ONTARIO POWER GENERATION

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May 13, 2013

VIA RESS AND COURIER

Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, Suite 2700
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: EB-2013-0061 – Thunder Bay Generating Station Reliability Must-Run Agreement – OPG Responses to Interrogatories

Attached please find interrogatory responses from Ontario Power Generation Inc. (OPG) in the above noted proceeding.

Pursuant to the Board's Procedural Order No. 1, provided are two (2) hardcopies of OPG's responses and one electronic copy filed through the Board's Regulatory Electronic Submission System (RESS).

Please direct any comments or questions in this matter to the undersigned.

Yours truly,

[Original signed by]

Andrew Barrett

Attach

cc: EB-2013-0061 Intervenors
Fred Cass, Aird & Berlis (email)
Carlton Mathias, OPG (email)

Board Staff Interrogatory #1 for OPG

Interrogatory

Notes:

A. Unless otherwise noted, all terms used in the interrogatories below are as defined in the RMR Agreement.

B. Information provided in response to the interrogatories below should be provided only in respect of Thunder Bay Generating Station Unit G3 and related facilities (the "reliability must-run facility" under the RMR Agreement). All of the information requested on an historic basis should be allocated in an appropriate manner to Unit G3. Thus historic costs that are common to the full Thunder Bay Generation Station should be adjusted so as to maintain comparability between pre-2013 data and 2013 data. In your responses regarding historic cost information, please explain how such common costs have been adjusted/allocated.

Ref: RMR Agreement, Schedule D and Definitions, and OPG Letter to the Board dated February 27, 2013

1. Please provide data for Unit G3 of the Thunder Bay Generation Station on the following revenue and cost items, on a monthly basis, for each of the calendar years 2010, 2011 and 2012:

Revenues	Costs
1. Hourly Settlement Amounts in the real-time energy market	1. Variable costs of generation for Minimum Generation Block Run Times ("MGBRT"). For this item and items 2 to 4 below, please identify and use an appropriate reference weighted average cost of coal for the applicable year.
2. Hourly Settlement Amounts for operating reserve	2. Variable costs of generation – start up
3. Congestion Management Settlement Credit ("CMSC") payments as follows: a. Total CMSC payments received. Please provide these numbers broken down for real-time energy market amounts (constrained on and constrained off) and operating reserve market amounts (constrained on and constrained off). b. If any CMSC payments were adjusted/recalculated by reason of local market power, the dollar amount by which CMSC payments were clawed back. c. If any CMSC payments were	3. Variable costs of generation – other (i.e., not included in 1 or 2 above).

adjusted/recalculated by reason of constrained off events in a "designated constrained off watch zone", the dollar amount by which the CMSC payments were clawed back.	
4. Real-time generator cost guarantee ("CGC") payments	4. Fuel costs: a. Cost of fuel b. Disposal costs. In addition to the value of the disposal costs, please explain how/under what circumstances "proceeds of disposition" arise.
5. Day-ahead production cost guarantee ("PCG") payments	5. Regulatory testing costs.
6. Reactive support service payments	6. Market costs, broken down as follows: a. Global Adjustment b. All other market costs
7. Voltage control service payments	7. OM&A costs Please provide a full breakdown of these costs as per Table 1 of Schedule D of the RMR Agreement.
8. Other market revenue (please specify)	8. Other costs Please provide a full breakdown of these costs as per Table 1 of Schedule D of the RMR Agreement
9. Non-IESO market revenue (please specify)	9. Auxiliary boiler fuel costs

Response

1. See tables included as Attachment 1 to this response.

Board Staff Interrogatory #1
ATTACHMENT 1 - Table 1

Filed: 2013-05-13
EB-2013-0061
OPG Responses

OPG RESPONSE - IR #1 - REVENUES ($) >>

Board Staff Table — 2010

No.	REVENUE CATEGORIES	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	Hourly Settlement Amounts in the real-time energy market	732,755	1,293,345	174,739	78,057	1,404,374	591,075	1,219,375	920,399	0	1,378	100,292	412,401
2	Hourly Settlement Amounts for operating reserve	0	0	34	0	0	0	0	55	0	0	1	1,304
3	Congestion Management Settlement Credit ("CMSC") payments as follows:												
3a	Total CMSC payments received. Please provide these numbers broken down for real-time energy market amounts (constrained on and constrained off) and operating reserve market amounts (constrained on and constrained off).	122,427	600,323	45,832	35,326	414,240	122,060	437,031	353,165	0	0	12,315	34,469
	- Real-time Energy Market - Constrained On	(153)	(261)	1,446	22	192	12,331	(124)	2,007	0	0	1,602	(1,515)
	- Real-time Energy Market - Constrained Off	121,573	599,652	35,640	35,304	414,048	109,449	436,869	351,127	0	0	10,609	31,634
	- Operating Reserve Market Market - Constrained On	1,006	932	8,768	0	0	280	286	57	0	0	104	4,384
	- Operating Reserve Market Market - Constrained Off	0	0	(23)	0	0	0	0	(26)	0	0	0	(35)
3b	If any CMSC payments were adjusted/recalculated by reason of local market power, the dollar amount by which CMSC payments were clawed back	0	0	0	0	0	0	0	0	0	0	0	0
3c	If any CMSC payments were adjusted/recalculated by reason of constrained off events in a "designated constrained off watch zone", the dollar amount by which the CMSC payments were clawed back.	0	0	0	0	0	0	0	0	0	0	0	0
4	Real-time generator cost guarantee ("CGC") payments	190,498	107,705	227,116	0	215,367	141,193	505,173	76,166	0	0	69,489	223,978
5	Day-ahead production cost guarantee ("PCG") payments	0	0	128,014	104,833	427,940	644,297	351,728	574,051	72,925	0	294,030	78,779
6	Reactive support service payments	1,440	1,631	426	282	1,398	984	1,824	2,203	0	0	138	489
7	Voltage control service payments	included in item 6	included in item 6	included in item 6	included in item 6	included in item 6	included in item 6	included in item 6	included in item 6	included in item 6	included in item 6	included in item 6	included in item 6
8	Other market revenue (Administered Prices, Local Market Power)	0	0	0	0	0	0	0	0	0	0	0	0
9	Non-IESO market revenue (please specify)												

Board Staff Table — 2011

No.	REVENUE CATEGORIES	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	Hourly Settlement Amounts in the real-time energy market	125,126	172,972	0	51,035	90	12,297	289,413	1,056,586	1,290,348	294,543	403,753	283,836
2	Hourly Settlement Amounts for operating reserve	59	0	0	541	0	0	16	224	11	822	104	37
3	Congestion Management Settlement Credit ("CMSC") payments as follows:												
3a	Total CMSC payments received. Please provide these numbers broken down for real-time energy market amounts (constrained on and constrained off) and operating reserve market amounts (constrained on and constrained off).	50,091	7,444	0	31,017	0	802	116,165	67,130	265,567	20,775	33,106	23,876
	- Real-time Energy Market - Constrained On	28,572	1,630	0	18,782	0	(203)	80,736	30,405	225,796	13,521	17,636	18,713
	- Real-time Energy Market - Constrained Off	16,512	4,452	0	2,055	0	1,005	34,565	31,864	38,312	6,234	13,535	1,106
	- Operating Reserve Market Market - Constrained On	5,007	1,363	0	10,179	0	0	847	4,975	1,425	996	1,970	4,058
	- Operating Reserve Market Market - Constrained Off	0	0	0	0	0	0	17	(114)	33	24	(36)	0
3b	If any CMSC payments were adjusted/recalculated by reason of local market power, the dollar amount by which CMSC payments were clawed back	0	0	(5,603)	0	0	0	0	0	0	0	0	0
3c	If any CMSC payments were adjusted/recalculated by reason of constrained off events in a "designated constrained off watch zone", the dollar amount by which the CMSC payments were clawed back.	0	0	0	0	0	0	0	0	0	0	0	0
4	Real-time generator cost guarantee ("CGC") payments	204,625	134,196	0	71,833	0	0	275,983	420,010	116,781	0	453,278	203,157
5	Day-ahead production cost guarantee ("PCG") payments	319,631	290,697	310,756	72,040	192,845	0	69,376	125,967	1,367,881	515,648	12,836	0
6	Reactive support service payments	350	221	0	75	0	11	1,023	2,423	3,531	448	693	545
7	Voltage control service payments	included in item 6	included in item 6	included in item 6	included in item 6	included in item 6	included in item 6	included in item 6	included in item 6	included in item 6	included in item 6	included in item 6	included in item 6
8	Other market revenue (Administered Prices, Local Market Power)	0	0	(5,402)	0	0	0	0	0	0	65	0	0
9	Non-IESO market revenue (please specify)												

Board Staff Table — 2012

No.	REVENUE CATEGORIES	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	Hourly Settlement Amounts in the real-time energy market	714,635	150,940	0	0	0	24,506	183,850	90,328	13,414	146,045	61,948	36,755
2	Hourly Settlement Amounts for operating reserve	970	0	0	0	0	0	0	0	242	20	301	760
3	Congestion Management Settlement Credit ("CMSC") payments as follows:												
3a	Total CMSC payments received. Please provide these numbers broken down for real-time energy market amounts (constrained on and constrained off) and operating reserve market amounts (constrained on and constrained off).	34,531	17,205	0	0	0	2,250	534,339	176,120	10,532	40,907	41,464	1,499
	- Real-time Energy Market - Constrained On	5,339	14,074	0	0	0	(96)	534,196	175,378	346	33,762	33,964	1,095
	- Real-time Energy Market - Constrained Off	12,838	2,702	0	0	0	2,346	143	609	10,328	5,635	5,462	117
	- Operating Reserve Market Market - Constrained On	16,495	429	0	0	0	0	0	133	82	1,517	2,104	286
	- Operating Reserve Market Market - Constrained Off	(141)	0	0	0	0	0	0	0	(224)	(7)	(65)	2
3b	If any CMSC payments were adjusted/recalculated by reason of local market power, the dollar amount by which CMSC payments were clawed back	0	0	0	0	0	0	0	0	0	0	0	0
3c	If any CMSC payments were adjusted/recalculated by reason of constrained off events in a "designated constrained off watch zone", the dollar amount by which the CMSC payments were clawed back.	0	0	0	0	0	0	0	0	0	0	0	0
4	Real-time generator cost guarantee ("CGC") payments	51,670	326,177	0	0	0	17,629	0	0	0	113,587	192,487	115,405
5	Day-ahead production cost guarantee ("PCG") payments	27,660	0	0	0	0	0	256,444	12,051	55,409	54,005	1,884	0
6	Reactive support service payments	3,011	237	0	0	0	28	181	225	14	214	78	101
7	Voltage control service payments	included in item 6	included in item 6	included in item 6	included in item 6	included in item 6	included in item 6	included in item 6	included in item 6	included in item 6	included in item 6	included in item 6	included in item 6
8	Other market revenue (Administered Prices, Local Market Power)	0	0	0	0	0	0	0	0	0	0	0	0
9	Non-IESO market revenue (please specify)												

OPG RESPONSE - IR #1 - COSTS ($) >>

Board Staff Table — 2010

No.	COST CATEGORIES	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	Variable costs of generation for Minimum Generation Block Run Times ("MGBRT"). For this item and items 2 to 4 below, please identify and use an appropriate reference weighted average cost of coal for the applicable year. (see Note 1)	1,496	1,517	1,617	1,601	1,793	1,810	1,850	1,920	1,898	1,804	1,718	1,704
2	Variable costs of generation – start up (avg of hot/cold/warm startup) See Note 1	8,846	7,915	8,445	8,754	8,618	8,090	8,092	8,395	8,453	9,139	10,612	9,970
3	Variable costs of generation – other (i.e., O&M Costs) See Note 1	38,835	38,281	39,258	40,044	64,177	64,340	63,842	62,995	64,371	65,895	65,626	65,340
4	Fuel costs:												
4a	Cost of fuel	719,599	1,379,083	303,450	140,734	1,469,273	647,467	967,647	780,630	202,402	18,278	177,217	516,273
4b	Disposal costs. In addition to the value of the disposal costs, please explain how/under what circumstances "proceeds of disposition" arise	0	0	0	0	0	0	0	0	202,402	9,450	0	0
5	Regulatory Testing costs (These Costs are Not Separately Tracked by OPG)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Market costs, broken down as follows:												
6a	Global Adjustment	134,785	57,937	215,404	118,953	65,437	60,966	18,822	31,144	58,210	135,426	182,114	205,334
6b	All other market costs	299,910	139,619	257,885	167,594	154,735	150,697	181,233	162,138	108,506	164,931	264,255	330,147
7	OM&A costs - Please provide a full breakdown of these costs as per Table 1 of Schedule D of the RMR Agreement *(See Table 2 for breakdown of costs)*	2,559,857	2,165,333	2,642,660	2,448,238	2,258,543	2,793,586	2,366,057	2,466,730	3,312,169	2,300,074	2,218,474	2,310,501
8	Other Costs - Financing Cost on Working Capital (all periods) and Inventory Write-Down (Mar 2012)	81,227	76,146	77,249	72,989	70,138	68,251	65,620	63,539	66,153	67,124	67,708	65,970
9	Auxiliary boiler fuel costs	0	0	0	0	0	0	0	0	0	0	0	2,233

Board Staff Table — 2011

No.	COST CATEGORIES	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	Variable costs of generation for Minimum Generation Block Run Times ("MGBRT"). For this item and items 2 to 4 below, please identify and use an appropriate reference weighted average cost of coal for the applicable year. (see Note 1)	2,221	2,164	2,196	2,163	2,134	2,242	2,299	2,255	2,259	2,255	2,187	2,150
2	Variable costs of generation – start up (avg of hot/cold/warm startup) See Note 1	10,480	10,842	11,570	12,119	11,112	11,393	11,515	11,453	11,667	11,610	12,597	11,836
3	Variable costs of generation – other (i.e., O&M Costs) See Note 1	66,459	54,678	55,441	55,924	55,510	55,636	56,379	54,800	54,540	53,212	53,165	52,453
4	Fuel costs:												
4a	Cost of fuel	243,872	333,207	0	150,660	0	39,654	507,687	1,290,192	1,840,336	962,257	737,374	608,385
4b	Disposal costs. In addition to the value of the disposal costs, please explain how/under what circumstances "proceeds of disposition" arise	0	0	0	0	0	0	0	0	0	562,332	0	0
5	Regulatory Testing costs (These Costs are Not Separately Tracked by OPG)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Market costs, broken down as follows:												
6a	Global Adjustment	242,360	189,633	206,851	190,174	106,895	75,475	59,933	86,154	84,517	82,323	125,764	177,680
6b	All other market costs	351,084	305,128	296,168	228,550	105,763	108,443	114,859	128,275	123,645	90,157	142,011	170,226
7	OM&A costs - Please provide a full breakdown of these costs as per Table 1 of Schedule D of the RMR Agreement *(See Table 2 for breakdown of costs)*	2,594,661	2,325,895	2,522,266	2,368,437	2,516,834	2,603,659	2,268,883	2,717,807	2,662,868	2,554,905	2,683,939	2,609,242
8	Other Costs - Financing Cost on Working Capital (all periods) and Inventory Write-Down (Mar 2012)	88,920	88,690	89,690	89,000	88,580	88,675	86,005	78,995	70,555	69,165	65,625	63,200
9	Auxiliary boiler fuel costs	2,900	0	5,725	0	0	0	0	0	0	2,039	46,746	105,263

Board Staff Table — 2012

No.	COST CATEGORIES	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	Variable costs of generation for Minimum Generation Block Run Times ("MGBRT"). For this item and items 2 to 4 below, please identify and use an appropriate reference weighted average cost of coal for the applicable year. (see Note 1)	2,039	1,980	1,935	1,880	1,960	1,861	1,882	1,908	1,929	1,931	1,983	2,001
2	Variable costs of generation – start up (avg of hot/cold/warm startup) See Note 1	11,910	11,729	12,329	12,198	11,959	10,717	10,876	11,022	12,186	11,924	12,092	12,516
3	Variable costs of generation – other (i.e., O&M Costs) See Note 1	45,912	47,033	47,489	47,132	46,831	38,990	39,355	40,278	40,954	40,858	39,864	40,688
4	Fuel costs:												
4a	Cost of fuel	1,512,232	407,053	0	0	0	67,433	121,422	30,985	37,431	114,829	48,992	55,421
4b	Disposal costs. In addition to the value of the disposal costs, please explain how/under what circumstances "proceeds of disposition" arise	0	0	0	0	0	0	0	0	0	0	0	0
5	Regulatory Testing costs (These Costs are Not Separately Tracked by OPG)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Market costs, broken down as follows:												
6a	Global Adjustment	100,313	274,878	357,667	272,184	93,573	86,301	55,288	72,448	64,188	152,842	254,936	263,504
6b	All other market costs	125,133	220,928	186,238	164,046	60,299	75,436	77,633	98,282	62,801	130,206	220,901	281,433
7	OM&A costs - Please provide a full breakdown of these costs as per Table 1 of Schedule D of the RMR Agreement *(See Table 2 for breakdown of costs)*	2,825,696	2,863,055	3,369,390	3,054,498	3,158,214	2,683,556	2,480,135	2,839,922	2,361,024	3,816,067	2,776,060	2,526,912
8	Other Costs - Financing Cost on Working Capital (all periods) and Inventory Write-Down (Mar 2012)	55,050	52,975	3,650,229	32,755	32,445	32,105	31,315	30,700	30,130	30,520	29,865	29,600
9	Auxiliary boiler fuel costs	0	12,808	0	0	50	0	0	0	0	319	331	1,455

Note 1:

- The costs are based on running costs issued in the middle of the respective months (the 15th or the following closest day).
- Thunder Bay's MGBRT: for all months assume 2 hours
- Marginal MGBRT Cost = MGBRT hour x minimum load (33MW) x Marginal Fuel Cost
- OPG has used the Marginal Cost of Coal instead of the Weighted Average Cost of Coal in the cost calculations, as OPG uses marginal cost (rather than average cost) to price and offer its units into the market.
- All original costs were calculated in $US and converted to $CAD using the following exchange rates: 2010: 1.03$C/$US; 2011: 0.99 $C/$US and 2012: 1.00$C/$US

Thunder Bay RMR
Breakdown of OM&A Costs ($)

2012 Actual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
OM&A Costs													
Labour	1,627,024	1,310,244	1,124,488	1,712,439	1,164,293	1,356,683	1,395,659	1,215,707	1,147,707	1,383,220	1,093,805	1,529,171	16,060,439
Direct Assigned	121,605	469,837	657,772	33,165	641,190	469,837	121,605	641,190	381,397	210,045	552,750	33,165	4,333,559
Business Unit Support - Direct	90,270	79,050	118,830	120,870	(146,740)	(17,850)	38,760	43,860	31,110	58,140	49,980	59,670	525,950
Central Support - BU Allocated	424,640	332,536	375,496	387,808	633,415	295,715	350,986	424,618	332,570	455,390	338,698	486,028	4,837,900
Materials	175,201	249,774	260,556	205,749	153,638	83,558	149,146	136,567	150,943	115,902	139,263	232,703	2,053,000
Other	146,780	148,439	155,073	212,293	324,244	284,439	175,805	175,805	111,122	1,388,195	396,390	(39,000)	3,479,585
Projects	34,000	67,000	471,000	176,000	182,000	5,000	42,000	(4,000)	0	0	0	5,000	978,000
Insurance	59,591	59,591	59,591	59,591	59,591	59,591	59,591	59,591	59,591	59,591	59,591	59,591	715,097
Property Taxes	146,583	146,583	146,583	146,583	146,583	146,583	146,583	146,583	146,583	145,583	145,583	160,583	1,771,000
Total	2,825,696	2,863,055	3,369,390	3,054,498	3,158,214	2,683,556	2,480,135	2,839,922	2,361,024	3,816,067	2,776,060	2,526,912	34,754,530

2011 Actual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
OM&A Costs													
Labour	1,238,098	1,534,976	1,184,195	1,246,390	1,641,122	1,336,780	1,109,561	1,357,512	1,176,732	1,202,439	1,414,732	1,164,293	15,606,829
Direct Assigned	348,134	(172,066)	552,134	200,234	(39,466)	348,134	256,334	37,034	348,134	256,334	(39,466)	348,134	2,443,613
Business Unit Support - Direct	85,807	90,907	75,607	80,707	85,807	50,107	34,807	65,407	50,107	96,007	34,807	85,807	835,880
Central Support - BU Allocated	348,330	384,030	246,330	338,130	333,030	276,930	292,230	322,830	256,530	276,930	348,330	32,130	3,455,760
Materials	143,463	160,878	206,488	115,268	38,976	151,756	196,537	208,146	127,707	177,463	168,341	266,195	1,961,220
Other	252,927	181,610	66,341	201,512	246,293	229,707	140,976	194,049	306,829	370,683	213,122	331,707	2,735,756
Projects	(7,463)	(39,805)	5,805	829	25,707	24,878	53,073	347,463	211,463	(3,317)	365,707	215,610	1,199,951
Insurance	34,366	34,366	34,366	34,366	34,366	34,366	34,366	34,366	34,366	34,366	34,366	34,366	412,387
Property Taxes	151,000	151,000	151,000	151,000	151,000	151,000	151,000	151,000	151,000	144,000	144,000	131,000	1,778,000
Total	2,594,661	2,325,895	2,522,266	2,368,437	2,516,834	2,603,659	2,268,883	2,717,807	2,662,868	2,554,905	2,683,939	2,609,242	30,429,396

2010 Actual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
OM&A Costs													
Labour	1,288,683	1,094,634	1,438,780	1,251,366	1,191,659	1,658,537	1,087,171	1,162,634	1,390,683	1,110,390	1,088,829	1,442,098	15,205,463
Direct Assigned	223,577	157,277	121,577	284,777	223,577	(26,323)	284,777	284,777	(26,323)	223,577	284,777	45,077	2,081,129
Business Unit Support - Direct	90,397	59,797	115,897	54,697	34,297	69,997	59,797	39,397	365,797	49,597	(103,403)	120,997	957,260
Central Support - BU Allocated	294,780	264,180	366,180	248,880	304,980	355,980	274,380	274,380	310,080	279,480	289,680	310,080	3,573,060
Materials	165,024	179,951	73,805	275,317	119,415	225,561	146,780	188,244	225,561	198,195	92,049	205,659	2,095,561
Other	242,146	174,976	297,707	136,000	233,854	307,659	252,098	217,268	361,561	43,122	240,488	171,659	2,678,537
Projects	48,927	28,195	22,390	(9,122)	(55,561)	(4,146)	54,732	93,707	478,488	260,390	190,732	11,610	1,120,341
Insurance	26,323	26,323	26,323	26,323	26,323	26,323	26,323	26,323	26,323	26,323	26,323	26,323	315,871
Property Taxes	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	109,000	109,000	(23,000)	1,815,000
Total	2,559,857	2,165,333	2,642,660	2,448,238	2,258,543	2,793,586	2,366,057	2,466,730	3,312,169	2,300,074	2,218,474	2,310,501	29,842,222

Board Staff Interrogatory #2 for OPG

Interrogatory

Notes:

A. Unless otherwise noted, all terms used in the interrogatories below are as defined in the RMR Agreement.

B. Information provided in response to the interrogatories below should be provided only in respect of Thunder Bay Generating Station Unit G3 and related facilities (the "reliability must-run facility" under the RMR Agreement). All of the information requested on an historic basis should be allocated in an appropriate manner to Unit G3. Thus historic costs that are common to the full Thunder Bay Generation Station should be adjusted so as to maintain comparability between pre-2013 data and 2013 data. In your responses regarding historic cost information, please explain how such common costs have been adjusted/allocated.

Ref: RMR Agreement, Schedule D and Definitions, and OPG Letter to the Board dated February 27, 2013

1. Please provide data for Unit G3 of the Thunder Bay Generation Station on the following revenue and cost items, on a monthly basis, for each of the calendar years 2010, 2011 and 2012:

Revenues	Costs
1. Hourly Settlement Amounts in the real-time energy market	1. Variable costs of generation for Minimum Generation Block Run Times ("MGBRT"). For this item and items 2 to 4 below, please identify and use an appropriate reference weighted average cost of coal for the applicable year.
2. Hourly Settlement Amounts for operating reserve	2. Variable costs of generation – start up
3. Congestion Management Settlement Credit ("CMSC") payments as follows: a. Total CMSC payments received. Please provide these numbers broken down for real-time energy market amounts (constrained on and constrained off) and operating reserve market amounts (constrained on and constrained off). b. If any CMSC payments were adjusted/recalculated by reason of local market power, the dollar amount by which CMSC payments were clawed back. c. If any CMSC payments were	3. Variable costs of generation – other (i.e., not included in 1 or 2 above).

adjusted/recalculated by reason of constrained off events in a "designated constrained off watch zone", the dollar amount by which the CMSC payments were clawed back.	
4. Real-time generator cost guarantee ("CGC") payments	4. Fuel costs: a. Cost of fuel b. Disposal costs. In addition to the value of the disposal costs, please explain how/under what circumstances "proceeds of disposition" arise.
5. Day-ahead production cost guarantee ("PCG") payments	5. Regulatory testing costs.
6. Reactive support service payments	6. Market costs, broken down as follows: a. Global Adjustment b. All other market costs
7. Voltage control service payments	7. OM&A costs Please provide a full breakdown of these costs as per Table 1 of Schedule D of the RMR Agreement.
8. Other market revenue (please specify)	8. Other costs Please provide a full breakdown of these costs as per Table 1 of Schedule D of the RMR Agreement
9. Non-IESO market revenue (please specify)	9. Auxiliary boiler fuel costs

2. Please provide an estimate of the revenues that OPG expects to earn during the term of the RMR Agreement, broken down by category as per the table set out in interrogatory 1 above, except for items 3(b) and 3(c) which need not be included.

Response

2. See table included as Attachment 1 to this response.

Board Staff Table		OPG RESPONSE - IR #2 - REVENUES
No.	**REVENUE CATEGORIES**	**Term of RMR Agreement (Jan 1 - Dec 31, 2013)**
1	Hourly Settlement Amounts in the real-time energy market	$1.0M
2	Hourly Settlement Amounts for operating reserve	$21K
3	Congestion Management Settlement Credit ("CMSC") payments as follows:	Not Forecasted
3a	Total CMSC payments received. Please provide these numbers broken down for real-time energy market amounts (constrained on and constrained off) and operating reserve market amounts (constrained on and constrained off).	Not Forecasted
	- Real-time Energy Market - Constrained On	Not Forecasted
	- Real-time Energy Market - Constrained Off	Not Forecasted
	- Operating Reserve Market Market - Constrained On	Not Forecasted
	- Operating Reserve Market Market - Constrained Off	Not Forecasted
4	Real-time generator cost guarantee ("CGC") payments	Not Forecasted
5	Day-ahead production cost guarantee ("PCG") payments	Not Forecasted
6	Reactive support service payments	$4K
7	Voltage control service payments	Included as part of (6)
8	Other market revenue (please specify)	n/a
9	Non-IESO market revenue (please specify)	n/a

Board Staff Interrogatory #3 for OPG

Interrogatory

Notes:
A. Unless otherwise noted, all terms used in the interrogatories below are as defined in the RMR Agreement.

B. Information provided in response to the interrogatories below should be provided only in respect of Thunder Bay Generating Station Unit G3 and related facilities (the “reliability must-run facility” under the RMR Agreement). All of the information requested on an historic basis should be allocated in an appropriate manner to Unit G3. Thus historic costs that are common to the full Thunder Bay Generation Station should be adjusted so as to maintain comparability between pre-2013 data and 2013 data. In your responses regarding historic cost information, please explain how such common costs have been adjusted/allocated.

Ref: RMR Agreement, Schedule D and Definitions, and OPG Letter to the Board dated February 27, 2013

1. Please provide data for Unit G3 of the Thunder Bay Generation Station on the following revenue and cost items, on a monthly basis, for each of the calendar years 2010, 2011 and 2012:

Revenues	Costs
1. Hourly Settlement Amounts in the real-time energy market	1. Variable costs of generation for Minimum Generation Block Run Times (“MGBRT”). For this item and items 2 to 4 below, please identify and use an appropriate reference weighted average cost of coal for the applicable year.
2. Hourly Settlement Amounts for operating reserve	2. Variable costs of generation – start up
3. Congestion Management Settlement Credit (“CMSC”) payments as follows: a. Total CMSC payments received. Please provide these numbers broken down for real-time energy market amounts (constrained on and constrained off) and operating reserve market amounts (constrained on and constrained off). b. If any CMSC payments were adjusted/recalculated by reason of local market power, the dollar amount by which CMSC payments were clawed back. c. If any CMSC payments were	3. Variable costs of generation – other (i.e., not included in 1 or 2 above).

adjusted/recalculated by reason of constrained off events in a "designated constrained off watch zone", the dollar amount by which the CMSC payments were clawed back.	
4. Real-time generator cost guarantee ("CGC") payments	4. Fuel costs: a. Cost of fuel b. Disposal costs. In addition to the value of the disposal costs, please explain how/under what circumstances "proceeds of disposition" arise.
5. Day-ahead production cost guarantee ("PCG") payments	5. Regulatory testing costs.
6. Reactive support service payments	6. Market costs, broken down as follows: a. Global Adjustment b. All other market costs
7. Voltage control service payments	7. OM&A costs Please provide a full breakdown of these costs as per Table 1 of Schedule D of the RMR Agreement.
8. Other market revenue (please specify)	8. Other costs Please provide a full breakdown of these costs as per Table 1 of Schedule D of the RMR Agreement
9. Non-IESO market revenue (please specify)	9. Auxiliary boiler fuel costs

3. Please provide an estimate of the costs that OPG expects to incur during the term of the RMR Agreement, broken down by category as per the table set out in interrogatory 1 above, except for items 7 and 8 which need not be included to the extent already set out in Table 1 of Schedule D of the RMR Agreement.

Response

3. See table included as Attachment 1 to this response.

Board Staff Table		OPG RESPONSE - IR #3 - COSTS
No.	**COST CATEGORIES**	**Term of RMR Agreement (Jan 1 - Dec 31, 2013)**
1	Variable costs of generation for Minimum Generation Block Run Times (“MGBRT”). For this item and items 2 to 4 below, please identify and use an appropriate reference weighted average cost of coal for the applicable year.	\$2,472 (Marginal MGBRT)[1,2,3,4]
2	Variable costs of generation – start up	\$12,978 (Avg of Hot, Warm Cold Unit Start)[1,4]
3	Variable costs of generation – other (i.e., not included in 1 or 2 above).	\$42,848 (O&M cost per unit start)[1,4]
4	Fuel costs:	
4a	Cost of fuel	\$0.5M
4b	Disposal costs. In addition to the value of the disposal costs, please explain how/under what circumstances “proceeds of disposition” arise	Not Forecasted
5	Regulatory testing costs.	\$122K
6	Market costs, broken down as follows:	
6a	Global Adjustment	\$2.5M
6b	All other market costs	\$0.8M
9	Auxiliary boiler fuel costs	\$15K

Notes:
1 Costs calculated using actual running costs issued in the middle of the month for Jan-April 2013 and on estimates for balanace of the year.
2 Thunder Bay MGBRT: Assume a 2 hour minimum run time for all months
3 Marginal MGBRT Cost = MGBRT hour x minimum load (33MW) x Marginal Fuel Cost
4 Costs calculated in \$US and converted to \$CAD with Exchange Rate = \$1.03 Cdn/US

Board Staff Interrogatory #4 for OPG

Interrogatory

Notes:

A. Unless otherwise noted, all terms used in the interrogatories below are as defined in the RMR Agreement.

B. Information provided in response to the interrogatories below should be provided only in respect of Thunder Bay Generating Station Unit G3 and related facilities (the "reliability must-run facility" under the RMR Agreement). All of the information requested on an historic basis should be allocated in an appropriate manner to Unit G3. Thus historic costs that are common to the full Thunder Bay Generation Station should be adjusted so as to maintain comparability between pre-2013 data and 2013 data. In your responses regarding historic cost information, please explain how such common costs have been adjusted/allocated.

Ref: RMR Agreement, Schedule D and Definitions, and OPG Letter to the Board dated February 27, 2013

4. Please identify and explain any incentive effects of the RMR Agreement in terms of the impact on OPG's offer behaviour and on the quantity of energy or operating reserve to be produced/scheduled in respect of Unit G3 of the Thunder Bay Generation Station. Please explain the potential impact on prices in the IESO-administered markets of any such incentive effects.

Response

4. OPG does not expect the RMR agreement to impact its offer strategy. Accordingly, OPG does not expect that there will be any impact on prices in the IESO-administered market from the agreement.

   Section 4(b), the Net Revenue Sharing Adjustment ("NRSA") "allows OPG to retain 5% of the operating profit (market revenue less actual fuel costs) when the RMR facility is dispatched to run. There is no NRSA when actual fuel costs exceed market revenues".

   The NRSA ensures that OPG continues to offer the facility into the IESO-administered market in the same manner as before; that is, at a price to recover the variable costs associated with operations to produce energy and operating reserve. The unit will be dispatched by the IESO if it is economical or if it is constrained on by the IESO to meet local system reliability or adequacy needs.

   Also please see response to Board Staff Interrogatory #9 regarding impacts on operations if the IESO issues a direction that the facility is considered to be energy limited.

Board Staff Interrogatory #5 for OPG

Interrogatory

Notes:

A. Unless otherwise noted, all terms used in the interrogatories below are as defined in the RMR Agreement.

B. Information provided in response to the interrogatories below should be provided only in respect of Thunder Bay Generating Station Unit G3 and related facilities (the "reliability must-run facility" under the RMR Agreement). All of the information requested on an historic basis should be allocated in an appropriate manner to Unit G3. Thus historic costs that are common to the full Thunder Bay Generation Station should be adjusted so as to maintain comparability between pre-2013 data and 2013 data. In your responses regarding historic cost information, please explain how such common costs have been adjusted/allocated.

Ref: RMR Agreement, Schedule A, Section 4

5. OPG filed its application on February 27, 2013, however the term of the RMR Agreement is for the period from January 1, 2013 to December 31, 2013. Please provide the forecast of fixed costs applicable to each of the first three months of the term of the RMR Agreement (January 1, 2013 to March 31, 2013) and the actual fixed costs for each month during the same period.

Response

5. The actual fixed costs are $2,816K, $2,857K and $2,940K, respectively for January, February and March 2013, which are consistent with forecast. In each of these three months the actual amounts are below the $3,164K MFP (monthly fixed payment) agreed to in the RMR because the MFP takes the annual budget and divides it into 12 equal payments. This calculation does not reflect the variability of the planned expenditures during the year. The cause of the variability is driven largely by the timing of execution of projects.

Board Staff Interrogatory #6 for OPG

Interrogatory

Notes:

A. Unless otherwise noted, all terms used in the interrogatories below are as defined in the RMR Agreement.

B. Information provided in response to the interrogatories below should be provided only in respect of Thunder Bay Generating Station Unit G3 and related facilities (the "reliability must-run facility" under the RMR Agreement). All of the information requested on an historic basis should be allocated in an appropriate manner to Unit G3. Thus historic costs that are common to the full Thunder Bay Generation Station should be adjusted so as to maintain comparability between pre-2013 data and 2013 data. In your responses regarding historic cost information, please explain how such common costs have been adjusted/allocated.

Ref: RMR Agreement Schedule B

6. Please provide the EFOR-OP rates for Unit G3 of the Thunder Bay Generation Station for each of the years 2010, 2011 and 2012, calculated in accordance with Schedule B of the RMR Agreement.

Response

6. The EFOR(OP) rates for Thunder Bay GS Unit G3 for 2010, 2011, 2012, calculated in accordance with Schedule B of the RMR Agreement, are provided in the table below.

Year	Actual EFOR(OP) for Thunder Bay GS Unit 3
2010	1.6
2011	0.1
2012	10.8

Board Staff Interrogatory #7 for OPG

Interrogatory

Notes:

A. Unless otherwise noted, all terms used in the interrogatories below are as defined in the RMR Agreement.

B. Information provided in response to the interrogatories below should be provided only in respect of Thunder Bay Generating Station Unit G3 and related facilities (the “reliability must-run facility” under the RMR Agreement). All of the information requested on an historic basis should be allocated in an appropriate manner to Unit G3. Thus historic costs that are common to the full Thunder Bay Generation Station should be adjusted so as to maintain comparability between pre-2013 data and 2013 data. In your responses regarding historic cost information, please explain how such common costs have been adjusted/allocated.

Ref: RMR Agreement Schedule B

7. Please provide the net penalty/reward that would have been payable under the RMR Agreement in each of the years 2010, 2011 and 2012 in respect of Unit G3 of the Thunder Bay Generation Station, had the RMR Agreement been in effect in those years.

Response

7. The table below provides the net penalty/reward that would have been payable in each of the years 2010, 2011 and 2012 for Thunder Bay GS Unit G3 had the RMR Agreement been in effect in those years.

Year	Actual EFOR(OP)	Target EFOR(OP)	Performance Point	Performance Point Value ($M)	Penalty/ Reward	Penalty/ Reward Before Cap ($M)	Capped Penalty/ Reward ($M)
2010	1.6	6<EFOR(OP)<10	4.4	0.17	Reward	0.75	0.5
2011	0.1	6<EFOR(OP)<10	5.9	0.17	Reward	1.00	0.5
2012	10.8	6<EFOR(OP)<10	0.8	0.17	Penalty	0.14	0.14

Board Staff Interrogatory #8 for OPG

Interrogatory

Notes:

A. Unless otherwise noted, all terms used in the interrogatories below are as defined in the RMR Agreement.

B. Information provided in response to the interrogatories below should be provided only in respect of Thunder Bay Generating Station Unit G3 and related facilities (the "reliability must-run facility" under the RMR Agreement). All of the information requested on an historic basis should be allocated in an appropriate manner to Unit G3. Thus historic costs that are common to the full Thunder Bay Generation Station should be adjusted so as to maintain comparability between pre-2013 data and 2013 data. In your responses regarding historic cost information, please explain how such common costs have been adjusted/allocated.

Ref: RMR Agreement, Section 3.3

8. Section 3.3 of the RMR Agreement requires OPG to participate in the IESO-administered markets and in other electricity markets "in a commercially reasonable manner and in accordance with [OPG's] mandate, including in accordance with the provisions of Schedule A". It further states that, for greater certainty, acting in a "commercially reasonable manner" with respect to any given activity "includes, other than in exceptional circumstances, that [OPG] will offer a unit economically over a sustained period of time based on its costs and in a manner consistent with how [OPG's] coal-fired generation is being offered pursuant to [OPG's] CO2 Implementation Strategy, as amended from time to time".

   a) Please further explain what is meant by the requirement to act in a "commercially reasonable manner". Please include the following in your response: (i) the costs that are being referred to in the phrase "based on its costs"; (ii) whether the phrase "based on its costs" refers to OPG's costs prior to or after the receipt of any reimbursement of such costs by the IESO; (iii) under what "exceptional circumstances" is OPG not required to act in a "commercially reasonable manner"; and (iv) describe the offer behaviour that is considered to be consistent with OPG's CO2 Implementation Strategy.

   b) Please provide a copy of the OPG CO2 Implementation Strategy that applies during the term of the RMR Agreement. Please confirm whether OPG expects its CO2 Implementation Strategy to change during the term of the RMR Agreement.

   c) Please provide a copy of the Resolution of OPG's Sole Shareholder – Addressing Carbon Dioxide (Co2) Emissions Arising from the Use of Coal as currently in effect. Please confirm whether OPG expects that this Resolution will remain in effect, unamended, during the term of the RMR Agreement.

Response

8 (a) (i) Acting in a commercially reasonable manner based on its costs means the unit will be offered into the IESO-administered market using variable costs which include fuel and variable maintenance costs.

(ii) These costs are prior to the receipt of any reimbursement of such costs by the IESO.

(iii) Exceptional circumstances include, but are not limited to:

- Fuel inventory management (i.e. having coal in inventory at site in surplus / shortfall of what is reasonably required to meet economical needs of the station).
- Fuel (PRB coal) in bunker which needs to consumed for safety reasons.
- Equipment protection issues.
- Environmental and Regulatory requirements such as equipment testing, etc.

(iv) Given the operating strategy and shutdown decisions noted in OPG's CO_2 implementation strategy (see 8(b) below), coupled with the market assumptions OPG has used in developing its 2013 Corporate Business Plan, OPG's offer behaviour is consistent with the CO2 Implementation plan in that no CO_2 emissions adder will be needed to meet the 2013 target on a forecast basis. OPG's offer strategy is not expected to change with the CO_2 Emission Target Strategy as OPG anticipates CO_2 emissions to be well below target.

8 (b). A copy of OPG's CO_2 implementation strategy is provided as Attachment 1 to this response. It can also be accessed on OPG's public web site at the following link:

http://opg.com/safety/sustainable/emissions/OPG%20Strategy%20to%20Meet%202012%20CO2%20Emission%20Target.pdf

OPG does not expect its CO_2 Emission Target Strategy to change during the term of the agreement. A 2013 strategy document has been submitted to the Provincial Government for approval, however, it is not expected to impact OPG's strategy during the term of the 2013 RMR Agreement.

8 (c). See document provided as Attachment 2 to this response "Resolution of the Sole Shareholder Addressing Carbon Dioxide (CO_2) Emissions Arising From The Use Of Coal At Its Coal-Fired Generating Stations", dated May 20, 2010.

OPG is not aware of any proposed changes to the Resolution of the Sole Shareholder during the term of the RMR Agreement. OPG therefore expects that this Resolution will remain in effect, unamended, during the term of the RMR Agreement.

Tom Mitchell
President & Chief Executive Officer

ONTARIO POWER GENERATION

700 University Avenue, H19 A24 Toronto, ON M5G 1X6

Tel: 416-592-2121 Fax: 416-592-2174
tom.mitchell@opg.com

November 24, 2011

File No.: 500 T5

The Honourable Chris Bentley
Minister of Energy
4th Floor, Hearst Block
900 Bay Street
Toronto, Ontario
M7A 2E1

Dear Minister Bentley:

OPG's Strategy to Meet the 2012 CO_2 Emission Target

In response to the requirements of Section 4 of the Resolution of the Sole Shareholder, dated May 16, 2008, *Addressing Carbon Dioxide Emissions Arising from the Use of Coal at Its Coal-Fired Generating Stations*, OPG is submitting the attached Implementation Strategy for 2012, to meet the CO2 requirements specified in Paragraph 2 of the resolution. The 2012 Strategy replaces the 2011 Strategy posted on OPG's website at this time last year.

The 2012 Implementation Strategy is similar to the 2011 Strategy except that in 2012, with expected low gas prices and weak power demand, OPG anticipates CO_2 emissions to be well below Target.

As in previous years, OPG will post this Implementation Strategy on its website as soon we receive your concurrence with the attached. Please let me know if you require any further information.

T.N. Mitchell
President and CEO

c: Dwight Duncan, Minister of Finance
Paul Murphy, President and CEO, Independent Electricity System Operator

Attachment

OPG's Strategy to Meet on a Forecast Basis the 2012 CO_2 Emission Target

The 2012 CO_2 Emission Target

The Ontario Government's Shareholder Resolution dated May 20, 2010 directs OPG to develop an Implementation Strategy (the "Strategy") 'to meet on a forecast basis CO_2 emissions, arising from the use of coal at its coal-fired generating stations, for the calendar 2012 year of not more than 11.5 million metric tonnes' (the "Target"). The Strategy is to be filed with the Minister of Energy by November 30, 2011. This document describes the measures OPG will take to meet the Target on a forecast basis.

OPG's Strategy to Meet the 2012 Target on a Forecast Basis

OPG's Strategy to meet on a forecast basis the emission target for 2012 is derived from procedures used in operating an energy-limited resource. There are four major elements to OPG's Strategy.

- **Planned Outage Strategy**: determining the duration and timing of the planned outages required by the coal fleet.
- **Operating Strategy**: determining the number of available units from the coal-fired fleet that will be offered into the IESO-administered market at any point in time while managing fleet reliability and emission rates.
- **Offer Strategy:** applying a uniform emission adder to the offers made for all units in all hours of the emission-limited period, calendar year 2012.
- **Fuel Strategy:** As OPG must cease burning coal by the end of 2014 (O.Reg 496/07), and, as a condition of its OEFC Agreement, OPG must ensure that sufficient fuel is available to meet overall system reliability requirements, OPG has developed a fuel strategy to minimize the remaining useable coal inventory at the stations and the ports, at the time coal production ceases. To that end, coal procurement decisions will use business judgment and will only be undertaken when it is considered highly likely that the procured coal will be consumed. With the current expectation of low gas prices and weak power demand, CO_2 emissions are forecast to be well below Target.

Outage Plans to Accommodate the CO_2 Initiative

OPG's planned outages for its coal units will be submitted to the IESO for approval following standard procedures. These outages will be designed to reduce maintenance and repair costs. CO_2 Outages, as defined in the Implementation Strategy for 2009, will not be used in 2012, but could be reintroduced in later years if necessary.

Operating Strategy for the Coal Fleet in 2012

Operating costs for a coal-fired unit increase, and fleet reliability decreases, with the number of starts each unit makes per year. To reduce the thermal stresses on each unit, it is also desirable to avoid short operating cycles.

OPG continues to have an incentive to reduce wear and tear on its remaining coal-fired units. The components of the units that are unique to coal-fired generation need to be reliable until the units no longer burn coal. The remainder of the plant needs to be maintained in good condition as there is value in converting some or all of these units to natural gas (with the possibility of co-firing on biomass) after the use of coal ends in 2014.

In its strategy for meeting the 2009 CO_2 emission target, OPG introduced the concept of NOBA (Not Offered But Available) units to address the need to preserve coal fleet reliability. NOBA units are units that are Not Offered into the market, But are Available on short notice if needed by the IESO for reliability purposes. These units could be offered into the market as per market rules with IESO approval and started if an operating coal-fired unit is forced out of service, or if the IESO directs a NOBA unit to operate for system reliability purposes.

In its 2010 CO_2 emission reduction strategy, OPG replaced the use of NOBA units with a procedure for offering coal units into the market so that they would only be dispatched if the market was relatively tight in real-time. This allowed these units to be available to the market while maintaining the capability to manage fleet reliability. If these units were required to run in real time, OPG would have offered these units at their normal prices.

For 2012, with the shutdown of 6 coal units in the south-west, OPG does not anticipate the need to employ either of these strategies to assist in reducing the wear and tear on its coal-fired units. However, as 2012 progresses, should OPG need to manage coal-fleet reliability through its offer strategy, it retains the option to do so. If required, OPG will provide sufficient notice of its specific change in offer strategy to the IESO so that the IESO may incorporate this information in its planned outage approval and reliability assessment processes.

Offer Strategy for the Emission-limited Coal Fleet in 2012

When a group of units is energy-limited, it is standard practice to apply a uniform adder ($/MWh) to the offers for the energy limited resources in order to price these resources out of the market enough of the time so that their total production does not exceed the desired target. The uniform adder approach results in the energy-limited resources running in the hours which are most valuable to the market.

Given the Shareholder Resolution, the coal-fired fleet is emission-limited, but the way to achieve the emission limit may be analyzed in a similar manner. The distinction is that the emission adder is expressed in $/tonne. To determine the size of the emission adder required to achieve the target on a forecast basis, OPG runs its inter-connected market simulation model, progressively increasing the offer adder on the coal-fired units until it finds the uniform adder that will yield the desired emission target. In each hour, the emission adder in $/tonne is translated into the appropriate $/MWh adder on the simulated offer using the CO_2 emission rate curve for each of the coal-fired units. (The CO_2 emission rate curve gives the emission rate of the unit at any level of its output. For instance, a 500 MW unit operating at the 100 MW output level is less efficient and therefore produces more CO_2 per MWh than when it operates at the 400 MW level.)

Given the operating strategy and shutdown decisions noted above, and the market assumptions OPG has used in developing its 2012 Corporate Business Plan, OPG estimates that no CO_2 emission adder will be needed to meet the 2012 target on a forecast basis.

Fuel Strategy for the Coal Fleet in 2012

Given the weak level of power market demands and low market prices for natural gas, OPG has sufficient quantities of fuel under contract and in storage to permit production of the expected requirements for coal-fired energy in Ontario in 2012.

November 9, 2011

Adjusting the Implementation Strategy as Year-end Forecasts Change

Risks to Meeting the 2012Target

The estimate of the CO_2 emission adder required to limit the coal-fired fleet to the targeted emissions on a forecast basis is subject to a high degree of uncertainty. In particular, it depends on the demand for power in Ontario and the demand for power exports from Ontario to its interconnected markets. The competitiveness of OPG's coal-fired fleet in export markets is driven by the spread between Western and Eastern coal prices and the spread between these coal prices and the natural gas price. The levels of demand and fuel prices are always uncertain. In addition, the underlying demand for energy from the coal fleet depends on the output of the baseload generators in Ontario: nuclear, hydro and wind.

Apart from issues with the forecasts of the market drivers and the baseload production assumptions used in the simulation model, the model and its market information may prove not to be precise in simulating the impact of any adder applied on coal-fired emissions. This is something that can only be learned by experience.

Monitoring Actual Emissions vs. the Forecast Profile for 2012

OPG will provide periodic emission tracking reports on its progress toward achieving the target. Preliminary CO_2 emission measurements from the coal-fired stations will be available within one month following a month's end, and final emission results will be available within two months following a month's end. OPG will provide the year-to-date actuals and updated forecasts of year-end emissions to the Ministry each month starting in March 2012.

OPG will establish a range around the target that recognizes the volatility of the marketplace. OPG will endeavour to manage its CO_2 emissions within this range. Should the updated year-end CO_2 emission forecast move outside the range, OPG will adjust its implementation strategy.

Adjusting the 2012 Implementation Strategy

In conditions where OPG has a positive adder in place to achieve the target range and a forecast update indicates that emissions will fall outside the target range, OPG will adjust its Implementation Strategy so that the forecast for year-end CO_2 emissions meets the target. OPG will adjust the CO_2 emission adder. Any revisions to the CO_2 emission adder will be posted publicly and will take effect with one week's notice.

If the operating strategy described above restricts OPG from managing the reliability of its coal fleet, OPG may need to adapt its offer strategy during 2012. OPG will update this Implementation Strategy and the IESO of any change to its operating strategy.

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

WHEREAS Her Majesty the Queen in right of the Province of Ontario, as represented by the Minister of Energy and Infrastructure (the "Shareholder'), as the registered holder of all the issued shares of Ontario Power Generation Inc. (the "Corporation"), executed a unanimous shareholder agreement (the "Shareholder Agreement") dated as of May 20, 2010 regarding the Corporation;

AND WHEREAS paragraph 1 of the Shareholder Agreement removed from the directors of the Corporation all of their rights, powers and duties in relation to decisions in respect of certain distinct aspects of the business operations of the Corporation, and in particular, as regards decisions relating to reducing CO_2 emissions arising from the use of coal at its coal-fired generating stations to be met annually on a forecast basis, as well as decisions relating to the development of, and the adherence to, an implementation Strategy (the "Strategy") for the reduction of CO_2 by the Corporation;

AND WHEREAS the Shareholder will ensure that an appropriate cost recovery mechanism is established to enable the Corporation to recover the costs of its coal-fired generating stations following the implementation of the Strategy;

AND WHEREAS the Shareholder wishes to achieve CO_2 emissions reductions in a manner that is cost-efficient and prudent for the Ontario electricity system and from the electricity customer's perspective;

AND WHEREAS the Shareholder wishes to exercise its rights and powers under paragraph 1 of the Shareholder Agreement to cause the Corporation to reduce CO_2 emissions from the use of coal arising at its coal-fired generating stations within specified times and in accordance with the Strategy;

NOW THEREFORE BE IT RESOLVED as a resolution of the sole Shareholder of the Corporation that:

1. The Corporation shall act in accordance with the Strategy to meet on a forecast basis CO_2 emissions arising from the use of coal at its coal-fired generating stations for the 2011 calendar year of not more than 11.5 megatonnes.

2. The Corporation shall act in accordance with the Strategy to meet on a forecast basis CO_2 emissions arising from the use of coal at its coal-fired generating stations for the 2012 calendar year of not more than 11.5 megatonnes.

3. The Corporation shall act in accordance with the Strategy to meet on a forecast basis CO_2 emissions arising from the use of coal at its coal-fired generating stations for the 2013 calendar year of not more than 11.5 megatonnes.

4. The Corporation shall act in accordance with the Strategy to meet on a forecast basis CO_2 emissions, arising from the use of coal at its coal-fired generating stations for the 2014 calendar year of not more than 11.5 megatonnes.

5. Despite paragraphs 1 to 4, the Corporation may emit CO_2 from its coal-fired generating stations and such emissions shall not be included in the total CO_2 emissions referred to

in paragraphs 1 to 4 if such emissions are the result of the Corporation's decision to operate one of its coal-fired generating stations:

(i) pursuant to a reliability must run contract as defined in the Market Rules made under section 32 of the *Electricity Act, 1998* (the "Market Rules"); or;

(ii) pursuant to a direction issued by the Independent Electricity System Operator as authorized by the Market Rules.

6. The Corporation shall file with the Minister of Energy and Infrastructure, by no later than November 30, 2010 for the 2011 calendar year, and within one year thereafter in respect of the 2012 calendar year, and within two years thereafter in respect of the 2013 calendar year, and within three years thereafter in respect of the 2014 calendar year, the Strategy to meet the CO_2 emissions requirements specified in paragraphs 1 to 4 above, which will reflect the use of coal as an energy-limited resource. The Strategy will include the steps, methods or other mechanisms which the Corporation intends to undertake or utilize, in order to achieve those emissions targets on a forecast basis.

7. The directors shall ensure that this resolution is carried out in a prudent and cost-efficient manner, in accordance with all applicable laws, and in accordance with sound commercial practice for a corporation involved in the generation of electricity and in accordance with the Market Rules.

8. Any officer or director of the Corporation be and is hereby authorized and directed to execute and deliver all documents and agreements, and to do and perform all things as may be necessary or desirable in order to give effect to and implement the foregoing resolutions.

The foregoing resolutions are hereby consented to as evidenced by the signature of the sole Shareholder of the Corporation pursuant to the provisions of the *Business Corporations Act* (Ontario).

DATED as of the 20th day of May, 2010.

HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF ONTARIO, AS REPRESENTED BY THE MINISTER OF ENERGY AND INFRASTRUCTURE

Per:

Brad Duguid
Minister of Energy and Infrastructure

ONTARIO POWER GENERATION INC.

DECLARATION OF THE SOLE SHAREHOLDER REGARDING CARBON DIOXIDE (CO_2) EMISSIONS ARISING FROM THE USE OF COAL AT ITS COAL-FIRED GENERATING STATIONS made as of the 20th day of May, 2010 (the "Effective Date").

WHEREAS Her Majesty the Queen in right of the Province of Ontario, as represented by the Minister of Energy and Infrastructure (the "Shareholder") is the registered holder of all the issued shares of Ontario Power Generation Inc. (the "Corporation");

AND WHEREAS the Shareholder finds it necessary to assume decision-making power and authority over certain distinct aspects of the business operations of the Corporation, and in particular, as regards decisions relating to reducing CO_2 emissions from the use of coal and its coal-fired generating stations;

AND WHEREAS the Shareholder, acting in his capacity as the Minister of Energy and Infrastructure for the Province of Ontario, has issued, and the Lieutenant Governor in Council has approved, a Directive made pursuant to section 28.1 of the *Ontario Energy Board Act, 1998* directing the Ontario Energy Board to amend aspects of the Corporation's generation licence in order to facilitate implementation of the Government's policy on reducing CO_2 emissions arising from the use of coal at the coal-fired generating stations owned or operated by the Corporation;

AND WHEREAS the Shareholder makes the following declaration pursuant to subsection 108(3) of the *Business Corporations Act* (Ontario) (the "Act") intending the same to be deemed to be a Unanimous Shareholder Agreement within the meaning of the Act;

NOW THEREFORE it is hereby declared that:

1. The rights, powers and duties of the Directors (the "Directors") of the Corporation to manage, or supervise the management of, the business and affairs of the Corporation, whether such rights, powers or duties arise under the Act, the articles of amalgamation of the Corporation or the by-laws of the Corporation, as and when amended, or otherwise, are forthwith restricted with regard to:

   (i) establishing limits on CO_2 emissions arising from the use of coal at the coal-fired generating stations owned or operated by the Corporation for any or all of the 2011, 2012, 2013 or 2014 calendar years;

   (ii) requiring the preparation, at or within specified times, of one or more documents setting out the Corporation's implementation strategy or strategies for achieving the limits referenced in (i) above (the "Strategy"), and requiring such documents to be filed with the Minister of Energy and Infrastructure; and

   (iii) determining whether the Corporation may depart from the Strategy as set out in the documents referenced in (ii) above,

   are hereby assumed by the Shareholder and no longer reside with the Board of Directors or any members thereof, from the Effective Date, until this Declaration is amended or revoked.

   (collectively, the "Restricted Powers").

2. This Declaration and the restriction of the powers of the Directors herein contained shall not affect any action, step, resolution or by-law duly taken, made, passed or consented to by the Directors prior to the Effective Date.

3. The Shareholder assumes all the rights, powers, duties and liabilities of the Directors to manage or supervise the management of the business and affairs of the Corporation in connection with the Restricted Powers and, pursuant to subsection 108(5) of the Act, the Directors are thereby relieved of their duties and liabilities, including any liabilities under section 131 of the Act, to the same extent.

4. For greater certainty, the Restricted Powers do not restrict the duties and liabilities of the Directors to manage, or supervise the management of, the business and affairs of the Corporation relating to the actual implementation of any decision made by the Shareholder pursuant to paragraph 1 above.

5. This Declaration shall be governed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

IN WITNESS WHEREOF the Shareholder has duly executed this Declaration as of the Effective Date.

HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF ONTARIO, AS REPRESENTED BY THE MINISTER OF ENERGY AND INFRASTRUCTURE

Per:

____
Brad Duguid
Minister of Energy and Infrastructure

Board Staff Interrogatory #9 for OPG

Interrogatory

Notes:

A. Unless otherwise noted, all terms used in the interrogatories below are as defined in the RMR Agreement.

B. Information provided in response to the interrogatories below should be provided only in respect of Thunder Bay Generating Station Unit G3 and related facilities (the "reliability must-run facility" under the RMR Agreement). All of the information requested on an historic basis should be allocated in an appropriate manner to Unit G3. Thus historic costs that are common to the full Thunder Bay Generation Station should be adjusted so as to maintain comparability between pre-2013 data and 2013 data. In your responses regarding historic cost information, please explain how such common costs have been adjusted/allocated.

Ref: RMR Agreement, Schedule E and OPG Letter to the Board dated February 27, 2013

9. Please explain the purpose of the first portion of Schedule E ("Fuel Management at the Reliability must-run Facility") and how/in what respects it interacts with the remainder of the RMR Agreement. If available, please provide an estimate of the percentage of time that OPG expects that Unit G3 of the Thunder Bay Generation Station will be declared energy-limited.

Response

9. The purpose of the first portion of Schedule E is to establish a methodology for OPG to manage its limited fuel supplies in order to meet the IESO's reliability needs and to minimize its stranded fuel costs at the expiration or termination of the agreement.

   Schedule E requires OPG to provide information to the IESO on a monthly basis to enable the IESO to assess if the remaining fuel inventory at the plant is sufficient to manage the IESO's forecasted reliability requirements for the remaining term of the agreement. The IESO has the right, under the agreement, to declare that the facility is energy limited and to direct OPG to curtail the use of coal and / or purchase additional coal if required.

   If the IESO issues a direction in this regard, OPG will operate the facility as an energy-limited resource and during the period of this direction, OPG will no longer receive an operating profit through the Net Revenue Sharing Adjustment ("NRSA") calculation. If the parties do not enter into a new reliability must run contract, the IESO shall be responsible for the disposition of any amounts of remaining coal resulting from this direction at the termination of the agreement.

OPG does not forecast the percentage of time that the facility may be declared to be energy-limited. OPG does not forecast system reliability and relies on the IESO-administered market to provide the appropriate signals.

Board Staff Interrogatory #10 for OPG

Interrogatory

Notes:

A. Unless otherwise noted, all terms used in the interrogatories below are as defined in the RMR Agreement.

B. Information provided in response to the interrogatories below should be provided only in respect of Thunder Bay Generating Station Unit G3 and related facilities (the "reliability must-run facility" under the RMR Agreement). All of the information requested on an historic basis should be allocated in an appropriate manner to Unit G3. Thus historic costs that are common to the full Thunder Bay Generation Station should be adjusted so as to maintain comparability between pre-2013 data and 2013 data. In your responses regarding historic cost information, please explain how such common costs have been adjusted/allocated.

Ref: RMR Agreement, Schedule E and OPG Letter to the Board dated February 27, 2013

10. OPG's request to de-register the Thunder Bay Generation Station was made on November 15, 2012, the IESO's technical assessment was communicated to OPG on January 7, 2013 and OPG's application for approval of the RMR Agreement was filed on February 27, 2013 (total elapsed time of a little over 3 months). Schedule E of the RMR Agreement states that OPG must notify the IESO no later than September 1, 2013 if OPG wishes to de-register Unit G3 of the Thunder Bay Generation Station. Please identify the date by which OPG would need to request de-registration of Unit G3 of the Thunder Bay Generation Station in order for any application for approval of a subsequent reliability must-run agreement to be filed with the Board by October 15, 2013. Please identify whether there are any technical or other reasons why the de-registration request could not be made as of that date.

Response

10. Using the assumptions set out below, OPG would need to request de-registration of the Thunder Bay Unit G3 approximately 11 weeks prior to October 15, 2013, or by July 30, 2013, in order for any application for approval of a subsequent reliability must-run agreement to be filed with the OEB by October 15, 2013.

    List of Assumptions:

    (i) Assume that a period of approximately 7 weeks would be required from the time of OPG's de-registration request to the IESO's notification to OPG that they were prepared to enter into discussions with a view to concluding a RMR contract. This is the same period of time as was required for this RMR agreement.

(ii) Assume that from the point at which the IESO notified OPG that they wished to enter into RMR discussions, a period of approximately 4 weeks would be required for OPG and the IESO to negotiate a RMR contract and for OPG to prepare an application to the OEB. While these activities actually took approximately 71/2 weeks for this RMR agreement, OPG is assuming that a second RMR contract for Thunder Bay GS would require less time for negotiation.

Finally, OPG is not aware of any technical reasons that would prevent it from filing a de-registration request by that date.

Board Staff Interrogatory #11 for OPG

Interrogatory

Notes:

A. Unless otherwise noted, all terms used in the interrogatories below are as defined in the RMR Agreement.

B. Information provided in response to the interrogatories below should be provided only in respect of Thunder Bay Generating Station Unit G3 and related facilities (the “reliability must-run facility” under the RMR Agreement). All of the information requested on an historic basis should be allocated in an appropriate manner to Unit G3. Thus historic costs that are common to the full Thunder Bay Generation Station should be adjusted so as to maintain comparability between pre-2013 data and 2013 data. In your responses regarding historic cost information, please explain how such common costs have been adjusted/allocated.

General

11. Please provide the following for Unit G3 of the Thunder Bay Generation Station for each month in each of the 2010, 2011 and 2012 calendar years:

    a) total MWh of energy production
    b) total MW of operating reserve scheduled
    c) total number of starts for the Unit
    d) the average run time for the Unit once started.

Please also explain whether there is significant variance of run times around the average run time (i.e., are run times mostly close to the average run time or do they vary significantly from the average?).

Response

11 (a). See table included as Attachment 1 to this response.

11(b). See table included as Attachment 1 to this response.

11(c). See table included as Attachment 1 to this response.

11(d). See table included as Attachment 1 to this response.

Over the operating history provided for 2010, 2011 and 2012, there is a significant variance between the run times and the average run time for any given month. This is a function of a number of factors, including system needs (both for reliability and generation), as well as the overall management of OPG’s coal inventory due to the anticipated closure of Thunder Bay GS by December 31, 2014.

Year	Month	Interrogatory 11(a) Total Energy (MWh)	Interrogatory 11(b) Total Operating Reserve (MW)	Interrogatory 11(c) Number of Starts	Interrogatory 11(d) Run Time Once Started (Hours) Min	Avg	Max
2010	Jan	20,611	347	5	1	60	137
	Feb	36,425	153	5	22	110	253
	Mar	5,779	1,720	9	7	14	27
	Apr	2,277	0	2	8	24	41
	May	33,198	0	13	7	34	129
	Jun	13,127	220	9	10	18	43
	Jul	22,261	46	15	4	18	64
	Aug	17,960	18	5	7	50	117
	Sep	0	0	0	0	0	0
	Oct	34	0	0	0	0	0
	Nov	2,921	73	6	4	8	14
	Dec	10,109	741	6	4	19	36
2011	Jan	3,033	768	8	0	8	24
	Feb	4,682	218	10	4	31	233
	Mar	0	0	0	0	0	0
	Apr	1,951	668	5	4	7	11
	May	2	0	0	0	0	0
	Jun	322	0	1	5	5	5
	Jul	8,529	393	4	4	52	182
	Aug	24,859	1,402	23	1	15	47
	Sep	39,685	214	18	4	26	235
	Oct	8,700	3,172	2	17	129	242
	Nov	12,208	1,466	8	4	17	92
	Dec	10,740	3,121	3	33	77	117
2012	Jan	26,632	6,621	4	0	167	466
	Feb	6,757	727	8	4	14	32
	Mar	0	0	0	0	0	0
	Apr	0	0	0	0	0	0
	May	0	0	0	0	0	0
	Jun	1,081	0	2	6	9	12
	Jul	6,010	0	4	10	58	107
	Aug	2,394	120	0	0	0	0
	Sep	1,433	23	1	28	28	28
	Oct	4,895	57	4	4	24	51
	Nov	2,192	507	4	8	11	19
	Dec	1,271	67	2	8	16	24

Board Staff Interrogatory #12 for OPG

Interrogatory

Notes:

A. Unless otherwise noted, all terms used in the interrogatories below are as defined in the RMR Agreement.

B. Information provided in response to the interrogatories below should be provided only in respect of Thunder Bay Generating Station Unit G3 and related facilities (the "reliability must-run facility" under the RMR Agreement). All of the information requested on an historic basis should be allocated in an appropriate manner to Unit G3. Thus historic costs that are common to the full Thunder Bay Generation Station should be adjusted so as to maintain comparability between pre-2013 data and 2013 data. In your responses regarding historic cost information, please explain how such common costs have been adjusted/allocated.

General

12. Please provide an estimate of the following for Unit G3 of the Thunder Bay Generation Station over the term of the RMR Agreement:

    a) total MWh of energy production
    b) total MW of operating reserve scheduled
    c) if available, total number of starts
    d) if available, the average run time once started

Response

12(a). See table included as Attachment 1 to this response.

12(b). See table included as Attachment 1 to this response.

12(c). See table included as Attachment 1 to this response.

12(d). See table included as Attachment 1 to this response.

Year	Month	Interrogatory 12(a) Total Energy (MWh)	Interrogatory 12(b) Total Operating Reserve (1) (MW)	Interrogatory 12(c) Number of Starts	Interrogatory 12(d) Run Time Once Started (Hours) (1)		
					Min	Avg	Max
2013	Jan	0	n/a	0	n/a	n/a	n/a
	Feb	0	n/a	0	n/a	n/a	n/a
	Mar	0	n/a	0	n/a	n/a	n/a
	Apr	0	n/a	0	n/a	n/a	n/a
	May	0	n/a	0	n/a	n/a	n/a
	Jun	1,710	n/a	1	n/a	n/a	n/a
	Jul	16,885	n/a	3	n/a	n/a	n/a
	Aug	4,006	n/a	1	n/a	n/a	n/a
	Sep	0	n/a	0	n/a	n/a	n/a
	Oct	0	n/a	0	n/a	n/a	n/a
	Nov	0	n/a	0	n/a	n/a	n/a
	Dec	2,939	n/a	1	n/a	n/a	n/a

(1) Operating Reserve and Run Time Once Started are not forecasted by OPG, and are only available as after-the-fact actuals.

Board Staff Interrogatory #13 for OPG

Interrogatory

Notes:

A. Unless otherwise noted, all terms used in the interrogatories below are as defined in the RMR Agreement.

B. Information provided in response to the interrogatories below should be provided only in respect of Thunder Bay Generating Station Unit G3 and related facilities (the "reliability must-run facility" under the RMR Agreement). All of the information requested on an historic basis should be allocated in an appropriate manner to Unit G3. Thus historic costs that are common to the full Thunder Bay Generation Station should be adjusted so as to maintain comparability between pre-2013 data and 2013 data. In your responses regarding historic cost information, please explain how such common costs have been adjusted/allocated.

General

13. Please provide the current status of the conversion of the Atikokan Generating Station conversion to biomass. Please include the date on which the conversion is expected to be complete and the converted Atikokan Generating Station is expected to be in service.

Response

13. The conversion of the Atikokan generating station to biomass is on plan and expected to be complete and in-service by August 2014.

CME Interrogatory #1 for OPG

Interrogatory

The February 27, 2013 Letter Application refers to the Board's prior approval of four (4) separate Reliability Must-Run ("RMR") Agreements for OPG's Lennox Generating Station ("GS"). In connection with those prior Agreements, please provide the following information:

(a) Do any portion of the amounts which the Board has approved for recovery by OPG under the auspices of RMR Agreements fall within the ambit of OPG's Regulated payment Amounts? If so, then please provide details of amounts of prior approved RMR payments recovered by OPG that are embedded in OPG's currently approved Payments Order.

(b) What annual Board approved amount, if any, is OPG currently recovering for RMR Agreements for its Lennox GS, which exceeds actual costs being incurred by OPG to operate those facilities?

Response

a) No. OPG's regulated payment amounts recover costs for OPG's prescribed facilities only, which consist of OPG's nuclear stations and baseload hydroelectric stations, as defined by Ontario Regulation O.Reg. 53/05 under the OEB Act. Lennox Generating Station is not a prescribed facility under the regulation and its costs have never been included in OPG's regulated payment amounts.

b) OPG is not currently recovering any Board approved amount for Lennox GS. The last Lennox RMR agreement (approved in EB-2008-0298) ended on September 30, 2009. There have been no Lennox RMR agreements since that time.

CME Interrogatory #2 for OPG

Interrogatory

The information provided in the February 27, 2013 Letter Application and in Attachment 3 thereof indicates that, on January 7, 2013, the Independent Electricity System Operator ("IESO") advised OPG that it was prepared to enter into discussions with a view to concluding a RMR contract for one (1) Thunder Bay unit for a period of up to one (1) year. The duly executed IESO-OPG RMR Agreement dated January 1, 2013, at Attachment 1 of the Letter Application, indicates that the agreement had been finalized and signed by the President of OPG by February 6, 2013. Please provide a brief description of the sequence of discussions and events related to the negotiation of that contract, including the following:

(a) A brief chronology of such discussions and events between January 7 and February 6, 2013, that led to the finalization of the terms of the agreement.

(b) Copies of any historic backup information relied upon by OPG to derive the annualized and monthly fixed payment budget amounts shown in Schedule D, Table 1 of Attachment 1.

(c) Copies of any historic backup information considered by the IESO and the criteria applied by the IESO to determine that the budget amount presented by OPG was reasonable.

(d) An indication of whether there is any return on investment component contained within the budget and, if so, then the equity return on investment reflected therein.

Response

(a)

Thunder Bay RMR Chronology of Discussions and Events Between January 7, 2013 and February 15, 2013		
Item	**Description**	**Date**
Letter from IESO (Bruce Campbell) to OPG (Colin Anderson) on De-registration of Thunder Bay GS	Letter sent from the IESO indicating that they were prepared to enter into negotiations for a RMR Agreement for at least one Thunder Bay GS unit	Jan. 7, 2013
Meeting between the IESO and OPG negotiating teams at IESO offices (Clarkson location)	Main agenda item discussed - overview of contract design	Jan. 14, 2013

Meeting between the IESO and OPG negotiating teams at OPG's offices and conference call (Kipling location)	Main agenda items discussed – cost overview, EFOR(OP) targets and major projects	Jan. 21, 2013
Conference call between the IESO and OPG negotiating teams	Main agenda item discussed – cost estimates and major projects	Jan. 24, 2013
Conference call between the IESO and OPG negotiating teams	Main agenda item discussed – cost estimates	Jan. 30, 2013
OPG Execution of the IESO-OPGI Reliability Must-Run Agreement for Procurement of Physical Services from Thunder Bay Generation Station	OPG President & CEO executed the agreement	Feb.6, 2013
IESO Execution of the IESO-OPGI Reliability Must-Run Agreement for Procurement of Physical Services from Thunder Bay Generation Station	IESO Chief Operating Officer executed the agreement	Feb.15, 2013

(b) Attachment 1 included with this response provides the historic backup information and analysis relied upon by OPG in the course of the negotiation to derive and validate the annualized and monthly fixed payment amounts. The information in Attachment 1 shows the historical progression of OPG's development of the cost data for Thunder Bay GS Unit 3 used during the contract negotiations. This was based on an analysis of actual costs incurred during 2012 to operate the plant, and OPG's business planning process which was the basis for determining 2013 cost projections for the plant.

(c) Response to be provided by the IESO.

(d) There is no return on investment component. The Thunder Bay GS assets were previously fully impaired and are recorded on OPG's books at a value of $NIL.

Thunder Bay GS RMR
Negotiation covering January to December 2013
COMPARISON - BP12-14 (2012) vs 2012 Actual

	Thunder Bay GS Unit 3			
Cost Category	BP12-14 (2012) ($k)	2012 Actual ($k)	Change ($k)	Explanation
OM&A Costs				
Labour	$18,397	$ 16,060	($2,337)	Reflects attrition not filled due to changing outlook for the plant
Direct Assigned	$3,326	$4,334	$1,007	Largely change in discount rates
Business Unit Support - Direct	$694	$526	($168)	Largely Business Transformation (BT) transfer of Supply Chain and Training from Thermal to Business & Administrative Services and People & Culture (Corporate Functions), respectively; also reflects BT reductions from measures such as amalgamation of Thermal and Hydro; none of this was known when BP12-14 was established
Corporate Functions at *reliability must-run facilities*	$967	$973	$6	<1% variance is estimation error
Central Support - BU Allocated	$3,739	$3,865	$126	Largely BT transfer of Supply Chain and Training from Thermal to Business & Administrative Services and People & Culture (Corporate Functions), respectively; none of this was known when BP12-14 was established
Subtotal primarily labour-related costs	**$27,124**	**$25,758**	**($1,366)**	
Materials	$1,659	$2,053	$394	Largely reflects a forced extension to a Planned Outage
Other	$3,158	$3,480	$322	Largely due to backfilling some Labour vacancies with contractors and maintenance program adjustments
Projects	$1,400	$978	($422)	Project portfolio adjusted given plant's changing outlook
Insurance	$816	$715	($101)	Replacement value was being revised with carriers in 2012, outcome not know when budget was set
Property Taxes	$1,805	$1,771	($34)	MPAC has applied additional functional and economic obsolescence assumptions to the valuation of the property given the off-coal regulation
Other Costs				
Financing Cost on Working Capital	$433	$420	($13)	3% variance is estimation error
Monthly Fixed Payment ("MFP") - Annualized	**$36,396**	**$35,175**	**($1,220)**	
Monthly Fixed Payment ("MFP")	**$3,033**	**$2,931**	**($102)**	

Filed: 2013-05-13
EB-2013-0061
OPG Responses

Thunder Bay GS RMR
Negotiation covering January to December 2013
COMPARISON - BP12-14 (2012) vs BP13-15 (2013)

Cost Category	Thunder Bay GS Unit 3 BP12-14 (2012) ($k)	Thunder Bay GS Unit 3 BP13-15 (2013) ($k)	Thunder Bay GS Unit 3 Change ($k)	Explanation
OM&A Costs				
Labour	$18,397	$ 17,311	($1,086)	BP13-15 reduced to reflect current actual headcount including various attrition that is not replaced given plant's outlook, partially offset by increased Standard Labour Rates and Burdens and negotiated reduction to G3
Direct Assigned	$3,326	$5,752	$2,426	Largely change in estimated discount rates
Business Unit Support - Direct	$694	$404	($290)	Largely business transformation (BT) transfer of Supply Chain and Training from Thermal to Business & Administrative Services and People & Culture (Central Support), respectively; also reflects BT reductions from measures such as amalgamation of Thermal and Hydro partly offset by SLR and Burden rate increases
Corporate Functions at *reliability must-run facilities*	$967	$0	($967)	Rolled in to Central Support - BU Allocated due to cost centre reduction efficiency measure
Central Support - BU Allocated	$3,739	$5,258	$1,519	Net increase between Central Support-BU Allocated and Corporate Functions at *reliability must-run facilities is* largely Supply Chain and Training, moved from Thermal to Corporate through BT
Subtotal primarily labour-related costs	**$27,124**	**$28,726**	**$1,602**	
Materials	$1,659	$1,224	($435)	Maintenance program adjustments to focus on asset preservation in light of the change in the station's future outlook
Other	$3,158	$4,330	$1,172	Largely due to acceleration of inventory obsolescence charges given change in end of accounting life assumption
Projects	$1,400	$970	($430)	Per project listing for 2013 plans; adjusted to reflect change in station's outlook
Insurance	$816	$795	($21)	Replacement value was being revised with carriers in 2012, estimate reflects better information plus rate increase
Property Taxes	$1,805	$1,660	($145)	MPAC has applied additional functional and economic obsolescence assumptions to the valuation of the property given the off-coal regulation
Other Costs				
Financing Cost on Working Capital	$433	$267	($167)	Coal significantly drawn down, Materials/Supply inventory more fully obsolesced
Monthly Fixed Payment ("MFP") - Annualized	**$36,396**	**$37,972**	**$1,576**	
Monthly Fixed Payment ("MFP")	**$3,033**	**$3,164**	**$131**	

Thunder Bay GS RMR
Negotiation covering January to December 2013
COMPARISON - 2012 Actual vs BP13-15 (2013)

Cost Category	Thunder Bay GS Unit 3: 2012 Actual ($k)	Thunder Bay GS Unit 3: BP13-15 (2013) ($k)	Thunder Bay GS Unit 3: Change ($k)	Explanation
OM&A Costs				
Labour (see Table 4)	$ 16,060	$ 17,311	$1,251	Increase due increased Standard Labour Rates, Burden increases, and labour charged to projects in 2012, NOTE: partly offset by reduction to BP13-15 to reflect current actual headcount as opposed to the estimate when business planning was conducted
Direct Assigned	$4,334	$5,752	$1,419	Largely due to the change in estimated discount rates
Business Unit Support - Direct	$526	$404	($122)	Reflects OPG Business Transformation Initiative reductions partially offset by rate changes
Corporate Functions at *reliability must-run facilities* (see Table 5)	$973	$0	($973)	Rolled in to Central Support - BU Allocated due to cost centre reduction efficiency measure
Central Support - BU Allocated	$3,865	$5,258	$1,393	Net increase between Central Support-BU Allocated and Corporate Functions at *reliability must-run facilities is* largely due to Standard Labour Rate and Burden rate increase of the corporate function staff, and a portion is due to normal attrition in 2012
Subtotal primarily labour-related costs	**$25,758**	**$28,726**	**$2,968**	
Materials	$2,053	$1,224	($829)	Maintenance program adjusted to focus on asset preservation in light of the change in the station's future outlook
Other	$3,480	$4,330	$850	Acceleration of inventory obsolescence charges due to change in accounting life of the plant given the change in the station's future outlook
Projects (see Table 6)	$978	$970	($8)	Per project listing for 2013 plans
Insurance	$715	$795	$80	Replacement value was being revised with carriers in 2012, estimate reflects better information plus rate increase
Property Taxes	$1,771	$1,660	($111)	MPAC has applied additional functional and economic obsolescence assumptions to the valuation of the property given the off-coal regulation
Other Costs				
Financing Cost on Working Capital	$420	$267	($153)	Coal significantly drawn down, Materials/Supply inventory more fully obsolesced
Monthly Fixed Payment ("MFP") - Annualized	**$35,175**	**$37,972**	**$2,796**	
Monthly Fixed Payment ("MFP")	**$2,931**	**$3,164**	**$233**	

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Thunder Bay GS RMR
Labour Breakdown
Comparing 2012 Actual to 2013 Proposal

	Total Thunder Bay			Unit 3		
	2012 Actual	2013 Proposal	Difference	2012 Actual	2013 Proposal	Difference
Internal regular labour	$ 17,571	$ 19,387	$ 1,816	$ 14,571	$ 15,824	$ 1,253
Temporary regular labour	$ 616	$ 586	$ (30)	$ 511	$ 486	$ (25)
Overtime	$ 1,180	$ 1,486	$ 306	$ 979	$ 1,001	$ 22
Total Labour per Schedule D	**$ 19,367**	**$ 21,459**	**$ 2,092**	**$ 16,060**	**$ 17,311**	**$ 1,251**
Labour charged to projects	$ 398	$ -	$ (398)	$ 398	$ -	$ (398)
Total Labour per SAP/Plan	$ 19,765	$ 21,459	$ 1,694	$ 16,458	$ 17,311	$ 853

Labour budget has been reduced in the proposal by 5 FTE to facilitate costing of current headcount at current plan rates. It was further reduced by a negotiated $250K in anticipation of attrition and unpaid personal time off, given past experience, which is not reflected in the budget. Note that the 2012 Actual has been increased by $718K to reflect certain time that was "banked", which is not recorded as an expense in the primary pay cost centre until the banked time is taken and paid out, but it is recorded as an expense elsewhere for OPG in 2012.

NOTE: 5 FTE's removed from BP13-15 to arrive at 2013 Proposal, which reflects current actual HC

	2012 Labour Budget (excl Temps)	2012-2013 SLR increase	SLR Increase %
SLR	$ 19,149	$ 440	2.30%
Burden	$ 19,149	$ 1,014	5.30%

	Total Thunder Bay	Unit 3
Difference	**$ 1,694**	**$ 853**
Change in Standard Labour Rate (SLR):		
Collective Agreement-driven payrate increases	(440)	(221)
Discount Rate-driven (pension/opeb included in SLR)	(1,014)	(510)
	(1,454)	(732)
Personal Time Off, Maternity Leave	(240)	(121)
	(1,694)	(853)
Unreconciled Difference	**$ -**	**$ -**
Negotiated Labour cost reduction:	0	(250)

- reflects reality that there will be attrition and PTO that is not reflected in the 2013 Proposal

CME Interrogatory #2(b)
ATTACHMENT 1 - Table 5

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OPG Responses

Thunder Bay GS RMR
Corporate Functions Breakdown

	TBGS	G3
Direct Assigned - 2013 estimate (using current HC to allocate)	$6,937	$5,752
Direct Assigned - BP12-14	$4,026	$3,326
Direct Assigned - 2012 Actual (using current HC to allocate)	$5,226	$4,334
BU Support - 2013 estimate (using current HC to allocate)	$488	$404
BU Support - BP12-14	$849	$694
BU Support - 2012 Actual (using BP12-14 to allocate)	$643	$526
Supply Chain - 50% 2012 Actual (using BP12-14 to allocate)	$111	$91
Insurance - BP12-14	$1,116	$816
2012 estimate as a %		73%
Insurance - 2013 estimate (using 2012 %)	$1,087	$795
Insurance - 2012 actual (prorate using 2012 %)	$978	$715
Central Support BU Allocated - 2013 (using current HC to allocate)	$6,341	$5,258
Central Support BU Allocated - BP12-14	$4,639	$3,739
Central Support BU Allocated - 2012 Actual (using current HC to allocate)	$4,661	$3,865
Corporate Functions at reliability must-run facilities - 2012 Actual (using current HC to allocate)	$973	$973

	HC %	HC#
G3	83%	102.0
G2	17%	21.0
Total TBGS	62%	123.0

adjusted to December/12 Actual

Thunder Bay GS RMR
Projects Breakdown

Project	Project No.	Budget ($k)	Description of Project	Investment Driver
U3 Waterwall sootblower opening cracking	TBGS1089	300	Addressing a known reliability condition in the boiler of cracking in the U3 waterwall sootblower openings. Low cost repair of pad welding, no large scale tube replacement.	Reliability
Treatment Boiler Makeup Water/Gas Exchange Membrane	TBGS1091	300	Addressing corrosion condition (high dissolved oxygen make up water) introduced due to the unit's mode of operation (unpredictable run pattern and long periods of inoperation). Project helps sustain reliability and chemistry control during both off-line and on-line operation.	Reliability
Electrical Reconfiguration	TBGS1086	370	There are a small number of common electrical loads required for common service that are fed from Unit 1. Project addressses obsolescence and known reliability issue (inability to start up/operate when failure occurs). Arc chutes of these common electrical breakers contain asbestos, parts no longer available. Reconfigure electrical feed to main control room and eliminate asbestos hazard.	Safety/Reliability
Total		970		

CME Interrogatory #3 for OPG

Interrogatory

With respect to the performance standards, including penalties or rewards that apply if the performance standards are missed or exceeded, as described in Schedule B of the RMR Agreement, please provide information pertaining to any industry standards that were used to establish the following:

(a) The performance standards expressed in the agreement.

(b) The EROR-OP target range of 6% to 10% used in calculating rewards and penalties.

(c) The capping of the net penalty/reward amount in a sum that shall not exceed $500,000.00.

Response

(a) The reliability standard EFOR(OP) contained in the RMR Agreement is based on the industry standard $EFOR_d$ (Equivalent Demand Forced Outage Rate) and industry measure DAUFOP (Derating Adjusted Utilization Forced Outage Probability).

These industry standards were developed by the Institute of Electrical and Electronics Engineers (IEEE) which is a US-based global organization dedicated to technological advancement.

$EFOR_d$ is defined in IEEE Standard. 762: "IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity" as: "A measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate." (DAUFOP is similar to $EFOR_d$ and is defined in IEEE Standard. 762 as: "A measure of the probability that a generating unit will not be available when needed (derating included)."

OPG developed EFOR(OP), which it now uses for all of its thermal units as a measure of reliability performance. EFOR(OP) is derived directly from DAUFOP, and measures the same performance (i.e. the probability that a unit is not available when needed) using a simplified formula which achieves similar results as DAUFOP and $EFOR_d$.

EFOR(OP) is the ratio of forced hours (outages or deratings) divided by exposure hours, where exposure hours is the time a unit is "exposed" to the potential of a forced event, i.e. the time when the unit is needed. Exposure hours essentially equates to all hours in a period excluding planned and maintenance outage hours.

(b) The RMR Agreement EFOR(OP) range was calculated from an 8% target plus/minus 2%. The EFOR(OP) target of 8% is from OPG’s business plan for Thunder Bay Unit 3 (the RMR unit) and reflects the condition of the unit, and the planned resource funding for maintenance and OM&A projects in 2013.

(c) The penalty/reward concept was developed during the original Lennox RMR negotiations. The maximum amount was reduced from the $2M cap used for the Lennox RMR contracts to $500K for the Thunder Bay contract as requested by the IESO during the negotiations. The penalty / reward cap of $500K is associated with a contractual performance standard and is intended to provide an operational driver for OPG. The smaller cap is appropriate as Thunder Bay GS Unit G3 is a lower capacity plant when compared to Lennox GS. The amount still provides a sufficient incentive to ensure the unit is available to be offered efficiently into the IESO market.

Energy Probe Interrogatory #1 (3-Energy Probe-1) for OPG

Interrogatory

Ref: OPG Letter Requesting Approval, dated February 27, 2013, s.4 (b) & Attachment 1, Sch. D, Table 1

S.4 (b) of OPG's letter indicates that the monthly fixed payment is designed to compensate OPG for costs "that would be avoided by OPG if the facility is deregistered" and "is based on a forecast of fixed costs". The Notes to Table 1 refer, as regards certain costs, to a "relatively short term".

a) Does OPG agree that over a sufficiently long period of time, all costs are avoidable?

b) What is (are) the time period(s) used to distinguish each cost or cost category in Table 1 as avoidable rather than unavoidable?

Response

(a) Yes, OPG agrees that all costs are avoidable over a sufficiently long period of time.

(b) If a cost was deemed reasonably avoidable within a period of one to two years following shutdown of the plant then it was considered variable and recovery was included in the contract.

Energy Probe Interrogatory #2 (3-Energy Probe-2) for OPG

Interrogatory

Ref: OPG Letter Requesting Approval, dated February 27, 2013, s.4 (b) & Attachment 1, Sch. D, Table 1

In this table, Central Support-BU Allocated is shown as a cost to be compensated by the fixed monthly payment. Footnote 3 in Table 1 identifies this cost as "avoidable".

a) Please confirm that this cost item is, as it appears to be, an allocation of overhead support costs to a business unit. Please identify the business unit.

b) Having regard to the time period indicated for this cost item in response to Interrogatory 1(b) above, would it in fact be shed within the relevant time period if de-registration occurred, or would it be reassigned to other fixed cost categories or business units within OPG and continue to be incurred?

c) If this cost item would continue to be incurred by OPG following deregistration (perhaps by reassignment to another fixed cost category or business unit), does OPG maintain that it would be an "avoidable" cost as indicated in Footnote 3 Table 1 for the purposes of s.4 (b) in OPG's letter?

d) If this cost item would continue to be incurred by OPG following deregistration (perhaps by reassignment to another fixed cost category or business unit), does OPG maintain that it would not have been avoided for the purposes of s.4 (b) in OPG's letter?

e) More generally, if a particular cost is shown in Table 1 as "avoidable" but would not, in fact, be avoided in the relevant time period following deregistration, does OPG maintain that the monthly fixed payment should compensate OPG for such cost or that it should not compensate OPG for such cost?

Response

(a) Confirmed. Central Support - BU Allocated costs shown in Schedule D, Table 1 are corporate support costs that are directly attributable to the plant. OPG has allocated these costs to the plant using the same cost allocation methodology as it uses for its regulated assets, primarily based on the amount of work effort the respective corporate group devotes to a particular plant. The relevant business unit is OPG's Hydro Thermal business unit.

OPG's fully allocated cost report which has as its foundation an OEB-approved allocation methodology was used as a starting point to determine the cost of running the RMR facility. From there, a methodology was applied to each cost line item to determine if the costs were fixed or variable in nature.

Costs deemed as fixed, i.e. those which would be expected to continue regardless of the nature of operations at Thunder Bay GS, were excluded from the RMR costs. Those costs deemed as variable and incurred due to the operation of Thunder Bay GS were included in the RMR costs. Such variable costs would be expected to be eliminated in a reasonable period of time following the closure of Thunder Bay GS, as discussed in OPG's responses to Energy Probe Interrogatories 2(b), 2(c), 2(d) and 2(e) below.

This particular cost line item, Central Support-BU Allocated, includes certain IT system costs which were excluded from the RMR because they were deemed fixed in nature, and would not be expected to be eliminated if Thunder Bay GS were closed. Similarly, Business Development costs associated with possible conversion of the plant to a fuel other than coal have been excluded from the RMR. In addition, other cost line items from the fully allocated cost report have been completely excluded from the RMR because the costs are considered fixed.

(b) These costs would be avoided within one to two years. As indicated in OPG's response to Energy Probe Interrogatory 2(a), any costs deemed fixed in nature were excluded from the RMR.

(c) Yes. Any costs incurred following unit de-registration would have no impact on the 2013 RMR contract for which approval is now being sought, as the RMR contract would have ended.

It should be noted that Note 3 to Schedule D, Table 1 indicates that the corporate support costs listed in the note are avoidable within a relatively short term following de-registration and unit *closure*. Any costs incurred following unit de-registration would have no impact on the 2013 RMR contract for which approval is now being sought, as the RMR contract would have ended.

Consistent with the wording in Note 3 and OPG's above response to Energy Probe Interrogatory 2(a), these are not fixed costs and are specific to Thunder Bay G.S, and OPG expects the costs would be avoided in a reasonable period of time following plant closure.

(d) See OPG's above responses to Energy Probe Interrogatories 2(b) and 2(c).

(e) These costs are avoidable, and the monthly fixed payment should compensate OPG for such costs as they are directly attributable to Thunder Bay GS Unit 3 during the period of the 2013 RMR contract. Further, the Monthly Fixed Payment has been negotiated with the IESO and is not subject to audit or "true-up" during or subsequent to the term of the contract.

Energy Probe Interrogatory #3 (3-Energy Probe-3) for OPG

Interrogatory

Ref: OPG Letter Requesting Approval, dated February 27, 2013, s.4 (b) & Attachment 1, Sch. D, Table 1

Table 1 includes property taxes of $1.66 million.

a) If deregistration occurs, would OPG sell the property on which the indicated property taxes are paid?

b) If not, how would OPG avoid the costs of those property taxes following de-registration?

Response

(a) OPG has no plans to sell the property.

(b) If OPG does not sell the property, steps would be taken to mitigate the amount of the taxes with the intent to recover the cost through investment in conversion of the plant. These include addressing increased functional and economic obsolescence of various structures and systems to minimize the property taxes payable should the plant cease generation. Property tax, along with any other costs required to preserve the option of productive use of the land, would be considered in the business case supporting any proposal regarding the future of the plant.

NOACC-NOMA Interrogatory #12 for OPG

Interrogatory

MODELING

Will the OPG cooperate with the IESO in developing responses to the interrogatories set out in #2 through #7 above?

Response

12. Yes, OPG has cooperated with the IESO in developing its responses to NOACC-NOMA Interrogatories #2 through #7.

NOACC-NOMA Interrogatory #13 for OPG

Interrogatory

MODELING

Will the OPG, where appropriate, respond *mutatis mutandis* to the interrogatories set out in #2 through #7 above?

Response

13. OPG's responses, *mutatis mutandis,* to NOACC-NOMA Interrogatories #2 through #7 are as follows:

2. Has *OPG* performed, any reliability modelling for a power system plan for the Northwest Region for a planning ~~period prior to commissioning of the proposed upgrade to the East /West Tie on any of the following assumptions~~ after December 31, 2013: (note: track changes are per NOACC-NOMA original interrogatory)

   - Both with and without the TBGS in service, on load and generation forecasts for the Northwest Region propounded by the OPA; and
   - Both with and without the TBGS in service, on load and generation forecasts for the Northwest Region propounded by the NOACC Coalition.

   OPG Response:
   OPG has not performed such reliability modeling for the Northwest Region.

3. If so, will *OPG* provide the results of such reliability modelling?

   OPG Response:
   As indicated in OPG's response to question 2, OPG has not performed such reliability modeling for the Northwest Region.

4. If not will *OPG* conduct such reliability modelling in relation to the RMR Application at hand?

   OPG Response:
   No. In accordance with the steps outlined in Chapter 7, Sections 2.4 and 9.6 of the Market Rules, such modeling in relation to an RMR application is performed by the IESO.

5. In the event of reliability modeling conducted under either # 3 or # 4, as the case may be, will *OPG* identify any reliance, for purposes of reliability for the Northwest Region, on transmission supplied through extra-provincial ties, and include:

- The amount of that supply required to be available,
- The geographical source of that supply,
- The generation mix comprising that supply,
- The security of that supply (identifying specifically whether or not there is in existence, or indicating what assurance is in place that there will be in a timely fashion, a firm contract for that supply, or, in the alternative, whether reliance will be on spot market availability and pricing for that supply), and
- The range of foreseeable costs that will pertain to that supply?

<u>OPG Response</u>:
No. As indicated in OPG's response to question 4, such modeling is performed by the IESO.

6. In the event of reliability modeling conducted under 2 either # 3 or # 4, as the case may be, will *OPG* identify any reliance, for purposes of power system planning for the Northwest Region, on load shedding or other consequences of diminished adequacy in the power system in the Northwest Region and, if so, identify for purposes of understanding the effects of such outcomes arising from inadequate supply:

- The amount of that load shedding required to be made,
- The criteria for selecting, and the method of selecting, customers to be exposed to that load shedding,
- The anticipated frequency and durations of such load shedding, and
- The information *OPG* has as to the economic consequences to customers, particularly industrial customers, of such load shedding?

<u>OPG Response</u>:
No. As indicated in OPG's response to question 4, such modeling is performed by the IESO.

7. Will *OPG* provide modelling and the information related to modelling outlined in #2 through and including #6 above for a five year period immediately following the commissioning of the planned upgrade to the East / West Tie?

<u>OPG Response</u>:
No. As indicated in OPG's response to question 4, such modeling is performed by the IESO.

NOACC-NOMA Interrogatory #14 for OPG

Interrogatory

DURATION OF THE RMR AGREEMENT

If the Board approves the 2013-0061 RMR Agreement, does the OPG foresee a need to negotiate and apply for an approval of an RMR Agreement for a further term beyond December 31, 2013? If not, why not?

Response

14. It is not clear at this time whether there will be a need for another RMR agreement after December 31, 2013. The need for another RMR agreement would be determined by the IESO in accordance with the Market Rules.

    OPG does not expect that Thunder Bay GS will be able to earn sufficient revenues in the wholesale electricity market to cover its fixed and variable operating costs after 2013. Accordingly, OPG expects to submit a request to the IESO, prior to the expiration date of the 2013 RMR Agreement, to de-register Thunder Bay GS. The process to determine whether RMR negotiations would take place, and whether OPG is required to submit a new Thunder Bay RMR contract to the OEB for approval, would be determined in accordance with the steps outlined in Chapter 7, Sections 2.4, 9.6 and 9.7 of the Market Rules.

NOACC-NOMA Interrogatory #15 for OPG

Interrogatory

DURATION OF THE RMR AGREEMENT

If it is agreed, does the OPG foresee a need for a multi-year RMR Agreement, either by amendment of the existing Agreement for which approval is being sought in this Application, or by a subsequent RMR agreement?

Response

15. Please see OPG's response to NOACC-NOMA Interrogatory #14.

NOACC-NOMA Interrogatory #16 for OPG

Interrogatory

DURATION OF THE RMR AGREEMENT

If the Board approves the 2013-0061 RMR Agreement, does the OPG expect to file with the IESO a Request to De-Register the TBGS effective December 31, 2013, when the 2013-0061 RMR Agreement expires?

a) If so, why?

Response

16. Yes. OPG expects that Thunder Bay GS will be unable to earn sufficient revenues in the wholesale electricity market to cover its fixed and variable operating costs after the current agreement expires. However, OPG has no information about whether another RMR would be needed for the post-2013 period. That would have to be determined by the IESO in accordance with the Market Rules.

NOACC-NOMA Interrogatory #17 for OPG

Interrogatory

DURATION OF THE RMR AGREEMENT

In its decision in EB-2007-0715 (approving an RMR agreement for OPG's Lennox GS), the Board stated the following at page 5 (quoting from the Board's Procedural Order No. 1):

"Under paragraph 5.2 of Part I of OPG's licence, an RMR contract must comply with the Market Rules and such other conditions as the Board may consider reasonable. One such condition **could** be that any future RMR contract have a term of more than one year, if that would be more cost effective. While section 9.7.1.1 of Chapter 7 of the Market Rules states that an RMR contract may have a term of not more than one year, this is expressly subject to section 9.6.11.2 which in turn contemplates the possibility of the Board approving a different term"

Response

17. OPG has no response to the above, which appears to be a statement rather than a question.

NOACC-NOMA Interrogatory #18 for OPG

Interrogatory

Would the OPG support a multi-year RMR agreement for the TBGS Unit by either seeking amendment to the RMR Agreement once the current RMR Agreement expires on December 31, 2013?

Response

18. No. Given Ontario Regulation 496/07, the maximum length of contract possible once the current RMR Agreement expires on December 31, 2013 is one year.

NOACC-NOMA Interrogatory #19 for OPG

Interrogatory

DURATION OF THE RMR AGREEMENT

Will the OPG provide a detailed account of output in MW/month in relation to Generator 2 and Generator 3 at the Thunder Bay Generating Station for the last 5 years (as opposed to the graph provided in the OPG's Request for Approval).

Response

19. Although specific references to the graphs in question were not provided in the interrogatory, OPG is assuming the graphs being referred to are Figures 10 and 11 in the Thunder Bay De-Registration document prepared by the IESO and provided as Attachment 4 in OPG's application to the OEB.

    Based on discussions with the IESO, it was determined that the figures plotted in Figures 10 and 11 are hourly outputs of Units 2 and 3. Any reference to "MW/month" would require further definition as OPG and the utility industry typically refer to MWh/Month (megawatt-hours/month) which is a measure of energy over a specified period of time, whereas MW is a measure of capacity and is typically an instantaneous amount (such as the hourly values plotted in Figures 10 and 11), rather than a quantity measured over a period of time.

    OPG could provide the hourly figures as plotted in Figures 10 and 11, however this is a very large amount of data (24 hours x 365 days x 5 years x 2 units = 87,600 quantities) and is much more meaningful when summarized in a more usable format such as the bar graphs provided in the IESO De-Registration assessment.

    In OPG's view the closest proxy to providing monthly MW figures requested in the interrogatory is to provide the peak hourly MW output for each month derived from the above mentioned figures. This provides a reasonable picture of unit utilization as it shows the approximate maximum output that was required from the unit during that month in order to meet electricity demand.

    The output data described above is provided in the table provided as Attachment 1 to this response.

		Thunder Bay GS Output (Note 1)	
Year	**Month**	**Unit 2**	**Unit 3**
2008	Jan	151.2	151.8
	Feb	155.5	155.4
	Mar	160.2	156.7
	Apr	154.0	157.0
	May	148.7	158.2
	Jun	0.0	154.3
	Jul	152.5	154.0
	Aug	152.6	154.5
	Sep	152.5	134.4
	Oct	155.4	0.0
	Nov	154.6	0.0
	Dec	155.2	155.1
2009	Jan	156.1	156.5
	Feb	141.0	114.2
	Mar	0.0	0.0
	Apr	0.0	89.9
	May	0.0	0.0
	Jun	141.2	0.0
	Jul	142.6	94.1
	Aug	0.0	91.6
	Sep	146.7	0.0
	Oct	0.0	0.0
	Nov	42.5	0.0
	Dec	152.2	0.0
2010	Jan	153.4	157.3
	Feb	0.0	155.5
	Mar	65.2	150.2
	Apr	155.7	137.6
	May	0.0	156.5
	Jun	0.0	157.2
	Jul	0.0	156.9
	Aug	75.4	155.1
	Sep	0.0	0.0
	Oct	49.4	0.0
	Nov	0.0	153.4
	Dec	153.5	154.9
2011	Jan	0.0	151.3
	Feb	0.0	122.9
	Mar	0.0	0.0

NOACC-NOMA Interrogatory #19
ATTACHMENT 1

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Year	Month	Thunder Bay GS Output (Note 1)	
		Unit 2	Unit 3
	Apr	0.0	151.1
	May	156.6	0.0
	Jun	0.0	83.0
	Jul	0.0	141.1
	Aug	0.0	157.5
	Sep	0.0	156.0
	Oct	0.0	151.9
	Nov	146.3	150.9
	Dec	0.0	153.6
2012	Jan	0.0	155.7
	Feb	0.0	155.3
	Mar	0.0	0.0
	Apr	0.0	0.0
	May	0.0	0.0
	Jun	0.0	137.0
	Jul	0.0	54.5
	Aug	35.6	53.4
	Sep	0.0	134.7
	Oct	0.0	151.5
	Nov	46.8	140.9
	Dec	0.0	46.5

Note (1) Peak hourly MW output for each month derived from data provided by the IESO.

NOACC-NOMA Interrogatory #20 for OPG

Interrogatory

DURATION OF THE RMR AGREEMENT

Does the OPG share the NOACC-NOMA Intervenors view that the TBGS will be needed to operate as a must-run facility to ensure the reliability of the IESO controlled grid after the East West Tie upgrade becomes operational?

Response

20. OPG does not have a view as to whether Thunder Bay GS will be needed to operate as a must-run facility to ensure the reliability of the IESO controlled grid after the East West Tie upgrade becomes operational.

Power Workers' Union Interrogatory #1 (2.0-PWU-1) for OPG

Interrogatory

2) Are the financial provisions of the reliability must-run agreement reasonable?

Ref (1): February 27, 2013 Application, Page 3
(a) Performance Terms
The RMR Agreement obligates OPG to offer into the IESO-administered market the maximum available amount of energy and operating reserve from one unit at Thunder Bay GS consistent with good utility practice and in a commercially reasonable manner.

Ref (2): February 27, 2013 Application, Page 4
(b) Payment Terms
The RMR Agreement compensates OPG for the following cost components as described in Schedule A of the agreement:
1. A monthly fixed payment to cover costs that would be avoided by OPG if the facility was de-registered;
2. Market costs, which cover IESO charges related to the energy withdrawn from the IESO-controlled grid to maintain station operations;
3. Auxiliary boiler fuel costs and, in certain situations, costs incurred for regulatory testing; and,
4. A Net Revenue Sharing Adjustment ("NRSA"), which allows OPG to retain 5% of the operating profit (market revenue less actual fuel costs) when the RMR facility is dispatched to run. There is no NRSA when actual fuel costs exceed market revenues. This calculation is performed on a quarterly basis.

Variable costs are compensated through revenues earned in the IESO markets and not via this agreement.

Ref (2): February 27, 2013 Application, Page 6
The improvements in the Agreement are as follows:
1. Previous contracts provided for the recovery of fixed and variable costs after-the-fact as determined and invoiced by OPG. As noted in section 4(b) above, this Agreement provides for a fixed monthly payment based on a mutually agreed forecast of fixed costs, with variable costs being recovered through IESO energy market revenues. The predetermined fixed payment provides an increased incentive for OPG to manage its costs within the agreed levels.
2. Previous contracts provided for a revenue sharing mechanism that allowed OPG to receive 5% of gross revenue. This Agreement provides for OPG to receive a smaller incentive; 5% of net revenues after deducting the actual costs of fuel used when dispatched. Consumers will benefit from the smaller incentive payment provided to OPG, while OPG still maintains a sufficient incentive to offer the unit efficiently into the IESO market.
3. In addition, Schedule E of the RMR Agreement provides that OPG will offer the facility in such a way as to manage its limited fuel supplies in order to meet the

IESO's reliability needs and minimize its stranded fuel costs at the termination of the agreement.

a. Do the performance and payment terms of the Reliability Must-Run ("RMR") Agreement prevent OPG from recovering its variable costs when it is obligated to dispatch one unit at Thunder Bay Generating Station (GS) during hours in which actual fuel costs exceed market revenue?
b. Please elaborate the improvements in the RMR Agreement for Thunder Bay GS compared to previous RMR contracts with regard to the cost-effectiveness of the operation of Thunder Bay GS as an RMR resource.

Response

(a) No. OPG will continue to offer Thunder Bay GS Unit 3 in a commercially reasonable manner based on its costs pursuant to OPG's CO2 Implementation Strategy.

The IESO will only dispatch the unit if it is economical in the IESO-administered market or if it is required for local system reliability or adequacy needs, at which point the unit will be constrained on and OPG will receive a Congestion Management System Credit payment ("CMSC"). The CMSC payment provides for OPG to recover its fuel costs.

(b) The pre-determined fixed payment was reviewed and agreed upon by the IESO during the RMR Agreement negotiations. A fixed payment caps the risk to ratepayers. If actual fixed costs are greater than the fixed payment, the IESO is not invoiced for these additional costs.

The Net Revenue Sharing Adjustment ("NRSA") increases the cost effectiveness of the agreement by providing a revenue sharing mechanism that allows OPG to share in the operating profits rather than the gross revenues. This provides an additional driver for OPG to offer the unit based on its costs.

Schedule E reduces the costs of the agreement by transferring the majority of the risk of fuel inventory levels to the IESO which is in a better position to manage this risk than OPG. The IESO will declare if the unit is energy limited or if it requires OPG to purchase additional fuel based on its forecast of system reliability needs. Since this risk is being managed by the IESO it does not need to be quantified and included in the fixed payment.

Power Workers' Union Interrogatory #2 (4.0-PWU-1) for OPG

Interrogatory

4) Should the Board develop an expedited process to deal with an extension of the term of the RMR agreement for Thunder Bay GS beyond December 31, 2013?

This issue was proposed by the PWU in its submission filed on April 23, 2013 in response to the request of the Board on for input on whether any further issue(s) should be added to the issues list for this proceeding.

Ref (1): February 27, 2013 Letter Application, Attachment 4. IESO Technical Assessment, Thunder Bay De-registration, Page 2.

The Northwest zone will need to rely on one Thunder Bay unit to supply the zonal demand for 2013 to allow for lower than normal water conditions. Beyond this period, a new assessment would be required to evaluate the need for one Thunder Bay unit after the conversion of Atikokan to biomass is completed, and the operating characteristics of the converted unit are well known.

a. When does OPG expect that the Atikokan Conversion project will be completed?
b. When does OPG expect that Atikokan GS will return to service?
c. Is it OPG's understanding that the IESO expects to conduct a new assessment to evaluate the need of a unit at Thunder Bay GS beyond the expected end date of the RMR Agreement of December 31, 2013 until the time when Atikokan GS returns to service?
d. Please confirm that if a unit at Thunder GS still is required to operate beyond the end date of the RMR Agreement of December 31, 2013, OPG and the IESO will need to sign a new RMR agreement that comes into effect January 1, 2014.
e. Will such a new agreement require a new assessment to be conducted by the IESO to evaluate the need of using Thunder Bay facilities as RMR resources?
f. If a new assessment is required and the result of the new assessment with respect to the need of one unit at Thunder GS is similar to the result of the IESO's assessment that is the basis for the current Thunder Bay RMR Agreement, would the RMR Agreement with an effective date of January 1, 2014 be similar to the current RMR Agreement? Please provide explanation in your response.

Response

(a) The conversion of Atikokan G.S. to biomass is expected to be complete and in-service by August 2014.

(b) The conversion of Atikokan G.S. to biomass is expected to be complete and in-service by August 2014.

(c) OPG does not know whether the IESO expects to conduct a new assessment to evaluate the need of a unit at Thunder Bay GS beyond the expected end date of the RMR Agreement of December 31, 2013 until the time when Atikokan GS returns to service.

(d) Confirmed, assuming that Thunder Bay GS is unable to earn sufficient revenues in the wholesale electricity market to cover its fixed and variable operating costs and assuming that the IESO determines, in accordance with the Market Rules, that the unit is required beyond December 31, 2013.

(e) OPG understands that the Market Rules would require a new assessment to be conducted by the IESO to evaluate the need of using Thunder Bay facilities as RMR resources.

(f) The structure of any new RMR contract would be determined during the negotiation process between OPG and the IESO in accordance with Chapter 7, Sections 9.6 and 9.7 of the Market Rules.

VECC Interrogatory #1 (1-VECC-1) for OPG

Interrogatory

Does the reliability must-run agreement comply with OPG's licence?

Reference: General

Is OPG aware of any changes in either the market rules or in the terms and conditions of OPG's licence – since the last time the Board approved an R M-R Agreement pursuant to an application by OPG – that would have any effect with respect to approval being granted on the instant application? If so, please provide details.

Response

1. OPG is not aware of any changes in the IESO Market Rules or the terms and conditions of OPG's Generation Licence, since the last time the Board approved an RMR agreement pursuant to an application by OPG that would have any effect with respect to approval being granted on the instant application.

VECC Interrogatory #2 (2-VECC-1) for OPG

Interrogatory

Are the financial provisions of the reliability must-run agreement reasonable?

Preamble:

The Board's Decision with Reasons issued in the EB-2005-0490 proceeding stated in part:

Some salient provisions of the RMR Contract include:

• term of 1 year, without renewal or extension;

• payments to OPG of an estimated $62 million over the contract term (comprised of OPG's fixed and variable costs for Lennox, a "margin amount" of $1.283 million, and additional revenues equivalent to 5% of the gross revenues earned by or attributed to Lennox in the IESO-administered markets); and

• an obligation on OPG to offer into the IESO-administered markets the maximum amount of energy and operating reserve from Lennox in a commercially reasonable manner and in accordance with stated performance standards.

The Board's Decision with Reasons issued in the EB-2006-0205 proceeding stated in part:

Salient provisions of the new RMR Contract include:

- *One-year term, from October 1, 2006 to September 30, 2007, without renewal or extension (although it may be terminated by either party upon written notice);*
- *Estimated payments to OPG of $62 million over the contract term (comprised of OPG's fixed and variable costs for Lennox, a "margin amount" of $1.404 million, and additional revenues equivalent to 5% of the gross revenues earned by or attributed to Lennox in the IESO-administered markets);*
- *An obligation on OPG to offer into the IESO-administered markets the maximum amount of energy and operating reserve from Lennox in a commercially reasonable manner and in accordance with stated performance standards; and*
- *Rewards or penalties (neither to exceed $2 million) based on OPG exceeding or failing to meet agreed performance standards.*

Reference: EB-2005-0490, EB-2006-0205, General and Application, Schedule D, Table 1

Do the payments to OPG include a margin payment for OPG? If so, (i) what is the purpose of the margin payment, (ii) what is the amount of the margin payment, (iii) how was the margin payment determined, and (iv) what is the NBV of the subject facility?

Response

2(i). No. The margin amount concept was not used for the Thunder Bay RMR contract.

2(ii). There is no margin payment, therefore the amount is $0.

2(iii). This question is not applicable. (see response to question 2(i))

2(iv). The NBV is $NIL. The plant was fully impaired from an accounting perspective several years ago and fully written off at that time.

VECC Interrogatory #3 (2-VECC-2) for OPG

Interrogatory

Are the financial provisions of the reliability must-run agreement reasonable?

Preamble:

The Board's Decision with Reasons issued in the EB-2005-0490 proceeding stated in part:

Some salient provisions of the RMR Contract include:

• term of 1 year, without renewal or extension;

• payments to OPG of an estimated $62 million over the contract term (comprised of OPG's fixed and variable costs for Lennox, a "margin amount" of $1.283 million, and additional revenues equivalent to 5% of the gross revenues earned by or attributed to Lennox in the IESO-administered markets); and

• an obligation on OPG to offer into the IESO-administered markets the maximum amount of energy and operating reserve from Lennox in a commercially reasonable manner and in accordance with stated performance standards.

The Board's Decision with Reasons issued in the EB-2006-0205 proceeding stated in part:

Salient provisions of the new RMR Contract include:

- *One-year term, from October 1, 2006 to September 30, 2007, without renewal or extension (although it may be terminated by either party upon written notice);*
- *Estimated payments to OPG of $62 million over the contract term (comprised of OPG's fixed and variable costs for Lennox, a "margin amount" of $1.404 million, and additional revenues equivalent to 5% of the gross revenues earned by or attributed to Lennox in the IESO-administered markets);*
- *An obligation on OPG to offer into the IESO-administered markets the maximum amount of energy and operating reserve from Lennox in a commercially reasonable manner and in accordance with stated performance standards; and*
- *Rewards or penalties (neither to exceed $2 million) based on OPG exceeding or failing to meet agreed performance standards.*

Ref.: Application, Schedule D, Table 1

Were contingency amounts included in any of the line items in the referenced table? If so, please break out the contingency amount for all line items that contain such an amount and explain how each was determined.

Response

3. Only the “Projects” amount in Schedule D, Table 1 included contingency amounts. The table provided as Attachment 1 to this response provides a breakdown of the total 2013 budget estimate for each project included in the Projects amount of $970k, the contingency included, and the basis for the contingency amount.

Thunder Bay GS - 2013 Projects included in Monthly Fixed Payment

Project	Project No.	Budget ($k)	Contingency Included in Budget $	Basis for Contingency	Description of Project	Investment Driver
U3 Waterwall sootblower opening cracking	TBGS1089	300	10% / $27k	External Contracted Services related to scaffolding contract - not tendered as yet.	Addressing a known reliability condition in the boiler of cracking in the U3 waterwall sootblower openings. Low cost repair of pad welding, no large scale tube replacement.	Reliability
Treatment Boiler Makeup Water/Gas Exchange Membrane	TBGS1091	300	10% / $27k	Concept phase activities in progress - standard estimate for contingency.	Addressing corrosion condition (high dissolved oxygen make up water) introduced due to the unit's mode of operation (unpredictable run pattern and long periods of inoperation). Project helps sustain reliability and chemistry control during both off-line and on-line operation.	Reliability
Electrical Reconfiguration	TBGS1086	370	9% / $35k	To account for potential minor variances in tender for materials.	There are a small number of common electrical loads required for common service that are fed from Unit 1. Project addressses obsolescence and known reliability issue (inability to start up/operate when failure occurs). Arc chutes of these common electrical breakers contain asbestos, parts no longer available. Reconfigure electrical feed to main control room and eliminate asbestos hazard.	Safety/Reliability
Total		970				

VECC Interrogatory #4 (2-VECC-3) for OPG

Interrogatory

Are the financial provisions of the reliability must-run agreement reasonable?

Preamble:

The Board's Decision with Reasons issued in the EB-2005-0490 proceeding stated in part:

Some salient provisions of the RMR Contract include:

• term of 1 year, without renewal or extension;

• payments to OPG of an estimated $62 million over the contract term (comprised of OPG's fixed and variable costs for Lennox, a "margin amount" of $1.283 million, and additional revenues equivalent to 5% of the gross revenues earned by or attributed to Lennox in the IESO-administered markets); and

• an obligation on OPG to offer into the IESO-administered markets the maximum amount of energy and operating reserve from Lennox in a commercially reasonable manner and in accordance with stated performance standards.

The Board's Decision with Reasons issued in the EB-2006-0205 proceeding stated in part:

Salient provisions of the new RMR Contract include:

- *One-year term, from October 1, 2006 to September 30, 2007, without renewal or extension (although it may be terminated by either party upon written notice);*
- *Estimated payments to OPG of $62 million over the contract term (comprised of OPG's fixed and variable costs for Lennox, a "margin amount" of $1.404 million, and additional revenues equivalent to 5% of the gross revenues earned by or attributed to Lennox in the IESO-administered markets);*
- *An obligation on OPG to offer into the IESO-administered markets the maximum amount of energy and operating reserve from Lennox in a commercially reasonable manner and in accordance with stated performance standards; and*
- *Rewards or penalties (neither to exceed $2 million) based on OPG exceeding or failing to meet agreed performance standards.*

Ref.: Application, Schedule D, Table 1

a) Are the cost estimates in Table 1, unbiased, expected values?

b) Are the cost estimates in Table 1 consistent with any Association for the Advancement of Cost Engineering (AACE) Class Standards? If so, please elaborate.

Response

a) Yes, the cost estimates in Table 1 are unbiased, expected values. They are the result of OPG's annual business planning and budgeting process which is subject to various levels of review.

b) No. The estimated project costs in Table 1 are based on a combination of local experience, previous project performance and corporate guidelines. The estimates are subject to rigorous evaluation through OPG's annual business planning process and are evaluated throughout the various phases of the project which include identification, initiation, definition and execution. Further, costs are evaluated following project completion in the form of a PIR (Post Implementation Review). Detailed estimates must accompany all Business Cases, and include an annual breakdown of estimated project costs which include amounts for the actual work to be completed, and any costs that will be committed to through that work along with contingencies.

VECC Interrogatory #5 (3-VECC-1) for OPG

Interrogatory

What are the incentive effects, if any, of the reliability must-run agreement?

Reference: EB-2006-0205 Decision with Reasons, page 2 and Application, page 4, Penalties/Rewards Cap

a) In the cited Lennox R M-R proceeding, penalties/rewards were capped at $2M. In the current proceeding, penalties/rewards are capped at $500K. Please provide the reasons as to why the smaller cap is appropriate in OPG's view.
b) For any previously (Board) approved R M-R Agreement, did OPG hit the specified cap for penalties/rewards? If so, please provide details.

Response

a) The penalty / reward cap of $500K is associated with a contractual performance standard and is intended to provide an operational driver for OPG. The smaller cap is appropriate as Thunder Bay GS Unit G3 is a lower capacity plant when compared to Lennox GS. The amount still provides a sufficient incentive to ensure the unit is available to be offered efficiently into the IESO market.

b) The penalties/rewards for the four Lennox RMR contracts are provided in the table below. As shown, none of the penalties/rewards for the four Lennox RMR contracts reached the $2M cap.

Lennox RMR Contract Period	OEB Case No.	Penalty/Reward	Actual (Penalty)/Reward
Oct. 1/05 – Sep. 30/06	EB-2005-0490	Reward	$738,750
Oct. 1/06 – Sep. 30/07	EB-2006-0205	Reward	$1,188,750
Oct. 1/07 – Sep. 30/08	EB-2007-0715	Reward	$1,562,500
Oct. 1/08 – Sep. 30/09	EB-2008-0298	Reward	$1,285,000