Ontario Wholesale Electricity Market Price Forecast

For the Period May 1, 2008 through October 31, 2009

Presented to

Ontario Energy Board

April 11, 2008

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No Warranties or Representations

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, Inc. (Navigant Consulting or NCI) was retained by the Ontario Energy Board (OEB or the Board) 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 Consulting used ProSym to develop our hourly Ontario electricity price (HOEP) forecast. Navigant Consulting's Ontario ProSym database 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. The sources of our assumptions are reviewed in detail in Chapter 3 of this report.

The table below presents the results of our base case market price forecast produced by ProSym. 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	May 08 - Jul 08	$81.39	$33.64	$56.38	
	Q2	Aug 08 - Oct 08	$92.29	$34.41	$61.97	
	Q3	Nov 08 - Jan 09	$95.65	$34.82	$63.78	
	Q4	Feb 09 - April 09	$87.41	$36.34	$60.66	$60.72
Other	Q1	May 09 - Jul 09	$76.69	$32.36	$53.47	
	Q2	Aug 09 - Oct 09	$78.08	$32.18	$54.04	$53.73

Source: NCI

Notes

1) The prices reflect an exchange rate of $1.00 CAD to $0.980 USD

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

Table of Contents

List of Figures & Tables

List of Figures

List of Tables

1. Introduction

Navigant Consulting, Inc. (Navigant Consulting or NCI) was retained by the Ontario Energy Board (OEB or the Board) 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 May 1, 2008 through October 31, 2009 and describes the major economic and energy market assumptions and inputs for the forecast, as well the source of information. In addition, given that this forecast is based on a specific set of assumptions, the report also 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 rate 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 Ontario Power Authority (OPA),
- the cost of renewable energy standard offer program (RESOP) contracts administered by the Ontario Power Authority, and
- the cost of the "Early Mover" and Bruce Power contracts administered by the OPA.

In addition this forecast will be used to determine the estimated value of the OPG non-prescribed asset rebate (OPG Rebate or ONPA Rebate) 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 next chapter reviews the source of forecast assumptions and reviews key forecast assumptions. 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 the forecast model (ProSym). The model then dispatches generation resources economically to meet hourly load. The output is a set of deterministic prices. If the model is properly specified with best available information it will yield a forecast of expected wholesale electricity prices.

2.1 Overview of the Forecasting Model

Navigant Consulting used ProSym to develop the HOEP forecast. Navigant Consulting's Ontario ProSym database reflects the Ontario hourly load shape, 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 review of ProSym.

ProSym is a detailed chronological model that simulates hourly operation of generation and transmission resources. It dispatches generating resources to match hourly electricity demand, dispatching the cheapest available generation first. The choice of generation is determined by the generator's offer to the market operator -- the Independent Electricity System Operator (IESO), by technical factors such as ramp rates (for fossil resources) or water availability (for hydraulic resources) and by transmission constraints. This dispatch establishes a 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.

For most resources, the offer price reflects the incremental cost of the generation. However, some resources have adders reflecting the generator's offer strategy.

Our ProSym model specification includes the entire Eastern Interconnect, so it captures trade between Ontario and its interconnected markets.

Within ProSym, thermal generating resources are characterized according to a range of capacity output levels. Generation costs are calculated based upon heat rate, fuel cost and other operating costs, expressed as a function of output. Physical operating limits related to expected maintenance and forced outages, start-up, unit ramping, minimum up and down time, and other characteristics are respected in the ProSym simulation.

Hydroelectric resources are also characterized in ProSym according to expected output levels, including monthly forecasts of expected energy production. Navigant Consulting has specified ProSym to reflect historical monthly output of Ontario's hydroelectric fleet. The data has been updated to reflect upgrades and capacity additions to Ontario's hydroelectric fleet. ProSym schedules run-of-river hydroelectric production based upon the minimum capacity rating of the unit. The dispatch of remaining hydroelectric energy is optimized on a weekly basis by scheduling hydro production in peak demand hours when it provides the most value to the electrical system.

Offer prices are developed for each unit and show the minimum price the unit owner is willing to accept to cause the unit to operate. For most generation resources, offer prices are composed primarily of incremental production costs. Incremental production cost is calculated as each station's fuel price multiplied by the incremental heat rate, plus variable operations and maintenance cost.

The offer price can also include a price mark-up factor taking the bid price above variable production costs. Navigant Consulting uses this factor where appropriate to reflect observed market behaviour where wholesale prices often rise above the underlying cost of production, particularly during times when supply/demand margins are tight. Navigant Consulting assigns price mark-ups to individual generators depending upon the underlying fuel efficiency, production cost and technology type. The specific mark-ups are designed so that offer prices rise above the cost of production as less efficient resources are called upon for power production and as the intersection of supply and demand occurs at higher points on the supply curve. The level of price mark-ups is determined through an iterative approach benchmarking against recent actual wholesale prices, and against observable prices in the forward market. In Ontario given the significant amount of the market represented by OPG's regulated generating assets and the structure of the Clean Energy Supply contracts and recent OPA RFPs and contracts[1], Navigant Consulting believes that the spot market will likely serve as more of a balancing market where in general (excluding storage hydroelectric generating resources) mark-ups are likely to be eliminated with offer strategies based on marginal operating costs.

Market clearing prices reflect the offer of the last generating resource used to meet the next incremental megawatt of demand. Station revenues are based on these market-clearing prices within the market area in which the plant is located.

Navigant Consulting runs ProSym in a mode that establishes market-clearing prices in a specific regional market and in adjacent markets with significant intertie connections. In establishing the market-clearing price, the ProSym simulation takes into account economic import and export possibilities and sets the market-clearing price as the offer price of the marginal generator needed to serve a final increment of demand within the region.[2]

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1 These contracts are structured so that generators' deemed net revenues from participating in the energy market are subtracted from their contracted net revenue requirements or capacity payments to determine the support payments to be made by the OPA. Deemed energy market revenues assume that the generating unit is operating whenever the HOEP is greater than the unit's variable operating costs. This provides a strong incentive for the generator to use a marginal cost based offer strategy, otherwise it will "miss" market revenues that it was deemed to earn in the spot market that are "netted" from its payment under the contract.

2 The Independent Electricity System Operator's (IESO's) Intertie Offer Guarantee (IOG) rule prevents imports from setting the HOEP. Therefore, there is a difference between our model structure and the Ontario market rules. If the Ontario market were forecast to be in need of significant amounts of energy and capacity and relying

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

A significant portion of Ontario's generation, i.e., OPG's nuclear and major baseload hydroelectric generating units (Saunders, Beck, and DeCew Falls), have been designated as regulated assets with the price for the output of these plants – up to 1,900 MW in any hour for the hydroelectric resources – currently set under regulation by the Government. While the price for the output of these plants is set under regulation, their value in the Ontario market will be established by the same market dynamics that are in place currently, i.e., a bid-based pool where participating generators receive a uniform price. Specifically, the party responsible for scheduling and ensuring the dispatch of this generation would seek to ensure that this generation 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 vast 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.

Power prices have a predictable time pattern. Given the optimal dispatch model, lower cost generation resources are used first, so prices can be expected to be lower when demand is low and higher when demand is high. One notion of price volatility, therefore, is the variation of prices over time as a function of demand. The ProSym model will reflect this variation in its hourly price forecasts.

However, each hourly price forecast is itself subject to random (or apparently random) variation. That variation can be measured as the variance of price around the expected hourly value. Variance is a statistical measure of random variation around an expected value. This type of price volatility is not fully captured by the deterministic ProSym model. In determining the RPP price for eligible consumers however, Navigant Consulting and the OEB have developed a methodology that captures, and reflects this potential price volatility. It is referred to as the

on imports for this required energy and capacity and if the pricing for imports was significantly different than that for Ontario generation, this difference might result in meaningful differences between our price forecast and actual market prices. However, during the term of this forecast we do not expect the Ontario market to need to rely on imports for significant amounts of energy and capacity and the prices of marginal generation in Ontario and its interconnected markets are not likely to differ significantly. Therefore, we do not believe that this difference between the model structure and market rules is likely to lead to significant differences between forecast prices and actual prices.

stochastic adjustment. A discussion of this methodology and the results of the analysis are presented in the *RPP Price Report (May 08 –April 09)*.

3. Short-Term Forecast Assumptions

As discussed above, NCI utilized ProSym as the primary price forecasting tool. The sources of the primary modeling assumptions as well as a review of the key assumptions is presented below.

3.1 Primary Assumptions and Data Sources

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

1. Demand forecast
    a. Peak demand
    b. Energy
2. Supply forecast
3. Transmission capabilities and constraints
4. Fuels
    a. Natural gas & oil prices
    b. Coal prices
    c. Hydroelectric resources

The forecast U.S. - Canada currency exchange rate[3] 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. Relevant but less important factors include offer strategies and price responsive load. The following sections present the data sources for each of the primary assumptions, in the base case scenario which represents the expected forecast.

3.1.1 Demand Forecast

The demand forecast is comprised of two separate components – a peak demand forecast and an energy forecast – for each month over the forecast period. The peak demand forecast defines the maximum hourly demand in each month. The energy forecast defines the total (sum over all hours) hourly consumption in each month. Together, the peak demand forecast and the energy forecast define a profile for electricity consumption throughout the forecast period. Both the peak demand forecast and the energy forecast are taken from the IESO's *18-Month Outlook: An Assessment of the Reliability of the Ontario Electricity System From April 2008 to September 2009,* (March 12, 2008).

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[3] The price forecast reflects an exchange rate of $1.00 CAD to $0.980 USD. This is based on the BMO Nesbitt Burns Capital Markets futures currency forecast of March 20, 2008. (www.bmonesbittburns.com/economics/forecast/ca/cdamodel.pdf)

For the peak demand and energy forecast in October 2009, NCI has applied the seasonal year over year growth rate to the forecast consumption for that month in 2008.

The IESO's *18-Month Outlook* bases the peak demand and 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 indicates the forecast of monthly energy consumption and peak demand that was used from the IESO. Peak demand and energy consumption are consistent with the IESO's "*normal weather*" forecast and reflect load reduction due to conservation initiatives over the forecast horizon.[4]

Table 1: Forecast Monthly Energy Consumption and Peak Demand

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2008	Energy (TWh)		N/A		11.7	11.8	12.2	13.2	13.1	11.6	12.1	12.5	13.4
	Peak Demand (MW)				20,326	20,177	24,224	25,193	24,445	22,281	20,264	22,150	23,204
2009	Energy (TWh)	14.0	12.6	13.1	11.6	11.8	12.1	13.2	13.1	11.6	12.1	N/A	
	Peak Demand (MW)	23,888	23,447	22,438	20,304	20,574	24,323	25,219	24,316	22,318	20,287		

Source: NCI, based on IESO, *18-Month Outlook: An Assessment of the Reliability of the Ontario Electricity System* (March 12, 2008)

3.1.2 Supply Assumptions

The existing generation capacity assumptions are consistent with the IESO's *18-Month Outlook* (dated March 12, 2008). No coal plant retirements are expected during the forecast period. Bruce A Unit 2 is expected to return to service in the second quarter of 2009, according to the IESO. Unit 1 is being refurbished but is not expected to return to service within this forecast horizon.

In addition to the existing supply resources, there are several projects that are expected to come on-line during the forecast horizon. The IESO's 18 month forecast lists the generation projects that are expected to come on-stream over the forecast period. These projects are listed in

Table 2 and have been included in the model specification. In addition to the projects in

Table 2, the OPA has contracted with various small renewable energy power producers under the Renewable Energy Standard Offer Program (RESOP) which is expected to add a further 110 MW of wind and 118 MW of photovoltaic (solar) capacity during the forecast period.

4 The IESO 18-month outlook presented two scenarios for the peak demand and energy forecast with respect to the conservation impact. The "Firm Resource" scenario completely discounted conservation measures undertaken, whereas the "Planned Resource" scenario included the full impact of conservation on peak demand and energy consumption forecasts. NCI has assumed that 50% of the impact of conservation measures in the IESO's "Planned Resource" scenario are realized over the forecast horizon.

Table 2: Major Generation Capacity Additions

Term	Project Name	Resource Type	Capacity (MW)	In-service date
RPP Year	Durham College District Energy Project	Gas Cogen	2	Q1-2008
	Great Northern Tri-Gen Facility	Gas Cogen	12	Q2-2008
	Countryside London Cogeneration Facility	Gas Cogen	12	Q2-2008
	Portlands Energy Centre Phase I	SCGT	250	Q2-2008
	Warden Energy Centre	Gas Cogen	5	Q2-2008
	Umbata Falls	Water	23	Q2-2008
	OPG Lac Seul	Water	13	Q3-2008
	Greenfield Energy Centre	CCGT	1005	Q4-2008
	Kruger Energy Port Alma	Wind	101	Q4-2008
	Wolfe Island	Wind	198	Q4-2008
	Melancthon II	Wind	132	Q4-2008
	Enbridge	Wind	200	Q4-2008
	St. Clair Energy Center	CCGT	570	Q1-2009
Other	Goreway Station	CCGT	860	Q2-2009
	Algoma Energy Cogen	Industrial Gas	63	Q2-2009
	Portlands Energy Centre Phase II	CCGT	538	Q2-2009
	Bruce Unit 2	Nuclear	750	Q2-2009
	East Windsor Cogeneration Centre	Gas Cogen	84	Q2-2009

Source: OPA, IESO

3.1.3 Outages

Generator outages happen for two reasons: planned outages for scheduled maintenance and forced outages for unplanned maintenance. The IESO provided its planned outage schedule on a confidential basis. We used information from this outage schedule to adjust our standard maintenance outage schedule that is reflected in our model specification.

ProSym includes a database of forced outages by unit type expressed as a percentage of time each unit would be expected to experience a forced outage. This database is based on empirical data and historical information on Ontario generating units.

3.1.4 Offer Strategies

Consistent with our observations of how the HOEP has been established, we assume that generators will offer their capacity into the IESO market at their variable cost (fuel cost plus variable operations & maintenance cost), with no provision for bid adders. For units where there was uncertainty regarding the likely offer strategy, Navigant Consulting used the daily generator disclosure reports, an assumed market supply curve and the HOEP to infer offer strategies for the unit.[5]

As discussed in Section 2.1, the Clean Energy Supply (CES) contract provides a strong incentive for generators to offer their electricity into the market at their marginal operating costs. Given the Ministerial Directive[6], Navigant Consulting expects that the Early Mover contracts have a similar incentive.

The Board decision to grant Lennox GS Reliability-Must-Run (RMR) status is not expected to effect the bidding behaviour of Lennox materially. OPG indicated that the financial provisions of the RMR contract will have no effect on its offer strategy. The Board decision explicitly states that the RMR contract obliges OPG to "offer into the IESO-administered markets the maximum amount of energy and operating reserve from Lennox in a commercially reasonable manner and in accordance with stated performance standards".[7] By definition, "[I]n a commercially reasonable manner" means that over a sustained period of time OPG will offer each Lennox unit at no less than its variable costs taking into account all necessary operational factors. OPG is subject to rewards or penalties of up to $2 million based on exceeding or failing to meet the performance standards. The current RMR contract expires September 30, 2008. We have assumed continued operation of Lennox GS under a similar arrangement for the remainder of the forecast period.

3.1.5 Price Responsive Load

Our assumptions regarding the amount of price responsive load reflect the assumptions in the "Planned Scenario" in the IESO's *18-Month Outlook* regarding the amount of demand measures, such as dispatchable loads and responsive demand. Over the 18-month forecast period, this is an average of 531 MW.

3.1.6 Transmission Capabilities and Constraints

Given that the HOEP is based on a uniform price which does not reflect transmission congestion within Ontario, we do not reflect internal Ontario transmission constraints in this model specification. The transfer capabilities of transmission interconnections with adjacent markets are from the IESO's *Ontario Transmission System* report, differentiated by season and direction of flow. Table 3 indicates the assumed ratings of Ontario's interconnections with adjacent markets based on the information presented in this report. The interconnection limits shown in Table 3 do not reflect the new 1,250 MW interconnection with Quebec forecast for completion in March 2009.

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5 These units included Lennox and the coal units.

6 http://www.powerauthority.on.ca/Storage/19/1457_Minister_of_Energy_letter_regarding_Contracts_with_Certain_Generation_Facilities_REVISED.pdf

7 Lennox RMR Board Decision (EB-2007-0715), December 21, 2007: http://www.oeb.gov.on.ca/documents/cases/EB-2007-0715/Dec_Reasons_20071221.pdf

Table 3: Ontario Interconnection Limits

Interconnection	Flows Out of Ontario (MW)	Flows Into Ontario (MW)
Manitoba		
Summer	262	330
Winter	274	342
Minnesota	140	90
Michigan		
Summer	2,080	1,640
Winter	2,400	1,800
New York East		
Summer	330	300
Winter	400	360
New York West		
Summer	1,520	1,350
Winter	1,600	1,350
Quebec South		
Summer	567	1,473
Winter	637	1,548
Quebec North		
Summer	95	65
Winter	110	85

Source: IESO, *Ontario Transmission System*, September 10, 2007

3.1.7 Fuel Prices

Given the uncertainty associated with fuel price forecasts, Navigant Consulting 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 and Fuel Oil

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 20 trading days 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.[8]

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

8 NYMEX future prices averaged over 20 day trading period from February 11, 2008 to March 9, 2008.

based on the Dawn basis forwards traded on the NGX exchange. Finally, we apply a local delivery charge to represent costs paid to the gas utility to deliver the gas from Dawn to individual generator locations such as Kingston and Sarnia.

For residual and distillate oil we also add a basis differential from New York Harbour to Kingston to reflect delivery at Lennox GS. Since Lennox operates as a dual-fuel facility, and we believe it has an environmental constraint on the number of oil-fired hours, we use a blend of natural gas and residual oil price, based on our judgement of when (which months) the facility is likely to burn oil and gas.

Natural gas and fuel oil price assumptions are presented in Table 4 below. All prices are in US dollars per MMBtu. The forecast average Henry Hub natural gas price for the twelve months commencing May 2008 is USD $9.58 / MMBtu. The forecast average price over the entire 18-month period is USD $9.27 / MMBtu. The twelve-month forecast was used to establish the RPP prices in the *RPP Price Report (May 2008 – April 2009)*.

Table 4: Natural Gas and Fuel Oil Prices (US$/MMBtu)

Term	Year	Natural Gas @ Henry Hub	#6 Residual Oil @ Southern Ontario	#2 Fuel Oil @ Southern Ontario
RPP Year	May-08	$9.55	$11.92	$21.13
	Jun-08	$9.61	$12.05	$21.10
	Jul-08	$9.68	$12.17	$21.15
	Aug-08	$9.74	$12.27	$21.20
	Sep-08	$9.75	$12.26	$21.30
	Oct-08	$9.81	$12.23	$21.30
	Nov-08	$10.07	$12.32	$21.20
	Dec-08	$10.40	$12.42	$21.06
	Jan-09	$10.62	$12.63	$20.77
	Feb-09	$10.58	$12.55	$20.68
	Mar-09	$10.32	$12.47	$20.70
	Apr-09	$8.86	$12.42	$20.77
Other	May-09	$8.74	$12.42	$20.84
	Jun-09	$8.78	$12.45	$20.88
	Jul-09	$8.84	$12.49	$20.94
	Aug-09	$8.89	$12.52	$20.99
	Sep-09	$8.90	$12.54	$21.03
	Oct-09	$8.98	$12.56	$21.04

Source: Henry Hub natural gas prices based on NYMEX futures. #2 Fuel Oil and #6 Fuel Oil prices derived from NYMEX futures for light sweet crude and historical relationship between crude and respective fuel oils. Delivery to Southern Ontario for fuel oils based on Navigant Consulting estimates.

3.1.8 Coal Prices

A 2004 study entitled *Cost Benefit Analysis: Replacing Ontario's Coal Fired Electricity Generation* was prepared by DSS Management Consultants Inc. and RWDI Air Inc. for the Ontario Ministry of Energy. This study provides site specific fuel costs for OPG's coal-fired facilities and is the only public source of information on fuel costs available.

The cost of coal to OPG includes two components: commodity cost and transportation cost. The commodity cost has been updated based on NYMEX futures prices for the forecast period.

Delivery and transportation costs were assumed to represent 40% of the total cost of the Eastern bituminous coals, 60% of the total cost for lignite and 50% of the total cost for Power River Basin coal, based on the DSS Management Consultants Inc. report. This portion of the total cost was adjusted for inflation through 2009. Prices were converted from US to Canadian dollars at an exchange rate of $1.00 CAD to $0.980 USD.

To verify the accuracy of this approach we compared our forecast to estimated prices based on the existing offer strategies for OPG's coal fleet as derived from the IESO's Daily Generator Disclosure Reports (and applying the unit heat rates).

The resulting delivered coal prices for the four coal-fired generation plants (five coal types) in Ontario are presented in Table 5. The prices associated with the coal types used at the Nanticoke and Lambton plants are the most salient in terms of their impact on Ontario electricity prices since they represent about 60% and 31%, respectively, of Ontario's total coal-fired capacity.

Table 5: Ontario Delivered Coal Price Outlook (US$/MMBtu)

Year	High Sulfur Bituminous - Lambton 3 & 4	Low Sulfur Bituminous - Lambton 1 & 2	Nanticoke (Blend of low sulfur bituminous and Powder River Basin coal)	Low Sulfur Lignite - Atikokan	Low Sulfur Lignite - Thunder Bay
2008	3.60	4.73	3.61	2.62	2.63
2009	3.46	4.54	3.44	2.50	2.51

Source: NCI

3.1.9 Hydro Resources

Our ProSym specification for Ontario includes a detailed specification of the monthly average hydroelectric output by major hydro unit. In our base case, we assume a normal hydroelectric resource level.

4. Review of Forecast Results

Table 6 presents the results of our base case market price forecast produced by ProSym. The on-peak and off-peak prices presented are simple averages, i.e., not load weighted.

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. [9] In recent years scheduled nuclear and coal maintenance outages have reduced 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	May 08 - Jul 08	$81.39	$33.64	$56.38	
	Q2	Aug 08 - Oct 08	$92.29	$34.41	$61.97	
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	Q4	Feb 09 - April 09	$87.41	$36.34	$60.66	$60.72
Other	Q1	May 09 - Jul 09	$76.69	$32.36	$53.47	
	Q2	Aug 09 - Oct 09	$78.08	$32.18	$54.04	$53.73

Source: NCI

Notes

1) The prices reflect an exchange rate of $1.00 CAD to $0.980 USD

2) On-peak hours include the hours ending at 8 a.m. through 11 p.m. Eastern Standard 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 specified in ProSym. To the degree that actual market variables (fuel prices, hourly loads and generator availabilities) are different than 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. 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 both are skewed to the right, indicating that the average value is higher than the median or 50% percentile value.

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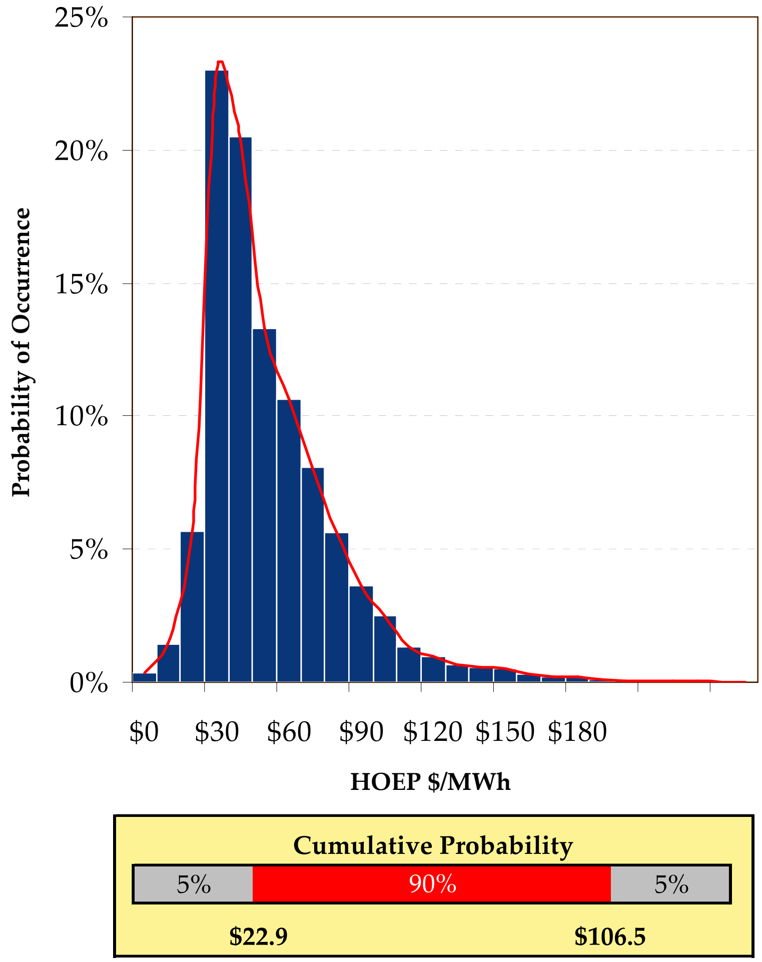
9 Freshet is the period during which melted snow causes the rise or overflowing of streams in Ontario.

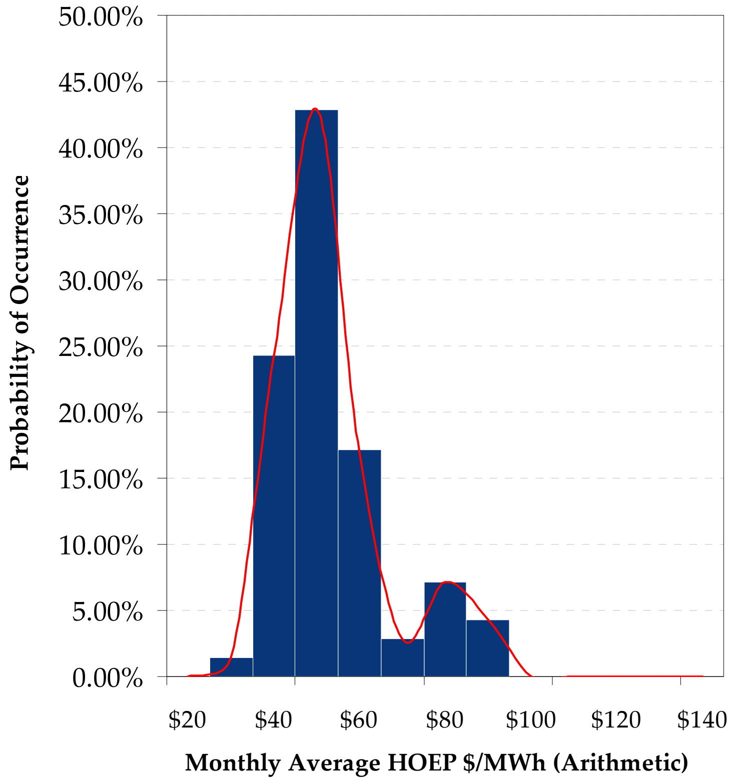
Not surprisingly, the hourly price distribution is significantly more skewed to the right than the monthly price distribution, reflecting the averaging that occurs for the monthly prices. While not as skewed as the distribution of hourly prices, Figure 2 demonstrates that even the distribution of monthly prices is skewed to the right.

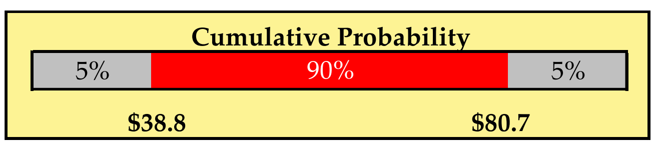
Figure 1: Historic Distribution of Hourly HOEP



Source: NCI analysis of IESO data (May 1, 2002 to March 18, 2008)

Figure 2: Historic Distribution of Monthly Average HOEP





Source: NCI analysis of IESO data (May 2002 to March 2008)

5. ASSESSMENT OF FORECAST RISKS

As discussed above, the foundation of our HOEP forecast is a market fundamentals analysis which is performed using ProSym. ProSym is a deterministic forecast developed using single point forecasts for each of the determinants of price, and that the potential exists for considerable variability in each of these assumptions. In setting the RPP price, Navigant Consulting and the OEB have used a statistical analysis to evaluate the uncertainty around this deterministic 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 will review the factors that present the greatest forecast risk and assess, in qualitative terms, the degree to which the forecast has addressed them.

Navigant Consulting believes that there are three major risks that an 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 and peak demand forecasts used by Navigant Consulting were developed by the IESO. The 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, as was experienced in the summer of 2005, energy consumption would be expected to vary from the forecast assumption.

In addition, various random elements to the forecast will cause actual loads to vary from our forecast, e.g., consumer behaviour, etc. For our short-term forecast, Navigant Consulting believes that the greatest source of load forecast risk is weather. The IESO indicates that a 1°C increase when the temperature is above 16°C results in approximately a 450 MW increase in the daily peak demand. The IESO's March 2008 18-Month Outlook forecasts a normal weather pre-conservation summer peak of 25,493 MW and an extreme weather peak of 27,748 MW for the summer of 2008, 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 (May 2008 – April 2009)*. Analysis of historical price and demand levels clearly demonstrates that load variability is a major contributor to spot market price volatility. Therefore, Navigant Consulting believes that this risk has been considered in our price forecasting approach.

5.2 Fuel Price Forecast Risk

The fuel prices used by Navigant Consulting for this forecast were largely based on the 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.

In general, the fuel price that is subject to the most uncertainty is natural gas. Currently Ontario has a relatively limited amount of natural gas-fired generation that is likely to set the HOEP, however natural gas-fired plants do set the HOEP a considerable amount of time and the amount of 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 TransAlta Sarnia project (575 MW), the Brighton Beach project (570 MW), the GTAA Cogeneration Facility (117 MW). However, the natural gas-fired generation capacity in Ontario is expected to almost double over the forecast period, with approximately 1,850 MW of natural gas-fired generation expected to go into service by April 20, 2009, and an additional 1200 MW by the end of the second quarter of 2009. 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 most obvious risk associated with natural gas prices is the inherent price volatility of the commodity itself. Natural gas prices are very closely correlated to crude oil prices, and the relative instability of world oil and natural gas markets has led to an increase in the volatility of the commodity price. While this is not captured by the ProSym model, an effort is made to account for a portion of this volatility when setting the RPP price.

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, NCI and the OEB have used an average of settlement prices for futures contracts over a 20 trading day period.

Figure 3 illustrates the trend in forward prices for natural gas for May 2008 delivery since May 2002. Navigant Consulting's assumption used in the ProSym forecast was based on an average of settlement prices over a recent 20 day 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.

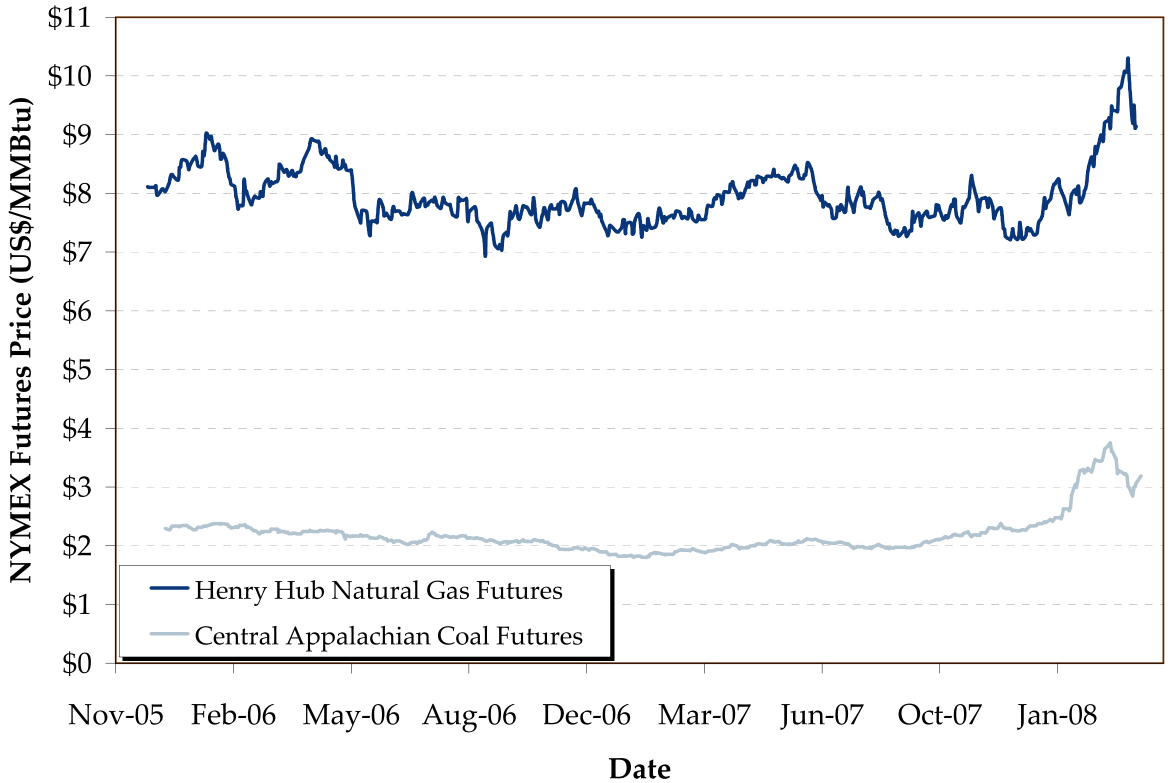
Figure 3: Historical May 2008 Futures Prices (US$/MMBtu)

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.

Coal-fired generation establishes the HOEP approximately 50% of all hours, particularly during off-peak hours. Historically, coal prices have been much less volatile than either natural gas or oil prices. This is apparent in Figure 4, where the trend in forward prices for natural gas for May 2008 delivery is compared to the trend in forward prices for Central Appalachian coal for May 2008 delivery. Navigant Consulting expects that this will continue to be the case.

Figure 4: Historical May 2008 Futures Central Appalachian Coal and Henry Hub Gas Prices (US$/MMBtu)

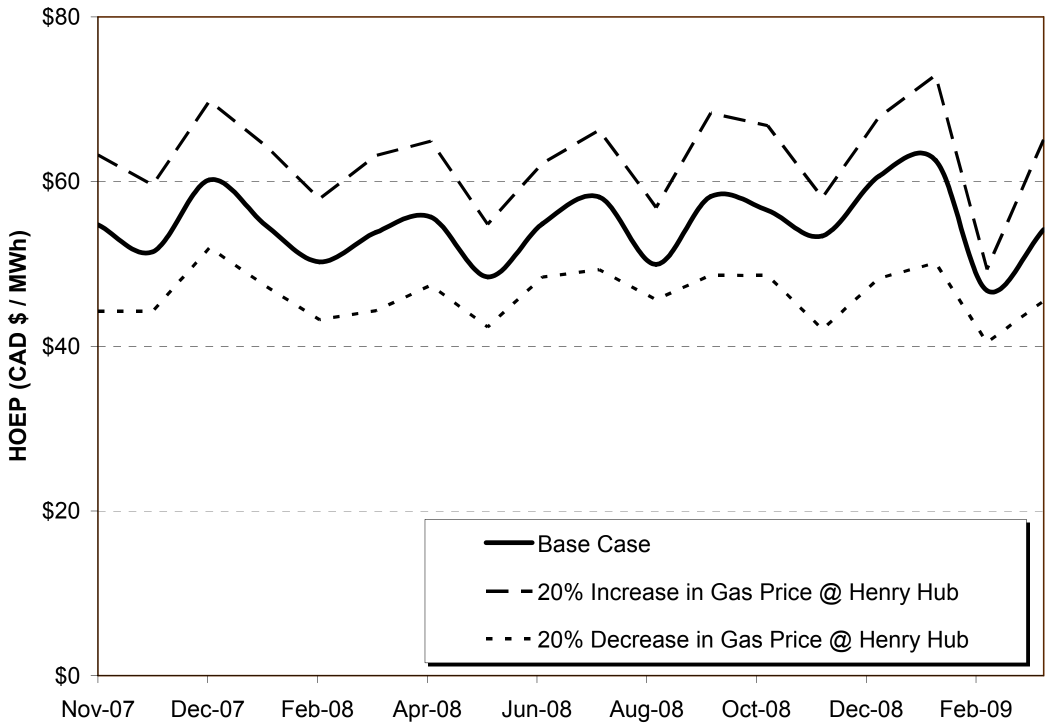


Source: NYMEX

Based on this assessment and the experience of the late summer and fall of 2005 (when both gas and electricity prices were very high), and the winter of 2006/2007 (when prices were low), Navigant Consulting 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.

As part of its development of the wholesale price forecast for the OEB in October 2007, Navigant Consulting evaluated the impact of a ± 20% change in Henry Hub natural gas prices on the HOEP using ProSym. The results of this analysis are shown in Figure 5 which shows the monthly average HOEP for the base case as well as high and low natural gas price sensitivities. This analysis indicated that the HOEP increased by an average of about 15% when natural gas prices were assumed to be 20% higher than forecast and also decreased by an average of 15% when natural gas prices were assumed to be 20% lower than forecast.

Figure 5: Comparison of Monthly Average HOEP with ±20% Change in Henry Hub Gas Price



Source: NCI

5.3 Generator Availability Price Risks

The third major source of electricity price forecast risk pertains to the availability of Ontario generation. ProSym reflects random generator forced outages and as such this risk is reflected in our model to the degree that the forced outage rates that we have specified in ProSym are reliable. 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 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.

Table 7 compares our capacity factor assumptions for Ontario's nuclear fleet with recent experience.

Table 7: Comparison of Historical Nuclear Capacity Factors with Forecast Values

	1999	2000	2001	2002	2003	2004	2005	2006	2007	RPP Year
Actual Capacity Factor	81.3%	79.3%	83.4%	82.5%	80.1%	80.4%	81.6%	84.2%	80.6%	
Forecast Capacity Factor										83.4%

Source: NCI analysis of IESO generator disclosure reports and ProSym market modeling results.
Note: RPP Year refers to the period May 2008 through April 2009 inclusive, one full calendar year.