care to ensure the forecast methodology is sound, by their nature forecasts are uncertain and cannot be guaranteed.