Ontario Energy Board Commission de l'énergie de l'Ontario

Ontario

Market Surveillance Panel

REPORT ON AN INVESTIGATION INTO ALLEGATIONS OF WITHHOLDING OF COAL-FIRED GENERATION

Investigation No. 2010-01
August 30, 2011

PUBLIC VERSION

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Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
27th Floor
Toronto ON M4P 1E4
Telephone: (416) 481-1967
Facsimile: (416) 440-7656
Toll Free : 1-888-632-6273

Commission de l'énergie de l'Ontario
C.P. 2319
2300, rue Yonge
27e étage
Toronto ON M4P 1E4
Téléphone: (416) 481-1967
Télécopieur: (416) 440-7656
Numéro sans frais : 1-888-632-6273

Ontario

August 30, 2011

BY COURIER

Ms. Rosemarie Leclair
Chair, Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, Ontario M4P 1E4

Dear Ms. Leclair,

RE: Report on Investigation into Allegations of Withholding of Coal-Fired Generation

As you know, further to a complaint received from a market participant the Market Surveillance Panel (the "Panel") has undertaken an investigation into allegations of withholding of coal-fired generation in the fall of 2009. The investigation has now been completed, and I am pleased to enclose the Report that sets out the Panel's findings. For the reasons set out in the Report, the Panel has concluded that Ontario Power Generation Inc. ("OPG") did not engage in the exercise or abuse of market power over the relevant period.

Prior to finalization of the Report, a draft was provided to OPG for review and comment on matters of factual accuracy and confidentiality. As a result, a redacted version of the final Report has been created for the purposes of public communications.

I understand that, in keeping with the Board's By-law #3, you will transmit the Report to OPG. As required by the Board's By-law #3, I will be providing the confidential and redacted versions of the Report to the Independent Electricity System Operator. It would also be my intention to provide the redacted version of the Report to the complainant.

Please do not hesitate to contact me should you have any questions or wish to discuss the above or the Panel's Report.

Yours sincerely,

Neil Campbell
Chair, Market Surveillance Panel

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REPORT ON AN INVESTIGATION INTO ALLEGATIONS OF WITHHOLDING OF COAL-FIRED GENERATION

1. Introduction

In January 2010, the Market Surveillance Panel ("MSP", or the "Panel") received a complaint from a market participant alleging that Ontario Power Generation Inc. ("OPG") withheld significant amounts of its coal-fired generation capacity in 2009. The Panel has conducted an investigation into the allegations. This report summarizes the complaint, the investigation process and framework, and the Panel's analysis and findings.

2. Summary of Findings

The Panel concludes that OPG's offer strategies for coal-fired generation during the period September – November 2009 did not constitute an exercise of market power. The units in question generally did not have enough lead time to come online on those days where it appeared, on an *ex post* basis, that they would have become economic as tighter supply / demand conditions emerged closer to or in real time.

The Panel also finds that OPG did not engage in any anti-competitive conduct related to coal-fired generation that would constitute an abuse of market power.

The Panel concludes that the negative financial impacts experienced by the complainant in its trading and contracting activities, including on its investments in transmission rights, were not the result of an exercise or abuse of market power by OPG.

The Panel does not make any recommendations related to market design or market participant conduct arising from this investigation.

3. The Complaint

The complainant is a trader that is a market participant authorized to participate in the Ontario wholesale electricity market. The complainant regularly offers to import electricity into or bids to export electricity from Ontario. The complainant also holds transmission rights ("TRs") at selected interfaces and engages in secondary market transactions with other market participants (*e.g.* bilateral contracts related to future electricity prices).

OPG is the operator of all coal-fired generation facilities in Ontario. It is a matter of public record that, to reduce CO_2 emissions in advance of the legislated phase-out of all coal-fired production by 2014, OPG adopted a CO_2 emissions strategy[1] in 2008 in accordance with annual maximum CO_2 emissions levels for 2009 established by resolution of OPG's sole shareholder (the provincial Crown, as represented by the Minister of Energy).[2] It is also well known that output from OPG's coal-fired generation facilities was substantially lower in 2009 than in 2008.

The complainant alleged that OPG withheld capacity at its coal-fired generating units beyond the levels set out in the Shareholder Resolution and that this activity resulted in:

(i) higher hourly Ontario energy prices (HOEP);

(ii) lower export volumes and export congestion levels; and

(iii) negative financial impacts on the complainant, which owned TRs in the export direction at selected interfaces and had bilateral contracts under which it would have benefited from lower energy prices.

While the complainant observed that output from OPG's coal-fired units was lower throughout 2009 than in 2008, the complaint focused primarily on the period from September through November 2009. The Panel therefore focused its analysis on this period (the "Relevant Period").

4. Investigation Process and Framework

4.1 Complaints by Market Participants

The general process applicable to Panel investigations is set out in Ontario Energy Board ("OEB") By-Law #3 (the "MSP By-Law").[3] Under the MSP By-Law, any person that wishes the Panel to conduct an investigation, including one that pertains to the conduct of a market participant, may make a written complaint setting out certain minimum information.[4] The complainant submitted a written complaint which complied with the requirements of this provision.

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[1] "OPG's strategy to meet the 2009 CO_2 emission target", November 28, 2008, available online at http://www.opg.com/safety/sustainable/emissions/carbon.asp; revised January 22, 2009, available online at http://www.opg.com/safety/sustainable/emissions/OPG%20Strategy%20to%20Meet%202009%20CO2%20Emission%20Targets%20Jan%2022.pdf .

[2] Ontario Power Generation Inc. — Resolution of the Sole Shareholder, "Addressing Carbon Dioxide (CO_2) Emissions Arising from the Use of Coal at its Coal-fired Generation Stations, May 16, 2008", available online at http://www.opg.com/about/governance/open/directives.asp (the "Shareholder Resolution") Annual maximum emissions levels have also been set for subsequent calendar years, and strategies to achieve them have been established annually by OPG accordingly.

[3] Ontario Energy Board, By-law #3 — Market Surveillance Panel, January 5, 2005, as amended, available online at: http://www.oeb.gov.on.ca/OEB/_Documents/About%20the%20OEB/OEB_bylaw_3.pdf.

[4] *Ibid.*, s. 5.1.3.

Section 5.1.4(a) of the MSP By-Law states that the Panel may refuse to commence an investigation where it determines that the complaint is "frivolous, vexatious or otherwise not material". Based on the written complaint and on additional information provided by the complainant in response to Panel requests for clarification and elaboration, the Panel concluded that the complaint was not frivolous, vexatious or immaterial. Therefore, and as required by the MSP By-Law, the Panel notified the Chair of the OEB of the Panel's decision to commence an investigation. Also as required by the MSP By-Law, the Panel notified OPG of the commencement of the investigation, and similarly advised the complainant. The commencement of an investigation does not explicitly or implicitly indicate that a market participant has engaged in inappropriate conduct.

4.2 Sources of Information

In addition to analyzing the information and allegations provided by the complainant, the Panel conducted its own extensive analysis using market data available to it as well as simulation studies which are described below. The Panel also obtained supplementary information from OPG and from the complainant. During 2010, as part of its ongoing market monitoring work, the Panel undertook an in-depth examination of the overall operations of the TR market which facilitated subsequent assessment of the aspects of the complaint related to the TR market.[5]

4.3 Analytical Framework

The Panel's mandate includes investigating the conduct of market participants that may constitute an abuse of market power or gaming. The complaint did not involve any allegations of gaming.

In order to determine whether an abuse of market power has occurred, the Panel must assess whether there has been an exercise of market power and, if so, whether the market participant's activities constitute an abuse of market power. The Panel has outlined the analytical framework for such assessments in its *Monitoring Document: Monitoring of Offers and Bids in the IESO-Administered Electricity Markets* (the "MOB Document").[6] The MOB Document identifies the circumstances in which physical or economic withholding by a generator may constitute an exercise of market power, the steps / factors involved in making such an assessment, and the types of conduct which may constitute an abuse of market power. The relevant elements of the MOB Document are discussed in subsequent sections of this report as applicable.

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[5] The results of this examination of the TR market were summarized in the MSP's semi-annual Monitoring Report for the period November 2009 - April 2010, August 30, 2010, available online at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20100830.pdf (the "Winter 2010 Report"), pp. 140-266.

[6] Market Surveillance Panel, Monitoring Document: Monitoring of Offers & Bids in the IESO-Administered Electricity Markets, March 2010, available online at http://www.oeb.gov.on.ca/OEB/Industry/About+the+OEB/Electricity+Market+Surveillance/Monitoring+Offers+and+Bids .

5. Analysis

The Panel began by examining the elements of OPG's CO_2 emissions strategy in detail and also reviewed the supply and demand conditions in the wholesale electricity market during the Relevant Period. Using the MOB Document analytical framework, the Panel then analyzed specific days during which OPG's coal-fired units did not operate. The Panel concluded by considering potential impacts on the TR market.

5.1 OPG's CO_2 Emissions Strategy

Under the Shareholder Resolution, OPG was instructed to meet on a forecast basis CO_2 emissions arising from the use of coal at its coal-fired generating stations[7] of not more than 19.6 mega tonnes ("Mt") for the calendar year 2009 and of not more than 15.6 Mt for the calendar year 2010. OPG was also directed to file with the Minister of Energy (the "Minister"), by no later than November 30th of each of 2008 and 2009, its implementation strategy for meeting these CO_2 emissions limits.[8]

5.1.1 Elements of the CO_2 Emissions Strategy

OPG submitted its CO_2 emissions strategy for 2009 to the Minister on November 28, 2008. The CO_2 emissions strategy consisted of four main elements, two of which were relevant to the Panel's analysis during the Relevant Period;[9] namely, the "planned outage strategy" and the "operating strategy".[10]

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[7] OPG's fleet of coal-fired generating units includes eight units at Nanticoke (each with approximately 500 MW of capacity), four units at Lambton (also approximately 500 MW/unit of capacity), one unit at Atikokan and two units at Thunder Bay. Most of the unit-specific activity examined in the investigation involved the Nanticoke and Lambton units.

[8] See the Shareholder Resolution cited above.

[9] OPG's 2008 emissions strategy is available at: http://www.opg.com/safety/sustainable/emissions/OPG%20Strategy%20to%20Meet%202009%20CO2%20Emission%20Targets.PDF. On November 27, 2009, OPG submitted to the Minister its implementation strategy for CO_2 emissions control for 2010. That strategy, which was implemented after the Relevant Period and therefore is not of direct consequence to this Investigation, indicated that OPG would offer all available coal units into the market on an hourly basis, although the initial offers for units that were not expected to be needed would be above cost. If it were to become apparent that one or more of the units offered above cost would be needed, the applicable offers would be reduced to their normal offer levels. See 'OPG's Strategy to Meet 2010,CO_2 Emission Target', available online at http://www.opg.com/safety/sustainable/emissions/OPG%20Strategy%20to%20Meet%202010%20CO2%20Emission%20Target.pdf

[10] The other elements of the CO_2 emissions strategy were: (a) the "fuel strategy", pertaining to the purchase of coal; and (b) the "offer strategy", consisting of the application of a uniform emission adder to the offers made for all units. The adder was reduced from $7.50/tonne to $1.00/tonne and then to $0.00/tonne early in 2009. It remained at $0.00/tonne throughout the Relevant Period.

Under the "planned outage strategy", certain of the planned outages required by OPG's coal fleet were designated as "CO_2 Outages".[11] They were similar in most respects to planned outages, but had the additional protection of being limited against movement or recall of the unit by the Independent Electricity System Operator ("IESO") to only those situations where system reliability issues exist and the IESO is unable to resolve the problem with other available actions. All of OPG's CO_2 Outages for 2009 were identified to the IESO before the start of the 2009 calendar year. Prior to being designated as CO_2 Outages, each of the applicable outages had already been scheduled as planned outages through the IESO's outage management system (although the duration may have been adjusted).

Under the "operating strategy", certain units were designated in advance to operate as units that would not be offered into the market but would be available on short notice if needed (these "Not Offered But Available" units being referred to as "NOBA" units). For example, NOBA units could be brought online (with required operational lead time) if an operating coal-fired unit was forced out of service, or if the IESO directed a NOBA unit to operate for reliability purposes. The IESO was notified of the number of NOBA units on a monthly basis. Specific NOBA units were identified on a weekly basis, with designations being revised as required to reflect unit conditions.

In addition to implementing its CO_2 emissions strategy, OPG also continued its practice of offering coal-fired units in a manner which attempts to ensure that operating units are scheduled at a relatively high level of capacity utilization before additional units are started. "Available But Not Operating" ("ABNO") units (which are different from the NOBA units) are units offered into the market. If pre-dispatch does not indicate the need for these units, offers are cancelled on an hourly basis for the pre-dispatch hour in which the unit would be unable to start. The Panel's analysis examined the ABNO units as well as the NOBA units and the CO_2 Outages.

5.1.2 Implementation of the CO_2 Strategy

Table 1 below summarizes the number of days in which there were CO_2 Outages, NOBA units and ABNO units during 2009 and during the three-month Relevant Period.

[11] A planned outage is an outage that is planned and intentional. It is required to be scheduled with the Independent Electricity System Operator, and typically reflects planned maintenance. Planned outages are posted on the IESO's website at http://ieso.ca/imoweb/marketdata/gendisreports.asp

Table 1: Coal-Fired Generation Not Offered into the Market
January – December, 2009
(Number of Days)

Designation	2009 Total	September – November 2009
CO_2 Outages	245	89
NOBA Units	139	57
ABNO Units	306	62
Total Unit-Days	690	208
Total Affected Days*	354	91

*Note: The lower number of total "affected days" relative to the total "unit-days" reflects the fact that, on many days, there were multiple coal-fired units not offered into the market.

The Panel reported on OPG's 2009 CO_2 emissions strategy in its Winter 2009 Report, which covered the initial four months of implementation of the strategy. At that point, it was already apparent that the emissions strategy measures likely would not be needed in order to comply with the emissions target limit set out in the Shareholder Resolution (see the demand and supply conditions discussed more fully below). The Panel observed that:

> *In light of extremely low coal production levels so far in 2009, the Panel also questions the need for the continuing use of NOBA's and further CO_2 outages, at least for the remainder of 2009.* [12]

In January 2010, the Panel provided the following further commentary regarding OPG's CO_2 emissions strategy:

> *OPG ended the year approximately 50 percent below its 2009 limit of 19.6 Mt of CO_2 emissions."*

> *"...it is apparent that some NOBA and CO_2 outages occurred on days when prices turned out to be relatively high"*[13]

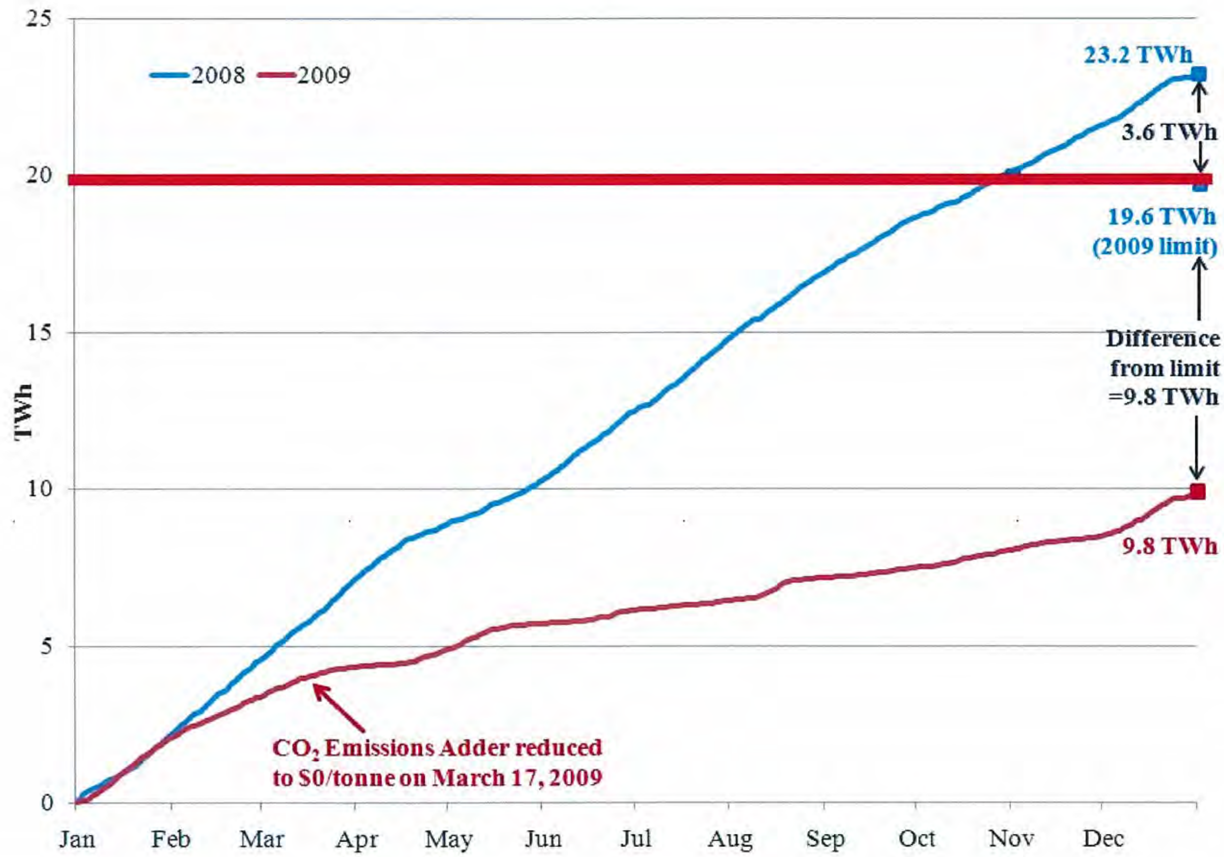
As can be seen from Figure 1 below, for the full 2009 calendar year, OPG's CO_2 emissions from coal-fired generation were roughly 9.8 Mt, or 50% below the target limit for the year set out in

[12] See the MSP's semi-annual Monitoring Report for the period November 2008 – April 2009, July 31, 2009, available online at http://www.oeb.gov.on.ca/OEB/_Documents/MSP/msp_report_200907.pdf (the "Winter 2009 Report"), p. 187.

[13] See the MSP's semi-annual Monitoring Report for the period May – October 2009, January 29, 2010, available online at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/msp_report_201001.pdf (the "Summer 2009 Report"), pp. 63 and 66.

the Shareholder Resolution. By the autumn of 2009 and throughout the Relevant Period, it was readily apparent that OPG no longer required any strategy to limit CO_2 emissions in order to meet the target limit of 19.6 Mt (*i.e.* approximately 19.6 TWh of coal-fired electricity production) for the year.

Figure 1: Coal-Fired Generation Output and CO2 Emissions Limit
January – December, 2008 and 2009
(TWh)



5.2 2009 Market Conditions

5.2.1 Demand

As the Panel noted in its Winter 2009 and Summer 2009 Reports, on a year-over-year basis, Ontario domestic demand declined significantly in 2009 while net exports increased in the early months of 2009 but dropped significantly in late 2009 relative to the corresponding periods in 2008.[14]

This decline in domestic demand and net exports was evident throughout the three-month Relevant Period, compared with the same months in 2008, as can be seen from Table 2 below.

Table 2 – Ontario Demand and Net Exports
September – November, 2008 and 2009
(TWh, Real-Time Unconstrained Schedules)

	Sept-Nov 2008 (TWh)	Sept-Nov 2009 (TWh)	Change	
			(TWh)	(%)
Ontario Demand	35.34	33.35	(1.99)	(5.6)
Net Exports	1.97	1.63	(0.34)	(17.0)
Total Demand	37.31	34.98	(2.33)	(6.2)

5.2.2 Supply

Table 3 below compares total domestic supply by fuel source in the Relevant Period against the same period one year earlier. Domestic supply was 2.33 TWh lower during the Relevant Period than in the same months of 2008, which mirrors the decreased demand shown in Table 2. As a percentage, supply from coal-fired and nuclear generating units during the Relevant Period dropped significantly relative to the prior year, while supply from gas-fired and hydro units increased significantly. A reduction of approximately 4.67 TWh in generation from coal and nuclear resources was offset by a 2.35 TWh increase in output from gas-fired, hydro and other generation units (along with a decline in demand).

[14] See the Winter 2009 Report, pp. 1-2; and the Summer 2009 Report, pp. 2-3.

Table 3 – Total Domestic Supply by Fuel Source September – November, 2008 and 2009 (TWh and %, Real-Time Unconstrained Schedules)

Resource	Sept-Nov 2008		Sept-Nov 2009		Change	
	(TWh)	(% of Total)	(TWh)	(% of Total)	(TWh)	(%)
Nuclear	21.00	56.3	19.78	56.5	(1.22)	(5.8)
Hydro	8.03	21.5	9.01	25.8	0.98	12.2
Coal-Fired	4.87	13.1	1.41	4.0	(3.45)	(71.0)
Gas-Fired	2.81	7.5	3.99	11.4	1.18	42.0
Other Generation	0.60	1.6	0.79	2.3	0.19	31.7
Total Domestic Supply	**37.31**	**100**	**34.98**	**100**	**(2.33)**	**(6.2)**

One of the most significant changes in supply during 2009 was the expansion of gas-fired generation capacity and output. Gas-fired nameplate capacity increased by 1,920 MW, or roughly 40%, compared to 2008. Commissioning of new gas-fired units and periods of relatively low natural gas prices during 2009 contributed to significant increases in gas-fired output and resulted in many hours where gas-fired units were scheduled ahead of coal-fired units.

5.2.3 Generator Cost Guarantees

Throughout the Relevant Period, the IESO's Day-Ahead Commitment Program ("DACP") and its real-time Spare Generation Online Program ("SGOL") (collectively "Generator Cost Guarantees") provided incentives for fossil-fired generators to offer at prices below cost as a result of the cost guarantees being independent of the offer price. As the Panel has previously reported, the structure of the Generator Cost Guarantees allowed these generators to be scheduled at least at minimum production levels for their minimum run times and to be compensated to the extent the revenue from the market was less than their costs.[15]

[15] See the MSP's semi-annual Report for the period November 2006 – April 2007, August 10, 2007, available online at http://www.ontarioenergyboard.ca/documents/msp/msp_report_20070810.pdf (the "Winter 2007 Report"), pp. 114-123. Effective December 9, 2009, the IESO implemented changes to the Market Rules in response to the Panel recommendations related to these inefficient incentives by tightening the cost guarantee eligibility and requiring the operating (but not start-up) portion of cost to be reflected in the offer price. See Market Rule Amendment MR-00356, approved by the IESO Board on September 11, 2009, available online at http://ieso.ca/imoweb/pubs/icms/tp/2009/08/IESOTP_228_4b_Revised_MR_00356_R00_R02_Amendment_Proposal_v5_0_1.pdf. The new rules have reduced but not eliminated the incentives for inefficient offers and dispatch: see the Winter 2010 Report, pp. 128-140.

During the Relevant Period, gas-fired dispatchable generators had total constrained schedule[16] output of 2.96 TWh, of which 0.75 TWh were directly covered by the Generator Cost Guarantees (an increase of 0.44 TWh or 127% from 2008).[17] Unlike many of the gas generators who adopted below-cost offer strategies (often at approximately $0/MWh) to increase the likelihood of being selected for DACP or SGOL operation, OPG generally did not typically offer its coal-fired units at below-cost prices.[18] As a result, various gas-fired units were often scheduled ahead of OPG's coal-fired units, even though this may have been economically inefficient based on relative production costs.[19]

5.2.4 Surplus Baseload Generation

At times, electricity production from baseload generation facilities is greater than market demand (*i.e.* total demand in Ontario plus net exports). In such "Surplus Baseload Generation" ("SBG") situations, the IESO has to take actions to reduce supply.[20] In 2009, there were frequent SBG events, as Figure 2 below depicts. In the Relevant Period, there were 178 SBG hours. In contrast, there were only 7 SBG hours in the same period in 2008. The significant increase in SBG events is another indicator that coal-fired units were much less frequently required to be operating during the Relevant Period.

[16] These numbers are based on total constrained schedules, which differs from the numbers reported in Table 3 that are based on the unconstrained schedules.

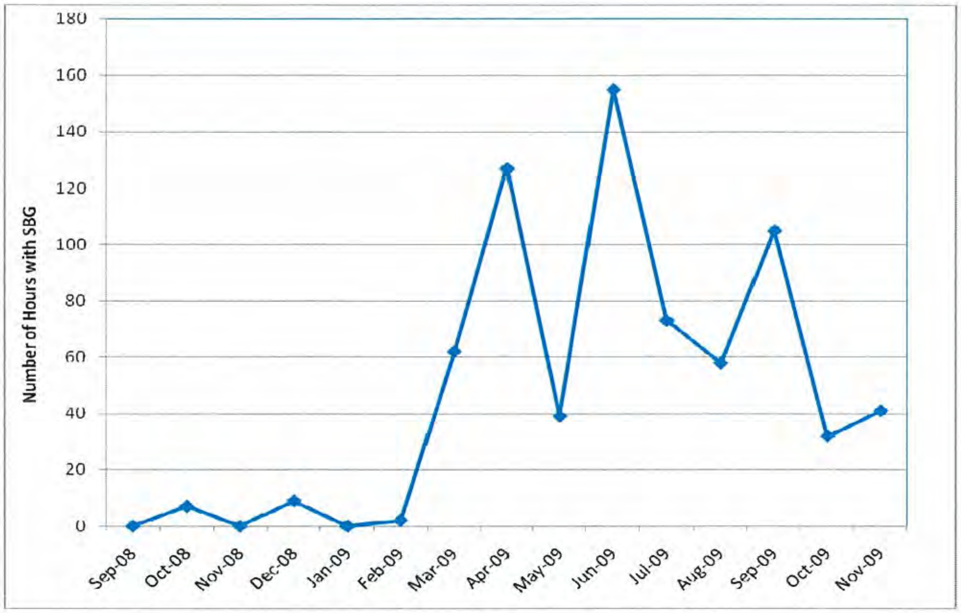
[17] These generators received cost guarantee payments of $29.4 million (compared to $11.5 million in 2008, a 156% increase).

[18] Coal-fired generators had total constrained schedule output of 1.31 TWh in 2009, compared to 4.57 TWh in 2008, a 71% reduction. These units received $• million in cost guarantees for 2009 versus $• million in 2008, a 40% increase.

[19] For an analysis of the dispatch merit order inefficiencies resulting from Generator Cost Guarantees, see the Winter 2007 Report, pp. 114-123.

[20] For a more detailed discussion of SBG, see the Winter 2009 Report, pp. 218-222.

Figure 2: Frequency of Surplus Baseload Generation
September 2008 – November, 2009
(Number of Hours with SBG by Month)



5.2.5 Prices

The demand and supply conditions described above resulted in relatively low average market prices throughout 2009. Table 4 summarizes the HOEP in on-peak and off-peak hours during the Relevant Period as well as the comparable months in 2008. During the Relevant Period, average on-peak HOEP was $31.74/MWh, or $26.34/MWh lower than the corresponding period in 2008. Similar price declines were observed during off-peak hours.

Table 4: HOEP, On-Peak and Off-Peak
September – November, 2008 and 2009
($/MWh)

Hours	Sept-Nov 2008	Sept-Nov 2009	Change	
			$/MWh	%
On-Peak	58.08	31.74	(26.34)	(45.4)
Off-Peak	40.61	20.24	(20.37)	(50.2)
All Hours	48.67	25.55	(23.12)	(47.5)

The Panel regularly reports[21] on the marginal resources which set prices during real time and also the extent to which imports or exports are the marginal resources in the final pre-dispatch sequence.[22] Table 5 lists the percentage of time that a specific type of resource set the pre-dispatch and real-time price in the periods September – November 2008 and 2009. Imports / exports set the final pre-dispatch price 52% of the time from September to November 2009 (down very slightly from 54% of the time in 2008). In real-time, OPG's coal-fired generation set the real-time Market Clearing Price ("MCP")[23] in 36% of the intervals during the Relevant Period compared to 62% of all real-time intervals during the corresponding period in 2008.

Table 5: Price-Setting Resources in Final Pre-dispatch and Real-Time September – November, 2008 and 2009 (% of Pre-Dispatch Hours and Real-Time Intervals)

Resource	Final Pre-Dispatch		Real-Time	
	Sept-Nov 2008	Sept-Nov 2009	Sept-Nov 2008	Sept-Nov 2009
Coal-Fired	34	22	62	36
Gas-Fired	7	20	15	28
Hydro	5	6	23	35
Other Generation	0	0	0	1
Dispatchable Load	0	0	0	0
Imports / Exports	54	52	n/a	n/a
Total	100	100	100	100

5.2.6 Excess Coal-Fired Capacity

The Panel reviewed historic levels of coal-fired capacity and output for the September – November time period. Table 6 below presents a number of coal-related ratios for the Relevant Period and compares those ratios over the corresponding period for the years 2004 to 2008. The terms used are defined as follows:

- **Output:** MWh of electricity produced
- **Total Capacity:** the total installed capacity in Ontario multiplied by the total number of hours in the period.
- **Available Capacity:** the total number of hours in the period multiplied by the total capacity reduced by the MW's of capacity that are on: (1) planned outages (including CO_2 Outages in 2009), (2) forced outages, and (3) deratings. NOBA units and ABNO

[21] See chapter 1 of the Panel's semi-annual monitoring reports.

[22] Imports and exports are scheduled based on the offers and bids in the final pre-dispatch, and are then placed at the bottom of the offer/bid stack in real-time because they are not subject to dispatch during real-time.

[23] Ontario's MCP is set on a five-minute basis. The HOEP is the arithmetic average of the 12 interval MCPs.

units are included in available capacity for 2009 even though they are not online or offered.

- **Online Capacity:** the total number of hours in the period multiplied by the maximum available MW of capacity from synchronized units. It does not include NOBA or ABNO units.

Table 6 indicates that coal-fired output in the Relevant Period was a much smaller fraction of total coal-fired capacity than in prior years, and that this reduction was accompanied by lower available capacity and online capacity in the Relevant Period than in prior years.

Table 6: Coal-Fired Generation Capacity Utilization Ratios September – November, 2004 – 2009 (%)

Year (Sept-Nov)	Output / Total Capacity (A) (%)	Output / Online Capacity (B) (%)	Online Capacity / Available Capacity (C) (%)	Available Capacity / Total Capacity (D) (%)
2004	45	80	96	59
2005	44	80	97	56
2006	39	76	91	56
2007	53	81	98	67
2008	30	68	90	49
Average 2004-2008	**42**	**77**	**94**	**58**
2009	7	48	30	50
Note: A = B * C * D				

Four key points emerge from these capacity ratios:

- The ratio of output to total capacity in 2009 was only 7%, far below the average of 42% in the preceding 5 years, indicating that the vast majority of installed coal-fired capacity was not utilized during the Relevant Period.

- The ratio of output to online capacity in 2009 (48%) was significantly lower than the historical average (77%), implying there was a greater proportion of spare online capacity[24] in the Relevant Period (52%) than in the past (23% on average).

- The ratio of online capacity to available capacity during the Relevant Period was only 30%, much lower than the 94% average in the previous five years. As

[24] Spare online capacity is the difference between the online capacity of units and the actual energy production from those same units. In some instances, spare online capacity may be providing operating reserve (OR), but providing OR is generally not a limiting constraint to providing energy.

detailed below, the decline in this ratio reflected significant NOBA units and ABNO units, especially during off-peak hours.

- The ratio of available capacity to total capacity was slightly lower in the Relevant Period than in most of the preceding five years (50% vs. an average of 58%), which may imply that the CO_2 Outages (which were combined with other planned outages) had a modest impact on the availability of coal-fired capacity in 2009. However, such a conclusion is tenuous as planned and forced outages are lumpy in nature, with the ratio of available capacity to total capacity before the adoption of CO_2 Outages in 2009 ranging from 49% in 2008 to 67% in 2007.

Table 7 provides a more detailed breakdown of the components which explain the difference between total capacity and online capacity for the Relevant Period and the comparable periods in prior years, all expressed as a percentage of total capacity.

Table 7: Online versus Total Coal-Fired Generation Capacity September – November, 2004 – 2009 (% of Total Capacity)

Year (Sept-Nov)	Online Capacity (A)	NOBA Units (B)	ABNO Units (C)	Available Capacity (D)	Planned (including CO_2) Outages (E)	Forced Outages & Deratings (F)
2004	57	n/a	2	59	20	19
2005	54	n/a	2	56	18	26
2006	51	n/a	4	56	26	18
2007	66	n/a	1	67	21	12
2008	44	n/a	5	49	38	12
Average 2004-2008	54	n/a	4	58	25	17
2009	15	18	17	50	40	10
Note: A + B + C = D; and D + E + F = 100 (*i.e.* Total Capacity)						

There are three notable observations from this analysis:

- The percentage of capacity online was only 15% in 2009, which is much lower than in the previous years.
- OPG's planned outages (including CO_2 Outages for 2009) were the highest in 2009, but the forced outages / deratings were the lowest. This is not a surprising observation given that the coal-fired units were not used frequently and thus less likely to have a forced outage / derating.

- About 18% of total capacity was designated as NOBA in 2009, and another 17% of total capacity was not offered into the market (the ABNO units).

5.2.7 Summary

2009 generally, and the Relevant Period in particular, was characterized by lower than historical demand, abundant domestic supply (including increased output from gas-fired generation facilitated by low natural gas prices, unit commissioning and the IESO's Generator Cost Guarantees), recurring SBG events and relatively low market prices. In this context, coal-fired generation output was well below available capacity. This differential took various forms, including approximately equal numbers of NOBA and ABNO units.

5.3 Market Power Assessment

Since the CO_2 Outages and NOBA offer strategy were not in fact necessary to meet the 2009 CO_2 emissions target limit set out in the Shareholder Resolution, the Panel has analysed OPG's coal-fired operating strategy during the Relevant Period in the same manner it would analyze any other alleged withholding of generation capacity. The fact that OPG was not offering a sizeable portion of its coal resources into the market during the Relevant Period is not determinative of whether withholding occurred or whether market power was exercised.

The MOB Document summarizes the framework for assessing whether an exercise of market power has occurred in the wholesale electricity market as follows:

> *Identifying a potential exercise of market power normally requires evidence involving:*
>
> *(i) Conduct – i.e. withholding or pricing-up has occurred;*
>
> *(ii) Price Effect – i.e. the MCP or HOEP has been increased materially; and*
>
> *(iii) Benefit to the Participant – i.e. the market participant involved has profited or otherwise benefited from the conduct.*
>
> *The Panel views these as necessary conditions for finding an exercise of market power. Before concluding that a market outcome is the result of an exercise of market power, however, the Panel also considers any explanation offered by the market participant concerned in respect of the conduct as well as its economic consequences for the market and the participant.*[25]

[25] MOB Document, p. 29.

5.3.1 Conduct Test – Withholding

As indicated in the MOB Document:

> *Withholding creates an artificial scarcity in the market. Withholding leads to a higher market price and thus to a wealth transfer from all consumers to all suppliers in the market during the affected time period. It also results in inefficient dispatch when higher-cost sources of energy are called to market before lower-cost resources. To the extent that loads respond to prices in excess of marginal cost by substituting other forms of energy, or by relocating or foregoing otherwise productive activities, withholding also results in inefficient consumption decisions.*[26]

The complaint focuses on physical withholding of coal-fired generation, which is described as follows in the MOB Document:

> ***Physical withholding*** *is defined as a decision not to offer available and infra-marginal or marginal capacity into the market. Physical withholding usually raises the MCP. Physical withholding normally results in dispatch inefficiency as well (unless the unit withheld is marginal).*
>
> *Physical withholding may or may not be profitable for a supplier. While the supplier foregoes profit on the output it withholds, any other infra-marginal generation it owns receives higher revenues due to the increase in the MCP above the competitive price.*[27]

The Panel assessed whether NOBA or ABNO units represented marginal or infra-marginal generating capacity by considering the price ranges for such units on days when they had been offered into the market.[28] Given the demand and supply conditions discussed above, the NOBA and ABNO units would often have been extra-marginal if offered at prices that reflected their prior operating history. However, there were also many days on which NOBA or ABNO units would have been a source of marginal or infra-marginal supply for a period of time had they been offered at prices comparable to their actual offers during the preceding 30 days (as can be seen from the simulation analysis discussed below).

The Panel also considered the potential impacts of the CO_2 Outages, but decided to focus on the NOBA and ABNO units for several reasons. First, on most CO_2 Outage days (75 out of 91 days), there was at least one NOBA or ABNO unit and the simulations showed considerable unutilized capacity after (and often before) NOBA or ABNO units were factored in. Second, on

[26] MOB Document, pp. 11-12.

[27] MOB Document, p. 12 (footnote omitted).

[28] In making this assessment, the Panel considered gas-fired generating units at the prices they were actually offered, even though these may have been below cost as a result of the Generator Cost Guarantee (DACP and SGOL) programs discussed above.

the 16 CO_2 Outage days where there were no NOBA or ABNO units, the locational shadow prices were so low that the CO_2 Outage units did not appear to be economic. Finally, neither the timing nor the duration of the two CO_2 Outages changed significantly from when the two units were initially identified to the IESO as planned outages in mid-Summer 2008 prior to the creation of the CO_2 Outage designation.[29]

The MOB Document recognizes that the Ontario market design does not allow for three-part offers which separate incremental running costs from start-up and speed-no-load costs.[30] It also recognizes that the Market Rules require that successive output laminations must be offered at increasing rather than decreasing prices, even though costs may fall as the utilization of a generating unit increases.[31] In this market context, the Panel recognizes that generators may offer at prices which allow them to recover their average incremental costs of starting a unit as well as the marginal costs of incremental output.[32]

OPG advised the Panel that the NOBA and CO_2 Outage strategies were motivated by: (i) the desire to run a fewer number of units on an efficient basis at high utilization levels (rather than running many units at or near their Minimum Loading Point (MLP)); (ii) the desire to minimize start-up and shut-down costs; (iii) the operational limitations of thermal units relating to the number of feasible starts per day (typically •) and the time period between starts; and (iv) potential increases in future maintenance costs (between 2009 and the phase-out of coal-fired units by 2014) resulting from more frequent ramping on and off of individual coal-fired units.

OPG provided cost information which demonstrated the impact of the incremental costs of start-ups and the manner in which such costs are related to expected unit output. OPG did not quantify the potential maintenance cost increases but asserted that they were significant. In view of the Panel's analysis of start-up lead times and price impacts (see below), it was not necessary to address the efficient utilization level and potential future maintenance cost issues in greater detail.

5.3.2 Price Effect Test — Simulation Analysis

The Panel regularly uses simulations, which re-run the market schedules for a period of time based on changes in particular inputs, as a method for assessing the impact of the activities of the IESO or a market participant (or of market rules / policy changes) on market outcomes. In order to address the market impact of coal-fired units that were not offered, the Panel ran simulations

[29] The two CO_2 Outages lasted one day longer than they had originally been scheduled to last when submitted to the IESO as planned outages in the summer of 2008.

[30] MOB Document, p. 33 (fn. 34). The Enhanced Day-Ahead Commitment ("EDAC") process to be introduced in the autumn of 2011 will provide for three-part bids; see http://www.ieso.ca/imoweb/edac/edac.asp

[31] See Chapter 7 of the Market Rules, s. 3.4.3.2, which reads: "in any *offer*, the price in each *price-quantity pair* must not decrease as the associated quantity increases".

[32] MOB Document, p. 33. However, as discussed above, the Panel also recognizes that the Generator Cost Guarantees may mitigate some of these costs.

in which offers for NOBA and ABNO units were added into the market schedule using a two-stage process:

- the final pre-dispatch sequence was re-run with the additional NOBA and ABNO unit offers in order to estimate the effect of the additional capacity on net exports (which are scheduled one-hour ahead); and
- the real-time dispatch sequence was then re-run, using the revised net exports determined in pre-dispatch, as well as the additional NOBA and ABNO unit offers, in order to estimate the effect of the additional capacity on total electricity output and the HOEP.

During the Relevant Period (in total 91 days), there were 57 days in which one or more NOBA units were designated and 62 days in which one or more coal-fired units were not offered (ABNO units). Of these, 45 were days with both NOBA and ABNO units.

The simulation requires offer prices for the NOBA and ABNO units.[33] For this purpose, the Panel estimated the offer prices based on the historical 30-day average of offers when the unit in question was last being offered. The offers for the various coal-fired units were quite stable during and in the month prior to the Relevant Period, so it was not considered necessary to test alternative offer price assumptions.

The Panel recognizes that an *ex post* examination of market outcomes including real-time prices would not reflect the information available to a generator when making start-up decisions that have significant lead times. Accordingly, the Panel focused on the information about expected market demand and supply contained in hourly pre-dispatch runs. In its preliminary analysis, the Panel assumed that NOBA or ABNO units would have been brought online if there were indications in the early morning pre-dispatch schedules that they would be economic during the day (typically in the peak periods). More specifically, the specification used was that, at any time between 2:00 am and 8:00 am (HE 3-8), the pre-dispatch locational price for a particular unit had to be greater than its estimated offer price for at least • hours[34] later in the day. Based on this test, there were 59 days[35] in which there was at least one NOBA or ABNO unit appearing to be economic.

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[33] During its preliminary analysis, the Panel conducted multiple simulations based on differing assumptions about the number of NOBA and ABNO units which would have been offered in to the market. Initially, it was assumed that all NOBA units would have offered into the market and stayed online in real-time. The Panel then examined pre-dispatch shadow prices and filtered out those days in which NOBA units would not realistically have been brought online because of low pre-dispatch shadow prices. This approach was then expanded by adding the ABNO units into the simulation on the same basis.

[34] The Minimum Generation Block Run Time ("MGBRT") for OPG's coal-fired units is generally •hours. In order to qualify for the SGOL program, a unit must be economic in the relevant pre-dispatch schedule for half of its MGBRT.

[35] If a •-hour rather than a •-hour test had been used, there would have 61 days (ie. two additional low-priced days in early September).

The pre-dispatch simulation results for the three-month Relevant Period indicated an estimated increase in net exports of 40 GWh (2%) and an estimated decrease in the average final pre-dispatch price of $0.68/MWh (2.3%).

The real-time schedules were then re-run using these simulated pre-dispatch outputs. The results of this preliminary simulation analysis suggested that the combined impact of NOBA and ABNO units being offered during the 59 days would be an estimated increase in total electricity output during the Relevant Period of 106 GWh (8%) and an estimated decrease in the average HOEP of $0.96/MWh (4%).

On many of the NOBA and/or ABNO days, the preliminary simulation showed little or no price effect. The average output and price effects were generated predominantly from 20 hours in 13 days. The Panel provided portions of its preliminary analysis to OPG along with requests for more detailed information about the NOBA and ABNO units on the relevant days, including the actual lead times for such units to come online and ramp up to their minimum loading points.

In response to the Panel's request for information about its offer strategy, OPG indicated that it was attempting to achieve relatively high capacity utilization levels for coal-fired units which were expected to be online during these days before incurring the costs of starting up an additional unit (*eg.* it is more efficient to operate three units near their operating capacities than to start and operate four or more units, some or all of which would be running closer to their minimum loading points). These decisions are made by considering available information including pre-dispatch pre-market prices and output levels for the entire day ahead.

OPG also emphasized that coal-fired units are not quick-start units. They are not designed or operated to cover short duration peaks in demand which can be responded to more efficiently by gas or hydro units (or coal-fired units that are already online but operating below full capacity). If a coal-fired unit is cold (*ie.* has not recently been operating), which was often the case for NOBA and ABNO units during the Relevant Period, the start-up time may be in the vicinity of 7-12 hours. This means that a decision on whether to start the unit, or to treat it as ABNO, must be made up to 7-12 hours ahead of the period in which it might be needed (usually the afternoon peak).

Based on the start-up lead time data provided by OPG for the NOBA and ABNO units for the top 20 hours identified in the preliminary simulation analysis discussed above, and on a detailed review of the actual and simulated pre-dispatch schedules, the Panel concluded that such units did not appear to be economic at the time the decision to bring the unit online needed to be made. In other words, the screen applied in the preliminary analysis (that the unit had to appear to be economic during the pre-dispatch schedules in HE 3-8 for at least • hours later in the day) did not allow enough response time, particularly for cold units.

By way of example, HE 7 on October 6, 2009 was the hour with the largest simulated output and price effect in the preliminary analysis, accounting for $0.11/MWh or 11.5% of the total simulated price impact over the Relevant Period (HE 6 accounted for a further \$0.04/MWh or 4.2% of the simulated price impact). HE 7 was also a high-priced hour that the Panel had reviewed in its Summer 2009 Report, which described in detail various unanticipated forced outages and deratings that led to a price spike in HE 6 and HE 7:

> *Going into October 6th, five coal units were on planned outages, another was on a planned CO_2 outage, and a sixth was designated as being a NOBA unit for the day. The NOBA unit was cold as it had been out for more than a month and pre-dispatch conditions had not indicted* (sic) *a need for the unit.*
>
> ...
>
> *At the beginning of HE 3, a gas-fired generator notified the IESO that one of its units, which was scheduled to start in HE 4, would not be available due to a faulty start-up control card. The IESO accepted its request to start another unit instead, an outage slip was issued for the unavailable unit up to the beginning of HE 5, and offers were modified accordingly. The outage was subsequently extended to the beginning of HE 7. However, the unit was unable to produce in HE 7, despite having been scheduled for 180 MW in the final pre-dispatch run.*
>
> *A steam unit at the same generating facility was expected to start-up in HE 5, but was forced out of service due to a stuck steam check valve leading to uncontrolled rising temperatures. The unit was scheduled for 220 MW in HE 5 and 290 MW in HE 6 but due to the outage, was unable to produce. The unit returned in the middle of HE 7, but was derated to 60 MW as only one gas unit was in service.*
>
> *An additional gas unit started as scheduled in HE 5 but was forced out of service in interval 5 of HE 6 due to boiler problems. This represented a loss of 185 MW in the unconstrained sequence beginning in interval 5 of HE 6 for the remainder of the hour and all of HE 7. In addition, a related combined cycle unit was derated from 185 MW to 126 MW (loss of 59 MW) due to the gas unit outage.*
>
> *In HE 6, interval 10, a coal unit was forced to derate to 125 MW (the unit was scheduled for 469 MW in the unconstrained sequence) due to a boiler feedpump problem. The derating lasted until the middle of HE 7. It led to a shortfall of 341 MW for intervals 10, 11, and 12 of HE 6, which corresponded with the large jump in MCP to \$427.00/MWh in interval 10 from \$41.80/MWh in interval 9. The derating also caused a 225 MW shortfall from the unit's 350 MW pre-dispatch schedule over the first 7 intervals of HE 7. The unit then began to ramp-up again and reached full output at 475 MW in the unconstrained schedule by the end of HE 7.*[36]

[36] Summer 2009 Report, pp. 31-33

Seven hours in advance of HE 6 and HE 7, OPG was offering three coal-fired units at Lambton and three coal-fired units at Nanticoke (in addition to various nuclear and hydroelectric generation). Consistent with its unit commitment optimization strategy, OPG was stacking its offers such that one unit would be scheduled close to full capacity before a second would be dispatched. Based on prevailing conditions seven hours ahead of HE 6 and HE 7, only two units were scheduled in the constrained seven hour ahead pre-dispatch schedule – one at each of the Nanticoke and Lambton stations. Neither unit was scheduled at full capacity for HE 6 or HE 7, and between them they were carrying approximately 300 MW of spare capacity. The highest scheduled offer price in the seven hour ahead pre-dispatch schedule was $•/MWh. For HE 8 through 10 of the same pre-dispatch schedule, the aggregate spare capacity increased to approximately 500 MW. Given that neither unit was scheduled to full capacity in the seven hour ahead pre-dispatch constrained schedule and given that aggregate spare capacity was quite high, OPG concluded there was no reason to start additional coal units. OPG cancelled the offers for HE6 and HE7 as there would have been insufficient lead-time to start the units. In summary, the derating and price spike experienced in HE 6 and 7 was unanticipated and was addressed by other units that could efficiently respond on a rapid basis. It would have been inefficient for the NOBA or the ABNO units to have been brought online based on the information available at the time that decision had to be taken (i.e. seven hours in advance of HE 6 and 7).

More generally, the actual coal-fired generator schedules show that there was a large amount of spare capacity during the 20 hours that were subjected to in-depth review by the Panel. Bringing the NOBA and/or ABNO units online would have further exaggerated the surplus capacity. With more coal-fired units online, each would have been producing at lower output levels, which would increase the average cost per unit. By avoiding the start-up of coal-fired units that were not needed, the total cost of generating a given level of output was reduced.

In summary, the Panel concluded that, in the 20 most significant hours identified in the preliminary analysis, the NOBA and/or ABNO units were not economic to run on the day based on expected market conditions and operational restrictions, particularly the lead time for synchronization.

5.3.3 Benefit to the Participant Test — Financial Implications for OPG

Whether withholding benefits the market participant is a further screen set out in the MOB Document to identify if conduct may constitute an exercise of market power:

> *The usual basis for determining whether conduct benefits the market participant involved is to examine its profit under the actual and competitive market outcomes. This involves comparing the actual profit earned by the supplier on all its energy supplied at the actual MCPs with the estimated profit that the supplier would have earned in the absence of the identified conduct. The additional revenues earned on infra-marginal output and the lost profit on withheld capacity are a starting*

> *point, but any other relevant profit impacts are also considered. In the Ontario market, this could include import or export transactions undertaken by the same market participant (or an affiliate), regulated rates and government contracts applicable to many dispatchable and non-dispatchable generators, secondary market trading / contracting, and payments arising from sources such as the day-ahead commitment process and the constrained schedule.*[37]

Given the Panel's conclusion that there was not a significant price impact resulting from the NOBA and ABNO units during the Relevant Period as discussed above, it was unnecessary to address the benefit to the participant test in a comprehensive manner.

5.3.4 Abuse of Market Power

The MOB Document explicitly distinguishes between an exercise of market power and an abuse of market power:

> *In the Panel's opinion, an abuse of market power entails some action on the part of a market participant (or group of market participants) that lessens or prevents competition. In other words, abuse of market power involves anti-competitive conduct by a firm (or a group of firms acting together). The Panel has adopted this approach because the design of the Ontario market and the Panel's monitoring mandate focus on conduct which is an "abuse", rather than the type of mitigation regimes that have been employed in other jurisdictions.*
>
> ***Anti-competitive conduct** is behaviour that in some way impedes competitive responses to price signals. Exclusionary practices, collusion (bid rigging, price fixing, agreements to withhold capacity, etc.) and predatory pricing (pricing below marginal cost to drive out or discipline competition) are classic examples of anti-competitive activity which could constitute an abuse of market power if engaged in by a firm (or multiple firms) that has (or collectively have) market power.*
>
> ...
>
> *In the absence of supporting anti-competitive conduct the Panel does not regard departures from the competitive norm resulting from unilateral physical or economic withholding or pricing-up as an abuse of market power, even though these actions may be noteworthy from the perspective of the performance and efficiency of the market. In other words, the ability to exercise market power is a necessary but not sufficient condition for finding an abuse of market power.*[38]

[37] MOB Document, p. 31 (footnote omitted).

[38] MOB Document, pp. 42-43 (footnotes omitted).

The Panel did not identify any anti-competitive conduct by OPG which would constitute an abuse of market power. The NOBA and CO_2 Outage strategies were announced in general terms and the much reduced operation of the coal fleet (including the cumulative impact of the ABNO units) was transparent from actual market statistics throughout 2009 including during the Relevant Period.[39] Other generators were able to and did respond with offers (including below-cost offers facilitated by the Generator Cost Guarantees) which competed to be scheduled, as did numerous importers and exporters.

The MOB Document also notes that a repeated exercise of market power could be noteworthy in the absence of anti-competitive conduct:

> *While a systematic exercise of market power is not abuse of market power in the absence of anti-competitive conduct, it will be reviewed to determine whether corrective competitive responses are being impeded by market structure, rules or procedures or other barriers. This could lead to recommendations that the Market Rules or aspects of market design be changed.*[40]

Given the Panel's findings on the price effect test as set out above, the NOBA and ABNO unit offer strategies did not represent a systematic exercise of market power that would warrant any remedial recommendations by the Panel.

5.4 Transmission Rights

The complainant owned TRs for exports at the Michigan interface: • MW in September 2009, and • MW in each of October and November 2009. Its estimated loss (assuming the auction payment for the long-term TR was evenly allocated to each month) was about $•. The complainant also had a bilateral contract on which it lost money during the Relevant Period.

OPG owned about • MW of export TRs at various interfaces (as well as various import TRs) during the Relevant Period. It incurred an estimated loss of $• (again based on allocation of the auction payment for long-term TRs evenly to all three months).

Table 8 summarizes the estimated profits and losses of the complainant and OPG on their TR investments during the Relevant Period.

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[39] On a daily basis the IESO publishes a Generator Planned Outages Report, which provides hourly outage information aggregated by fuel type for the next 14 days and daily aggregated fuel type outage totals for the following 21 days. Generator Planned Outage Reports are available online at: http://www.ieso.ca/imoweb/marketdata/genOutage.asp

[40] MOB Document, p. 43.

Table 8: Transmission Rights, Purchase Costs and Payouts
September – November, 2009
(MW and $ 000)

			September 2009			October 2009			November 2009		
Participant	**From**	**To**	**TR (MW)**	**Received for TR ($000)**	**Paid for TR ($000)**	**TR (MW)**	**Received for TR ($000)**	**Paid for TR ($000)**	**TR (MW)**	**Received for TR ($000)**	**Paid for TR ($000)**
Complaint	**Ontario**	**Michigan**	●	●	●	●	●	●	●	●	●
	Gain (Loss) [(ie. Received - Paid)]				●			●			●
OPG	**Ontario**	**Michigan**	●	●	●	●	●	●	●	●	●
	Ontario	**Minnesota**	●	●	●	●	●	●	●	●	●
	Ontario	**New York**	●	●	●	●	●	●	●	●	●
	Total		●	●	●	●	●	●	●	●	●
	Gain (Loss) [(ie. Received - Paid)]				●			●			●

Given the Panel's findings on the price effect test as set out above, the Panel concludes that the financial outcomes for the complainant and OPG in the TR market and under the complainant's bilateral contract were not affected by an exercise of market power by OPG.

6. Conclusions and Recommendations

The Panel concludes that OPG's NOBA and ABNO unit offer strategies and its CO_2 Outage strategy during the period September – November 2009 did not constitute an exercise of market power. The units in question generally did not have enough lead time to come online on those days where it appeared, on an *ex post* basis, that they would have become economic as tighter supply / demand conditions emerged closer to or in real-time.

The Panel also finds that the NOBA, ABNO and CO_2 Outage strategies did not engage in any anti-competitive conduct related to coal-fired generation that would constitute an abuse of market power.

The Panel concludes that the negative financial impacts experienced by the complainant in its trading and contracting activities, including on its investments in transmission rights, were not the result of an exercise or abuse of market power by OPG.

The Panel does not make any recommendations related to market design or market participant conduct arising from this investigation.