NAVIGANT CONSULTING

Ontario Wholesale Electricity Market Price Forecast

For the Period
November 1, 2015 through April 30, 2017

Presented to

Ontario Energy Board

October 15, 2015

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Some of the assumptions used in the preparation of this wholesale electricity market price forecast, although considered reasonable at the time of preparation, inevitably will not materialize as forecasted as unanticipated events and circumstances occur subsequent to the date of the forecast. Accordingly, actual electricity market prices will vary from the electricity market price forecast and the variations may be material. There is no representation that our Ontario electricity market price forecast will be realized. Important factors that could cause actual electricity market prices to vary from the forecast are disclosed throughout the report.

EXECUTIVE SUMMARY

Navigant Consulting Ltd. (Navigant) was retained by the Ontario Energy Board (OEB) to provide an independent market price forecast for the Ontario wholesale electricity market. This wholesale electricity price forecast will be used, as one of a number of inputs, to set the price for eligible consumers under the Regulated Price Plan (RPP).

Navigant used a statistical model of the Ontario electricity market to develop our hourly Ontario electricity price (HOEP) forecast. Navigant's Ontario model draws on our Ontario database, which reflects the Ontario hourly load shape, all committed new entrant generation, best available information regarding the operating profile of Ontario's hydroelectric generation (baseload and peaking resources), and operating characteristics and fuel prices for Ontario's thermal generation. Our assumptions and their sources are discussed in detail in Chapter 3 of this report.

The table below presents the results of our base case market price forecast. The on-peak and off-peak prices presented are simple averages, i.e., not load weighted.

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

Term	Quarter	Calendar Period	On-Peak	Off-Peak	Average	Term Average
RPP Year	Q1	Nov 15 - Jan 16	$31.02	$19.40	$24.69	
	Q2	Feb 16 - Apr 16	$23.80	$13.56	$18.27	
	Q3	May 16 - Jul 16	$23.93	$12.08	$17.56	
	Q4	Aug 16 - Oct 16	$20.81	$9.74	$14.77	$18.82
Other	Q1	Nov 16 - Jan 17	$32.29	$20.32	$25.77	
	Q2	Feb 17 - Apr 17	$30.83	$20.87	$25.44	$25.61

Source: Navigant Consulting

Notes

1) The price forecast reflects an average exchange rate of $1.306 CAD between Nov 2015 and April 2017. The exchange rate forecast is taken from the Bank of Montreal's "Canadian Economic Outlook" issued Oct 2015.

2) On-peak hours include the hours ending at 8 a.m. through 11 p.m. Eastern Time (EST) on working weekdays and off-peak hours include all other hours.

NAVIGANT CONSULTING

TABLE OF CONTENTS

NAVIGANT CONSULTING

LIST OF FIGURES & TABLES

List of Figures

List of Tables

1. INTRODUCTION

Navigant Consulting Ltd. (Navigant) was retained by the Ontario Energy Board (OEB) to provide an independent market price forecast for the Ontario wholesale electricity market. This wholesale electricity price forecast will be used, among other inputs, to set the price for eligible consumers under the Regulated Price Plan (RPP).

This report presents the results of our forecast of the Hourly Ontario Energy Price (HOEP) for the period from November 1, 2015 through April 30, 2017 and describes the major economic and energy market assumptions and inputs for the forecast, as well the sources of information. In addition, given that this forecast is based on a specific set of assumptions, the report evaluates major risk factors in the forecast.

This forecast of the HOEP will be used along with the following to establish the price for the RPP:

- the regulated payment amounts for Ontario Power Generation's (OPG's) prescribed assets,
- the cost of non-utility generation (NUG) contracts administered by the Ontario Electricity Financial Corporation,
- the cost of renewable energy supply (RES) and clean energy supply (CES) contracts administered by the Independent Electricity System Operator (IESO) (the pre-merger Ontario Power Authority),
- the cost of renewable energy standard offer program (RESOP) and Feed-In tariff (FIT) program contracts administered by the IESO,
- the cost of the "Early Mover", Combined Heat and Power and Bruce Power contracts administered by the IESO; and
- the balance in the variance account held by the IESO.

This forecast will also be used to determine the estimated value of the Global Adjustment as part of the RPP price.

1.1 Contents of This Report

This report contains five chapters. The first is this Introduction. The second reviews the forecasting methodology, including the framework used for evaluating forecast uncertainty. The third chapter reviews the key forecast assumptions and identifies the information source. The fourth chapter reviews the forecast results. The final chapter discusses the forecast risks.

2. PRICE FORECASTING METHODOLOGY

The major factors driving the equilibrium of supply and demand are reflected in our statistical forecast model. The model draws on the history of the Ontario electricity market to determine the relationship between the drivers of market prices and the resulting market prices. This relationship is then extended forward to produce a forecast of expected wholesale electricity prices.

2.1 Overview of the Forecasting Model

Navigant used our statistical price forecasting model to develop the HOEP forecast. Navigant's Ontario electricity database reflects all committed new entrant generation, best available information regarding the operating profile of Ontario's hydroelectric fleet (baseload and peaking resources), and operating characteristics and fuel prices for Ontario's thermal generation. The sources of our assumptions are reviewed in the next chapter. Presented below is a brief review of our electricity price forecasting model.

The Ontario electricity market features a mandatory competitive wholesale pool. Any generator wishing to supply electricity to the Ontario market must offer its output to the system operator – the Independent Electricity System Operator (IESO) – as a series of hourly price/quantity pairs. The IESO then chooses the least-cost combination of generation resources which can meet the demand in each hour, subject to technical factors such as ramp rates (for fossil resources) and transmission constraints. The cost of the most expensive generation dispatched then becomes the market-clearing price which each generator located within the same market area (i.e., Ontario) receives for its energy output, regardless of its actual offer price.

The hourly electricity price in Ontario is therefore determined by the interaction of supply and demand as reflected in the information provided to the IESO. A statistical model will represent these factors.

The Navigant statistical model was developed using our extensive historical database for the Ontario electricity market. The data include a complete history of HOEP, historical electricity output by fuel type of plants in Ontario and historical electricity demand in Ontario. The database also includes information on market prices for the important fuels (natural gas and uranium) used for electricity generation in Ontario. In the development of the model, all of these factors were considered. The model was selected as that which best represents the actual history of Ontario electricity prices.

The model considers HOEP to be determined by several important factors.

- Hourly demand for electricity is an important determinant of demand, as noted above. The demand variable included in the model is the total energy demand over the time period.
- The amount of nuclear and hydroelectric energy available to the Ontario market has a strong influence on the hourly electricity price, due to their low operating costs. The more such low-cost energy is available, the less the IESO has to rely on relatively high-

cost sources like natural gas generation. The availability of these two forms of low-cost energy is treated in the model as a determinant of electricity price.

- The price of natural gas is also an important determinant of electricity price in Ontario, because it is likely to be the marginal fuel (that is, the resource that sets the market-clearing price) in times when supplies from lower-priced resources (hydroelectric, and nuclear) are insufficient. The outcome of an increase in Ontario's fleet of natural-gas fired generators combined with the retirement of Ontario's coal generation further increases the importance of natural gas generation. Natural gas is also important in setting the price in neighbouring markets, which can influence prices in Ontario. Therefore, natural gas prices have a strong role in explaining HOEP and the model includes the price of natural gas as a determinant of the Ontario electricity price.

2.2 Treatment of "OPG Prescribed Assets" in the Model Specification

Ontario Power Generation's (OPG) nuclear generating stations and most of its hydroelectric assets have been designated as regulated assets by government regulation. The price for the output of these plants is and will be set by the OEB. OPG continues to operate these facilities in the real time electricity market, i.e. a bid-based pool where participating generators receive a uniform price for their output. In this context, the party responsible for operating this generation would seek to ensure that it is available to the maximum degree possible, particularly during periods when market prices are high and the value of the generation is the greatest. Furthermore, if the scheduling and dispatch of these units does not change given that OPG's regulated assets do not establish the market-clearing price for the majority of hours, we expect that the treatment of these generating stations as regulated assets will not affect the HOEP.

2.3 Recognizing Market Pricing Volatility

Experience demonstrates that electricity market prices are inherently volatile. Any wholesale market price forecast should reflect this volatility or, at a minimum, acknowledge it as a source of risk to the price forecast. To determine the volatility of power prices and reflect the uncertainty around any forecast one needs to properly characterize how power prices behave and reflect the shape of the power price probability distribution.

However, each price forecast is itself subject to random (or apparently random) variation. That variation can be measured as the variance of price around the expected value. Variance is a statistical measure of random variation around an expected value. This type of price volatility is not fully captured by the statistical model. Therefore, in determining the RPP price for eligible consumers, Navigant and the OEB have developed a methodology that captures and reflects this potential price volatility. It is referred to as the stochastic adjustment. A discussion of this methodology and the results of the analysis are presented in the *RPP Price Report (November 2015 –October 2016)*.

3. SHORT-TERM FORECAST ASSUMPTIONS

As discussed above, Navigant has used our statistical model as the primary price forecasting tool. The sources of the primary modeling assumptions as well as a review of the key assumptions are presented below.

Broadly, three classes of primary assumptions underpin our short-term HOEP forecast:

1. Demand forecast
2. Supply forecast
3. Fuel Prices

The forecast U.S. - Canada currency exchange rate[1] also influences the short term HOEP forecast indirectly by affecting the price of fuel in Ontario and the price of electricity in neighbouring U.S. markets. The following sections present the data sources for each of the primary assumptions in the base case scenario which represents the expected forecast.

3.1 Demand Forecast

The demand forecast is comprised of an energy forecast for each month over the forecast period. The energy forecast defines the total (sum over all hours) hourly consumption in each month. The energy forecast is taken from the IESO's *18-Month Outlook Update: An Assessment of the Reliability and Operability of the Ontario Electricity System from October 2015 to March 2017* (dated September 21, 2015).

The IESO's *18-Month Outlook Update* bases the energy forecast on "normal weather". The "normal weather" forecast assumes that each day in a year experiences weather conditions that are representative of normal weather conditions for that day.

Table 1 shows the forecast of monthly energy consumption that was used from the IESO. Energy consumption is consistent with the IESO's "normal weather" forecast and reflects load reduction due to conservation initiatives over the forecast horizon.

Table 1: Forecast Monthly Energy Consumption and Peak Demand

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2015	Energy (TWh)									10.5	11.2	11.6	12.7
	Peak Demand (MW)									18,485	18,339	20,306	21,041
2016	Energy (TWh)	13.1	11.9	11.9	10.5	10.7	11.4	11.8	11.7	10.4	11.0	11.6	12.6
	Peak Demand (MW)	22,389	20,976	19,901	17,456	19,278	22,333	22,712	21,243	18,062	18,153	20,323	21,051
2017	Energy (TWh)	13.1	11.5										
	Peak Demand (MW)	22,340	21,118										

Source: IESO, *18-Month Outlook Update: An Assessment of the Reliability and Operability of the Ontario Electricity System From October 2015 to March 2017* (September 21, 2015).

[1] 1) The price forecast reflects an average exchange rate of $1.306 CAD between Nov 2015 and April 2017. The exchange rate forecast is taken from the Bank of Montreal's "Canadian Economic Outlook" issued Oct 2014.

3.2 Supply Assumptions

The existing generation capacity assumptions are consistent with the IESO's *18-Month Outlook Update* (September 21, 2015). In addition to the existing supply resources, several major projects are expected to come on-line during the forecast horizon, as listed in the IESO's *18-Month Outlook Update*. These projects are listed in Table 2 and have been included in the model specification. The IESO capacity additions include, among the largest capacity projects, the K2 wind project, the Green Electron gas plant and the Niagara Region wind farm.

Table 2: Major Generation Capacity Additions

	Project Name	Resource Type	Capacity (MW)	In-Service Date
RPP Period	Thunder Bay Condensing Turbine Project	Biomass	40	In Operation
	Goulais Wind Farm	Wind	25	In Operation
	K2 Wind Project	Wind	270	In Operation
	Northland Power Solar Empire	Solar	10	2015-Q4
	Cedar Point Wind Power Project Phase II	Wind	100	2015-Q4
	Northland Power Solar Abitibi	Solar	10	2015-Q4
	Kingston Solar Project	Solar	100	2015-Q4
	Northland Power Solar Martin's Meadows	Solar	10	2015-Q4
	Bow Lake Phase 1	Wind	20	2015-Q4
	Northland Power Solar Long Lake	Solar	10	2015-Q4
	Grand Valley Wind Farms (Phase 3)	Wind	40	2015-Q4
	Green Electron Power Project	Gas	298	2015-Q4
	Armow Wind Project	Wind	180	2015-Q4
	White Pines Wind Farm	Wind	60	2016-Q2
	Niagara Region Wind Farm	Wind	230	2016-Q2
	Grand Bend Wind Farm	Wind	99	2016-Q2
	Amherst Island Wind Project	Wind	75	2016-Q4
	Belle River Wind	Wind	100	2016-Q4
	Bow Lake Phase 2b	Wind	40	2016-Q4
	South Gate Solar	Solar	50	2016-Q4
	Windsor Solar	Solar	50	2016-Q4
	North Kent Wind 1	Wind	100	2016-Q4

Source: IESO, *18-Month Outlook Update: An Assessment of the Reliability and Operability of the Ontario Electricity System From October 2015 to March 2017* (September 21, 2015)

In addition to the projects in Table 2, the IESO has contracted with renewable energy power producers under the Renewable Energy Standard Offer Program (RESOP) and the Feed-in Tariff (FIT) program. As of the last quarterly report published by the IESO (Q2 2015), 830 MW remain under contract, of which 827 MW were in commercial operation[2]. Only one project, a 4.0 MW bio-energy contract, remains under development.

As of Q2 2015, the IESO had executed 3,182 FIT contracts with a total capacity of 4,628 MW. Of these, 1,727 contracts representing 2,586 MW have reached commercial operation with the remaining balance being under development. About 63.9% of the total FIT MWs approved to

[2] IESO. September 21, 2015, *Progress Report on Contracted Electricity Supply, Second Quarter 2015*.

date are for wind projects, 31.9% are for solar PV projects, 2.6% are for hydroelectricity and 1.4% is bio-energy projects.

There are over 20,851 microFIT projects that have achieved commercial operation, representing 181 MW of capacity. The government has set a procurement target of approximately 240 MW to FIT 4.0 projects. The 240 MW includes 150 MW of the annual FIT target, 50 MW of unallocated FIT capacity from the previous year, and 41 MW of unallocated microFIT capacity from the previous year. The microFIT 4.0 target was set at 50 MW, and for subsequent years, any unallocated capacity will be allocated to the subsequent year's FIT target. Renewable generation under contract with the IESO supplied generation equivalent to approximately 7% of Ontario demand in 2014. This is estimated to increase to 9% by 2015 and 11% in 2016. The effect of this increase in supply is to decrease Ontario wholesale electricity prices.

3.3 Nuclear Capacity

The statistical model finds that the performance of the nuclear generation fleet is an important factor in influencing HOEP, so the HOEP forecast needs a forecast of nuclear output. Historical generation patterns were used to estimate monthly capacity factors for each plant. Average annual capacity factors range from 74% for Pickering to 90% for Darlington, but all plants show higher capacity factors during summer and winter and lower capacity factors during the shoulder seasons (spring and fall). Capacity factors are multiplied by the available capacity (taking into account capacity additions such as the return to service of Bruce Units 1 and 2) and the number of hours in each month to estimate monthly nuclear generation.

Table 3: Historical and Forecast Nuclear Capacity Factors

	2011	2012	2013	2014	RPP Year	18 Months
Average Monthly MW	9,739	9,689	10,344	10,775	11,133	10,775
Average Monthly Capacity	11,263	10,987	12,275	12,709	12,475	12,063
Annual Capacity Factor	86%	88%	84%	85%	89%	89%

Source: Navigant Consulting analysis of IESO generator disclosure reports.

3.4 Transmission Capabilities and Constraints

Given that the HOEP is based on a uniform price which does not reflect transmission congestion within Ontario, internal Ontario transmission constraints are not tracked in the forecast model. The transfer capabilities of transmission interconnections with adjacent markets are shown in the IESO's *Ontario Transmission System* (June 22, 2015) report, 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

Interconnection	Flows Out of ON (MW)	Flows Into ON (MW)
Manitoba		
Summer	288	356
Winter	300	368
Minnesota		
Summer	150	100
Winter	150	100
Michigan		
Summer	1,700	1,700
Winter	1,750	1,750
New York		
Summer	1,650	1,500
Winter	1,800	1,800
Quebec		
Summer	2,135	2,775
Winter	2,170	2,795

Source: IESO, *Ontario Transmission System*, June 22, 2015

3.5 Fuel Prices

Given the uncertainty associated with fuel price forecasts, Navigant typically relies on liquid financial and physical markets to specify the underlying fuel forecasts we use in power market modeling, unless our clients derive their own forecasts. Since we forecast prices in US dollars, we specify fuel prices within the model in US dollars.

Natural Gas

For short-term forecasts, we use the futures prices as reported publicly on the NYMEX website in US$/MMBtu. Sufficient liquidity exists through the end of the forecast period to justify this source. To reduce the volatility associated with taking a snap-shot of future prices on a single day, an average of settlement prices over the past three week period is used. This is similar to the process that Enbridge Gas Distribution and Union Gas use in determining forecast natural gas prices as part of their quarterly rate adjustment mechanism (QRAM) applications to the OEB.

To these futures prices, we apply a basis differential. For natural gas this basis differential is from Henry Hub to the Dawn trading hub in South-western Ontario. This basis differential is based on Navigant's North American gas price forecast.

Natural gas price assumptions are presented in Table 5 below. All prices are in dollars per MMBtu – US dollars for Henry Hub, Canadian dollars for Dawn. The forecast average Dawn natural gas price for the twelve months commencing November 2015 is C$3.90/MMBtu. The forecast average price over the entire 18-month period is C$4.01/MMBtu. The twelve-month forecast was used to establish the RPP prices in the *RPP Price Report (November 2015 – October 2016)*.

Table 5: Natural Gas Price Forecast

Term	Month	Henry Hub (US$/MMBtu)	Dawn (C$/MMBtu)
RPP Period	Nov-15	$2.72	$3.85
	Dec-15	$2.87	$4.05
	Jan-16	$2.98	$4.19
	Feb-16	$2.99	$4.20
	Mar-16	$2.95	$4.15
	Apr-16	$2.82	$3.83
	May-16	$2.82	$3.80
	Jun-16	$2.85	$3.78
	Jul-16	$2.88	$3.69
	Aug-16	$2.90	$3.70
	Sep-16	$2.89	$3.80
	Oct-16	$2.92	$3.81
Other	Nov-16	$3.00	$4.06
	Dec-16	$3.16	$4.24
	Jan-17	$3.27	$4.44
	Feb-17	$3.26	$4.46
	Mar-17	$3.20	$4.29
	Apr-17	$2.97	$3.93

Source: NYMEX, Navigant Consulting

3.6 Hydro Resources

Navigant's statistical model for Ontario requires a specification of the monthly average hydroelectric output for the province. In our base case, we assume a normal hydroelectric resource level. Our forecast of hydroelectric generation is based on a statistical analysis of historical monthly generation and its seasonality pattern. Over the last six months (March 2015 – August 2015) generation has been slightly higher than the 5-year average over the same months. For the forecast, we have assumed a normal output over the forecast period.

4. Review of Forecast Results

Table 6 presents the results of our base case market price forecast based on our statistical model. The prices presented are simple (i.e., not load-weighted) averages.

The seasonal price distribution is reasonably reflective of the seasonal pattern of prices that we would expect given that the highest loads are experienced in the summer and winter months and lower loads are experienced in the "shoulder" months of April, May, October and November. An additional factor contributing to the seasonal price pattern is the typical output profile of Ontario's hydroelectric generation. September is generally the lowest hydro output month, with May and June representing the highest output based on the spring freshet.[3] Nuclear and thermal maintenance outages tend to be scheduled in the shoulder seasons, reducing the price impact of lower demand in the shoulder seasons and the spring freshet.

Table 6: HOEP Forecast (CAD $ per MWh)

Term	Quarter	Calendar Period	On-Peak	Off-Peak	Average	Term Average
RPP Year	Q1	Nov 15 - Jan 16	$31.02	$19.40	$24.69	
	Q2	Feb 16 - Apr 16	$23.80	$13.56	$18.27	
	Q3	May 16 - Jul 16	$23.93	$12.08	$17.56	
	Q4	Aug 16 - Oct 16	$20.81	$9.74	$14.77	$18.82
Other	Q1	Nov 16 - Jan 17	$32.29	$20.32	$25.77	
	Q2	Feb 17 - Apr 17	$30.83	$20.87	$25.44	$25.61

Source: Navigant Consulting
Notes:
1) The price forecast reflects an average exchange rate of $1.306 CAD between Nov 2015 and April 2017. The exchange rate forecast is taken from the Bank of Montreal's "Canadian Economic Outlook" issued Oct 2015.
2) On-peak hours include the hours ending at 8 a.m. through 11 p.m. Eastern Time (EST) on working weekdays and off-peak hours include all other hours.

This price forecast is based on market fundamentals and reflects the assumptions used for the forecast from the statistical model. To the degree that actual market variables (gas prices, hourly loads and generator availabilities) are different from our forecast assumptions, market prices are likely to differ from our forecast. As an example of the variability of electricity prices over time, Figure 1 presents the distribution of the hourly HOEP since market opening, and

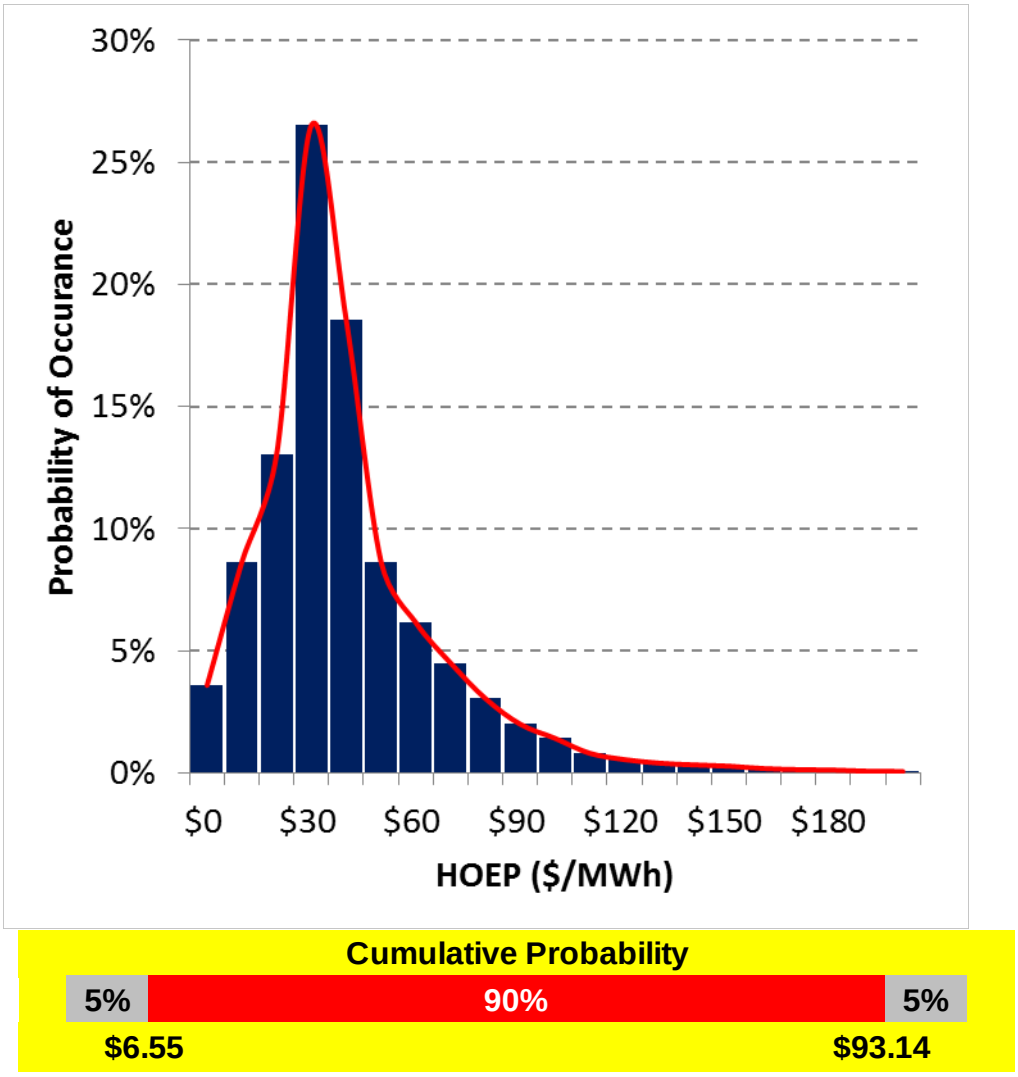
Figure 2 presents the distribution of monthly average prices since market opening. The HOEP is captured on the x-axis and the number of times that the HOEP occurred is reflected in the height of the bars. A key takeaway from these curves is that both are skewed to the right, indicating that the average value is higher than the median or 50% percentile value.

[3] Freshet is the period during which melted snow causes the rise or overflowing of streams in Ontario.

Not surprisingly, the hourly price distribution is significantly more skewed to the right than the monthly price distribution, reflecting the averaging that occurs for the monthly prices. While not as skewed as the distribution of hourly prices,

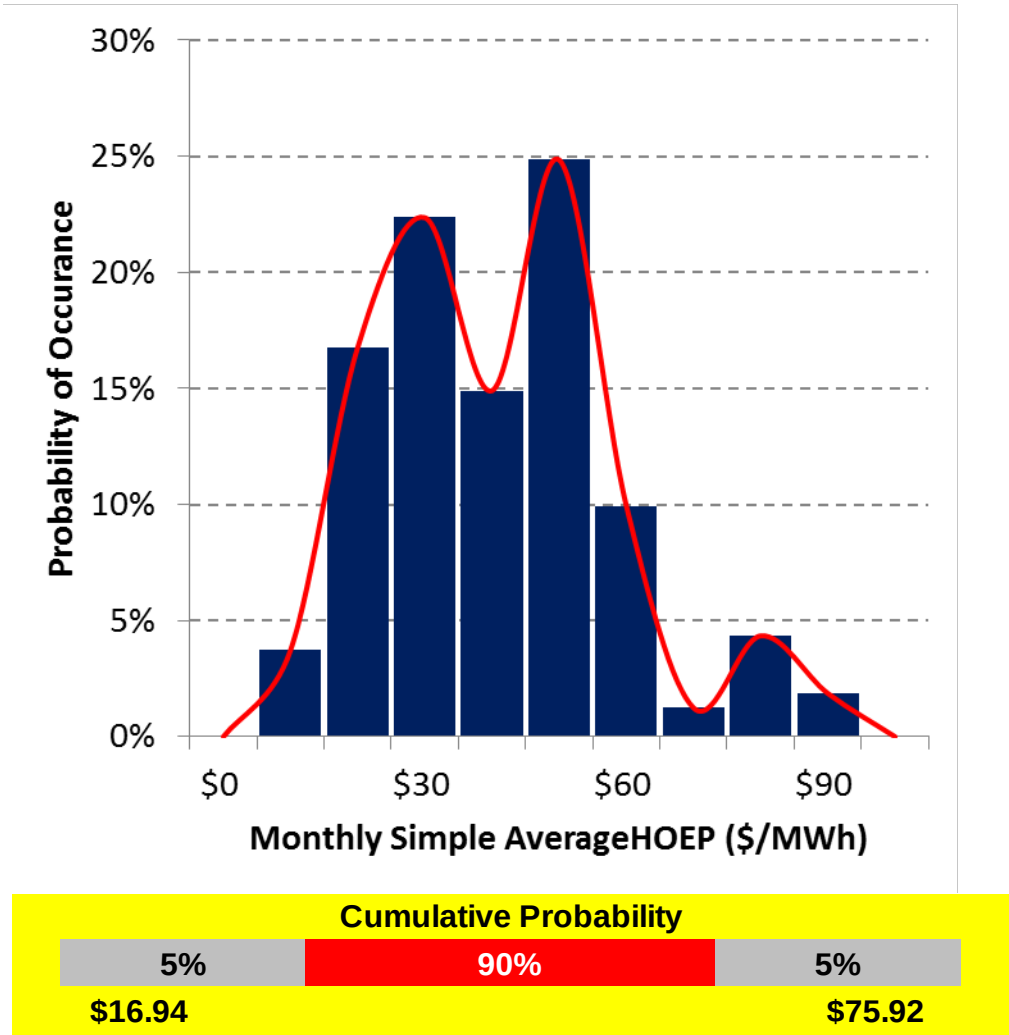
Figure 2 demonstrates that even the distribution of monthly prices is skewed to the right.

Figure 1: Historic Distribution of Hourly HOEP



Source: Navigant Consulting analysis of IESO data (May 2002 to September 2015)

Figure 2: Historic Distribution of Monthly Average HOEP



Source: Navigant Consulting analysis of IESO data (May 2002 to September 2015)

5. ASSESSMENT OF FORECAST RISKS

As discussed above, the foundation of our HOEP forecast is a statistical model of the Ontario electricity market. This forecast is developed using single point forecasts for each of the determinants of price. There could be considerable variability in each of these assumptions. In setting the RPP price, Navigant and the OEB have used statistical analysis to evaluate the uncertainty around this market price forecast and the impact on the RPP price. We believe that this probability analysis allows the OEB to adequately evaluate forecast risks when determining the RPP price. In this chapter we review the factors that present the greatest forecast risk and assess, in qualitative terms, the degree to which the forecast has addressed them.

Navigant believes that there are three major risks that a specific electricity price forecast will not be realized. These stem from differences between forecast and actual: (1) load; (2) fuel prices; and (3) generator availabilities. Each of these forecast risks are assessed below.

5.1 Load Forecast Risk

As discussed, the energy demand forecast used by Navigant was developed by the IESO. Their energy consumption forecast is based on a forecast of economic activity in Ontario and the assumption that weather conditions will be "normal", i.e., reflective of 30-year average weather over the entire forecast period. To the degree that this economic forecast is wrong or weather conditions depart significantly from normal, actual energy consumption would be expected to vary from forecast consumption. In addition, other factors, such as economic activity or consumer behaviour, will cause actual loads to vary from the forecast. For our short-term forecast, Navigant believes that the greatest source of load forecast risk is weather. The IESO's *18-Month Outlook Update* (September 21, 2015) forecasts, for the summer of 2015, a normal weather peak of 22,712 MW and an extreme weather peak of 24,569 MW, reflecting how load is forecast to increase under more extreme weather conditions. The variability in loads was specifically considered in the analysis which is reviewed in the companion report, *RPP Price Report (November 2015 – October 2016)*. Analysis of historical price and demand levels clearly demonstrates that load variability is a major contributor to spot market price volatility. Therefore, Navigant believes that this risk has been considered in our price forecasting approach.

5.2 Fuel Price Forecast Risk

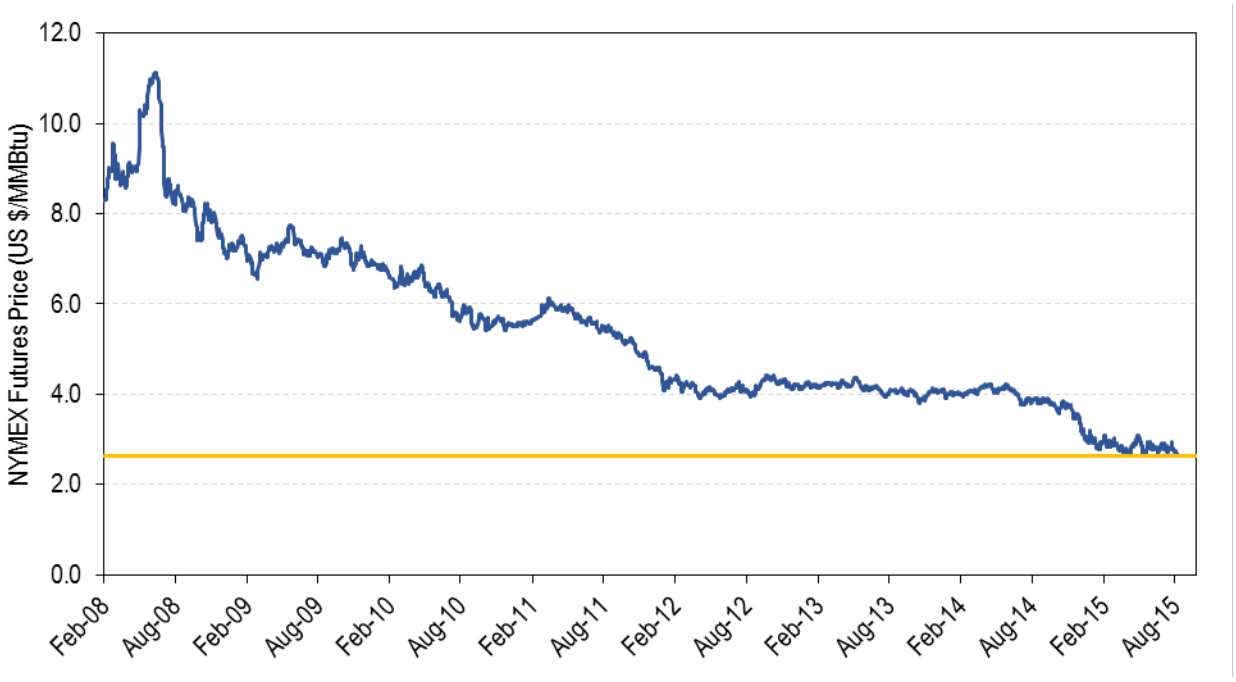
In general, the fuel price with the greatest impact on electricity market prices is the gas price. Currently, Ontario has a moderate amount of natural gas-fired generation that is likely to set the HOEP. However, natural gas-fired generation in the Ontario market will grow over time. The largest natural gas facilities include Lennox (2,140 MW) which is also capable of burning residual oil, the Greenfield Energy Centre (1,005 MW), Goreway Station (839 MW), Halton Hills Generating Station (632 MW), St. Clair Energy Centre (577 MW), Brighton Beach Power Station (550 MW), Portlands Energy Centre (550 MW), the Sarnia Regional Cogeneration Plant (505 MW), Thorold Cogeneration Plant (287 MW), GTAA Cogeneration Plant (90 MW) and the York Energy Center (393 MW). The total gas-fired generation operating under contract is approximately 5,570 MW. In addition, the Green Electron Power Project (298 MW) is expected

to reach commercial operation by the fourth quarter of 2015. There is also a considerable amount of natural gas-fired generation in interconnected markets, i.e., primarily New York and Michigan. While generation from these markets cannot set the HOEP under the IESO's Intertie Offer Guarantee rule, it nonetheless has an influence on Ontario market prices.

The gas prices used by Navigant for this forecast were based on NYMEX futures prices. While we believe that the NYMEX futures represent an appropriate fuel price outlook, as with any forecast there is a significant degree of risk that forecast fuel prices will not be realized.

The most obvious risk associated with natural gas prices is the inherent price volatility of the commodity itself, as was experienced in the winter of 2014. Figure 3 illustrates the trend in forward prices for natural gas for September 2015 delivery since February 2008. When using futures prices for forecasting purposes, the point in time when the natural gas price outlook is cast is another source of risk. To minimize the RPP exposure to this risk, Navigant and the OEB have used an average of settlement prices for futures contracts over a three-week period. This averaging approach mitigates some of the short-term volatility in natural gas prices. Nonetheless, there is a risk that the natural gas price forecast will be wrong, leading to higher or lower electricity prices than forecast.

Figure 3: Historical September 2015 Futures Prices (US$/MMBtu)



Source: NYMEX

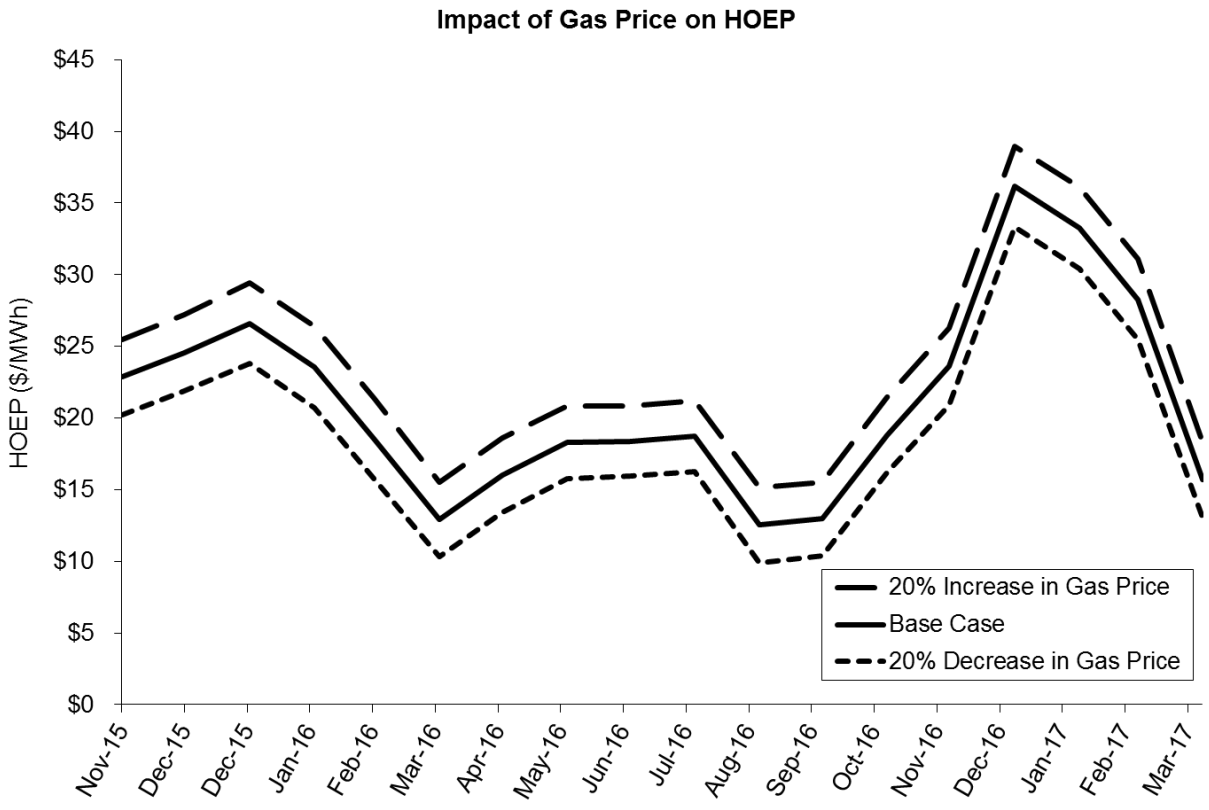
Lennox is the only major Ontario generator which burns oil, but generally residual oil is not its primary fuel. Furthermore, there is a relatively limited amount of oil-fired generation in Ontario's interconnected markets. Therefore, Ontario electricity market prices are not significantly influenced by oil prices.

Based on this assessment and the experience of the winter of 2006/2007 (when prices were low), and the winter of 2013/2014 (when both gas and electricity prices were very high), Navigant

believes that the most significant fuel price forecast risk remains natural gas. A cold winter or hot summer that increases the demand for natural gas-fired generation can result in significant increases in natural gas prices. Conversely, a warm winter or cool summer can result in a softening of near-term natural gas prices.

Navigant has evaluated the impact of a ±20% change in Henry Hub natural gas prices on the HOEP. The results of this analysis are shown in Figure 4 which shows the monthly average HOEP for the base case as well as high and low natural gas price sensitivities. This analysis indicates that the forecast of HOEP increased by an average of 14% when natural gas prices were assumed to be 20% higher than forecast, and decreased by an average of 14% when natural gas prices were assumed to be 20% lower than forecast. HOEP has become more sensitive to increases in gas prices with the elimination of coal generation and the amount of gas generation increases.

Figure 4: Comparison of Monthly Average HOEP with ±20% Change in Henry Hub Gas Price



Source: Navigant Consulting

5.3 Generator Availability Price Risks

The third major source of electricity price forecast risk pertains to the availability of Ontario generation. Changes in the availability of Ontario's nuclear fleet are likely to have the most dramatic impact on market prices. A 2% change in capacity factor for Ontario's nuclear fleet results in a 2.3 TWh change in the availability of low variable cost energy from nuclear capacity.

This change in nuclear output is most likely to affect the requirements for Ontario fossil generation.