Ex. K4.1

EB-2007-0905

AMPCO Cross-examination

Document Brief

OPG Panel #4: Nuclear Base OM&A

May 27, 2008

AMPCO'S EVIDENCE FOR EB-2007-0905

ONTARIO POWER GENERATION INC.

PAYMENT AMOUNT FOR PRESCRIBED GENERATING FACILITIES

EXHIBIT M TAB 2

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OPG is also planning to stabilize the operating cost per unit of production below the cost realized in 2007.

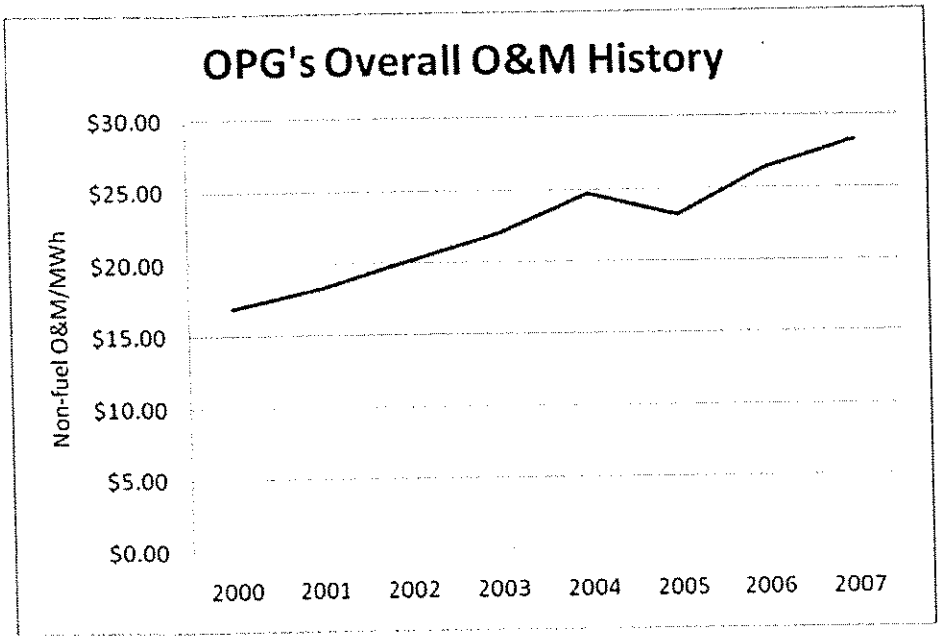
Table # 5 OPG Nuclear O&M and Production				
Year	production (TWh)	non-fuel o&m ($M)	Corp. O&M (N)	Unit Cost ($/MWh)
2005	45	1726.2	356.2	$46.28
2006	46.9	1,917.50	423.2	$49.91
2007	44.2	2,023.80	446.8	$55.90
2008	51.4	2,184.60	457	$51.39
2009	49.9	2,168.70	430.2	$52.08
Sources:	E2-1-1	F2-1-1	F3/1/1 T2	
Notes	2005 excludes $120M P2/3 impairment charge			

OPG is seeking approval of a payment amount for the nuclear facilities of $58.2M/month irrespective of output (up from zero under existing government direction) plus $41.50/MWh (down from $49.50/MWh under existing government direction) plus a rate rider.

Since 2004, OPG Nuclear claims to have been focused on increased investment in the material condition of the units, while maintaining the focus on safety performance, with an expectation that over the long-term, performance and reliability of the stations will improve resulting in increased production.[11]

[11] Prefile: A1/4/3 p. 9.

compound annual rate of approximately 8% per year. The worst period of cost escalation occurred during the period up and until the end of 2004.



Net income declined from $881 million in 2000 to $83 million in 2003, during a period when average revenue per unit production was reasonably stable.

As KPMG noted in the report "Ontario Power Generation Inc.: Financial Review of Operations" March 15, 2004, the key drivers for OPG's growing financial problems in 2003 were as follows:

> "The underperformance of OPG' s nuclear assets had a cascading negative financial impact on OPG' s overall operations. The cost overruns and delays on Pickering A, and the increased outages experienced by the nuclear fleet in general, caused OPG to rely much more heavily than expected on relatively expensive fossil generation." [30]

[30] KPMG, Ontario Power Generation Inc.: Financial Review of Operations, p. 4.

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CCC Interrogatory #49

Ref: Ex. A1-T3-S1, pages 8 - 10

Issue Number:
Issue:

Interrogatory

OPG has set out several "drivers" of the revenue deficiency. Please provide a value for each of the drivers listed. In effect, of the $1029.2 million deficiency how much is attributable to each of the drivers?

Response

The information requested is provided in the attached tables.

Quantification of Revenue Deficiency

Hydroelectric - Drivers of Revenue Defficiency

	Interim Rates	Updated Submission	Change	Drivers				
Average Rate Base ($M)	3966	3874	(92)	Increased ROE	Capital Structure	Other Factors	Total Change	"Other Factors" Notes
Allowable Costs ($M)								
Fuel /GRC Costs	416	424	8			8	8	Impact of graduated rates in test period
OM&A	136	201	64			64	64	Esclatation, payroll burden, programs, OPEB interest
Property Tax								
Capital Tax	19	15	(4)			(4)	(4)	
Depreciation	112	111	(1)			(1)	(1)	Small changes in assets/rate base
Interest	227	169	(58)		(51)	(7)	(58)	
Current Income Taxes	15		(15)			(15)	(15)	Application of tax losses to reduce taxes
Large Corporate Tax	9		(9)			(9)	(9)	Eliminated
Return on Equity	163	409	246	168	89	(11)	246	Lower assets/rate base
Required Revenues ($M)	1097	1329	232	168	38	26	232	
less Excess Earnings from: Ancillary and Other Services	(59)	(47)	13			13	13	Lower revenue forecast
Required Revenues less Excess Earnings ($M)	**1038**	**1282**	**244**	**168**	**38**	**38**	**244**	

Nuclear - Drivers of Revenue Defficiency

	Interim Rates	Updated Submission	Change	Drivers						
Average Rate Base ($M)	3300	3495	195	Nuclear Liabilities	Amort of deferred Nuc Liab costs	Increased ROE	Capital Structure	Other Factors	**Total Change**	"Other Factors" Notes
Allowable Costs ($M)										
Fuel /GRC Costs	202	330	128					128	**128**	Uranium & Used Fuel Management escalation
OM&A	3240	3799	559					559	**559**	Escalation, payrol burden costs, programs & new build, OPEB interes
Property Tax	47	25	(22)					(22)	**(22)**	Expected increases did not occur;
Capital Tax	38	14	(24)					(24)	**(24)**	Lower Asset Base
Depreciation	653	654	1	79	116			(194)	**1**	Lower assets/rate base,extended depreciation lives
Interest	195	152	(43)	24			(46)	(21)	**(43)**	Lower assets/rate base
Current Income Taxes	12		(12)	(137)				124	**(12)**	Offset to Nuclear Liability impact due to no taxes actually paid
Large Corporate Tax	19		(19)					(19)	**(19)**	Eliminated
Return on Equity	197	369	172	17		151	80	(76)	**172**	Lower assets/rate base
Required Revenues ($M)	**4604**	5342	739	(17)	116	151	34	454	**739**	
less Excess Earnings from: Bruce Lease	(211)	(121)	90	98		48	11	(67)	**90**	Extended Bruce asset life reduces dep'n, increases excess earnings
Ancillary and Other Services	(24)	(68)	(44)					(44)	**(44)**	Lower sales forecast
Required Revenues less Excess Earnings ($M)	**4368**	**5153**	**785**	**82**	**116**	**200**	**45**	**342**	**785**	

UNDERTAKING J1.1

Undertaking

To file the Ontario government backgrounder announcing prices on electricity from Ontario Power Generation:.

Response

Attached is the Ministry of Energy Backgrounder.

Backgrounder/ Document d'information

Ontario

Ministry of Energy Ministère de l'Énergie

February 23, 2005

ONTARIO GOVERNMENT ANNOUNCES PRICES ON ELECTRICITY FROM ONTARIO POWER GENERATION

The Ontario government has established prices for electricity produced by Ontario Power Generation (OPG) effective April 1, 2005. These prices are designed to:

- Better reflect the true cost of producing electricity
- Ensure a reliable, sustainable and diverse supply of power in Ontario
- Protect Ontario's medium and large businesses by ensuring rates are stable and competitive
- Provide an incentive for OPG to contain costs and to maximize efficiencies
- Allow OPG to better service its debt while earning a rate of return that balances the needs of customers and ensures a fair return for taxpayers
- Relieve taxpayers of the burden of a financially unsustainable rebate program.

Prices on Output of OPG's Regulated Assets

- Under Bill 100, the Electricity Restructuring Act, the government is obliged to set a price for the output of OPG's regulated assets. These assets include the Adam Beck and Decew hydro stations at Niagara, the R.H. Saunders hydro station near Cornwall, and the Pickering and Darlington nuclear stations. These assets provide much of the province's baseload generation, and operate on a nearly constant basis to provide Ontario's homes and businesses with power.

- Regulating the price of OPG's baseload nuclear and hydroelectric assets will reduce price volatility and have a stabilizing effect on electricity prices, which will be of benefit to all consumers.

- Ontario Power Generation's regulated assets represent approximately 60 per cent of OPG's annual output, and approximately 40 per cent of the total generation in Ontario.

- Under the regulation announced today, OPG's baseload hydroelectric generation will be set at 3.3 cents per kilowatt hour, and the price for OPG's nuclear generation will be set at 4.95 cents per kilowatt hour. An average price of 4.5 cents per kilowatt hour is projected for the weighted forecast output for the hydroelectric and nuclear generation combined.

- The prices on OPG's regulated assets are based on projected costs of operation, plus a five per cent return on equity (ROE). While the standard ROE for North

American utilities is ten per cent, a five per cent ROE will generate revenue to service the OPG debt held by the Ontario Electricity Financial Corporation, while putting significant discipline on OPG to contain costs and improve overall operating efficiencies.

- The new prices will stay in effect until the Ontario Energy Board (OEB) develops mechanisms for setting prices for OPG's regulated assets as stipulated in the Electricity Restructuring Act, 2004, no later than March 31, 2008. Transferring the authority to the OEB to set prices for electricity generated from OPG is consistent with the government's commitment to ensure politics are taken out of electricity pricing in the province.

Prices on Output of OPG's Unregulated Assets

- As a result of a ministerial directive, OPG's revenues on most of the output of its unregulated assets (non-baseload hydroelectric, coal and gas-fired stations), which represents approximately 33 per cent of all generation in Ontario, will be temporarily set at an upper limit of 4.7 cents per kilowatt hour. Ontario Power Generation will pay a rebate on revenues over this amount.

- This revenue limit will temporarily be in place from April 1, 2005 to April 30, 2006. It replaces the Market Power Mitigation Agreement (MPMA) implemented by the previous government when it attempted to open Ontario's electricity market in May 2002.

- The revenue limit on OPG's unregulated assets is designed to ensure continued pressure on OPG to contain costs and enhance performance, while acting as a transitional measure to protect consumers as they adjust to the new prices. It is also designed to ensure that OPG has the incentive to respond to market signals and limit OPG's market power.

- The recent Request for Proposals (RFP) which will result in almost 400 megawatts of new renewable energy supply, together with the current RFP for 2,500 megawatts of new clean energy supply, demand response and energy conservation initiatives, both clearly demonstrate that the McGuinty government is taking decisive steps to close the looming gap between electricity supply and demand in the province.

Effect on Consumers

- The new pricing takes effect on April 1, 2005, and will have an immediate impact on the approximately 55,000 large industrial and commercial electricity customers across Ontario who use more than 250,000 kilowatt hours per year.

- To provide some recent historical comparisons on the likely price impacts, commodity prices that large consumers will pay starting April 1 are expected to be 1.5 per cent higher than the prices which prevailed in 2002/2003, the first year of

market opening. The prices will be about 5 per cent higher than 2003 prices, and between 8 to12 per cent higher than the unusually soft prices in 2004 (in part, the result of extremely moderate weather in both the summer and winter peak demand periods).

- It is important to look at today's announcement in the broader context of price trends over a number of years, rather than just looking at comparisons to any one specific period where, for example, unusual weather patterns could be a key driver in setting overall price levels.

- It is also important to look at today's announcement in the context of commodity price increases that have also recently taken place or have been announced in key U.S. jurisdictions, as well as in Quebec and Manitoba, two of the lowest cost electricity jurisdictions in North America. By April 1, 2005, for example, it is forecast that Quebec (which relies almost exclusively on hydroelectric power) prices for all classes of customers will have increased by about 7 per cent over the period 2004/2005. In addition, on August 1, 2004, Manitoba (another major hydroelectric jurisdiction) introduced new general rates which represented an average increase of 5 per cent for all customer classes.

- Even with the removal of the MPMA, electricity costs for large industrial and commercial users in Ontario will continue to match neighbours with whom we compete such as Michigan and Illinois, and in fact will be lower than such jurisdictions as New York, Masssachusetts and Pennsylvania.

- In order to help large customers cope with the realities of increasing electricity prices, while adding needed new electricity supply to Ontario, the McGuinty government has also announced that it is appointing an industrial co-generation facilitator to actively encourage industrial cogeneration projects in the province (see accompanying backgrounder). Co-generation opportunities can significantly reduce electricity costs for large industrial users, resulting in enhanced operational efficiencies and improved overall competitiveness.

- While residential, small business and designated consumers will not be affected immediately the Ontario Energy Board's new regulated price plan (RPP) will take effect no later than May 1, 2005. The board will blend the various prices paid to generators into a fixed price that consumers will pay under the RPP. That price will be stable but still reflect the true cost of producing electricity.

History of the Market Power Mitigation Agreement

- The MPMA was put in place by the previous government when it tried to open Ontario's electricity market in May 2002, in order to prevent OPG from exploiting its dominant position as the majority supplier of Ontario's electricity. The MPMA structure was intended to be a temporary measure consistent with the previous government's policy of selling OPG's generation assets.

- Since its inception, the MPMA has cost OPG approximately $100 million per month and approximately $3.3 billion in total. As a result, OPG has suffered poor financial performance over the last three years, and the government and taxpayers have not been able to realize any financial benefit from OPG.

- Under the MPMA, all customers who use more than 250,000 kilowatt hours per year receive a rebate if the annual average Ontario electricity price exceeds 3.8 cents per kilowatt hour. This rebate applies to half of the electricity they consume.

- Due to the MPMA, electricity prices for consumers have been effectively subsidized by taxpayers, and OPG has not been able to recover the cost of generating the electricity it produces. This has severely compromised the company's ability to improve its overall financial performance.

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Numbers may not add due to rounding.

Updated: 2008-03-14
EB-2007-0905
Exhibit F3
Tab 1
Schedule 2
Table 2a

Table 2a
Comparison of Allocation of Corporate Support & Administrative Costs ($M)
Nuclear

Line No.	Corporate Group	2005 Budget	(c)-(a) Change	2005 Actual	(e)-(c) Change	2006 Actual	(e)-(g) Change	2006 Budget	(i)-(e) Change	2007 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Finance	34.3	(3.0)	31.3	1.3	32.6	(1.0)	33.6	1.7	34.3
2	Corporate Affairs	10.7	(1.5)	9.2	1.8	11.0	(1.0)	12.0	(0.4)	10.6
3	CIO	109.6	(10.8)	98.8	(2.9)	95.9	(13.3)	109.2	15.6	111.5
4	Corporate Centre[1]	16.9	(5.0)	11.9	(1.7)	10.2	(2.7)	12.9	1.6	11.8
5	Energy Markets	2.8	0.0	2.8	(1.5)	1.3	(0.1)	1.4	1.2	2.5
6	Human Resources	27.3	0.7	28.0	2.7	30.7	(1.8)	32.5	2.1	32.8
7	Real Estate	35.7	0.4	36.1	(7.5)	28.6	(3.9)	32.5	4.5	33.1
8	Sub-Total	237.3	(19.2)	218.1	(7.8)	210.3	(23.8)	234.1	26.3	236.6
	Centrally Held Costs:									
9	Pension/OPEB Related	73.6	(0.8)	72.8	85.1	157.9	40.9	117.0	(23.1)	134.8
10	Insurance	14.3	(2.5)	11.8	0.0	11.8	(1.4)	13.2	(0.3)	11.5
11	Performance Incentives	24.6	0.0	24.6	4.3	28.9	4.2	24.7	0.1	29.0
12	IESO Non-Energy Charges	11.5	(0.7)	10.8	(0.7)	10.1	(2.7)	12.8	(0.3)	9.8
13	Other	35.6	(17.5)	18.1	(13.9)	4.2	(7.5)	11.7	20.9	25.1
14	Sub-Total	159.6	(21.5)	138.1	74.8	212.9	33.5	179.4	(2.7)	210.2
15	Total	396.9	(40.7)	356.2	67.0	423.2	9.7	413.5	23.6	446.8

1 Corporate Centre includes Executive Office, Corporate Secretary, and Law.

Chart 3
Nuclear Benchmarking Results

Measure		Value*	Comparison	Source and Peer Group
Production Unit Energy Costs "PUEC" ($/MWh Can$)	Pickering A	68	US industry median is 24 $/MWh, US top quartile is 20 $/MWh. PA/PB U.S size peer group median 32 $/MWh DN U.S. size peer group median 23 $/MWh	EUCG** for 2006 (CANDU worldwide PUEC data is not available) U.S. – Can. $ Fx rate 0.88
	Pickering B	50		
	Darlington	26		
	Nuclear	48		
Unit Capability Factor (%)	Pickering A	69.6	CANDU : Median: 86.4 Top quartile: 92.4.	OPG/WANO data: three year average. CANDU unit capability factor scores include OPG
	Pickering B	74.3		
	Darlington	89.2		
	Nuclear	81.4		
Nuclear Performance Index (NPI)	Pickering A	56.6	CANDU: Median: 74.6; Top quartile: 85.8	OPG/WANO NPI data: up to 3 year averages for various components CANDU NPI scores exclude OPG
	Pickering B	56.9		
	Darlington	92.7		
	Nuclear	68.7		
Elective Maintenance Backlogs (# outstanding per unit)	Pickering A	450	US industry median: 348; US top quartile: 304	Sourced from WANO working group but not standard WANO measure. One year data for OPG/WANO.
	Pickering B	850		
	Darlington	400		
	Nuclear avg.	590		

*OPG benchmark data are based on current business plan information provided to the Shareholder.
**EUCG cost data are always in U.S. dollars of the year, and are not normalized in any way for unit size, age, or technology differences.

1.0 Production Unit Energy Cost

External information is collected via EUCG, a non-profit organization whose membership includes 99 percent of U.S. nuclear operators, as well as many others outside of the U.S. The organization collects, validates, and publishes blinded cost and production data to

AMPCO Interrogatory #43

Ref: Ex. A1-T4-S3, page 18 - "Darlington continues to perform very well, relative to its peer group, at $26/MWh."

Issue Number: 5.1
Issue: Are the Operation, Maintenance and Administration ("OM&A") budgets for the prescribed hydroelectric and nuclear business appropriate?

Interrogatory

OPG indicates that the median Partial Unit Energy Cost (PUEC) performance for U.S. reactors of similar size is $23/MWh. Please indicate the third quartile PUEC boundary.

Response

The 3rd quartile Production Unit Energy Cost ("PUEC") boundary is $27/MWh (Cdn $).

AMPCO Interrogatory #46

Ref:

Issue Number: 5.1
Issue: Are the Operation, Maintenance and Administration ("OM&A") budgets for the prescribed hydroelectric and nuclear business appropriate?

Interrogatory

Based on information from New Brunswick (NB) Power's annual reports and OPG's prefiled material (where general nuclear operating costs are allocated on a per unit basis), the operating cost per unit of production for Pickering B compare with those of Point Lepreau as follows:

Year	Lepreau Op Cost ($/MWh)	Pickering B Op Cost ($/MWh)
2005	$33.49	$50.69
2006	$32.80	$54.12
2007	$35.25	$54.99

Please comment on the appropriateness of this comparison. In comparing Pickering B with Point Lepreau, what adjustment is appropriate in OPG's opinion taking into account Pickering B's younger age and larger station output, multi-unit design. Please explain why OPG has been unable to match the performance of NB Power with respect to operating costs.

Response

OPG does not have detailed knowledge of what is included in the NB Power Unit costs shown in the chart. For example, capitalization policies can vary from company to company. This will influence OM&A costs.

Also refer to L-1-34, which outlines additional issues that must be taken into account when performing inter-utility cost comparisons.

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The design of the Point Lepreau reactor (Candu 6) is significantly different than that of the Pickering B reactors. The Point Lepreau reactor was specifically designed to be a single unit reactor, whereas the Pickering B design is an updated version of the Pickering A reactor design. Listed in the table below is a comparison between the Pickering B and the Point Lepreau reactor design. Given the significant design differences, operating costs will differ and a direct cost comparison between the two stations is not a meaningful benchmark.

Comparison	Pickering B	Point Lepreau (Candu 6)
Generator output	540 MWe	680 MWe
Steam Generators (per unit)	12	4
Main Coolant (pumps / unit)	16	4
Moderator Pumps (per unit)	5	2
Heat Transport Pressure Control	Feed / Bleed System	Pressurizer
Negative Pressure Containment System	Vacuum building - requires vacuum pumps and instrumentation to support system operation - results in a station outage for all units at Pickering A & B once every 10 years	Dousing tank inside containment
Boiling allowed by design in the outlet of the fuel channels	No	Yes
In-service Date	1983 (first unit)	1983
Refurbishment	- current end of production life in 2014 - decision expected on refurbishment no later than early 2009	2008 (already in progress)

The evidence at Ex. A1-T4-S3, Section 9 outlines additional issues around benchmarking industry peers.

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AMPCO Interrogatory #41

Ref: Ex. A1-T4-S3 page 13

Issue Number: 5.1
Issue: Are the Operation, Maintenance and Administration ("OM&A") budgets for the prescribed hydroelectric and nuclear business appropriate?

Interrogatory

Please reproduce Chart #2 including actual results for 2005-2007.

Response

Chart 2

Nuclear Generating Station Actual Results

MEASURE	2005	2006	2007
Generation (TWH)			
Pickering A	3.60	6.42	3.63
Pickering B	13.90	13.54	13.37
Darlington	27.60	26.97	27.25
Total Nuclear	45.00	46.92	44.25
Production Unit Energy cost (PUEC) - ($/MW/h)			
Pickering A	113.9	75.6	130.1
Pickering B	51.3	55.5	55.9
Darlington	23.9	28.7	31.6
Nuclear Avg.	39.7	42.9	47.2
Unit Capability Factor %			
Pickering A	69.9	72.0	41.3
Pickering B	77.7	75.2	75.0
Darlington	90.6	88.7	89.5
Nuclear Avg.	84.4	81.9	77.5
Nuclear Performance Index			
Pickering A	60.2	63.5	54.7
Pickering B	61.6	63.8	61.8
Darlington	95.3	91.6	91.2
Nuclear Avg.	76.4	76.1	72.1

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Elective Maintenance Backlogs (per unit)			
Pickering A	541	558	428
Pickering B	805	885	926
Darlington	767	584	373
Nuclear Avg.	605	676	576

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