

Board Staff Interrogatory #1(A) for OPG

Interrogatory

Re: Need for Lennox as a Reliability Must Run (“RMR”) Resource

- i. Please file the technical assessment.

Response

- i. The technical assessment conducted by the IESO under the Market Rules which is the basis for entering into the 2008-09 RMR Agreement is located at:

<http://www.ieso.ca/imoweb/pubs/corp2/IESO-Lennox-RMR-2009.pdf>

Board Staff Interrogatory #2(A) for OPG

Interrogatory

Re: Financial Provisions of the RMR Agreement

- i. Please confirm the correctness of the values shown in Table A and make any necessary corrections, with appropriate explanations.
- ii. Please explain the significant differences (42-57%) between "Forecast" and "Actual" values in the "Fixed and Variable Fuel Costs" and "Net Energy Market Settlement" categories for the 1st and 2nd RMR.
- iii. Please provide the "Actual" values for the 3rd RMR Agreement in the attached Table A.
- iv. For the categories shown in Table A, please provide an explanation with supporting documentation, for any significant variation (greater than 10% and greater than \$50,000) between:
 - i. "Forecast" and "Actual" amounts in the 3rd RMR period;
 - ii. "Actual" amounts in the 2nd and 3rd RMR periods;
 - iii. "Forecast" amounts in the 3rd and 4th RMR periods; and
 - iv. "Actual" amounts in the 3rd RMR period and "Forecast" amounts in the 4th RMR period.
- v. Please provide the amount of any performance reward payable under the 3rd RMR agreement for the term of the agreement.

Response

- i. The "TOTAL ESTIMATED PAYMENT" for the 1st RMR was corrected by OPG by rounding it to the nearest thousand dollars, as this is how it was presented in the agreement which was submitted for approval. With the exception of this change, each value in the table was correct to within +/- \$5. As OPG did not produce the table, we cannot explain these minor differences.
- ii. The differences are due to the fact that the IESO dispatched Lennox to produce more energy than had been forecast, thereby increasing the Fixed and Variable Fuel Costs and the Net Energy Market Settlement categories above the forecast amounts.
- iii. See table A below.
- iv. See table B below. Supporting documentation in addition to the explanations provided in Table B consists of numerous spreadsheets and extracts from various systems residing in a number of groups within OPG, and has not been provided as it would be very onerous to collect and organize for presentation. This is made more

complex due to much of the information, such as business planning information, being based on calendar years, whereas the Lennox RMR agreements are based on October to September terms.

- v. The total amount of the performance incentive payable under the 3rd RMR agreement was \$1,562,500.

TABLE A							
Comparison of the 2009 RMR Contract (4th RMR) to the Previous Three RMR Contracts							
	1st RMR		2nd RMR		3rd RMR		4th RMR
Cost Category	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast
<i>Fuel Costs</i>							
Fixed and Variable Fuel Costs	29,625,000	52,148,980	43,183,823	78,600,319	23,881,471	66,879,785	11,586,761
<i>OM&A Costs</i>							
Labour	24,106,000	24,647,591	26,450,067	26,474,892	28,203,833	26,822,746	28,868,029
Energy Markets (fuel purchasing / trading)	215,000	215,000	216,900	216,900	254,800	254,800	275,000
Materials	5,210,000	4,107,836	5,133,287	4,067,558	4,871,972	4,383,326	4,922,645
Other	3,497,000	4,362,119	4,366,952	4,499,734	4,518,123	5,329,874	4,190,259
OEB Approval Process	0	39,208	12,000	20,704	28,000	11,366	12,048
Projects	14,555,000	11,271,646	9,026,000	10,232,308	16,641,000	11,085,804	5,177,206
Corporate Functions at Facilities	1,344,000	1,381,800	1,404,480	1,376,884	1,400,000	1,140,319	1,250,000
Insurance	1,782,000	1,683,024	1,707,224	1,731,413	1,750,000	1,532,586	1,550,000
Property Taxes	1,042,000	2,655,199	2,935,373	2,774,749	3,000,000	2,799,782	2,900,000
<i>IESO Market Costs</i>							
Net Energy Market Settlement for Non-dispatchable Load - CC 101	0	4,684,107	0	3,974,645	0	4,403,778	0
Network Pool Service Charge - CC 650	0	689,094	780,352	677,276	682,856	536,838	527,655
Debt Retirement Charge - CC 752	0	602,959	632,750	613,843	631,151	644,348	728,117
Rural Rate Assistance Settlement Credit - CC 753	0	86,137	90,393	87,692	90,164	92,050	104,017
OPA Administration Charge - CC 754				25,180	18,658	33,887	39,046
IESO Energy Market Administration Charge - CC 9990	0	72,000	85,096	73,349	77,245	73,944	83,704
Uplift	0	227,392	246,078	65,190	221,653	221,977	243,943
<i>Other Costs</i>							
Non-IESO Market Revenue Costs	0		0		0	0	0
Financing Cost on Working Capital	2,976,000	4,668,602	4,043,904	3,445,741	3,700,000	4,472,775	4,500,000
TOTAL ESTIMATED OPERATING COST (O)	84,352,000	113,542,692	100,314,679	138,958,377	89,970,926	130,719,985	66,958,430
MARGIN AMOUNT (M)	1,283,000	1,312,220	1,403,572	1,403,434	1,492,932	1,410,893	1,519,651

TABLE A Cont'd Comparison of the 2009 RMR Contract (4th RMR) to the Previous Three RMR Contracts							
Energy							
Net Energy Market Settlement - CC 100	21,445,000	48,334,799	38,701,645	66,300,639	12,806,898	50,572,691	1,045,786
CMSC for Energy - CC 105	0	4,732,924	0	4,593,843	0	3,551,793	0
Generation Cost Guarantee Payment - CC 133	0	5,089,896	0	4,203,792	0	5,545,848	0
Ancillary							
10 Minute Spinning Reserve Market Settlement Credit - CC 200	3,351,000	420,166	3,451,933	669,913	1,551,973	1,093,058	2,400,000
10 Minute Non-spinning Reserve Market Settlement Credit - CC 202	0	0	0	0	0	0	0
30 Minute Operating Reserve Market Settlement Credit - CC 204	0	654,100	0	693,513	0	1,556,752	0
CMSC for 10 Minute Spinning Reserve - CC 106	0	218,259	0	489,788	0	228,531	0
CMSC for 10 Minute Non-spinning Reserve - CC 107	0	0	0	0	0	0	0
CMSC for 30 Minute Operating Reserve - CC 108	0	316,077	0	974,494	0	406,612	0
Salvage							
Gas Salvage Margin	0	-460,867	0	171,710	0	-205,372	0
Other							
Global Adjustment Settlement Amount - CC 146	0	89,612	0	-383,109	0	-456,012	0
OPG Non-Prescribed Assets Adjustment	0	205,145	0	128,255	0	128,890	0
Other IESO Market Revenues	0	0	0	20,678	0	17,475	0
Non-IESO Market Revenues	0		0	0	0	0	0
Total Estimated Gross Revenues (T)	24,796,000	59,600,111	42,153,578	77,863,516	14,358,871	62,440,265	3,445,786
TOTAL ESTIMATED RETAINED GROSS REVENUE (G) (95% of (T))	23,556,000	56,620,105	40,045,899	73,970,340	13,640,928	59,318,251	3,273,497
TOTAL ESTIMATED PAYMENT (O) + (M) - (G)	62,079,000	58,234,806	61,672,352	66,391,470	77,822,930	72,812,627	65,204,584
MONTHLY PAYMENT [(O) + (M) - (G)]/12	5,173,250		5,139,363		6,485,244		5,433,715

TABLE B				
Explanation of Variances for RMR Contracts				
Variances greater than 10% and greater than \$50k requiring explanations are shaded				
Cost Category	Actual vs Forecast amounts in the 3rd RMR period	3rd RMR period Actual amounts vs 2nd RMR period Actual amounts	4th RMR period Forecast amounts vs 3rd RMR period Forecast amounts	4th RMR period Forecast amounts vs 3rd RMR period Actual amounts
Fuel Costs				
Fixed and Variable Fuel Costs	+\$42,998k, 180%	-\$11,721k, -15%	-\$12,295k, -51%	-\$55,293k, -83%
OM&A Costs				
Labour	-\$1,381k, -5%	+\$348k, 1%	+\$664k, 2%	+\$2,045k, 8%
Energy Markets (fuel purchasing / trading)	-\$0k, 0%	+\$38k, 17%	+\$20k, 8%	+\$20k, 8%
Materials	-\$489k, -10%	+\$316k, 8%	+\$51k, 1%	+\$539k, 12%
Other	+\$812k, 18%	+\$830k, 18%	-\$328k, -7%	-\$1,140k, -21%
OEB Approval Process	-\$17k, -59%	-\$9k, -45%	-\$16k, -57%	+\$1k, 6%
Projects	-\$5,555k, -33%	+\$853k, 8%	-\$11,464k, -69%	-\$5,909k, -53%
Corporate Functions at Facilities	-\$260k, -19%	-\$237k, -17%	-\$150k, -11%	+\$110k, 10%
Insurance	-\$217k, -12%	-\$199k, -11%	-\$200k, -11%	+\$17k, 1%
Property Taxes	-\$200k, -7%	+\$25k, 1%	-\$100k, -3%	+\$100k, 4%
IESO Market Costs				
Net Energy Market Settlement for Non-dispatchable Load - CC 101	+\$4,404k	+\$429k, 11%	-\$0k	-\$4,404k
Network Pool Service Charge - CC 650	-\$146k, -21%	-\$140k, -21%	-\$155k, -23%	-\$9k, -2%
Debt Retirement Charge - CC 752	+\$13k, 2%	+\$31k, 5%	+\$97k, 15%	+\$84k, 13%
Rural Rate Assistance Settlement Credit - CC 753	+\$2k, 2%	+\$4k, 5%	+\$14k, 15%	+\$12k, 13%
OPA Administration Charge - CC 754	+\$15k, 82%	+\$9k, 35%	+\$20k, 109%	+\$5k, 15%
IESO Energy Market Administration Charge - CC 9990	-\$3k, -4%	+\$1k, 1%	+\$6k, 8%	+\$10k, 13%
Uplift	+\$0k, 0%	+\$157k, 241%	+\$22k, 10%	+\$22k, 10%
Other Costs				
Non-IESO Market Revenue Costs	\$0k	\$0k	\$0k	\$0k
Financing Cost on Working Capital	+\$773k, 21%	+\$1,027k, 30%	+\$800k, 22%	+\$27k, 1%
TOTAL ESTIMATED OPERATING COST (O)				
MARGIN AMOUNT (M)				

TABLE B - Continued				
Explanation of Variances for RMR Contracts				
Energy				
Net Energy Market Settlement - CC 100	+\$37,766k, 295%	-\$15,728k, -24%	-\$11,761k, -92%	-\$49,527k, -98%
CMSC for Energy - CC 105	+\$3,552k	-\$1,042k, -23%	\$0k	-\$3,552k
Generation Cost Guarantee Payment - CC 133	+\$5,546k	+\$1,342k, 32%	\$0k	-\$5,546k
Ancillary				
10 Minute Spinning Reserve Market Settlement Credit - CC 200	-\$459k, -30%	+\$423k, 63%	+\$848k, 55%	+\$1,307k, 120%
10 Minute Non-spinning Reserve Market Settlement Credit - CC 202	\$0k	\$0k	\$0k	\$0k
30 Minute Operating Reserve Market Settlement Credit - CC 204	+\$1,557k	+\$863k, 124%	\$0k	-\$1,557k
CMSC for 10 Minute Spinning Reserve - CC 106	+\$229k	-\$261k, -53%	\$0k	-\$229k
CMSC for 10 Minute Non-spinning Reserve - CC 107	\$0k	\$0k	\$0k	\$0k
CMSC for 30 Minute Operating Reserve - CC 108	+\$407k	-\$568k, -58%	\$0k	-\$407k
Salvage				
Gas Salvage Margin	-\$205k	-\$377k, -220%	\$0k	+\$205k
Other				
Global Adjustment Settlement Amount - CC 146	-\$456k	-\$73k, 19%	\$0k	+\$456k
OPG Non-Prescribed Assets Adjustment	+\$129k	+\$1k, 0%	\$0k	-\$129k
Other IESO Market Revenues	+\$17k	-\$3k, -15%	\$0k	-\$17k
Non-IESO Market Revenues	\$0k	\$0k	\$0k	\$0k

TABLE B - Continued				
Explanation of Variances for RMR Contracts				
Explanations are provided in cells where criteria of greater than 10% and greater than \$50k were met	Explain Actual vs Forecast amounts in the 3rd RMR period	Explain 3rd RMR period Actual amounts vs 2nd RMR period Actual amounts	Explain 4th RMR period Forecast amounts vs 3rd RMR period Forecast amounts	Explain 4th RMR period Forecast amounts vs 3rd RMR period Actual amounts
Cost Category				
Fuel Costs				
Fixed and Variable Fuel Costs	Primarily due to actual energy production exceeding the forecast energy production.	Energy production was 33% lower in the 3rd RMR period, and fuel costs were about 15% higher, resulting in moderately lower costs in the 3rd RMR period.	Energy production is forecast to be lower in the 4th RMR period.	Energy production is forecast to be lower in the 4th RMR period.
OM&A Costs				
Labour				
Energy Markets (fuel purchasing / trading)				
Materials	Some expenditures planned as materials were reclassified as other costs			Some expenditures planned as materials were reclassified as other costs
Other	Some expenditures planned as materials were reclassified as other costs	Higher Relocation costs during this contract period		Some expenditures planned as materials were reclassified as other costs
OEB Approval Process				
Projects	Projects completed for less than estimated (\$3M); Projects delayed and deferred (\$1.4M); Projects cancelled (\$1M)		Generator Rotor and Train Unloading Shed were included in 3rd RMR Contract	Generator Rotor and Train Unloading Shed were included in 3rd RMR Contract
Corporate Functions at Facilities	Hiring lag and lower material purchases	Hiring lag and lower material purchases	Revised planning assumptions based on 3rd contract actuals	Hiring lag and lower material purchases
Insurance	Favourable exchange rate - Insurance is paid in US dollars	Favourable exchange rate - Insurance is paid in US dollars	Favourable exchange rate - Insurance is paid in US dollars	
Property Taxes				

TABLE B - Continued				
Explanation of Variances for RMR Contracts				
IESO Market Costs				
Net Energy Market Settlement for Non-dispatchable Load - CC 101	The station consumes energy to maintain its readiness to generate, however that amount is not forecast.	Comparing 3rd RMR to 2nd RMR, HOEP was 6% higher, and 5% more energy was withdrawn. The energy volume variance is within the normal range of station operation.		The station consumes energy to maintain its readiness to generate, however that amount is not forecast.
Network Pool Service Charge - CC 650	Hydro One decreased the demand charge for this service by 17%	Hydro One decreased the demand charge for this service by 17%	The respective forecasts are based on different business assumptions relating to Lennox production. Lower production would also lead to lower peak demand load costs.	
Debt Retirement Charge - CC 752			Charge is based on load consumed by Lennox GS at a fixed rate. As Lennox production decreases, an increased amount of station supply load must be supplied from the grid.	Charge is based on load consumed by Lennox GS at a fixed rate. As Lennox production decreases, an increased amount of station supply load must be supplied from the grid.
Rural Rate Assistance Settlement Credit - CC 753				
OPA Administration Charge - CC 754				
IESO Energy Market Administration Charge - CC 9990				
Uplift		These costs are based on market conditions which are difficult to forecast.		

TABLE B - Continued				
Explanation of Variances for RMR Contracts				
Other Costs				
Non-IESO Market Revenue Costs				
Financing Cost on Working Capital	Fuel Costs have increased resulting in higher inventory values	Fuel Costs have increased resulting in higher inventory values	Fuel Costs have increased resulting in higher inventory values	
TOTAL ESTIMATED OPERATING COST (O)				
MARGIN AMOUNT (M)				
Energy				
Net Energy Market Settlement - CC 100	Energy production was higher than forecast	Energy production was lower in the 3rd RMR period	Energy production is forecast to be lower in the 4th RMR period	Energy production is forecast to be lower in the 4th RMR period
CMSC for Energy - CC 105	Historically OPG does not forecast these costs at the station level for business planning purposes or for the RMR submissions. These costs are based on market conditions which are difficult to forecast.	These costs are based on market conditions which are difficult to forecast.		Historically OPG does not forecast these costs at the station level for business planning purposes or for the RMR submissions. These costs are based on market conditions which are difficult to forecast.
Generation Cost Guarantee Payment - CC 133	Historically OPG does not forecast these costs at the station level for business planning purposes or for the RMR submissions. These costs are based on market conditions which are difficult to forecast.	These costs are based on market conditions which are difficult to forecast.		Historically OPG does not forecast these costs at the station level for business planning purposes or for the RMR submissions. These costs are based on market conditions which are difficult to forecast.

TABLE B - Continued				
Explanation of Variances for RMR Contracts				
Ancillary				
10 Minute Spinning Reserve Market Settlement Credit - CC 200	Energy production was higher than forecast, such that the generators were available less often to provide this service	Energy production was lower in the 3rd RMR period, so the generators were available more often to provide this service	Revised planning assumptions based on 3rd contract actuals	4th RMR forecast assumes less energy production than occurred in the 3rd RMR period, so generators would be available more often to provide this service
10 Minute Non-spinning Reserve Market Settlement Credit - CC 202				
30 Minute Operating Reserve Market Settlement Credit - CC 204	OPG does not forecast OR revenues as per the 3 categories of OR at the station level for business planning purposes. All OR revenues were forecasted in aggregate and included in the 10 minute spinning reserve category which is the main OR product supplied by Lennox.	Energy production was lower in the 3rd RMR period, so the generators were available more often to provide this service.		OPG does not forecast OR revenues as per the 3 categories of OR at the station level for business planning purposes. All OR revenues were forecasted in aggregate and included in the 10 minute spinning reserve category which is the main OR product supplied by Lennox.
CMSC for 10 Minute Spinning Reserve - CC 106	Historically OPG does not forecast these revenues at the station level for business planning purposes or for the RMR submissions. These revenues are based on market conditions which are difficult to forecast.	These revenues are affected by market conditions which vary over time.		Historically OPG does not forecast these revenues at the station level for business planning purposes or for the RMR submissions. These revenues are based on market conditions which are difficult to forecast.
CMSC for 10 Minute Non-spinning Reserve - CC 107				
CMSC for 30 Minute Operating Reserve - CC 108	Historically OPG does not forecast these revenues at the station level for business planning purposes or for the RMR submissions. These revenues are based on market conditions which are difficult to forecast.	These revenues are affected by market conditions which vary over time.		Historically OPG does not forecast these revenues at the station level for business planning purposes or for the RMR submissions. These revenues are based on market conditions which are difficult to forecast.

TABLE B - Continued				
Explanation of Variances for RMR Contracts				
Salvage				
Gas Salvage Margin	Historically OPG does not forecast these costs at the station level for business planning purposes or for the RMR submissions. These costs are based on market conditions which are difficult to forecast.	This represents the aggregate of several gas salvage transactions, which in total are minute compared to the total fuel cost.		Historically OPG does not forecast these costs at the station level for business planning purposes or for the RMR submissions. These costs are based on market conditions which are difficult to forecast.
Other				
Global Adjustment Settlement Amount - CC 146	Historically OPG does not forecast these amounts at the station level for business planning purposes or for the RMR submissions. These amounts are based on market conditions which are difficult to forecast.	These amounts are affected by market conditions which vary over time and are difficult to forecast.		Historically OPG does not forecast these amounts at the station level for business planning purposes or for the RMR submissions. These amounts are based on market conditions which are difficult to forecast.
OPG Non-Prescribed Assets Adjustment	Historically OPG does not forecast these costs at the station level for business planning purposes or for the RMR submissions. These costs are based on market conditions which are difficult to forecast.			Historically OPG does not forecast these costs at the station level for business planning purposes or for the RMR submissions. These costs are based on market conditions which are difficult to forecast.
Other IESO Market Revenues				
Non-IESO Market Revenues				

Board Staff Interrogatory #3(A) for OPG

Interrogatory

Re: Interim Payment Arrangement

- i. Please advise what payments, if any, have been or are planned to be made by the IESO to OPG in relation to Lennox as of the date of expiry of the 3rd RMR Contract (September 30, 2008), as well as the basis on which those payments have been or are intended to be made.

Response

- i. The table below identifies the payments made by the IESO to OPG after September 30, 2008 and the basis on which they were made.

These payments were required under the terms of the 2007-08 Lennox RMR Agreement. No further payments relating to the 2007-08 agreement are planned. No payments have been made in relation to the pending 2008-09 Lennox RMR Agreement.

Payments Made After September 30, 2008	
Amount	Description
\$6,485,244.13	fixed payment for September 2008
\$185,116.09	accrued true-up for September 2008 ¹
-\$1,172,972.96	monthly true-up for August 2008 ²
\$792,378.06	monthly true-up for September 2008 ²
\$185,116.09	final accrued true-up ¹
\$1,562,500.00	performance award
-\$2,019,998.78	interim true-up for Jul, Aug, Sep 2008 ³
\$6,017,382.63	Total payments made after Sept. 30, 2008

Notes:

- 1 Accrued true-ups are to recover the true-up for October 2007 that is required under clause 3 in Schedule A of the RMR Agreement. Because the 2007-08 RMR agreement was approved by the OEB on December 21, 2007, the October true-up was accrued and recovered through a series of monthly payments beginning with November 2007, each of which is 1/11 of the October 2007 true-up.

- 2 Monthly true-ups reconcile actual market revenues and fuel costs to the forecast amounts in the RMR agreement as per clause 3 in Schedule A of the RMR Agreement.
- 3 The interim true-up reconciles actual non-market costs to those forecast in the RMR agreement as per clause 4 in Schedule A of the RMR Agreement.

Board Staff Interrogatory #4(A) for OPG

Interrogatory

Re: Additional Evidence Filed by OPG

- i. Board staff's understanding is that the evidence filed by OPG regarding the cost-effectiveness of a longer term agreement for Lennox is presented in anticipation of a possible determination that Lennox is required for reliability reasons beyond September 30, 2009 and that the Board may therefore wish to pursue the merits of a multi-year RMR agreement. Please confirm that this understanding is accurate.
- ii. OPG's evidence states that OPG has held discussions with the IESO and OPA regarding the future need for Lennox. Please confirm whether and to what extent the evidence filed by OPG reflects the views of and/or is supported by the IESO and/or the OPA.
- iii. What contractual commitments does OPG require in order to proceed with the Combined Heat and Power (CHP) project at Lennox?

Response

- i. The evidence filed by OPG regarding the cost-effectiveness of a longer term agreement for Lennox was filed in response to an interest expressed by the Board in the EB-2007-0715 Decision, and reiterated in Procedural Order No. 1 for EB-2008-0298, in a multi-year RMR arrangement.
- ii. OPG provided the IESO and OPA with a copy of OPG's draft evidence for review prior to submitting it to the OEB. OPG understands that references in its evidence with respect to the IESO's need for Lennox to address local reliability concerns are generally supported by the IESO, and that references to the OPA's requirements for Lennox are generally supported by the OPA.
- iii. OPG would require a contractual commitment from a third party to fund the cost of the project. This commitment would be required by April 2009 to enable OPG to issue an RFP for engineering services with sufficient lead time to have a services contract in place by July 2009.