ONTARIO WHOLESALE ELECTRICITY MARKET PRICE FORECAST

FOR THE PERIOD JANUARY 1, 2005 THROUGH DECEMBER 31, 2006

Presented to

ONTARIO ENERGY BOARD

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Presented by

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No Warranties or Representations

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

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1. INTRODUCTION

Navigant Consulting Ltd. (Navigant Consulting) was retained by the Ontario Energy Board (OEB) to provide an independent market price forecast for the Ontario wholesale power market. This electricity price forecast is provided under a broader project where Navigant Consulting is assisting the OEB with the development of a regulated price plan (RPP) for eligible consumers. This forecast will be used by the OEB to help set the prices for the RPP. The consumers that will be eligible for the regulated price plan are determined by regulation.[1]

This report presents the results of our forecast of the Hourly Ontario Energy Price (HOEP) for the period from January 1, 2005 through December 31, 2006 and describes the major economic and energy market assumptions and inputs for the forecast and sources of that 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 by the OEB with prices for other sources of RPP supply to establish the prices for the RPP.

This report also describes the model that Navigant Consulting developed to model the variance of the RPP supply cost. This model takes account of random variation in the factors driving the forecast of RPP costs to provide a probability distribution of their variance. Subsequent reports will provide an assessment of the performance of previous quarterly price forecasts against actual market prices and the reasons for any deviations.

Contents of This Report

This report contains six chapters. The first is this Introduction. The second reviews the forecasting methodology, including the framework used for evaluating forecast

[1] On March 1, 2005, the Ministry of Energy posted on its website a draft regulation regarding the determination of rates by the OEB under section 79.16 of the *Ontario Energy Board Act, 1998* (the section of the *Act* under which the Board's authority to determine RPP prices arises). The draft regulation indicates that low volume and designated consumers will be eligible for the RPP, just as they are now eligible for the regulated 4.7/5.5 cents/kWh price. The determination of rates by the OEB is subject to adoption of the draft regulation.

uncertainty and incorporating this uncertainty into the price forecast. The third chapter reviews the source of forecast assumptions and reviews key forecast assumptions. The fourth chapter reviews the forecast results. The fifth chapter discusses the forecast risks. The final chapter describes the RPP supply cost variance model.

2. PRICE FORECASTING METHODOLOGY

To forecast the HOEP and account for the uncertainty around this price forecast and the inherent volatility of wholesale market prices, Navigant Consulting adopted an approach that combines fundamental analysis and statistical analyses of the variables that will contribute to variance between the forecast and actual costs of the RPP. Fundamental analysis examines the factors driving supply and demand and develops price forecasts based on a view of market equilibrium. This chapter reviews our fundamental price forecasting methodology.

The major factors driving the equilibrium of supply and demand are reflected in the forecast model (ProSym) to develop the fundamental forecast. The model dispatches generation resources economically to meet hourly load. The output of the model is a set of deterministic prices. If the model is properly specified with the best available information, it will yield a forecast of expected electricity prices. This forecast and the forecast of the cost and amount of supply from the regulated and contracted sources (OPG prescribed assets, NUGs, and contracts with the Ontario Power Authority (OPA)) are then used with the RPP supply cost variance model to simulate the range of possible balances in the variance account carried by the OPA, assuming different RPP supply cost levels.

Overview of the Fundamental Forecasting Model

Navigant Consulting used ProSym to develop our 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 OPG's hydroelectric fleet (baseload and peaking resources), and operating characteristics and fuel prices for OPG's fossil fleet. 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 achieves an optimal outcome by dispatching generating resources to match hourly electricity demand, always dispatching the cheapest available generation first. The choice of generation is determined by the generator's offer to the market operator, by technical factors such as ramp rates (for fossil resources) or water availability (for hydraulic resources) and by transmission constraints. This dispatch establishes market-clearing prices which each generator located within the same market area 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 outage, 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 have 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.

Where relevant (primarily for thermal units), the offer price also includes a component reflecting the unit's start-up and no-load costs.

The Start Cost component incorporates fuel costs and other operating costs encountered in starting the generating unit, beyond those reflected in the heat rate and variable operating cost assumptions. The No-Load Cost reflects the difference between average and incremental fuel costs for generating stations that are dispatched at less than full output.

The offer price can also include a price markup factor taking the bid price above variable production costs. Navigant Consulting uses this factor where appropriate to reflect observed market behavior where wholesale prices often rise above the underlying cost of production, particularly during times when supply/demand margins are tight. Navigant Consulting assigns price markups to individual generators depending upon the underlying fuel efficiency, production cost and technology type. The specific markups 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 markups 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 prescribed assets and the structure of the Ministry of Energy's recent Clean Energy Supply (2,500 MW) RFP,[2] 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 increment (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

[2] The RFP is structured so that generators' deemed net revenues from participating in the energy market are subtracted from their net revenue requirements to establish the support payments to be made by the Ontario Power Authority. Deemed energy market revenues assume that the generating unit is operating whenever the HOEP is greater than the unit's variable operating costs. Therefore, if the generator departs from a marginal cost based offer strategy it risks being deemed to have made money from spot market sales when in fact it wasn't operating, i.e., its "top-up" payment from the OPA will be reduced to account for these deemed revenues.

price of the marginal generator needed to serve a final increment of demand within the region.[3]

Treatment of OPG Prescribed Assets in the Model Specification

A significant portion of Ontario's generation -- OPG's nuclear and major baseload hydroelectric generating units (Saunders, Beck, and DeCew Falls) -- has been designated by the Government as prescribed assets. The net price these plants receive is initially set under regulation by the Government[4]. Although the net price to these plants is set by regulation, they are still offered to and priced in the Ontario market under the same market dynamics that are in place currently, i.e., a bid-based pool where participating generators receive a uniform price. The rules for their net prices give the party responsible for scheduling and ensuring the dispatch of this generation incentives 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 prescribed assets don't establish the market-clearing price for the vast majority of hours, we expect that the treatment of these generating stations as assets whose price is regulated will not affect the HOEP.

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[3] The Independent Electricity System Operator's (IESO's) Import 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 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 our price forecast and actual prices.

[4] The *Payments under Section 78.1 of the Act Regulation*, O. Reg. 53/05, identifies the prescribed assets as well as the regulated prices that apply to them.

Recognizing Market Pricing Volatility

Experience demonstrates that power 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, cheaper 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.

But 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 kind of price volatility is not fully captured by the deterministic ProSym model. The methodology used to reflect this price volatility is reviewed in Chapter 6.

3. SHORT-TERM FORECAST ASSUMPTIONS

As discussed above, we utilized ProSym as one of the primary price forecasting tools during this engagement. The sources of the primary modeling assumptions as well as the key assumptions are reviewed below.

Data Sources for Primary Assumptions

Broadly, four classes of primary assumptions underpin our short-term 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. Hydro resources

Relevant but less important factors include offer strategies, price responsive load and the US-Canada currency exchange rates.[5] The following sections present our data sources for each of the primary assumptions, for our base case scenario which represents our expected forecast.

Demand Forecast

The demand forecast used was from the IESO's most current *18-Month Outlook: Ontario Demand Forecast From January 2005 to June 2006* (January 3, 2005). The IESO's energy

[5] The price forecast reflects an exchange rate of $1.00 Cdn to $0.80 US.

forecast for each month, which reflects normal weather, was used with an actual Ontario load shape (from a year which represents normal weather). For the period from July through December 2006, we applied the growth rate for the last 12 months of the forecast to the forecast consumption for that month in 2005. Table 1 indicates the forecast of monthly energy consumption that we used from the IESO.

Table 1: Forecast Monthly Energy Consumption

Month	Monthly Energy (GWh)
Jan-05	14,270
Feb-05	12,795
Mar-05	13,319
Apr-05	11,926
May-05	12,048
Jun-05	12,273
Jul-05	13,355
Aug-05	13,457
Sep-05	12,214
Oct-05	12,377
Nov-05	12,680
Dec-05	13,686
Jan-06	14,269
Feb-06	12,835
Mar-06	13,396
Apr-06	11,927
May-06	12,175
Jun-06	12,420
Jul-06	13,456
Aug-06	13,559
Sep-06	12,307
Oct-06	12,413
Nov-06	12,716
Dec-06	13,726

Source: IESO, 18-Month Outlook, Ontario Demand Forecast, January 3, 2005

Supply Assumptions

Installed Capacity

The generation capacity assumptions are consistent with the IESO's *18-Month Outlook*. TransAlta's Sarnia cogeneration project is currently operating at a reduced output level.

TransAlta has indicated that it is only generating 150 MW at its Sarnia cogeneration project, but that it could increase the output of the project to its rated capacity (575 MW) if it receives guarantees from the Government that its power sales would be under the same conditions as other plants in the Province.[6] Navigant Consulting assumes that TransAlta will receive sufficient financial compensation (from the market or the Government) to make the full output of its project available to the Ontario market during the forecast horizon.

These supply forecasts use information regarding generator output capabilities, planned outages, allowances for hydroelectric generation production below rated capacity, assumptions for the amount of price-responsive demand, and major transmission interface limitations.

The *18-Month Outlook* from which we derived our generation availability assumptions indicated that OPG plans to return the Pickering A Unit 1 to service by September 1, 2005. OPG's *Third Quarter 2004 Financial Report* indicated that the construction phase of the refurbishment of Pickering 1 is scheduled to be completed between early June and mid July 2005, followed by a commissioning and testing period of approximately three months.[7] Based on this schedule, we have assumed that Pickering 1 returns to service on October 1, 2005. We evaluate the impacts of delays in this return to service date in forecast risks. Also, laid-up Bruce-A Units 1 & 2 are assumed not to return to service in this forecast horizon given the estimated time required for refurbishing the units.

In addition, the Minister of Energy announced in November 2004 that contracts had been awarded to 10 renewable energy projects that participated in the Renewable Energy Request for Proposals. Navigant Consulting attempted to contact the developers of these projects to ascertain their anticipated commercial in-service date.[8] Table 2

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[6] *Electric Power Daily*, August 9, 2004, p. 4.

[7] www.opg.com/ir/reports/Q3_04all.pdf

[8] The production incentive in the federal government's Wind Power Purchase Incentive program is scheduled to be reduced to $8/MWh from $10/MWh as of April 1, 2006. Therefore, there is a significant incentive for these wind project developers to have their projects in-service prior to that date.

indicates (based on this contact) those projects that were assumed to begin commercial operation prior to the end of the forecast period and included in the model specification.[9]

Table 2: Renewable Generation Capacity Additions

Project Name	Type of Generation	Capacity (MW)	In-service date
Glen Miller Hydroelectric Project	Hydro	8	Aug-05
Prince Wind Farm	Wind	99	Dec-05
Erie Shores Wind Farm	Wind	99	Mar-06
Melancthon Grey Wind Project	Wind	68	Mar-06
EPCOR Kingsbridge Wind Project	Wind	40	Mar-06

Source: Ministry of Energy, Navigant Consulting

Outages

Generator outages happen for two reasons: planned outages for scheduled maintenance and forced outages for unplanned maintenance. The IESO provided us with its scheduled outage schedule by capacity (fuel) type, on a weekly basis through the end of 2006. We used information from this outage schedule to adjust our standard maintenance outage schedule that is reflected in our model specification.

Also reflected in the model specification availability assumptions is Ontario Regulation 396/01, which effectively restricts OPG from operating the Lakeview Fossil Generating Station at higher than a 27% capacity factor, through limiting the amount of nitric oxide the station can emit.

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

[9] We were unable to reach some of the developers of several of the smaller projects and elected to not include the capacity from these projects in the forecast. This should not have a material impact on the forecast results.

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.[10]

Price Responsive Load

Our assumptions regarding the amount of price responsive load reflect the information reported by the IESO regarding the amount of price responsive load participating in the Operating Reserve Market and the Hour Ahead (dispatchable load) Market.

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 *10-Year Outlook* (dated March 25, 2004), 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 the IESO's *10-Year Outlook*.

[10] These units included Lennox and the coal units.

Table 3: Ontario Interconnection Limits

Interconnection	Flows Out of Ontario (MW)	Flows Into Ontario (MW)
Manitoba	268	336
Minnesota	140	90
Michigan		
Summer	1,900	1,200
Winter	2,000	1,450
New York East	400	400
New York West		
Summer	1,250	1,150
Winter	1,500	1,350
Quebec South	750	1,410
Quebec North	103	75

Source: IMO, 10-Year Outlook, March 25, 2004

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. Since we forecast electricity 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 these futures prices, we apply a basis differential. For natural gas this basis differential is from Henry Hub to the Union Dawn trading hub in southwestern Ontario. This basis differential is based on the historical relationship between futures prices for delivery at Henry Hub and Dawn. 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. Since Lennox operates as a dual-fuel facility, and we believe it has an environmental constraint on the number of oil-fired hours, we propose to 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.

Table 4: Natural Gas and Fuel Oil Prices

Month	Natural Gas @ Southern Ontario ($U.S./MMBtu)	#2 Fuel Oil @ Southern Ontario ($U.S./MMBtu)	#6 Residual Oil @ Southern Ontario ($U.S./MMBtu)
Jan-05	7.30	8.82	5.24
Feb-05	7.34	10.13	5.37
Mar-05	7.31	10.08	5.39
Apr-05	6.92	9.75	5.38
May-05	6.89	9.46	5.36
Jun-05	6.92	9.29	5.33
Jul-05	6.97	9.25	5.31
Aug-05	6.99	9.26	5.28
Sep-05	6.96	9.31	5.26
Oct-05	6.99	9.37	5.24
Nov-05	7.29	9.43	5.22
Dec-05	7.59	9.49	5.20
Jan-06	7.79	9.53	5.18
Feb-06	7.78	9.48	5.16
Mar-06	7.56	9.30	5.14
Apr-06	6.61	9.03	5.12
May-06	6.47	8.84	5.11
Jun-06	6.49	8.85	5.09
Jul-06	6.52	8.86	5.08
Aug-06	6.54	8.86	5.07
Sep-06	6.51	8.87	5.05
Oct-06	6.53	8.88	5.04
Nov-06	6.82	8.88	5.03
Dec-06	7.10	8.89	5.02

Source: NYMEX natural gas futures for Henry Hub and #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 fuels based on Navigant Consulting estimates.

Coal

We estimated current delivered coal prices to OPG 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). Our forecast of the coal price escalation rates was based on the NYMEX futures coal price (Central Appalachian).

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 5 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. This forecast ties closely to forward prices. The 7 x 24 forward price for 2006 at the time the forecast was finalized was just above $54/MWh. Navigant Consulting believes that the fact that our ProSym forecast was consistent with the forward market prices demonstrates the reasonableness of our forecast results.

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 output month, with May and June representing the highest output based on the spring freshet.

Table 5: Fundamentals Forecast of HOEP ($/MWh)

Year	Quarter	On-Peak	Off-Peak	Average	Annual Average
2005	1	$77.78	$31.55	$53.56	
	2	$78.54	$30.76	$53.51	
	3	$84.49	$35.21	$58.68	
	4	$75.89	$31.27	$52.52	$54.57
2006	1	$83.84	$32.24	$56.82	
	2	$73.94	$29.76	$50.80	
	3	$78.11	$34.57	$55.30	
	4	$71.98	$31.15	$50.59	$53.38

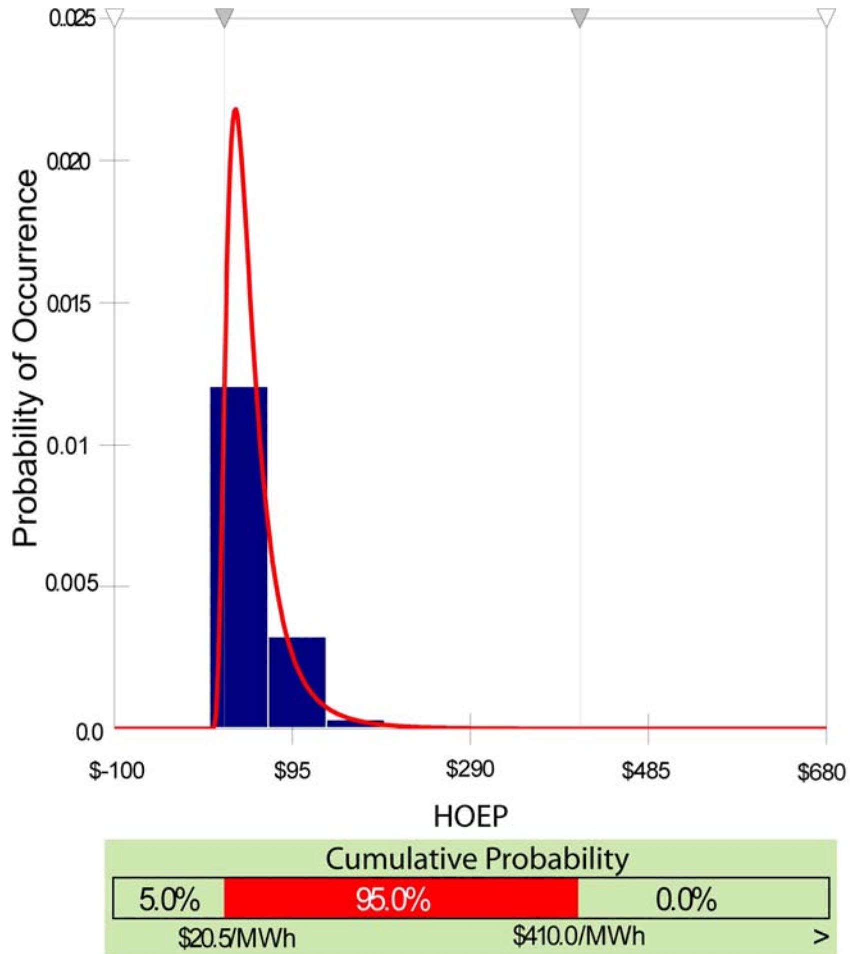
Source: Navigant Consulting

As discussed, 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. Figure 1 & Figure 2 present the hourly and monthly HOEP price distributions since market opening and compare these price distributions to the fitted price distribution that we have used for our volatility analysis. The HOEP is captured on the x axis and the number of times that the HOEP occurred is reflected in the y axis. The most meaningful element of these curves is the fact that both are skewed to the right, indicating that the expected value is likely to be higher than the 50% percentile value,[11] the ProSym forecast. The fitted price distribution consistently underestimates the number of hours when prices are in the $80 to $100 range (the actual value depends on whether the evaluation is of the monthly or hourly fitted distribution). We believe that the actual prices reflect OPG's offer strategy for Lennox and the importance of Lennox in price setting at higher loads. The fitted distribution is not able to capture this physical element of the Ontario market. However, it is captured in the ProSym analysis where Lennox and its anticipated offer strategy is an element of the model specification.

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 hourly HOEP distribution, Figure 2 demonstrates that even monthly prices are skewed to the right. This suggests that the ProSym forecast which is believed to represent the 50 percentile forecast value might require adjustment to ensure that the regulated price plan prices based on this forecast are likely to minimize variance account balances.

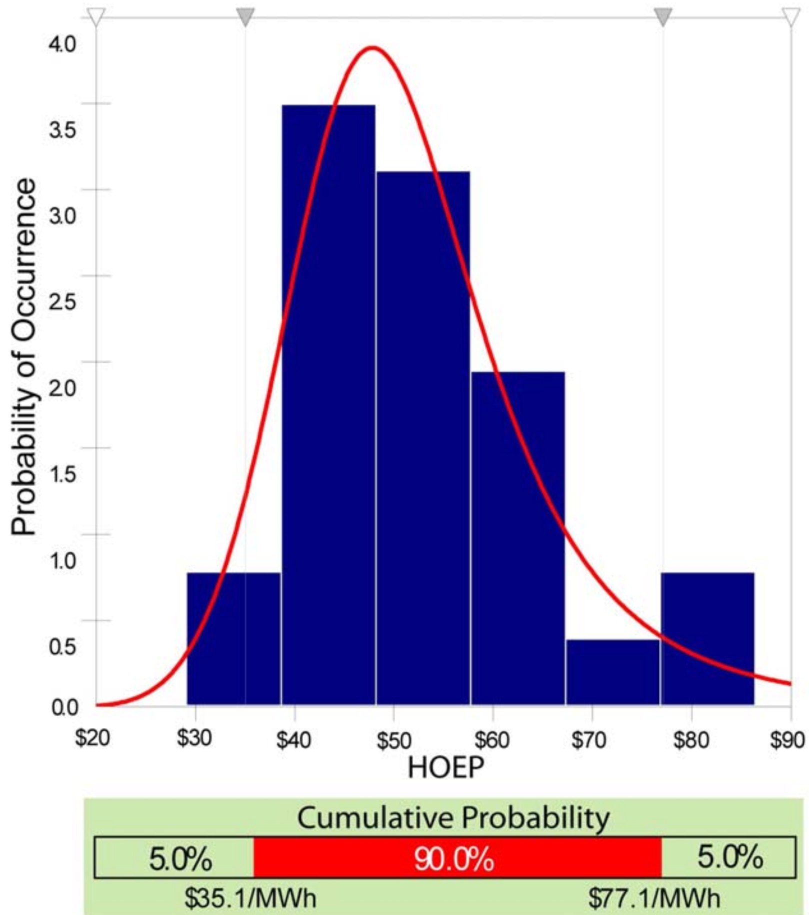
[11] The 50% percentile value is the HOEP estimate for which we forecast there to be a 50% probability of prices being lower than this.

Figure 1: Hourly HOEP Distribution



Note: Fitted price distribution based on observed hourly prices from 5/1/02 to 7/20/04

Figure 2: Monthly HOEP Distribution



Note: Fitted price distribution based on observed monthly prices from 5/1/02 to 7/20/04

5. ASSESSMENT OF FORECAST RESULTS

As discussed above, the foundation of our HOEP forecast is a market fundamentals analysis which is performed using ProSym. Recognizing that ProSym is a deterministic forecast developed using single point forecasts for each of the determinants of price and that there is the potential for considerable variability in each of these assumptions, Navigant Consulting used statistical analysis to evaluate the uncertainty around this market price forecast. We believe that this probability analysis allows us to adequately evaluate forecast risks. Nonetheless, it is appropriate to review these forecast risks 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.[12] These stem from differences between forecast and actual: (1) loads; (2) fuel prices; and (3) generator availabilities. Each of these forecast risks is assessed below.

Load Forecast Risk

As discussed, the load forecast used by Navigant Consulting was developed by the IESO. This load 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. To the degree that the economic forecast is wrong or weather conditions depart from normal, load would be expected to vary from the forecast assumption. In addition, various random elements, such as consumer behaviour, will cause actual loads to vary from our forecast. 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 380 MW increase in the daily peak demand. The IESO's January 2005 *18-Month Outlook* forecasts a normal weather summer peak of 23,636 MW and an extreme weather peak of 26,583 MW, reflecting how load is forecast to increase under more extreme weather conditions.

[12] Another risk that is not explicitly considered is the exchange rate. Given that most of the fuel consumed by fossil-fueled generators is denominated in US$, changes in the exchange rate are likely to affect Ontario market prices. To some degree, this risk can be viewed as an element of the fuel price risks that are formally considered and evaluated.

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The variability in loads was specifically considered in the analysis which is reviewed in the following chapter. Past analyses have demonstrated 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.

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. Figure 3 illustrates the trend in forward prices for natural gas for January 2005 delivery since the end of 2001 and Navigant Consulting's assumption used in the ProSym forecast. This clearly demonstrates that while the forecast natural gas prices used in the ProSym forecast are at the upper end of this gas price trend, these prices are lower than market levels from September to December 2004. Although the fuel price forecasts are based on the best available information, there is a risk that the forecasts were compiled at the peak for forward prices and therefore may possibly lead to higher electricity prices than if compiled at a subsequent date.

Figure 3: Historical January 2005 Forward Prices (US$ per MMBtu)

Source: NYMEX

In general, the fuel price that is subject to the most uncertainty is natural gas. However, Ontario has a relatively limited amount of natural gas-fired generation that is likely to set the HOEP. This includes Lennox (2,140 MW) which is also capable of burning residual oil, the TransAlta Sarnia project (575 MW) and the Brighton Beach project (570 MW).[13] However, there is 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 Import Offer Guarantee rule, it nonetheless has an influence on Ontario market prices.

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. In general, coal prices are not as volatile as natural gas or oil prices, as outlined in Table 6.[14] However, Figure 4 demonstrates that in the past 12 months coal prices have increased markedly. Reduced Appalachian coal supplies with increasing demand have lead to these price increases. Near term, increased production at existing mines is anticipated to reduce the need for additional price increases. Historically, coal prices have been much less volatile than either natural gas or oil prices. Navigant Consulting expects that this will continue to be the case.

[13] The natural gas-fired non-utility generation capacity that is administered by OEFC is largely must-run and thus is not price setting.

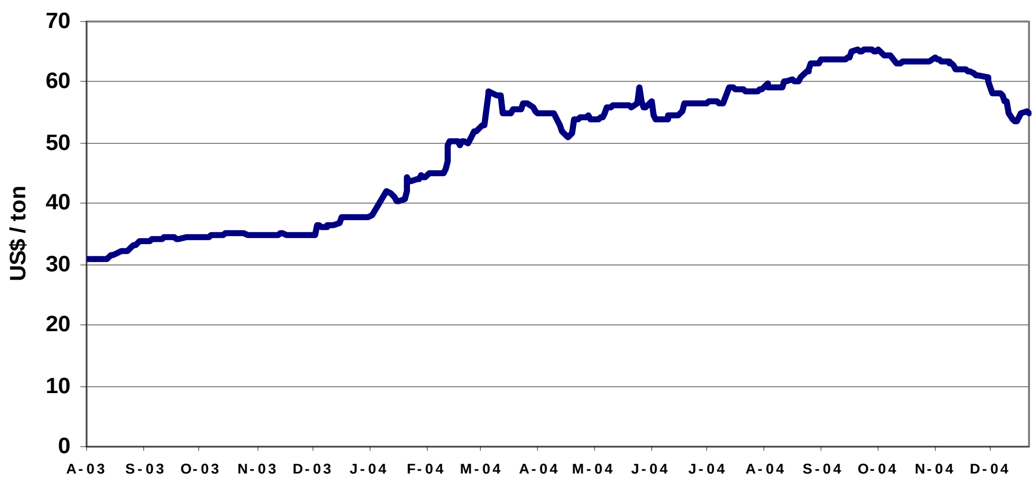
[14] Volatility is a measure of risk that reflects the tendency of the commodity's price to rise or fall. Volatility is measured based on the dispersion from the mean.

Table 6: Annual Fuel Price Volatility

	2001	2002	2003	2004	Annual Average
Natural Gas	86.8%	57.6%	166.3%	55.0%	91.4%
Oil	46.5%	33.3%	44.8%	27.5%	38.0%
Coal	35.2%	27.0%	10.4%	16.4%	22.2%

Source: Navigant Consulting analysis of NYMEX Prices

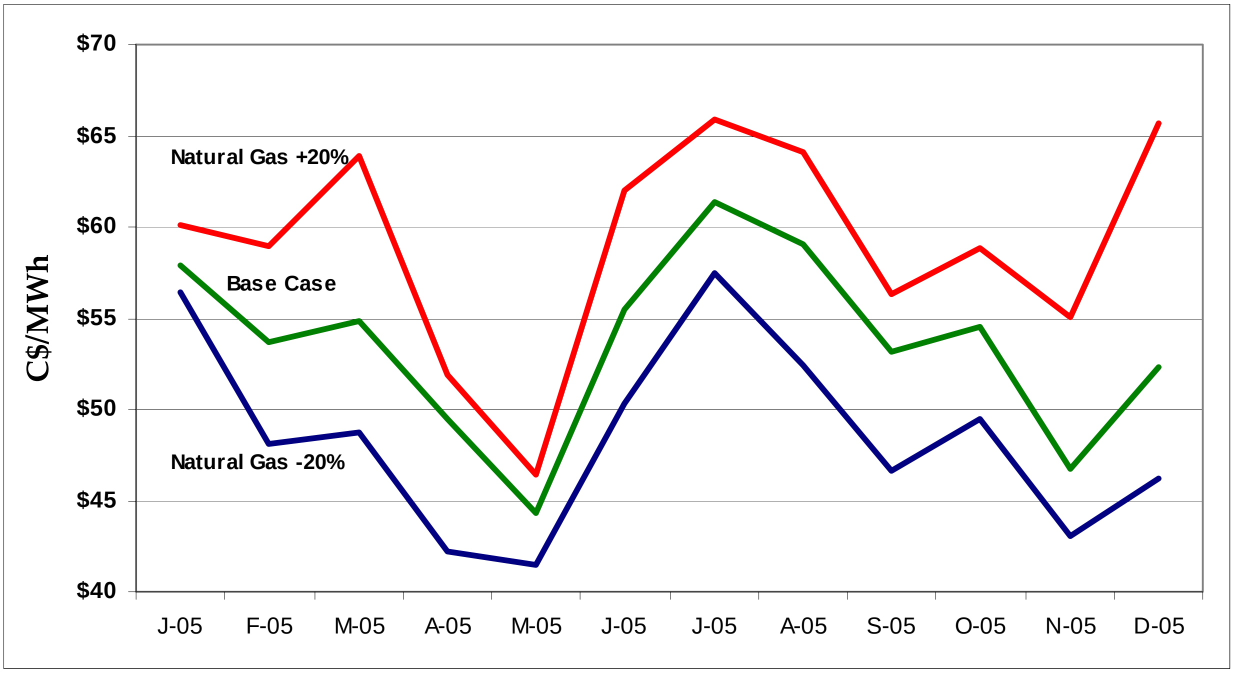
Figure 4: Historical Central Appalachian Coal Prices (US$ per ton)



Source: NYMEX

Based on this assessment, Navigant Consulting believes that the most significant fuel price forecast risk is posed by natural gas. With limited surplus natural gas production, a cold winter or hot summer that increases the demand for natural gas-fired generation could result in significant increases in natural gas prices. Conversely, a warm winter or cool summer should result in a softening of near term natural gas prices, such as was witnessed in late August and early September of 2004. Therefore, we 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 a base case and high and low gas price sensitivities. This analysis indicated that the HOEP increased by an average of about 12% when natural gas prices were assumed to be 20% higher than our forecast and decreased by an average of 10% when natural gas prices were assumed to be 20% lower than our forecast. We assume that the lower price elasticity for lower prices reflects the substitution effects at lower natural gas prices, i.e., greater use of natural gas-fired generation at these lower natural gas prices.

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



Source: Navigant Consulting

Generator Availability Price Risks

The third major source of electricity price forecast risks 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 6 contrasts 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
Average	81.3%	79.3%	83.4%	82.5%	80.1%	80.4%	82.1%	83.8%

Another generator availability forecast risk is our assumption that the Pickering 1 nuclear generating unit will begin commercial operation on October 1, 2005. The return to service of the four units at the Pickering A nuclear generating station has been delayed numerous times. These delays have been attributed to inadequate project planning and co-ordination. However, if Pickering 1 were not returned to service as scheduled, Navigant Consulting estimates that this would result in less than a $1/MWh increase in the HOEP for the period over which the delay was experienced.

6. VARIANCE OF RPP SUPPLY COST

Introduction

This section describes the methodology for modeling variances from the forecast RPP supply cost. This variance will be carried by the OPA.

The RPP supply will come from three kinds of sources: those subject to contract, those that are regulated and those priced in the IESO-administered markets. Sources subject to regulation are the supply from the prescribed OPG assets (baseload hydroelectric and nuclear), whose revenue will be regulated initially by the Ontario Government and later by the OEB. Sources subject to contract include supply from existing non-utility generators (NUGs), which are under contracts now held by the Ontario Electricity Financial Corporation (OEFC); and supply from contracts with the OPA, such as the results of the Clean Energy Supply (2500 MW) and renewables RFPs.

The variance of the RPP supply cost is calculated against the Navigant Consulting forecast of the RPP supply cost. The random processes creating variance are modeled by considering the factors subject to random variation and simulating that variation.

RPP supply cost can be influenced by several factors subject to random variation. These include the quantity of supply from the OPG prescribed assets and contracted sources, the level of demand from RPP consumers, and the Ontario market price.[15]

The interaction among these factors can be complex, because the first two, supply and demand conditions, can affect the third, the Ontario market price. Navigant Consulting has modeled this complex relationship using a combination of econometric and statistical techniques. These have been applied to the supply from the OPG prescribed assets, the demand from consumers taking RPP supply, and the market price.

The level of demand from RPP consumers will itself be affected by a number of factors. The most significant is the Government's determination of which consumers will be

[15] Variations in fuel prices, such as natural gas and coal, also have a significant influence on RPP supply costs.

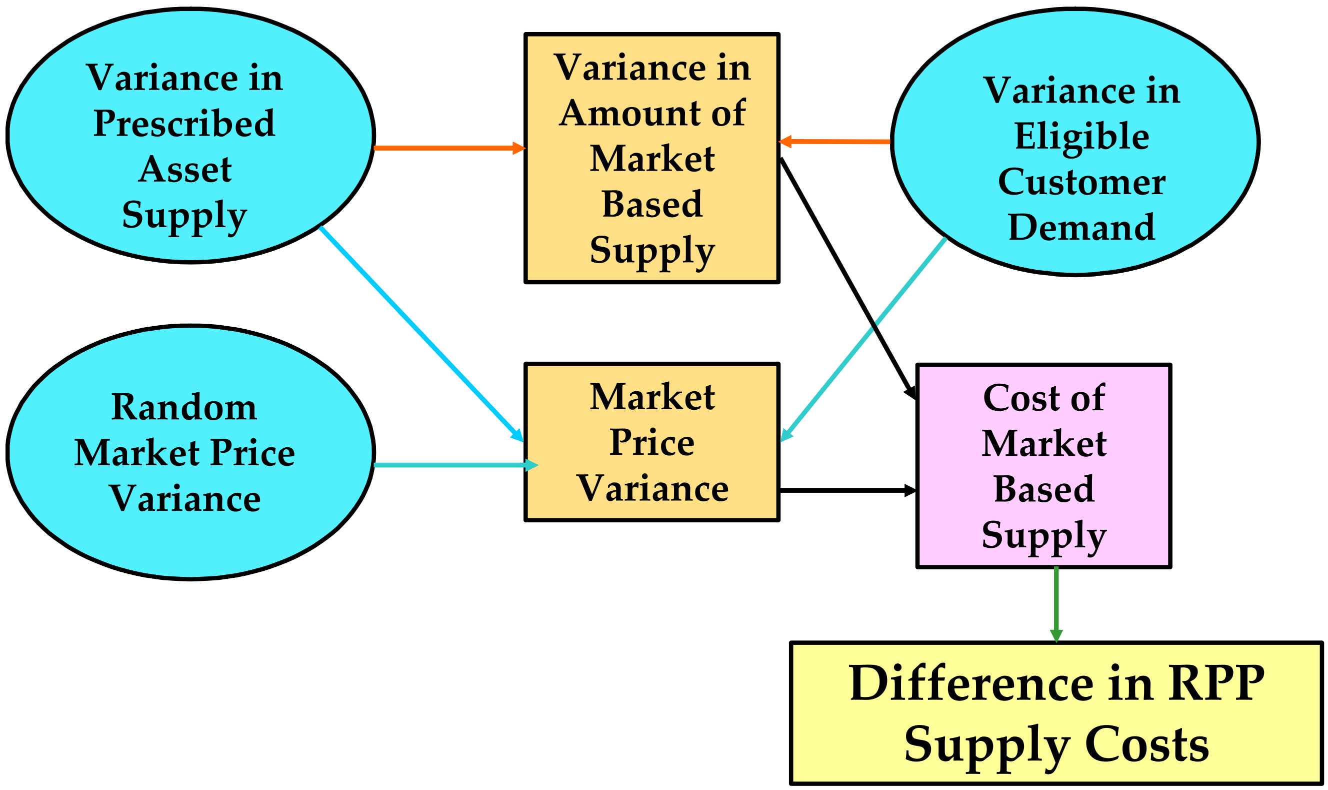
eligible for the RPP. After the RPP is in place, the forecast will also need to make assumptions on the expected degree of migration of consumers from RPP to competitive retailers or the spot market price option. The amount of migration is influenced by which consumers are eligible.

We have not modeled the variance of supply from the NUGs and OPA contracts. The NUGs' technology, diverse number of resources and fuel sources make them less subject to variability than the other sources of RPP supply. For similar reasons, we have not modeled variance in supply from sources contracted to OPA.

The Model of Supply Cost Variance

Figure 6 shows the relationships among the modeled factors and their variance. This is a simplified diagram to show the interaction among these factors. In the explanation of the diagram, we will use the assumption that the cost of supply from the prescribed assets is lower than the cost of supply from the IESO-administered markets. The explanation will also track the case of a decrease in the amount of that supply below its forecast level and that of an increase in demand for RPP supply above the forecast level. The reverse of the effects on price can be expected if these cases are reversed.

Figure 6: Diagram of Supply Cost Variance



The factor in the upper left of Figure 6 shows the supply from OPG's prescribed assets. Any deviation of this supply from forecast creates a deviation both in the total supply of electricity generated in Ontario and in the amount available for RPP supply. The change in total supply in Ontario in turn affects the market price in Ontario, because it reduces the amount of low price generation available and therefore forces the use of larger amounts of more expensive generation. The market price (hourly Ontario energy price, or HOEP) will therefore increase for a decrease in the amount of supply available from the prescribed assets.

This impact on the market price is not the only effect on the RPP supply cost. The change in supply changes the quantity of electricity available from the prescribed assets at the regulated price. The amount of RPP supply to be obtained through and priced (at HOEP) in the IESO-administered markets is the residual of the demand after the supply from prescribed assets, NUG contracts, and any contracts OPA signs with generators. A decrease in the supply from the prescribed assets will therefore increase the amount to be obtained in the market. Since the regulated price of electricity from the prescribed assets is expected, at most times, to be lower than HOEP, a decrease in supply available from the prescribed assets will increase the RPP supply cost.

The upper right hand side of the diagram shows a similar situation for variances from expected demand. As with a change in supply, this affects RPP supply costs in two ways. An increase in demand produces an increase in the amount of supply that is required for the RPP consumers, and therefore a change in the amount that must be obtained and priced in the IESO-administered markets. A deviation in demand from forecast amounts also changes the supply and demand situation in the IESO-administered markets and impacts prices.

Of course, the specific factors of RPP supply and demand are not the only influences on market price. Many other factors, including demand from other consumers, supply from other generators and from imports and the cost of natural gas and other fuels influence the HOEP. These other factors are illustrated in Figure 6 on the middle of the left side of the diagram, where other random factors create variance in the market price.

Simulating the Model

We used a combination of statistical and econometric techniques to model this system and produce a distribution for the variance of RPP supply costs.

Our basic methodology was a Monte Carlo technique. Such techniques make a large number of simulations of a complex system where each of several input variables is subject to random factors that can be described by a probability distribution. The model simulates the system by taking a large number of random draws from the distributions of each of the variables subject to random factors. Each draw produces a value of the variable to be used as input to the model.

Deriving Probability Distributions

The first steps were to estimate probability distributions for the three key factors: supply from the prescribed assets, demand from RPP consumers, and the HOEP itself.

There are two kinds of prescribed assets, both owned by OPG: nuclear generation stations and baseload hydroelectric stations. To estimate nuclear supply probabilities, we used available information and our modeling assumptions about forced and unforced outage rates. Since our existing forecast of nuclear supply, and therefore of total Ontario supply, already models random forced outages, we chose probabilities that represented extreme outage situations that are not captured in our ProSym model. For the hydroelectric assets, we used information provided to the RPP working group by OPG on water availability in the last four years. We combined these distributions to create an overall probability distribution of supply.

The major factor causing day-to-day variance in customer demand is weather. The most important weather factor is temperature. In the winter, colder weather means more electricity is used for space heating, and in the summer, warmer weather means more electricity is used for air conditioning. From historical weather data for 20 years, we computed a historical frequency distribution of temperature. We used that historical frequency distribution as the (assumed normal) probability distribution of temperature.

To calculate the effect of weather on demand, we used data published by the IESO on the sensitivity of Ontario load to weather. These data show the effect of weather, as measured by degree days, on total Ontario load. The weather data provided a distribution of weather, and the translation through the IESO information provided a distribution of demand. The IESO data show the effect of weather on load for the entire system. Electricity demand from RPP consumers is likely to be more sensitive to weather than Ontario demand as a whole, because industrial load (which will not be eligible for RPP) is not very responsive to weather. In modeling the variance, we therefore allocated 80% of the weather impact in the winter to RPP consumers; in summer, we allocated 60%. The difference in attribution reflects the fact that commercial consumers are very likely to have air conditioning, and therefore have load that is sensitive to heat, but not very likely to have electric space heating.

Finally, we needed a probability distribution for the HOEP itself. Navigant Consulting's analyses found that the distribution of HOEP is not symmetrical in that it has a large upward tail. This occurs for several reasons. First, the distribution below the mean is truncated because it cannot be negative. Second, prices can rise dramatically above the mean; in Ontario, the maximum market clearing price is $2,000. Finally, events in the electricity supply industry tend to have an asymmetric impact on price; that is, events are more likely to drive price above its mean than below it. For these reasons, we fitted a log normal distribution to the historical HOEP data.

The Effect on Market Price

The diagram and the above discussion indicate that a change in supply or demand conditions can be expected to have an impact on RPP supply cost in two ways: through the impact on the portion of supply to be priced in the IESO-administered markets and through the price in those markets. The impact of the supply amount can be calculated directly. The impact on the market price must be estimated.

For that estimation, Navigant Consulting used econometric techniques. We constructed a single-equation regression model for the HOEP, with electricity demand and supply and natural gas prices in Ontario as the independent variables. The resulting equation fit the data reasonably well. The coefficients of the independent variables were all highly significant and had the expected signs. The equation explained about 60% of the historical variance in the HOEP.

Computing RPP Supply Cost

All of these elements together then allowed calculation of the variance of the RPP supply cost from its expected level. For this calculation, as mentioned, we used a random simulation (Monte Carlo) technique, under which we made independent draws from each of the three probability distributions.

Each set of random draws sampled from the 3 probability distributions to obtain values of supply from the prescribed assets, weather conditions, and market price. Weather conditions were translated into demand impacts, using the information from the IESO. The supply and demand conditions were then translated into a market price, using the structure of the estimated equation.

The quantities of supply available from the prescribed assets determined the supply cost for that portion of the RPP supply, using the Navigant Consulting forecast of cost of the prescribed assets. The cost of RPP supply also included the cost of other contracted supply, from the existing NUGs and from new generation contracted to OPA.

The remainder of supply was obtained in the IESO-administered markets. For the calculation of its cost, we used a weighted average market price. The two components of the market price weighting were the market price calculated from the econometric model and the market price from the random draw of the market price distribution. The weight for the econometric component was roughly equal to the fraction of the total market price variance that the estimation explained; the weight for the remainder of the market price was the fraction of total market price variance that the equation did not explain.

Variance Results

Figure 7 shows the cumulative variance in the first year for all 1000 simulations. Most of the simulations (about 700 of the 1000) have negative variances; that is, they generate variances that consumers will later have to pay. Also shown on this chart are the approximate locations of the variance simulations chosen to represent the 10th, 25th, 50th, 75th, and 90th percentiles of the total variance. These particular simulations were used to test strawman models for the RPP price development.

Figure 7: Cumulative Variances in First Year

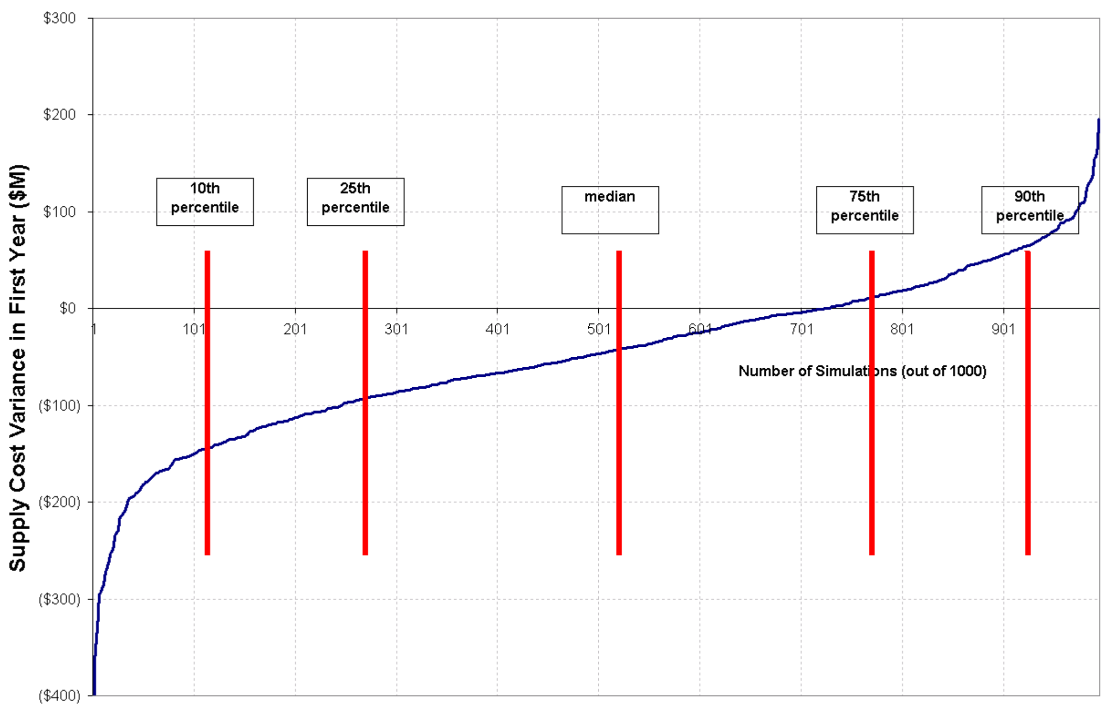


Figure 8 shows the variance for those five simulations. The amounts in the chart are the total variances for the quarter, taken as the arithmetic sum of the three monthly variances. The chart shows that quarterly variances in a range from about $60 million favourable to almost $100 million unfavourable.

Figure 8: Simulations Used in Strawmen Analysis