A REVISED BASIS FOR ESTIMATING THE STANDARD SUPPLY SERVICE REFERENCE PRICE UPON OPENING OF THE RETAIL ELECTRICITY MARKET IN ONTARIO, CANADA

REVISION 1

Prepared for:

The Ontario Energy Board

Prepared by:

Charles River Associates
1201 F Street, NW
Suite 700
Washington, DC 20004
(202) 662-3800

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EXPLANATORY NOTE

The Ontario Energy Board (the Board) retained Charles River Associates (CRA) to review and update the reference price report prepared last summer titled, "A Proposed Basis for Estimating the Standard Supply Service Reference Price Upon Opening of the Retail Electricity Market in Ontario, Canada" (the original report).

The original report is the result of an independent study commissioned by the Board in the spring of last year to propose a methodology to calculate the "reference price." The reference price is the price that small consumers on standard supply service (SSS) will pay until they ultimately are "trued-up" to the spot market price. Effectively, the reference price is a vehicle by which the volatility of the spot market price can be smoothed. At the time of the report, opening of the wholesale and retail electricity markets was targeted for November 2000. The reference price was to be used for up to a year after market opening.

Based on the original report, the Board set a reference price of $42/MWh. Also based on the report, the Board set a ceiling of $51/MWh for distributors who acquire SSS through a third party. Distributors are allowed to seek an exemption from the reference price in order to provide a spot price pass-through directly, so long as certain information is provided regarding consumer notification and equal billing plans are made available to consumers.

Since the report was produced, market conditions have changed. The Minister has announced, "The government is confident that conditions necessary to open Ontario's electricity market to competition will exist by May 2002."[1] The reference price that was calculated by the proposed methodology for the year 2001 may not reflect an updated market situation in Ontario for the year 2002 or more current assumptions about factors that affect the results of the methodology. This report is an update of the original report that incorporates more recent assumptions and reviews the methodology that was adopted for continued relevancy. For consistency, it contains verbatim discussion that continues to apply. Dollar amounts throughout the report are expressed in Canadian dollars, unless stated otherwise.

1 Statement in the Legislature by Jim Wilson, Minister of Energy, Science and Technology, On Electricity Market Opening, April 23, 2001.

1 INTRODUCTION

Standard Supply Service (SSS) is the electricity supply service provided by distributors to customers that do not wish to choose to receive services from a competitive retailer. The Ontario Energy Board (the Board) requested short-term specialized technical consulting services relating to the development of a reference price and an associated price band for third party provision of SSS. The Board engaged Charles River Associates to provide:

- Review of the original report published in June 2000 on this same issue;
- Identification of significant changes in the electricity industry that have occurred since the issuance of the report; and
- An update of the calculation of a reference price for the period following the opening of the market that reflects relevant changes.

In order to accomplish these tasks, Charles River Associates has adapted the structure of the original report and modified it as required. This section introduces the report. Section 2 describes the current state of demand and supply in Ontario. Section 3 summarizes key aspects of the Market Power Mitigation Agreement (MPMA). Section 4 discusses the potential for early decontrol. Section 5 describes a methodological approach for projecting market prices for electricity in Ontario during the first year of market opening. Section 6 updates the prior methodology to calculate the cost of a new entrant under current assumptions. Section 7 presents an alternative methodology to project electricity prices under perfect competition, using a marginal cost pricing model. Section 8 presents recommendations for a reference price and price cap for third party provision of SSS. Section 9 provides final observations.

2 DEMAND AND SUPPLY IN ONTARIO

2.1 Load in Ontario

Ontario load usually peaks in the winter, although the past few years have experienced summer peaking, due to warmer than normal winter and unusually hot summer weather resulting from La Niña and El Niño. The peak of 23,435 MW in July 1999 was the highest summer peak experienced, until this year. A peak of 23,630 MW in June 2001 is now reported as the highest summer peak experienced by the system.[1] The year 2000 was closer to normal, with peak

[1] "Ontario's Electricity Demand Breaks All-Time Summer Record, Bulk System Running Smoothly with Supply to Spare," *Independent Electricity Market Operator News Advisory*, June 27, 2001.

demands in the summer and winter of 23,222 MW and 23,428 MW, respectively.[2] The peak for winter 2001 was 22,672 MW. The highest peak demand in the history of Ontario occurred in January 1994, when demand reached 24,007 MW.

Annual electricity demand in Ontario in the year 2000 was 147.9 TWh. Demand is expected to grow at an annual growth rate of 1.4 percent in 2001 and 1.5 percent in 2002, with an average annual growth rate projected for the next ten years at 1.2 percent.[3] The following table presents projected demand through 2004.

Exhibit 2-1
Projected Demand for Electricity in Ontario

Resource	2001	2002	2003	2004
Total Energy Use (TWh)[4]	149.9	152.1	154.0	156.2
Summer Peak Demand (MW)[5]	22,333	22,611	22,841	23,228
Winter Peak Demand (MW)[6]	23,149	23,731	24,051	24,232

2.2 Generating Capacity in Ontario

Ontario has approximately 30,000 MW of generating capacity. Ontario Power Generation, Inc. (OPG) is the largest generator in Ontario, supplying about 85 percent of electricity consumed in Ontario. OPG owns approximately 80 generating stations, consisting of hydroelectric, nuclear, and fossil plants.[7] Electricity also is produced by non-utility generators (NUGs) under power purchase agreements. Generation assets in Ontario are summarized in the following table.

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2 Independent Electricity Market Operator, "18-Month Outlook: An Assessment of the Adequacy of the Ontario Electricity System," from April 2001 to September 2002, IMO_REP_0013v1.0, April 20, 2001, p. 6.

3 Independent Electricity Market Operator, "10 Year Outlook: An Assessment of the Adequacy of Generation and Transmission Facilities to Meet the Future Electricity Needs in Ontario," January 2002 to December 2011 F&A 2000-1, June 28, 2001, p. 7.

4 Ibid.

5 Ibid, p. 10.

6 Ibid.

7 Ontario Power Generation, www.ontariopowergeneration.com/newgen/powerfacont.asp

Exhibit 2-2
Summary of Generation Resources Assumed Available
(MW)[8]

	Summer Peak 2001	**Winter Peak 2002**	**Summer Peak 2002**
Installed Resources	29,492	29,492	29,492
Imports	700	650	200
Total Resources	**30,192**	**30,142**	**29,692**
Total Reductions in Resources	4,309	3,574	4,557
Available Resources	**25,883**	**26,568**	**25,135**

According to the IMO's report on the Ontario Electricity System, adequate generation resources exist through September 2002. At the beginning of this year, the IMO warned that the possibility of additional generator outages would reduce available resources and reserve margins in May 2001, June 2001 and May 2002.[9] The expected return of one Pickering A unit in early 2002 and an additional unit six months later should provide adequate supply for the Ontario market for electricity to meet the median forecast. In addition, new supply from announced projects should relieve any remaining concerns about tight supply.[10]

In the short run, the effect that supply will have on Ontario's market prices for electricity will depend, in part, on the supply and demand in neighboring jurisdictions. Reserve margins in ECAR (Michigan's NERC region) and NPCC (New York's NERC region) indicate tight markets in the near term, especially in ECAR. However, forecasted margins imply that overall supply conditions are improving in neighboring markets. Reserve margins for Ontario's neighboring NERC regions for 2000 and 2004 are presented in the following tables.

8 Independent Electricity Market Operator, "18-Month Outlook: An Assessment of the Adequacy of the Ontario Electricity System," From April 2001 to September 2002, IMO_REP_0013v1.0, April 20, 2001, p. 11. See notes to Table 3.3.

9 Independent Electricity Market Operator, "18-Month Outlook: An Assessment of the Adequacy of the Ontario Electricity System," From April 2001 to September 2002, IMO_REP_0013v1.0, April 20, 2001, p. 16.

10 Ontario Power Generation, "Electricity Demand and Supply in Ontario: A Report on the State of Electricity Demand and Supply within Ontario in the Period 2000 to 2003," December 1999, p. 12.

Exhibit 2-3
Reserve Margins for NERC Regions Surrounding Ontario[11]
Summer 2000 Reserve Margins

NERC Region	Net Internal Demand (MW)	Planned Capacity Resources (MW)	Reserve Margin (% of Net Internal Demand)
ECAR	94,072	107,451	14.2%
MAAC	49,325	57,831	17.2%
MAIN	47,165	55,984	18.7%
MAPP-US	30,606	35,373	15.6%
NPCC-US	53,450	63,077	18.0%
US Total	**653,856**	**765,949**	**17.1%**

Exhibit 2-4
Reserve Margins for NERC Regions Surrounding Ontario[12]
Summer 2004 Projected Reserve Margins

NERC Region	Net Internal Demand (MW)	Planned Capacity Resources (MW)	Reserve Margin (% of Net Internal Demand)
ECAR	101,230	114,862	13.5%
MAAC	52,406	74,496	42.2%
MAIN	50,567	62,530	23.7%
MAPP-US	31,488	35,399	12.4%
NPCC-US	56,205	79,967	42.3%
US Total	**709,640**	**870,000**	**22.6%**

2.3 Development of New Generation

In Ontario, over 3,000 MW of new generation has been announced. This new generation, in addition to the return of Pickering A to service in 2002 through 2004, the expected return of Bruce A to service in 2003, and performance improvements at Bruce B that may increase generating

[11] *NERC*, 2000 Reliability Assessment: 2000 - 2009, Table 1, p. 12.

[12] Ibid.

capacity by 500 MW,[13] will place Ontario in a capacity surplus position over the next three years. Industry trade journals as well as the IMO have listed new units that have been announced or are under development. These are summarized in the following table.

Exhibit 2-5
Announced Development of New Generation In Ontario[14]

Developer	Location of Plant	Capacity (MW)	Proposed Date of Operation	Status of Project	UnitType / Fuel
Sentinel Power	Sarnia	100	2001	Going Forward / Gas Price Sensitive	Cogeneration (natural gas)
AGSTAR	Tilbury	88	2001	Pending/Market Sensitive	Cogeneration (natural gas)
Toronto Hydro/ Boralex	Toronto Portlands	150	Late 2001	Going Forward / Gas Price Sensitive	Cogeneration (natural gas)
Enron Canada Corp	Sarnia	286	2002	Market Sensitive	Single Cycle
Northland Power Inc	Kirkland Lake	48	2002	Going Forward	Cogeneration (natural gas)
TransAlta	Sarnia	491	2002	Going Forward	Cogeneration (natural gas)
Northland Power Inc.	Thorold	296	2003	Going Forward	Cogeneration (natural gas)
Sithe	Brampton	932	2003	Going Forward/Market Sensitive	Combined cycle gas and steam turbines
ATCO Power Ltd	Windsor	578	2003	Market Sensitive	Combined cycle gas and steam turbines
Calpine Canada Power Holdings	Sarnia	870	2003	Market Sensitive	Combined cycle gas and steam turbines
AES Kingston Inc	Leamington	531	Late 2003	Market & Gas Price Sensitive	Cogeneration (natural gas)
Sithe	Mississauga	763	2004	Going Forward/Market Sensitive	Combined cycle gas and steam turbines
Imperial Oil Ltd	Sarnia	212	2004	Going Forward / Gas Price Sensitive	Cogeneration (natural gas)

Most new additions to capacity are not scheduled for commercial operation until after 2002. As a result, Ontario's internal supply is expected to meet reserve requirements for Ontario, although there is potential for a relatively tight market in the short term. However, the return of the Pickering units in early and mid-2002 will place Ontario in a position of surplus.

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13 "Two Ontario Reactors Get Restart Nod," *The Energy Daily*, Volume 29, Number 68, Friday, April 9, 2001.

14 The Independent Electricity Market Operator, "10 Year Outlook: An Assessment of the Adequacy of Generation and Transmission Facilities to Meet the Future Electricity Needs in Ontario," January 2002 to December 2011 F&A 2000-1, June 28, 2001, p. 12, in addition to application information provided on http://www.theimo.com/imoweb/connAssess/caa_StatusSummary.asp

Since the original study, the development of several of these announced projects has slowed. Reasons cited for the slowdown include uncertainties about the nascent competitive wholesale and retail electricity markets in Ontario, including the date of market opening, the potential for high gas prices, and the ongoing market power of OPG. For example, Enron indicates that it is holding off on building its plant near Sarnia, awaiting Ontario's decision on when to open markets.[15] The Sithe projects continue to be developed for the Greater Toronto Area, but their progress also is dependent on the market opening.[16]

The recent announcement of market opening by May 2002 provides some assurance to investors and stakeholders. In addition, several investors in the plants that are moving forward have offset market uncertainties with other certainties, including load displacement needs that will exist regardless of the date of market start-up. Thus, planned cogeneration plants are most likely to be realized.

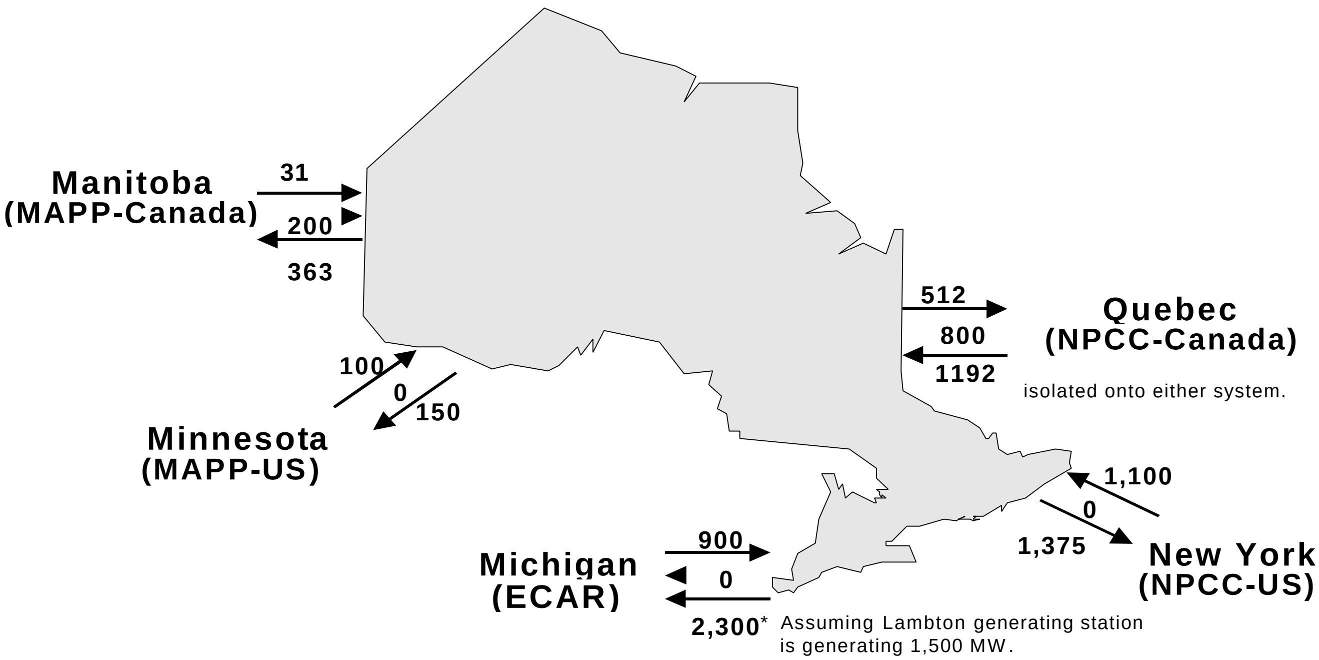
2.4 Transmission Interties Within Ontario and With Other Regions

Competing with generation in Ontario will be generation from neighboring jurisdictions. Ontario's electricity grid is interconnected with the power grids of Manitoba, Quebec and the states of New York, Michigan, and Minnesota. Ontario has 17 interconnection facilities with neighboring provinces and the U.S. Normal energy flows during summer months at these interconnections are represented in the following graph.

15 "Enron Urges Ontario to Open at Retail," *Restructuring Today*, Friday, April 6, 2001.

16 "Move on Power Competition, Ontario Urged," *The Toronto Star*, March 16, 2001.

Exhibit 2-6
NERC 2001 Summer Assessment
Normal Base Electricity Transfer and Incremental Transfer
(MW)[17]



It is clear from the chart above that Ontario has little interconnection capability with Manitoba and Minnesota. Intertie capability with Michigan and New York is much larger. In the past, the connections with Michigan and New York resulted in loop flows by which power flowed through Ontario from New York to Michigan instead of through U.S. transmission systems. This constraint will be reduced in the future when Hydro One, Ontario's transmission provider, completes its Niagara phase shifter project, effectively increasing transmission capability both into and out of Ontario.

Quebec is distinct from other markets connected to Ontario, because Quebec's grid is not synchronized to Ontario's grid.[18] As a result, the interconnection capability simply measures the

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[17] *NERC*, 2001 Summer Assessment: Reliability of Bulk Electricity Supply in North America, May 2001, p. 11.

[18] The Hydro Quebec transmission system operates differently than the Ontario system. Consequently, there are frequency and voltage differences that could lead to outages and damaged equipment if the two systems were interconnected through normal intertie lines. However, a permanent interconnection can achieved through the use of high voltage direct current converter equipment, referred to as "HVDC." This equipment takes alternating current, converts it into direct current and back into alternating current. In doing so, the two systems can be tied together to allow continuous flow of power in both directions.

hydroelectric generating units located in each province that are connected to both grids and can be synchronized to either one. This will change with the planned DC intertie. However, until the DC line is built, other generating units in Quebec will not have the capability to export into Ontario.

There has been discussion related to expanding existing transmission interties to other jurisdictions. To the extent existing interconnection capability is expanded, Ontario market participants may have increased ability to import from, or export to, other electricity markets. However, these expansions are not scheduled to be implemented during the first year after market opening Originally planned for completion in the third quarter of 2002, the project to construct a 1,200 MW DC line to Quebec is in a legal proceeding, resulting in an expected delay in construction beyond 2002. In addition, a proposal to build an underwater line beneath Lake Erie to the United States has not been approved. If approved, this project would not be completed for a few years.

After the Ontario wholesale electricity market opens, it is likely that there will be significant electricity exchanges between Ontario and the U.S. In particular, it is likely that Ontario prices will equilibrate with prices in Michigan (the ECAR NERC region) and New York (the NPCC NERC region) so long as there is available capacity on the interconnection.[19] However, as interconnection capacity becomes filled, price differentials between jurisdictions may persist. Local constraints in the Sarnia/Windsor area also may hinder the balancing of ECAR and Ontario prices. To determine how these constraints would affect Ontario prices requires simulations with a full transmission system model, including identification of local constraints and capacity limits with other jurisdictions. However, other analytical methods can provide useful insights and robust conclusions about interactions between Ontario and its interconnected markets.

Due to the interconnection capability, historic prices in interconnected jurisdictions may provide an indication of what prices might have been in Ontario during the same time period. The following charts show estimated average weekly prices based on *Power Market Week* surveys for ECAR and West NYPP for the period January 1998 through March 2001.

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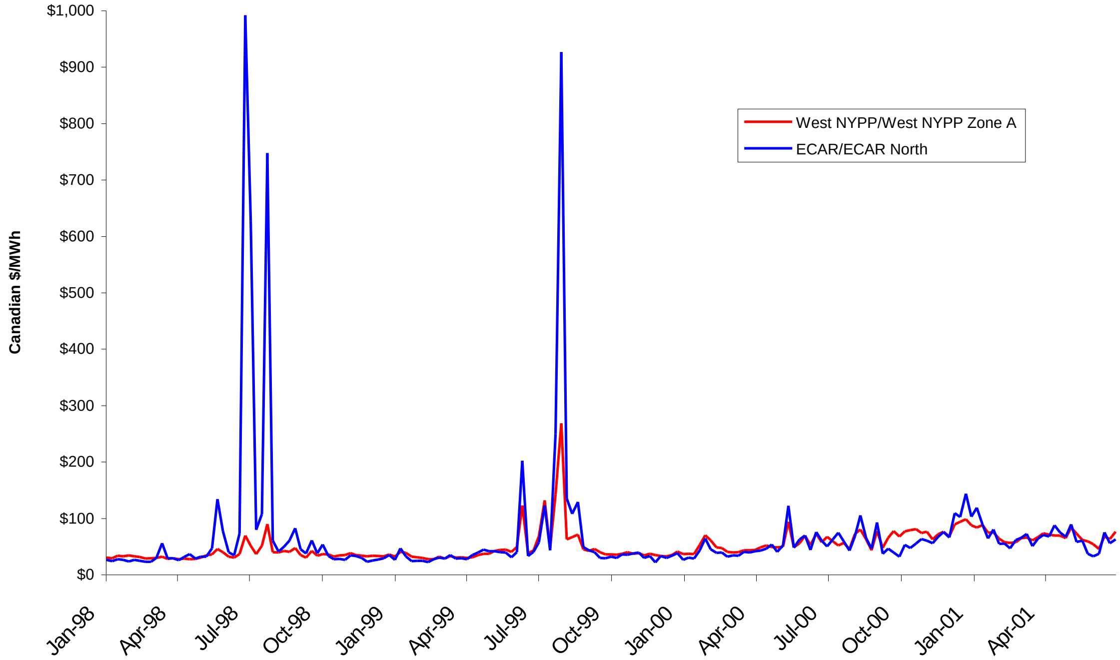
19 Equilibration should reflect energy prices in the other jurisdiction and any wheeling charges required to transmit power to that jurisdiction.

Exhibit 2-7
ECAR/ECAR North and West NYPP
Historical Weekly Average Peak Energy Prices
($/MWh in Nominal Dollars)[20]



Volatility in 1998 and 1999 in the charts above mask the historic averages in the U.S. markets that are interconnected with Ontario. The following table indicates the annual average prices for these electricity markets. The higher average prices in ECAR during 1998 and 1999 reflect the summer price spikes that occurred due to high demand. Recently, electricity prices have not been as volatile. The more recent increase in average electricity prices in New York (West NYPP) reflect the higher gas prices that have been experienced since mid-2000.

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20 *Power Market Week* price index database. Dollars have been converted to Canadian dollars assuming a US Dollar: Canadian Exchange Rate of 1:1.50.

Exhibit 2-8
Historical Annual Average Energy Prices
($/MWh in Nominal Dollars)[21]

Year	**Average Electricity Price**	
	ECAR & ECAR North	**West NYPP**
1998	85.48	36.79
1999	48.28	49.32
2000	41.70	61.11
2001 (through 6/30)	47.99	67.26

Another indication of the impact market prices in other jurisdictions may have in Ontario is the historic level of imports and exports of power scheduled by OPG and the average cost of these power flows. As discussed above, Ontario has large interconnections with New York and Michigan. As a result, power exported to these two jurisdictions accounted for 75 percent of total exports in 1998 and 1999. Power imported from these jurisdictions accounted for almost 75 percent of total imports in 1998 and 50 percent of total imports in 1999.[22] The following table provides more detail on the source and average price of Ontario electricity imports and exports for 1998 and 1999. Information for total scheduled imports and exports are available on a weekly basis for the year 2000, but associated revenues and pricing information is proprietary.

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21 *Power Market Week* price index database. Dollars have been converted to Canadian dollars assuming a US Dollar: Canadian Exchange Rate of 1:1.50. The average is a straight average of the weighted on-peak and off-peak average daily price, and does not reflect volumes traded at each price.

22 Ontario imported an abnormally large volume of electricity from Manitoba in 1999.

Exhibit 2-9
Historical Ontario Electricity Exports and Imports[23]

Interconnected Jurisdiction	1998 Exports	1998 Imports	1999 Exports	1999 Imports
Amount of Power (MWh)				
Manitoba	35,827	473,720	27,738	1,462,895
Michigan	2,025,492	3,556,768	2,136,630	2,513,173
Minnesota	57,119	67,322	236,347	11,067
New York	405,680	1,402,304	1,338,181	754,794
Quebec	699,528	1,166,478	877,804	1,680,245
Total (MWh)	3,223,646	6,666,592	4,616,700	6,422,174
Revenues ($)	98,767,865	123,036,824	200,973,826	182,950,248
Average Price ($/MWh)	**30.64**	**18.46**	**43.53**	**28.49**

There are two items to note about this table. First, OPG historically has exported power at a higher average price than the average price of power imported into Ontario.[24] Second, average prices of imports and exports increased between 1998 and 1999, but were still far below the fully allocated cost of a new entrant.

3 MARKET POWER MITIGATION AGREEMENT

Given OPG's ownership and control of a dominant share of Ontario's generation, a Market Power Mitigation Agreement (MPMA) was negotiated through the combined efforts of the Ontario Government's Market Design Committee, the Ministry of Energy, Science and Technology, the Ministry of Finance, and the former Ontario Hydro. This agreement mitigates OPG's ability to benefit financially from the exercise of market power and potential manipulation of prices. However, it does not prevent OPG from exercising market power to achieve pricing outcomes that are consistent with the terms of the agreement.

23 Docket number RP-1999-0044: Ontario Hydro Network Company Transmission Cost Allocation and Rate Design Proceeding. Ontario Power Generation Responses to Questions from Pollution Probe, Answer to Question 9, Reference: Boland evidence, page 5, question 13, February 3, 2000.

24 The lower average price could reflect a variety of factors, including differences in timing of purchases versus sales, the low marginal cost of power produced by the hydroelectric units that are shared by Ontario and Quebec, and the lack of a transparent market for electricity in ECAR and Ontario.

The MPMA is not a single agreement between parties, but rather a series of legal vehicles that collectively implement the various aspects of the agreement. It has seven components:[25]

1. Licence Conditions on OPG;
2. Licence Conditions on the IMO;
3. Licence Conditions on Ontario Hydro Service Company (OHSC) (i.e., Hydro One);
4. Licence Conditions on other Generators, Wholesale Sellers, and Retailers;
5. Settlement Agreement between the IMO and OPG;
6. Minister's Directive and Referral to the Board; and,
7. Market Rule addressing Local Market Power.

The first and largest component of the agreement consists of licence conditions on OPG. For the first four years after open access begins in Ontario, there is a revenue cap on the commodity supplied by OPG of $38/MWh.[26] OPG's calculated revenues from sales at an average price (AP) above this level would be rebated to Ontario consumers. Under the agreement, OPG has the explicit right to engage in unilateral actions to attempt to maintain hourly prices at levels that will result in the AP equaling the revenue cap. For any settlement period where the AP is greater than $38/MWh, the rebate would equal the difference between the AP and $38/MWh multiplied by the Contract Required Quantity (CRQ). The CRQ is a schedule of hourly energy outputs that OPG is required to supply to the Ontario market.

Licence conditions on distributors, wholesale sellers, and retailers require that the rebates received from the IMO be passed-through to end use customers unless there is an explicit re-assignment of the rebate as part of a contract offer. The MPMA consists of details for the calculation and payment of the rebate. A key aspect of the rebate calculation is the CRQ -- a pre-defined amount of power for which OPG may receive a weighted average price of no more than $38/MWh. OPG is required to reimburse the following amount:

(Average hourly market price weighted by the hourly CRQ amounts - $38/MWh) x CRQ

The manner in which this amount is reimbursed to customers has yet to be determined. Depending on the mechanics of the reimbursement, a customer may receive more or less than the CRQ percentage of total market production. However, on a provincial-wide basis, the cost of the CRQ can be assumed to be $38/MWh.

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25 Market Power Mitigation Detailed Description, www.ontariopowergeneration.com/newgen/mdc.asp

26 The annual average "market price" in the MPMA is weighted by the hourly CRQ quantities. Therefore, the MPMA market price may not be the same as average annual market prices published by the IMO.

For amounts outside of the CRQ, OPG will receive, and customers will pay, the market price for electricity. The weighted average price of the non-CRQ power will depend on how the actual dispatch compares to the CRQ hourly dispatch, and may be calculated by weighting the hourly market price by the total production of OPG's units minus the CRQ for that hour. As already discussed, this measure is not a precise representation of what individual consumers will pay. However, for purposes of setting a benchmark for market prices, one can assume that OPG will try to receive a market price for its power (either through contracts or the spot market) that is at least $38/MWh.

The proportion of total electricity consumed in Ontario that is subject to the $38/MWh price cap depends on total demand. The amount of the CRQ for 2002 is 102 TWh.[27] This amount is not affected by the amount of exports sold by OPG. Total load for the year 2002 is projected to be 152.1 TWh.[28] Thus, the amount of electricity subject to the MPMA in 2002 can be assumed to be approximately 70 percent of total load. The remainder would be purchased at market prices.

Under the MPMA, decontrol within the next four years will affect the amount of the CRQ. The agreement and OPG’s licence stipulate that effective decontrol will reduce the CRQ by 110 percent of the projected generation from the decontrolled unit.[29] To obtain this CRQ adjustment, OPG must apply to the Board for a determination that a particular decontrol action qualifies for CRQ reduction. If the Board determines that effective decontrol is achieved, then OPG receives the CRQ reduction immediately. Thus, to the extent OPG achieves effective decontrol of its units, the CRQ should be adjusted downward accordingly.

4 POTENTIAL FOR EARLY DECONTROL

The MPMA rebate can be reduced by various adjustments. For example, the revenue cap and rebate mechanism could be altered if the IMO decides to implement a capacity market or initiate locational marginal pricing. As already mentioned, effective decontrol of a unit modeled in the CRQ calculation would decrease the CRQ by the projected generation from that unit plus 10 percent. The cap is scheduled to expire four years after market opening, but could be terminated earlier if the OEB determines that the 10-year decontrol target has been met.

The MPMA includes decontrol targets. By 42 months after open access, OPG is required to relinquish control of a minimum of 4,000 megawatts of Tier 2 capacity or enough of its

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27 Presentation by OPG to the Board, March 31, 2000. Specific data for 2002 provided on the IMO website: http://www.iemo.com/imoweb/transInfo/spotmarket.asp

28 Independent Electricity Market Operator, "18-Month Outlook: An Assessment of the Adequacy of the Ontario Electricity System," From April 2001 to September 2002, IMO_REP_0013v1.0, April 20, 2001, p. 5.

29 Market Power Mitigation Detailed Description, www.ontariopowergeneration.com/newgen/mdc.asp

generating output so that its share of the Tier 2 market is not greater than 35 percent.[30] Tier 2 capacity is the transfer capability of the interties, demand-side bidding, and all generation other than hydroelectric and nuclear. Within 10 years after market opening, OPG is required to reduce its capacity in Ontario to 35 percent of total Ontario generating supply.

The MPMA also restricts OPG's ability to import power. OPG is restricted from importing more than 7.24 TWh during the winter months and 6.58 TWh during the summer months.[31] These import limits are increased on the in-service date of new or upgraded intertie facilities. As already discussed, the projected date of expanded interconnections will not affect OPG's import capability within the next two years, but will serve to equilibrate prices in Ontario with the other jurisdictions once in operation. There are no restrictions on OPG's ability to export power.

OPG has announced plans for early decontrol. However, some of the early efforts have been stalled due to uncertainty in the market and the fear that these uncertainties would result in a large discounted value. For example, in December 1998, OPG issued a request for expression of interest pertaining to the sale or renegotiation of its NUG contracts. A request for proposals was issued in 1999. The process was put on hold based on a recommendation from the NUG task force.

In February 2000, Ron Osborne, President and CEO of OPG announced that the company is moving early to "decontrol" 4,000 megawatts (MW) of its generating capacity to encourage competition in the Ontario electricity marketplace.[32] In particular, OPG had targeted roughly 4,000 MW of hydroelectric and fossil generation, including the 2,140 MW Lennox station near Kingston, and 1,140 MW Lakeview station in Mississauga. However, OPG ceased these efforts when the Minister of the Environment placed a moratorium on the sale of coal plants pending the enacting of rules for environmental protection, possibly including gas conversion.[33] Now that the environmental regulations have been passed, OPG continues to examine the investment alternatives and is analyzing whether emissions mitigation equipment would increase the potential return of a sale. OPG's 2000 Annual Report stated an expectation to resume the search for opportunities to decontrol these stations once the review of environmental regulations has been finalized.[34]

In April 2001, Ron Osborne revealed OPG also plans to decontrol six more plants, including Thunder Bay and Atikokan coal-fired plants in Northern Ontario, and four hydro plants

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30 Ibid.

31 Ibid.

32 "Ontario Power Generation Announces Faster Decontrol," February 14, 2000, OPG website: http://www.ontariopowergeneration.com/media/Feb142000spch.asp

33 "Ontario announces environmental moratorium on sale of all coal-fired electricity generation facilities," May 17, 2000, OPG website: http://www.ene.gov.on.ca/envision/news/029.htm

34 OPG Annual Report 2000, http://www.opg.com/investor/ar2000/yir/competition1.htm.

on the Mississagi River, near Sault Ste. Marie.[35] The date of the sale or lease of these plants remains unknown.

OPG has entered into an agreement to lease its Bruce nuclear units to Bruce Power L.P., an entity controlled by British Energy PLC.[36] The leasing agreement is contingent upon market opening. For OPG to receive CRQ reduction, the Board must agree that such an agreement meets the decontrol conditions in the MPMA. Effective decontrol of the Bruce units could have a substantial impact on the CRQ.

It is unclear how decontrol of the Lennox and Lakeview stations would affect the MPMA rebate mechanism. Both plants are peaking units; Lennox generates approximately 379 GWh per year and Lakeview generates approximately 1,608 GWh per year.[37] The combined production is only 2 TWh, less than 2 percent of the amount of generation subject to the MPMA rebate mechanism. Thus, even if OPG decontrols Lakeview and Lennox, and the CRQ can be recalculated to consider this decontrol, the expected effect is not significant.

Thunder Bay, Atikokan and the four hydro plants are considered baseload generating plants. However, the plants' overall capacity is small (approximately 800 MW) and therefore do not considerably affect the CRQ.

Although OPG has announced its expectation to decontrol these plants before market opening, uncertainty associated with the new market and the potential for new environmental regulations to affect the value of these assets has delayed OPG's progress in closing deals.

Lennox is composed of four units fueled by oil and natural gas. Two units were converted in 2000 to be able to burn natural gas in addition to oil. The other two were converted in 1998. Lakeview is fueled by low sulphur coal. The value of these plants will be significantly affected by greenhouse-gas regulations recently proposed in Canada. As already noted, coal plants can not be sold until the moratorium declared by the Minister of the Environment is lifted. The moratorium is scheduled to be lifted following a consultation period that began in mid-March of 2001.

5 REFERENCE PRICE METHODOLOGY

As discussed above, OPG retains control over a significant portion of total generating capacity in Ontario and is not prohibited from exercising market power. Given the rebate

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35 Ontario Power Generation - Reports and Speeches Notes for Remarks of Ron Osborne, President and CEO, to the Empire Club, Toronto, April 26, 2001 http://www.opg.com/media/empire2001.asp; and Tom Blackwell, "Ontario to privatize eight power stations," *The Ottawa Citizen*, April 27, 2001.

36 "Ontario Power Generation Posts Strong Results for 2000," February 7, 2001, OPG website: http://www.ontariopowergeneration.com/media/News/NewsFeb72001.asp

37 "Facts on Lakeview and Lennox Generating Stations," February 14, 2000, OPG website: http://www.ontariopowergeneration.com/media/News/Newsfeb142000backgrd.asp

mechanism in the MPMA, there would be no reason for OPG to let average annual electricity prices as calculated in the MPMA to fall below $38/MWh. Thus, $38/MWh serves as a floor for what average annual market prices for electricity are likely to be. Furthermore, across the Province, in absence of significant changes to CRQ from OPG's decontrol activities, approximately 70 percent of electricity consumption ultimately can be expected to cost $38/MWh once the rebate mechanism is exercised.[38]

Theoretically, OPG has sufficient market power to raise electricity prices to very high levels. However, neighboring jurisdictions are likely to respond to high price signals and fill the intertie capacity with imported power to receive the high prices. Imported power will serve as a mitigating force and should equilibrate prices between markets unless the interties are filled or constrained through localized congestion that would inhibit imports into the greater Ontario region. Also, OPG is unlikely to want price signals that would encourage new entry sooner than is required. As a result, OPG is likely to exercise its market power to allow market prices in Ontario to rise with market prices in neighboring jurisdictions, above $38/MWh, but maintain an average market price in Ontario below the fully allocated cost of a new generator. This is a likely market and bidding strategy, regardless of whether the CRQ to which the $38/MWh is applied is substantially reduced.

The fully allocated cost of a new entrant reflects the average annual electricity price that a new generating unit (assumed to be a combined cycle gas turbine) would require in order to be built. If there is a surplus of supply in Ontario, and market prices are sending the right signal, the average market price should be less than the fully allocated cost of a new combined cycle. If supply-demand balances tighten and new generation is required, the average electricity market prices should exceed the fully allocated cost of a new combined cycle to encourage new generation. Similar logic applies to prices in the markets that are interconnected with Ontario.

As discussed in section 2, the short-term supply of generating capacity in Ontario is relatively tight, although it will loosen substantially when expected capacity comes on line in early- and mid-2002 and 2003. Interconnected jurisdictions face a similar situation with an apparent balance of supply and demand in the short run and increased capacity additions beyond demand growth projected over the next few years. For this reason, electricity prices in Ontario and surrounding jurisdictions are unlikely to exceed the fully allocated cost of a new entrant for several years. Furthermore, while OPG has market power, there is likely to be little incentive for OPG to entice new entrants by setting the average market price higher than the fully-allocated cost of a new combined cycle; thus, market prices are likely to be at or below this level. Therefore, the fully-allocated cost of a new entrant provides a cap on where market prices are likely to be in Ontario in the short to medium term.

The fully allocated cost of a new combined cycle plant can be assessed using a proforma spreadsheet model that incorporates assumptions regarding dispatch of a new entrant, heat rates,

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[38] As discussed above, the actual cost of power for individual customers will depend on the rebate mechanism and the manner in which the rebate is distributed to individual consumers. This amount also may vary with OPG's decontrol efforts, as described later in this report.

gas price projections, O&M costs, capital costs, debt structure, cost of equity and other revenue and cost items. The price for electricity could be set using an iterative process to determine the electricity price at which the net present value of equity cash flows equals zero (discounted at the required return to equity). This electricity price would yield a measure of the fully allocated cost of a new entrant.

6 FULLY ALLOCATED COST OF A NEW ENTRANT

The original report proposed using a fully-allocated cost model for projecting electricity prices in 2001. This approach was consistent with the expected conditions of supply and demand in Ontario and surrounding jurisdictions for the year 2001. Projected surpluses of capacity in Ontario in 2002 makes such an approach less applicable now. However, the same fully-allocated cost model with updated assumptions can be used to establish a ceiling for a projected market price in Ontario.

In a competitive environment, the price of electricity is set by the bid of the last generating unit dispatched. For a developer to commit to a new generating plant, the developer must believe that the revenues the plant will receive for electricity it generates will, over time, be at least equal to the fully allocated costs of the plant. Fully allocated costs include both direct cash costs for fuel and O&M and recovery of and return on capital. The return on capital includes a required return on equity; rational power plant investors would have to expect to earn a minimum rate of return on the equity investment before undertaking the project. The announced plans for new generation indicate that many investors believe that market prices in Ontario will be high enough to support the cost of a new combined cycle plant, although strategic considerations such as load displacement likely provide additional incentive.

For the foreseeable future, combined cycle gas turbine units (CCGTs) are the most cost-effective source of new generating capacity for base and cycling loads in Ontario.[39] Indeed, only plans for gas-fired turbine units have been announced in Ontario. While these units have higher delivered fuel costs than coal units, their initial capital costs are substantially lower than the capital required for a coal-fired unit. Furthermore, the lower heat rate of CCGTs offsets the higher fuel costs; new CCGTs have heat rates in the range of 6,600 to 6,900 Btu per kWh compared with new coal-fired heat rates in the range of 9,000 Btu per kWh. Environmental regulations that require scrubbers on new coal plants also make gas plants more attractive. Therefore, the fully allocated cost of a new CCGT was used to approximate the all-in expected price of electricity that would be received by a new entrant.

39 Gas turbines may continue to be a cost-effective source of peaking capacity. These units combine a very low capital cost with a high variable operating cost. They are well suited for quick starts and operations over the limited number of hours needed to meet daily peak demands. Although the recent gas prices have made them less economic operationally, gas prices are projected to decline.

A projection of the first year electricity price required by a new CCGT is based on a cash flow model of a new CCGT assumed to be put into operation for the year 2002. The assumed characteristics of new CCGTs are presented below. These characteristics described below capture typical financial, cost and operating parameters for new CCGT units.

Exhibit 6-1
Input Assumptions to Cash Flow Analysis of New CCGTs[40]

Parameter	Assumption
Capacity of plant	375 MW
Physical/economic life of plant	30 years
Initial capacity factor	80%
Annual decline of capacity factor	0.5%
Capital cost of CCGT plant built in 2001 (per kW of installed capacity)	$742.36/kW ($2001)
Heat rate of CCGT plant built in 2001	6,600 Btu/kWh
Long-term debt portion of initial capital structure	51%
Life of debt	20 years
Long-term debt rate (nominal)	8.10%
Required rate of return on equity	13.5%
Effective income tax rate (combined federal and provincial)	34.12% in 2001, declining to 30.12% in 2006, and constant thereafter
Annual property taxes as percent of initial capital	1%
Annual insurance as percent of initial capital	0.5%
Capital cost allowance	30% Declining Balance Basis
Annual fixed O&M plus A&G costs (per kW of installed capacity)	$23.46/kW-year ($2001)
Variable O&M costs	$2.25/MWh ($2001)
Average annual inflation rate[41]	2.2 %

Technical assumptions related to the costs and configuration of the new combined cycle gas turbine unit have not changed since the original report was submitted in June 2000. A comparison of output, heat rates, and prices of combined cycle plants as listed in Gas Turbine

40 All costs are in Canadian dollars, converted from US dollars at an exchange rate of $1US:$1.50CAN

41 Average of total inflation (total CPI) in 2001, "TD Quarterly Economic Forecast," TD Economics, March 22, 2001; "Provincial and Sectoral Outlook," Royal Bank, Spring 2001.

World Handbook for 1999-2000 and 2000-2001 shows that there was negligible change, if any, in these characteristics during the past year.

Although technical assumptions remain the same, a few of the financial assumptions have changed. The projected inflation rate in Ontario has decreased by thirty basis points. The corporate income tax rate has been decreased to account for provincial and federal corporate tax rate reductions. The long-term debt rate, which was calculated using a series of corporate bond yields as well as the Canadian 20-year government bond rate, also has decreased. At the time of the initial submission, bond yields were on an upward trend. In the last few months, corporate and government bond yields have steadily decreased. The updated assumptions reflect this decrease by using an 8.10 percent long-term debt rate. A similar decrease was assumed for the required return on equity. However, the model is relatively insensitive to changes in interest rates. Increasing both the long-term debt rate and the required return on equity by 100 basis points increases the fully-allocated cost of a new combined cycle by less than one dollar. Thus, although the debt structure would have a significant effect on the cost recovery period and capital costs, changes in interest rates, holding the debt structure and other technical assumptions constant, has minimal impact.

Charles River Associates performed a cash flow analysis for a new plant coming on line on January 1, 2002. The analysis calculates the projection of electricity prices that the plant would need to cover its costs, including the required rate of return on equity. In and of itself, there is no unique pricing schedule that meets a return on equity target; prices could start low and rapidly increase or start high and decline or remain constant and still meet the target rate return on equity. However, another rule can be imposed that, in combination with the required return on equity, does yield a unique price series. This price series would be used to establish the minimum prices that a developer would expect before committing to build a new CCGT plant.

Charles River Associates used two methodologies to calculate a unique price series. One approach adjusts a single debt-service coverage ratio to provide the new plant with the required return on equity. The second approach assumes electricity price escalation would be at the same rate as gas price escalation and calculates the starting electricity price that would be required to obtain the required return on equity over the life of the project. Each of these is discussed in more detail below.

Methodology 1: Debt Service Coverage Ratio

For each new unit to be built, Charles River Associates estimated the minimum price series that met both a required after-tax target return on equity and an acceptable debt coverage ratio (i.e., EBITDA divided by debt service cost remained constant over life of debt financing). The calculated debt service coverage ratio was compared to a benchmark ratio of 2.25.[42] Accelerated capital cost allowance was assumed for tax purposes and long-term debt payments were calculated

[42] The debt service coverage ratio that would be required by banks will be affected by the characteristics of the loan including the term, the interest rate and debt payment guarantees that are negotiated as part of the financing. A ratio of 2.25 is reflective of the financing assumptions assumed for the new entrant.

based on a fixed mortgage principle payment schedule paid annually. The cash flow analysis for each unit yields a set of annual electricity prices that must be met or exceeded for the plant to earn its required hurdle rate while maintaining an adequate debt service coverage ratio.

Methodology 2: Real Levelized Electricity Price

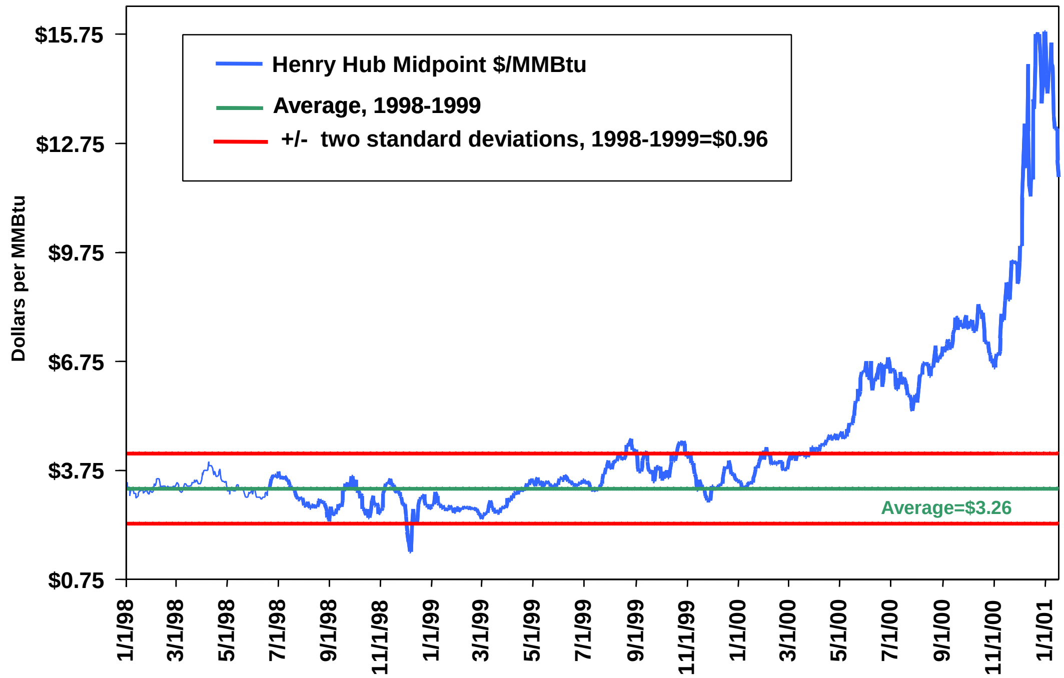
The real levelized electricity price approach sets electricity prices so that they increase at the same rate as gas price escalation. Depending on the trajectory of assumed gas prices, early electricity prices may not provide a plant with sufficient cash flow to meet its desired debt coverage requirements, but higher prices in the later years of operation would make up for the low cash flows in the early years so that the plant still earns its targeted return on equity. Thus, unlike the Debt Service Coverage Ratio approach, coverage ratios required by financing institutions may not be met in the early years, especially if gas prices are projected to decline in real terms.

6.1 Gas Price Projection

A key component of the costs of a new combined cycle is the cost of fuel. To develop a fuel forecast, Charles River Associates used the NYMEX futures prices to establish a base gas price for the year 2001 and subsequent years through 2003. The base price was escalated under various scenarios in accordance with the escalation of NYMEX futures through 2003, then projected forward for the remaining life of the CCGT assuming a constant real gas price.

It should be noted that gas prices increased dramatically during the fall and winter of the year 2000, dropping to more normal levels in the spring and summer of 2001. Since the submission of the original report, prices had increased from approximately $5.25/MMBtu to a high of over $15/MMBtu. Currently, prices are in the $5.00/MMBtu range. It is unlikely that prices would consistently rise at the same rate as this past year or be sustained at the higher average levels of late-2000 and early-2001. Indeed, general consensus of forecasts is that gas prices will decline or remain in the $5.00/MMBtu range to reflect recent drilling activities and decreased demand.

Exhibit 6-2
Henry Hub Daily Spot Prices Compared to Typical Range[43]



Source: Financial Times Energy, Gas Daily

The most updated gas price projection in the industry is the forward price curve at Henry Hub from NYMEX, which extends through early-2004. Longer term forecasts are performed annually and quickly become outdated during periods of increased volatility. Thus, for this report, escalation beyond the NYMEX forecast, must be developed as a scenario, without the benefit of consensus forecasts. This simplification, however, is not necessarily problematic since the proposed methodology for calculating the fully allocated cost of a new entrant is strongly influenced by short-term fuel prices as opposed to long-term projections.

The table below illustrates three potential scenarios for future gas prices. The first scenario assumes that gas prices will change in accordance with NYMEX futures prices through 2003. The low case reduces the NYMEX 2001 starting point by $1.50 per mmBtu; the high case increases the NYMEX 2001 starting point by $1.50 per mmBtu. Escalation through 2003 reflects NYMEX projections, which are relatively flat in nominal terms. Prices after 2003 are assumed to escalate at inflation.

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43 All costs are in Canadian dollars, converted from US dollars at an exchange rate of $1US:$1.50CAN

The assumption of a flat real escalation in the long-term is a simplifying assumption that, as already discussed, does not have a significant effect on the calculation of the fully allocated cost of a new combined cycle in comparison to the short-term assumptions.

Exhibit 6-3
Delivered Natural Gas Price Projection
($Nominal/MMBtu)

	2002 (Base Price)	2005	2010	2015	2020
Scenario 1 – Base Case[44]	**5.99**	**6.22**	**6.89**	**7.64**	**8.48**
Scenario 2 – Low Case	4.40	4.56	5.05	5.59	6.19
Scenario 3 – High Case	7.58	7.87	8.74	9.70	10.77

6.2 Additional Project Value

The electricity pricing methodology described in this section is based on the assumption that developers would expect to earn an appropriate return on their invested capital in the long-term. This approach does not capture short-term congestion, location or regulation rents. Aberrant spikes in electricity prices that may occur because of unexpected outages and limitations on transmission capacity also are not taken into account. Furthermore, no additional value was assigned to having plant capacity available when others either have lost capacity or are unable to meet their short-term obligations. Each of these factors could increase the average price of electricity that would be received by the new entrant.

6.3 Results

Based on the approaches described above, the first-year fully allocated cost of a new combined cycle under the various scenarios is summarized below in the following table.

44 Based on NYMEX Henry Hub gas futures prices for 2001 through 2003 as of June 29, 2001and assumes constant real gas prices thereafter. Delivered Ontario gas prices are assumed to be $0.60/mmBtu higher than Henry Hub prices to account for transportation costs. This estimated transportation cost is different from that assumed by Union Gas, but is consistent with the interjurisdictional marginal cost model used in addition to the fully-allocated cost model.

Exhibit 6-4
First-Year Fully Allocated Cost of a New CCGT
($/MWh)

	Prices Based on Debt Coverage Requirement	Prices Based on Real Levelized Price
Scenario 1 – Base Case	**59.65**	**52.28**
Scenario 2 – Low Case	49.15	41.83
Scenario 3 – High Case	70.15	62.74

Based on the original report, the Board adopted the fully allocated cost of a new CCGT as the cap for standard supply service provided through a third-party. A similar approach can be adopted using these numbers. However, these values must be used with caution. Given the surplus supply conditions in Ontario and surrounding jurisdictions, competitive electricity prices should be less than the fully allocated cost of a new entrant. The amount by which market prices will be below the fully allocated cost of a new combined cycle can be examined using a marginal cost model that considers supply and demand in Ontario and surrounding jurisdictions. This methodology is described in the next section.

Furthermore, the sensitivity of the fully-allocated cost in the gas price scenarios shows that projected gas prices are very important to establishing a credible price cap. If projected gas prices fall, the fully-allocated cost of a new entrant also will fall; higher projected gas prices would imply a higher cost of entry.

In the near term, however, Ontario electricity prices should be somewhat immune to changes in gas prices because: 1) a small percentage of Ontario's capacity is fueled by natural gas; and, 2) Ontario is expected to have excess supply with the expected return of the Pickering units to service, delaying any need for new entry in the near-term.

7 MARGINAL COST MODEL PRICE FORECAST

As already discussed, the fully allocated cost of a new entrant provides a ceiling for an estimate of market prices in Ontario. Capacity surplus in Ontario and surrounding jurisdictions for the year 2002 implies that electricity prices should be below the cost of entry. The amount by which prices may fall short of the cost of new entry can be examined using a marginal cost pricing model.

A marginal cost pricing model establishes prices under the assumption of perfect competition and marginal cost bidding. Although such a model will not reflect strategic bidding behavior by OPG or generators in other jurisdictions, a marginal cost pricing model can provide additional information for purposes of establishing a reference price. This section summarizes the marginal cost analysis of Ontario and surrounding jurisdictions.

7.1 Model Description

Charles River Associates used a production cost model of the Canadian Provinces and the entire United States called the Electric Power Market Model (EPMM) to estimate competitive electricity prices in Ontario and interconnected jurisdictions using marginal costs of production and interconnection capability.

EPMM simulates a competitive market for electric power and determines competitive prices for energy by year, season and time of day, as well as competitive capacity prices by year. EPMM divides the U.S. and Canada into 30 interconnected power markets and determines competitive prices for each region by balancing supplies of, and demands for, electricity by year, season and by time of day, taking into account transmission of electricity from one region or utility to another. Demand reflects the peak demands, energy requirements and hourly load variations specific to each region. Supply includes all existing utility and non-utility generating units, generating facilities under construction and generic, potential new additions. For each type of generating facility, EPMM considers the operating costs and characteristics of the facilities including fuel price, heat rate, equivalent availability, equivalent forced outage rate and annual maintenance requirements as well as relevant environmental regulations.

For each demand period within a year and over the period of analysis, EPMM orders the generating units from lowest to highest cost. It then dispatches the units to meet demands at lowest cost taking into account their operating characteristics. EPMM meets demands in each region in the way that minimizes the present value of the incremental costs in the market (across all of the regions) for the period of analysis. This process provides projections of the prices that would emerge in a competitive power market where generating units are bid in at their marginal cost of production. The energy price set for each load period is the marginal cost of the lowest cost unit available to meet the next increment in demand in that period. In determining when units are used to meet demands, EPMM takes into account limits on unit operations, including forced outage rates, maintenance requirements and equivalent availability and environmental regulations.

7.2 Model Assumptions

Projected demand for Ontario was created using the peak and energy demands from section 2 of this report, together with an historical hourly load shape based on a winter-peaking system.

Capacity and availability of existing generators in Ontario was based on the NPCC's 2001 EIA-411 filing.[45] In addition, we assume that the projects in Exhibit 2-5 with online dates of 2001 or 2002 will be in operation, providing a total of nearly 1,200 MW of new gas-fired capacity.

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45 These capacity values differ slightly from the summary of generation resources assumed by the IMO in its 10-Year Outlook dated June 28, 2001. The values from the EIA filings were adopted in order to be consistent with the assumed capacity in other regions which also comes from the EIA report.

The model assumes that electricity can be transferred to and from Ontario according to the limits specified in the NERC's 2001 Summer and Winter Assessments. The summer and winter limits are shown in Exhibit 7-1.

Exhibit 7-1
Transfer Capabilities Between Ontario and Interconnected Markets
(Winter/Summer MW)

	Destination			
Origin	**Ontario**	**Quebec**	**Upstate New York**	**ECAR**
Ontario	N/A	550/512	1,750/1,375	2,600/2,300
Quebec	1,200/1,192	N/A	1,500/1,500	N/A
Upstate New York	1,800/1,100	1,150/2,200	N/A	N/A
ECAR	2,550/900	N/A	N/A	N/A

Wheeling charges assumed in the model are specified in Exhibit 7-2.

Exhibit 7-2
2002 Wheeling Charges Between Ontario and Interconnected Markets
($/MWh)

	Destination			
Origin	**Ontario**	**Quebec**	**Upstate New York**	**ECAR**
Ontario	N/A	4.96	6.56	4.96
Quebec	4.96	N/A	4.96	N/A
Upstate New York	4.96	4.96	N/A	N/A
ECAR	4.96	N/A	N/A	N/A

Gas prices for Ontario are specified in Exhibit 6-3. Coal prices are assumed to be $2.08 per mmBtu for the Atikokan and Thunder Bay plants, and $2.54 per mmBtu for the remainder of the Ontario coal units.

7.3 Model Results

Load weighted average electricity prices generated by EPMM are shown in Exhibit 7-3. In each of the cases, prices in Western New York and ECAR are significantly higher than prices in Ontario, due to the transmission constraints and wheeling charges between the regions. In addition, projected prices in Western New York and ECAR vary significantly with changes in the gas price assumption, reflecting the larger portion of gas-fired capacity in those jurisdictions compared to Ontario.

Exhibit 7-3
2002 Load-Weighted Average Prices
($/MWh)

Case	Ontario	Western New York	ECAR
Base Case	31.54	43.30	42.98
High Gas Price Case	31.92	51.19	48.01
Low Gas Price Case	30.42	36.44	38.00

7.4 Implications

OPG currently receives a regulated rate of approximately $41/MWh for electricity. As already discussed, the MPMA creates an incentive for OPG to maintain average annual prices at, or above, $38/MWh in order to maximize profits. Given the current arrangements, OPG is unlikely to allow average annual market prices in Ontario to fall below $38/MWh, regardless of the marginal cost of the dispatched units. Thus, electricity prices based on a perfectly competitive market and marginal cost pricing do not provide a good estimate of expected market prices in Ontario.

Although OPG's intended bidding behavior is unknown at this time, it is unlikely that OPG will allow electricity prices in Ontario to exceed the prices in interconnected jurisdictions. Consumers and other stakeholders will be sensitive to inter-jurisdictional price comparisons. Thus, it is unlikely that average prices in Ontario will exceed market prices in interconnected jurisdictions. However, OPG will have the ability and the incentive to allow electricity prices in Ontario to track those in other jurisdictions, regardless of capacity constraints in the interties.

Although OPG does have the incentive to match prices in Ontario with prices in interconnected jurisdictions, OPG is unlikely to allow hourly prices to track significant price spikes in other jurisdictions. In the near-term, OPG's dominant market share gives it the ability to counteract price spikes and avoid the possibility of interventions to protect consumers from price excursions. As a result, average market prices in Ontario are likely to be lower than average prices in interconnected jurisdictions that have experienced dramatic price spikes. Given the state of supply and demand in these interconnected jurisdictions; however, plus the recent history of wellbehaved prices, significant price spikes may be less likely than in previous years, resulting in a close match between Ontario prices and those in interconnected jurisdictions.

8 CONCLUSIONS

The information and analyses described above can be used to develop a reference price and a price cap for third party provision of SSS.

8.1 Reference Price

The original report weighted the fully allocated cost of a new entrant and the MPMA revenue cap price of $38/MWh to develop a reference price for the year 2001. This approach provided a projected average price for what Ontario consumers ultimately would pay for electricity. The analysis ignored the timing of the rebate, effectively assuming that it would be distributed throughout the year.

Since the original report, it has become clear that any MPMA rebate would be distributed on an annual basis, and not throughout the year. As a result, incorporating the rebate into a projection of average market prices for electricity to establish a reference price may create a cash flow dilemma for distributors who are forced to finance the rebate throughout the year. If the rebate is not provided until the end of the year, and average market prices are significantly higher than the revenue cap, distributors may be placed in an unsustainable cash flow situation in which revenues during the year do not cover costs. Removal of rebate from incorporation into the reference price helps to mitigate this potential cash flow tension for distributors, better matching the timing of the rebate with the timing of reimbursement to consumers.[46]

Under the assumption that the rebate will occur annually, and not throughout the year in quarterly or monthly installations, the reference price should be set at a level close to projected prices. Given projected market conditions for the year 2002, electricity prices in Ontario should be lower than the fully allocated cost of a new entrant. Thus, the methodology that was appropriate for projecting average market prices in the year 2001 must be modified to reflect the conditions of surplus capacity in Ontario and surrounding jurisdictions projected for 2002. Use of the fully allocated cost model would overstate expected market prices. The results from EPMM provide a better estimate of projected market prices since it considers supply and demand in Ontario as well as other jurisdictions and the interties through which power may flow.

EPMM projects electricity prices under conditions of perfect competition in Ontario for the year 2002 of approximately $32/MWh. For the reasons discussed above, this price does not reflect

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46 Although use of any smoothing mechanism such as a reference price and a Power Purchase Variance Account may result in cash flow issues throughout the year, those issues will reflect the difference between the projected price for electricity and the actual price of electricity. Under the proposed approach, the timing of the rebate will not contribute to a mismatch between cash flows.

expected prices in Ontario. OPG is unlikely to allow average electricity prices to fall below the MPMA revenue cap of $38/MWh. Furthermore, OPG is incentivised by profit maximizing behavior to allow prices in Ontario to track prices for electricity in interconnected jurisdictions.

During the past two years, average annual electricity prices in ECAR have been less than those in New York. The results from EPMM indicate that average annual prices in ECAR are likely to continue to be lower than those in New York. OPG may allow prices in Ontario to hover between prices in the two jurisdictions, but for political reasons, would be more likely to ensure that average annual electricity prices more closely reflect those in the jurisdiction with lower prices. As a result, ECAR provides a better benchmark for what projected prices in Ontario are likely to be in the year 2002.

Given the logical market behavior by OPG in which Ontario prices are more likely to reflect market prices in other jurisdictions as opposed to marginal cost pricing of Ontario generating units, the recommended reference price is the projected electricity price for ECAR under base case gas price assumptions:

$43/MWh

Since electricity prices in interconnected jurisdictions are dependent upon the gas price assumption, the Board should revisit this recommendation and be prepared to adjust the reference price to reflect any dramatic changes in gas prices between now and market opening.

8.2 Cap Price

In conjunction with the original report, the Board set a price cap for third party supply of SSS at the fully allocated cost of a new entrant. Given projected conditions of supply and demand in Ontario for the year 2002, use of the fully allocated cost of a new entrant to set the price cap is likely to overstate the market value of a fixed price product. However, the fixed price product should be allowed at a price higher than projected market prices.

Third parties that provide standard supply service are required to offer a fixed price with no true-ups. As a result, the electricity product offered by third parties has greater price and quantity risks than a reference price with true-ups. In addition, the higher risk for a retailer that provides third party supply of SSS requires additional effort by the retailer to hedge the fixed price position. Thus, the fixed price charged to consumers is a different product than the spot price pass-through and should be allowed to exceed the projected spot market price for electricity.

Although the fixed price should be higher than the projected spot market price, the Board should ensure that the fixed price allowed to a third party provider of SSS does not create the wrong incentives for the market as a whole. In a market with excess supply, for example, the fixed price for electricity should not exceed the fully allocated cost of a new generating unit. Allowing the third party price to exceed the cost of a new entrant, when a new entrant is not required, could promote the building of unneeded generation capacity. Thus, the fully allocated cost of a new entrant should set the upper bound for a fixed price SSS.

In addition, consideration should be given to the MPMA reimbursement. The fixed price SSS offering may not have any true-ups, not even a true-up to reflect a rebate by OPG. It is possible that the third party supplier would receive the rebate and not be required to pass the rebate through to consumers if this were a contract condition agreed to by the distributor and supplier. If this is the situation, the fixed price allowed to be charged by third parties should not exceed the weighted average of the fully allocated cost and the $38/MWh revenue cap since the retailer's cost to procure power would reflect the $38/MWh revenue cap in addition to the cost to procure fixed price power.

The Board's use of the fully allocated cost as a cap on third party fixed price supply of SSS could be justified for the year 2001 when supply was projected to be tighter. For the year 2002, however, surplus conditions in Ontario and surrounding jurisdictions result in projected market prices at levels much lower than the cost of a new entrant. From a consumer protection standpoint, very serious consideration should be given to how the MPMA rebate, which results in a large portion of power supply being provided at $38/MWh, should be passed through to consumers who receive a fixed price SSS through a third party. At a minimum, the capped price should reflect some portion of power being provided at $38/MWh since a retailer could be assured of obtaining a portion of power at this price from the market. The remainder should be obtained at a price that does not exceed the fully allocated cost of a new entrant.

The amount by which the fully allocated cost should be weighted depends on OPG's decontrol efforts. As discussed above, in the absence of decontrol, approximately 70 percent of total supply in Ontario is expected to be subject to the MPMA rebate. The cost of this power to Ontario consumers or the retailer providing third party SSS, will be on average, $38/MWh. The remaining portion likely would be purchased at full market prices or a negotiated contract price. For the reasons discussed above, the market price should be no more than the fully allocated cost of a new combined cycle and, under a marginal cost pricing model, is projected to be much less.

There may be adjustments in the amount of CRQ that will change the percentage of total generation in Ontario that is expected to be subject to the MPMA rebate. If the Board accepts the lease of the Bruce B units as effective decontrol, the CRQ would have to be adjusted downward to remove the units' projected generation plus a 10 percent credit. Although the lease also decontrols Bruce A, Bruce A is not in the CRQ and thus would not prompt any adjustment to the CRQ amount.

Between 1994 and 1997, the Bruce Nuclear Units averaged 35,234 GWh[47] of annual energy production. To determine the contribution of the Bruce B unit, a ratio of the capacity of the Bruce B and Bruce A was applied to total production. According to the calculation, Bruce B generated 17.7 TWh of electricity. This is consistent with a capacity factor of around 65 percent.[48]

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47 Quick Facts on Bruce Nuclear Power Development http://www.opg.com/media/reports/back_general_2.doc

48 Although Bruce B has been operating recently at capacity factors above 90 percent, the relevant levels of output for CRQ adjustment are in the detailed schedule of individual plant outputs that form part of

After applying the 10 percent credit, it was assumed that 19.5 TWh would be deducted from the CRQ if effective control of the Bruce B unit occurred. Initially, the level of CRQ was estimated to be 102 TWh. After decreasing that range to account for effective decontrol of the Bruce B unit, the CRQ is estimated to be 82.5 TWh. When compared to the total projected load of 152.1 TWh for 2002, the amount of electricity subject to the MPMA can be assumed to be approximately 55 percent of total load. Therefore, approximately 45 percent of electricity will be purchased by consumers at market prices.

Recently, Ontario Power Generation announced the sale or lease of eight power plants in addition to the Bruce B units. They plan to decontrol Thunder Bay, Atikokan, and Lakeview coal-fired plants, the oil-and gas-fired Lennox plant, and four hydro plants on the Mississagi River. If these plants are effectively decontrolled, OPG can apply to have the CRQ adjusted downward. As discussed earlier, the Lennox and Lakeview plants are peaking units and produce 2 TWh annually. Although detailed generation schedules are not available for the other six plants, an assumption of a 75 percent capacity factor on aggregate yields an estimated production that, in combination with the Lennox and Lakeview plants, would reduce the CRQ by approximately 8 TWh. When combined with the 19.5 TWh reduction in the CRQ associated with the decontrol of the Bruce B unit, the overall level of the CRQ could be reduced by 28 TWh through decontrol to 74 TWh. When compared to the total projected load of 152.1 TWh for 2002, the amount of electricity subject to the MPMA could be approximately 50 percent of total load served by a third party provider of SSS.

Weighting each price by the adjusted proportion of generation in the various scenarios results in the following weighted average prices:

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the MPMA. These detailed plant schedules are confidential; therefore, in this report, historical data is used to approximate the potential impact on the CRQ of Bruce B decontrol.

Exhibit 8-1
Potential Caps for Third-Party Standard Supply Service Prices[49]
($/MWh)

		Average OPG Price / Market Price Weighting Percentages		
	Fully Allocated Cost	**68% / 32%**	**55% / 45%**	**49% / 51%**
Scenario 1 – Base Case	**59.64**	**44.93**	**47.74**	**49.04**
Scenario 2 – Low Prices	49.15	41.57	43.02	43.68
Scenario 3 – High Prices	70.15	48.29	52.47	54.39

The Board is responsible for setting the price cap for third party SSS. The table above provides guidance on the level of the cap under various scenarios. As already mentioned, the fully allocated cost of a new entrant could be used to set a cap. However, this price does not reflect the fact that a significant portion of power will be provided to the market at $38/MWh and is available to a retailer that provides third party SSS. Even under the maximum decontrol scenario, approximately 50 percent of power consumed in Ontario will be provided at $38/MWh during 2002. Assuming a retailer can obtain the remaining amount of load at less than the fully allocated cost of a new entrant implies a recommended price cap of approximately:

$50/MWh.

The proposed cap of $50/MWh is slightly less than the price cap set by the Board for the year 2001 of $51/MWh. This lower price cap is consistent with new information that indicates a different situation for Ontario in 2002 as opposed to 2001:

- Gas prices have settled down from their recently high levels, and are projected to remain relatively stable in the near term.
- Ontario is projected to have surplus capacity with new gas-fired generation and the return of Pickering units to service in 2002.
- Projected electricity prices for interconnected jurisdictions under a marginal cost pricing model for 2002 show electricity prices under a high gas price scenario of approximately $49/MWh, and much less under a base case scenario with lower gas prices.

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49 Prices based on the fully allocated cost model calculation of required electricity prices set by EBITDA over debt service.

- Average annual electricity prices in ECAR since 1999 have been less than $50/MWh (even with the recent gas price spikes), and projected supply and demand conditions imply that prices in ECAR will continue to be lower than historic levels.

If the Board does set a price cap for third party supply that incorporates the MPMA revenue cap price of $38/MWh, some accommodation should be made for the cash flow issues that were described above with respect to distributors. Although a third party provider of SSS may be better able to finance a mismatch between revenues and expenditures that results from the annual rebate, the third party may wish to structure the fixed price product so as to include a direct pass through of the rebate to consumers at the end of the year. If the Board chooses to allow such an arrangement, the interim price charged to consumers should not exceed the fully allocated cost of a new entrant, and assurance should be provided that consumers that receive SSS from a third party ultimately will not pay more than the price cap set by the Board.

9 FINAL OBSERVATIONS

Ontario is in the midst of transition from:

- a regulated industry to competitive markets;
- a monopoly generator subject to a market power mitigation agreement to effective decontrol;
- an incumbent generator to new entrants;
- a price spike in gas prices to a potential surplus in the market; and ,
- tight supply to surplus capacity.

As a result, the recommendations in this report, although robust under current conditions, should be revisited if decontrol or gas price conditions change dramatically or market opening is delayed beyond May 2002.

This report provides a basis for setting the reference price and price cap under various scenarios, including different gas prices and different decontrol scenarios. These variables have the most significant influence on the conclusions of this report. The supply and demand balance in interconnected jurisdictions also is critical to understanding market pressures that prices in Ontario will face. Market opening may be nearly a year away. Although the scenario table can serve as a guide to the Board, a review of current conditions should be performed again before the market opens.