EB-2010-0008

SCHOOL ENERGY COALITION

CROSS- EXAMINATION MATERIALS

PANEL 1

1. Ex. L-12-44
2. Ex. L-12-46
3. Ex. L-12-48
4. Ex. G-1-1
5. EB-2007-0905, Ex. G-1-1, pp. 13-15
6. EB-2007-0905, Ex. L-1-67
7. EB-2007-0905, Ex. L-3-96
8. EB-2007-0905, Decision with Reasons, pp. 45-50
9. Ex. A2-1-1, Attach. 2, Excerpts
10. Ex. F1-1-1, Attach 1, pp. 32-34

SEC Interrogatory #044

Ref: Ex. D1-T1-S2, Attachment 1 (Niagara Tunnel Project)

Issue Number: 4.2
Issue: Are the capital budgets and/or financial commitments for 2011 and 2012 for the regulated hydroelectric business appropriate and supported by business cases?

Interrogatory

a) P. 1. Please provide a copy of the report and recommendations of the Dispute Review Board.

b) P. 1. Please provide a copy of the agreement with OEFC increasing the facility limit to $1.6 billion.

c) P. 1. Please show full calculations of the LUEC of under 7 cents and the equivalent Power Purchase Agreement price of under 10 cents, in both cases including all necessary assumptions and the sources for those assumptions.

d) P. 3. Please provide a copy of the non-binding Principles of Agreement in 2008 and the non-binding Term Sheet in February 2009.

e) P. 3. Please advise the members of the Major Projects Committee in November 2008.

f) P. 3. Please provide the agreement or other document setting out the new arrangement between the Applicant and Strabag, including the Project Execution Plan.

g) P. 12. Please provide a copy of the Chestnut Park Accord Addendum.

h) P. 12. Please confirm that the methodology for forecasting the cost of the project is the same as that used for the original budget estimates.

i) P. 12. Please provide a copy of the analysis on which the XXXX month contingency is based.

j) App. B. Please re-run the cost model using the higher ROE now being sought by the company, and report the impact on the results.

Response

a) OPG declines to provide the requested document as a review of this document would necessarily involve inquiry into issues that are not relevant to an update of the project's current status, but relate instead to matters that are covered by the OEB's express determination not to review the prudence of projects that will not close to rate base in the test period.

b) Attached is the Amending Agreement to the Credit Facility Agreement between OPG and the OEFC for the purpose of financing the Niagara Tunnel Project (Attachment 1).

c) The requested calculations are shown in Attachment 2.

d) See response to part a).

e) David McMillan (Chair), Ian Ross, Marie Rounding, Bill Sheffield, David Unruh.

f) See response to part a).

g) OPG declines to produce this document because it is not relevant to a status update for the Niagara Tunnel project. The Chestnut Park Accord Addendum ("CPAA") outlines the protocol that OPG has agreed to follow for trades work assignment on OPG work. In the case of the Niagara Tunnel which is new construction, all of the construction work was assigned as Building Trades work.

h) Yes, the same cost model (Work Breakdown Structure and Cost Breakdown Structure) is being used.

i) See response to part a).

j) The Niagara Tunnel Project costs model was re-run based on a return of equity of 9.85 per cent. The following are the resulting changes. The Levelized Unit Energy Cost ("LUEC") and Power Purchase Agreement ("PPA") rates are not affected as the discount rate of 7 per cent is unchanged (see response to Interrogatory L-6-002 for details).

Filed: 2010-08-12
EB-2010-0008
L-12-044
Attachemnt 2

Costs - Present Value

Capital Costs	($M)	886.5
Operating Costs		
GRC	($M)	117.8
OM&A	($M)	1.1
Capital Tax	($M)	3.8
Large Corporation Tax	($M)	0.6
NPV - Total (2005$)	($M)	$\boxed{1009.8}$

Assumptions:

1) PV date July 1, 2005
2) Operating cash flows assumed to occur in June of each year
3) Discount Rate 7%
4) Total Project cost of $1.6B (includes $286.6M of Interest During Construction)
5) 100% assigned to Capital Cost Allowance (CCA) Class 1 which includes "Dams, tunnel, buildings & other structures"
6) Capital costs include working capital requirements which has been calculated assuming:
   a) on average revenues paid to OPG based on a 37 day lag
   b) on average OPG pays OM&A based on a 14 day lag
   c) on average GRC is paid immediately, 0 day lag
7) 10 year GRC holiday starting upon COD
8) GRC property tax rate of 26.5% and GRC water rental rate of 9.5%
9) GRC cost based on $40/MWh escalating at 2% starting 2014
10) OM&A costs of $.11M (2005$M/year) escalated by CPI
11) Capital Tax Rate: 2005 .3%, 2006 .3%, 2007 .3%, 2008 .3%, 2009 .23%, 2010 .15%, 2011 .08%, disappears after 2011
12) Large Corporation Tax Rate: 2005 .18%, 2006 .13% 2007 .06%, disappears after 2007
13) Income Tax Rate (Federal and Provincial): 2005 34.12%, 2006 34.12%, 2007 31.0%, 2008 30.0%, 2009 28.5%, after 2009 27.0%
14) Annual Energy Production based on Niagara River flows from 1926 to 2002 to determine diversion flows
15) in 2017 a scheduled outage on Niagara's canal is expected to occur resulting in increased energy produciton for the tunnel
16) LUEC escalates at CPI
17) PPA - 20% of PPA escalates at CPI
18) Total NPV of costs equals total NPV of LUEC revenues over 90 year life
19) Total NPV of costs equals total NPV of PPA revenues over 90 year life

LUEC

				2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Year				2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Energy Production	(TWh)		(a)	-	-	-	-	-	-	-	-	-	1.6	1.6	1.6	2.7	1.6	1.6
Yearly Escalation (CPI)	(%)			1.80%	1.60%	1.80%	1.90%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Escalation Rate from 2009								1.000	1.020	1.040	1.061	1.082	1.104	1.126	1.149	1.172	1.195	1.219
LUEC Rate (escalated)	(¢/kWh)	6.8	(b)					6.8	6.9	7.1	7.2	7.4	7.5	7.7	7.8	8.0	8.1	8.3
Yearly Revenue	($M)		(c) = (a)*(b)					0.0	0.0	0.0	0.0	0.0	117.2	119.5	121.9	212.1	126.9	129.4
Discount Rate	(%)			7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
Annual Discount Factor			(d)	1.000	0.935	0.874	0.816	0.763	0.713	0.666	0.623	0.582	0.544	0.508	0.475	0.444	0.415	0.388
(1 - combined income tax rate)			(e)	65.9%	65.9%	69.0%	70.0%	71.5%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%
NPV - LUEC Revenue (sum all years)			(f) = (c) * (d) * (e)	$\boxed{1009.8}$									46.5	44.4	42.3	68.7	38.4	36.6

PPA

					2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Year					2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Energy Production	(TWh)			(a)	-	-	-	-	-	-	-	-	-	1.6	1.6	1.6	2.7	1.6	1.6
Yearly Escalation (CPI)	(%)				1.80%	1.60%	1.80%	1.90%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
PPA Rate (escalated)	(¢/kWh)	9.6	20%											1.9	2.0	2.0	2.0	2.1	2.1
	(¢/kWh)		80%											7.7	7.7	7.7	7.7	7.7	7.7
	(¢/kWh)			(b)										9.6	9.6	9.7	9.7	9.8	9.8
Yearly Revenue	($M)			(c) = (a)*(b)										149.7	150.3	150.9	258.3	152.1	152.8
Discount Rate	(%)				7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
Annual Discount Factor				(d)	1.000	0.935	0.874	0.816	0.763	0.713	0.666	0.623	0.582	0.544	0.508	0.475	0.444	0.415	0.388
(1 - combined income tax rate)				(e)	65.9%	65.9%	69.0%	70.0%	71.5%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%
NPV - LUEC Revenue (sum all years)				(f) = (c) * (d) * (e)	$\boxed{1009.8}$									59.4	55.8	52.3	83.7	46.1	43.2

Costs - Present Value

Capital Costs	($M)
Operating Costs	
GRC	($M)
OM&A	($M)
Capital Tax	($M)
Large Corporation Tax	($M)
NPV - Total (2005$)	($M)

Assumptions:
1) PV date July 1, 2005
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LUEC

Year		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Energy Production	(TWh)	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Yearly Escalation (CPI)	(%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Escalation Rate from 2009		1.243	1.268	1.294	1.319	1.346	1.373	1.400	1.428	1.457	1.486	1.516	1.546	1.577	1.608	1.641	1.673	1.707	1.741	1.776	1.811	1.848
LUEC Rate (escalated)	(¢/kWh)	8.5	8.6	8.8	9.0	9.2	9.3	9.5	9.7	9.9	10.1	10.3	10.5	10.7	10.9	11.2	11.4	11.6	11.8	12.1	12.3	12.6
Yearly Revenue	($M)	132.0	134.6	137.3	140.1	142.9	145.7	148.6	151.6	154.6	157.7	160.9	164.1	167.4	170.7	174.2	177.6	181.2	184.8	188.5	192.3	196.1
Discount Rate	(%)	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
Annual Discount Factor		0.362	0.339	0.316	0.296	0.276	0.258	0.241	0.226	0.211	0.197	0.184	0.172	0.161	0.150	0.140	0.131	0.123	0.115	0.107	0.100	0.094
(1 - combined income tax rate)		73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%
NPV - LUEC Revenue (sum all years)		34.9	33.3	31.7	30.2	28.8	27.5	26.2	25.0	23.8	22.7	21.6	20.6	19.6	18.7	17.9	17.0	16.2	15.5	14.7	14.0	13.4

PPA

Year		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Energy Production	(TWh)	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Yearly Escalation (CPI)	(%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
PPA Rate (escalated)	(¢/kWh)	2.2	2.2	2.2	2.3	2.3	2.4	2.4	2.5	2.5	2.6	2.6	2.7	2.7	2.8	2.9	2.9	3.0	3.0	3.1	3.1	3.2
	(¢/kWh)	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
	(¢/kWh)	9.8	9.9	9.9	10.0	10.0	10.1	10.1	10.2	10.2	10.3	10.3	10.4	10.4	10.5	10.5	10.6	10.6	10.7	10.8	10.8	10.9
Yearly Revenue	($M)	153.5	154.1	154.8	155.5	156.2	157.0	157.7	158.5	159.2	160.0	160.8	161.7	162.5	163.4	164.2	165.1	166.0	166.9	167.9	168.9	169.8
Discount Rate	(%)	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
Annual Discount Factor		0.362	0.339	0.316	0.296	0.276	0.258	0.241	0.226	0.211	0.197	0.184	0.172	0.161	0.150	0.140	0.131	0.123	0.115	0.107	0.100	0.094
(1 - combined income tax rate)		73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%
NPV - LUEC Revenue (sum all years)		40.6	38.1	35.8	33.6	31.5	29.6	27.8	26.1	24.5	23.0	21.6	20.3	19.1	17.9	16.8	15.8	14.9	14.0	13.1	12.3	11.6

Costs - Present Value

Capital Costs	($M)
Operating Costs	
GRC	($M)
OM&A	($M)
Capital Tax	($M)
Large Corporation Tax	($M)
NPV - Total (2005$)	($M)

Assumptions:
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LUEC

		2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061
Year		2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061
Energy Production	(TWh)	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Yearly Escalation (CPI)	(%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Escalation Rate from 2009		1.885	1.922	1.961	2.000	2.040	2.081	2.122	2.165	2.208	2.252	2.297	2.343	2.390	2.438	2.487	2.536	2.587	2.639	2.692	2.745	2.800
LUEC Rate (escalated)	(¢/kWh)	12.8	13.1	13.3	13.6	13.9	14.2	14.4	14.7	15.0	15.3	15.6	15.9	16.3	16.6	16.9	17.3	17.6	18.0	18.3	18.7	19.1
Yearly Revenue	($M)	200.1	204.1	208.1	212.3	216.5	220.9	225.3	229.8	234.4	239.1	243.9	248.7	253.7	258.8	264.0	269.2	274.6	280.1	285.7	291.4	297.3
Discount Rate	(%)	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
Annual Discount Factor		0.087	0.082	0.076	0.071	0.067	0.062	0.058	0.054	0.051	0.048	0.044	0.042	0.039	0.036	0.034	0.032	0.030	0.028	0.026	0.024	0.023
(1 - combined income tax rate)		73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%
NPV - LUEC Revenue (sum all years)		12.8	12.2	11.6	11.1	10.5	10.0	9.6	9.1	8.7	8.3	7.9	7.5	7.2	6.8	6.5	6.2	5.9	5.7	5.4	5.1	4.9

PPA

Year		2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061
Energy Production	(TWh)	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Yearly Escalation (CPI)	(%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
PPA Rate (escalated)	(¢/kWh)	3.3	3.3	3.4	3.5	3.5	3.6	3.7	3.8	3.8	3.9	4.0	4.1	4.2	4.2	4.3	4.4	4.5	4.6	4.7	4.8	4.9
	(¢/kWh)	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
	(¢/kWh)	11.0	11.0	11.1	11.2	11.2	11.3	11.4	11.4	11.5	11.6	11.7	11.7	11.8	11.9	12.0	12.1	12.2	12.3	12.4	12.4	12.5
Yearly Revenue	($M)	170.8	171.9	172.9	174.0	175.1	176.2	177.3	178.4	179.6	180.8	182.0	183.3	184.5	185.8	187.2	188.5	189.9	191.3	192.7	194.2	195.7
Discount Rate	(%)	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
Annual Discount Factor		0.087	0.082	0.076	0.071	0.067	0.062	0.058	0.054	0.051	0.048	0.044	0.042	0.039	0.036	0.034	0.032	0.030	0.028	0.026	0.024	0.023
(1 - combined income tax rate)		73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%
NPV - LUEC Revenue (sum all years)		10.9	10.2	9.6	9.1	8.5	8.0	7.5	7.1	6.7	6.3	5.9	5.6	5.2	4.9	4.6	4.4	4.1	3.9	3.6	3.4	3.2

Costs - Present Value

Capital Costs	($M)
Operating Costs	
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OM&A	($M)
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NPV - Total (2005$)	($M)

Assumptions:
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   a) on average revenues paid to OPG based on a 37 day lag
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   c) on average GRC is paid immediately, 0 day lag
7) 10 year GRC holiday starting upon COD
8) GRC property tax rate of 26.5% and GRC water rental rate of 9.5%
9) GRC cost based on $40/MWh escalating at 2% starting 2014
10) OM&A costs of $.11M (2005$M/year) escalated by CPI
11) Capital Tax Rate: 2005 .3%, 2006 .3%, 2007 .3%, 2008 .3%, 2009 .23%, 20
12) Large Corporation Tax Rate: 2005 .18%, 2006 .13% 2007 .06%, disappear
13) Income Tax Rate (Federal and Provincial): 2005 34.12%, 2006 34.12%, 20
14) Annual Energy Production based on Niagara River flows from 1926 to 20
15) in 2017 a scheduled outage on Niagara's canal is expected to occur resul
16) LUEC escalates at CPI
17) PPA - 20% of PPA escalates at CPI
18) Total NPV of costs equals total NPV of LUEC revenues over 90 year life
19) Total NPV of costs equals total NPV of PPA revenues over 90 year life

LUEC

		2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075	2076	2077	2078	2079	2080	2081	2082
Year		2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075	2076	2077	2078	2079	2080	2081	2082
Energy Production	(TWh)	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Yearly Escalation (CPI)	(%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Escalation Rate from 2009		2.856	2.913	2.972	3.031	3.092	3.154	3.217	3.281	3.347	3.414	3.482	3.551	3.623	3.695	3.769	3.844	3.921	4.000	4.080	4.161	4.244
LUEC Rate (escalated)	(¢/kWh)	19.4	19.8	20.2	20.6	21.0	21.5	21.9	22.3	22.8	23.2	23.7	24.2	24.7	25.1	25.6	26.2	26.7	27.2	27.8	28.3	28.9
Yearly Revenue	($M)	303.2	309.3	315.5	321.8	328.2	334.8	341.5	348.3	355.3	362.4	369.6	377.0	384.5	392.2	400.1	408.1	416.2	424.6	433.1	441.7	450.6
Discount Rate	(%)	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
Annual Discount Factor		0.021	0.020	0.018	0.017	0.016	0.015	0.014	0.013	0.012	0.011	0.011	0.010	0.009	0.009	0.008	0.008	0.007	0.007	0.006	0.006	0.005
(1 - combined income tax rate)		73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%
NPV - LUEC Revenue (sum all years)		4.7	4.5	4.2	4.0	3.9	3.7	3.5	3.3	3.2	3.0	2.9	2.8	2.6	2.5	2.4	2.3	2.2	2.1	2.0	1.9	1.8

PPA

Year		2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075	2076	2077	2078	2079	2080	2081	2082
Energy Production	(TWh)	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Yearly Escalation (CPI)	(%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
PPA Rate (escalated)	(¢/kWh)	5.0	5.1	5.2	5.3	5.4	5.5	5.6	5.7	5.8	5.9	6.1	6.2	6.3	6.4	6.6	6.7	6.8	7.0	7.1	7.2	7.4
	(¢/kWh)	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
	(¢/kWh)	12.6	12.7	12.8	12.9	13.0	13.2	13.3	13.4	13.5	13.6	13.7	13.8	14.0	14.1	14.2	14.4	14.5	14.6	14.8	14.9	15.1
Yearly Revenue	($M)	197.2	198.7	200.3	201.9	203.6	205.2	207.0	208.7	210.5	212.3	214.1	216.0	218.0	219.9	221.9	224.0	226.1	228.2	230.4	232.6	234.8
Discount Rate	(%)	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
Annual Discount Factor		0.021	0.020	0.018	0.017	0.016	0.015	0.014	0.013	0.012	0.011	0.011	0.010	0.009	0.009	0.008	0.008	0.007	0.007	0.006	0.006	0.005
(1 - combined income tax rate)		73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%
NPV - LUEC Revenue (sum all years)		3.0	2.9	2.7	2.5	2.4	2.3	2.1	2.0	1.9	1.8	1.7	1.6	1.5	1.4	1.3	1.2	1.2	1.1	1.0	1.0	0.9

Costs - Present Value

Capital Costs	($M)
Operating Costs	
GRC	($M)
OM&A	($M)
Capital Tax	($M)
Large Corporation Tax	($M)
NPV - Total (2005$)	($M)

Assumptions:

1) PV date July 1, 2005
2) Operating cash flows assumed to occur in June of each year
3) Discount Rate 7%
4) Total Project cost of $1.6B (includes $286.6M of Interest During Constru
5) 100% assigned to Capital Cost Allowance (CCA) Class 1 which includes "[
6) Capital costs include working capital requirements which has been calcu
   a) on average revenues paid to OPG based on a 37 day lag
   b) on average OPG pays OM&A based on a 14 day lag
   c) on average GRC is paid immediately, 0 day lag
7) 10 year GRC holiday starting upon COD
8) GRC property tax rate of 26.5% and GRC water rental rate of 9.5%
9) GRC cost based on $40/MWh escalating at 2% starting 2014
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11) Capital Tax Rate: 2005 .3%, 2006 .3%, 2007 .3%, 2008 .3%, 2009 .23%, 2(
12) Large Corporation Tax Rate: 2005 .18%, 2006 .13% 2007 .06%, disappea
13) Income Tax Rate (Federal and Provincial): 2005 34.12%, 2006 34.12%, 2(
14) Annual Energy Production based on Niagara River flows from 1926 to 20
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16) LUEC escalates at CPI
17) PPA - 20% of PPA escalates at CPI
18) Total NPV of costs equals total NPV of LUEC revenues over 90 year life
19) Total NPV of costs equals total NPV of PPA revenues over 90 year life

LUEC

Year		2083	2084	2085	2086	2087	2088	2089	2090	2091	2092	2093	2094	2095	2096	2097	2098	2099	2100	2101	2102	2103
Energy Production	(TWh)	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Yearly Escalation (CPI)	(%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Escalation Rate from 2009		4.329	4.416	4.504	4.594	4.686	4.780	4.875	4.973	5.072	5.174	5.277	5.383	5.491	5.600	5.712	5.827	5.943	6.062	6.183	6.307	6.433
LUEC Rate (escalated)	(¢/kWh)	29.5	30.0	30.6	31.3	31.9	32.5	33.2	33.8	34.5	35.2	35.9	36.6	37.4	38.1	38.9	39.6	40.4	41.3	42.1	42.9	43.8
Yearly Revenue	($M)	459.6	468.8	478.1	487.7	497.4	507.4	517.5	527.9	538.5	549.2	560.2	571.4	582.8	594.5	606.4	618.5	630.9	643.5	656.4	669.5	682.9
Discount Rate	(%)	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
Annual Discount Factor		0.005	0.005	0.004	0.004	0.004	0.004	0.003	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.001	0.001
(1 - combined income tax rate)		73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%
NPV - LUEC Revenue (sum all years)		1.7	1.6	1.6	1.5	1.4	1.3	1.3	1.2	1.2	1.1	1.1	1.0	1.0	0.9	0.9	0.8	0.8	0.8	0.7	0.7	0.7

PPA

Year		2083	2084	2085	2086	2087	2088	2089	2090	2091	2092	2093	2094	2095	2096	2097	2098	2099	2100	2101	2102	2103
Energy Production	(TWh)	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Yearly Escalation (CPI)	(%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
PPA Rate (escalated)	(¢/kWh)	7.5	7.7	7.8	8.0	8.1	8.3	8.5	8.6	8.8	9.0	9.2	9.4	9.5	9.7	9.9	10.1	10.3	10.5	10.7	11.0	11.2
	(¢/kWh)	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
	(¢/kWh)	15.2	15.4	15.5	15.7	15.8	16.0	16.1	16.3	16.5	16.7	16.8	17.0	17.2	17.4	17.6	17.8	18.0	18.2	18.4	18.6	18.9
Yearly Revenue	($M)	237.1	239.5	241.9	244.3	246.8	249.3	251.9	254.6	257.3	260.0	262.8	265.7	268.6	271.6	274.6	277.7	280.9	284.1	287.4	290.7	294.2
Discount Rate	(%)	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
Annual Discount Factor		0.005	0.005	0.004	0.004	0.004	0.004	0.003	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.001	0.001
(1 - combined income tax rate)		73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%
NPV - LUEC Revenue (sum all years)		0.9	0.8	0.8	0.7	0.7	0.7	0.6	0.6	0.6	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3

SEC Interrogatory #046

Ref: Ex. D1-T1-S2, Attachment 3 (Saunders)

Issue Number: 4.2
Issue: Are the capital budgets and/or financial commitments for 2011 and 2012 for the regulated hydroelectric business appropriate and supported by business cases?

Interrogatory

(a) P. 3. Please confirm that this project achieves a security benefit, but no financial benefit or future cost savings.

(b) P. 3. Please advise the total cost of the generator controls. Please advise whether there are any financial benefits or future cost savings associated with that part of the project. Please advise whether there was a separate business case summary for that part of the project, and if so provide that summary.

(c) P. 4. Please confirm that a similar project has been or will be undertaken on the New York side of the power complex. If that is not the case, please advise the reasons why the need for this work would be different in New York than in Ontario.

(d) P. 5. Please confirm that the project was completed in January 2010.

Response

a) This project does achieve a security benefit – implementing the “air gap” solution was necessary to satisfy the North American Electric Reliability Corporation’s Critical Infrastructure Protection requirements by the end of 2009. However, the primary objectives for this project were to replace the generator and transformer protections and controls to sustain reliable generation. The investment was required to bring the generator and transformer protections and controls up to current standards. Protecting this valuable asset and ensuring the station continues to operate reliably will provide financial benefits well into the future.

b) The cost of the generator controls is estimated to be approximately $7M based on the quotes that were obtained from suppliers during the developmental phase release. Protecting the assets will avoid equipment damage and the associated repair costs and lost generation opportunities. A separate business case for the controls was not prepared.

c) New York Power Authority’s investment strategy is commercially sensitive information that OPG is not privy to.

d) This project is scheduled for completion in 2012. It remains on schedule and on budget.

SEC Interrogatory #048

Ref: Ex. F1-T1-S1, Attachment 1 - Hydroelectric Business Plan

Issue Number: 4.2
Issue: Are the capital budgets and/or financial commitments for 2011 and 2012 for the regulated hydroelectric business appropriate and supported by business cases?

Interrogatory

a) P. 3. Please confirm that, based on current information, the Applicant has been underinvesting in the "re-investment" component of hydroelectric for the past 10 years. If this is the case, please estimate the amount of underinvestment, and estimate the amount of the spending going forward that can fairly be termed "catch-up" to get the hydroelectric reinvestment levels back to a proper amount.

b) P. 6. Please explain why hydroelectric OM&A and Operations Capital are both forecast to drop from 2011 to 2012.

c) P. 7. Please provide a copy of the business case and related cost/benefit analysis for the Niagara Bridge Divestiture Strategy.

d) P. 7. Please explain in detail the strategy to reduce the labour and payroll burden rates as indicated.

e) P. 9. Please provide a copy of the preliminary review of the expansion of the existing PGS reservoir. Please advise what work is being done on this project in 2011 and 2012.

f) P. 17. Please provide updated tables for Age Distribution and Retirement Eligibility.

g) P. 18. Please describe in detail the "over-hiring" strategy and estimate its cost implications.

h) P. 27. Please explain the 6% increase in Regular Staff from 2009 to 2010.

i) P. 27. Please explain the terminology "contribution margin" and describe how the figure is calculated.

j) P. 33. Please disaggregate the causes for the 1.8% EFOR forecast, and quantify the impact on revenue requirement of the difference between the 1.8% forecast and the 1.5% benchmark.

Response

a) No, the regulated hydroelectric facilities have received and continue to receive appropriate levels of reinvestment based on the Hydroelectric portfolio management system described on page 3 of Ex. F1-T1-S1.

b) The forecast totals for OM&A and Capital on page 6 of the Hydroelectric Business Plan presentation include unregulated facilities and are therefore not relevant to this rate application. Please refer to Ex. D1-T1-S1, Ex. F1-T2-S2, and Ex. F1-T3-S2 for year-over-year explanations of Capital, Base OM&A, and Project OM&A for the regulated stations.

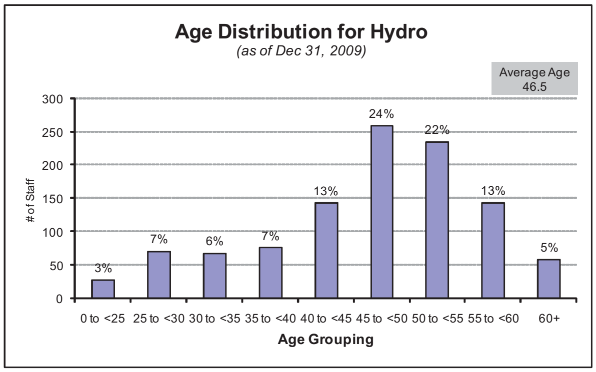
c) OPG does not have a single business case summary ("BCS") prepared for the overall bridge divestiture strategy. Individual BCSs are prepared for each bridge divestiture as each bridge has its own unique agreements, obligations, and asset condition. OPG has ongoing legal obligations related to roadway bridges in the Niagara Region. A strategy has been put in place to divest the bridges to the local municipalities in order to reduce the future costs, liabilities, and risks to OPG. The costs and benefits of this program are described in Ex. F1-T2-S1, page 2, lines 26-30, and in Ex. F1-T2-S2 on pages 2 and 3.

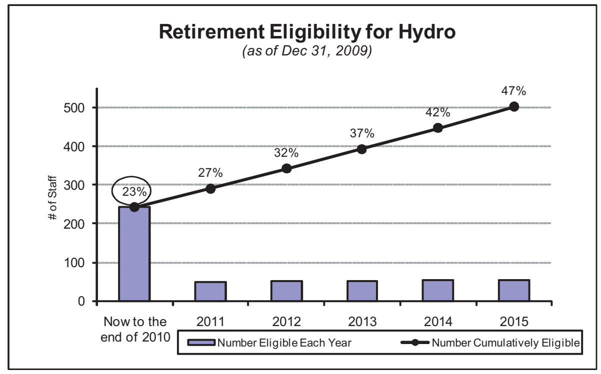
d) A description of labour burdens, along with the related pension and benefits discussion, can be found in sections 6 and 7 of Ex. F4-T3-S1 on Compensation, Wages and Benefits.

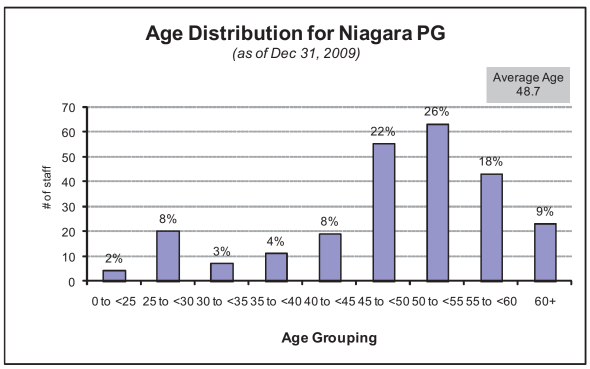
e) The preliminary review report summarizing the expansion options for the reservoir has not been finalized. A draft report has been received from the consultant, Hatch Energy, and is currently being reviewed by OPG's technical staff. The preliminary review report is expected to be completed by the end of 2010.

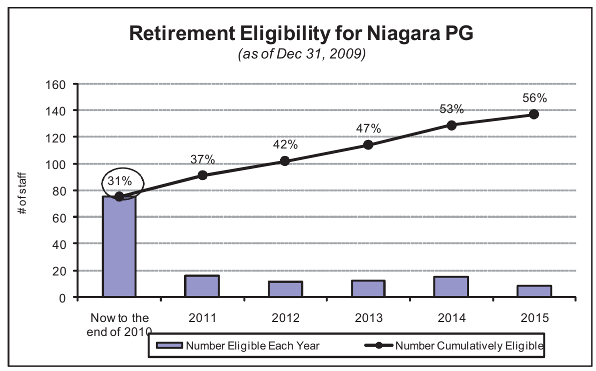
As described in the Board staff interrogatory in Ex. L-1-043, the preliminary review referenced in the Business Plan Presentation considered the following options: expanding the footprint of the reservoir, deepening the reservoir, and increasing the dyke elevation. While the reservoir volume increases under the individual options can be as high as 27 per cent, a combination of options could result in volume increases of over 40 per cent. The next steps include the preparation of cost estimates and geotechnical reviews of the options by third-party experts. If the expansion work proceeds, it will be aligned with the comprehensive remedial work on the present dyke.

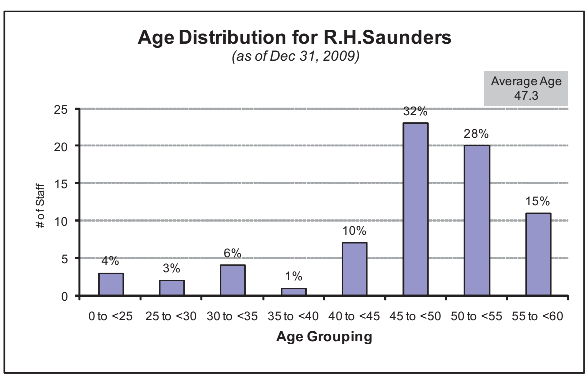
f) Updated Age Distribution and Retirement Eligibility graphs are below.

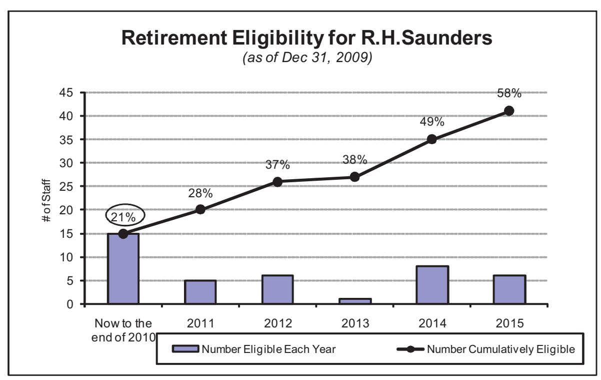












g) Please see responses to Board staff and Energy Probe interrogatories in Ex. L-1-041 and Ex. L-6-004 respectively for a description of the "over-hiring" strategy. In addition to changes in labour rates, staff counts are a significant contributor to the year-over-year changes in total labour costs observed in Ex. F1-T2-S1, Tables 1 and 2.

h) The regular staff Full Time Equivalents ("FTE") for 2009 and 2010 on page 27 of the Hydroelectric Business Plan presentation include unregulated facilities and are therefore not relevant to this rate application. However, the Hydroelectric business unit total FTEs do include the impact of the hiring strategy described in part g).

i) The contribution margins presented on page 27 of the Hydroelectric Business Plan presentation include unregulated facilities and are therefore not relevant to this rate application. However, contribution margin is defined as the total revenues minus all OM&A, Gross Revenue Charges, and other water rental payments. Taxes and other costs are excluded.

j) A discussion of reliability performance, including station level Equivalent Forced Outage Rate ("EFOR") data, is included in Ex. F1-T1-S1, Section 3 and 4. By definition, the EFOR measure captures reliability-related forced outages, which are unplanned events. In general, at the low levels of EFOR experienced by OPG's regulated hydroelectric facilities, forced outages do not have a material impact on revenue requirements because repairs are usually funded by existing Base OM&A budgets.

OTHER REVENUES – REGULATED HYDROELECTRIC

1.0 PURPOSE

The purpose of this evidence is to present the forecast of revenues from sources other than energy production ("other revenues") from OPG's regulated hydroelectric generating facilities and to explain the proposed treatment of these other revenues.

2.0 OVERVIEW

Other revenues earned by OPG's regulated hydroelectric facilities are revenues associated with ancillary services, which include black start capability, operating reserve ("OR"), reactive support/voltage control service, and automatic generation control ("AGC"). Provision of these ancillary services is integral to the operation of OPG's prescribed assets. In addition, other revenues include revenues from segregated mode of operation ("SMO") and water transactions ("WT").

A forecast of other revenues for the test period is included as an offset in the calculation of the revenue requirement for the regulated hydroelectric facilities. Differences between forecast and actual revenues associated with ancillary services are recorded in the Ancillary Service Net Revenue Variance Account - Hydroelectric Sub Account, as approved by the OEB in EB-2007-0905. See Ex. H1-T1-S1, section 4.1 for information on this account.

Forecast revenues from SMO and WT are also included as an offset in the calculation of the revenue requirement during the test period as per the OEB's Order in EB-2007-0905.

Revenues associated with congestion management settlement credits ("CMSC") payments are not forecast, and consistent with the OEB's Order in EB-2007-0905, are not considered part of "other revenues" for revenue requirement calculation because CMSC revenues are designed to compensate OPG for losses which are not otherwise incorporated into the revenue requirement. This methodology is continued during the test period.

Exhibit G1-T1-S1, Table 1 presents the other revenues associated with the regulated hydroelectric assets for the period 2007 - 2012.

3.0 ANCILLARY SERVICES

There are three ancillary services purchased by the IESO under contract to maintain the reliability of the Ontario power network. The services of black start capability and AGC are purchased through competitive tendering processes. The service of reactive support/voltage control is contracted through a negotiated process. Suppliers of these three services receive compensation for costs associated with being available to provide the service, out-of-pocket costs, opportunity costs when providing the service, and any other compensation deemed by the IESO to be fair and reasonable. The cost of these services is passed on to consumers by the IESO through monthly uplift charges. In contrast, operating reserve is a market-based ancillary service that is jointly optimized with the energy market.

3.1 Black Start Capability

Black start capability, as defined in the Market Rules, refers to the capability of a generation facility to start without an outside electrical supply so as to be used to energize a defined portion of the IESO-controlled grid. Sir Adam Beck II and R.H. Saunders are currently under contract with the IESO for black start capability.

OPG forecasts revenues for black start capability for 2011 and 2012 based on the terms of the negotiated Procurement of Certified Black Start Facilities Agreement effective November 1, 2008 to May 1, 2010. OPG's forecast methodology is consistent with the approach used in EB-2007-0905.

3.2 Reactive Support/Voltage Control Service

Under the Market Rules, reactive support service refers to a service provided by a market participant so as to allow the IESO to maintain the reactive power levels required by the IESO-controlled grid. Similarly, voltage control service is a service provided by a market participant so as to allow the IESO to maintain voltage levels required by the IESO-controlled grid. Collectively, these are referred to in this Application as reactive support/voltage control service.

OPG and the IESO negotiated a Reactive Support/Voltage Control Service Agreement effective from January 1, 2008 until December 31, 2010. OPG's expectation for the test period is that a new contract will be in effect with terms and conditions similar to those in the existing contract. OPG's forecast methodology is consistent with the approach used in EB-2007-0905.

OPG's nuclear assets also provide reactive support/voltage control service and receive revenues from this activity. These revenues are presented in Ex. G2-T1-S1 Table 1.

3.3 Automatic Generation Control

As defined in the Market Rules, AGC refers to the process that automatically adjusts the output from a generation facility based on automated, electronic signals in order to provide frequency control and to maintain the balance between the demand from load and the supply from generation facilities.

A new contract for AGC was executed with the IESO and became effective May 1, 2009 with an expiration date of October 31, 2010. The current total AGC market is 100 MW. Forecast contract revenues were decreased in 2010 by 20 per cent due to market price variations and an expectation of increased competition in the AGC market. For the test period, OPG expects that an AGC contract with similar conditions and revenues will be executed with the IESO.

3.4 Operating Reserve

Operating reserve ("OR") refers to the capacity that can be called upon on short notice by the IESO to replace scheduled energy supply that is unavailable as a result of an unexpected outage or to augment scheduled energy as a result of unexpected demand or other contingencies. The IESO establishes separate prices for the energy market and the operating reserve markets.

Because OR is a market-based ancillary service, the amount of OR accepted depends on OPG's operating reserve offers and market conditions.

For 2011, the OR revenue forecasts are reduced by 25 per cent from 2010 based on the expectation that OR prices will clear lower and closer to the longer term trend (OR prices were significantly lower in 2002 - 2007 than they have been recently). Recent prices have been two to three times higher than earlier years, and those earlier years are considered by OPG to be more representative of revenues going forward. For 2012, OPG's revenue forecast is based on the 2011 estimate plus escalation.

Darlington also provides OR from stand-by generation units and receives revenues from this activity. These revenues are presented in Ex G2-T1-S1 Table 1.

4.0 SEGREGATED MODE OF OPERATION

Segregated mode of operation ("SMO") is defined in the Market Rules as an electrical configuration where a portion of the IESO-controlled grid is used to connect one or more registered generating facilities to a neighbouring control area using a radial intertie for the purposes of delivering electricity or physical services.

SMO transactions are accommodated by segregating up to eight units (or two banks of four units) of production from R.H. Saunders to Hydro-Québec's control area at the St. Lawrence Transformer Station. Prior to entering into a SMO configuration, OPG must seek approval from the IESO which can be refused or revoked at any time.

SMO is conducted by OPG when it identifies economic opportunities in neighbouring markets. These transactions are arranged in advance with counterparties and are typically conducted in off-peak periods. The economic drivers used in deciding whether or not to engage in an SMO transaction are the forecast market prices in Ontario and surrounding markets.

SMO net revenues are calculated by subtracting the incremental costs associated with these transactions from the SMO revenues received. These incremental costs consist of export fees, transmission charges in other control areas, costs associated with the non-regulated business and transmission losses between generator source and point of delivery. SMO transactions are also exposed to market price forecasting risk. The net revenues from SMO transactions are acquired through OPG's non-regulated business which moves generation to higher priced markets. The non-regulated business incurs additional costs associated with these transactions including; arranging, conducting and settling these transactions; IT systems; control and governance functions; and market memberships.

OPG also incurs additional costs, which are applied as incurred in transacting SMO. By engaging in these transactions, OPG incurs a production loss during switching operations and may experience other commercial costs arising from an inability to complete the transaction due to the IESO preventing or recalling the units as per the Market Rules; equipment failure (i.e., a breaker or switch failure), which may prevent the units from being connected back to Ontario until the equipment is repaired; or a unit being forced out. If the units are unable to segregate for the reasons identified above, OPG may be financially responsible for not delivering on its commitment to a transaction in another market. Examples of other commercial costs which may be applied include counterparty credit and liquidated damages.

The OEB's Decision with Reasons in EB-2007-0905 specified that the average of the previous three historical years of actual net revenue values for SMO (i.e., 2005, 2006, and 2007) be applied as an offset against OPG's revenue requirement for the 2008 - 2009 period. In accordance with EB-2007-0905, the budget amount for 2008 is set at 75 per cent of the budget amount for 2009. The budget amount for 2010, the bridge year, is set identical to the budget amount for 2009. Any incremental revenues above these values are to be retained by OPG.

A new direct current transmission interconnection ("DC intertie") between Ontario and Québec came into commercial service on July 2, 2009 with an initial capability of 625 MW (Phase 1 of the project plan). The DC intertie was expanded to its full transfer capability of 1,250 MW as of November 21, 2009.

The impact of the DC intertie on SMO revenues to date has been significant. Actual SMO revenues were $10.1M lower in 2009 relative to 2008. The expectation is that the reduction in SMO revenues experienced in the last six months of 2009 will be permanent – revenues will not return to pre-DC intertie levels. Therefore, the use of the three year historical average would overstate the value of revenues anticipated in the test period.

Given this significant change, OPG proposes to use actual SMO results during the latter part of 2009 to forecast the revenues over the test period. A forecast based on SMO exports for the period after the DC intertie was placed in-service is superior to a forecast based on the period prior to the operation of the DC intertie because it reflects the significant change in SMO volume attributable to the new interconnection. Actual SMO revenues between July 2009 and December 2009 were used to as forecast revenue for the test period.

For segregated mode net revenues, OPG has assumed a 1.5 per cent escalation factor for inflation for 2010, and 2.0 per cent for both 2011 and 2012 as per OPG's 2010 - 2014 Business Plan projections. Consistent with the OEB's previous direction, OPG will use the forecast SMO net revenues to offset the revenue requirement during the test period.

5.0 WATER TRANSACTIONS

Water transactions between the New York Power Authority ("NYPA") and OPG are associated with the regulated hydroelectric facilities. NYPA and OPG are designated in their respective jurisdictions as the entities responsible for developing and operating the hydroelectric facilities on the Niagara and St. Lawrence Rivers. Pursuant to agreements between the parties, NYPA and OPG coordinate certain operations to maximize energy production from the total water available for generation under the relevant international treaties. Water transactions are one means by which NYPA and OPG maximize energy production and make best use of an important renewable resource.

Water transactions provide an opportunity to maximize use of the available water by allowing either OPG or NYPA to use a portion of the other's share of the water available for power generation. In return, the entity that used the water provides the revenues resulting from the water transactions, minus an accommodation charge, to the other entity. Since the opening of electricity markets in Ontario and New York, water transactions are settled financially. The majority of water transactions are for the purposes of salvaging the water that otherwise would be spilled over Niagara Falls or to facilitate ice control procedures.

When OPG engages in a water transaction that allows NYPA to extract the potential energy from Canada's share of available water, NYPA pays OPG an amount equal to the energy production priced at New York market prices less accommodation charges associated with the transaction. When NYPA engages in water transactions that allow OPG to extract the potential energy from the United States' share of available water, OPG pays NYPA an amount equal to the energy production priced at the Hourly Ontario Energy Price ("HOEP") less accommodation charges associated with the transaction.

The OEB's Decision with Reasons in EB-2007-0905 specified that the average of the previous three historical years (i.e., 2005, 2006, and 2007) of actual net water transactions revenues be applied as an offset against OPG's revenue requirement for the 2008 - 2009 period. Net water transactions revenues are calculated by removing accommodation charges and gross revenue charges ("GRC") attributable to these transactions from the gross revenues. In accordance with EB-2007-0905, the budget amount for 2008 is set at 75 per cent of the budget amount for 2009. The budget amount for 2010, the bridge year, is set identical to the budget amount for 2009. Any incremental revenues above these values are retained by OPG.

As expressed in EB 2007-0905, Exhibit G1-T1-S1, section 5.0, OPG continues to believe that both the value and volume of water transactions are highly volatile and therefore difficult to forecast. Forecasts based on averages of past years' results do not incorporate recent market trends, such as continued low spot prices. These trends, though difficult to characterize precisely, are highly likely to influence future revenues. As shown in Ex. G1-T1-S2 Table 1, low market prices in 2009 reduced water transactions revenues. These low market prices are expected to continue during the test period.

OPG proposes that test period water transactions net revenues be forecast based on the actual net revenues realized in 2009, since this period is considered to be more representative of market prices during the test period than the three year average referenced in EB 2007-0905. Any incremental revenues above these values would be retained by OPG. For net revenues, OPG has assumed a 1.5 per cent escalation factor for inflation for 2010, and 2.0 per cent for the test period, per OPG's 2010 - 2014 Business Plan projections.

6.0 OTHER REVENUES – 2007 ACTUAL TO 2012 PLAN

Ex. G1-T1-S1 Table 1 presents the other revenues associated with the regulated hydroelectric assets.

Nuclear ancillary service revenues are presented in Exhibit G2-T1-S1 Table 1.

revenue was $11.6M, for the 2006 calendar year was $12.5M and for the 2007 calendar year was $5.9M. Gross revenue charges costs associated with these transactions were $5.2M in 2005 (for the entire year), $4.1M in 2006 and $1.4M in 2007 (see Ex. F1-T4-S1). Water transaction net revenues were $7.8M during April 1 to December 31, 2005, $8.4M for 2006 and $4.5M for 2007.

For the test period, OPG is proposing a similar approach to the one used in the interim period, modified consistent with the treatment previously described for SMO.

It is expected that water transactions will decrease significantly when the Niagara tunnel is in-service since increased diversion capability will then be available to the Niagara stations.

6.0 CONGESTION MANAGEMENT SETTLEMENT CREDITS

All dispatchable generating facilities in Ontario are dispatched under the Market Rules by the IESO's dispatch scheduling optimizer ("DSO"). The DSO is an algorithm that is used by the IESO to determine prices and schedules for dispatch. Prices are first determined by an unconstrained run of the DSO, which does not take transmission or other constraints into consideration. This results in an unconstrained schedule. Dispatch, including OPG's prescribed generating facilities, is next determined by a constrained run of the DSO, which does consider constraints, and results in the schedule actually used to dispatch the generation. Any difference between the unconstrained schedule and the constrained or dispatch schedule can give rise to a CMSC payment, which is intended to compensate a market participant for either being constrained on (operating when not economically justified) or constrained off (not operating when economically justified).

The DSO will jointly optimize energy and the three types of operating reserve (ten minute spinning, ten minute non-spinning and thirty minute). Congestion management settlement credits payments are available for energy and for each of the three types of OR in each five minute interval of dispatch.

Congestion management settlement credits payments ensure that a market participant who has been constrained on or constrained off by system conditions beyond its control is made whole up to the operating profit they would have received under an unconstrained schedule. This is to ensure that no market participant is put at an advantage or disadvantage by virtue of their geographic position relative to the grid. The unconstrained schedule is used to set the market clearing price and constrained on units do not benefit from their higher offers. The amount of the CMSC payment is primarily based on operating profit which is calculated as the difference between the unconstrained and the constrained quantity as well as the difference between the offer price and the market clearing price.

The majority of the CMSC payments associated with OPG's prescribed assets are for energy, with OPG's regulated facilities attracting some CMSC OR.

Although transmission limitations are the major cause for differences between the unconstrained and constrained schedules, there are other factors that give rise to such differences. These include unit operating minimums, unit ramp rates and the use of actual metered output for the unit. The IESO does not provide the means for market participants to identify all of the reasons for a constrained on or constrained off event.

Congestion management settlement credits are subject to review by the Market Assessment and Compliance Department of the IESO. These reviews can result in recovery of CMSCs by the IESO if the CMSC was associated with a local transmission restriction and there was insufficient competition available to satisfy the restriction.

CMSC situations typically result in inefficient operation and/or the incurring of additional costs by generators, driven by market conditions. For example, constrained off situations can result in wasted or inefficient use of water as the generator is operated below its maximum efficiency point. Similarly, constrained on situations typically require inefficient use of the hydroelectric generating units above the point of maximum efficiency. In addition, in a constrained off situation, lost production will not be recoverable through the water variance account and if the CMSC value is less than the regulated rate, OPG will not recover its costs.

CMSC payments for regulated assets were $12.6M for 2005, $8.5M for 2006 and $7.7M for 2007. OPG will retain all CMSC payments from prescribed generating facilities as constrained operation typically gives rise to inefficient operation and increased costs. The CMSC payment is not incremental revenue but is an offset to lost production/revenue and increased costs that are generally not included in the revenue requirement. The CMSC payment during constrained events is reasonable compensation for such inefficiencies and costs. Moreover, CMSC OR is separately addressed by the variance account associated with the operating reserve ancillary service.

7.0 OTHER REVENUES – 2006 ACTUAL TO 2009 PLAN

Exhibit G1-T1-S1 Table 1 presents the revenues associated with the regulated hydroelectric assets.

Nuclear ancillary service revenues are presented in Exhibit G2.

Board Staff Interrogatory #67

Ref: Ex. G1-T1-S1, pages 13 - 15

Issue Number: 6.1
Issue: Are the proposals for the treatment of revenues from Segregated Mode of Operation, water transactions and congestion Management Settlement Credits appropriate?

Interrogatory

The Application proposes not to include payments from the IESO to OPG for congestion management settlement credits in revenues to offset the revenue requirement. This differs from the proposed treatments for Segregated Mode of Operation and water transactions. The argument advanced in favour of this approach is that the IESO payments compensate OPG for costs incurred in not providing energy as dispatched.

a) What costs are incurred?

b) If the "costs" are foregone revenues, in what sense are these "opportunity costs" in the sense of standard economic theory (as opposed to rents)?

c) Why in the cases of Segregated Mode of Operation and water transactions does OPG propose to treat revenues for the non-use of facilities for Ontario load as appropriate to offset the revenue requirement but not those of congestion credits?

Response

a) Hydroelectric energy is typically offered to the market in a fashion that will result in the most efficient production of electricity given the prevailing hydroelectric conditions. Constrained operation typically results in less efficient production of electricity than would have otherwise occurred. Given the limited storage at Beck, it is also possible that prolonged constrained off operation will result in the spilling of water. The cost associated with CMSCs is therefore the lost energy production due to reduced efficiency and possible spill.

b) Constrained on operation can include opportunity costs when water which could have been stored for future periods and is valued above the current energy price is constrained on by the IESO due to system requirements.

The costs associated with constrained off operation relate to the inefficient operation detailed in part a).

c) CMSCs should not be used to offset the revenue requirement because the lost energy production from the inefficient use of the hydroelectric facilities from constrained operation is not forecast by OPG nor recoverable through the water condition variance account. Ontario consumers have benefited from constrained operation as the constrained off energy has been economically scheduled in the IESO's price setting calculation and has therefore lowered the energy clearing price.

In contrast, Segregated Mode of Operation and Water Transactions are actions OPG undertakes to provide a potential economic benefit to ratepayers in Ontario (see Ex. G1-T1-S1, page 6, lines 13 – 20) and a potential commercial benefit to OPG.Thus these actions merit different revenue treatment. Although the net revenues associated with SMO and WT activities are not used to offset the revenue requirement (See Ex. G1-T1-S1, page 7, lines 16 - 17 and page 11, lines 10 -12), OPG proposes to share any incremental net revenues realized with ratepayers. CMSCs on the other hand are payments from the IESO for energy that has been dispatched to meet system requirements. In these instances, OPG has either lost revenue from constrained off production or lost the opportunity to earn higher revenues in the future from constrained on production (these losses are not recovered - once they are gone, they are gone for good).

CCC Interrogatory #96

Ref: Ex. G1-T1-S1, page 15

Issue Number:
Issue:

Interrogatory

Please provide evidence to support the claim that CMSC payments directly offset lost production/revenue and increased costs associated with constrained operations. In effect, please demonstrate that there is actually an offset between CMSC payments and the related lost revenue and increased costs.

Response

For additional information see L-1-67 and Ex. G1-T1-S1, Section 6.0.

OPG does not specifically track losses that occur as a result of constrained operations. The complexity of tracking these losses is prohibitive.

Congestion Management Settlement Credit ("CMSC") payments under the Market Rules are designed to ensure that a market participant who has been "constrained on" or "constrained off" by the IESO due to system conditions beyond its control is made whole up to the operating profit they would have received under the IESO's unconstrained dispatch schedule. This is to ensure that market participants are not advantaged or disadvantaged by virtue of their location on the grid.

CMSC payments from the IESO cover either lost revenue from "constrained off" production or the lost opportunity to earn higher revenues in a future period as a result of "constrained on" production (these losses are not recoverable - once they are gone, they are gone for good).

CMSC situations typically result in inefficient operation and/or the incurring of additional costs by generators, driven by market conditions. For example, "constrained off" situations can result in wasted or inefficient use of water as the generator is operated below its maximum efficiency point. Similarly, "constrained on" situations can require generators to move their generation units above their maximum efficiency point. In addition, in a "constrained off" situation, lost production will not be recoverable through the water conditions variance account.

The following are examples of losses and costs that would occur if a Sir Adam Beck II unit was constrained off and constrained on for one hour.

Example 1: Sir Adam Beck II Unit Constrained Off for 1 Hour

- In normal efficient operation, a Sir Adam Beck II unit would generate 82,086 kW while using 101.6 cubic metres per second (cms) of water. This can be expressed as generating 808 kW for every cubic meter of water used (82,086 kW /101.6 cms = 808 kW per cms).

- If the unit were constrained off to 70,000 kW the unit would be using 87.8 cms of water. This translates into an efficiency of 797 kW for every cms of water used. This is due to the fact that hydroelectric units operate at different efficiencies depending on the output required.

- There are two types of losses in this situation:

1) Efficiency loss – Through being constrained off there is a difference in efficiencies, 808 kW/cms versus 797 kW/cms. This difference of 11 kW/cms means that there is an efficiency loss of 965.8 kW (11 kW/cms * 87.8 cms =965.8 kW). This is an energy production loss that cannot be recovered.

2) Spill or wasted water loss - This type of loss is due to spill or wasted water. The Sir Adam Beck complex has limited ability to store water and therefore operation below OPG's allocated portion of stream flow would result in the water being spilled over Niagara Falls. CMSC payments will only cover the difference between the scheduled quantity (82,086 kW) and the constrained quantity (70,000 kW). This results in an energy production loss of 12,086 kW.

- The CMSC payment compensates OPG for the revenues above marginal cost associated with the 12.086 kW but does not compensate OPG for the lost production or costs from operating at lower efficiencies (965.8 kW).

Example 2: Sir Adam Beck II Unit Constrained On for 1 Hour

- In normal efficient operation, a Sir Adam Beck II unit would generate 82,086 kW while using 101.6 cubic metres per second (cms) of water. This can be expressed as generating 808 kW for every cubic meter of water used (82,086 kW /101.6 cms = 808 kW per cms)

- If the unit is constrained on to full output of 92,723 kW the unit would be using 118.4 cms of water. This translates into an efficiency of 783 kW for every cms of water used.

- There are two types of losses in this situation:

1. Efficiency loss at Sir Adam Beck II - In this scenario, 2,960 kW of energy is lost due to the reduction in efficiency from using the same water. This energy cannot be recovered.

2. Efficiency loss at Sir Adam Beck Pump Generating Station - The increase in production above forecast requires additional water which is greater than the

allocated stream flow. This additional water must be taken from water stored at the Sir Adam Beck Pump Generating Station. The water stored at Sir Adam Beck Pump Generating Station incurred an efficiency loss and a cost when it was originally pumped into the reservoir. These costs are theoretically recoverable through the constrained on payment.

- In the case of constrained on operations, the offered price of the additional energy is greater than the current market price. The offered price reflects the costs from the loss of efficiency at Sir Adam Beck II and the Pump Generating Station. The CMSC payment compensates OPG for the incremental costs associated with this lost efficiency.

3.4 Other Revenues

In the hydroelectric business, OPG earns additional revenues from the following activities:

- Ancillary Services
- Segregated Mode of Operation
- Water Transactions
- Congestion Management Settlement Credits

We will address each activity in turn.

3.4.1 Ancillary Services

Ancillary services provided by some of the hydroelectric generating facilities include the provision of black start capability, operating reserve, reactive support/voltage control service, and automatic generation control. OPG forecast ancillary service revenues of $32.4 million in 2008 and $33.1 million in 2009. These forecast revenues are used as an offset when determining the revenue requirement. OPG proposed that any variance between forecast and actual be captured in a deferral and variance account. No intervenor opposed the forecast.

Board Findings

The Board will accept the forecast for purposes of determining the revenue requirement. The Board's finding with respect to the proposed variance and deferral account is set out in Chapter 7.

3.4.2 Segregated Mode of Operation ("SMO") and Water Transactions ("WT")

OPG earns SMO revenues by segregating some of its R.H. Saunders generating units from Ontario and reconnecting them directly into Quebec. Revenues are received from Hydro Quebec. SMO net revenues have ranged between $9.9 million and $4.4 million over the last 3 years.[18] OPG submitted that forecasting revenues from SMO is difficult

[18] "SMO net revenues are defined as gross revenues less HOEP (or HOEP proxy costs), incremental variable costs, and costs associated with the non-regulated business. If the transaction is not indexed to HOEP but is executed at a fixed price, the HOEP for that hour is used as a proxy." (Ex. G1-1-1, p. 8)

because SMO is dependent upon hourly market conditions and advised that these revenues are expected to decline with the new high voltage transmission line between Ontario and Quebec. As a result, OPG did not propose to include a forecast of SMO net revenues as a revenue offset, but rather proposed to track the revenues in a variance account for later disposition. Further, OPG submitted that because it incurs costs and risks in undertaking these transactions it is necessary for it to have an incentive to undertake this activity. OPG pointed out that its trading function (which undertakes these transactions) has other commercial opportunities: "Without sufficient incentive to engage in SMO transactions, OPG will focus on these other opportunities."[19] OPG proposed that the net revenues be shared 50/50 with customers.

Water Transactions (WT) occur pursuant to agreements between the New York Power Authority and OPG to maximize energy production from the total water available for generation under international treaties. WT generally happen for maintenance, economic efficiency and climatic (ice) reasons, largely with the intention to salvage the water that forms part of an entity's generation share that would otherwise be spilled over Niagara Falls. WT net revenues have ranged between $8.4 million and $4.5 million over the last 3 years.[20] As with the SMO, OPG proposed to track WT revenues and to return 50% of the net revenues to customers through the use of a variance account. No forecast revenue would be included as a revenue offset in the determination of the revenue requirement.

Board staff questioned whether SMO revenues should in some way be incorporated into the revenue requirement and noted the approach used in the past for Union Gas Limited whereby a forecast of net revenues from transactional services is incorporated in the revenue requirement, and any incremental revenues are subject to variance account treatment and sharing. Board staff noted that under OPG's proposal, it is possible there could be a debit in the variance account if costs exceeded revenues.

CCC and AMPCO proposed alternative sharing formulas. CCC submitted that the customers should receive 75% of the net revenue, in recognition that the assets are included in rate base and in line with other similar sharing mechanisms in the gas industry. AMPCO submitted that a sharing ratio of 80/20 between customers and OPG would be appropriate, recognizing that OPG needs an incentive to undertake these

[19] OPG Argument in Chief, p. 74

[20] WT net revenues "are gross revenues less accommodation charges, and GRC." (Ex.G1/Tab1/Sch.1/p.11)

transactions, and that customers bear the costs underpinning these transactions and all costs are netted against the gross revenues before any sharing. CME supported AMPCO's submissions. VECC also questioned whether customers should receive the majority of the net revenues, given that the assets are included in rate base.

CCC also submitted that customers should not bear the costs of any uneconomic transactions. OPG did accept that customers should not be responsible for a negative balance in the account, but it was of the view that if individual transactions resulted in a net cost, those should be included in the account:

> Transactions are economic when entered into; if they become uneconomic, it is due to changing market conditions and prices. Transactions to manage excess baseload generation may result in a negative sub-account entry but have associated social and environmental benefits.[21]

SEC noted OPG's testimony that it has other incentives to enter into SMO transactions, including allowing OPG to manage excess baseload generation. SEC submitted that customers should receive 100% of the net revenues from these transactions as there is no real risk associated with the transactions and the transactions provide ancillary benefits to OPG which make them economic in any event. SEC also made an alternative proposal based on the transactional services model for gas distributors. Under SEC's alternative proposal, a forecast of SMO net revenues based on the average of the last three years' experience would be included as a revenue requirement offset and OPG would be entitled to retain a portion of any net revenues in excess of this forecast. SEC proposed that 75% of the forecast be included as an offset to the revenue requirement and that the excess be shared 75/25 between customers and OPG. SEC noted that in the case of Enbridge Gas Distribution Inc., this incentive structure worked to increase transactional revenues over a several year period.

OPG responded that changing the sharing would "disincent economic SMO transactions, as OPG's trading function will pursue other, more lucrative, opportunities."[22] OPG noted that unlike the transactional services in the gas utilities, the SMO and WT transactions are undertaken by staff which is also engaged in other transactional opportunities.

[21] OPG Reply Argument, p. 106.

[22] OPG Reply Argument, p. 104.

OPG also argued that the SMO transactions benefit consumers more generally because Hydro Quebec has significant water storage capacity and the SMO transactions tend to take place during off-peak hours, thereby facilitating greater generation at peak. Although OPG could not quantify the benefit, it claimed that to the extent there is more supply available at peak times, the market price (Hourly Ontario Energy Price, or HOEP) will decline, to the benefit of Ontario consumers.

With respect to SEC's proposed alternative, OPG responded that the use of a three year average for purposes of establishing a revenue offset is inconsistent with the evidence that these transactions are difficult to forecast and are expected to decline.

Board Findings

The Board agrees with intervenors that the analogy of transactional services in the natural gas industry is appropriate in the context of SMO and WT transactions. In both cases, the assets are part of the regulated business and customers pay all of the costs associated with operating these assets. OPG has an obligation to manage these regulated assets in an efficient manner, and if there are market opportunities available to offset costs, then the benefits of those transactions are appropriately shared with customers. It is also appropriate for OPG to have an incentive to optimize these revenues. The Board concludes that it is appropriate to incorporate a forecast of the net revenues from SMO and WT into the test period revenue requirement and to allow OPG to retain any incremental revenues during the test period. The Board concludes that this will provide a strong incentive to the company to pursue these transactions and will ensure that customers receive a benefit from the transactions as well.

The Board must establish the appropriate forecast to be included. The Board accepts OPG's position that it is difficult to forecast market driven activities, but concludes that a forecast of zero does not accord with the historical evidence. OPG has claimed that these transactions are likely to decline because of various developments. With respect to SMO transactions, the Board notes that only Phase 1 of the Ontario-Quebec interconnection is forecast to be in-service during the test period. With respect to WT, OPG's claim that WT activity will decline with completion of the Niagara Tunnel Project is not relevant since the project will not be completed during the test period.

OPG also argued that an enhanced incentive is required as these transactions compete for trading resources within OPG's unregulated trading business. However, the fact that the trading staff is also undertaking unregulated trading activities does not diminish

OPG's obligation to manage the regulated assets efficiently and for customers to share in those benefits. Incorporating a forecast into the revenue requirement determination will provide a positive incentive to pursue these transactions.

The Board concludes that an appropriate approach will be to include the average net revenues over the last three years into the forecast as a revenue offset in each year of the test period. In the case of SMO, the offset will be $6.6 million; for WT, the offset will be $6.9 million. (These amounts are for 2009; the amount for test period portion of 2008 will be 75% of that amount.) Any incremental revenues will accrue to OPG. This also simplifies the regulatory structure by eliminating the need for deferral accounts.

OPG has also argued that these transactions benefit customers generally through a beneficial impact on market prices. The Board finds that these benefits are too speculative to be taken into account in the determination of an appropriate sharing mechanism.

3.4.3 Congestion Management Settlement Credit ("CMSC") Payments

Under the IESO market rules, the IESO dispatches wholesale electricity generating facilities using its dispatch scheduling optimizer which determines process and schedules. Two schedules are run, one assuming no transmission or other constraints in the system and the other which considers known constraints, and which is actually used to dispatch. A Congestion Management Settlement Credit (CMSC) is paid to any market participant in compensation for either being constrained on (operating when not economically justified) or constrained off (not operating when economically justified). CMSC payments for OPG's regulated assets have ranged between $7.7 million and $12.6 million over the last three years.

OPG submitted that CMSC payments are different from SMO and WT revenues because "CMSC payments are not incremental revenues but rather an offset to lost production/revenue and increased costs."[23] OPG explained that most CMSC payments arise from constrained off situations that can result in wasted or inefficient use of water because dispatch is below the level of maximum efficiency. Similarly, constrained on situations can result in use of the generating units above the level of maximum efficiency or inefficient use of the Beck Pump Generation Station. OPG proposed to

[23] OPG Argument in Chief, p. 75.

retain all of the CMSC payments, arguing that to do otherwise would prevent it from recovering its losses associated with constrained off or constrained on situations. AMPCO submitted that OPG had failed to demonstrate that CMSC revenues are totally absorbed by the incremental costs and therefore recommended that the revenues be shared 50/50 net of incremental costs. Similarly, SEC submitted that OPG had provided no evidence to support its claim that the CMSC revenues equal the incremental unforecast costs. SEC submitted that these revenues should be treated as a revenue offset because the costs are likely included in OPG's forecasts.

OPG responded:

> CMSCs are intended to keep market participants whole, up to the operating profit they would have otherwise received, had they not been constrained-on or off by system conditions beyond their control.[24]

OPG quoted from an IESO presentation in support of this characterization. OPG maintained that if it is not able to retain the payments it will have no way to recoup the losses it would otherwise experience. OPG maintained that it would be too complex to quantify the incremental costs associated with constraint situations, but maintained that the payments, over a year, are a reasonable approximation of the impact on OPG's revenue. OPG noted that these payments are also subject to IESO review.

Board Findings

The Board will accept OPG's proposal. The losses which OPG incurs in constrained on and constrained off situations are mostly related to opportunity costs – the reduced production or less efficient production which results in lost revenues. The Board accepts OPG's evidence that the CMSC payments are designed to compensate for these losses – losses which are not otherwise incorporated into the revenue requirement. The Board will therefore not establish a deferral and variance account for this item.

3.5 Design of Payment Amount

Under the existing payment design, OPG receives $33/MWh for the first 1,900 MWh of output in any hour. Any production beyond the level of 1,900 MWh receives the market

[24] OPG Reply Argument, p. 107.

ONTARIOPOWER GENERATION

2009 YEAR END REPORT

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The regulated price for production from OPG's nuclear facilities for the period April 1, 2005 to March 31, 2008 was 4.95¢/kWh. The regulated price for nuclear generation increased to 5.50¢/kWh effective April 1, 2008. This price includes a rate rider of 0.20¢/kWh for the recovery of approved nuclear variance and deferral account balances.

The regulated price received for the period April 1, 2005 to March 31, 2008 for the first 1,900 megawatt hours ("MWh") of production from the regulated hydroelectric facilities in any hour was 3.30¢/kWh. For generation above 1,900 MWh in any hour, OPG received the Ontario spot electricity market price as an incentive mechanism to optimize hydroelectric production. The OEB established a new price for regulated hydroelectric generation of 3.67¢/kWh effective April 1, 2008. The OEB also approved a revised incentive mechanism, which became effective December 1, 2008. Under this mechanism, OPG receives the approved regulated price of 3.67¢/kWh for the actual average hourly net energy production from these hydroelectric facilities in that month. In the hours when the actual net energy production in Ontario is greater or less than the average hourly net volume in the month, hydroelectric revenues are adjusted by the difference between the average hourly net volume and the actual net energy production multiplied by the spot market price. The regulated price of 3.67¢/kWh includes the recovery of approved hydroelectric regulatory balances. The OEB's 2008 decision also established a number of variance and deferral accounts for the period after April 1, 2008.

In January 2009, OPG filed a motion with the OEB to review, and vary a portion of the OEB's decision establishing current regulatory prices, as it pertains to the treatment of tax losses and their use for mitigation of regulated prices. The OEB granted OPG's motion in a decision and order in May 2009. This order also directed OPG to establish a variance account to record the difference between the amount of mitigation included in the approved payment amounts and the revenue requirement reduction available from tax loss carry forwards recalculated as per the OEB's decision. The balance in the variance account will be reviewed by the OEB as part of OPG's next hearing. The establishment of this variance account resulted in an increase in regulatory assets and a corresponding increase in revenue in 2009.

Also during 2009, OPG filed an accounting order application to address the treatment of a number of variance and deferral accounts for the period after December 31, 2009. In the application for the accounting order, OPG sought the continuation of the rate rider of 0.20¢/kWh for recovery of nuclear regulatory balances approved in the OEB's 2008 decision. OPG also sought to establish the basis for recording entries to existing variance and deferral account balances after 2009. These requests were approved by the OEB's decision in October 2009. In addition, the OEB directed that OPG establish a new variance account to record potential over collection of hydroelectric variance account balances through the hydroelectric payment amount during 2010. OPG plans to file an application with the OEB for new payment amounts for its regulated facilities effective January 1, 2011.

The production from OPG's other generating assets remains unregulated and continues to be sold at the Ontario electricity spot market price, with the exception of a Hydroelectric Energy Supply Agreement ("HESA") for the production from the Lac Seul and Ear Falls generating stations, and the production from the Lennox generating station. For the period April 1, 2005 to April 30, 2009, the generation output from 85 percent of OPG's other generating assets, excluding the Lennox generating station, stations whose generation output is subject to a HESA with the Ontario Power Authority ("OPA") pursuant to a ministerial directive, and forward sales as of January 1, 2005, was subject to a revenue limit. The output from a generating unit where there has been a fuel conversion and the incremental output from a generating station where there has been a refurbishment or expansion of these assets were also excluded from the output covered by the revenue limit.

The revenue limit was 4.7¢/kWh for the period May 1, 2007 to April 30, 2008, and increased to 4.8¢/kWh effective May 1, 2008. During this period, volumes sold under a Pilot Auction administered by the OPA were subject to a revenue limit that was 0.5¢/kWh higher than the revenue limit applicable to OPG's other generating assets. Revenues above these limits were returned to the Independent Electricity System Operator ("IESO") for the benefit of consumers. The term of the revenue limit rebate ended on April 30, 2009.

The Lambton and Nanticoke generating stations are subject to a contingency support agreement with the OEFC. The agreement was put in place to enable OPG to recover the costs of its coal-fired generating before earnings from the Nuclear Funds, and a lower income tax component of the Bruce Lease Net Revenues Variance Account in 2009. Earnings on the Nuclear Funds are not taxable, and losses are not deductible, when incurred. The income tax expense in 2008 was favourably affected by a reduction in income tax liabilities as a result of the resolution of a number of tax uncertainties related to the audit of OPG's 1999 taxation year.

Average Sales Prices

The weighted average Ontario spot electricity market price and OPG's average sales prices by reportable electricity segment, net of the revenue limit rebate for the years ended December 31, 2009 and 2008, were as follows:

(¢/kWh)	**2009**	**2008**
Weighted average hourly Ontario spot electricity market price	**3.2**	5.2
Regulated – Nuclear Generation	**5.5**	5.3
Regulated – Hydroelectric	**3.7**	3.9
Unregulated – Hydroelectric	**3.2**	4.8
Unregulated – Thermal	**3.9**	5.0
OPG's average sales price	**4.5**	4.9

The weighted average hourly Ontario spot electricity market price was 3.2¢/kWh for 2009 compared to 5.2¢/kWh for 2008. The significant decrease in the average Ontario spot electricity market price for 2009 compared to 2008 was primarily due to lower Ontario primary demand, and lower natural gas and coal prices, partially offset by the impact of a weaker Canadian dollar.

The decrease in average sales prices for the unregulated segments for 2009 compared to 2008 was primarily due to the impact of lower Ontario spot electricity market prices.

The average sales price for the Regulated – Nuclear Generation segment for 2009 compared to 2008 was primarily impacted by the increase in the regulated prices effective April 1, 2008, resulting from the OEB's decision in December 2008.

For the Regulated – Hydroelectric segment, the decrease in the average electricity sales price for 2009 compared to 2008 was primarily due to the impact of lower electricity market prices on the revenue from the regulated hydroelectric incentive mechanism. The impact of the decrease was partially offset by the increase in the regulated prices resulting from the OEB's decision in 2008.

The term of the revenue limit rebate ended April 30, 2009. The revenue limit was 4.7¢/kWh for the period May 1, 2007 to April 30, 2008, and increased to 4.8¢/kWh for the period May 1, 2008 to April 30, 2009.

Electricity Generation

OPG's electricity generation for the years ended December 31, 2009 and 2008, was as follows:

(TWh)	**2009**	**2008**
Regulated – Nuclear Generation	**46.8**	48.2
Regulated – Hydroelectric	**19.4**	18.8
Unregulated – Hydroelectric	**16.8**	17.6
Unregulated – Thermal	**9.5**	23.2
Total electricity generation	**92.5**	107.8

OPG will continue to maintain the reliability of its coal-fired generating stations to produce the electricity required until their scheduled closure dates, or upon conversion to alternative fuels.

In addition to the discussion in this section, OPG's capability to deliver results is affected by factors discussed in the *Risk Management* section.

ONTARIO ELECTRICITY MARKET TRENDS

In its 18-Month Outlook published on February 23, 2010, the IESO indicated that as of February 4, 2010, Ontario's installed electricity generating capacity was 35,485 MW. As of December 31, 2009, OPG's in-service electricity generating capacity was 21,729 MW or 61 percent of Ontario's capacity. The IESO reported that the outlook for the reliability of Ontario's electricity system remains positive over the next 18 months. The expected addition of 2,600 megawatts ("MW") of new and refurbished supply comprising of a mix of wind, water, nuclear, gas and biomass facilities over this period will reinforce and solidify Ontario's already positive electricity supply situation. The early shutdown of four coal-fired units, two units at Lambton and two units at Nanticoke for a reduction of 2,000 MW of generating capacity, is planned for 2010, but will have no undue impacts on energy adequacy or reliability in Ontario. The new intertie with Quebec provides 1,250 MW of transfer capability. The IESO Outlook incorporates the implementation of emission reductions for coal-fired generation in Ontario, which commenced in 2009.

The IESO expects energy demand to increase by 0.5 percent to 141.1 TWh during 2010, with a 0.6 percent increase to 141.9 TWh in 2011. The slight increase in demand is primarily attributable to expected modest economic recovery. The expected peak electricity demand during the summer of 2010, under normal weather conditions, is expected to decline and is forecast to be 23,556 MW. The IESO expects that the risk of SBG will be low until sometime in the spring of 2010, but will re-emerge in the summer of 2010, and might persist into the fall. Increasing embedded generation and conservation initiatives create the potential for SBG, although their effects are mitigated during winter when minimum overnight demand is affected by heating load.

Fuel prices can have a significant impact on OPG's revenue and gross margin. Uranium spot market prices displayed some variation during 2009. Spot prices began the year at U.S. $53 per pound and declined to a low of U.S. $40 per pound at the beginning of the second quarter. Spot market prices then peaked for the year at U.S. $54 per pound in June and have since generally declined to U.S. $45 per pound at the end of 2009. Long-term uranium prices began the year at U.S. $70 per pound then displayed a slow decline to U.S. $62 at the end of 2009.

For most of 2009, natural gas prices at Henry Hub have been under strong downward pressure due to the economic recession, declining demand, and strong production in the United States. Natural gas prices have rebounded in December 2009 to U.S. $5.56/MMBtu, significantly higher than in recent months and reaching the highest level since December 2008. Gas prices at Henry Hub averaged U.S. $4.41/MMBtu in the fourth quarter, 39 percent above the prices in the third quarter of 2009, but still 31 percent below the fourth quarter of 2008. Eastern bituminous coal prices have experienced a similar trend. After reaching an all time high during the third quarter of 2008, prices have been under strong downward pressure and averaged around U.S. $53.00/tonne during the fourth quarter of 2009, a decline of 49 percent compared to the fourth quarter of 2008. Powder River Basin coal prices, which averaged U.S. $13.50/tonne during the fourth quarter of 2008, had declined to about U.S. $8.85/tonne by June 2009 and has stayed at approximately that level for the balance of the year. Powder River Basin coal prices averaged U.S. $8.80/tonne during the fourth quarter of 2009, which is a decline of 35 percent compared to the same period in 2008.

BUSINESS SEGMENTS

OPG has five reportable business segments. The business segments are Regulated – Nuclear Generation, Regulated – Nuclear Waste Management, Regulated – Hydroelectric, Unregulated – Hydroelectric, and Unregulated – Thermal. Prior to the fourth quarter of 2008, OPG had four reportable business segments as described in *The Company* section.

OPG has entered into various energy and related sales contracts to hedge commodity price exposure to changes in electricity prices associated with the spot market for electricity in Ontario. Contracts that are designated as hedges of OPG's generation revenues are included in the Unregulated – Hydroelectric and Unregulated – Thermal generation segments. Gains or losses from these hedging transactions are recognized in revenue over the terms of the contract when the underlying transaction occurs.

Regulated – Nuclear Generation Segment

OPG's Regulated – Nuclear Generation business segment operates in Ontario, generating and selling electricity from the nuclear generating stations that it owns and operates. The business segment includes electricity generated by the Pickering A and B, and Darlington nuclear generating stations. This business segment also includes revenue under the terms of a lease arrangement with Bruce Power related to the Bruce nuclear generating stations. This arrangement includes lease revenue and revenue from engineering analysis and design, technical and other services. Revenue is also earned from isotope sales and ancillary services. Ancillary revenues are earned through voltage control and reactive support.

Regulated – Nuclear Waste Management Segment

OPG's Regulated – Nuclear Waste Management segment engages in the management of used nuclear fuel and low and intermediate level waste, the decommissioning of OPG's nuclear generating stations (including the stations on lease to Bruce Power), the management of the Nuclear Funds, and related activities including the inspection and maintenance of the waste storage facilities. Accordingly, accretion expense on the Nuclear Liabilities and earnings (losses) from the Nuclear Funds are reported under this segment.

As the nuclear generating stations operate over time, OPG incurs variable costs related to nuclear used fuel and low and intermediate level waste generated. These costs increase the Nuclear Liabilities through the generation of additional used nuclear fuel bundles and other waste. These variable costs are charged to current operations in the Regulated – Nuclear Generation segment to reflect the cost of producing energy and earning revenue under the Bruce Power lease arrangement. Since variable costs increase the Nuclear Liabilities in the Regulated – Nuclear Waste Management segment, OPG records an inter-segment charge between the Regulated – Nuclear Generation and the Regulated – Nuclear Waste Management segments. The impact of the inter-segment charge between these segments is eliminated on OPG's consolidated statements of income and balance sheets.

The Regulated – Nuclear Waste Management segment is considered regulated because the costs associated with the Nuclear Liabilities are included in the calculation of regulated prices for production from OPG's regulated nuclear facilities by the OEB.

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of the Company's baseload hydroelectric generating stations. The business segment is comprised of electricity generated by the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and the R.H. Saunders hydroelectric facilities. Ancillary revenues are earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities and automatic generation control.

Unregulated – Hydroelectric Segment

The Unregulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from its hydroelectric generating stations that are not subject to rate regulation. Ancillary revenues are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, certified black start facilities, automatic generation control, and other services.

Unregulated – Thermal Segment

The Unregulated – Thermal business segment operates in Ontario, generating and selling electricity from its thermal generating stations, which are not subject to rate regulation. Ancillary revenues are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, automatic generation control, and other services.

Other

The Other category includes revenue that OPG earns from its 50 percent joint venture share of the Brighton Beach Power Limited Partnership ("Brighton Beach") related to an energy conversion agreement between Brighton Beach and Coral Energy Canada Inc. This category also includes revenue that OPG earns from its 50 percent share of the results of the PEC gas-fired generating station, which is co-owned with TransCanada Energy Ltd and is operated under the terms of an ACES contract with the OPA. The revenue and expenses related to OPG's trading and other non-hedging activities are also included in the Other category. As part of these activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate primarily to physical energy that is purchased and sold at the Ontario border, sales of financial risk management products and sales of energy-related products. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value, with changes in fair value recorded in other revenue as gains or losses. In addition, the Other category includes revenue from real estate rentals.

KEY GENERATION AND FINANCIAL PERFORMANCE INDICATORS

Key performance indicators that directly pertain to OPG's mandate and corporate strategies are measures of production efficiency, cost effectiveness, and environmental performance. OPG evaluates the performance of its generating stations using a number of key performance indicators, which vary depending on the generating technology. These indicators are defined in this section and are discussed in the *Discussion of Operating Results by Business Segment* section.

Nuclear Unit Capability Factor

OPG's nuclear stations are baseload facilities as they have low marginal costs and are not designed for fluctuating production levels to meet peaking demand. The nuclear unit capability factor is a key measure of nuclear station performance. It is the amount of energy that the unit(s) generated over a period of time, adjusted for externally imposed constraints such as transmission or demand limitations, as a percentage of the amount of energy that would have been produced over the same period had the unit(s) produced maximum generation. Capability factors are primarily affected by planned and unplanned outages. Capability factors by industry definition exclude grid-related unavailability and high lake water temperature losses.

Thermal and Hydroelectric Equivalent Forced Outage Rate ("EFOR")

OPG's thermal stations provide a flexible source of energy and may operate as baseload, intermediate and peaking facilities, depending on the characteristics of the particular stations and demand of the market. OPG's hydroelectric stations, which operate as baseload, intermediate, and peaking stations, provide a safe, reliable and low-cost source of renewable energy. A key measure of the reliability of the thermal and hydroelectric generating stations is the proportion of time they are available to produce electricity when required. EFOR is an index of the reliability of the generating unit measured by the ratio of time a generating unit is forced out of service by unplanned events, including any forced deratings, compared to the amount of time the generating unit was available to operate.

OPG continues its strategy for its thermal stations to ensure units are available when they are required, and to optimize how coal-fired units are offered into the electricity system, to reduce equipment damage from frequent starts and stops. In addition, OPG has extended the length of outages and reduced outage scope, where warranted, to reduce maintenance related expenditures, such as overtime, as OPG continues to experience low demand for thermal generation. Thermal EFOR for 2009 reflected this strategy.

Hydroelectric Availability

Hydroelectric availability is a measure of the reliability of a hydroelectric generating unit. It is represented by the percentage of time the generating unit is capable of providing service, whether or not it is actually in-service, compared to the total time for a respective period.

Nuclear Production Unit Energy Cost ("PUEC")

Nuclear PUEC is used to measure the cost effectiveness of the operations-related costs of production of OPG's nuclear generating assets. Nuclear PUEC is defined as the total cost of nuclear fuel, OM&A expenses including allocated corporate costs, and variable costs related to used fuel disposal and storage and the disposal of low and intermediate level radioactive waste materials, divided by nuclear electricity generation.

Hydroelectric OM&A Expense per MWh

Hydroelectric OM&A expense per MWh is used to measure the cost effectiveness of the hydroelectric generating stations. It is defined as total hydroelectric OM&A expenses excluding expenses related to past grievances by First Nations, including allocated corporate costs, divided by hydroelectric electricity generation.

Thermal OM&A Expense per MW

Since thermal generating stations are primarily employed during periods of intermediate and peak demand, the cost effectiveness of these stations is measured by their annualized OM&A expenses for the period, including allocated corporate costs, divided by total station nameplate capacity.

Other Key Indicators

In addition to performance and cost effectiveness indicators, OPG has identified certain environmental indicators. These indicators are discussed under the heading *Risk Management*.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

This section summarizes OPG's key results by segment for the years ended December 31, 2009 and 2008. The following table provides a summary of revenue, earnings, and key generation and financial performance indicators by business segment:

(millions of dollars)	**2009**	2008
Revenue, net of revenue limit rebate		
Regulated – Nuclear	**3,179**	2,987
Regulated – Nuclear Waste Management	**44**	46
Regulated – Hydroelectric	**782**	754
Unregulated – Hydroelectric	**605**	902
Unregulated – Thermal	**901**	1,286
Other	**143**	153
Elimination	**(41)**	(46)
	5,613	6,082
Income (loss) before interest and income taxes		
Regulated – Nuclear	**390**	235
Regulated – Nuclear Waste Management	**52**	(670)
Regulated – Hydroelectric	**327**	310
Unregulated – Hydroelectric	**209**	508
Unregulated – Thermal	**(99)**	(25)
Other	**74**	78
	953	436
Electricity generation (TWh)		
Regulated – Nuclear	**46.8**	48.2
Regulated – Hydroelectric	**19.4**	18.8
Unregulated – Hydroelectric	**16.8**	17.6
Unregulated – Thermal	**9.5**	23.2
Total electricity generation	**92.5**	107.8
Nuclear unit capability factor (percent)		
Darlington	**85.9**	94.5
Pickering A	**64.2**	71.8
Pickering B	**84.0**	71.4
Equivalent forced outage rate (percent)		
Regulated – Hydroelectric	**1.0**	1.5
Unregulated – Hydroelectric	**1.6**	0.9
Unregulated – Thermal	**8.5**	12.8
Availability (percent)		
Regulated – Hydroelectric	**93.6**	93.8
Unregulated – Hydroelectric	**92.4**	94.6
Nuclear PUEC ($/MWh)	**44.09**	44.31
Regulated – Hydroelectric OM&A expense per MWh ($/MWh)	**5.46**	6.01
Unregulated – Hydroelectric OM&A expense per MWh ($/MWh)	**11.67**	10.97
Unregulated – Thermal OM&A expense per MW ($000/MW)	**60.20**	65.20

Regulated – Hydroelectric Segment

(millions of dollars)	**2009**	**2008**
Regulated generation sales	**718**	733
Variance accounts	**11**	(32)
Other	**53**	53
Revenue	**782**	754
Fuel expense	**264**	254
Gross margin	**518**	500
Operations, maintenance and administration	**106**	108
Depreciation and amortization	**75**	70
Property and capital taxes	**10**	12
Income before interest and income taxes	**327**	310

Revenue

Regulated – Hydroelectric revenue was $782 million for the year ended December 31, 2009 compared to $754 million in 2008. The increase in revenue was as a result of the recognition of a regulatory asset of $47 million related to the Tax Loss Variance Account authorized by the OEB, and higher generation volume, partially offset by lower electricity sales prices.

Electricity Prices

The average electricity sales price for 2009 and 2008 was 3.7¢/kWh and 3.9¢/kWh, respectively. The decrease in average electricity sales price was primarily due to the impact of lower electricity market prices on the revenue from the regulated hydroelectric incentive mechanism. The impact of this decrease was partially offset by the increase in the regulated prices resulting from the OEB's decision in 2008.

Effective April 1, 2008, electricity generation from the regulated hydroelectric stations received a fixed price of 3.67¢/kWh. During the first quarter of 2008, OPG received a fixed price of 3.3¢/kWh. In the fourth quarter of 2008, OPG recorded retrospective revenue of $44 million for the period April 1, 2008 to November 30, 2008 based on the difference between the revenue earned at the new regulated price and the amounts received at the previous price.

The revised incentive mechanism resulted in net revenue of $21 million for 2009. Regulated generation sales included revenue of $189 million that OPG received at the Ontario spot electricity market price for generation over 1,900 MWh in any hour during the 11 months ended November 30, 2008. OPG also earned additional revenue of $3 million during December 2008 based on a revised regulated hydroelectric incentive mechanism, as described under the heading, *Rate Regulation*.

These transactions are summarized below:

(millions of dollars)	Revenue 2009	Expenses 2009	Revenue 2008	Expenses 2008
Hydro One				
Electricity sales	**20**	**-**	35	-
Services	**-**	**13**	-	7
Province of Ontario				
GRC water rentals and land tax	**-**	**146**	-	151
Guarantee fee	**-**	**4**	-	4
Used Fuel Fund rate of return guarantee	**-**	**493**	-	(971)
Decommissioning Fund excess funding	**-**	**-**	-	(3)
OEFC				
GRC and proxy property tax	**-**	**224**	-	215
Interest expense on long-term notes	**-**	**210**	-	-
Capital tax	**-**	**31**	-	215
Income taxes	**-**	**221**	-	36
Contingency support agreement	**412**	**-**	-	88
Infrastructure Ontario				
Reimbursement of expenses incurred during the procurement of new nuclear units	**-**	**21**	-	-
	-	**-**	-	-
IESO				
Electricity sales	**4,434**	**31**	5,330	127
Revenue limit rebate	**(27)**	**-**	(277)	-
Ancillary services	**153**	**-**	155	-
Other	**6**	**-**	-	-
	4,998	**1,394**	5,243	(131)

As at December 31, 2009, accounts receivable included $2 million (2008 – nil) due from Hydro One and $189 million (2008 – $207 million) due from the IESO. Accounts payable and accrued charges as at December 31, 2009 included $3 million (2008 – $1 million) due to Hydro One and $21 million (2008 – nil) due to Infrastructure Ontario.

CORPORATE GOVERNANCE

Corporate Governance

National Instrument 58-101, *Disclosure of Corporate Governance Practices*, has been implemented by Canadian securities regulatory authorities to provide greater transparency for the marketplace regarding issuers' corporate governance practices. Information with respect to OPG's Board of Directors is as follows:

Board of Directors and Directorships

OPG's Board of Directors is made up of 12 individuals with substantial capability in managing and restructuring large businesses, managing and operating nuclear stations, managing capital intensive companies, and overseeing regulatory, government and public relations. The Board exercises its independent supervision over management as follows: the majority of members of the Board of Directors are independent of the Company; meetings of the Board of Directors are held at least six times a year; a formal Charter for the Board of Directors, and for each Board Committee has been adopted; each Board

18. OTHER (GAINS) AND LOSSES

(millions of dollars)	**2009**	**2008**
Change in estimated cost required to decommission thermal generating stations	**(9)**	(21)
ABCP valuation adjustment *(Note 4)*	**(1)**	14
Other	**-**	(2)
	(10)	(9)

During the fourth quarter of 2009, the Company re-estimated the costs to complete the remaining work to remediate the Lakeview coal-fired generating station site. As a result, OPG recorded a recovery of $9 million in other gains and losses to reflect a change in the estimated costs.

19. BUSINESS SEGMENTS

OPG has five reportable business segments. The business segments are Regulated – Nuclear Generation, Regulated – Nuclear Waste Management, Regulated – Hydroelectric, Unregulated – Hydroelectric, and Unregulated – Thermal.

Regulated – Nuclear Generation Segment

OPG's Regulated – Nuclear Generation business segment operates in Ontario, generating and selling electricity from the nuclear generating stations that it owns and operates. The business segment includes electricity generated by the Pickering A and B, and Darlington nuclear generating stations. This business segment also includes revenue under the terms of a lease arrangement with Bruce Power related to the Bruce nuclear generating stations. This arrangement includes lease revenue and revenue from engineering analysis and design, technical and other services. Revenue is also earned from isotope sales and ancillary services. Ancillary revenues are earned through voltage control and reactive support.

Bruce Nuclear Generating Stations

In May 2001, the Company leased its Bruce A and Bruce B nuclear generating stations to Bruce Power until 2018, with options to renew for up to 25 years.

Under the Bruce Lease agreement, lease revenue is reduced in each calendar year where the annual arithmetic Average HOEP falls below $30/MWh and certain other conditions are met. As a result of the Average HOEP for 2009 being less than $30/MWh, the Bruce Lease revenue for 2009 was reduced by $69 million. The reduction of lease revenue is offset by the impact of the Bruce Lease Net Revenues Variance Account described in Note 7 to these consolidated financial statements. The conditional reduction to revenue in the future, embedded in the terms of the Bruce Lease, is treated as a derivative according to CICA Section 3855, *Financial Instruments – Recognition and Measurement*. Derivatives are measured at fair value and changes in fair value are recognized in the statement of income. As a result of the significant reduction in the arithmetic Average HOEP, the fair value of the derivative has increased to $118 million for 2009. The increase in the fair value of this derivative was recognized as a reduction to revenue, offset by the impact of the Bruce Lease Net Revenues Variance Account.

During 2009, OPG recorded lease revenue related to the Bruce generating stations of $160 million (2008 – $258 million). In late 2008, OPG re-evaluated the Bruce Lease for accounting purposes due to a modification to the lease. As a result of the re-evaluation, the timing in which certain of the lease revenues are recognized for accounting purposes was revised. This results in reductions to the lease revenue for accounting purposes during initial years of the remaining lease term, and increases in lease revenue for accounting purposes during the later years of the remaining lease term. The impact of these timing changes on the amount of lease revenue recognized during 2008 was offset by the impact of the Bruce Lease Net Revenues Variance Account described in Note 7 to these consolidated financial statements. The net book value of fixed assets on lease to Bruce Power at December 31, 2009 was $1,073 million (2008 – $1,134 million).

Regulated – Nuclear Waste Management

OPG's Regulated – Nuclear Waste Management segment engages in the management of used nuclear fuel and low and intermediate level waste, the decommissioning of OPG's nuclear generating stations (including the stations on lease to Bruce Power), the management of the Nuclear Funds, and related activities including the inspection and maintenance of the waste storage facilities. Accordingly, accretion expense on the Nuclear Liabilities and earnings (losses) from the Nuclear Funds is reported under this segment.

As the nuclear generating stations operate over time, OPG incurs variable costs related to nuclear used fuel and low and intermediate level waste generated. These costs increase the Nuclear Liabilities through the generation of additional used nuclear fuel bundles and other waste. These variable costs are charged to current operations in the Regulated – Nuclear Generation segment in order to appropriately reflect the cost of producing energy and the earning of revenues under the lease arrangement with Bruce Power that are recorded in this segment. Since variable costs increase the Nuclear Liabilities in the Regulated – Nuclear Waste Management segment, OPG records an inter-segment charge between the Regulated – Nuclear Generation and the Regulated – Nuclear Waste Management segments. The impact of the inter-segment charge between these segments is eliminated on OPG's consolidated statements of income and balance sheets.

The Regulated – Nuclear Waste Management segment is considered regulated because the costs associated with the Nuclear Liabilities are included in the OEB's determination of regulated prices for production from OPG's regulated nuclear facilities by the OEB.

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of OPG's baseload hydroelectric generating stations. The business segment is comprised of electricity generated by the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and the R.H. Saunders hydroelectric facilities. Ancillary revenues related to these stations are earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities and automatic generation control.

Unregulated – Hydroelectric Segment

The Unregulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from its hydroelectric generating stations that are not subject to rate regulation. Ancillary revenues earned through offering available generating capacity as operating reserve, and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities, automatic generation control, and other services.

Unregulated – Thermal Segment

The Unregulated – Thermal business segment, which was previously named the Unregulated – Fossil-Fuelled segment, operates in Ontario, generating and selling electricity from its thermal generating stations, which are not subject to rate regulation. Ancillary revenues are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, automatic generation control, and other services.

Other

OPG earns revenue from its joint venture share of Brighton Beach related to an energy conversion agreement between Brighton Beach and Coral. The Other category also includes OPG's share of joint venture revenues and expenses from the PEC gas-fired generating station, which is co-owned with TransCanada Energy Ltd. In addition, the Other category includes revenue from real estate rentals.

The revenue and expenses related to OPG's trading and other non-hedging activities are also included in the Other category. As part of these activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate primarily to physical energy that is purchased and sold at the Ontario border, sales of financial risk management products and sales of energy-related products. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value, with changes in fair value recorded in other revenue as gains or losses.

OM&A expenses of the generation segments include an inter-segment service fee for the use of certain property, plant and equipment, and intangibles held within the Other category. The total service fee is recorded as a reduction to the Other category's OM&A expenses. For the year ended December 31, 2009, the service fee was $27 million for Regulated – Nuclear Generation, $3 million for Regulated – Hydroelectric, $4 million for Unregulated – Hydroelectric and $9 million for Unregulated – Thermal, with a corresponding reduction in OM&A expenses of $43 million for the Other category. For the year ended December 31, 2008, the service fee was $29 million for Regulated – Nuclear Generation, $3 million for Regulated – Hydroelectric, $4 million for Unregulated – Hydroelectric, $9 million for Unregulated – Thermal, with a corresponding reduction in OM&A expenses of $45 million for the Other category.

Segment Income (Loss) for the Year Ended December 31, 2009 *(millions of dollars)*	**Regulated**			**Unregulated**				
	Nuclear Generation	**Nuclear Waste Manage -ment**	**Hydro-electric**	**Hydro-electric**	**Thermal**	**Other**	**Elimination**	**Total**
Revenue	**3,179**	**44**	**782**	**615**	**918**	**143**	**(41)**	**5,640**
Revenue limit rebate	**-**	**-**	**-**	**(10)**	**(17)**	**-**	**-**	**(27)**
	3,179	**44**	**782**	**605**	**901**	**143**	**(41)**	**5,613**
Fuel expense	**210**	**-**	**264**	**104**	**413**	**-**	**-**	**991**
Gross margin	**2,969**	**44**	**518**	**501**	**488**	**143**	**(41)**	**4,622**
Operations, maintenance and administration	**2,057**	**48**	**106**	**210**	**492**	**10**	**(41)**	**2,882**
Depreciation and amortization	**481**	**-**	**75**	**73**	**79**	**52**	**-**	**760**
Accretion on fixed asset removal and nuclear waste management liabilities	**-**	**627**	**-**	**-**	**7**	**-**	**-**	**634**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**-**	**(683)**	**-**	**-**	**-**	**-**	**-**	**(683)**
Property and capital taxes	**41**	**-**	**10**	**9**	**18**	**8**	**-**	**86**
Other (gains) and losses	**-**	**-**	**-**	**-**	**(9)**	**(1)**	**-**	**(10)**
Income (loss) before interest and income taxes	**390**	**52**	**327**	**209**	**(99)**	**74**	**-**	**953**

Segment Income (Loss) for the Year Ended December 31, 2008 (millions of dollars)	Regulated Nuclear Generation	Regulated Nuclear Waste Manage-ment	Regulated Hydro-electric	Unregulated Hydro-electric	Unregulated Thermal	Other	Elimination	Total
Revenue	2,987	46	754	974	1,491	153	(46)	6,359
Revenue limit rebate	-	-	-	(72)	(205)	-	-	(277)
	2,987	46	754	902	1,286	153	(46)	6,082
Fuel expense	167	-	254	111	659	-	-	1,191
Gross margin	2,820	46	500	791	627	153	(46)	4,891
Operations, maintenance and administration	2,098	50	108	198	552	7	(46)	2,967
Depreciation and amortization	462	-	70	76	94	41	-	743
Accretion on fixed asset removal and nuclear waste management liabilities	-	573	-	-	8	-	-	581
Losses on nuclear fixed asset removal and nuclear waste management funds	-	93	-	-	-	-	-	93
Property and capital taxes	25	-	12	9	21	13	-	80
Other (gains) and losses	-	-	-	-	(23)	14	-	(9)
Income (loss) before interest and income taxes	235	(670)	310	508	(25)	78	-	436

Selected Consolidated Balance Sheet Information as at December 31, 2009 *(millions of dollars)*	**Regulated**			**Unregulated**			
	Nuclear Generation	**Nuclear Waste Manage-ment**	**Hydro-electric**	**Hydro-electric**	**Thermal**	**Other**	**Total**
Segment fixed assets in service, net	**3,661**	**-**	**3,791**	**2,968**	**384**	**808**	**11,612**
Segment construction in progress	**217**	**-**	**663**	**308**	**32**	**4**	**1,224**
Segment property, plant and equipment, net	**3,878**	**-**	**4,454**	**3,276**	**416**	**812**	**12,836**
Segment intangible assets in service, net	**22**	**-**	**-**	**2**	**-**	**15**	**39**
Segment development in progress	**8**	**-**	**-**	**1**	**1**	**3**	**13**
Segment intangible assets, net	**30**	**-**	**-**	**3**	**1**	**18**	**52**
Segment materials and supplies inventory, net:							
Short-term	**70**	**-**	**-**	**-**	**60**	**2**	**132**
Long-term	**386**	**-**	**-**	**1**	**1**	**-**	**388**
						-	
Segment fuel inventory	**333**	**-**	**-**	**-**	**504**	**-**	**837**
Fixed asset removal and nuclear waste management liabilities	**-**	**(11,711)**	**-**	**-**	**(146)**	**(2)**	**(11,859)**
Nuclear fixed asset removal and nuclear waste management funds	**-**	**10,246**	**-**	**-**	**-**	**-**	**10,246**

Selected Consolidated Balance Sheet Information As at December 31, 2008 *(millions of dollars)*		**Regulated**		**Unregulated**			
	Nuclear Generation	**Nuclear Waste Manage-ment**	**Hydro-electric**	**Hydro-electric**	**Thermal**	**Other**	**Total**
Segment fixed assets in service, net	3,822	-	3,823	2,970	396	456	11,467
Segment construction in progress	234	-	444	192	30	363	1,263
Segment property, plant and equipment, net	4,056	-	4,267	3,162	426	819	12,730
Segment intangible assets in service, net	23	-	-	1	-	24	48
Segment development in progress	3	-	-	-	1	5	9
Segment intangible assets, net	26	-	-	1	1	29	57
Segment materials and supplies inventory, net:							
Short-term	77	-	-	-	55		132
Long-term	336	-	-	1	1	-	338
						-	
Segment fuel inventory	301	-	-	-	435	-	736
Fixed asset removal and nuclear waste management liabilities	-	(11,233)	-	-	(117)	(34)	(11,384)
Nuclear fixed asset removal and nuclear waste management funds	-	9,209	-	-	-	-	9,209

Selected Consolidated Cash Flow Information *(millions of dollars)*		**Regulated**		**Unregulated**			
	Nuclear Generation	**Nuclear Waste Manage -ment**	**Hydro-electric**	**Hydro-electric**	**Thermal**	**Other**	**Total**
Year ended December 31, 2009							
Investment in fixed and intangible assets	**200**	**-**	**254**	**239**	**32**	**27**	**752**
Year ended December 31, 2008							
Investment in fixed and intangible assets	194	-	161	150	63	93	661

Hydro Regulated Asset Performance & Cost Summary

Regulated Hydro (Includes Hydro Central Office Allocations)	2009 Forecast	2010	2011	2012	2013	2014
Energy TW.h	**19.5**	**19.3**	**19.4**	**19.0**	**19.6**	**20.3**
Total Revenue (M$)	**733**	**713**	**741**	**730**	**804**	**837**
OM&A (M$)	**67**	**67**	**78**	**72**	**71**	**76**
- Base	59.7	61.9	68.7	62.2	63.7	67.0
- Projects (Totals from project listings)	6.9	5.3	9.7	10.0	7.7	8.7
Capital & MFA (M$)	**41**	**54**	**40**	**37**	**32**	**29**
- MFA	0.2	0.2	1.2	0.3	0.3	0.3
- Projects (Totals from project listings)	40.5	53.3	38.7	36.5	31.6	28.4
Total Regular Staff at YE	**313**	**319**	**318**	**307**	**309**	**309**
Temporary Staff FTEs	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**
Fuel/GRC & Other Water Rentals (M$)	**263**	**266**	**269**	**269**	**267**	**260**
Total Gross Labour ($M)	**42**	**43**	**45**	**47**	**47**	**49**
- Total Gross Regular	40.9	42.3	44.3	46.2	46.2	48.3
- Total Gross Temporary & Other	0.8	0.3	0.3	0.3	0.4	0.4
- Overtime	2.2	2.2	2.4	2.5	2.5	2.6
- Overtime (% of Gross labour)	**5.4**	**5.2**	**5.3**	**5.4**	**5.4**	**5.3**
Availability Factor %	**93.8**	**90.3**	**90.8**	**90.7**	**91.7**	**92.0**
Equivalent Forced Outage Rate (EFOR) %	**1.4**	**1.3**	**1.3**	**1.3**	**1.3**	**1.3**
Scheduled Outage Factor (SOF) %	5.1	8.7	8.1	8.3	7.3	6.9
Incapability Factor %	6.2	9.7	9.2	9.3	8.3	8.0
OM&A UEC ($/MW.h)	**3.4**	**3.5**	**4.0**	**3.8**	**3.6**	**3.7**
FUEC ($/MW.h) (GRC+Water Rentals)	**13.5**	**13.7**	**13.9**	**14.1**	**13.6**	**12.8**
PUEC ($/MW.h)	**16.9**	**17.2**	**17.9**	**17.9**	**17.3**	**16.5**
Contribution Margin (M$)	**403**	**380**	**393**	**390**	**465**	**502**
Capacity (MW)	**3302**	**3312**	**3312**	**3315**	**3320**	**3322**

Niagara Plant Group

Niagara Plant Group	2009 Forecast	2010	2011	2012	2013	2014
Energy TW.h	**12.4**	**12.4**	**12.4**	**12.1**	**12.7**	**13.4**
Total Revenue (M$)	**465**	**457**	**474**	**463**	**519**	**551**
OM&A (M$)	**45.8**	**44.4**	**53.4**	**46.3**	**47.7**	**50.1**
- Base	40.6	40.3	46.7	40.3	41.4	43.9
- Projects	5.2	4.0	6.7	6.0	6.3	6.3
Capital & MFA (M$)	**28.0**	**36.2**	**30.7**	**30.9**	**25.3**	**25.2**
- MFA	0.2	0.2	1.2	0.3	0.3	0.3
- Projects	27.8	36.0	29.5	30.6	25.0	24.9
Total Regular Staff at YE	**243**	**251**	**250**	**239**	**241**	**241**
Temporary Staff FTEs	**0**	**0**	**0**	**0**	**0**	**0**
GRC & Other Water Rentals (M$)	**167**	**172**	**175**	**174**	**173**	**166**
Total Gross Labour ($M)	**33**	**34**	**35**	**37**	**37**	**38**
- Total Gross Regular	31.9	33.4	35.0	36.5	36.2	37.9
- Total Gross Temporary & Other	0.7	0.3	0.3	0.3	0.3	0.4
- Overtime	1.9	1.9	2.0	2.1	2.2	2.2
- Overtime (% of Gross labour)	**6.0**	**5.7**	**5.8**	**5.8**	**6.0**	**5.8**
Availability Factor %	**89.5**	**88.2**	**89.5**	**88.3**	**90.0**	**89.1**
Equivalent Forced Outage Rate (EFOR) %	1.5	1.8	1.8	1.8	1.8	1.8
Scheduled Outage Factor (SOF) %	9.3	9.9	9.0	10.2	8.5	9.5
Incapability Factor %	10.5	11.8	10.5	11.7	10.0	10.9
OM&A UEC ($/MW.h)	**3.7**	**3.6**	**4.3**	**3.8**	**3.8**	**3.7**
GRC UEC ($/MW.h) (GRC+Water Rentals)	**13.5**	**13.9**	**14.1**	**14.4**	**13.7**	**12.4**
PUEC ($/MW.h)	**17.2**	**17.4**	**18.4**	**18.3**	**17.5**	**16.1**
Capacity (MW)	**2257**	**2267**	**2267**	**2270**	**2275**	**2277**

Key Programs & Issues

- Major rehabilitation/upgrade of SAB1 G9 in 2009/2010, G10 in 2013, G3 in 2012.
- Civil rehabilitation projects for SAB1 continue through planning period (e.g. concrete restoration, roof replacement, tailrace bridge and piers, etc.)
- DeCew Falls ND1 G8 scheduled for overhaul in 2011. Penstock replacement 2009 to 2011. Station Protection and control upgrades scheduled for 2011/2012.
- SAB PGS Unit rehabilitation on G2-5 planned for 2011-2014. PGS Unit transformers also scheduled for replacement 2009-11. Unit breakers and governors planned for replacement 2011-13.
- SAB 2 Station Service System Replacement 2010/2011 and Governor system upgrade 2013/2014
- Development and implementation of Niagara Bridge program including maintenance, divestment and investment ongoing. Divestiture of four bridges being pursued.
- Optimization Initiative – Niagara Optimization Working Group
- Continue to build and improve public franchise.
- Manage risks of equipment failures:
  - PGS Reliability & Turbine Leakage.
  - PGS Transformer failure. Replacement planned in 2010/11.

Saunders GS

Saunders GS (includes OSPG Support Costs)	2009 Forecast	2010	2011	2012	2013	2014
Energy TW.h	**7.1**	**6.9**	**7.0**	**7.0**	**7.0**	**7.0**
Total Revenue (M$)	**268**	**255**	**267**	**267**	**285**	**286**
OM&A (M$)	**16.2**	**13.6**	**16.0**	**17.6**	**15.4**	**16.7**
- Base	14.6	12.4	13.1	13.6	14.0	14.3
- Projects (Totals from project listings)	1.7	1.2	3.0	4.0	1.4	2.4
Capital & MFA (M$)	**12.7**	**17.3**	**9.2**	**5.9**	**6.6**	**3.4**
- MFA	0.0	0.0	0.0	0.0	0.0	0.0
- Projects (Totals from project listings)	12.7	17.3	9.2	5.9	6.6	3.4
Total Regular Staff at YE (Saunders Only)	**71**	**68**	**68**	**68**	**68**	**68**
Temporary Staff FTEs	**0.0**	**1**	**1**	**1**	**1**	**1**
GRC & Other Water Rentals (M$)	**96**	**94**	**94**	**94**	**94**	**94**
Total Gross Labour (M$)	**9**	**10**	**10**	**11**	**11**	**11**
- Total Gross Regular	8.6	9.8	10.2	10.7	11.0	11.4
- Total Gross Temporary & Other	0.1	0.0	0.0	0.0	0.0	0.0
- Overtime	0.4	0.3	0.3	0.3	0.4	0.4
- Overtime (% of Gross labour)	**4.2**	**3.2**	**3.1**	**3.1**	**3.2**	**3.2**
Availability Factor %	95.5	93.7	94.2	96.1	96.3	98.9
Equivalent Forced Outage Rate (EFOR) %	1.1	0.4	0.4	0.4	0.4	0.4
Scheduled Outage Factor (SOF) %	3.6	6.0	5.5	3.6	3.4	0.8
Incapability Factor %	4.5	6.3	5.8	3.9	3.7	1.1
OM&A UEC ($/MW.h)	**2.3**	**2.0**	**2.3**	**2.5**	**2.2**	**2.4**
FUEC ($/MW.h)	**13.6**	**13.5**	**13.5**	**13.5**	**13.5**	**13.5**
PUEC	**15.8**	**15.5**	**15.8**	**16.1**	**15.7**	**15.9**
Capacity (MW)	**1045**	**1045**	**1045**	**1045**	**1045**	**1045**

Key Programs & Issues

- Protection and Controls replacement project (2009 to 2011).
- St. Lawrence Power Development Visitor Centre to be completed in 2010 (part of Saunders GS capital costs)
- Barnhardt Island Bridge Repainting – Joint Works (NYPA Project) in 2012
- Ice Sluices Deck and Steel Support Beam Rehabilitation in 2011
- NYPA Joint Works including the Barnhardt Island Bridge repairs, inspection of Long Sault Dam and crane lead abatement totals $5.5M

Issues/Risks:

- American eel mitigation funding included at ($540-$685k per year). Improved Eel Ladder was installed in 2009.
- Saunders concrete growth rate faster than expected. Monitoring continues. Could require re-slotting in 3 to 8 yrs.