ONTARIO POWER GENERATION

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March 21, 2011

VIA RESS AND COURIER

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

EB-2010-0008 – Ontario Power Generation Inc. Draft Order for Payment Amounts for the Period March 1, 2011 – December 31, 2012 (NON-CONFIDENTIAL VERSION)

Attached is a non-confidential version of a draft payment amounts order and supporting schedules for payment amounts for Ontario Power Generation's (OPG's) prescribed facilities.

The draft payment amounts order reflects the Board's March 10, 2011 Decision with Reasons in the EB-2010-0008 proceeding (the "Decision with Reasons"). The payment amounts are effective March 1, 2011 and will be implemented by the Independent Electricity System Operator (IESO) no later than five business days after receipt of the final OEB Order. The IESO will ensure retroactive recovery for the period March 1 up to the implementation date.

The Decision with Reasons confirms that OPG's forecast of proceeds from the sales of heavy water is OPG confidential information. This information was also previously ordered protected by the OEB in Procedural Order No. 7. As the draft payment amounts order incorporates OPG's confidential information in this regard, a separate confidential version is also being filed with the OEB for review by only those persons who have signed the appropriate Declaration and

Undertaking. The confidential information is included in certain lines of Tables 1, 1a, 2 and 2a of Appendix A to the draft payment amounts order. This information is redacted from the non-confidential version of the draft order.

Attached is a summary of the Decision with Reasons to assist parties in cross-referencing specific decisions to the schedules associated with the draft payment amounts order. Also attached is the Global Insight forecast (referenced on page 123 of the Board's Decision) used in determining the 2012 ROE value.

OPG has provided a draft payment amounts order consistent with the findings in the Decision in accordance with the Board's direction. However, there are certain findings in the Decision which OPG continues to review. This draft payment amounts order is being provided without prejudice to all OPG's rights of rehearing, review, petition and appeal.

If you have any questions regarding this submission, please contact me at 416-592-4463.

Yours truly,

[Original signed by]

Andrew Barrett

Attach. As above

cc: Charles Keizer (Torys) via e-mail
Crawford Smith (Torys) via e-mail
EB-2010-0008 Intervenors via e-mail

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S. O. 1998, c. 15, Schedule B;

AND IN THE MATTER OF an Application by Ontario Power Generation Inc. pursuant to section 78.1 of the *Ontario Energy Board Act, 1998* for an Order or Orders approving payment amounts for the output of certain of its generating facilities.

BEFORE: Cynthia Chaplin
Presiding Member & Chair

Marika Hare
Member

Cathy Spoel
Member

DRAFT PAYMENT AMOUNTS ORDER

March 21, 2011

Ontario Power Generation Inc. ("OPG") filed an Application dated May 26, 2010 with the Ontario Energy Board (the "Board") under section 78.1 of the *Ontario Energy Board Act,* S.O. 1998, c. 15, Schedule B (the "Act") for an order or orders approving the payment amounts for generating facilities prescribed under *Ontario Regulation 53/05* ("O. Reg. 53/05"), as amended, of the Act, effective March 1, 2011, based on a test period of January 1, 2011 through December 31, 2012. The Board assigned file number EB-2010-0008 to the Application.

On February 17, 2011, the Board issued an Interim Order granting OPG's request to declare its current payment amounts interim, effective March 1, 2011.

The Board held an oral hearing on OPG's Application and issued a Decision with Reasons (the "Decision") on March 10, 2011. The Decision directed OPG to file a draft payment amounts order by March 21, 2011.

The Board made a number of findings in its Decision which are reflected in the appendices to this order. The Board also orders that the forecast proceeds from surplus heavy water sales for 2011 and 2012, as identified by OPG, be split 50/50 between ratepayers and OPG.

THE BOARD THEREFORE ORDERS THAT:

1. The test period revenue requirement is $1,419.2M for the prescribed hydroelectric facilities and $5,251.5M for the prescribed nuclear facilities, as set out in Appendix A. The amortization amounts for variance and deferral accounts for the period March 1, 2011 to December 31, 2012 are a credit of ($60.2)M for the prescribed hydroelectric facilities and a debit of $403.2M for the nuclear facilities, as set out in Appendix A. These revenue requirements and amortization amounts shall form the basis of the payment amounts, including the authorized payment riders.

2. Effective March 1, 2011 and subject to sections 3 and 4, for the prescribed hydroelectric facilities, the payment amount is $35.78/MWh, as set out in Appendix B.

3. Effective March 1, 2011, the hydroelectric payment amount, including the authorized hydroelectric payment rider, applies to the average hourly net energy production in megawatt hours from the prescribed hydroelectric facilities in any given month ~~that is supplied into the IESO-administered energy market~~ (the "average hourly volume") for each hour of that month. Where the actual net energy production from the prescribed hydroelectric facilities that is supplied into the IESO-administered energy market in a given hour is greater than the average hourly volume, the incremental net energy production supplied into the IESO-administered energy market will receive the market price, calculated on a five minute basis. Where the actual net energy production from the prescribed hydroelectric facilities that is supplied into the IESO-administered energy market in a given hour is less than the average hourly volume, OPG's revenues will be adjusted by the difference between the average hourly volume and the actual net energy production that is supplied into the IESO-administered energy market, multiplied by the market price, calculated on a five minute basis.

4. Effective March 1, 2011, for the prescribed hydroelectric facilities, the regulated hydroelectric payment rider for the amortization of approved variance and deferral account balances is $(1.65)/MWh, as set out in Appendix D.

5. Effective March 1, 2011 and subject to section 6, for the prescribed nuclear facilities, the payment amount is $51.52/MWh, as set out in Appendix C.

6. Effective March 1, 2011, for the prescribed nuclear facilities, the nuclear payment rider for the amortization of the approved variance and deferral account balances is $4.33/MWh, as set out in Appendix E.

7. The Independent Electricity System Operator (“IESO”) shall make payments to OPG in accordance with this Order as of March 1, 2011.

8. OPG shall recover the December 31, 2010 approved balances in the following variance and deferral accounts in accordance with Appendix F, effective March 1, 2011:

   – Hydroelectric Water Conditions Variance Account
   – Ancillary Services Net Revenue Variance Account – Hydroelectric
   – Income and Other Taxes Variance Account
   – Tax Loss Variance Account
   – Hydroelectric Interim Period Shortfall (Rider D) Variance Account
   – Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
   – Pickering A Return To Service Deferral Account
   – Nuclear Liability Deferral Account
   – Nuclear Development Variance Account
   – Transmission Outages and Restrictions Variance Account
   – Ancillary Services Net Revenue Variance Account – Nuclear
   – Capacity Refurbishment Variance Account
   – Nuclear Fuel Cost Variance Account
   – Bruce Lease Net Revenues Account
   – Nuclear Interim Period Shortfall (Rider B) Variance Account
   – Nuclear Deferral and Variance Over/Under Recovery Variance Account

9. OPG shall continue the following variance and deferral accounts in accordance with Appendix F, effective March 1, 2011:

   – Hydroelectric Water Conditions Variance Account
   – Ancillary Services Net Revenue Variance Account – Hydroelectric
   – Income and Other Taxes Variance Account
   – Tax Loss Variance Account
   – Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
   – Nuclear Liability Deferral Account
   – Nuclear Development Variance Account
   – Ancillary Services Net Revenue Variance Account – Nuclear
   – Capacity Refurbishment Variance Account
   – Bruce Lease Net Revenues Account
   – Nuclear Deferral and Variance Over/Under Recovery Variance Account

10. OPG shall continue the following variance and deferral accounts only for entries of amortization and interest in accordance with Appendix F, effective March 1, 2011:

    - Hydroelectric Interim Period Shortfall (Rider D) Variance Account
    - Pickering A Return To Service Deferral Account
    - Transmission Outages and Restrictions Variance Account
    - Nuclear Fuel Cost Variance Account
    - Nuclear Interim Period Shortfall (Rider B) Variance Account

11. OPG shall establish the following variance and deferral accounts in accordance with Appendix F, effective March 1, 2011:

    - Hydroelectric Surplus Baseload Generation Variance Account
    - Hydroelectric Incentive Mechanism Variance Account

DATED at Toronto ________________, 2011

ONTARIO ENERGY BOARD

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Kirsten Walli
Board Secretary

EB-2010-0008 PAYMENT AMOUNTS ORDER - APPENDICES

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Numbers may not add due to rounding.

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Appendix A
Table 1
(NON-CONFIDENTIAL)

Table 1
Summary of Regulated Hydroelectric Revenue Requirement and Variance and Deferral Account Amortization Amounts ($M)

Line No.	Description	Note	2011 OPG Proposed	2011 Board Adjustment	2011 Board Approved	2012 OPG Proposed	2012 Board Adjustment	2012 Board Approved	Total OPG Proposed	Total Board Adjustment	Total Board Approved
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
			Note 1			Note 1			Note 1		
	Rate Base										
1	**Net Fixed Assets**		3,781.3	0.0	3,781.3	3,765.3	0.0	3,765.3	N/A	N/A	N/A
2	**Working Capital**		0.6	0.0	0.6	0.6	0.0	0.6	N/A	N/A	N/A
3	**Cash Working Capital**		21.5	0.0	21.5	21.5	0.0	21.5	N/A	N/A	N/A
4	**Total Rate Base**		3,803.4	0.0	3,803.4	3,787.4	0.0	3,787.4	N/A	N/A	N/A
	Capitalization										
5	**Short-term Debt**	2	114.0	2.3	116.3	111.3	5.5	116.8	N/A	N/A	N/A
6	**Long-Term Debt**	2	1,901.8	(2.3)	1,899.5	1,896.0	(5.6)	1,890.5	N/A	N/A	N/A
7	**Common Equity**	2	1,787.6	(0.0)	1,787.6	1,780.1	0.0	1,780.1	N/A	N/A	N/A
8	**Adjustment for Lesser of UNL or ARC**	2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
9	**Total Capital**		3,803.4	(0.0)	3,803.4	3,787.4	(0.0)	3,787.4	N/A	N/A	N/A
	Cost of Capital										
10	**Short-term Debt**	3	4.6	0.1	4.7	6.1	0.3	6.4	10.7	0.4	11.1
11	**Long-Term Debt**	3	106.9	(1.9)	105.0	105.8	(1.9)	104.0	212.7	(3.8)	208.9
12	**Return on Equity**	3	176.1	(7.5)	168.6	175.3	(5.3)	170.0	351.4	(12.8)	338.6
13	**Adjustment for Lesser of UNL or ARC**	3	N/A	0.0	N/A	N/A	0.0	N/A	N/A	0.0	N/A
14	**Total Cost of Capital**		287.6	(9.3)	278.2	287.3	(6.9)	280.4	574.9	(16.3)	558.6
	Expenses										
15	**OM&A**		128.2	0.0	128.2	125.9	0.0	125.9	254.1	0.0	254.1
16	**Fuel and GRC**	4	257.1	6.6	263.7	252.2	11.5	263.7	509.3	18.1	527.4
17	**Depreciation & Amortization**		65.6	0.0	65.6	65.0	0.0	65.0	130.6	0.0	130.6
18	**Property Taxes**		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	**Total Expenses**		450.9	6.6	457.5	443.1	11.5	454.6	894.0	18.1	912.1
	Less:										
	Other Revenues										
20	**Bruce Lease Revenues Net of Direct Costs**		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
21	**Ancillary and Other Revenue**	5	44.9	[redacted]	[redacted]	46.2	[redacted]	[redacted]	91.1	[redacted]	[redacted]
22	**Total Other Revenues**		44.9	[redacted]	[redacted]	46.2	[redacted]	[redacted]	91.1	[redacted]	[redacted]
23	**Income Tax**	6	26.9	[redacted]	[redacted]	24.4	[redacted]	[redacted]	51.4	[redacted]	[redacted]
24	**Revenue Requirement**	7	720.5	(8.5)	711.9	708.7	(1.4)	707.2	1,429.2	(10.0)	1,419.2
25	**Amortization of Variance & Deferral Account Amounts**	8	(27.3)	0.0	(27.3)	(32.8)	0.0	(32.8)	(60.2)	0.0	(60.2)
26	**Revenue Requirement Plus Variance & Deferral Account Amortization Amounts**	7	693.1	(8.5)	684.6	675.9	(1.4)	674.4	1,369.0	(10.0)	1,359.0

For notes see Table 1a.

Table 1a
Notes to Table 1
Summary of Regulated Hydroelectric Revenue Requirement and Variance and Deferral Account Amortization Amounts

Notes:

1 Agrees to Ex. I1-T1-S1 Table 1 - Summary of Revenue Requirement for 2011 and 2012 as filed in EB-2010-0008, with the exception of Income Tax at line 23 (see Note 6) and Amortization of Variance & Deferral Account Amounts at line 25 (see Note 8).

2 Capitalization for OPG's combined regulated operations for January 1 to December 31, 2011 is provided in Payment Amounts Order, Appendix A, Table 4a (OPG Proposed) and Table 4b (Board Approved), and for January 1 to December 31, 2012 is provided in Payment Amounts Order, Appendix A, Table 5a (OPG Proposed) and Table 5b (Board Approved). Capital structure amounts are allocated to regulated hydroelectric and nuclear based on their relative rate base amounts as presented below.
OPG has directly assigned the portion of rate base financed at the weighted average accretion rate to its nuclear operations.
The allocation of the remaining capital structure components has been revised to reflect the change in the nuclear rate base.

Table to Note 2 - Allocation of Capital Structure Amounts to Regulated Hydroelectric and Nuclear

Line No.	Item	Reference	2011	2012
			(a)	(b)
1	Approved reg. hydroelectric rate base ($M)	Payment Amounts Order, Appendix A, Table 1, cols. (c) and (f), line 4	3,803.4	3,787.4
2	Approved nuclear rate base ($M)	Payment Amounts Order, Appendix A, Table 2, cols. (c) and (f), line 4	3,915.8	3,844.9
3	Financing directly assigned to nuclear rate base ($M)	Payment Amounts Order, Appendix A, Table 2, cols. (c) and (f), line 8	1,523.3	1,490.1
4	Nuclear rate base financed by capital structure ($M) (line 2 - line 3)		2,392.5	2,354.8
5	Reg. hydroelectric allocation (line 1 / (line 1+line 4))		61.39%	61.66%
6	Nuclear allocation (line 4 / (line 1+line 4))		38.61%	38.34%

3 Cost of capital for OPG's combined regulated operations is provided in Payment Amounts Order, Appendix A, Tables 4a (2011 OPG Proposed), 4b (2011 Board Approved), 5a (2012 OPG Proposed) and 5b (2012 Board Approved).
The cost of capital is allocated between regulated hydroelectric and nuclear operations consistent with the capital structure allocation described in Note 2 above.

4 Gross Revenue Charge increased by $6.6M in 2011 and $11.5M in 2012 to reflect the increase in the regulated hydroelectric production forecast per EB-2010-0008 Decision With Reasons, p. 24.

5 [redacted]

6 Board Approved regulatory income tax expense for combined regulated operations is provided in Payment Amounts Order, Appendix A, Table 6 (for 2011) and Table 7 (for 2012), at line 27. The expense is allocated between the regulated hydroelectric and nuclear businesses on the basis of each business' taxable income, as described in EB-2010-0008, Ex. F4-T2-S1.

7 Amounts on lines 24 and 26 for "OPG Proposed" differ from amounts filed in EB-2010-0008 due to changes in amounts for Income Tax (line 23) and Amortization of Variance & Deferral Account Amounts (line 25) as discussed in notes 6 and 8.

8 Amortization of Variance & Deferral Account Amounts in "OPG Proposed" and "Board Approved" columns are based on actual variance and deferral account balances as at Dec. 31, 2010. See Payment Amounts Order, Appendix D, Table 1, cols. (e) and (f), line 7.

Numbers may not add due to rounding.

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Draft Payment Amounts Order
EB-2010-0008
Appendix A
Table 2
(NON-CONFIDENTIAL)

Table 2

Summary of Nuclear Revenue Requirement and Variance and Deferral Account Amortization Amounts ($M)

			2011			2012			Total		
Line No.	Description	Note	OPG Proposed	Board Adjustment	Board Approved	OPG Proposed	Board Adjustment	Board Approved	OPG Proposed	Board Adjustment	Board Approved
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
			Note 1			Note 1			Note 1		
	Rate Base										
1	**Net Fixed Assets**	2	3,172.2	(125.5)	3,046.7	3,302.3	(306.0)	2,996.3	N/A	N/A	N/A
2	**Working Capital**		865.1	0.0	865.1	844.5	0.0	844.5	N/A	N/A	N/A
3	**Cash Working Capital**		4.0	0.0	4.0	4.0	0.0	4.0	N/A	N/A	N/A
4	**Total Rate Base**		4,041.3	(125.5)	3,915.8	4,150.8	(306.0)	3,844.9	N/A	N/A	N/A
	Capitalization										
5	**Short-term Debt**	3	75.5	(2.3)	73.2	78.2	(5.5)	72.6	N/A	N/A	N/A
6	**Long-Term Debt**	3	1,259.0	(64.2)	1,194.9	1,332.0	(156.6)	1,175.4	N/A	N/A	N/A
7	**Common Equity**	3	1,183.5	(59.0)	1,124.5	1,250.5	(143.8)	1,106.7	N/A	N/A	N/A
8	**Adjustment for Lesser of UNL or ARC**	3	1,523.3	0.0	1,523.3	1,490.1	0.0	1,490.1	N/A	N/A	N/A
9	**Total Capital**	2	4,041.3	(125.5)	3,915.8	4,150.8	(306.0)	3,844.8	N/A	N/A	N/A
	Cost of Capital										
10	**Short-term Debt**	4	3.0	(0.1)	2.9	4.3	(0.3)	4.0	7.3	(0.4)	6.9
11	**Long-Term Debt**	4	70.8	(4.7)	66.0	74.4	(9.7)	64.6	145.1	(14.5)	130.7
12	**Return on Equity**	4	116.6	(10.5)	106.0	123.2	(17.5)	105.7	239.7	(28.0)	211.7
13	**Adjustment for Lesser of UNL or ARC**	4	85.0	0.0	85.0	83.1	0.0	83.1	168.1	0.0	168.1
14	**Total Cost of Capital**		275.4	(15.4)	260.0	284.9	(27.5)	257.4	560.3	(42.9)	517.4
	Expenses										
15	**OM&A**	5	2,021.2	(55.7)	1,965.5	2,067.9	(91.6)	1,976.3	4,089.1	(147.3)	3,941.9
16	**Fuel and GRC**	6	235.6	4.5	240.1	261.7	4.5	266.2	497.4	9.0	506.4
17	**Depreciation & Amortization**		235.4	0.0	235.4	256.4	0.0	256.4	491.8	0.0	491.8
18	**Property Taxes**		16.0	0.0	16.0	16.6	0.0	16.6	32.6	0.0	32.6
19	**Total Expenses**		2,508.3	(51.2)	2,457.1	2,602.6	(87.1)	2,515.6	5,110.9	(138.3)	4,972.7
	Less:										
	Other Revenues										
20	**Bruce Lease Revenues Net of Direct Costs**		128.1	0.0	128.1	143.0	0.0	143.0	271.1	0.0	271.1
21	**Ancillary and Other Revenue**	7	32.0	[redacted]	[redacted]	24.0	[redacted]	[redacted]	56.0	[redacted]	[redacted]
22	**Total Other Revenues**		160.1			167.0			327.1		
23	**Income Tax**	8	47.5	[redacted]	[redacted]	67.8	[redacted]	[redacted]	115.2	[redacted]	[redacted]
24	**Revenue Requirement**	9	2,671.1	(85.1)	2,586.0	2,788.3	(122.8)	2,665.5	5,459.4	(207.9)	5,251.5
25	**Amortization of Variance & Deferral Account Amounts**	10	201.4	0.0	201.4	201.8	0.0	201.8	403.2	0.0	403.2
26	**Revenue Requirement Plus Variance & Deferral Account Amortization Amounts**	9	2,872.5	(85.1)	2,787.4	2,990.2	(122.8)	2,867.3	5,862.6	(207.9)	5,654.7

For notes see Table 2a.

Table 2a
Notes to Table 2
Summary of Nuclear Revenue Requirement and Variance and Deferral Account Amortization Amounts

Notes:

1 Agrees to Ex. I1-T1-S1 Table 1 - Summary of Revenue Requirement for 2011 and 2012 as filed in EB-2010-0008, with the exception of Income Tax at line 23 (see Note 8) and Amortization of Variance & Deferral Account Amounts at line 25 (see Note 10).

2 Adjustment to remove Darlington CWIP from Nuclear rate base per EB-2010-0008 Decision with Reasons, p. 79: $125.5M in 2011 (Ex. B3-T1-S1, Table 1, col. (c), line 14) and $306.0M in 2012 (Ex. B3-T1-S1, Table 1, col. (f), line 14).

3 Capitalization for OPG's combined regulated operations for January 1 to December 31, 2011 is provided in Payment Amounts Order, Appendix A, Table 4a (OPG Proposed) and Table 4b (Board Approved), and for January 1 to December 31, 2012 is provided in Payment Amounts Order, Appendix A, Table 5a (OPG Proposed) and Table 5b (Board Approved).

Capital structure amounts are allocated between regulated hydroelectric and nuclear consistent with the capital structure allocation described in Payment Amounts Order, Appendix A, Table 1a, Note 2. The resulting allocation ratios for nuclear operations are:
Nuclear allocation for 2011: 38.61%
Nuclear allocation for 2012: 38.34%

4 Cost of capital for OPG's combined regulated operations is provided in Payment Amounts Order, Appendix A, Tables 4a (2011 OPG Proposed), 4b (2011 Board Approved), 5a (2012 OPG Proposed) and 5b (2012 Board Approved).
The cost of capital is allocated between regulated hydroelectric and nuclear consistent with the capital structure allocation described in Payment Amounts Order, Appendix A, Table 1a, Note 2.

5 Combined impact on nuclear OM&A of Board adjustments to increase CNSC costs, reduce compensation costs, reduce nuclear insurance costs and correct the Fuel Channel Lifecycle Management (FCLM) cost double count is as follows:

Table to Note 5 - Nuclear OM&A Adjustments

Line No.	Item	Reference	Board Adjustments ($M) 2011	2012	Total
			(a)	(b)	(c)
1	Increase CNSC costs	EB-2010-0008 Decision p. 49 / Ex. N-T1-S1, p. 1	6.5	6.5	13.0
2	Reduce compensation costs	EB-2010-0008 Decision pp. 86, 87	(55.0)	(90.0)	(145.0)
3	Reduce nuclear insurance costs	EB-2010-0008 Decision p. 96	(2.5)	(4.4)	(6.9)
4	Remove FCLM cost double count	EB-2010-0008 Decision p. 50 / OPG's EB-2010-0008 Argument-in-Chief, p. 98	(4.9)	(3.9)	(8.8)
5	Add 50% share of other support costs related to heavy water sales*	EB-2010-0008 Ex. G2-T1-S1, Section 4.1	0.2	0.2	0.4
6	Total		(55.7)	(91.6)	(147.3)

* Adjustment to increase nuclear base OM&A for Commercial Services presented in EB-2010-0008, Ex. F2-T2-S1, Tables 4 and 5, line 24.

6 Fuel cost increased by $9.0M over test period to reflect the increase in the nuclear production forecast per EB-2010-0008 Decision With Reasons, p. 55.

7 Per EB-2010-0008 Decision, p. 64, the adjustments reflect the 50/50 sharing of [redacted] in 2011 and [redacted] in 2012 of forecast heavy water sales, net of direct costs. The effect of 50/50 sharing of forecast heavy water sales is calculated as follows:

Table to Note 7 - Forecast Heavy Water Sales Adjustments

Line No.	Item	Reference	Board Adjustments ($M) 2011	2012	Total
			(a)	(b)	(c)
1	Forecast heavy water sales revenue	EB-2010-0008 Decision p. 64 / EB-2010-0008 Ex. J5.5	[redacted]	[redacted]	[redacted]
2	Forecast of direct costs	EB-2010-0008 Decision p. 64 / EB-2010-0008 Ex. L14.27	(0.8)	(1.0)	(1.8)
3	Revenues net of direct costs		[redacted]	[redacted]	[redacted]
4	50% of revenues net of direct costs				

8 Board Approved regulatory income tax expense for combined regulated operations is provided in Payment Amounts Order, Appendix A, Table 6 (for 2011) and Table 7 (for 2012), at line 27. The expense is allocated between the regulated hydroelectric and nuclear businesses on the basis of each business' taxable income, as described in EB-2010-0008, Ex. F4-T2-S1.

9 Amounts on lines 24 and 26 for "OPG Proposed" differ from amounts filed in EB-2010-0008 due to changes in amounts for Income Tax (line 23) and Amortization of Variance & Deferral Account Amounts (line 25) as discussed in notes 8 and 10.

10 Amortization of Variance & Deferral Account Amounts in "OPG Proposed" and "Board Approved" columns are based on actual variance and deferral account balances as at Dec. 31, 2010. See Payment Amounts Order, Appendix E, Table 1, cols. (e) and (f), line 13.

Table 3
Summary of Approved Revenue Requirement Deficiency/Sufficiency by Technology ($M)
Test Period January 1, 2011 to December 31, 2012

Line No.	Description	Regulated Hydroelectric 2011	Regulated Hydroelectric 2012	Regulated Hydroelectric Total	Nuclear 2011	Nuclear 2012	Nuclear Total	Total Test Period
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Forecast Production (TWh)**[1]	19.8	19.8	39.7	50.4	51.5	101.9	N/A
2	**Prescribed Payment Amount ($/MWh)**[2]	36.66	36.66	36.66	52.98	52.98	52.98	N/A
3	**Indicated Production Revenue ($M)**	727.0	727.0	1,454.1	2,671.4	2,728.4	5,399.8	6,853.8
	(line 1 x line 2)							
4	**Approved Revenue Requirement ($M)**[3]	711.9	707.2	1,419.2	2,586.0	2,665.5	5,251.5	6,670.7
5	**Revenue Requirement Deficiency (Sufficiency) ($M)**	(15.1)	(19.8)	(34.9)	(85.4)	(62.9)	(148.3)	(183.2)
	(line 4 - line 3)							
6	**Revenue Requirement Deficiency (Sufficiency) Approved for Recovery ($M)**[4]	(12.7)	(19.8)	(32.5)	(70.6)	(62.9)	(133.5)	(166.0)

Notes:

1 Forecast production adjusted to remove the allowance for surplus baseload generation (SBG) from the regulated hydroelectric forecast and reduce the allowance for major unforeseen events in nuclear forecast, per EB-2010-0008 Decision with Reasons, pp. 22 and 39.

Table to Note 1 - Forecast Production Adjustments

Line No.	Item	Regulated Hydroelectric (TWh) 2011	Regulated Hydroelectric (TWh) 2012	Regulated Hydroelectric (TWh) Total	Nuclear (TWh) 2011	Nuclear (TWh) 2012	Nuclear (TWh) Total
		(a)	(b)	(c)	(d)	(e)	(f)
1	Forecast Production from EB-2010-0008, Ex. I1-T1-S1, Table 4	19.4	19.0	38.4	48.9	50.0	98.9
2	Board Adjustments - EB-2010-0008 Decision With Reasons, pp. 22 and 39	0.5	0.8	1.3	1.5	1.5	3.0
3	Board Approved Test Period Forecast Production	19.8	19.8	39.7	50.4	51.5	101.9

2 From EB-2007-0905 Payment Amounts Order, Appendix B, Table 1 (regulated hydroelectric) and Appendix C Table 1 (nuclear).

3 From Payment Amounts Order, Appendix A, Table 1 (regulated hydroelectric) and Appendix A, Table 2 (nuclear).

4 Value for 2011 is line 5 x (March to December forecast production / line 1). March to December 2011 forecast production is from Payment Amounts Order, Appendix D, Table 1, line 8 (regulated hydro) and Appendix E, Table 1, line 14 (nuclear). Value for 2012 is the amount on line 5.

Table 4a

Summary of Proposed Capitalization and Cost of Capital: January 1, 2011 to December 31, 2011 ($M)[1]

Line No.	Capitalization	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
		(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:				
1	**Short-term Debt**	189.5	3.0%	2.64%	7.6
2	**Existing/Planned Long-Term Debt**	2,283.1	36.1%	5.53%	126.2
3	**Other Long-Term Debt Provision**	877.7	13.9%	5.87%	51.5
4	**Total Debt**	3,350.3	53.0%	5.53%	185.3
5	**Common Equity**	2,971.1	47.0%	9.85%	292.7
6	**Rate Base Financed by Capital Structure**	6,321.4	80.6%	7.56%	477.9
7	**Adjustment for Lesser of UNL or ARC**	1,523.3	19.4%	5.58%	85.0
8	**Rate Base**	7,844.7	100%	7.18%	562.9

Notes:
1 Amounts in table as per EB-2010-0008, Ex. C1-T1-S1, Table 2.

Table 4b
Summary of Board Approved Capitalization and Cost of Capital: January 1, 2011 to December 31, 2011 ($M)

Line No.	Note	Capitalization	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
		Capitalization and Return on Capital:				
1	1	**Short-term Debt**	189.5	3.1%	2.64%	7.6
2	1	**Existing/Planned Long-Term Debt**	2,283.1	36.9%	5.53%	126.2
3	2	**Other Long-Term Debt Provision**	811.2	13.1%	5.53%	44.9
4	3	**Total Debt**	3,283.8	53.0%	5.44%	178.6
5	3	**Common Equity**	2,912.1	47.0%	9.43%	274.6
6		**Rate Base Financed by Capital Structure**	6,195.9	80.3%	7.31%	453.2
7	4	**Adjustment for Lesser of UNL or ARC**	1,523.3	19.7%	5.58%	85.0
8	5	**Approved Rate Base**	7,719.2	100.0%	6.97%	538.2

Notes:

1 Methodology to determine regulated portion of short-term and existing/planned long-term debt, the associated cost rates and the associated cost amounts were approved as proposed by OPG.

2 Debt required to balance capital structure with approved rate base. Interest rate of 5.53%, the rate for existing and planned long term debt at col. (c), line 2, is used as directed by the Board in EB-2010-0008 Decision With Reasons, p. 125.

3 The Board approved a Debt / Equity ratio of 53% debt, 47% equity (EB-2010-0008 Decision With Reasons, p. 116) and a 9.43% return on common equity (EB-2010-0008 Decision With Reasons, p. 122).

4 The Board accepted OPG's proposed Adjustment for Lesser of UNL or ARC. Adjustment for Lesser of UNL or ARC calculation is referenced at EB-2010-0008, Ex. C2-T1-S2, Table 1, line 29.

5 The Board approved rate base reflects the adjustment to remove Darlington CWIP of $125.5M as discussed in Payment Amounts Order, Appendix A, Table 2a, Note 2.

Table 5a

Summary of Proposed Capitalization and Cost of Capital: January 1, 2012 to December 31, 2012 ($M)[1]

Line No.	Capitalization	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
		(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:				
1	**Short-term Debt**	189.5	2.9%	4.13%	10.4
2	**Existing/Planned Long-Term Debt**	2,502.8	38.8%	5.50%	137.6
3	**Other Long-Term Debt Provision**	725.2	11.2%	5.87%	42.6
4	**Total Debt**	3,417.5	53.0%	5.58%	190.6
5	**Common Equity**	3,030.6	47.0%	9.85%	298.5
6	**Rate Base Financed by Capital Structure**	6,448.1	81.2%	7.59%	489.1
7	**Adjustment for Lesser of UNL or ARC**	1,490.1	18.8%	5.58%	83.1
8	**Rate Base**	7,938.2	100.0%	7.21%	572.2

Notes:

1 Amounts in table as per EB-2010-0008, Ex. C1-T1-S1, Table 1.

Table 5b
Summary of Board Approved Capitalization and Cost of Capital: January 1, 2012 to December 31, 2012 ($M)

Line No.	Note	Capitalization	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
		Capitalization and Return on Capital:				
1	1	**Short-term Debt**	189.5	3.1%	4.13%	10.4
2	1	**Existing/Planned Long-Term Debt**	2,502.8	40.8%	5.50%	137.6
3	2	**Other Long-Term Debt Provision**	563.0	9.2%	5.50%	31.0
4	3	**Total Debt**	3,255.3	53.0%	5.50%	179.0
5	3	**Common Equity**	2,886.8	47.0%	9.55%	275.7
6		**Rate Base Financed by Capital Structure**	6,142.1	80.5%	7.40%	454.7
7	4	**Adjustment for Lesser of UNL or ARC**	1,490.1	19.5%	5.58%	83.1
8	5	**Approved Rate Base**	7,632.2	100.0%	7.05%	537.8

Notes:

1 Methodology to determine regulated portion of short-term and existing/planned long-term debt, the associated cost rates and the associated cost amounts were approved as proposed by OPG.

2 Debt required to balance capital structure with approved rate base. Interest rate of 5.50%, the rate for existing and planned long term debt at col (c), line 2, is used as directed by the Board in EB-2010-0008 Decision With Reasons, p. 125.

3 The Board approved a Debt / Equity ratio of 53% debt, 47% equity (EB-2010-0008 Decision With Reasons, p. 116) and a 9.55% return on common equity (EB-2010-0008 Decision With Reasons, p. 123).
Refer to Payment Amounts Order Appendix A, Table 5c for derivation of 9.55%.

4 The Board accepted OPG's proposed Adjustment for Lesser of UNL or ARC. Adjustment for Lesser of UNL or ARC calculation is referenced at EB-2010-0008, Ex. C2-T1-S2, Table 1, line 29.

5 The Board approved rate base reflects the adjustment to remove Darlington CWIP of $306.0M as discussed in Payment Amounts Order, Appendix A, Table 2a, Note 2.

Numbers may not add due to rounding.

Table 5c
Calculation of 2012 Return on Equity

Market Rates for the Month of: **November 2010**

Step 1: Analysis of Business Day Information in Month

	Government of Canada 10 yr	Government of Canada 30 yr	A - Rated Utilities 30 yr	30 yr Govt over 10 yr Govt	30 yr Utility over 30 yr Govt
01-Nov-10	2.8300	3.4700	4.9703	0.6400	1.5003
02-Nov-10	2.8800	3.4800	4.9160	0.6000	1.4360
03-Nov-10	2.8700	3.4900	4.9410	0.6200	1.4510
04-Nov-10	2.8100	3.4700	4.9161	0.6600	1.4461
05-Nov-10	2.8500	3.4900	4.9534	0.6400	1.4634
06-Nov-10					
07-Nov-10					
08-Nov-10	2.8900	3.5000	4.9359	0.6100	1.4359
09-Nov-10	2.9700	3.5700	4.9701	0.6000	1.4001
10-Nov-10	2.9800	3.5900	4.9390	0.6100	1.3490
11-Nov-10					
12-Nov-10	3.0200	3.6300	4.9708	0.6100	1.3408
13-Nov-10					
14-Nov-10					
15-Nov-10	3.1400	3.7100	5.0822	0.5700	1.3722
16-Nov-10	3.0700	3.6800	5.0204	0.6100	1.3404
17-Nov-10	3.1000	3.6700	5.0243	0.5700	1.3543
18-Nov-10	3.1200	3.6600	5.0419	0.5400	1.3819
19-Nov-10	3.1400	3.6200	5.0317	0.4800	1.4117
20-Nov-10					
21-Nov-10					
22-Nov-10	3.0800	3.5800	5.0010	0.5000	1.4210
23-Nov-10	3.1100	3.6000	5.0436	0.4900	1.4436
24-Nov-10	3.1900	3.6500	5.0476	0.4600	1.3976
25-Nov-10	3.1600	3.6300	5.0354	0.4700	1.4054
26-Nov-10	3.1100	3.5700	5.0193	0.4600	1.4493
27-Nov-10					
28-Nov-10					
29-Nov-10	3.0800	3.5200	4.9801	0.4400	1.4601
30-Nov-10	3.0700	3.4800	4.9516	0.4100	1.4716
	3.02	3.57	4.99	0.552	1.416
Source	Bank of Canada		Bloomberg L.P.		
Identifier	**v39055**	**v39056**	**C29530Y Index**		

Step 2: 10-Year Government of Canada Bond Yield Forecast

Source: Global Insight[1]	**Publication Date:**		**4-Nov-10**
	Full Year	Full Year	Average
November-2011	**3.29**	**3.29**	3.29%
	2012	2012	

Step 3: Long Canada Bond Forecast

10 Year Government of Canada Concensus Forecast (from Step 2)	3.29%
Actual Spread of 30-year over 10-year Government of Canada	0.55%
Long Canada Bond Forecast (LCBF)	3.84%

Step 4: Return on Equity (ROE) Forecast

Initial ROE		**9.75%**
Change in Long Canada Bond Yield Forecast from Base Year		
LCBF (November 2010) (from Step 3)	3.84%	
Base LCBF	**4.25%**	
Spread	-0.41%	
0.5		-0.204%
Change in A-rated Utility Bond Yield from Base Year		
A-Rated Bond Yield Spread (November 2010) (from Step 1)	1.42%	
Base A-Rated Utility Bond Yield	**1.42%**	
Spread	0.00%	
0.5		0.000%
Return on Equity based on November 2010 data		**9.55%**

Step 5: Deemed Long-term Debt Rate Forecast

Long Canada Bond Forecast for November 2010 (from Step 3)	3.84%
A-Rated Utility Bond Yield Spread November 2010 (from Step 1)	1.42%
Deemed Long-Term Debt Rate Based on November 2010 data	**5.26%**

Notes:
1 Global Insight data is available for the entire 2012 year. It was used as the 10-year Government of Canada Bond Yield forecast in Step 2 of the OEB's formula for determining ROE.

Table 6
Summary of Changes in Regulatory Income Taxes for Prescribed Facilities ($M)
Year Ending December 31, 2011

Line No.	Particulars	OPG Proposed	Board Adjustment	Board Approved
		(a)	(b)	(c)
		Note 1		
	Determination of Regulatory Taxable Income			
1	**Regulatory Earnings Before Tax**[2]	246.4	(51.1)	195.3
	Additions for Regulatory Tax Purposes:			
2	**Depreciation and Amortization**	298.4	0.0	298.4
3	**Nuclear Waste Management Expenses**	27.5	0.0	27.5
4	**Receipts from Nuclear Segregated Funds**	46.6	0.0	46.6
5	**Pension and OPEB/SPP Accrual**	287.1	0.0	287.1
6	**Regulatory Asset Amortization - Nuclear Liability Deferral Account**	17.8	0.0	17.8
7	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Account**[3]	113.4	0.0	113.4
8	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**[4]	(12.8)	0.0	(12.8)
9	**Reversal of Amounts Recorded in Income and Other Taxes Variance Account**	0.0	0.0	0.0
10	**Adjustment Related to Financing Cost for Nuclear Liabilities**	85.0	0.0	85.0
11	**Taxable SR&ED Investment Tax Credits of Prior Periods**	8.7	0.0	8.7
12	**Other**	42.8	0.0	42.8
13	**Total Additions**	914.4	0.0	914.4
	Deductions for Regulatory Tax Purposes:			
14	**CCA**	298.9	0.0	298.9
15	**Cash Expenditures for Nuclear Waste & Decommissioning**	127.3	0.0	127.3
16	**Contributions to Nuclear Segregated Funds**	145.0	0.0	145.0
17	**Pension Plan Contributions**	206.1	0.0	206.1
18	**OPEB/SPP Payments**	75.6	0.0	75.6
19	**Regulatory Asset Deduction - Nuclear Liability Deferral Account**[5]	3.9	0.0	3.9
20	**SR&ED Qualifying Capital Expenditures**	8.0	0.0	8.0
21	**SR&ED Investment Tax Credits Recognized in Regulatory Earnings Before Tax**	8.8	0.0	8.8
22	**Other**[6]	3.1	0.0	3.1
23	**Total Deductions**	876.8	0.0	876.8
24	**Regulatory Taxable Income** (line 1 + line 13 - line 23)	284.0	(51.1)	233.0
25	**Regulatory Income Taxes - Federal** (line 24 x line 28)	46.9	(8.4)	38.4
26	**Regulatory Income Taxes - Provincial** (line 24 - line 11) x (line 29 + line 30)	27.5	(5.1)	22.4
27	**Total Regulatory Income Taxes**	74.4	(13.5)	60.9
	Income Tax Rate:			
28	**Federal Tax**	16.50%	N/A	16.50%
29	**Provincial Tax**	12.00%	N/A	12.00%
30	**Provincial Manufacturing & Processing Profits Deduction**	-2.00%	N/A	-2.00%
31	**Total Income Tax Rate**	26.50%	N/A	26.50%

For notes see Table 6a.

Numbers may not add due to rounding.

Table 6a
Notes to Table 6
Summary of Changes in Regulatory Income Taxes for Prescribed Facilities ($M)
Year Ending December 31, 2011

Notes:

1 "OPG Proposed" amounts agree to Ex. F4-T2-S1 Table 5, col. (b) as filed in EB-2010-0008, with the exception of lines 1, 7, 8, 19 and 22, which changed to reflect audited balances in variance and deferral accounts as at December 31, 2010. Specific changes are discussed in notes 2 through 6 below.

2 Regulatory Earnings Before Tax for 2011 are calculated as follows:

Table to Note 2 - Calculation of Regulatory EBT for 2011 ($M)

Line No.	Item	Reference	OPG Proposed	Board Adjustment	Board Approved
			(a)	(b)	(c)
1a	Requested After Tax Return on Equity	"OPG Proposed" per EB-2010-0008 Ex. F4-T2-S1 Table 5, Note 1, line 1. "Board Approved" per Payment Amounts Order, Appendix A, Table 4b, col (d), line 5.	292.7	(18.0)	274.6
2a	Less: Bruce Lease Net Revenues	EB-2010-0008 Ex. F4-T2-S1 Table 5, Note 1, line 2	128.1	0.0	128.1
3a	Add: Single Payment Amounts Adjustment	EB-2010-0008 Ex. F4-T2-S1 Table 5, Note 1, line 3	7.4	(19.5)	(12.1)
4a		line 1a - line 2a + line 3a	172.0	(37.5)	134.4
5a	Additions for Regulatory Tax Purposes	line 13 (where line 13 refers to EB-2010-0008 Payment Amounts Order, Appendix A, Table 6)	914.4	0.0	914.4
6a	Deductions for Regulatory Tax Purposes	line 23 (where line 23 refers to EB-2010-0008 Payment Amounts Order, Appendix A, Table 6)	876.8	0.0	876.8
7a		line 4a + line 5a - line 6a	209.6	(37.5)	172.1
8a	Regulatory Income Taxes - Federal	line 7a x line 28 / (1 - line 31) (where lines 28 and 31 refer to EB-2010-0008 Payment Amounts Order, Appendix A, Table 6)	47.1	(8.4)	38.6
9a	Regulatory Income Taxes - Provincial	(line 7a - line 11) x (line 29 + line 30) / (1- line 31) (where lines 11, 29, 30 and 31 refer to EB-2010-0008 Payment Amounts Order, Appendix A, Table 6)	27.3	(5.1)	22.2
10a	Total Regulatory Income Taxes	line 8a + line 9a	74.4	(13.5)	60.9
11a	Requested After Tax Return on Equity	line 1a	292.7	(18.0)	274.6
12a	Less: Bruce Lease Net Revenues	line 2a	128.1	0.0	128.1
13a	Add: Total Regulatory Income Taxes	line 10a	74.4	(13.5)	60.9
14a	Add: Single Payment Amounts Adjustment		7.4	(19.5)	(12.1)
15a	Regulatory Earnings Before Tax	line 11a - line 12a + line 13a + line 14a	246.4	(51.1)	195.3

3 "OPG Proposed" amount reflects the audited balance of the Bruce Lease Net Revenues Variance Account as at December 31, 2010. The amount is equal to the amortization of the account balance in 2011 as per Payment Amounts Order, Appendix E, Table 1, col. (e), line 8.

4 "OPG Proposed" amount reflects the amortization of the portion of the audited balance of the Income and Other Taxes Variance Account as at December 31, 2010 pertaining to variances that are not deductible for tax purposes.

5 "OPG Proposed" amount reflects the amortization of the tax deductible portion of the audited balance of the Nuclear Liability Deferral Account as at December 31, 2010.

6 "OPG Proposed" amount reflects the amortization of the interest improvement portion of the audited balance of the Bruce Lease Net Revenues Variance Account as at December 31, 2010.

Numbers may not add due to rounding.

Table 7
Summary of Changes in Regulatory Income Taxes for Prescribed Facilities ($M)
Year Ending December 31, 2012

Line No.	Particulars	OPG Proposed	Board Adjustment	Board Approved
		(a)	(b)	(c)
		Note 1		
	Determination of Regulatory Taxable Income			
1	**Regulatory Earnings Before Tax**[2]	240.3	(4.4)	235.9
	Additions for Regulatory Tax Purposes:			
2	**Depreciation and Amortization**	320.1	0.0	320.1
3	**Nuclear Waste Management Expenses**	29.3	0.0	29.3
4	**Receipts from Nuclear Segregated Funds**	58.0	0.0	58.0
5	**Pension and OPEB/SPP Accrual**	345.9	0.0	345.9
6	**Regulatory Asset Amortization - Nuclear Liability Deferral Account**	21.4	0.0	21.4
7	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Account**[3]	136.0	0.0	136.0
8	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**[4]	(15.4)	0.0	(15.4)
9	**Reversal of Amounts Recorded in Income and Other Taxes Variance Account**	0.0	0.0	0.0
10	**Adjustment Related to Financing Cost for Nuclear Liabilities**	83.1	0.0	83.1
11	**Taxable SR&ED Investment Tax Credits of Prior Periods**	8.8	0.0	8.8
12	**Other**	39.0	0.0	39.0
13	**Total Additions**	1,026.2	0.0	1,026.2
	Deductions for Regulatory Tax Purposes:			
14	**CCA**	315.1	0.0	315.1
15	**Cash Expenditures for Nuclear Waste & Decommissioning**	126.6	0.0	126.6
16	**Contributions to Nuclear Segregated Funds**	140.4	0.0	140.4
17	**Pension Plan Contributions**	206.1	0.0	206.1
18	**OPEB/SPP Payments**	80.8	0.0	80.8
19	**Regulatory Asset Deduction - Nuclear Liability Deferral Account**[5]	4.6	0.0	4.6
20	**SR&ED Qualifying Capital Expenditures**	8.0	0.0	8.0
21	**SR&ED Investment Tax Credits Recognized in Regulatory Earnings Before Tax**	8.8	0.0	8.8
22	**Other**[6]	3.8	0.0	3.8
23	**Total Deductions**	894.1	0.0	894.1
24	**Regulatory Taxable Income** (line 1 + line 13 - line 23)	372.4	(4.4)	367.9
25	**Regulatory Income Taxes - Federal** (line 24 x line 28)	55.9	(0.7)	55.2
26	**Regulatory Income Taxes - Provincial** (line 24 - line 11) x (line 29 + line 30)	36.4	(0.4)	35.9
27	**Total Regulatory Income Taxes**	92.2	(1.1)	91.1
	Income Tax Rate:			
28	**Federal Tax**	15.00%	N/A	15.00%
29	**Provincial Tax**	11.00%	N/A	11.00%
30	**Provincial Manufacturing & Processing Profits Deduction**	-1.00%	N/A	-1.00%
31	**Total Income Tax Rate**	25.00%	N/A	25.00%

For notes see Table 7a.

Numbers may not add due to rounding.

Table 7a
Notes to Table 7
Summary of Changes in Regulatory Income Taxes for Prescribed Facilities ($M)
Year Ending December 31, 2012

Notes:

1 "OPG Proposed" amounts agree to Ex. F4-T2-S1 Table 5, col. (c) as filed in EB-2010-0008, with the exception of lines 1, 7, 8, 19 and 22, which changed to reflect audited balances in variance and deferral accounts as at December 31, 2010. Specific changes are discussed in notes 2 through 6 below.

2 Regulatory Earnings Before Tax for 2012 are calculated as follows:

Table to Note 2 - Calculation of Regulatory EBT for 2012 ($M)

Line No.	Item	Reference	OPG Proposed	Board Adjustment	Board Approved
			(a)	(b)	(c)
1a	Requested After Tax Return on Equity	"OPG Proposed" per EB-2010-0008 Ex. F4-T2-S1 Table 5, Note 1, line 1. "Board Approved" per Payment Amounts Order, Appendix A, Table 5b, col (d), line 5.	298.5	(22.8)	275.7
2a	Less: Bruce Lease Net Revenues	EB-2010-0008 Ex. F4-T2-S1 Table 5, Note 1, line 2	143.0	0.0	143.0
3a	Add: Single Payment Amounts Adjustment	EB-2010-0008 Ex. F4-T2-S1 Table 5, Note 1, line 3	(7.4)	19.5	12.1
4a		line 1a - line 2a + line 3a	148.1	(3.3)	144.8
5a	Additions for Regulatory Tax Purposes	line 13 (where line 13 refers to EB-2010-0008 Payment Amounts Order, Appendix A, Table 7)	1,026.2	0.0	1,026.2
6a	Deductions for Regulatory Tax Purposes	line 23 (where line 23 refers to EB-2010-0008 Payment Amounts Order, Appendix A, Table 7)	894.1	0.0	894.1
7a		line 4a + line 5a - line 6a	280.2	(3.3)	276.8
8a	Regulatory Income Taxes - Federal	line 7a x line 28 / (1 - line 31) (where lines 28 and 31 refer to EB-2010-0008 Payment Amounts Order, Appendix A, Table 7)	56.0	(0.7)	55.4
9a	Regulatory Income Taxes - Provincial	(line 7a - line 11) x (line 29 + line 30) / (1- line 31) (where lines 11, 29, 30 and 31 refer to EB-2010-0008 Payment Amounts Order, Appendix A, Table 7)	36.2	(0.4)	35.7
10a	Total Regulatory Income Taxes	line 8a + line 9a	92.2	(1.1)	91.1
11a	Requested After Tax Return on Equity	line 1a	298.5	(22.8)	275.7
12a	Less: Bruce Lease Net Revenues	line 2a	143.0	0.0	143.0
13a	Add: Total Regulatory Income Taxes	line 10a	92.2	(1.1)	91.1
14a	Add: Single Payment Amounts Adjustment		(7.4)	19.5	12.1
15a	Regulatory Earnings Before Tax	line 11a - line 12a + line 13a + line 14a	240.3	(4.4)	235.9

3 "OPG Proposed" amount reflects the audited balance of the Bruce Lease Net Revenues Variance Account as at December 31, 2010. The amount is equal to the amortization of the account balance in 2012 as per Payment Amounts Order, Appendix E, Table 1, col. (f), line 8.

4 "OPG Proposed" amount reflects the amortization of the portion of the audited balance of the Income and Other Taxes Variance Account as at December 31, 2010 pertaining to variances that are not deductible for tax purposes.

5 "OPG Proposed" amount reflects the amortization of the tax deductible portion of the audited balance of the Nuclear Liability Deferral Account as at December 31, 2010.

6 "OPG Proposed" amount reflects the amortization of the interest improvement portion of the audited balance of the Bruce Lease Net Revenues Variance Account as at December 31, 2010.

Table 8
Annualized Residential Consumer Impact Assessment
Board Approved Revenue Requirement
Test Period January 1, 2011 to December 31, 2012

Line No.	Description	Notes	Test Period: Regulated Hydroelectric	Test Period: Nuclear	Test Period: Total
			(a)	(b)	(c)
1	**Typical Residential Consumer Usage (kWh/Month)**	1	800.0	800.0	800.0
2	**Gross-up for Line Losses**	2	1.0728	1.0728	1.0728
3	**OPG Portion**	3	14.0%	35.9%	49.9%
4	**Residential Consumer Usage of OPG Generation (kWh/Month)**		119.9	308.2	428.2
	(line 1 x line 2 x line 3)				
	IMPACT OF RECOVERY OF REVENUE REQUIREMENT DEFICIENCY (SUFFICIENCY):				
5	**Revenue Requirement Deficiency (Sufficiency) Approved for Recovery ($M)**	4	(32.5)	(133.5)	(166.0)
6	**Impact of Amortization of Variance and Deferral Account Amounts ($M)**	5	(60.2)	216.8	156.7
7	**Amount to be Recovered From Customers ($M)** (line 5 + line 6)		(92.6)	83.3	(9.3)
8	**Forecast Production (TWh)**	6	39.7	101.9	141.6
9	**Required Recovery ($/MWh)** (line 7 / line 8)		(2.34)	0.82	(0.07)
10	**Typical Monthly Consumer Bill Impact ($)**		(0.28)	0.25	(0.03)
	(line 4 x line 9)				
11	**Typical Monthly Residential Consumer Bill ($)**	7	109.40	109.40	109.40
12	**Percentage Change in Consumer Bills**		-0.26%	0.23%	-0.03%
	(line 10 / line 11)				

Notes:

1 From EB-2010-0008 Ex. I1-T1-S2, Table 1, line 1.
2 From EB-2010-0008 Ex. I1-T1-S2, Table 1, line 2.
3 From EB-2010-0008 Ex. I1-T1-S2, Table 1, line 3, adjusted for production forecast increases per OEB Decision.
4 From Payment Amounts Order, Appendix A, Table 3, line 6.
5 For regulated hydroelectric, amortization from Payment Amounts Order, Appendix A, Table 1, line 25.
For nuclear, amortization of $403.2M from Payment Amounts Order, Appendix A, Table 2, line 25, less the EB-2007-0905 approved Rider A of $2.00/MWh multiplied by the forecast nuclear production for March 1, 2011 to December 31, 2012 of 93.2 TWh per Payment Amounts Order, Appendix E, Table 1, line 16.
6 From Payment Amounts Order, Appendix A, Table 3, line 1.
7 From EB-2010-0008 Ex. I1-T1-S2, Table 1, line 11.

Table 1
Regulated Hydroelectric Payment Amount
Test Period January 1, 2011 to December 31, 2012

Line No.	Description	Test Period
		(a)
	PAYMENT AMOUNT:	
1	**Revenue Requirement[1] ($M)**	1,419.2
2	**Forecast Production[2] (TWh)**	39.7
3	**Payment Amount ($/MWh)**	35.78
	(line 1 / line 2)	
	DEFERRAL AND VARIANCE ACCOUNT PAYMENT RIDER:	
4	**Recovery of Variance and Deferral Account Amounts[3] ($M)**	(60.2)
5	**Payment Rider ($/MWh)** (line 4 / Mar 2011 - Dec 2012 Production[4])	(1.65)

Notes:
1 From Payment Amounts Order, Appendix A, Table 3, line 4.
2 From Payment Amounts Order, Appendix A, Table 3, line 1.
3 From Payment Amounts Order, Appendix A, Table 1, line 25.
4 March 2011 - December 2012 production from Payment Amounts Order, Appendix D, Table 1, line 10.

Table 1
Nuclear Payment Amount
Test Period January 1, 2011 to December 31, 2012

Line No.	Description	Test Period
		(a)
	PAYMENT AMOUNT:	
1	**Revenue Requirement[1] ($M)**	5,251.5
2	**Forecast Production[2] (TWh)**	101.9
3	**Payment Amount ($/MWh)**	51.52
	(line 1 / line 2)	
	DEFERRAL AND VARIANCE ACCOUNT PAYMENT RIDER:	
4	**Recovery of Variance and Deferral Account Amounts[3] ($M)**	403.2
5	**Payment Rider ($/MWh)** (line 4 / Mar 2011 - Dec 2012 Production[4])	4.33

Notes:
1 From Payment Amounts Order, Appendix A, Table 3, line 4.
2 From Payment Amounts Order, Appendix A, Table 3, line 1.
3 From Payment Amounts Order, Appendix A, Table 2, line 25.
4 March 2011 - December 2012 Production from Payment Amounts Order, Appendix E, Table 1, line 16.

Numbers may not add due to rounding.

Table 1
Regulated Hydroelectric Payment Rider

Line No.	Account Description	Notes	Audited Dec. 31 2010 Balance (Note 1)	Board Adjustment	Board Approved Dec. 31 2010 Balance	Amortization Period (Months)	Amortization 2011 (Note 2)	Amortization 2012 (Note 3)	Total Amortization / Rider
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Hydroelectric Water Conditions Variance ($M)**		(70.2)	0.0	(70.2)	22.0	(31.9)	(38.3)	(70.2)
2	**Ancillary Services Net Revenue Variance - Hydroelectric ($M)**		(9.4)	0.0	(9.4)	22.0	(4.3)	(5.1)	(9.4)
3	**Income and Other Taxes Variance ($M)**		(8.1)	0.0	(8.1)	22.0	(3.7)	(4.4)	(8.1)
4	**Tax Loss Variance ($M)**		78.8	0.0	78.8	46.0	17.1	20.6	37.7
5	**Hydroelectric Interim Period Shortfall (Rider D) Variance ($M)**		(2.3)	0.0	(2.3)	22.0	(1.0)	(1.2)	(2.3)
6	**Hydroelectric Deferral and Variance Over/Under Recovery Variance ($M)**		(7.9)	0.0	(7.9)	22.0	(3.6)	(4.3)	(7.9)
7	**Total ($M)**		(19.1)		(19.1)		(27.3)	(32.8)	(60.2)
8	**2011 Production (March 1 - December 31) (TWh)[4]**								16.7
9	**2012 Production (TWh)[5]**								19.8
10	**Total Forecast Production (TWh)**								36.5
11	**Regulated Hydroelectric Payment Rider ($/MWh)**								(1.65)
	(line 7 / line 10)								

Notes:
1 Audited balances per "Schedule of Regulatory Balances as at December 31, 2010", as filed on Feb. 7, 2011 and referenced in Table 28 of EB-2010-0008 Decision with Reasons (p. 127).
2 Column (c) amount x 10 months / amortization period in column (d).
3 Column (c) amount x 12 months / amortization period in column (d).
4 From Payment Amounts Order, Appendix A, Table 3, col. (a), line 1, adjusted to remove forecast January and February 2011 production.
5 From Payment Amounts Order, Appendix A, Table 3, col. (b), line 1, adjusted to remove forecast January and February 2011 production.

Numbers may not add due to rounding.

Table 1
Nuclear Payment Rider

Line No.	Account Description	Notes	Audited Dec. 31 2010 Balance (Note 1)	Board Adjustment	Board Approved Dec. 31 2010 Balance	Amortization Period (Months)	Amortization 2011 (Note 2)	Amortization 2012 (Note 3)	Total Amortization / Rider
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Pickering A Return To Service (PARTS) Deferral ($M)**		33.2	0.0	33.2	10.0	33.2	0.0	33.2
2	**Nuclear Liability Deferral ($M)**		39.2	0.0	39.2	22.0	17.8	21.4	39.2
3	**Nuclear Development Variance ($M)**		(110.8)	0.0	(110.8)	22.0	(50.4)	(60.4)	(110.8)
4	**Transmission Outages and Restrictions Variance ($M)**		0.1	0.0	0.1	22.0	0.0	0.0	0.1
5	**Ancillary Services Net Revenue Variance - Nuclear ($M)**		0.6	0.0	0.6	22.0	0.3	0.3	0.6
6	**Capacity Refurbishment Variance ($M)**		(8.5)	0.0	(8.5)	22.0	(3.9)	(4.6)	(8.5)
7	**Nuclear Fuel Cost Variance ($M)**		6.4	0.0	6.4	22.0	2.9	3.5	6.4
8	**Bruce Lease Net Revenues Variance ($M)**		249.4	0.0	249.4	22.0	113.4	136.0	249.4
9	**Income and Other Taxes Variance ($M)**		(31.6)	0.0	(31.6)	22.0	(14.3)	(17.2)	(31.6)
10	**Tax Loss Variance ($M)**		413.7	0.0	413.7	46.0	89.9	107.9	197.8
11	**Nuclear Interim Period Shortfall (Rider B) Variance ($M)**		6.6	0.0	6.6	22.0	3.0	3.6	6.6
12	**Nuclear Deferral and Variance Over/Under Recovery Variance ($M)**		20.8	0.0	20.8	22.0	9.5	11.4	20.8
13	**Total ($M)**		619.0		619.0		201.4	201.8	403.2
14	**2011 Production (March 1 - December 31) (TWh)**[4]								41.7
15	**2012 Production (TWh)**[5]								51.5
16	**Total Forecast Production (TWh)**								93.2
17	**Nuclear Payment Rider ($/MWh)** (line 13 / line 16)								4.33

Notes:
1. Audited balances per "Schedule of Regulatory Balances as at December 31, 2010", as filed on Feb. 7, 2011 and referenced in Table 28 of EB-2010-0008 Decision with Reasons (p. 127).
2. Column (c) amount x 10 months / amortization period in column (d).
3. Column (c) amount x 12 months / amortization period in column (d), with the exception of the PARTS Deferral Account which is amortized until December 31, 2011.
4. From Payment Amounts Order, Appendix A, Table 3, column (d), line 1 adjusted to remove forecast January and February 2011 production.
5. From Payment Amounts Order, Appendix A, Table 3, col. (e), line 1, adjusted to remove forecast January and February 2011 production.

Appendix F: Variance and Deferral Accounts

CLEARANCE OF EXISTING VARIANCE AND DEFERRAL ACCOUNTS

With respect to the variance and deferral accounts established by O. Reg. 53/05 and the Board's decisions and orders in EB-2007-0905, EB-2009-0038 and EB-2009-0174, the Board approves the recovery of December 31, 2010 balances in these accounts and recovery periods as provided in the following tables:

Table F - 1
Regulated Hydroelectric Accounts

Account	Approved Dec 31, 2010 Balances ($M)	Approved Recovery Period Starting	Approved Recovery Period Ending
Hydroelectric Water Conditions Variance	(70.2)	Mar 1, 2011	Dec 31, 2012
Ancillary Services Net Revenue Variance - Hydroelectric	(9.4)	Mar 1, 2011	Dec 31, 2012
Income and Other Taxes Variance	(8.1)	Mar 1, 2011	Dec 31, 2012
Tax Loss Variance	78.8	Mar 1, 2011	Dec 31, 2014
Hydroelectric Interim Period Shortfall (Rider D) Variance	(2.3)	Mar 1, 2011	Dec 31, 2012
Hydroelectric Deferral and Variance Over/Under Recovery Variance	(7.9)	Mar 1, 2011	Dec 31, 2012

Table F - 2
Nuclear Accounts

Account	Approved Dec 31, 2010 Balances ($M)	Approved Recovery Period Starting	Approved Recovery Period Ending
Pickering A Return To Service Deferral	33.2	Mar 1, 2011	Dec 31, 2011
Nuclear Liability Deferral	39.2	Mar 1, 2011	Dec 31, 2012
Nuclear Development Variance	(110.8)	Mar 1, 2011	Dec 31, 2012
Transmission Outages and Restrictions Variance	0.1	Mar 1, 2011	Dec 31, 2012
Ancillary Services Net Revenue Variance - Nuclear	0.6	Mar 1, 2011	Dec 31, 2012
Capacity Refurbishment Variance	(8.5)	Mar 1, 2011	Dec 31, 2012
Nuclear Fuel Cost Variance	6.4	Mar 1, 2011	Dec 31, 2012
Bruce Lease Net Revenues Variance	249.4	Mar 1, 2011	Dec 31, 2012
Income and Other Taxes Variance	(31.6)	Mar 1, 2011	Dec 31, 2012
Tax Loss Variance	413.7	Mar 1, 2011	Dec 31, 2014
Nuclear Interim Period Shortfall (Rider B) Variance	6.6	Mar 1, 2011	Dec 31, 2012
Nuclear Deferral and Variance Over/Under Recovery Variance	20.8	Mar 1, 2011	Dec 31, 2012

The Board approves OPG's recovery of the approved balances in the regulated hydroelectric variance and deferral accounts using a payment rider. A payment rider of $(1.65)/MWh (Regulated Hydroelectric Payment Rider), determined in Appendix D, Table 1, effective March 1, 2011, shall apply to OPG's regulated hydroelectric production.

The Board approves OPG's recovery of the approved balances in the nuclear variance and deferral accounts using a payment rider. A payment rider of $4.33/MWh (Nuclear Payment Rider) determined in Appendix E, Table 1, effective March 1, 2011, shall apply to OPG's nuclear production.

For the period January 1, 2011 to February 28, 2011, OPG shall continue to record entries into the variance and deferral accounts established by O. Reg. 53/05 and the Board's decisions and orders in EB-2007-0905, EB-2009-0038 and EB-2009-0174 pursuant to the methodologies established by O. Reg. 53/05 and the above decisions and orders.

CONTINUING VARIANCE AND DEFERRAL ACCOUNTS

OPG shall continue the variance and deferral accounts listed below effective March 1, 2011, as follows:

<u>Hydroelectric Water Conditions Variance Account</u>

The Hydroelectric Water Conditions Variance Account shall continue to record the financial impact of differences between forecast and actual water conditions as proposed in OPG's application. OPG shall determine the production impact of changes in water conditions by entering the actual flow values into the same production forecast model used to calculate the Board approved production forecast, holding all other variables constant. OPG shall determine the deviations from forecast as the difference between the resulting production from the production forecast model based on actual flows and the energy production forecast approved by the Board. OPG shall determine the revenue impact of the production variance by multiplying the deviation from forecast, as described above, by the approved regulated hydroelectric payment amount of $35.78/MWh as calculated in Appendix B, Table 1. The resulting amount shall be recorded in the Hydroelectric Water Conditions Variance Account.

OPG shall also continue to record in this account changes in the gross revenue charge costs reflected in the revenue requirement approved by the Board as a result of differences in energy production described above. OPG shall determine amounts to be recorded in this account by multiplying the production deviation as described above by the applicable gross revenue charge rate.

OPG shall also continue to record in this account any variations from the amounts payable to the St. Lawrence Seaway Management Corporation reflected in the revenue requirement approved by the Board for the conveyance of water in the Welland Ship Canal.

Ancillary Services Net Revenue Variance Account – Hydroelectric

OPG shall compare actual hydroelectric ancillary services net revenue to the forecast amount reflected in the revenue requirement approved by the Board. The difference shall continue to be recorded in this variance account. The ancillary services for regulated hydroelectric operations include black start capability, operating reserve, automatic generation control, and reactive support/voltage control service.

Income and Other Taxes Variance Account

The Income and Other Taxes Variance Account shall continue to record the financial impact on the revenue requirement approved by the Board of:

- Any differences in payments in lieu of corporate income or capital taxes that result from a legislative or regulatory change to the tax rates or rules of the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) (formerly the *Corporations Tax Act* (Ontario)), as modified by the regulations under the *Electricity Act, 1998*, and any differences in payments in lieu of property tax to the Ontario Electricity Financial Corporation that result from changes to the regulations under the *Electricity Act, 1998*.
- Any differences in municipal property taxes that result from a legislative or regulatory change to the tax rates or rules for OPG's prescribed assets under the *Assessment Act, 1990*.
- Any differences in payments in lieu of corporate income or capital taxes that result from a change in, or a disclosure of, a new assessing or administrative policy that is published in

the public tax administration or interpretation bulletins by relevant federal or provincial tax authorities, or court decisions on other taxpayers.

- Any differences in payments in lieu of income or capital taxes that result from assessments or re-assessments (including re-assessments associated with the application of the tax rates and rules to OPG's regulated operations or changes in assessing or administrative policy including court decisions on other taxpayers).

The income tax provision reflected in the revenue requirement approved by the Board shall be used to calculate any variances in income taxes recorded in the Income and Other Taxes Variance Account. The income tax provision reflected in the revenue requirement approved by the Board is calculated in Appendix A, Tables 6 and 7.

<u>Tax Loss Variance Account</u>

OPG shall record only interest and amortization in the Tax Loss Variance Account based on the approved recovery period.

<u>Hydroelectric Interim Period Shortfall (Rider D) Variance Account</u>

OPG shall record only interest and amortization in the Hydroelectric Interim Period Shortfall (Rider D) Variance Account based on the approved recovery period. The balance remaining in the account as at December 31, 2012 shall be transferred to the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account. Following this transfer, the Hydroelectric Interim Period Shortfall (Rider D) Variance Account shall be terminated on December 31, 2012.

<u>Hydroelectric Deferral and Variance Over/Under Recovery Variance Account</u>

The Hydroelectric Deferral and Variance Over/Under Recovery Variance Account shall record the differences between the amounts approved for recovery in the hydroelectric variance and deferral accounts and the actual amounts recovered resulting from the differences between the forecast and actual regulated hydroelectric production. The account shall also include the transfer of the balance remaining in the Hydroelectric Interim Period Shortfall (Rider D) Variance Account as at December 31, 2012.

<u>Pickering A Return To Service Deferral Account</u>

As the approved balance in this account as at December 31, 2010 is ordered to be cleared by December 31, 2011, OPG shall record amortization and interest only in the Pickering A Return To Service Deferral Account until December 31, 2011. The balance remaining in the account as at December 31, 2011 shall be transferred to the Nuclear Deferral and Variance Over/Under Recovery Variance Account. Following this transfer, the Pickering A Return To Service Deferral Account shall be terminated on December 31, 2011.

<u>Nuclear Liability Deferral Account</u>

The Nuclear Liability Deferral Account shall continue to record the revenue requirement impact of any change in OPG's nuclear decommissioning liability arising from an approved reference plan measured against the forecast impact reflected in the revenue requirement approved by the Board. OPG shall not record the revenue requirement impact of a change in its nuclear decommissioning liability associated with its nuclear obligations related to the Bruce facilities in this account. OPG shall record the return on rate base in the account using the weighted average accretion rate on OPG's nuclear liabilities of 5.58 per cent.

The "nuclear decommissioning liability" shall be defined as "the liability of Ontario Power Generation Inc. for decommissioning its nuclear generating facilities and the management of its nuclear waste and nuclear fuel." An "approved reference plan" shall be defined as "a reference plan, as defined in the Ontario Nuclear Funds Agreement, which has been approved by Her Majesty the Queen in the right of Ontario in accordance with that agreement."

<u>Nuclear Development Variance Account</u>

The Nuclear Development Variance Account shall continue to record variances between the actual non-capital costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities and those forecast costs and firm financial commitments reflected in the revenue requirement approved by the Board.

Transmission Outages and Restrictions Variance Account

The approved balance in the Transmission Outages and Restrictions Variance Account as at December 31, 2010 represents accumulated unrecovered interest. Therefore, OPG shall record only amortization in this account based on the approved recovery period. The balance remaining in the account as at December 31, 2012 shall be transferred to the Nuclear Deferral and Variance Over/Under Recovery Variance Account. Following this transfer, the Transmission Outages and Restrictions Variance Account shall be terminated on December 31, 2012.

Ancillary Services Net Revenue Variance Account - Nuclear

OPG shall compare actual nuclear ancillary services net revenue to the forecast amount reflected in the revenue requirement approved by the Board. The difference shall continue to be recorded in this variance account. The ancillary services for nuclear operations include operating reserve and reactive support/voltage control service.

Capacity Refurbishment Variance Account

The Capacity Refurbishment Variance Account shall continue to record variances between the actual capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a prescribed generation facility referred to in O. Reg. 53/05 section 2 and those forecast costs and firm financial commitments reflected in the revenue requirement approved by the Board. This account shall include assessment costs and pre-engineering costs and commitments.

Nuclear Fuel Cost Variance Account

OPG shall record only interest and amortization in the Nuclear Fuel Cost Variance Account based on the approved recovery period. The balance remaining in the account as at December 31, 2012 shall be transferred to the Nuclear Deferral and Variance Over/Under Recovery Variance Account. Following this transfer, the Nuclear Fuel Cost Variance Account shall be terminated on December 31, 2012.

Bruce Lease Net Revenues Variance Account

The Bruce Lease Net Revenues Variance Account shall continue to capture differences between (i) the forecast revenues and costs related to the Bruce lease that are factored into the nuclear revenue requirement approved by the Board, and (ii) OPG's actual revenues and costs in respect of the Bruce facilities.

The variance recorded in this account shall continue to be measured by comparing the Bruce lease revenues net of costs credited to customers through the approved nuclear payment amount of $51.52/MWh, as calculated in Appendix C, Table 1, to the actual Bruce lease revenues net of costs realized by OPG. The Bruce lease revenues net of costs credited to customers shall be equal to the rate of recovery reflected in the nuclear revenue requirement approved by the Board multiplied by OPG's actual nuclear production. The rate of recovery shall be calculated using the forecast Bruce lease revenues net of costs reflected in the nuclear revenue requirement approved by the Board divided by the nuclear production forecast approved by the Board.

The cost impact of any changes in OPG's liability for decommissioning the Bruce nuclear generating facilities and the management of nuclear waste and nuclear fuel related to the Bruce stations shall also continue to be recorded in this account.

Nuclear Interim Period Shortfall (Rider B) Variance Account

OPG shall record only interest and amortization in the Nuclear Interim Period Shortfall (Rider B) Variance Account based on the approved recovery period. The balance remaining in the account as at December 31, 2012 shall be transferred to the Nuclear Deferral and Variance Over/Under Recovery Variance Account. Following this transfer, the Nuclear Interim Period Shortfall (Rider B) Variance Account shall be terminated on December 31, 2012.

Nuclear Deferral and Variance Over/Under Recovery Variance Account

The Nuclear Deferral and Variance Over/Under Recovery Variance Account shall record the differences between the amounts approved for recovery in the nuclear variance and deferral accounts and the actual amounts recovered resulting from the differences between the forecast and actual nuclear production. The account shall also include the transfer of the balances remaining in the Pickering A Return To Service Deferral Account as at December 31, 2011, the Transmission Outages and Restrictions Variance Account as at December 31, 2012, the Nuclear Fuel Cost Variance Account as at December 31, 2012 and the Nuclear Interim Period Shortfall (Rider B) Variance Account as at December 31, 2012.

NEW VARIANCE AND DEFERRAL ACCOUNTS

OPG shall establish the following two new accounts effective March 1, 2011:

<u>Hydroelectric Surplus Baseload Generation Variance Account</u>

OPG shall establish the Hydroelectric Surplus Baseload Generation Variance Account to record the financial impact of foregone production at its prescribed hydroelectric facilities due to surplus baseload generation ("SBG").

OPG shall determine the revenue impact of SBG by multiplying the foregone production volume due to SBG by the approved regulated hydroelectric payment amount of $35.78/MWh as calculated in Appendix B, Table 1. The resulting amount shall be recorded in the Hydroelectric Surplus Baseload Generation Variance Account.

OPG shall also record in this account changes in the gross revenue charge costs reflected in the revenue requirement approved by the Board as a result of SBG. OPG shall determine amounts to be recorded in this account by multiplying the foregone production volume at its prescribed hydroelectric facilities due to SBG by the applicable gross revenue charge rate.

OPG shall also record in this account any variations from the amounts payable to the St. Lawrence Seaway Management Corporation reflected in the revenue requirement approved by the Board for the conveyance of water in the Welland Ship Canal as a result of foregone production at its prescribed hydroelectric facilities due to SBG.

The reconciliation of the account will be based on any IESO order or instructions (if applicable), general market conditions (e.g., total demand, total baseload, total supply) and actual production reports from the SBG-affected prescribed generation units that show deviations from production that are contemporaneous with SBG conditions.

<u>Hydroelectric Incentive Mechanism Variance Account</u>

OPG shall establish the Hydroelectric Incentive Mechanism ("HIM") Variance Account to record 50 per cent of HIM net revenues above $10M in 2011 and $14M in 2012 as a credit to ratepayers.

INTEREST

Unless otherwise provided in this payment amounts order, OPG shall record interest on the balances in the variance and deferral accounts using the interest rates set by the Board from time to time pursuant to the Board's interest rate policy. OPG shall apply simple interest to the opening monthly balance of the accounts until the balances are fully recovered.

ATTACHMENT
EB-2010-0008 SUMMARY OF BOARD DECISION WITH REASONS

Decision Section	Pg	Application Issue	Board Decision	PA Order Schedule Reference
3	**REGULATED HYDROELECTRIC**			
3.1	22 to 23	Production forecast	Rejected OPG's proposal to include SBG in production forecast resulting in an increase in production forecast by 1.3 TWh.	Appendix A, Table 3, line 1 and Footnote 1
			Approved the creation of a variance account for SBG, with SBG to be measured on the basis proposed by OPG.	Appendix F, page 8
3.2	24	Operating Costs	Approved.	N/A
			Increased the provision for GRC by $6.6M in 2011 and $11.5M in 2010.	Appendix A, Table 1, line 16
3.3	26	Capital Expenditures and Rate Base	Approved.	N/A
3.3.1	28	Niagara Tunnel Project	Will not require additional reporting on the status of the Niagara Tunnel Project prior to OPG's next payments case.	N/A
3.3.2	28	Investment in Hydroelectric Assets	Will not direct OPG to perform the asset demographics analysis proposed by PWU.	N/A
3.3.4	31	St. Lawrence Power Development Visitor Centre	Approved.	N/A
3.4	33	Other Revenues	Approved forecast test period revenue for ancillary services.	N/A
			Water Transactions ("WT") – revenue forecast to be based on the three-year average for 2007, 2008 and 2009.	Appendix A, Table 1, line 21
4	**NUCLEAR**			
4.1	39	Production Forecast	A forecast of 50.4 TWh for 2011 and 51.5 TWh for 2012 should be used for determining the revenue requirement.	Appendix A, Table 3, line 1 and Footnote 1
			Reduced OPG's forecast for "major unforeseen events" ("MUE") from 2.0 TWh per year to 0.5 TWh per year.	Appendix A, Table 3, line 1 and Footnote 1

N/A – not applicable

Decision Section	Pg	Application Issue	Board Decision	PA Order Schedule Reference
4.2	45 to 46	Nuclear Benchmarking	Accepted the benchmarking methodology and finds that the ScottMadden reports were conducted objectively and based on considerable expertise and experience in these types of studies.	N/A
			OPG to continue undertaking the benchmarking work and to produce a report to be filed with the next cost of service application.	N/A
			OPG to conduct an examination of staffing levels as part of its next benchmarking study.	N/A
			The Board expects to review in the next application the initiatives OPG has taken and intends to take to improve Forced Loss Rate ("FLR").	N/A
4.3.1	49	Base, Project and Outage OM&A	OPG has made progress in controlling costs and the growth of costs, but the benchmarking evidence and compensation evidence demonstrate that further progress is warranted.	N/A
			Allowed the $13M increase over the test period for Canadian Nuclear Safety Commission ("CNSC") fees.	Appendix A, Table 2a, Note 5
4.3.2	51	Pickering B Continued Operations	Approved $84.1M for Pickering B Continued Operations. Double counting of fuel channel life management project ($8.8M) to be corrected.	Appendix A, Table 2a, Note 5
4.3.3	55	Nuclear Fuel	2011 and 2012 fuel forecast to increase by $9M in recognition of the increased production forecast (see Decision 4.1 above).	Appendix A, Table 2, line 16
			The Board has determined that a variance for nuclear fuel costs is not an appropriate way to incent OPG to look for the most efficient portfolio of contracts for nuclear fuel procurement, and it is more appropriate for the company to bear the risk that the forecast is inaccurate, than for ratepayers to do so.	Appendix F, page 6
			OPG to file an external review as part of its next application.	N/A
4.4	59 to 60	Nuclear Capital Expenditures and Rate Base	Approved proposed capital budget for projects entering service in the test period.	N/A
			Gross plant and accumulated depreciation for asset retirement costs ("ARC") be separately identified in rate base evidence in the next application, to improve transparency for regulatory purposes.	N/A
			The Board will re-examine the issue of rate base additions and the accuracy of OPG's forecasts in this area in the next proceeding.	N/A
			Approved overspending on the Pickering cafeteria.	N/A

N/A – not applicable

Decision Section	Pg	Application Issue	Board Decision	PA Order Schedule Reference
			The Board does not accept the range of +60% to -40% around a capital project's estimated cost as acceptable for larger projects as it suggests a lack of adequate cost control. The Board finds a range of +25% to -25% around the midpoint (for the Darlington Refurbishment Project ("DRP") as reasonable on any other projects of substance. In addition to rigorous cost control, the Board is also concerned that projects be assessed on an accurate analysis of the costs and benefits.	N/A
4.5	62 to 64	Other Revenues	Approved OPG's forecast of other revenues from nuclear operations.	N/A
			Proceeds from heavy water sales to be split 50/50. These amounts to be incorporated in the Payments Order.	- Appendix A, Table 2, lines 15 and 21 - Appendix A, Table 2a, Notes 5 and 7
			No variance account for heavy water sales will be set up (although OPG did not specifically request one), and OPG will bear the risk between sales and forecast.	N/A
5	**DARLINGTON REFURBISHMENT**			
5.1	70 to 73	Darlington Refurbishment Project ("DRP")	Agreed with OPG that section 6(2)4 of O. Reg. 53/05 applies to the DRP as it is designed to refurbish a generating facility to which O. Reg. 53/05 applies.	N/A
			The Board expects to examine the reasonableness of proceeding with the project once the DRP reaches the stage of having a release quality cost estimate.	N/A
			The Board expects OPG to file updated information on its progress for examination in the next proceeding.	N/A
			The Board declines to find that the Minister's letter concurring with the DRP means that the DRP is, by definition, in the public interest.	N/A
			The Board expects OPG's Board to reassess the project if the results of the definition phase demonstrate that the costs will rise significantly.	N/A
			The Board expects that in future payments cases the business case will be updated, and therefore will not require any additional reporting at this time.	N/A
			The Board will be interested in examining whether any performance incentives might be appropriate within the parameters of O. Reg. 53/05 and the variance account in examining the project going forward.	N/A

N/A – not applicable

Decision Section	Pg	Application Issue	Board Decision	PA Order Schedule Reference
5.2	78 to 79	Construction Work in Progress ("CWIP")	The Board finds that the Report is clear that the policy could apply in other circumstances beyond the Green Energy Act and beyond transmission and distribution infrastructure.	N/A
			Disallowed inclusion of CWIP in rate base.	- Appendix A, Table 2, line 1 - Appendix A, Table 4b, line 8 and Note 5 - Appendix A, Table 5b, line 8 and Note 5
			Prepared to consider the proposal again in the future, but expect better evidence in support of the proposal.	N/A
6	**CORPORATE COSTS**			
6.1	84 to 88	Compensation	OPG to present staff information on an FTE basis in the next application and restate historical years on that basis.	N/A
			The Board will examine the issue of overtime more closely in the next proceeding, and expects OPG to demonstrate that it has optimized the mix of potential staffing resources.	N/A
			The Board is of the view that OPG has opportunities to reduce the overall number of employees further as a means of controlling total costs and enhancing productivity.	N/A
			As noted in Section 4.2, conduct a staff level analysis as part of Nuclear's benchmarking studies.	N/A
			With 20 to 25% of staff expected to retire between 2010 and 2014, OPG has a timely opportunity to review its organizational structure, taking actions to reassign functions and eliminate positions.	N/A
			Compensation benchmark should generally be set at the 50th percentile.	N/A
			Reduced Nuclear compensation costs by $55M in 2011, and $90M in 2012.	- Appendix A, Table 2, line 15 - Appendix A, Table 2a, Note 5

N/A – not applicable

Decision Section	Pg	Application Issue	Board Decision	PA Order Schedule Reference
			OPG to conduct an independent compensation benchmarking study to be filed with the next application. The study should compare OPG's total compensation with broadly comparable organizations and cover a significant proportion of its positions. Consultation with Board staff and stakeholders concerning the scope of the study, in advance of issuing a Terms of Reference, is advised. Costs of the study to be absorbed with Regulatory Affairs budget.	N/A
6.2	91	Pension and Other Post Employment Benefits ("OPEB")	Approved both the cash and accrual methods to setting pension and other post employment benefit expenses.	N/A
			Denied OPG's request for a Pension and OPEB Variance Account.	Absent from Appendix F
			OPG to provide a fuller range and discussion of alternatives to the use of AA bond yields to forecast discount rates in its next application.	N/A
6.3.1	94	Corporate Support Costs	Accepted OPG's evidence on the benchmarking studies and the cost allocation methodology.	N/A
			Accepted Regulatory Affairs test period forecast.	N/A
			The Board expects the cost savings impact of the efficiency improvement initiatives undertaken by OPG to be reflected in the company's forecasted budgets.	N/A
6.3.2	96	Centrally Held Costs	Rejected OPG's request to increase nuclear insurance costs. As a result, 2011 proposed amount for nuclear insurance costs to be reduced by \$2.5M, resulting in \$8.8M for 2011. The amount to be included for 2012 is \$9.0M	- Appendix A, Table 2, line 15 - Appendix A, Table 2a, Note 5
6.4	97	Depreciation	Accepted the end of service life estimates for the prescribed facilities as filed by OPG, including the extended service life for Darlington.	N/A
			OPG to file an independent depreciation study at the next proceeding.	N/A
6.5	98	Taxes	Accepted OPG's evidence with respect to HST and OPG does not have to provide details regarding of its HST returns.	N/A
			The Board expects OPG to continue to demonstrate that the impacts of HST have been appropriately incorporated into its forecasts.	N/A
7	**BRUCE LEASE – REVENUES AND COSTS**			
	100	Bruce Lease – Revenues and Costs	Approved OPG's test period forecast for the Bruce Lease net revenues.	N/A

N/A – not applicable

Decision Section	Pg	Application Issue	Board Decision	PA Order Schedule Reference
8	**NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING**			
8.1	103	Methodology	Accepted OPG's methodology to calculate the revenue requirement impacts of OPG's nuclear liabilities, and agrees with OPG and CME that it would be premature to revise the existing methodology for the regulatory treatment of nuclear facilities.	N/A
8.2	110	Station End of Life Dates and Test year Nuclear Liabilities	Accepted 2051 as the Darlington station end of life for regulatory purposes.	N/A
			The Board expects that there will be more information on the expected end of life for Pickering A and Pickering B in the next proceeding and expects a new end of life may well be adopted then.	N/A
9	**CAPITAL STRUCTURE AND COST OF CAPITAL**			
9.1	116	Technology-Specific Capital Structures	There is no sufficient evidence to support a change to technology-specific capital structures.	N/A
			The use of a separate capital structure related to the assessment of large capital projects can be pursued further by parties in subsequent proceedings.	N/A
9.2.1	119 to 120	Should the ROE be reduced?	Accepted OPG's proposal to use the ROE determined on the basis of the Board's Cost of Capital Report.	N/A
			Agreed that there is flexibility to apply a different ROE in appropriate circumstances, but there was no evidence of a compelling reason to do so in this case.	N/A
9.2.2	122 to 123	How should the ROE for 2011 and 2012 be set?	Approved: 2011 - 9.43% 2012 - 9.55%	 Appendix A, Table 4b Appendix A, Table 5b
			The Board concluded that it is reasonable to use the Global Insight forecast for purposes of setting the ROE for 2012.	N/A
			OPG shall file the relevant documentation as part of its draft payment amounts order, consistent with the methodology adopted by the Board in its Cost of Capital Report, supporting the derivation of the ROE for 2012.	Appendix A, Table 5c
9.3	124	Cost of Short-Term Debt	Agreed with OPG that its approach to short-term debt rates is consistent with the previous decision and will not require OPG to update the short-term debt rates for either 2011 or 2012.	N/A

N/A – not applicable

Decision Section	Pg	Application Issue	Board Decision	PA Order Schedule Reference
9.4	125	Cost of Long-Term Debt	Rejected OPG's proposal that the Board's deemed long-term debt rate be applied to any unfunded portion of its long-term debt.	
			OPG's weighted average cost of existing and forecasted long-term debt will apply to the unfunded portion of long-term debt as well as to actual or forecasted long-term debt in each test year.	- Appendix A, Table 4b and Footnote 2 - Appendix A, Table 5b and Footnote 2
10	**DEFERRAL AND VARIANCE ACCOUNTS**			
10.2	128	Existing Hydroelectric Accounts	Approved the audited December 31, 2010 balances for disposition as proposed by OPG.	N/A
10.3.1	135	Tax Loss Variance Account	Approved recovery of the balance in the Tax Loss Variance Account in accordance with OPG's proposal to recover the balances over a 46-month period. However, the riders that will be given effect by this Decision and subsequent payment order will be effective until December 31, 2012.	- Appendix D, Table 1 - Appendix E, Table 1 - Appendix F, pages 1 and 4
10.3.2	138	Nuclear Liability Deferral Account	Satisfied with OPG's explanation for the entries for the first quarter of 2008 in relation to section 5.1(1) of O. Reg. 53/05.	N/A
10.3.3	139	Bruce Lease Net Revenues Variance Account	Approved proposed disposition.	N/A
10.3.4	139	Capacity Refurbishment Variance Account	The Board will not remove the costs associated with the Pickering B refurbishment studies. These activities were prudently undertaken and the costs are therefore eligible for recover under O. Reg. 53/05 and the account.	N/A
10.3.5	139	All Other Existing Common and Nuclear Accounts	- The audited December 31, 2010 balances are approved for disposition as proposed by OPG. - Approved the continuation of the existing common and nuclear accounts as proposed by OPG.	N/A
10.4.1	141	IESO Non-energy Charges Variance Account	Denied OPG's request for this variance account.	Absent from Appendix F
10.4.2	141	Pension and Other Post Employment Benefits Cost Variance Account	Denied OPG's request for this variance account (also see Decision 6.2).	Absent from Appendix F

N/A – not applicable

Decision Section	Pg	Application Issue	Board Decision	PA Order Schedule Reference
10.5	142	New Accounts Proposed by Other Parties	The only new variance accounts to be established are: - Surplus Baseload Generation (Hydroelectric) Variance Account - Hydroelectric Incentive Mechanism Variance Account	Appendix F, pages 8 and 9
11	**DESIGN AND DETERMINATION OF PAYMENT AMOUNTS**			
11.1	143	Design of Payment Amounts	The Board found that the previously approved methodology should continue.	N/A
11.2	146 to 148	Hydroelectric Incentive Mechanism ("HIM")	OPG will be compensated for SBG. When assessing the circumstances which give rise to lost production due to SBG, the Board will examine the use of PGS and OPG will have to fully justify any instances in which the PGS is not used. If the Board finds that OPG could have, or should have, used the PGS to mitigate SBG, the Board will adjust the balance in the SBG account accordingly.	Appendix F, page 9
			50% of the proceeds of the HIM be returned to customers and OPG will incorporate HIM revenues into the revenue requirement as a revenue offset.	Appendix F, page 9
			Only a portion of the HIM revenue forecast will be incorporated in revenue requirement $5M for 2011 and $7M for 2012. Establish a variance account to track all additional HIM net revenues about this forecast provision. Any additional net revenues beyond the above levels will be shared equally between OPG and ratepayers.	Appendix F, page 9
			OPG to re-address the HIM structure in its next application. Specifically provide a more comprehensive analysis of the benefits of the HIM for ratepayers, the interaction between the mechanism and SBG, and an assessment of potential alternative approaches in light of expected future conditions in the contracted and traded market.	N/A
12	**REPORTING AND RECORD KEEPING REQUIREMENTS**			
	150 to 151	Reporting and Record Keeping Requirements ("RRR")	The following reports shall be filed, beginning in 2011:	
			Unaudited balances of deferral and variance accounts within 60 days after calendar quarter end.	N/A
			The MD&A and financial statements as filed with the OSC within 60 days for the first three quarters, and within 120 days for December year-end statements as long as the OSC requires these documents to be filed.	N/A

N/A – not applicable

Decision Section	Pg	Application Issue	Board Decision	PA Order Schedule Reference
			Nuclear unit capability factors and hydroelectric availability for the regulated facilities within 60 days for the first three quarters and within 120 days for December year end as reported in OPG's quarterly and annual MD&A.	N/A
			FTE information, similar to the presentation in Ex. F4-T3-S1, Chart 1 by April 30.	N/A
			Capital in-service additions and construction work in progress by April 30.	N/A
			An analysis of the actual annual regulatory return, after tax on rate base, both dollars and percentages, for the regulated business and a comparison with the regulatory return included in the payment amounts by June 30th of each year. It would be similar to what is set out in Ex. C1-T1-S1, Table 7 for the historical period.	N/A
			When OPG brings forward its incentive regulation mechanism proposal, as part of that application, OPG should propose the suite of RRR that might be applicable for its incentive plan period.	N/A
			OPG to continue to provide annual audited financial statements for the prescribed facilities.	N/A
13	**METHODOLOGIES FOR SETTING PAYMENT AMOUNTS**			
	156 to 157	Methodologies for Setting Payment Amounts	OPG to file another cost of service application for the 2013 and 2014 years.	N/A
			Board will commence work in 2011 to lay out the scope of the required IRM and productivity studies to be filed by OPG.	N/A
			OPG to provide a proposed work plan and status report for an independent productivity study as part of its 2013 and 2014 cost of service application, which would be expected in early 2012.	N/A
			OPG to file an application for incentive regulation to be in effect starting in 2015. This application should be filed no later than the fourth quarter of 2013, and would be subject to a hearing in 2014.	N/A
			OPG to engage stakeholders in meaningful discussions about the proposed incentive regulation mechanism in advance of the actual IRM regime filing.	N/A
14	**IMPLEMENTATION AND COST AWARDS**			
14.1	158	Implementation	OPG to file the draft payment amounts order by March 21, 2011.	Draft Payment Amounts Order page 1

N/A – not applicable

Decision Section	Pg	Application Issue	Board Decision	PA Order Schedule Reference
			Board staff and intervenors shall respond to OPG's draft payment order by March 28, 2011.	N/A
			OPG shall respond to any comments by Board staff and intervenors by April 4, 2011.	N/A
14.2	159	Cost Awards	Intervenors submit cost claim by April 8, 2011.	N/A
			OPG shall objections by April 15, 2011.	N/A
			Intervenor to file response to objections by April 21, 2011.	N/A

N/A – not applicable

CANADIAN FORECAST EXECUTIVE SUMMARY

NOVEMBER 2010

Update of the Canadian Short-Term Outlook

A Brighter But Still Weak Outlook

Canada's economic outlook has been revised only in the near term. Given the stronger than initially anticipated real GDP by industry for August, we are boosting our third-quarter forecast from 0.8% to 1.1%. Economic activity is expected to pick up, but stay relatively subdued in the fourth quarter, climbing 2%. Overall, real GDP for 2010 is expected to advance 2.9%. We are still forecasting a general economic cooling in 2011. Growth should pick up speed again in 2012, advancing around 3%.

Canadian real GDP by industry bounced back by 0.3%. The gain in output is a nice rebound from a 0.1% decline in July. Manufacturing output advanced by 0.5% in the month, and industrial production was up by 0.4%. Services-producing industry output increased 0.3%, bouncing back from a decline in July. Finance and real estate were the main contributors.

One caveat is that the gains in manufacturing and trade were largely connected to an August jump in net exports to the United States, and relatively strong U.S. inventory accumulation in the third quarter overall, a situation that is unlikely to be sustained in September, or in the fourth quarter of 2010.

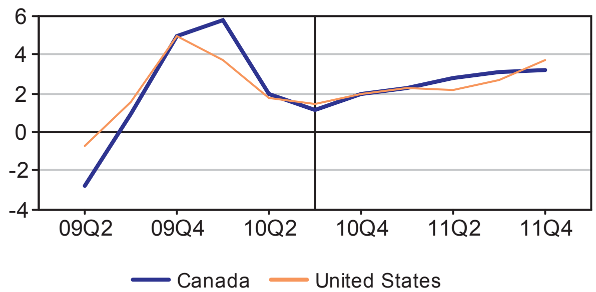
Growth is still running below potential in the second half of 2010, so we are unlikely to see much progress in terms of reducing the unemployment rate which is stubbornly stuck around 7.9%.

U.S. economic growth is slated for 2.6% this year and 2.2 in 2011, the same as last month's forecast.

Also in this Issue

Canada and U.S. Real GDP Growth

(Percent change, annualized)



With a rather dramatic change in the language of its press release, and a much more subdued characterization of the global recovery as well as prospects for growth in Canada for the remainder of 2010 and in 2011, the Bank of Canada announced on October 19 that it would pause in its recent campaign to hike short-term interest rates.

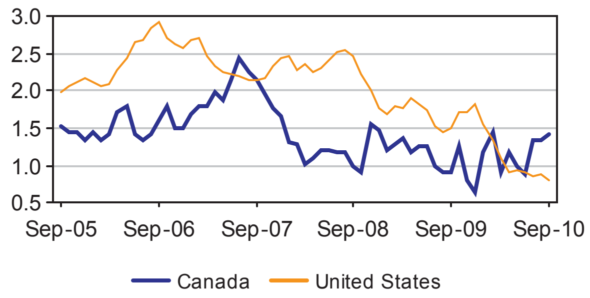
In addition, the Bank also signaled that monetary policy is on hold in view of the transition of the world economy to a lower growth outlook, a reduced outlook for growth in Canada and the United States, constraints on growth in emerging market economies, and heightened tensions in currency markets.

From our perspective, the change in the Bank of Canada's tone and more subdued outlook for both growth and inflation did not come as a surprise. A number of transitory factors boosted growth in both Canada and the United States in the first half of 2010, and now those factors have run their course. The North American economic zone is still struggling to extract itself from the worst recession in postwar history, and the recent indications of flagging growth in both the United States and Canada indeed are a major cause for concern.

IHS GLOBAL INSIGHT

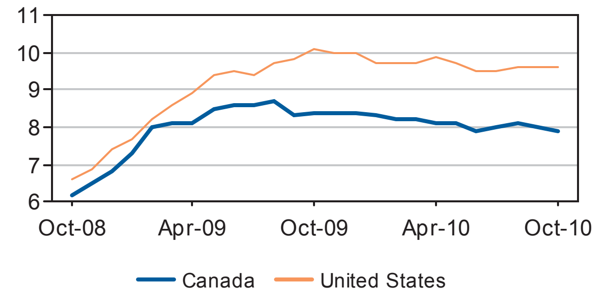
Core Inflation: Excluding Food and Energy

(Percent change from a year earlier)



Unemployment Rate

(Percent)



Monthly inflation figures have been more volatile since the implementation of the harmonized sales tax (HST) with a bias on the upside. As such, Canadian prices jumped 0.3% in September. This is a slight acceleration from the previous month's 0.1% rise.

Climbing more quickly than those of the United States, Canadian core prices, which excludes food and energy, rose 0.2%. The impacts of food and energy are weighing on the all-items price index as core prices increased by just 1.4% y/y. Overall consumer prices jumped 1.9% y/y.

Meanwhile, inflation pressures in the production pipeline remain relatively tame. In September, Canadian industrial product prices rose 0.2% from a month earlier, decelerating from a 0.4% increase in August. Prices are up by 1.4% from a year ago. Prices were mostly unchanged when you exclude the impact of petroleum and coal products, rising a mere 0.1% in the month.

There is scant evidence of any inflationary pressures in recent trends of Canadian industrial product prices. Indeed, finished goods prices continue to decline, suggesting some evidence of deflation, and considerable pressure on Canadian producer margins. Deflationary trends on finished goods prices, particularly capital equipment, are partly connected with the strength of the Canadian dollar over the past year. Again, this corroborates the scenario of slow growth and relatively low inflation trends, indicating that the Bank of Canada will continue to be on hold through early 2011.

Partially reversing the previous month's decline, 3,000 jobs were added to Canadian payrolls in October. While this is weaker than anticipated, jobs are still up 2.2% from a year earlier. The labour force shrank for the second consecutive month, reducing the labour force participation rate to 67.2%. With fewer people in the labour force, the unemployment rate fell by 0.1 percentage point to 7.9%. The good news was a bounce back private sector employment and the strong transition to full-time employment. With the unemployment rate expected to remain near 7.9% until the end of the year and into the first quarter of 2011, employment growth this quarter and next will be much slower than the past two quarters, below 2%.

by Canadian Macro Staff

High-Frequency Indicators

(As of November 8)

	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Dec-11
Real GDP by Industry (M/M, percent)	**0.3**	0.0	0.2	0.2	0.2	0.2	0.3
Employment (Thous.)	**36**	**-7**	**3**	30	35	26	15
Unemployment Rate (Percent)	**8.1**	**8.0**	**7.9**	7.9	7.8	7.8	7.5
Consumer Price Index (Y/Y, percent)	**1.7**	**1.9**	2.1	2.2	2.4	2.2	2.0
Exchange Rate, Month-End (U.S. cents)	**93.76**	**97.18**	**98.02**	97.47	97.25	97.43	96.47
Exchange Rate, Average (U.S. cents)	**96.02**	**96.80**	**98.23**	97.57	97.39	97.11	96.31
3-Month T-Bill Rate, Month-End	**0.70**	**0.87**	**0.92**	1.01	1.02	1.05	1.98
Overnight Rate, Month-End	**0.75**	**1.00**	**1.00**	1.00	1.00	1.00	2.00

Note: Bolded numbers indicate historical data.

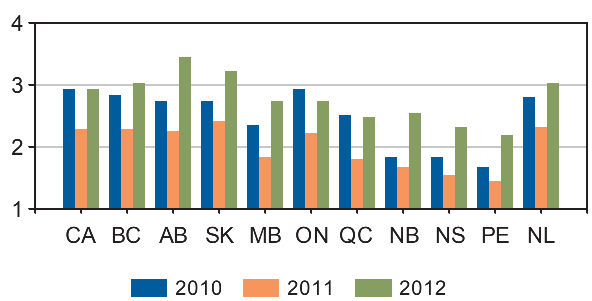
Provincial Forecast and Analysis—November Forecast

British Columbia's economic output fell 1.8% in 2009, but it recovered well with a rebound of 2.9% this year. Affected by the general slowdown in both the U.S. and Canadian economies, British Columbia's economy will decelerate to a 2.3% pace, matching the national average in 2011. The province will also have to deal with the fact that the strong positive impact of the Winter Olympics earlier this year was a one-time boost. Beyond 2011, British Columbia's economy will grow at an above-national pace, around 3%. Following the robust economic expansion, we expect employment growth to be strong as well. Advancing at a similar pace to last year, employment growth is forecasted around 2% in 2011. It will slow in 2012 in conjunction with the overall slowdown expected in the rest of Canada. And after two years of holding at a six-year high, the province's unemployment rate is poised to fall to 7.0% next year. This trend is expected to continue, with the unemployment rate ending the forecast period around 6%. Despite the introduction of the harmonized sales tax (HST) in mid-2010, the downward impact on housing starts will be short-lived as home-buyers adjust. Starts are expected to be slightly below current-year levels in 2011. Over the forecast horizon, regional starts are going to be affected by the gradual slowing of starts to sustainable household formation levels, well below the highs reached in the mid-2000s.

Energy can be a boom or a bust for **Alberta** (and other energy commodity-rich provinces) and the economic performances in 2009 and 2010 were a testament to that. The price of West Texas Intermediate oil has fluctuated greatly this year, from the low of US$67/barrel in May to the current highs hovering around $90. However, the fluctuation is in a much tighter range than the $34-81 range in 2009. Even though 2010 oil prices have averaged higher than those in 2009, natural gas prices have, for the most part, been on a steady downward trend due to excess supply. While Alberta's economy was one of the stronger performers this year, expanding at 2.7%, it will likely top the leader board again by 2012, expanding around 3.4% for several years as energy prices are forecasted to rise steadily beyond next year. We are forecasting the province's unemployment rate to fall below 6% by 2012 as we expect plenty of employment opportunities to still exist in relation to oil sands activity.

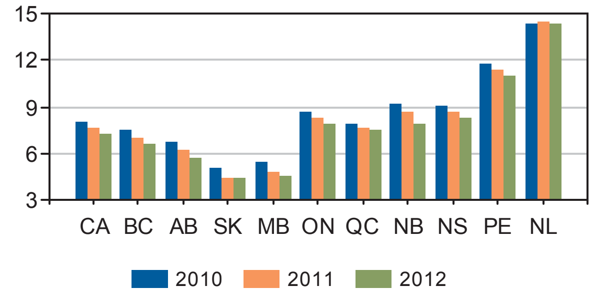
Real GDP - Weak 2011, Robust 2012

(Percent change)



Unemployment Rate Slow to Decline

(Percent)



Saskatchewan's real GDP expanded by 2.7% as well this year. We expect Saskatchewan's economy to edge out other high-performing provinces, but by only 0.1 percentage points in 2011, climbing by 2.4%. Stronger growth is anticipated in 2012 with the growing number of energy-related projects leading the advance. Economic output will likely grow just over 3.0% for a few years before slowing to a still-healthy national average pace of 2.5%. The unemployment rate is expected to remain relatively stable in the mid-4% range starting next year, and fall gradually through 2015 to 4%.

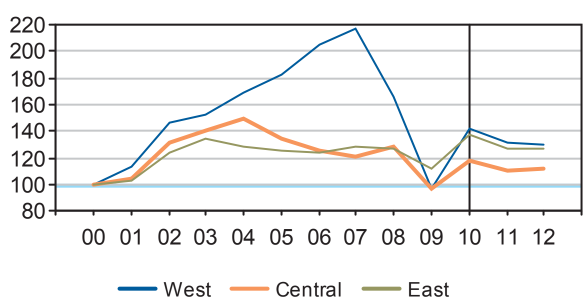
The diverse nature of **Manitoba**'s economy sheltered it from the extreme drops in economic output like those in other provinces. However, this also limited the recovery uptick in 2010; the province's economy expanded 2.4%, a middle-of-the-pack performance. We expect real GDP growth levels to remain relatively stable throughout our forecast period, with growth coming in below 3.0% with the exception of next year, when growth is forecasted around 2.0%, slightly weaker than the 2.3% national pace. Growth in certain commodity industries are likely to outshine others, but output growth in services industries will also keep pace. The province's unemployment rate has been flirting with Saskatchewan for the lowest among the provinces throughout 2010. We expect this trend to continue until 2013, when Manitoba will hold bragging rights to the lowest unemployment rate (at 4%) among the provinces.

Ontario was most likely the top economic performer in 2010 as real GDP grew by 3%. Most of that strength was experienced in the first half of the year, but the slowdown in the United States did affect the province's output, diminishing growth prospects in the second half of 2010. Economic growth in 2011 will be much more subdued as the weakening trend flows into next year. A pickup in the U.S. economy in 2012 will be a positive for Ontario, with real GDP growth anticipated at solid 2.8% pace. Ontario is expected to maintain this level of growth, not only because of the provincial trade ties with the United States, but also thanks to the growing provincial green initiatives and business-friendly policies in the *Open Ontario Plan*, which is spurring growth and investment in the province. The unemployment rate will stay around 8.4% next year, then decline and stubbornly stay in the 7% range for most of our forecast horizon. Housing starts will gradually level off to 64,000 units starting in 2013, after two years of a slight cool down.

Quebec's economy grew 2.5% in 2010, aided by strong stimulus measures, namely infrastructure projects. The ending of the stimulus measures and the overall cooling in the U.S. and Canadian economies will keep real GDP growth down around 2% next year. As the economic landscape improves on both sides of the border starting in 2012, real GDP growth will expand at a 2.5%-plus rate going forward. Energy investment in the region, especially made in shale gas, will offer greater chances for growth potential. Quebec's unemployment rate will stay below Ontario's until 2015, when they will be the same at 6.9%. Housing starts are projected to remain around the 50,000 unit mark over the next several years.

Housing Starts - Levelling

(Indexed, 2000=100)



Despite faring relatively well during the recession in comparison with the rest of Canada, the Atlantic region experienced weaker economic growth than the rest of the nation in 2010. **Prince Edward Island**, **Nova Scotia**, and **New Brunswick** were the worst performers, posting real GDP below 2.0%. **Newfoundland** took a major negative hit in 2009, but recovered well with a 2.8% real growth rate for 2010. For the most part, each region has reached pre-recession growth levels in 2010. However, we expect the region will experience more moderate growth in 2011 than we forecasted previously, as the country continues to stabilize. Further into 2012 and through 2014, the region is expected to undergo slight acceleration in growth. During this period, Newfoundland is expected to generate an average growth rate of 3.1%, beating the 2.9% national average. Average growth in Prince Edward Island, Nova Scotia, and New Brunswick will come in at 2.1%, 2.4%, and 2.4%, respectively, before returning to more stable levels in 2015.

Stimulus spending put in place by the government's Economic Action Plan helped provided a sizable boost to employment in parts of the Atlantic region. Newfoundland created the most jobs in 2010, with an employment growth rate just under 3.5%, the highest in the nation. Not too far behind, employment in Prince Edward Island grew 3.0% in 2010, the nation's second highest rate. In Nova Scotia, recent full-time job losses held down employment growth to under 1.0%. New Brunswick fared the worst, with more jobs lost than gained, pushing its unemployment rate to 9.2% from 8.8% in 2009. The other three provinces in the region were able to reduce unemployment rates in 2010. Moving forward through 2015, we expect unemployment rates to decelerate further in the Atlantic region.

by Arlene Kish and Leslie Levesque

TABLE 1

Provincial Forecast Summary

	2007	2008	2009	2010	2011	2012	2013	2014	2015
Real GDP Growth Rates									
Newfoundland	9.2	2.0	-10.2	2.8	2.3	3.0	3.3	3.0	2.4
Prince Edward Island	1.8	0.4	-0.1	1.7	1.5	2.2	2.1	2.0	1.8
Nova Scotia	1.6	1.3	-0.1	1.9	1.5	2.3	2.6	2.4	1.9
New Brunswick	1.1	-0.2	-0.3	1.9	1.7	2.5	2.3	2.3	2.2
Quebec	2.1	1.1	-0.3	2.5	1.8	2.5	2.8	2.6	2.3
Ontario	2.0	-0.9	-3.6	3.0	2.2	2.8	2.9	2.8	2.4
Manitoba	2.7	1.9	0.0	2.4	1.9	2.7	2.6	2.6	2.3
Saskatchewan	3.6	4.6	-3.9	2.7	2.4	3.2	3.2	2.9	2.5
Alberta	1.7	1.4	-4.5	2.7	2.3	3.4	3.4	3.4	2.9
British Columbia	3.0	0.2	-1.8	2.9	2.3	3.0	3.2	3.0	2.7
Canada	2.2	0.5	-2.5	2.9	2.3	2.9	3.0	2.9	2.5
Employment Growth Rates									
Newfoundland	0.6	1.4	-2.4	3.4	1.8	1.5	1.4	1.5	1.3
Prince Edward Island	1.1	1.3	-1.1	3.0	1.7	1.4	1.3	1.4	1.3
Nova Scotia	1.3	1.3	0.0	0.5	1.7	1.4	1.4	1.4	1.3
New Brunswick	2.0	1.0	0.1	-0.4	1.8	1.4	1.3	1.4	1.3
Quebec	2.3	0.7	-0.9	2.0	1.9	1.5	1.5	1.6	1.3
Ontario	1.6	1.4	-2.4	1.9	2.0	1.6	1.5	1.6	1.4
Manitoba	1.6	1.8	0.0	2.1	1.9	1.5	1.3	1.4	1.3
Saskatchewan	2.1	2.2	1.5	1.3	1.8	1.5	1.4	1.5	1.4
Alberta	4.7	2.7	-1.2	0.5	1.9	1.6	1.4	1.5	1.4
British Columbia	3.2	2.1	-2.3	2.1	2.1	1.6	1.5	1.5	1.4
Canada	2.3	1.5	-1.6	1.7	1.9	1.6	1.5	1.5	1.4
Unemployment Rates									
Newfoundland	13.6	13.3	15.5	14.4	14.4	14.4	14.4	14.6	14.7
Prince Edward Island	10.4	10.7	12.0	11.8	11.4	11.0	11.0	10.8	10.5
Nova Scotia	8.0	7.7	9.2	9.1	8.7	8.3	8.1	7.9	7.8
New Brunswick	7.6	8.6	8.8	9.2	8.7	8.0	7.9	7.7	7.6
Quebec	7.2	7.3	8.5	8.0	7.7	7.5	7.4	7.2	6.9
Ontario	6.4	6.5	9.0	8.7	8.4	7.9	7.7	7.1	6.9
Manitoba	4.4	4.1	5.2	5.4	4.8	4.6	4.0	4.1	4.1
Saskatchewan	4.2	4.1	4.8	5.1	4.5	4.4	4.4	4.3	4.0
Alberta	3.5	3.6	6.6	6.7	6.3	5.8	5.4	5.1	4.7
British Columbia	4.2	4.6	7.6	7.6	7.0	6.7	6.4	6.2	5.9
Canada	6.0	6.2	8.3	8.0	7.7	7.3	7.1	6.7	6.5
Consumer Price Inflation (Percent change)									
Newfoundland	1.4	2.9	0.3	2.6	2.0	2.1	2.0	2.0	2.0
Prince Edward Island	1.8	3.4	-0.1	1.9	2.0	2.0	2.0	2.0	2.0
Nova Scotia	1.9	3.0	-0.1	2.2	2.1	2.1	2.0	2.0	2.0
New Brunswick	1.9	1.7	0.3	2.3	1.9	2.0	2.0	1.9	1.9
Quebec	1.6	2.1	0.6	1.3	1.9	1.9	2.0	2.0	2.0
Ontario	1.8	2.3	0.4	2.4	2.0	2.1	2.0	2.0	2.0
Manitoba	2.1	2.2	0.6	0.9	1.9	2.0	2.0	2.0	2.0
Saskatchewan	2.9	3.2	1.1	1.2	1.9	2.0	2.1	2.0	2.0
Alberta	4.9	3.2	-0.1	1.2	2.1	2.1	2.0	2.0	2.0
British Columbia	1.7	2.1	0.0	1.4	2.1	2.0	2.1	2.0	2.0
Canada	2.1	2.4	0.3	1.8	2.0	2.0	2.0	2.0	2.0
Housing Starts									
Newfoundland	2,649	3,261	3,057	4,288	3,322	3,034	3,200	3,319	2,964
Prince Edward Island	750	712	877	670	639	603	675	711	698
Nova Scotia	4,750	3,982	3,438	4,224	4,199	4,170	3,873	4,032	4,031
New Brunswick	4,242	4,274	3,521	4,116	4,077	4,541	4,350	4,392	4,422
Quebec	48,553	47,901	43,403	52,659	50,855	51,330	50,825	50,172	49,536
Ontario	68,123	75,076	50,370	60,836	54,980	57,133	63,784	63,781	63,731
Manitoba	5,738	5,537	4,174	5,493	4,513	4,181	3,922	4,029	4,055
Saskatchewan	6,007	6,828	3,866	5,279	4,282	4,514	4,453	4,089	4,388
Alberta	48,336	29,164	20,298	28,277	26,486	25,798	25,134	25,926	25,557
British Columbia	39,195	34,321	16,077	25,989	24,582	25,167	24,386	24,228	23,855
Canada	228,343	211,056	149,081	191,830	177,936	180,471	184,601	184,679	183,236
Real GDP per Capita (Chained 2002)									
Newfoundland	39,083	39,878	35,657	36,540	37,327	38,399	39,631	40,780	41,715
Prince Edward Island	30,030	29,861	29,512	29,759	29,963	30,400	30,839	31,206	31,551
Nova Scotia	30,574	30,925	30,806	31,264	31,661	32,303	33,056	33,746	34,286
New Brunswick	31,440	31,319	31,113	31,587	32,032	32,768	33,439	34,051	34,650
Quebec	34,548	34,627	34,168	34,680	34,991	35,518	36,171	36,784	37,292
Ontario	41,682	40,877	38,992	39,699	40,112	40,775	41,486	42,149	42,664
Manitoba	34,571	34,887	34,502	34,860	35,171	35,863	36,452	37,055	37,527
Saskatchewan	39,616	40,870	38,683	39,120	39,463	40,042	40,684	41,284	41,813
Alberta	52,384	51,938	48,553	49,205	49,477	50,216	50,932	51,671	52,285
British Columbia	38,169	37,608	36,287	36,740	36,980	37,452	38,053	38,582	39,007
Canada	39,820	39,562	38,126	38,796	39,232	39,909	40,636	41,318	41,873

Highlights of the November U.S. Forecast

Our calendar-year growth forecasts have edged up to 2.7% for 2010 (from 2.6%) and 2.3% for 2011 (from 2.2%). But there remains the possibility that politicians will throw a monkey wrench in the works by failing to take action on expiring tax breaks and inadvertently producing—at least temporarily—a severe tightening of fiscal policy in 2011.

Third-quarter growth came in at 2.0%, not much different from 1.7% in the second, and with a similar composition: little growth in final sales, a big boost from inventory accumulation, and a big drag from foreign trade (as inventory rebuilding sucked in imports). The expiry of the homebuyers' tax credit hammered housing activity, but federal spending was a major plus for growth again, at least partly stimulus-related. Consumer spending growth stepped up to 2.6%, from 2.2% in the second quarter, a welcome advance. While equipment and software spending growth halved, it still ran at a double-digit pace.

Several key October indicators have shown a better start to the fourth quarter. The biggest piece of good news was the October employment report that showed 151,000 jobs added, and showed private-sector job creation exceeding 100,000 for four consecutive months. The report suggests that GDP growth will improve in the fourth quarter. We are estimating a 2.5% growth rate, with a very different composition from the third quarter. We expect inventory accumulation to slow and become a drag on growth, but (not coincidentally) we expect imports to drop at the same time, making trade a plus for growth. We expect consumer spending growth to be little changed, at 2.5%, helped by the rise in incomes evident in October's employment report.

The setback for housing after the expiry of the homebuyers' tax credit proved severe. New home sales remain close to July's all-time low, while existing home sales are only gradually recovering from July's collapse. This picture suggests a weak market that was temporarily brought to life by the tax credit. The slow pace of job creation is chilling the prospects for a rebound. We expect housing starts to improve gradually, but only to 783,000 units in 2011, up from 604,000 this year.

House prices were propped up by the homebuyers' tax credit, and they should slide further. We expect the FHFA house price index (purchase only) to drop 8.0% from the second quarter of 2010 to the second quarter of 2011.

Export growth eased substantially in the third quarter, to just 5.0% at an annual rate, but we see this as a temporary deceleration. Rapid growth in emerging markets and a weak dollar should promote a reacceleration in export growth during the fourth quarter. Imports surged in the third quarter making trade a huge drag on growth. We believe that this drag is now at an end. Import growth should now slow, in part because inventory rebuilding will slow.

The dollar softened as the markets priced in further easing by the Federal Reserve. We are not convinced that the euro has turned the corner for good, though, given continued debt crises in the Eurozone periphery and the likelihood that economic growth will slow across Europe too. We expect the dollar to move roughly sideways against major currencies in 2011, on average, and to depreciate against emerging-market currencies.

Inflation is not an issue. Global commodity prices are moving back up again, but wage inflation remains very low, and core PCE price inflation is heading towards the bottom of the Federal Reserve's 1-2% comfort zone.

The Fed launched a new $600-billion program of Treasury purchases at its November meeting, largely as anticipated. The biggest effects of this second round of quantitative easing—driving down long-term interest rates and the dollar—are probably already in the market, and we do not expect it to give a major boost to growth. But it is, at present, the only policy game in town. We assume that there will be no move to raise interest rates until 2012.

by Nariman Behravesh and Nigel Gault

TABLE 2

Summary of the U.S. Economy

	2010:2	2010:3	2010:4	2011:1	2011:2	2011:3	2009	2010	2011	2012	2013	2014	2015
Composition of Real GDP, Percent Change, Annual Rate													
Gross Domestic Product	1.7	2.0	2.5	2.2	2.0	2.5	-2.6	2.7	2.3	2.9	2.7	3.1	3.1
Final Sales of Domestic Product	0.9	0.6	4.3	2.6	2.1	2.7	-2.1	1.2	2.5	2.9	2.7	3.1	3.1
Total Consumption	2.2	2.6	2.5	2.4	2.0	2.5	-1.2	1.7	2.4	2.0	1.4	2.0	2.6
Durables	6.8	6.1	7.8	5.8	6.3	9.0	-3.7	6.6	7.1	7.4	3.5	3.1	5.9
Nondurables	1.9	1.3	4.4	1.4	1.1	1.8	-1.2	2.6	2.0	1.4	0.9	1.4	1.9
Services	1.6	2.4	1.1	2.2	1.6	1.7	-0.8	0.6	1.8	1.4	1.2	2.0	2.3
Nonresidential Fixed Investment	17.2	9.8	5.6	3.4	4.3	5.2	-17.1	5.6	5.9	7.3	9.0	7.6	5.0
Equipment & Software	24.8	12.0	11.7	9.2	8.6	8.9	-15.3	15.1	10.6	8.9	7.8	6.4	3.3
Information Processing Equipment	15.3	5.7	12.6	2.2	8.5	6.4	0.2	12.9	7.3	6.6	6.3	6.0	6.1
Computers & Peripherals	45.2	-4.5	37.3	-6.5	29.5	14.9	-1.5	27.1	14.4	16.3	16.1	15.3	15.2
Communications Equipment	10.1	14.9	13.2	8.1	10.1	11.9	0.3	12.4	11.1	9.5	6.0	5.9	6.0
Industrial Equipment	44.2	7.3	23.3	14.4	10.7	11.5	-23.3	6.5	15.2	9.0	4.1	4.4	1.7
Transportation equipment	74.8	42.1	-5.4	38.9	7.7	20.4	-51.5	60.3	20.9	22.0	19.1	8.2	-8.8
Aircraft	9.4	40.3	-40.7	14.0	15.1	8.4	-19.4	-7.9	2.8	16.0	8.0	5.7	4.4
Other Equipment	16.1	21.6	11.0	10.0	7.2	6.9	-22.3	9.7	10.7	6.6	6.9	8.1	8.1
Structures	-0.5	3.9	-9.8	-11.9	-7.8	-5.7	-20.4	-13.8	-6.7	2.5	12.9	11.3	9.7
Commercial & Health Care	-18.0	-18.6	-9.0	-7.5	-1.4	7.7	-29.9	-25.9	-5.8	8.2	22.7	22.0	18.6
Manufacturing	-18.3	-33.7	-27.5	-18.7	-13.4	-11.1	7.6	-31.2	-20.2	-0.7	29.3	20.7	14.8
Power & Communication	-7.1	10.6	-9.0	-10.2	-5.9	-4.1	2.5	-8.9	-5.2	-0.4	-0.4	4.1	2.2
Mining & Petroleum	58.2	59.1	-4.5	-18.3	-16.9	-20.5	-35.5	25.1	-4.9	-2.0	6.8	-3.0	-2.8
Other	-16.0	-11.7	-9.2	-3.0	1.9	3.8	-18.7	-26.5	-4.1	7.1	12.1	10.7	9.1
Residential Fixed Investment	25.6	-29.1	-12.9	5.4	22.1	22.7	-22.9	-4.2	4.1	33.4	14.2	9.5	5.5
Exports	9.1	5.0	8.7	9.1	8.4	9.1	-9.5	11.5	8.3	8.1	8.7	8.4	7.5
Imports	33.5	17.4	-7.1	3.2	7.2	7.1	-13.8	13.2	5.6	5.3	4.4	4.5	4.0
Federal Government	9.1	8.8	-2.3	-2.7	-1.5	0.1	5.7	4.7	0.0	-3.5	-2.9	-1.3	-0.5
State & Local Government	0.6	-0.2	0.8	0.6	0.2	-1.0	-0.9	-1.3	0.2	0.0	1.1	1.3	1.4
Billions of Dollars													
Real GDP	13194.9	13260.7	13341.9	13413.2	13480.1	13563.3	12880.6	13234.1	13532.1	13921.4	14298.2	14741.9	15194.7
Nominal GDP	14578.7	14730.2	14825.7	14977.3	15089.1	15224.9	14119.1	14645.2	15172.1	15831.1	16527.5	17363.8	18235.6
Prices & Wages, Percent Change, Annual Rate													
GDP Deflator	1.9	2.3	0.0	2.0	1.0	1.1	0.9	1.0	1.3	1.4	1.6	1.9	1.9
Consumer Prices	-0.7	1.5	2.7	1.4	1.1	1.7	-0.3	1.7	1.5	1.9	2.0	2.2	2.2
Producer Prices, Finished Goods	-0.4	0.8	6.9	-0.4	-1.3	1.7	-2.5	4.3	1.4	1.8	1.6	1.5	1.8
Employment Cost Index - Total Comp.	1.8	1.8	1.9	2.4	1.8	1.9	1.5	1.9	2.0	2.1	2.3	2.7	2.8
Other Key Measures													
Oil - WTI ($ per barrel)	77.91	76.11	81.86	80.50	81.17	84.00	61.77	78.67	82.83	89.16	93.02	96.27	100.20
Productivity (%ch., saar)	-1.8	1.9	1.9	1.2	0.7	0.7	3.5	3.4	1.1	0.7	0.8	1.7	1.8
Total Industrial Production (%ch., saar)	7.0	4.8	0.4	2.8	2.7	3.4	-9.3	5.3	2.9	3.5	3.8	3.9	3.5
Factory Operating Rate	71.6	72.2	72.6	73.1	73.5	74.2	67.2	71.6	73.8	75.6	77.2	78.8	79.6
Nonfarm Inven. Chg. (Bil. 2005 $)	61.0	109.9	56.6	43.8	43.0	39.3	-116.9	66.0	39.7	43.6	45.3	52.0	43.0
Consumer Sentiment Index	73.9	68.3	68.5	72.3	74.1	74.4	66.3	71.1	74.3	75.8	76.1	79.9	80.4
Light Vehicle Sales (Mil. units, saar)	11.34	11.56	11.90	12.15	12.47	12.97	10.40	11.44	12.79	14.79	16.00	16.63	17.05
Housing Starts (Mil. units, saar)	0.602	0.589	0.607	0.644	0.718	0.824	0.554	0.604	0.783	1.210	1.408	1.592	1.678
Exist. House Sales (Total, Mil. saar)	5.570	4.163	4.306	4.661	4.750	4.644	5.160	4.795	4.721	5.371	5.639	6.257	6.431
Unemployment Rate (%)	9.7	9.6	9.7	9.7	9.7	9.6	9.3	9.7	9.6	9.1	8.5	7.9	7.3
Payroll Employment (%ch., saar)	2.2	-0.2	0.7	0.9	1.3	1.4	-4.3	-0.5	1.0	1.8	1.8	1.8	1.7
Federal Surplus (Unified, nsa, bil. $)	-287.0	-290.1	-468.2	-445.0	-124.3	-289.9	-1415.7	-1294.1	-1327.3	-948.3	-730.0	-707.5	-738.3
Current Account Balance (Bil. $)	-493.1	-522.8	-525.5	-487.6	-481.3	-490.3	-378.4	-494.5	-486.3	-495.7	-528.4	-520.3	-529.1
Financial Markets, NSA													
Federal Funds Rate (%)	0.19	0.19	0.16	0.12	0.12	0.14	0.16	0.17	0.14	1.27	3.43	3.62	4.7
3-Month Treasury Bill Rate (%)	0.15	0.15	0.14	0.18	0.21	0.30	0.15	0.14	0.28	1.43	3.39	3.61	4.54
10-Year Treasury Note Yield (%)	3.49	2.79	2.57	2.45	2.48	2.56	3.26	3.14	2.58	3.43	4.62	4.77	5.61
30-Year Fixed Mortgage Rate (%)	4.91	4.45	4.25	4.15	4.18	4.25	5.04	4.65	4.27	5.02	6.10	6.24	7.08
S&P 500 Stock Index	1135	1096	1190	1165	1185	1205	947	1136	1196	1291	1372	1450	1538
(Four-Quarter % change)	27.2	10.0	9.3	3.9	4.4	9.9	-22.5	20.0	5.3	7.9	6.3	5.7	6.1
Exchange Rate, Major Trading Partners	0.925	0.905	0.856	0.858	0.858	0.862	0.926	0.895	0.862	0.883	0.885	0.872	0.862
(% change, annual rate)	15.6	-8.5	-19.9	0.8	0.1	2.0	4.3	-3.4	-3.7	2.4	0.3	-1.4	-1.2
Incomes													
Personal Income (% ch., saar)	4.1	2.1	3.5	3.3	2.9	3.2	-1.7	2.7	3.2	3.9	4.4	5.6	5.7
Real Disposable Income (%ch., saar)	4.4	0.5	1.2	0.5	1.8	1.5	0.6	1.1	1.4	1.0	1.2	3.2	3.4
Saving Rate (%)	5.9	5.5	5.4	4.9	4.9	4.7	5.9	5.6	4.8	3.7	3.4	4.4	5.0
After-Tax Profits (Billions of $)	1383	1452	1416	1287	1299	1325	1062	1405	1314	1386	1366	1415	1392
(Four-quarter % change)	38.7	30.4	15.2	-6.1	-6.0	-8.7	3.6	32.3	-6.5	5.5	-1.5	3.6	-1.6

TABLE 3

Canadian Short-Term Forecast Update

	09Q4	10Q1	10Q2	10Q3	10Q4	11Q1	2009	2010	2011	2012	2013	2014	2015
Real GDP (Bil. chained 2002 $)	1296.4	1314.9	1321.4	1325.2	1331.6	1339.1	1285.6	1323.3	1353.8	1393.6	1435.6	1477.0	1513.8
Annual % Ch.	4.9	5.8	2.0	1.1	2.0	2.3	-2.5	2.9	2.3	2.9	3.0	2.9	2.5
Consumer	825.2	833.8	839.3	844.6	850.3	855.9	814.3	842.0	863.8	884.1	904.9	925.7	945.8
Annual % Ch.	3.9	4.3	2.6	2.5	2.7	2.7	0.4	3.4	2.6	2.3	2.4	2.3	2.2
Government	331.3	333.0	334.6	338.8	341.6	341.7	321.3	337.0	344.6	350.1	352.7	358.5	366.5
Annual % Ch.	9.1	2.2	1.9	5.1	3.4	0.1	5.1	4.9	2.2	1.6	0.8	1.6	2.2
Bus. Res. Investment	75.4	79.2	79.4	79.4	79.8	80.2	71.2	79.5	81.0	83.3	85.0	86.2	87.4
Annual % Ch.	26.3	21.6	1.2	-0.2	2.2	1.9	-8.2	11.6	2.0	2.8	2.1	1.3	1.5
Bus. Non-Res. Inv.	154.7	156.6	162.0	168.6	172.8	174.5	160.0	165.0	176.9	183.1	188.5	192.7	196.5
Annual % Ch.	-9.8	5.0	14.7	17.1	10.6	3.9	-19.9	3.1	7.2	3.5	3.0	2.2	2.0
Exports	428.0	439.1	445.6	448.8	454.3	460.4	417.7	446.9	470.5	500.6	533.6	568.5	602.2
Annual % Ch.	13.8	10.7	6.0	3.0	4.9	5.5	-14.2	7.0	5.3	6.4	6.6	6.5	5.9
Imports	525.3	542.6	563.6	573.2	580.0	586.0	499.6	564.8	595.4	622.4	650.4	678.9	709.4
Annual % Ch.	12.4	13.9	16.4	7.0	4.8	4.2	-13.9	13.1	5.4	4.5	4.5	4.4	4.5
Business Inventory Ch.	-1.2	5.6	12.7	15.5	9.8	9.3	-2.9	10.9	9.4	11.7	17.5	20.1	19.8
Statistical error	0.0	0.3	-1.0	0.0	0.0	0.0	0.4	-0.2	0.0	0.0	0.0	0.0	0.0
Nominal GDP (Bil. $)	1561.2	1597.8	1609.1	1631.0	1651.5	1672.4	1527.3	1622.3	1707.0	1802.6	1901.2	1997.4	2085.9
Annual % Ch.	9.9	9.7	2.9	5.5	5.1	5.2	-4.5	6.2	5.2	5.6	5.5	5.1	4.4
Raw Mat. Price Index	146.4	152.3	148.6	146.7	145.3	144.3	136.3	148.2	143.0	141.8	143.0	144.9	147.5
% Ch. Year Ago	8.2	25.5	8.9	4.2	-0.8	-5.2	-22.9	8.8	-3.5	-0.9	0.9	1.3	1.8
Industry Price Index	107.9	108.9	109.2	109.7	109.7	110.6	108.4	109.4	112.0	114.2	116.4	118.2	119.7
% Ch. Year Ago	-3.3	-0.2	0.6	1.6	1.7	1.6	-3.5	0.9	2.5	2.0	1.8	1.6	1.3
GDP Deflator	120.4	121.5	121.8	123.1	124.0	124.9	118.8	122.6	126.1	129.3	132.4	135.2	137.8
Annual % Ch.	4.4	3.7	1.0	4.3	3.1	2.8	-2.1	3.2	2.8	2.6	2.4	2.1	1.9
CPI	114.9	115.4	116.2	116.8	117.5	118.0	114.4	116.5	118.8	121.2	123.7	126.1	128.7
% Ch. Year Ago	0.8	1.6	1.4	1.8	2.3	2.2	0.3	1.8	2.0	2.0	2.0	2.0	2.0
Employment (Thousands)	16876	16944	17119	17203	17282	17347	16849	17137	17468	17742	18000	18278	18529
Annual % Ch.	1.3	1.6	4.2	2.0	1.9	1.5	-1.6	1.7	1.9	1.6	1.5	1.5	1.4
Unemployment Rate (%)	8.4	8.2	8.0	8.0	7.9	7.8	8.3	8.0	7.7	7.3	7.1	6.7	6.5
Productivity (Annual % Ch.)	3.7	4.2	-2.2	-0.8	0.1	0.8	-0.9	1.2	0.4	1.4	1.6	1.3	1.1
Average Hourly Earnings	20.52	20.58	20.77	20.86	20.99	21.12	20.44	20.80	21.33	22.04	22.94	23.86	24.77
Annual % Ch.	1.0	1.2	3.9	1.7	2.6	2.4	1.4	1.7	2.5	3.3	4.1	4.0	3.8
3-Month T-Bill Rate (%)	0.22	0.21	0.47	0.74	0.98	1.03	0.35	0.60	1.28	2.82	3.87	4.62	4.75
US 3-Month T-Bill Rate (%)	0.06	0.11	0.15	0.16	0.15	0.17	0.15	0.14	0.25	1.39	3.39	3.61	4.54
Canada-U.S. Differential (% pts.)	0.16	0.11	0.32	0.58	0.83	0.86	0.20	0.46	1.03	1.43	0.48	1.01	0.21
Prime Rate (%)	2.25	2.25	2.33	2.83	3.00	3.00	2.40	2.60	3.26	4.82	5.87	6.62	6.75
Overnight Rate (%)	0.24	0.25	0.33	0.83	1.00	1.00	0.39	0.60	1.26	2.82	3.87	4.62	4.75
Bank Rate (%)	0.50	0.50	0.58	1.08	1.25	1.25	0.65	0.85	1.51	3.07	4.12	4.87	5.00
GOC Bond Rate (1-3 yrs.) (%)	1.26	1.34	1.59	1.39	1.65	1.64	1.21	1.50	1.83	3.01	4.23	4.74	5.16
GOC Bond Rate (3-5 yrs.) (%)	2.34	2.35	2.43	1.96	2.13	2.07	2.15	2.22	2.22	3.14	4.49	4.82	5.45
GOC Ten-Year Bond Rate (%)	3.43	3.45	3.33	2.93	2.66	2.55	3.29	3.09	2.65	3.29	4.77	4.92	5.76
U.S. Ten-Year T-Note Rate (%)	3.46	3.72	3.49	2.79	2.51	2.40	3.26	3.13	2.50	3.14	4.62	4.77	5.61
U.S. Real GDP (Bil. 2005 $)	13019.0	13138.8	13194.9	13244.1	13307.8	13381.1	12880.6	13221.4	13510.6	13913.9	14285.6	14732.0	15175.0
Annual % Ch.	5.0	3.7	1.7	1.5	1.9	2.2	-2.6	2.6	2.2	3.0	2.7	3.1	3.0
Household Credit (Billion $)	1395.7	1423.0	1448.6	1475.2	1502.8	1531.4	1357.0	1462.4	1574.8	1684.8	1784.6	1875.7	1962.0
Annual % Ch.	8.3	8.1	7.4	7.5	7.7	7.8	7.7	7.8	7.7	7.0	5.9	5.1	4.6
Standard of Living Canada/U.S. (Nominal GDP per Capita at PPP Can/U.S.)							0.830	0.831	0.832	0.832	0.833	0.832	0.826
ExCh. Rate (U.S.-Can.)	94.7	96.1	97.3	96.2	97.7	97.7	87.9	96.8	98.0	94.9	93.7	92.1	89.0
Curr. Acct. Bal. (Billion $)	-40.8	-33.8	-44.1	-42.2	-41.9	-37.7	-43.5	-40.5	-33.8	-22.9	-12.0	-0.9	2.3
Fed. Gov't. NA Bal.(Billion $)	-37.5	-23.9	-38.7	-21.4	-21.7	-19.5	-39.9	-26.4	-16.7	-10.2	-6.0	1.2	6.8
% GNP	-2.4	-1.5	-2.4	-1.3	-1.3	-1.2	-2.7	-1.7	-1.0	-0.6	-0.3	0.1	0.3
Before-Tax Profit (Billion $)	158.9	172.6	170.8	186.5	192.1	196.1	146.9	180.5	205.0	223.8	240.5	260.3	266.4
Annual % Ch.	36.8	39.1	-3.9	41.9	12.7	8.6	-32.3	22.9	13.6	9.2	7.4	8.2	2.4
Housing Starts (Thousands)	178	193	200	192	182	178	149	192	178	180	185	185	183
Auto Sales (Thous. SAAR)	1546.2	1583.0	1551.7	1602.4	1579.1	1624.3	1484.9	1579.1	1683.4	1736.8	1786.3	1808.6	1768.8
Nominal Exports (Billion $)	450.9	470.6	476.1	481.9	490.1	499.1	438.6	479.6	513.3	556.4	602.7	650.5	695.8
Nominal Imports (Billion $)	471.3	485.8	502.4	512.9	521.4	529.2	464.7	505.6	540.3	574.2	610.0	647.6	690.5
Nominal Trade Balance (Billion $)	-20.5	-15.3	-26.3	-31.0	-31.3	-30.1	-26.2	-26.0	-27.0	-17.8	-7.4	3.0	5.3
Personal Saving Rate (%)	3.5	3.0	5.9	3.5	3.5	3.3	4.6	3.9	3.4	4.0	4.6	4.6	4.8
Real Disp. Inc. - Annual % Ch.	0.1	1.9	15.8	-7.7	2.3	1.4	1.2	2.6	1.6	2.8	3.0	2.3	2.4
Industrial Production - Annual % Ch.	9.6	11.2	9.2	4.0	4.9	6.3	-9.4	5.3	6.5	6.3	4.5	4.4	3.5