CAPITAL STRUCTURE AND RETURN ON EQUITY

1.0 PURPOSE

This evidence describes the methodology that OPG has used to determine its capital structure and return on equity ("ROE") for the test period. This evidence also summarizes the capitalization and cost of capital for 2007 - 2010.

2.0 OVERVIEW

OPG is seeking approval of the test period cost of capital as presented in Ex. C1-T1-S1 Tables 1 and 2. In determining the cost of capital, OPG has applied the capital structure of 47 per cent equity and 53 per cent debt approved by the OEB in EB-2007-0905. OPG has applied the ROE of 9.85 per cent set by the OEB for use in 2010 cost of service applications in the OEB's letter of February 24, 2010.

In EB-2007-0905, the OEB directed OPG to examine the issue of separate costs of capital for its nuclear and regulated hydroelectric facilities. To respond to this direction, OPG retained Foster Associates Inc. ("Fosters") to examine potential methodologies for developing technology-specific costs of capital. The Fosters report, found in Ex. C3-T1-S1, concludes that none of the cost of capital methodologies examined yields a robust and analytically sound basis for specifying technology-specific costs of capital.

OPG continues to support the use of a single cost of capital for its prescribed facilities. This is the approach that was used in the last application and this is the approach that is consistent with the manner in which OPG is actually financed. This issue is explored in section 5.0 below.

The debt component of OPG's capital structure is determined using the methodologies approved by the OEB in EB-2007-0905. These are described in Ex. C1-T1-S2 and Ex. C1-T1-S3 for long-term and short-term debt, respectively.

OPG has applied this capitalization to the rate base described in Exhibit B. The resulting capitalization and cost of capital for 2007 - 2012 is summarized in Ex. C1-T1-S1 Tables 1 - 6.

3.0 CAPITAL STRUCTURE

For the test period, OPG has applied the deemed capital structure of 47 per cent equity and 53 per cent debt approved by the OEB in EB-2007-0905.

There have been changes in OPG's operating and financial risks since EB-2007-0905 as discussed by Fosters in Ex. C3-T1-S1. However, at this time OPG is not proposing any changes to its capital structure to address these risks. The debt component of OPG's capital structure is determined using the methodologies approved by the OEB in EB-2007-0905. OPG's test period capital structure is provided in Ex. C1-T1-S1 Table 1 (2012) and Table 2 (2011).

For the period April 1, 2008 to December 31, 2010, OPG has applied the capital structure approved by the OEB in EB-2007-0905. For the period prior to April 1, 2008 OPG applied the capital structure (45 per cent equity and 55 per cent debt) that was reflected in information provided by OPG to the Province for use in setting the interim period payment amounts. OPG's historical period and bridge year capital structures are provided in Ex. C1-T1-S1 Table 3 (2010), Table 4 (2009), Table 5 (2008) and Table 6 (2007). The 2008 capital structure in Table 5 is weighted to reflect the change in capital structure effective April 1, 2008. The 2007 capital structure in Table 6 is unchanged from the evidence provided in EB-2007-0905.

4.0 RETURN ON COMMON EQUITY

In EB-2007-0905 the OEB determined that OPG's allowed ROE was to be 8.65 per cent effective April 1, 2008. The OEB also determined that "adoption of a formula approach to setting the ROE is appropriate in the circumstances."

On December 11, 2009, the OEB issued the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 2009, EB-2009-0084* ("Cost of Capital Report"). The

Cost of Capital Report establishes a revised base ROE and annual adjustment mechanism for setting ROE for rate-regulated utilities submitting a cost of service rate application for rates effective on or after 2010.

4.1 Forecast Return on Equity for the Test Period

For 2011 and 2012 OPG has adopted the results of the OEB's Cost of Capital Report.

The Cost of Capital Report establishes a revised base ROE and a modified automatic ROE adjustment mechanism. Given that the revised base ROE and the refined automatic ROE adjustment mechanism represent the same concepts that were adopted for OPG's prescribed assets in EB-2007-0905, both are applicable to OPG at the approved capital structure and appropriate to the business risks of the prescribed assets.

OPG has applied the adjusted ROE of 9.85 per cent as set by the OEB for use in 2010 cost of service applications in the OEB's letter of February 24, 2010. When calculating the final payment amounts, OPG proposes that the ROE be updated using data for the month that is three months prior to the effective date of the new payment amounts as required by the Cost of Capital Report.

4.2 Return on Equity: 2007 - 2010

For the 2010 bridge year, OPG has calculated a forecast ROE based on the 2010 - 2014 Business Plan. This unadjusted forecast of ROE is $226.3M[1] or 7.80 per cent[2]. To provide another way of assessing the adequacy of the current payment amounts, OPG's forecast 2010 earnings were adjusted to remove the impact of three variance accounts using the same approach described in EB-2007-0905[3]. These three variance accounts reflect costs that are representative of what OPG will incur in the test period but that are not reflected in the current payment amounts. They are the Hydroelectric Over/Under Recovery, the Income

[1] Ex I1-T1-S1, Table 5: Pre-tax Return on Equity of $242.8M less income tax of $16.5M
[2] Unadjusted ROE of $226.3M divided by common equity of $2,900.4M in Ex C1-T1-S1 Table 3, line 5.
[3] EB-2007-0905 Ex C1-T2-S1 Section 3.2.3: An adjustment was made to 2007 return on equity as OPG would incur significantly higher expenses on an on-going basis as a result of the 2006 increase in the Asset Retirement Obligations which were not reflected in approved payment amounts and which are representative of the costs OPG would incur in the EB-2007-0905 test period.

and Other Taxes and the Tax Loss Variance Accounts. This adjusted forecast ROE is $61.9M as shown in Ex. I1-T1-S1 Table 5 or 2.13 per cent as shown in Ex. C1-T1-S1-Table 3.

OPG determines its achieved ROE for the historical period using a reconciliation approach as described in EB-2007-0905 (see Ex. C1-T2-S1 in EB-2007-0905). OPG does not determine a stand-alone ROE for its regulated operations for the purposes of operating its business, financial accounting or filing its taxes. The derivation of an achieved ROE for the regulated operations in 2008 and 2009 is provided solely to support the stand-alone income tax evidence provided in Ex. F4-T2-S1 Table 6.

For the 2008 and 2009 fiscal years, OPG has prepared audited financial statements for its prescribed assets (Ex. A2-T1-S1 Attachment 3). The reconciliation between accounting earnings for OPG's prescribed assets and the achieved ROE for OPG's regulated operations is provided in Ex. C1-T1-S1 Table 7. The ROE has been adjusted to remove certain variance account amounts related to the 2008 and 2009 period as described in the adjustment to the 2010 ROE. The adjustment for Hydroelectric Over/Under Recovery variances was not made as it relates only to 2010.

OPG's audited financial statements have been prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). For 2008 and 2009, accounting earnings amounts are adjusted to reflect differences between accounting earnings for prescribed assets and regulatory earnings. To the extent that OPG's accounting treatment and regulatory treatment differ, the accounting numbers are removed, and the regulatory amounts are included. This provides a consistent basis for comparing historic and forecast regulatory earnings. The footnotes to Ex. C1-T1-S1 Table 7 (found in Ex. C1-T1-S1 Table 7b) explain the derivation of the specific adjustments included in the reconciliation.
For the 2007 fiscal year OPG presented a reconciliation between accounting earnings for OPG's segmented financial results in its consolidated financial statements in EB-2007-0905, Ex. C1-1-1 Table 1.

5.0 TECHNOLOGY-SPECIFIC COST OF CAPITAL

In EB-2007-0905, the OEB determined that the cost of capital for OPG's regulated operations:

- shall be established based on the stand-alone principal (pages 140 to 142)
- shall be established using a 47 per cent common equity ratio (page 149)
- shall reflect the adoption of the formula approach to setting the ROE (page 162), consistent with the OEB's expectation that risk differences in the regulated businesses are appropriately addressed through the capital structure rather than the ROE (page 162)
- shall reflect the OEB's views that "OPG's regulated nuclear business is riskier than regulated distribution and transmission utilities in terms of operational and production risk, but is less risky than merchant generation" (page 149)

These findings govern the cost of capital for OPG's combined nuclear and regulated hydroelectric operations. The Decision also provided that "there *may* be merit in establishing separate capital structures for the two businesses as it would enhance transparency and more accurately match costs with the payment amounts" (emphasis added - page 162). The OEB concluded that separate capital structures should be further explored in OPG's next proceeding.

OPG engaged Fosters through a competitive request for proposal ("RFP") process to conduct the analysis requested by the OEB. The results of Fosters' analysis are presented in Ex. C3-T1-S1. The analysis considered five different potential quantitative methodologies for isolating the cost of capital for OPG's regulated hydroelectric and nuclear generation operations. None of the five methodologies proved to be sufficiently robust to serve as a basis for estimating technology-specific costs of capital and technology-specific capital structures for OPG's regulated hydroelectric and nuclear prescribed assets.

The analysis also considered a non-quantitative method based on the Standard & Poor's debt ratio guideline matrix for different debt ratings and business risk categories for regulated electric utility and power companies. Here again, Fosters found that this approach did not provide sufficiently robust information to serve as a basis for estimating technology-specific costs of capital.

OPG continues to support the use of a single cost of capital for its prescribed facilities. OPG is financed as one company with hydroelectric, nuclear and other generating facilities. Moving away from a single cost of capital would add unnecessary complexity and, given the absence of a robust and analytically sound method for calculating technology-specific costs of capital, would not improve the accuracy in the matching of costs. Therefore, OPG proposes a single cost of capital for its prescribed facilities.

The capital structure of 47 per cent common equity and 53 per cent debt is applied to the total rate base and subsequently allocated to nuclear and regulated hydroelectric based on the relative size of the rate base for these two segments. A rate base allocation factor was used given the capital invested in both the nuclear and regulated hydroelectric operations create the need for financing and therefore drive the need for, timing of and cost of capital. This approach was approved by the OEB in EB-2007-0905 and continues to be appropriate for setting rates in the 2011 - 2012 test period.

Table 1
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital ($M)
Calendar Year Ending December 31, 2012

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	189.5	2.9%	4.13%	10.4
2	**Existing/Planned Long-Term Debt**	2	2,502.8	38.8%	5.50%	137.6
3	**Other Long-Term Debt Provision**	3	725.2	11.2%	5.87%	42.6
4	**Total Debt**	4	3,417.5	53.0%	5.58%	190.6
5	**Common Equity**	4	3,030.6	47.0%	9.85%	298.5
6	**Rate Base Financed by Capital Structure**	5	6,448.1	81.2%	7.59%	489.1
7	**Adjustment for Lesser of UNL or ARC**	5, 6	1,490.1	18.8%	5.58%	83.1
8	**Rate Base**	7	7,938.2	100%	7.21%	572.2

Notes:

1 Short Term Financing allocated at: 64.7%
Short-term Debt Cost includes interest at the cost rate shown plus an allocation of the credit facility cost shown at Ex. C1-T1-S3 Table 2, line 10.

2 Ex. C1-T1-S2 Table 7 (line 43).

3 Debt required to balance capital structure with proposed rate base. See Ex. C1-T1-S2 Section 5.0.

4 Capital Structure and Return on Equity approved by the OEB in EB-2007-0905 as discussed in Ex. C1-T1-S1.

5 The portion of rate base to be financed by the capital structure approved by the Board excludes the lesser of the forecast of the average unfunded liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

6 Principal from C2-T1-S2 Table 1, line 29. Cost Rate from Ex. C2-T1-S2, Section 4.1.

7 Ex. B1-T1-S1 Table 1 (Regulated Hydroelectric) and Ex. B1-T1-S1 Table 2 (Nuclear).

Table 2
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital ($M)
Calendar Year Ending December 31, 2011

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

Notes:
1 Short Term Financing allocated at: 64.7%
Short-term Debt Cost includes interest at the cost rate shown plus an allocation of the credit facility cost shown at Ex. C1-T1-S3 Table 2, line 10.
2 Ex. C1-T1-S2 Table 6 (line 39).
3 Debt required to balance capital structure with proposed rate base. See Ex. C1-T1-S2 Section 5.0.
4 Capital Structure and Return on Equity approved by the OEB in EB-2007-0905 as discussed in Ex. C1-T1-S1.
5 The portion of rate base to be financed by the capital structure approved by the Board excludes the lesser of the forecast of the average unfunded liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.
6 Principal from C2-T1-S2 Table 1, line 29. Cost Rate from Ex. C2-T1-S2, Section 4.1.
7 Ex. B1-T1-S1 Table 1 (Regulated Hydroelectric) and Ex. B1-T1-S1 Table 2 (Nuclear).

Numbers may not add due to rounding.

Table 3
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital ($M)
Calendar Year Ending Dec. 31, 2010

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	189.5	3.1%	1.31%	5.1
2	**Existing/Planned Long-Term Debt**	2	2,134.3	34.6%	5.70%	121.6
3	**Other Long-Term Debt Provision**	3	947.0	15.4%	5.77%	54.6
4	**Total Debt**	4	3,270.7	53.0%	5.54%	181.3
5	**Common Equity**	4, 5	2,900.4	47.0%	2.13%	61.9
6	**Rate Base Financed by Capital Structure**	6	6,171.2	79.9%	3.94%	243.2
7	**Adjustment for Lesser of UNL or ARC**	6, 7	1,556.5	20.1%	5.58%	86.9
8	**Rate Base**	8	7,727.7	100%	4.27%	330.1

Notes:

1 Short Term Financing allocated at: 64.7%
Short-term Debt Cost includes interest at the cost rate shown plus an allocation of the credit facility cost shown at Ex. C1-T1-S3 Table 2, line 10.

2 Ex. C1-T1-S2 Table 5 (line 35).

3 Debt required to balance capital structure with proposed rate base. See Ex C1-T1-S2 Section 5.0.

4 Capital Structure approved by the OEB in EB-2007-0905 as discussed in Ex. C1-T1-S1. The Return on Equity forecast is detailed in Ex. I1-T1-S1 Table 5.

5 Cost of Capital for 2010 is determined in Ex. I1-T1-S1 Table 5.

6 The portion of rate base to be financed by the capital structure approved by the Board excludes the lesser of the forecast of the average unfunded liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

7 Principal from C2-T1-S2 Table 1, line 29. Cost Rate from Ex. C2-T1-S2, Section 4.1.

8 Ex. B1-T1-S1 Table 1 (Regulated Hydroelectric) and Ex. B1-T1-S1 Table 2 (Nuclear).

Table 4
Capitalization and Cost of Capital
Summary of Capitalization and Actual Cost of Capital ($M)
Calendar Year Ending Dec. 31, 2009

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Actual Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Achieved Capitalization and Return on Capital:					
1	**Short-term Debt**	1	186.2	3.1%	1.58%	6.6
2	**Existing Long-Term Debt**	2	2,019.8	33.1%	5.82%	117.5
3	**Other Long-Term Debt Provision**	3	1,024.6	16.8%	6.76%	69.3
4	**Total Debt**	4	3,230.6	53.0%	5.99%	193.4
5	**Common Equity**	4, 5	2,864.9	47.0%	1.10%	31.6
6	**Rate Base Financed by Capital Structure**	6	6,095.5	84.0%	3.69%	225.0
7	**Adjustment for Lesser of UNL or ARC**	6, 7	1,159.8	16.0%	5.60%	65.0
8	**Rate Base**	8	7,255.4	100%	4.00%	290.0

Notes:

1 Short Term Financing allocated at: 64.7%
Short-term Debt Cost includes interest at the cost rate shown plus an allocation of the credit facility cost shown at Ex. C1-T1-S3 Table 2, line 10.

2 Ex. C1-T1-S2 Table 4 (line 31).

3 Debt req'd to balance capital structure with proposed rate base. See Ex . C1-T1-S2 Table 4a Note 11 for interest rate calculation.

4 Capital Structure approved by the OEB in EB-2007-0905 as discussed in Ex. C1-T1-S1.

5 For actual Return on Equity achieved for 2009 see Ex. C1-T1-S1 Table 7.

6 The portion of rate base to be financed by the capital structure approved by the Board excludes the lesser of the forecast of the average unfunded liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

7 From C2-T1-S2 Table 1, line 29.

8 Ex. B1-T1-S1 Table 1 (Regulated Hydroelectric) and Ex. B1-T1-S1 Table 2 (Nuclear).

Numbers may not add due to rounding.

Table 5
Capitalization and Cost of Capital
Summary of Capitalization and Actual Cost of Capital ($M)
Calendar Year Ending Dec. 31, 2008

Line No.	Capitalization	Note	Principal ($M) Q1 (45% Equity)	Q2-Q4 (47% Equity)	((a) x .25 + (b) x .75) Annualized	Component (%)	Actual Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Achieved Capitalization and Return on Capital:							
1	**Short-term Debt**	1	169.6	169.6	169.6	2.7%	4.10%	7.7
2	**Existing Long-Term Debt**	2	2,052.5	2,052.5	2,052.5	32.2%	5.78%	118.7
3	**Other Long-Term Debt Provision**	3	1,812.6	985.5	1,192.2	18.7%	5.66%	67.5
4	**Total Debt**	4	4,034.6	3,207.5	3,414.3	53.6%	5.68%	193.9
5	**Common Equity**	4, 5	3,301.1	2,844.4	2,958.6	46.4%	-3.11%	(92.0)
6	**Rate Base Financed by Capital Structure**	6	7,335.7	6,052.0	6,372.9	86.9%	1.60%	102.0
7	**Adjustment for Lesser of UNL or ARC**	6, 7		1,283.7	962.8	13.1%	5.60%	53.9
8	**Rate Base**	8	7,335.7	7,335.7	7,335.7	100%	2.13%	155.9

Notes:
1 Short Term Financing allocated at: 56.3%
Short-term Debt Cost includes interest at the cost rate shown plus an allocation of the credit facility cost shown at Ex. C1-T1-S3 Table 2, line 10.
2 Q1 and Q2-Q4 from Ex. C1-T1-S2 Table 3 (line 28).
3 Debt req'd to balance capital structure with proposed rate base. See Ex . C1-T1-S2 Table 3a Note 10 for interest rate calculation.
4 Q2-Q4 Capital Structure approved by the OEB in EB-2007-0905 as discussed in Ex. C1-T1-S1.
5 Col. (f) from Ex. C1-T1-S1 Table 7 line 14 for 2008.
6 The portion of rate base to be financed by the capital structure approved by the Board excludes the lesser of the forecast of the average unfunded liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.
7 Col. (b) from C2-T1-S2 Table 1, line 29.
8 Ex. B1-T1-S1 Table 1 (Regulated Hydroelectric) and Ex. B1-T1-S1 Table 2 (Nuclear).

Table 6
Capitalization and Cost of Capital
Summary of Capitalization and Actual Cost of Capital ($M)
Calendar Year Ending Dec. 31, 2007

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Actual Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Achieved Capitalization and Return on Capital:					
1	**Short-term Debt**	1	189.0	2.6%	4.92%	10.0
2	**Existing/Planned Long-Term Debt**	2	1,855.8	25.0%	5.90%	109.5
3	**Other Long-Term Debt Provision**	3	2,031.3	27.4%	5.29%	107.5
4	**Total Debt**	4, 5	4,076.1	55.0%	5.57%	227.0
5	**Common Equity**	4, 5	3,335.0	45.0%	-6.70%	(223.3)
6	**Rate Base**	5, 6	7,411.1	100%	0.05%	3.7

Notes:
1 Short Term Financing allocated at: 57.1%
Short-term Debt Cost includes interest at the cost rate shown plus an allocation of the credit facility cost shown at Ex. C1-T1-S3 Table 2, line 10.
2 From EB-2007-0905.
3 Debt required to balance capital structure with proposed rate base. See Ex. C1-T1-S2 Table 2a, Note 11 for interest rate calculation.
4 Applied the capital structure reflected in the information OPG supplied to the Province for the purposes of establishing the interim payment amounts. Return in $M from EB-2007-0905 Ex. C1-T2-S1 Table 1.
5 The cost of capital for 2007 is calculated using a rate base amount that includes the increase in the Nuclear Liabilities recorded on Dec 31, 2006.
Earnings reflect the regulatory methodologies reflected in 2007 payment amounts.
6 Ex. B1-T1-S1 Table 1 (Regulated Hydroelectric) and Ex. B1-T1-S1 Table 2 (Nuclear).

Numbers may not add due to rounding.

Table 7
Capitalization and Cost of Capital
Actual Return on Equity - Reconciliation to Audited Financial Statements for Prescribed Facilities ($M)
Calendar Years Ending December 31, 2008 and December 31, 2009

Line No.	Description	Note	Regulated Hydroelectric 2008	Nuclear 2008	Total 2008	Regulated Hydroelectric 2009	Nuclear 2009	Total 2009
			(a)	(b)	(c)	(d)	(e)	(f)
1	**Accounting EBIT (includes rounding)**	1	309.9	(538.4)	(228.5)	326.5	279.6	606.1
Accounting Expenses/Revenues not Included in Regulatory EBIT								
2	**Add: Accretion on Nuclear Fixed Asset Removal and Nuclear Waste Management Liabilities**	2	0.0	325.9	325.9	0.0	344.8	344.8
3	**Deduct: Earnings/(Losses) on Nuclear Fixed Asset Removal and Nuclear Waste Management Funds**	2	0.0	(242.1)	(242.1)	0.0	415.5	415.5
Differences Between Accounting and Regulatory Treatment								
	(1) HYDROELECTRIC PRODUCTION ABOVE 1900 MW/Hr:							
4	**Deduct: Revenue at Market Price Included in Accounting EBIT**	3	189.0	0.0	189.0	0.0	0.0	0.0
5	**Add: Revenue at Regulated Hydroelectric Payment Amounts**	4	125.4	0.0	125.4	0.0	0.0	0.0
	(2) HYDROELECTRIC INCENTIVE MECHANISM:							
6	**Deduct: Hydroelectric Incentive Revenue**	5	3.0	0.0	3.0	21.0	0.0	21.0
	(3) CAPITAL TAXES:							
7	**Add: Accounting Capital Tax on Regulated Assets**	6	11.7	8.5	20.2	10.5	7.3	17.8
8	**Deduct: Regulatory Capital Tax on Regulated Assets**	7	8.7	7.8	16.5	8.6	7.7	16.3
	(4) UNREALIZED EXCHANGE RATE ADJUSTMENTS:							
9	**Add: (Gains)/Losses Included in Accounting EBIT**	8	0.0	(7.9)	(7.9)	0.0	0.0	0.0
10	**Regulatory EBIT** (line 1+2-3-4+5-6+7-8+9)		246.3	22.4	268.7	307.4	208.5	515.8
Cost Related to Deemed Debt and UNL/ARC Adjustment								
11	**Deduct: Cost of Deemed Debt for Regulated Assets**	9	117.7	76.3	193.9	121.7	71.8	193.5
12	**Deduct: Cost Related to UNL/ARC Adjustment**	9	N/A	53.9	53.9	N/A	65.0	65.0
13	**Regulatory EBT** (line 10 - line 11 - line 12)	10	128.7	(107.8)	20.8	185.7	71.7	257.3
Determination of Return on Equity								
14	**Deduct: Income Taxes on Regulated Assets**	11	0.0	0.0	0.0	23.0	45.0	68.0
Systematic Adjustments								
15	**Deduct: Transactions in Income and Other Taxes Variance**	12	(0.2)	(11.7)	(11.9)	(0.1)	(8.4)	(8.5)
16	**Deduct: Transactions in Tax Loss Variance Account**	12	20.0	104.7	124.7	26.6	139.6	166.2
17	**Total Systematic Adjustments**		19.8	93.0	112.8	26.5	131.2	157.7
18	**Return on Equity** (line 13 - line 14 - line 17)		108.9	(200.8)	(92.0)	136.2	(104.6)	31.6

See Ex. C1-T1-S1 Table 7a for notes

Table 7a
Capitalization and Actual Cost of Capital
Actual Return on Equity - Reconciliation to Audited Financial Statements for Prescribed Facilities($M)
Notes to Ex. C1, Tab 1, Sch. 1, Table 7

Notes:

1 Accounting EBIT for 2008 and 2009 as reflected in the audited financial statements for prescribed facilities in Ex. A2-T1-S1 Attachment 3.
Nuclear EBIT consists of EBIT of the Nuclear Generation and Nuclear Waste Management segments in the audited financial statements for prescribed facilities.

2 Accretion on Nuclear Fixed Asset Removal and Nuclear Waste Management Liabilities and Earnings/Losses on Nuclear Fixed Asset Removal and Nuclear Waste Management Funds for 2008 and 2009 as reflected in the Nuclear Waste Management segment in the audited financial statements for prescribed facilities in Ex. A2-T1-S1 Attachment 3.
Accretion for 2009 and Fund Earnings/(Losses) for 2008 and 2009 are also presented in Ex. C2-T1-S2 Table 1.
Accretion for 2008 presented in Ex. C2-T1-S2 Table 1 differs from the amount per the audited financial statements for prescribed facilities as the amount in the financial statements reflects a reduction for amounts deferred in the Nuclear Liability Deferral Account, Transition during Q1 2008.

3 Revenue at Market Price for 2008 as reflected on page 29 in Management's Discussion and Analysis accompanying OPG's 2009 audited consolidated financial statements in Ex. A2-T1-S1 Attachment 2 .
Regulated Hydroelectric production above 1900 MWh/Hr does not receive market prices effective December 1, 2008, as discussed in Ex. E1-T1-S1.

4 Revenue at Regulated Hydroelectric Payment Amounts for 2008 is computed as total hourly production over 1900 MWh x $33.00/MWh for Q1 2008 and $36.66/MWh for April 1 to November 30, 2008.

5 Hydroelectric Incentive Revenue for 2008 and 2009 is earned pursuant to the revised hydroelectric incentive mechanism approved by the OEB in EB-2007-0905 effective December 1, 2008, and is reflected on page 29 in Management's Discussion and Analysis accompanying OPG's 2009 audited consolidated financial statements in Ex. A2-T1-S1 Attachment 2. The hydroelectric incentive mechanism is discussed in Ex. E1-T1-S1.

6 Capital Tax included in Accounting EBIT is based on an allocation of accounting capital taxes to prescribed assets determined on a corporate basis.

7 Capital Tax for regulatory purposes for OPG's prescribed assets is determined in Ex. F4-T2-S1 Tables 2 and 4.

8 OPG recognizes certain unrealized exchange rate gains/losses in Accounting EBIT for derivatives related to some of its future purchase obligations. For regulatory purposes, any such gains/losses are reflected in the cost of actual purchases as they are received.

9 Interest cost of deemed debt allocated to Regulated Hydroelectric and Nuclear based on rate base as follows:

Table to Note 9 - Interest Expense Calculation ($M)		Regulated Hydroelectric			Nuclear		
Line		2008			2008		
No.	Item	Q1	Q2 - Q4	2009	Q1	Q2 - Q4	2009
		(a)	(b)	(c)	(d)	(e)	(f)
1	Interest Rate (from Ex. C1-1-1 Tables 4, 5)	5.68%	5.68%	5.99%	5.68%	5.68%	5.99%
2	Rate Base (from B1-1-1 Tables 1 and 2)	3,871.5	3,871.5	3,834.0	3,464.2	3,464.2	3,421.4
3	ARC / UNL Adjustment (Ex. C2-1-2 Table 1)	N/A	N/A	N/A	0.0	1,283.7	1,159.8
4	Rate base financed by capital structure	3,871.5	3,871.5	3,834.0	3,464.2	2,180.5	2,261.5
	(line 2 - line 3)						
5	Debt Ratio	55%	53%	53%	55%	53%	53%
6	Deemed Debt (line 4 x line 5)	2,129.3	2,051.9	2,032.0	1,905.3	1,155.7	1,198.6
7	Proportion of year	25%	75%	100%	25%	75%	100%
8	Cost of Deemed Debt for Regulated Assets	30.2	87.4	121.7	27.1	49.2	71.8
	(line 1 x line 6 x line 7)						
9		2008 Total >	117.7		2008 Total >	76.3	
10	Cost Related to UNL/ARC Adjustment	N/A	N/A	N/A	0.0	53.9	65.0
	(5.60% line 3 x line 7)						

10 Regulatory EBT for 2008 and 2009 is used to determine regulatory income taxes in Ex. F4-T2-S1 Table 6.

11 Regulatory income taxes for 2008 and 2009 as reflected in Ex. F4-T2-S1 Tables 1 and 3.

12 Ex. H1-T1-S1 Tables 1b and 1c.

COST OF LONG-TERM DEBT

1.0 PURPOSE

This evidence describes how the methodology approved by the OEB in EB-2007-0905 was used to determine the long-term debt and associated cost for OPG's regulated operations for the test period. It also provides details of OPG's existing and planned annual long-term borrowing and associated costs for 2007 – 2012.

2.0 OVERVIEW

The long-term debt supporting OPG's regulated operations is comprised of existing and planned long-term debt issues plus a long-term debt provision required to reconcile OPG's regulated debt to the capital structure approved by the OEB in EB-2007-0905**.** The summary of capitalization for the test period is provided in Ex. C1-T1-S1 Tables 1 and 2.

OPG has used the same methodology to determine the regulated portion of existing and planned new debt issues as was approved by the OEB in EB-2007-0905. Section 3.0 discusses methodology, while section 4.0 presents the cost of these issues. Section 5.0 describes OPG's other long-term debt provision. OPG's existing and planned long-term debt is comprised of project-related and general corporate issues ("company-wide borrowing"). OPG has entered into financial hedges associated with certain existing and planned new debt issues to reduce its exposure to interest rate fluctuations.

3.0 METHODOLOGY

3.1 Project-Related Long-Term Debt Issues

OPG assigns all existing and planned project-related financing to regulated or unregulated operations based on whether the project is related to its regulated assets. For example, project-related financing associated with nuclear projects, or projects at R.H. Saunders or at the Niagara Plant Group, is assigned to OPG's regulated operations. All project-related financing that is not associated with OPG's regulated assets is assigned to unregulated operations. OPG also forecasts its financing requirements for projects that are still in the design/assessment phase; however these financing requirements are not assigned to OPG's regulated operations unless and until they are specifically identified as a project in OPG's capital budget for its regulated operations.

3.2 Corporate Long-Term Debt Issues

The company-wide borrowing portfolio of long-term debt remaining after project-related financing has been directly assigned must be allocated to regulated and unregulated operations for the test period. OPG has applied the allocation methodology approved by the OEB in EB-2007-0905. In summary, the book value of OPG's net fixed assets (gross fixed assets less accumulated depreciation plus construction work in progress) is the basis for allocating the company-wide borrowing portfolio of long-term debt. The net fixed asset values are adjusted to remove asset values that were financed pursuant to project specific arrangements, and nuclear liabilities (the lesser of OPG's asset retirement cost and unfunded nuclear liabilities). The adjusted relative net fixed asset ratio is then applied to OPG's company-wide borrowing portfolio of long-term debt to determine the amount of existing/planned debt to be included in the long-term debt component of OPG's capital structure for its regulated assets.

Consistent with the approach approved in EB-2007-0905, OPG has used information from its most recent audited financial statements (2009) to develop the allocation factor used to determine the amount of long-term debt for OPG's regulated operations in 2010, 2011, and 2012. The use of audited 2009 financial information is appropriate because the ratio of regulated net fixed assets to corporate net fixed assets does not change significantly from year to year (see Ex. C1-T1-S2 Table 1, line 13). In addition, this approach is simple and does not require assumptions about corporate net fixed asset growth.

For all company-wide, long-term debt issued prior to December 31, 2009, the allocation ratio is based on actual year-end values for net fixed assets in that year. For example, the allocation ratio for 2008 is determined by comparing the regulated net fixed assets at December 31, 2008 (as reflected in Exhibit B) to the total net fixed assets reflected in OPG's 2008 audited financial statements. The allocation ratios for 2007, 2008 and 2009 are provided in Ex. C1-T1-S2, Table 1.

3.3 Risk Management Activities

OPG's Executive Risk Committee ("ERC"), formerly the Risk Oversight Committee ("ROC"), is a senior management committee that has been delegated authority to review and approve financial and operational risk mitigation strategies. In November 2009, the ERC approved interest rate risk management strategy for Niagara Tunnel debt to mitigate exposure to interest rate fluctuations. This strategy permits hedging up to 50 per cent of the remaining budget for the Niagara Tunnel project of $1.1 billion. Hedging pursuant to this strategy was completed by early January, 2010.[1] The primary benefit of the interest rate hedging activity is that it fixes the interest cost on the hedged portion of the debt thereby reducing the exposure to interest rate volatility and refinancing risk.

The financial impact of the hedge transactions that have matured is amortized over the life of the underlying debt issue, in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"), and is reflected in the effective interest rate cost of the debt issue. To the extent a forecast debt issue is hedged and OPG does not ultimately require the underlying debt issue, the impact of the hedge transaction is charged to unregulated operations.

4.0 COST OF EXISTING AND PLANNED NEW DEBT ISSUES

4.1 Existing Debt Issues

OPG's debt continuity schedules (Ex. C1-T1-S2 Tables 2 through 4) provide the actual cost of debt issued on or before December 31, 2009.

All OPG debt issues with the OEFC contain covenant conditions that apply to corporate debt issued in the public debt markets. The average remaining term of these long-term debt issues is approximately 4.7 years as at December 31, 2009.

[1] As described in EB-2007-0905, the ROC previously had approved hedging up to 75 per cent of total planned cash expenditures (net of contingencies) for the Niagara Tunnel project and up to 50 per cent of the OEFC debt maturing in the second half of 2007 and all of 2008. All heading transactions under this approval were completed by June 2007.

Existing OEFC debt will be retired or refinanced at maturity depending on OPG's liquidity at that time. OPG does not plan to redeem the debt prior to its maturity since its agreements with the OEFC contain call provisions that make it more expensive to redeem the debt compared to the potential benefit of refinancing in a lower interest rate environment.

OEFC debt outstanding at December 31, 2009 consists of both senior and subordinate notes under which the OEFC has different rights. The existence of subordinate debt in OPG's debt portfolio could make any senior issue offered into the capital market more attractive to investors. Payments on subordinated notes (issues 7 to 10 in Ex. C1-T1-S2 Tables 2, 3, 4 and 5 and issues 9 and 10 in Ex. C1-T1-S2 Table 6) are made only after full payment is made on senior notes.

OPG's long-term debt outstanding at December 31, 2009, as reflected in OPG's audited financial statements, is $4,046M. This balance consisted of corporate debt held by the OEFC of $2,745M, and project-related debt held by the OEFC related to regulated operations of $490M. The remaining $811M of OPG's long-term debt obligation outstanding as of December 31, 2009 is OEFC and non-OEFC project-related financing associated with OPG's unregulated operations. Debt issued prior to December 31, 2007 was described in detail in EB-2007-0905. Debt issued in 2008 and 2009 is described below.

OPG's 2008 debt issues are listed in Ex. C1-T1-S2 Table 3. OPG refinanced $200M out of the $400M of debt that matured in 2008. OPG retired one $200M debt issue on March 22 (Issue 3), replacing it with a $200M issue of 10-year term debt also on March 22 (Issue 20) at a rate of 5.09 per cent. These notes were issued under the $950M refinancing credit agreement with the OEFC. An effective interest rate of 5.35 per cent is applied to this $200M debt issue. This represents the blend of hedged and unhedged debt costs, and is consistent with the accounting and rate making approach used to determine the effective interest cost as described in section 3.5 below. The effective interest rate is determined in Ex. C1-T1-S2 Table 3a. OPG was able to fund the retirement of a second $200M debt issue on September 22 (Issue 6) from operations.

OPG completed three debt issues pursuant to the Credit Facility Agreement for the Niagara Tunnel Project in 2008. OPG hedged its interest rate exposure with respect to its forecast quarterly borrowing for the Niagara Tunnel project in accordance with the direction approved by OPG's ROC (now replaced by the ERC). The interest rates for the three completed debt issues (listed as Niagara 4, Niagara 5 and Niagara 6 in Ex. C1-T1-S2 Table 3) are:

- Niagara 4: $40M on January 22, 2008 at an effective rate of 5.53 per cent reflecting a rate of 3.82 per cent and an applicable spread for OPG of 1.40 per cent plus an amortization of hedging cost of 0.31 per cent.
- Niagara 5: $30M on April 22, 2008 at an effective rate of 5.90 per cent reflecting a rate of 3.79 per cent and an applicable spread for OPG of 1.63 per cent plus an amortization of hedging cost of 0.48 per cent.
- Niagara 6: $30M on July 22, 2008 at an effective rate of 5.87 per cent reflecting a rate of 3.90 per cent and an applicable spread for OPG of 1.60 per cent plus an amortization of hedging cost of 0.37 per cent.

OPG's 2009 debt issues are listed in Ex. C1-T1-S2 Table 4. OPG refinanced $100M out of the $350M debt that matured in 2009. OPG retired one $175M debt issue on March 22 (issue 3), replacing it with a $100M issue of 10-year term debt also on March 22 (issue 21) and $75M provided from operations. OPG retired a second $175M debt issue on September 22 (issue 4) funded from operations. The $100M notes on March 22, 2009 were issued at a rate of 5.65 per cent reflecting a rate of 2.74 per cent and an applicable spread for OPG of 2.91 per cent.

OPG completed four debt issues pursuant to the Niagara Tunnel project financing agreement in 2009. The interest rates for the four completed debt issues (listed as Niagara 7, Niagara 8, Niagara 9 and Niagara 10 in Ex. C1-T1-S2 Table 4a are:

- Niagara 7: $30M on January 22, 2009 at an effective rate of 8.41 per cent reflecting a rate of 2.88 per cent and an applicable spread for OPG of 3.30 per cent plus an amortization of hedging cost of 2.23 per cent.

- Niagara 8: $35M on April 22, 2009 at an effective rate of 7.71 per cent reflecting a rate of 2.88 per cent and an applicable spread for OPG of 2.75 per cent plus an amortization of hedging cost of 2.08 per cent.
- Niagara 9: $35M on July 22, 2009 at an effective rate of 6.41 per cent reflecting a rate of 3.52 per cent and an applicable spread for OPG of 1.67 per cent plus an amortization of hedging cost of 1.22 per cent.
- Niagara 10: $50M on October 22, 2009 at an effective rate of 5.63 per cent reflecting a rate of 3.56 per cent and an applicable spread for OPG of 1.30 per cent plus an amortization of hedging cost of 0.77 per cent.

4.2 Planned New Debt Issues

The interest rate associated with OEFC debt is fixed at the time the funds are advanced. The rate of interest is determined prior to the date the funds are advanced based on the prevailing benchmark Government of Canada 10-year bond as published by a verifiable market monitoring service (currently Bloomberg) on the day prior to the date funds are advanced, plus a credit margin determined five business days before the date funds are advanced. The credit margin is determined based on a sample of quotes for OPG's credit margin as provided by a selected group of Canadian banks.

The cost of planned new and refinanced corporate debt and project-related debt for 2010, 2011 and 2012 is based on a forecast of the 10-year Long Canada Bond as published in December 2009 by Global Insight, a third party, independent market source. The long-term interest rates forecast for the 10-year Government of Canada bonds are provided in Chart 1. As discussed below, a credit risk spread for OPG of 126 basis points is added to the Global Insight rates noted in Chart 1 to determine the forecast rate for OPG's OEFC debt in 2010, 2011 and 2012.

Chart 1 – Forecast 10-year Long Canada Bond Rates

Year	Q1	Q2	Q3	Q4
2010	3.80	3.83	3.84	3.87
2011	3.94	4.08	4.19	4.38
2012*	4.68			

* Annual forecast

The average OPG credit spread from 2005 to 2009 was approximately 145 basis points. The average OPG credit spread from 2005 to 2007 was 86 basis points. The average OPG credit spread from 2008 to 2009 was 206 basis points which was significantly in excess of the credit spread of 130 basis points used in EB-2007-0905 for new debt issues in 2008 and 2009. The tightening of credit which began in late 2007 following the asset-backed commercial paper disruption resulted in increasing credit spreads which was further compounded by the credit crisis in the fall of 2008. These events sparked a significant spike in credit spreads that continued for the first half of 2009. The period prior to the 2007 credit disruption was a period of excess liquidity in the market, which resulted in credit spreads being compressed to unusually low levels. OPG does not expect the market to return to such low credit spreads during the bridge year or test period. During 2009, credit spreads fell from the very high levels seen at the beginning of the year to a range of about 120 to 140 basis points in the fall of 2009. OPG's credit spread at the end of 2009 was 126 basis points and this figure has been used for 2010, 2011 and 2012.

OPG incurs costs to set-up each new credit facility with the OEFC (e.g., legal fees), these costs are relatively minor and are reflected in OPG's forecast OM&A costs for its legal department in the period the credit facility is forecast to be established. OPG may incur expenses to compensate the OEFC in the event of default; however OPG has not planned to incur such expenses.

4.3 Planned Corporate Long-Term Debt Issues

The total amounts of OPG's planned debt issues are listed in the notes to Ex. C1-T1-S2, Table 5 (2010), Table 6 (2011), and Table 7 (2012). OPG will retire approximately $1.75B of debt maturing between 2010 and 2012 and plans to issue long term debt of approximately $1.43B over the same time period as summarized in Chart 2, below:

Chart 2
Planned Corporate Long-Term Debt Retirements and Issues
($M)

	2010	2011	2012	Total
Debt Issues Maturing	970	375	400	1,745
New Debt Issues	830	300	300	1,430

In EB-2007-0905 OPG indicated it was developing plans to issue new incremental corporate debt into the external market in 2009, should OPG's updated long-term borrowing requirements turn out to be greater than forecast (see EB-2007-0905 Ex. C1-T1-S2, section 2.2). This financing was not required in 2009, but OPG expects to issue debt in the external marketplace before the end of the test period. In addition, a credit facility agreement with the OEFC was executed in March 2010 to re-finance debt maturing in 2010, as required.

4.4 Planned Project-Related Long-Term Debt Issues

Approximately $800M in new borrowing is needed to finance the Niagara Tunnel project over the 2010 - 2012 period. OPG does not plan to undertake other project-related financing for the regulated assets during the test period.

OPG has an agreement in place with the OEFC to provide debt financing for the Niagara Tunnel project. This agreement enables OPG to issue notes each quarter with a term of up to 10 years to meet OPG's financing obligations for this project. OPG may borrow up to $1B over the duration of the project to meet the financial requirements of the project. OPG is pursuing an amendment to this agreement to increase the maximum amount available to $1.6B which is consistent with the revised cost estimate. Borrowings under project-related credit facility agreements between OPG and the OEFC are on an unsecured basis for the purpose of financing construction requirements of specific projects.

The total amount for each of OPG's planned debt issues for the Niagara Tunnel Project is shown in the notes to Ex. C1-T1-S2 Table 5 (2010), Table 6 (2011) and Table 7 (2012). OPG expects to borrow $800M over 2010 through 2012 as summarized in Chart 3, below.

Chart 3
Planned Niagara Tunnel Project Related Long Term Debt Issues ($M)

	2010	2011	2012	Total
New Debt Issues	200	300	300	800

OPG has partially hedged all expected debt issues during this period. The impact of hedging activities on OPG's effective debt cost for project-related debt is described below. To the extent that a portion of the debt is hedged in any period, the interest rate cost for each specific debt issue reflects a weighted average of the hedge amount and the unhedged amount.

Details of hedge transactions that have a maturity date after December 31, 2009 are provided in Ex. C1-T1-S2 Table 10 for the Niagara Tunnel project. The financial impact of these hedge transactions cannot be determined until the issue reaches maturity. For illustrative purposes the market value (market-to-market) of each of the hedges as at December 31, 2009 has been shown in the tables. A negative market value corresponds to a payment owing by OPG if the hedge had to be settled as at December 31, 2009, similarly a positive market value corresponds to a payment owing to OPG. The consolidated market value of all hedges that had not matured as at December 31, 2009 and that are forecast to mature prior to the end of the test period amounts to a positive $0.6M.

5.0 OTHER LONG-TERM DEBT

As discussed above, OPG finances long-term assets with long-term financing. Consistent with the methodology approved in EB-2007-0905, OPG has used a provision for long-term debt to reconcile the debt component of OPG's regulated capital structure with the proposed rate base that financing supports. OPG's other long-term debt provision is determined based on:

- The difference between the debt resulting from the application of OPG's proposed capital structure to its proposed regulated rate base.
- The project-related and corporate long-term debt assigned or allocated to OPG's regulated operations as discussed above.
- The portion of short-term debt allocated to regulated operations. This calculation is described in Ex. C1-T1-S3.

In EB-2007-0905, the OEB required OPG to use the hedged interest rates rather than the unhedged rates to calculate the interest rate on the debt provision. Accordingly, for 2008 and 2009, the hedged interest rate for debt issued each year for both corporate and project-related borrowing purposes is added together and divided by the number of debt issues in that year to determine the interest rate attributable to the other long-term debt provision for those years. OPG has provided a calculation identifying all debt issued in the year, the hedged interest rate and the resulting average interest rate applicable to its other long-term debt provision in the footnotes of Ex. C1-T1-S2 Table 2a (2007), Table 3a (2008), Table 4a (2009).

As discussed in Ex C1-T1-S1, OPG has used the cost of capital methodology contained in the OEB's Report on the Cost of Capital for Ontario's Regulated Utilities in EB-2009-0084 ("Cost of Capital Report"). OPG's other long-term debt provision is consistent with the definition used by the OEB to describe the deemed debt component of the approved capital structure for electricity distributors. Page 54 of the Cost of Capital Report states that "the deemed long-term debt rate will be used where an electricity distribution utility has no actual debt". For 2010 and subsequent years, OPG will apply the OEB's approved methodology for determining the interest rate associated with deemed debt. The applicable interest rate is determined by the OEB as "an estimate based on the long (30-year) Government of Canada bond yield forecast plus the average spread between an A-rated Canadian utility bond yield and 30-year Government of Canada bond yield for all business days in the month three (3) months in advance of the (proposed) effective date for the rate changes." (Cost of Capital Report, page 58). OPG has applied the rate of 5.87 per cent to its Other Long-Term Debt for 2010, 2011 and 2012. This rate was determined by the OEB and published in its letter of

February 24, 2010 regarding Cost of Capital Parameter Updates for 2010 Cost of Service Applications. When calculating the final payment amounts, OPG proposes that this rate be updated using data for the month that is three months prior to the effective date of the new payment amounts as required by the Cost of Capital Report.

Table 1
Capitalization and Cost of Capital
Allocation of Existing Long-term Debt ($M)

Line No.	Asset	Amount ($M) 2007	2008	2009
		(a)	(b)	(c)
	Company-Wide:			
1	**Net Fixed Assets**	11,827.0	11,515.4	11,651.3
2	**Adjusted Construction Work in Progress**	950.0	1,271.8	1,236.7
3	**Asset Values Using Project Financing**	(860.0)	(1,100.8)	(1,266.4)
4	**Adjusted Net Fixed Assets**	11,917.0	11,686.4	11,621.6
5	**Adjustment for Lesser of UNL or ARC**[1,2]	N/A	1,767.6	1,740.0
6	**Adjusted Net Fixed Funded Assets**	11,917.0	9,918.8	9,881.6
	Regulated Operations:			
7	**Net Fixed Assets**[3]	6,696.9	6,529.4	6,396.9
8	**Adjusted Construction Work in Progress**	508.7	681.8	888.1
9	**Asset Values Using Project Financing**	(281.0)	(431.1)	(644.3)
10	**Adjusted Net Fixed Assets**	6,924.6	6,780.1	6,640.7
11	**Adjustment for Lesser of UNL or ARC**[1,4]	N/A	1,283.7	1,159.8
12	**Adjusted Net Fixed Funded Assets**	6,924.6	5,496.4	5,480.9
	Relative Ratio:			
13	**Regulated/Company-Wide Net Fixed Assets**	58.11%	55.41%	55.47%
	(line 12 / line 6)			

Notes:

1 Reflects OEB direction to adjust the allocation of existing long-term debt to regulated operations to reflect the Board's Decision with respect to the unfunded nuclear liabilities (Decision with Reasons, Pg. 165). See Ex. C2-T1-S2 Tables 1 and 2 for 2008 and 2009 adjustments.

2 Methodology as reflected in EB-2007-0905 Payment Amounts Order, App. A. Company-wide adjustment for 2008 and 2009 derived from Ex. C2-T1-S2 Tables 1 and 2 as follows:

Company-Wide Lesser of UNL and ARC	2008	2009
Company-Wide UNL:		
C2-T1-S2 Table 1, Line 21	1,329.1	1,449.7
+ C2-T1-S2 Table 2, Line 11	4,967.7	5,196.4
- C2-T1-S2 Table 2, Line 19	4,529.1	4,906.2
= Company Wide UNL	1,767.6	1,740.0
Company-Wide ARC:		
C2-T1-S2 Table 1, Line 28	1,283.7	1,159.8
+ C2-T1-S2 Table 2, Line 26	1,108.7	1,060.1
= Company Wide ARC	2,392.4	2,219.9
Lesser of UNL and ARC	1,767.6	1,740.0

3 Ex. B2-T3-S1 Table 1 and Ex. B2-T4-S1 Table 1 (Regulated Hydroelectric) and Ex. B3-T3-S1 Table 1 and B3-T4-S1 Table 1 (Nuclear).

4 C2-T1-S2 Table 1, line 28.

Table 2
Capitalization and Cost of Capital
Summary of Existing Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2007

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
							(Note 10)	
1	**Issue 1**	1	44.4			3/22/2007	5.85%	2.6
2	**Issue 2**	2	145.2			9/22/2007	5.85%	8.5
3	**Issue 3**		200.0			3/22/2008	5.90%	11.8
4	**Issue 4**		200.0			9/22/2008	5.90%	11.8
5	**Issue 5**		175.0			3/22/2009	6.01%	10.5
6	**Issue 6**		175.0			9/22/2009	6.01%	10.5
7	**Issue 7**	8	187.5			3/22/2010	6.60%	12.4
8	**Issue 8**	8	187.5			9/22/2010	6.60%	12.4
9	**Issue 9**	8	187.5			3/22/2011	6.65%	12.5
10	**Issue 10**	8	187.5			9/22/2011	6.65%	12.5
11	**Issue 11**		100.0	3/22/2005	5.0	3/22/2010	5.49%	5.5
12	**Issue 12**		150.0	3/22/2005	5.0	3/22/2010	5.71%	8.6
13	**Issue 13**		100.0	9/22/2005	5.0	9/22/2010	5.49%	5.5
14	**Issue 14**		150.0	9/22/2005	5.0	9/22/2010	5.71%	8.6
15	**Issue 15**		95.0	3/22/2005	5.0	3/22/2010	5.62%	5.3
16	**Issue 16**		400.0	4/29/2005	7.0	4/30/2012	5.72%	22.9
17	**Issue 17**	3, 12	52.6	6/22/2007	10.0	6/22/2017	5.44%	2.9
18	**Issue 18**	4,11,12	53.7	9/24/2007	10.0	9/22/2017	5.53%	3.0
19	**Issue 19**	5, 12	11.0	12/21/2007	9.8	9/22/2017	5.31%	0.6
20	**Total**		2,801.8				6.00%	168.1
	Regulated Portion of Company-Wide Borrowing							
21	**Allocation**	9	1,628.1				6.00%	97.7
	Project Financing--Regulated Projects							
22	**Niagara 1**		160.0	10/22/2006	10.0	10/22/2016	5.23%	8.4
23	**Niagara 2**	6, 12	47.0	1/22/2007	10.0	1/22/2017	5.10%	2.4
24	**Niagara 3**	7, 12	28.2	4/23/2007	10.0	4/22/2017	5.09%	1.4
25	**Total**		235.2				5.18%	12.2
	Total Regulated Long-Term Debt							
26	Line 21+25		1,863.2				5.90%	109.9

See Ex. C1-T1-S2 Table 2a for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 2a
Capitalization and Cost of Capital
Summary of Existing Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2007
Notes to Ex. C1, Tab 1, Sch. 1, Table 2

	Issue	Issue/Redemption Date	Face Value ($M)	Effective Days	Weighted Principal ($M)	New Issues Effectiive Rates
Note 1	Issue 1	3/22/2007	200.0	81.0	44.4	
Note 2	Issue 2	9/22/2007	200.0	265.0	145.2	
Note 3	Issue 17	6/22/2007	100.0	192.0	52.6	5.44%
Note 4	Issue 18	9/24/2007	200.0	98.0	53.7	5.53%
Note 5	Issue 19	12/21/2007	400.0	10.0	11.0	5.31%
Note 6	Niagara 2	1/22/2007	50.0	343.0	47.0	5.10%
Note 7	Niagara 3	4/23/2007	30.0	343.0	28.2	5.09%
	See Ex. C1-T1-S2 Table 8 for effective interest rates for Project Related Debt. See Ex C1-T1-S2 Table 9 for effective interest rates for non-Project Debt.					

Note 8 Issues 7, 8, 9 and 10 are subordinated debt issues.

Note 9 Allocation ratio for 2007 described in Ex. C1-T1-S2 Table 1.

Note 10 Includes related costs of issuance/redemption and the amortization of debt discount or premium.

Note 11 See Ex. C1-T1-S2 Table 9 for effective interest rate.

Note 12 Other Long-Term Debt Provision

New Issues	Effective Rate
Issue 17	5.44%
Issue 18	5.53%
Issue 19	5.31%
Niagara 2	5.10%
Niagara 3	5.09%
Average Rate	5.29%

Table 3
Capitalization and Cost of Capital
Summary of Existing Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2008

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 and 2 Redeemed During 2007						**(Note 9)**	
1	**Issue 3**	1	44.9			3/22/2008	5.90%	2.7
2	**Issue 4**	2	145.8			9/22/2008	5.90%	8.6
3	**Issue 5**		175.0			3/22/2009	6.01%	10.5
4	**Issue 6**		175.0			9/22/2009	6.01%	10.5
5	**Issue 7**	7	187.5			3/22/2010	6.60%	12.4
6	**Issue 8**	7	187.5			9/22/2010	6.60%	12.4
7	**Issue 9**	7	187.5			3/22/2011	6.65%	12.5
8	**Issue 10**	7	187.5			9/22/2011	6.65%	12.5
9	**Issue 11**		100.0	3/22/2005	5.0	3/22/2010	5.49%	5.5
10	**Issue 12**		150.0	3/22/2005	5.0	3/22/2010	5.71%	8.6
11	**Issue 13**		100.0	9/22/2005	5.0	9/22/2010	5.49%	5.5
12	**Issue 14**		150.0	9/22/2005	5.0	9/22/2010	5.71%	8.6
13	**Issue 15**		95.0	3/22/2005	5.0	3/22/2010	5.62%	5.3
14	**Issue 16**		400.0	4/29/2005	7.0	4/30/2012	5.72%	22.9
15	**Issue 17**		100.0	6/22/2007	10.0	6/22/2017	5.44%	5.4
16	**Issue 18**	10	200.0	9/24/2007	10.0	9/22/2017	5.53%	11.1
17	**Issue 19**		400.0	12/21/2007	9.8	9/22/2017	5.31%	21.2
18	**Issue 20**	3,10,11	155.6	3/22/2008	10.0	3/22/2018	5.35%	8.3
19	**Total**		3,141.3				5.87%	184.4
	Regulated Portion of Company-Wide Borrowing							
20	**Allocation**	8	1,740.7				5.87%	102.2
	Project Financing--Regulated Projects							
21	**Niagara 1**		160.0	10/22/2006	10.0	10/22/2016	5.23%	8.4
22	**Niagara 2**		50.0	1/22/2007	10.0	1/22/2017	5.10%	2.5
23	**Niagara 3**		30.0	4/23/2007	10.0	4/22/2017	5.09%	1.5
24	**Niagara 4**	4, 11	37.7	1/22/2008	10.0	1/22/2018	5.53%	2.1
25	**Niagara 5**	5, 11	20.8	4/22/2008	10.0	4/22/2018	5.90%	1.2
26	**Niagara 6**	6, 11	13.3	7/22/2008	10.0	7/22/2018	5.87%	0.8
27	**Total**		311.8				5.30%	16.5
	Total Regulated Long-Term Debt							
28	Line 20+27		2,052.5				5.78%	118.7

See Ex. C1-T1-S2 Table 3a for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 3a
Capitalization and Cost of Capital
Summary of Existing Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2008
Notes to Ex. C1, Tab 1, Sch. 2, Table 3

	Issue	Issue/Redemption Date	Face Value ($M)	Effective Days	Weighted Principal ($M)	New Issues Effectiive Rates
Note 1	Issue 3	3/22/2008	200.0	82.0	44.9	
Note 2	Issue 4	9/22/2008	200.0	266.0	145.8	
Note 3	Issue 20	3/22/2008	200.0	284.0	155.6	5.35%
Note 4	Niagara 4	1/22/2008	40.0	344.0	37.7	5.53%
Note 5	Niagara 5	4/22/2008	30.0	253.0	20.8	5.90%
Note 6	Niagara 6	7/22/2008	30.0	162.0	13.3	5.87%
	See Ex. C1-T1-S2 Table 8 for effective interest rates for Project Related Debt. See Ex C1-T1-S2 Table 9 for effective interest rates for non-Project Debt					

Note 7 Issues 7, 8, 9 and 10 are subordinated debt issues.
Note 8 Allocation ratio for 2008 described in Ex. C1-T1-S2 Table 1.
Note 9 Includes related costs of issuance/redemption and the amortization of debt discount or premium.
Note 10 See Ex. C1-T1-S2 Table 9 for effective interest rate.
Note 11 Other Long-Term Debt Provision

New Issues	Effective Rate
Issue 20	5.35%
Niagara 4	5.53%
Niagara 5	5.90%
Niagara 6	5.87%
Average Rate	5.66%

Numbers may not add due to rounding.

Table 4
Capitalization and Cost of Capital
Summary of Existing Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2009

Line No.	Issue	Note	Weighted Principal* ($M)	Issue/Redemption Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 and 2 Redeemed During 2007							
	Issues 3 and 4 Redeemed During 2008						**(Note 10)**	
1	**Issue 5**	1	38.8			3/22/2009	6.01%	2.3
2	**Issue 6**	2	127.1			9/22/2009	6.01%	7.6
3	**Issue 7**	8	187.5			3/22/2010	6.60%	12.4
4	**Issue 8**	8	187.5			9/22/2010	6.60%	12.4
5	**Issue 9**	8	187.5			3/22/2011	6.65%	12.5
6	**Issue 10**	8	187.5			9/22/2011	6.65%	12.5
7	**Issue 11**		100.0	3/22/2005		3/22/2010	5.49%	5.5
8	**Issue 12**		150.0	3/22/2005		3/22/2010	5.71%	8.6
9	**Issue 13**		100.0	9/22/2005		9/22/2010	5.49%	5.5
10	**Issue 14**		150.0	9/22/2005		9/22/2010	5.71%	8.6
11	**Issue 15**		95.0	3/22/2005		3/22/2010	5.62%	5.3
12	**Issue 16**		400.0	4/29/2005		4/30/2012	5.72%	22.9
13	**Issue 17**		100.0	6/22/2007		6/22/2017	5.44%	5.4
14	**Issue 18**	11	200.0	9/24/2007		9/22/2017	5.53%	11.1
15	**Issue 19**		400.0	12/21/2007		9/22/2017	5.31%	21.2
16	**Issue 20**	11	200.0	3/22/2008		3/22/2018	5.35%	10.7
17	**Issue 21**	3, 12	77.8	3/22/2009		3/22/2019	5.65%	4.4
18	**Total**		2,888.7				5.84%	168.8
	Regulated Portion of Company-Wide Borrowing							
19	Allocation	9	1,602.2				5.84%	93.6
	Project Financing--Regulated Projects							
20	**Niagara 1**		160.0	10/22/2006		10/22/2016	5.23%	8.4
21	**Niagara 2**		50.0	1/22/2007		1/22/2017	5.10%	2.5
22	**Niagara 3**		30.0	4/23/2007		4/22/2017	5.09%	1.5
23	**Niagara 4**		40.0	1/22/2008		1/22/2018	5.53%	2.2
24	**Niagara 5**		30.0	4/22/2008		4/22/2018	5.90%	1.8
25	**Niagara 6**		30.0	7/22/2008		7/22/2018	5.87%	1.8
26	**Niagara 7**	4, 12	28.2	1/22/2009		1/22/2019	8.41%	2.4
27	**Niagara 8**	5, 12	24.3	4/22/2009		4/22/2019	7.71%	1.9
28	**Niagara 9**	6, 12	15.5	7/22/2009		7/22/2019	6.41%	1.0
29	**Niagara 10**	7, 12	9.6	10/22/2009		10/22/2019	5.63%	0.5
30	**Total**		417.6				5.74%	24.0
	Total Regulated Long-Term Debt							
31	Line 19+30		2,019.8				5.82%	117.5

See Ex. C1-T1-S2 Table 4a for notes
* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 4a
Capitalization and Cost of Capital
Summary of Existing Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2009
Notes to Ex. C1, Tab 1, Sch. 2, Table 4

	Issue	Issue/Redemption Date	Face Value ($M)	Effective Days	Weighted Principal ($M)	New Issues Effectiive Rates
Note 1	Issue 5:	3/22/2009	175	81.0	38.8	
Note 2	Issue 6:	9/22/2009	175	265.0	127.1	
Note 3	Issue 21:	3/22/2009	100	284.0	77.8	5.65%
Note 4	Niagara 7	1/22/2009	30	343.0	28.2	8.41%
Note 5	Niagara 8	4/22/2009	35	253.0	24.3	7.71%
Note 6	Niagara 9	7/22/2009	35	162.0	15.5	6.41%
Note 7	Niagara 10	10/22/2009	50	70.0	9.6	5.63%
	See Ex. C1-T1-S2 Table 8 for effective interest rates for Project Related Debt. No hedging occurred in 2009 for non-project related debt.					

Note 8 Issues 7, 8, 9 and 10 are subordinated debt issues.

Note 9 Allocation ratio for 2009 described in Ex. C1-T1-S2 Table 1.

Note 10 Includes related costs of issuance/redemption and the amortization of debt discount or premium.

Note 11 See Ex. C1-T1-S2 Table 9 for effective interest rate.

Note 12 Other Long-Term Debt Provision

New Issues	Effective Rate
Issue 21:	5.65%
Niagara 7	8.41%
Niagara 8	7.71%
Niagara 9	6.41%
Niagara 10	5.63%
Average Rate	6.76%

Numbers may not add due to rounding.

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Exhibit C1
Tab 1
Schedule 2
Table 5

Table 5
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2010

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 and 2 Redeemed During 2007							
	Issues 3 and 4 Redeemed During 2008							
	Issues 5 and 6 Redeemed During 2009						**(Note 16)**	
1	**Issue 7**	1, 14	41.6			3/22/2010	6.60%	2.7
2	**Issue 8**	2, 14	136.1			9/22/2010	6.60%	9.0
3	**Issue 9**	3, 14	187.5			3/22/2011	6.65%	12.5
4	**Issue 10**	4, 14	187.5			9/22/2011	6.65%	12.5
5	**Issue 11**	5	22.2	3/22/2005		3/22/2010	5.49%	1.2
6	**Issue 12**	6	33.3	3/22/2005		3/22/2010	5.71%	1.9
7	**Issue 13**	7	72.6	9/22/2005		9/22/2010	5.49%	4.0
8	**Issue 14**	8	108.9	9/22/2005		9/22/2010	5.71%	6.2
9	**Issue 15**	9	69.0	3/22/2005		3/22/2010	5.62%	3.9
10	**Issue 16**		400.0	4/29/2005		4/30/2012	5.72%	22.9
11	**Issue 17**		100.0	6/22/2007	10.0	6/22/2017	5.44%	5.4
12	**Issue 18**	17	200.0	9/24/2007	10.0	9/22/2017	5.53%	11.1
13	**Issue 19**		400.0	12/21/2007	9.8	9/22/2017	5.31%	21.2
14	**Issue 20**	17	200.0	3/22/2008	10.0	3/22/2018	5.35%	10.7
15	**Issue 21**		100.0	3/22/2009	10.0	3/22/2019	5.65%	5.7
16	**Issue 22**	18	412.4	3/22/2010	10.0	3/22/2020	5.06%	20.9
17	**Issue 23**	18	82.2	9/22/2010	10.0	9/22/2020	5.10%	4.2
18	**Total**		2,753.3				5.66%	155.9
	Regulated Portion of Company-Wide Borrowing							
19	**Allocation**	15	1,527.1				5.66%	86.4
	Project Financing--Regulated Projects							
20	**Niagara 1**		160.0	10/22/2006	10.0	10/22/2016	5.23%	8.4
21	**Niagara 2**		50.0	1/22/2007	10.0	1/22/2017	5.10%	2.5
22	**Niagara 3**		30.0	4/23/2007	10.0	4/22/2017	5.09%	1.5
23	**Niagara 4**		40.0	1/22/2008	10.0	1/22/2018	5.53%	2.2
24	**Niagara 5**		30.0	4/22/2008	10.0	4/22/2018	5.90%	1.8
25	**Niagara 6**		30.0	7/22/2008	10.0	7/22/2018	5.87%	1.8
26	**Niagara 7**		30.0	1/22/2009	10.0	1/22/2019	8.41%	2.5
27	**Niagara 8**		35.0	4/22/2009	10.0	4/22/2019	7.71%	2.7
28	**Niagara 9**		35.0	7/22/2009	10.0	7/22/2019	6.41%	2.2
29	**Niagara 10**		50.0	10/22/2009	10.0	10/22/2019	5.63%	2.8
30	**Niagara 11**	10,18	47.0	1/22/2010	10.0	1/22/2020	5.60%	2.6
31	**Niagara 12**	11,18	45.1	4/22/2010	10.0	4/22/2020	6.02%	2.7
32	**Niagara 13**	12,18	15.5	7/22/2010	10.0	7/22/2020	5.71%	0.9
33	**Niagara 14**	13,18	9.6	10/22/2010	10.0	10/22/2020	5.07%	0.5
34	**Total**		607.2				5.79%	35.2
	Total Regulated Funded Long-Term Debt							
35	(line 19+34)		2,134.3				5.70%	121.6

See Ex. C1-T1-S2 Table 5a for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Numbers may not add due to rounding.

Table 5a
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2010
Notes to Ex. C1, Tab 1, Sch. 2, Table 5

	Issue	Issue/Redemption Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1	Issue 7	3/22/2010	187.5	81.0	41.6
Note 2	Issue 8	9/22/2010	187.5	265.0	136.1
Note 3	Issue 11	3/22/2010	100.0	81.0	22.2
Note 4	Issue 12	3/22/2010	150.0	81.0	33.3
Note 5	Issue 13	9/22/2010	100.0	265.0	72.6
Note 6	Issue 14	9/22/2010	150.0	265.0	108.9
Note 7	Issue 15	3/22/2010	95.0	265.0	69.0
Note 8	Issue 22	3/22/2010	530.0	284.0	412.4
Note 9	Issue 23	9/22/2010	300.0	100.0	82.2
Note 10	Niagara 11	1/22/2010	50.0	343.0	47.0
Note 11	Niagara 12	4/22/2010	65.0	253.0	45.1
Note 12	Niagara 13	7/22/2010	35.0	162.0	15.5
Note 13	Niagara 14	10/22/2010	50.0	70.0	9.6
	See Ex. C1-T1-S2 Table 10 for effective interest rate for Niagara issues 11-14.				

Note 14 Issues 7, 8, 9 and 10 are subordinated debt issues.
Note 15 Allocation ratio for 2009 described in Ex. C1-T1-S2 Table 1.
Note 16 Includes related costs of issuance/redemption and the amortization of debt discount or premium.
Note 17 See Ex. C1-T1-S2 Table 9 for effective interest rate.
Note 18 Future issue rate reference global insight (December 2009) & Interest Rate Hedges

Issue 22

GOC & OPG Spread		Swap Rate+106bps	Effective Rate
GOC Q1-10	3.80%	n/a	
OPG spread	1.26%	1.06%	
	5.06%	1.06%	5.06%
	530.0	0.0	

Issue 23

GOC & OPG Spread		Swap Rate+106bps	Effective Rate
GOC Q3-10	3.84%	n/a	
OPG Spread	1.26%	1.06%	
	5.10%	1.06%	5.10%
	300.0	0.0	

Niagara 11

GOC & OPG Spread		Swap Rate+106bps	Effective Rate
GOC Q1-10	3.80%	4.54%	
OPG spread	1.26%	1.06%	
	5.06%	5.60%	5.60%
	0.0	50.0	

Niagara 12

GOC & OPG Spread		Swap Rate+106bps	Effective Rate
GOC Q2-10	3.83%	4.96%	
OPG Spread	1.26%	1.06%	
	5.09%	6.02%	6.02%
	0.0	65.0	

Niagara 13

GOC & OPG Spread		Swap Rate+106bps	Effective Rate
GOC Q3-10	3.84%	4.90%	
OPG Spread	1.26%	1.06%	
	5.10%	5.96%	5.71%
	10.0	25.0	

Niagara 14

GOC & OPG Spread		Swap Rate+106bps	Effective Rate
GOC Q4-10	3.87%	3.99%	
OPG Spread	1.26%	1.06%	
	5.13%	5.05%	5.07%
	10.0	40.0	

Table 6
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2011

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Coupon Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 and 2 Redeemed During 2007							
	Issues 3 and 4 Redeemed During 2008							
	Issues 5 and 6 Redeemed During 2009							
	Issues 7, 8, 11, 12, 13, 14, 15 Redeemed During 2010						**(Note 10)**	
1	**Issue 9**	1	41.6			3/22/2011	6.65%	2.8
2	**Issue 10**	2	136.1			9/22/2011	6.65%	9.1
8	**Issue 16**		400.0	4/29/2005		4/30/2012	5.72%	22.9
9	**Issue 17**		100.0	6/22/2007	10.0	6/22/2017	5.44%	5.4
10	**Issue 18**	11	200.0	9/24/2007	10.0	9/22/2017	5.53%	11.1
11	**Issue 19**		400.0	12/21/2007	9.8	9/22/2017	5.31%	21.2
12	**Issue 20**	11	200.0	3/22/2008	10.0	3/22/2018	5.35%	10.7
13	**Issue 21**		100.0	3/22/2009	10.0	3/22/2019	5.65%	5.7
14	**Issue 22**		530.0	3/22/2010	10.0	3/22/2020	5.06%	26.8
15	**Issue 23**		300.0	9/22/2010	10.0	9/22/2020	5.10%	15.3
16	**Issue 24**	3,12	116.7	3/22/2011	10.0	3/22/2021	5.20%	6.1
17	**Issue 25**	4,12	41.1	9/22/2011	10.0	9/22/2021	5.45%	2.2
18	**Total**		2,565.5				5.43%	139.2
	Regulated Portion of Company-Wide Borrowing							
19	**Allocation**	9	1,423.0				5.43%	77.3
	Project Financing - Regulated Projects							
20	**Niagara 1**		160.0	10/22/2006	10.0	10/22/2016	5.23%	8.4
21	**Niagara 2**		50.0	1/22/2007	10.0	1/22/2017	5.10%	2.5
22	**Niagara 3**		30.0	4/23/2007	10.0	4/22/2017	5.09%	1.5
23	**Niagara 4**		40.0	1/22/2008	10.0	1/22/2018	5.53%	2.2
24	**Niagara 5**		30.0	4/22/2008	10.0	4/22/2018	5.90%	1.8
25	**Niagara 6**		30.0	7/22/2008	10.0	7/22/2018	5.87%	1.8
26	**Niagara 7**		30.0	1/22/2009	10.0	1/22/2019	8.41%	2.5
27	**Niagara 8**		35.0	4/22/2009	10.0	4/22/2019	7.71%	2.7
28	**Niagara 9**		35.0	7/22/2009	10.0	7/22/2019	6.41%	2.2
29	**Niagara 10**		50.0	10/22/2009	10.0	10/22/2019	5.63%	2.8
30	**Niagara 11**		50.0	1/22/2010	10.0	1/22/2020	5.60%	2.8
31	**Niagara 12**		65.0	4/22/2010	10.0	4/22/2020	6.02%	3.9
32	**Niagara 13**		35.0	7/22/2010	10.0	7/22/2020	5.71%	2.0
33	**Niagara 14**		50.0	10/22/2010	10.0	10/22/2020	5.07%	2.5
34	**Niagara 15**	5,12	70.5	1/22/2011	10.0	1/22/2021	5.28%	3.7
35	**Niagara 16**	6,12	52.0	4/22/2011	10.0	4/22/2021	5.39%	2.8
36	**Niagara 17**	7,12	33.3	7/22/2011	10.0	7/22/2021	5.54%	1.8
37	**Niagara 18**	8,12	14.4	10/22/2011	10.0	10/22/2021	5.63%	0.8
38	**Total**		860.1				5.68%	48.9
	Total Regulated Funded Long-Term Debt							
39	(line 19+38)		2,283.1				5.53%	126.2

See Ex. C1-T1-S2 Table 6a for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 6a
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2011
Notes to Ex. C1, Tab 1, Sch. 2, Table 6

Also see notes on Ex. C1-T2-S2 Table 5b		Issue/Redemption Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1	Issue 9:	3/22/2011	187.5	81.0	41.6
Note 2	Issue 10:	9/22/2011	187.5	265.0	136.1
Note 3	Issue 24	3/22/2011	150.0	284.0	116.7
Note 4	Issue 25	9/22/2011	150.0	100.0	41.1
Note 5	Niagara 15	1/22/2011	75.0	343.0	70.5
Note 6	Niagara 16	4/22/2011	75.0	253.0	52.0
Note 7	Niagara 17	7/22/2011	75.0	162.0	33.3
Note 8	Niagara 18	10/22/2011	75.0	70.0	14.4
	See Ex. C1-T1-S2 Table 10 for effective interest rate for Niagara issues 15-18.				

Note 9 Allocation ratio for 2009 described in Ex. C1-T1-S2 Table 1.
Note 10 Includes related costs of issuance/redemption and the amortization of debt discount or premium.
Note 11 See Ex. C1-T1-S2 Table 9 for effective interest rate.
Note 12 Future issue rate reference global insight (December 2009) & Interest Rate Hedges

Issue 24

GOC & OPG Spread		Swap Rate+106bps	Effective Rate
GOC Q1-11	3.94%	n/a	
OPG spread	1.26%	1.06%	
	5.20%	1.06%	5.20%
	150.0	0.0	

Issue 25

GOC & OPG Spread		Swap Rate+106bps	Effective Rate
GOC Q3-11	4.19%	n/a	
OPG spread	1.26%	1.06%	
	5.45%	1.06%	5.45%
	150.0	0.0	

Niagara 15

GOC & OPG Spread		Swap Rate+106bps	Effective Rate
GOC Q1-11	3.94%	4.29%	
OPG spread	1.26%	1.06%	
	5.20%	5.35%	5.28%
	35.0	40.0	

Niagara 16

GOC & OPG Spread		Swap Rate+106bps	Effective Rate
GOC Q2-11	4.08%	4.40%	
OPG Spread	1.26%	1.06%	
	5.34%	5.46%	5.39%
	40.0	35.0	

Niagara 17

GOC & OPG Spread		Swap Rate+106bps	Effective Rate
GOC Q3-11	4.19%	4.53%	
OPG Spread	1.26%	1.06%	
	5.45%	5.59%	5.54%
	25.0	50.0	

Niagara 18

GOC & OPG Spread		Swap Rate+106bps	Effective Rate
GOC Q4-11	4.38%	4.56%	
OPG Spread	1.26%	1.06%	
	5.64%	5.62%	5.63%
	15.0	60.0	

Table 7
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2012

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Coupon Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 and 2 Redeemed During 2007							
	Issues 3 and 4 Redeemed During 2008							
	Issues 5 and 6 Redeemed During 2009							
	Issues 7, 8, 11, 12, 13, 14, 15 Redeemed During 2010							
	Issues 9 and 10 Redeemed During 2011						**(Note 9)**	
6	**Issue 16**	1	132.6	4/29/2005		4/30/2012	5.72%	7.6
7	**Issue 17**		100.0	6/22/2007		6/22/2017	5.44%	5.4
8	**Issue 18**	10	200.0	9/24/2007		9/22/2017	5.53%	11.1
9	**Issue 19**		400.0	12/21/2007		9/22/2017	5.31%	21.2
10	**Issue 20**	10	200.0	3/22/2008		3/22/2018	5.35%	10.7
11	**Issue 21**		100.0	3/22/2009		3/22/2019	5.65%	5.7
12	**Issue 22**		530.0	3/22/2010		3/22/2020	5.06%	26.8
13	**Issue 23**		300.0	9/22/2010		9/22/2020	5.10%	15.3
14	**Issue 24**		150.0	3/22/2011		3/22/2021	5.20%	7.8
15	**Issue 25**		150.0	9/22/2011		9/22/2021	5.45%	8.2
16	**Issue 26**	2,11	116.7	3/22/2012	10.0	3/22/2022	5.94%	6.9
17	**Issue 27**	3,11	41.1	9/22/2012	10.0	9/22/2022	5.94%	2.4
18	**Total**		2,420.4				5.34%	129.2
	Regulated Portion of Company-Wide Borrowing							
19	**Allocation**	8	1,342.5				5.34%	71.7
	Project Financing - Regulated Projects							
20	**Niagara 1**		160.0	10/22/2006		10/22/2016	5.23%	8.4
21	**Niagara 2**		50.0	1/22/2007		1/22/2017	5.10%	2.5
22	**Niagara 3**		30.0	4/23/2007		4/22/2017	5.09%	1.5
23	**Niagara 4**		40.0	1/22/2008		1/22/2018	5.53%	2.2
24	**Niagara 5**		30.0	4/22/2008		4/22/2018	5.90%	1.8
25	**Niagara 6**		30.0	7/22/2008		7/22/2018	5.87%	1.8
26	**Niagara 7**		30.0	1/22/2009		1/22/2019	8.41%	2.5
27	**Niagara 8**		35.0	4/22/2009		4/22/2019	7.71%	2.7
28	**Niagara 9**		35.0	7/22/2009		7/22/2019	6.41%	2.2
29	**Niagara 10**		50.0	10/22/2009		10/22/2019	5.63%	2.8
30	**Niagara 11**		50.0	1/22/2010		1/22/2020	5.60%	2.8
31	**Niagara 12**		65.0	4/22/2010		4/22/2020	6.02%	3.9
32	**Niagara 13**		35.0	7/22/2010		7/22/2020	5.71%	2.0
33	**Niagara 14**		50.0	10/22/2010		10/22/2020	5.07%	2.5
34	**Niagara 15**		75.0	1/22/2011		1/22/2021	5.28%	4.0
35	**Niagara 16**		75.0	4/22/2011		4/22/2021	5.39%	4.0
36	**Niagara 17**		75.0	7/22/2011		7/22/2021	5.54%	4.2
37	**Niagara 18**		75.0	10/22/2011		10/22/2021	5.63%	4.2
38	**Niagara 19**	4,11	70.7	1/22/2012		1/22/2022	5.73%	4.0
39	**Niagara 20**	5,11	52.0	4/22/2012		4/22/2022	5.80%	3.0
40	**Niagara 21**	6,11	33.3	7/22/2012		7/22/2022	5.85%	1.9
41	**Niagara 22**	7,11	14.4	10/22/2012		10/22/2022	5.93%	0.9
42	**Total**		1,160.3				5.68%	66.0
	Total Regulated Funded Long-Term Debt							
43	(line 19+42)		2,502.8				5.50%	137.6

See Ex. C1-T1-S2 Table 7a for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Numbers may not add due to rounding.

Table 7a
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2012
Notes to Ex. C1, Tab 1, Sch. 2, Table 7

		Issue/Redemption Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1	Issue 16	4/30/2012	400.0	121.0	132.6
Note 2	Issue 26	3/22/2012	150.0	284.0	116.7
Note 3	Issue 27	9/22/2012	150.0	100.0	41.1
Note 4	Niagara 19	1/22/2012	75.0	344.0	70.7
Note 5	Niagara 20	4/22/2012	75.0	253.0	52.0
Note 6	Niagara 21	7/22/2012	75.0	162.0	33.3
Note 7	Niagara 22	10/22/2012	75.0	70.0	14.4
	See Ex. C1-T1-S2 Table 10 for effective interest rate for Niagara issues 19-22.				

Note 8 Allocation ratio for 2009 described in Ex. C1-T1-S2 Table 1.
Note 9 Includes related costs of issuance/redemption and the amortization of debt discount or premium.
Note 10 See Ex. C1-T1-S2 Table 9 for effective interest rate.
Note 11 Future issue rate reference global insight (December 2009) & Interest Rate Hedges.

Issue 26

GOC & OPG Spread		Swap Rate+106bps	Effective Rate
GOC 2012	4.68%	n/a	
OPG spread	1.26%	1.06%	
	5.94%	1.06%	5.94%
	150.0	0.0	

Issue 27

GOC & OPG Spread		Swap Rate+106bps	Effective Rate
GOC 2012	4.68%	n/a	
OPG Spread	1.26%	1.06%	
	5.94%	1.06%	5.94%
	150.0	0.0	

Niagara 19

GOC & OPG Spread		Swap Rate+106bps	Effective Rate
GOC 2012	4.68%	4.48%	
OPG spread	1.26%	1.06%	
	5.94%	5.54%	5.73%
	35.0	40.0	

Niagara 20

GOC & OPG Spread		Swap Rate+106bps	Effective Rate
GOC 2012	4.68%	4.58%	
OPG Spread	1.26%	1.06%	
	5.94%	5.64%	5.80%
	40.0	35.0	

Niagara 21

GOC & OPG Spread		Swap Rate+106bps	Effective Rate
GOC 2012	4.68%	4.72%	
OPG Spread	1.26%	1.06%	
	5.94%	5.78%	5.85%
	30.0	45.0	

Niagara 22

GOC & OPG Spread		Swap Rate+106bps	Effective Rate
GOC 2012	4.68%	4.86%	
OPG Spread	1.26%	1.06%	
	5.94%	5.92%	5.93%
	45.0	30.0	

Numbers may not add due to rounding.

Table 8
Capitalization and Cost of Capital
Hedging Activity - Interest Rate Swap Agreements - Niagara Tunnel Project
Existing Debt Issues up to December 31, 2009

Line No.	Year	Deal	Amount ($)	Fixed Rate (%)	Deal Date	Underlying Bond FV ($)	Underlying Bond Issue Date[1]	Underlying Bond Maturity	Underlying Bond Rate	Impact ($)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**2006**	67631	25,000,000	4.986%	Jul 12, 06					(716,160)
2		67632	25,000,000	4.985%	Jul 12, 06					(704,442)
3		67633	25,000,000	4.980%	Jul 12, 06					(679,000)
4		67634	25,000,000	4.980%	Jul 12, 06					(688,000)
5		67635	25,000,000	4.980%	Jul 12, 06					(686,692)
6		67636	15,000,000	4.919%	Jul 24, 06					(349,970)
7			140,000,000	4.975%		160,000,000	10/23/2006	10/22/2016	4.99%	(3,824,264)
		Effective Rate[2]							5.23%	
8	**2007**	67637	30,000,000	4.663%	Nov 08, 05					(374,920)
9		67638	15,000,000	5.035%	Jul 13, 06					(635,193)
10			45,000,000	4.787%		50,000,000	1/22/2007	1/23/2017	4.89%	(1,010,113)
11		**Effective Rate[2]**							5.10%	
12		70594	20,000,000	4.680%	Nov 08, 05					(60,000)
13		70595	10,000,000	5.010%	Jul 21, 06					(292,700)
14			30,000,000	4.790%		30,000,000	4/23/2007	4/24/2017	4.97%	(352,700)
		Effective Rate[2]							5.09%	
22	**2008**	50931	25,000,000	4.749%	Nov 15, 05					(688,741)
23		60496	10,000,000	5.037%	Jul 27, 06					(555,960)
24			35,000,000	4.831%		40,000,000	1/22/2008	1/22/2018	5.22%	(1,244,701)
25		**Effective Rate**							5.53%	
26		50930	25,000,000	4.780%	Nov 15, 05					(1,083,000)
27		60284	5,000,000	5.090%	Jul 24, 06					(345,500)
28			30,000,000	4.832%		30,000,000	4/22/2008	4/22/2018	5.42%	(1,428,500)
29		**Effective Rate**							5.90%	
30		51231	25,000,000	4.680%	Nov 22, 05					(780,000)
31		60285	5,000,000	5.120%	Jul 24, 06					(342,000)
32			30,000,000	4.753%		30,000,000	7/22/2008	7/22/2018	5.50%	(1,122,000)
33		**Effective Rate**							5.87%	
37	**2009**	51227	25,000,000	4.747%	Nov 22, 05					(5,387,000)
38		60132	5,000,000	5.240%	Jul 19, 06					(1,301,000)
39			30,000,000	4.829%		30,000,000	1/22/2009	1/22/2019	6.18%	(6,688,000)
40		**Effective Rate**							8.41%	
41		50574	25,000,000	4.973%	Nov 04, 05					(4,940,000)
42		59751	10,000,000	5.360%	Jul 07, 06					(2,330,000)
43			35,000,000	5.084%		35,000,000	4/22/2009	4/22/2019	5.64%	(7,270,000)
44		**Effective Rate**							7.71%	
45		51233	25,000,000	4.790%	Nov 22, 05					(2,755,000)
46		60130	10,000,000	5.290%	Jul 19, 06					(1,536,000)
47			35,000,000	4.933%		35,000,000	7/22/2009	7/22/2019	5.18%	(4,291,000)
48		**Effective Rate**							6.41%	
49		51230	30,000,000	4.825%	Nov 22, 05					(3,150,000)
50		60232	5,000,000	5.233%	Jul 21, 06					(704,000)
51			35,000,000	4.883%		50,000,000	10/22/2009	10/22/2019	4.86%	(3,854,000)
52		**Effective Rate**							5.63%	
53	**Total**		445,000,000	4.896%		490,000,000			5.17%	(31,085,278)
54	**Effective Rate**								5.81%	

Notes:
1 The underlying bond issue date also corresponds to the maturity of the swap deals.
2 The Effective rate = underlying bond rate + $impact of the hedge settlement/ 10 years/ the notional value of the bond = h+ ((i)/10/(e)).

Numbers may not add due to rounding.

Table 9
Capitalization and Cost of Capital
Hedging Activity - Interest Rate Swap Agreements - Non Project Related
Existing Debt Issues up to December 31, 2009

Line No.	Year	Deal	Amount ($)	Fixed Rate (%)	Deal Date	Underlying Bond FV ($)	Underlying Bond Issue Date[1]	Underlying Bond Maturity	Underlying Bond Rate	Impact ($)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**2007**	70234	$25,000,000	4.659%	Apr 23, 07					458,250
2		70597	$25,000,000	4.650%	Apr 30, 07					475,800
3		71316	$25,000,000	4.875%	May 24, 07					37,050
4		72051	$25,000,000	5.265%	Jun 13, 07					(723,450)
5			100,000,000	4.862%		200,000,000	9/24/2007	9/22/2017	5.546%	247,650
6		**Effective Rate[2]**							5.534%	
7	**2008**	70458	25,000,000	4.650%	Apr 25, 07					(970,000)
8		70789	25,000,000	4.700%	May 07, 07					(1,065,000)
9		70916	25,000,000	4.690%	May 11, 07					(974,000)
10		71940	25,000,000	5.243%	Jun 08, 07					(2,165,019)
11			100,000,000	4.821%		200,000,000	3/24/2008	3/22/2018	5.090%	(5,174,019)
12		**Effective Rate**							5.349%	
13	**Total**		200,000,000	4.842%		400,000,000			5.32%	(4,926,369)
14	**Effective Rate**								5.44%	

Notes:
1 The underlying bond issue date also corresponds to the maturity of the swap deals.
2 The Effective rate = underlying bond rate + $impact of the hedge settlement/ 10 years/ the notional value of the bond = h+ ((i)/10/(e)).

Numbers may not add due to rounding.

Table 10
Capitalization and Cost of Capital
Hedging Activity - Interest Rate Swap Agreements - Niagara Tunnel Project
Planned Debt Issues after December 31, 2009

Line No.	Year	Deal	Face Value	Mark-to-Market (12/31/09)	Fixed Rate (%)	Deal Date	Start Date	Maturity Date
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**2010**	51311	$20,000,000	($1,182,666)	4.790%	Nov 24, 05	Jan 22, 10	Jan 22, 20
2		60113	$10,000,000	($1,049,746)	5.330%	Jul 19, 06	Jan 22, 10	Jan 22, 20
3		106426	$20,000,000	$0	3.905%	Jan 04, 10	Jan 22, 10	Jan 22, 20
4			$50,000,000	($2,232,412)	4.544%			
5		51490	$25,000,000	($1,481,556)	4.875%	Nov 29, 05	Apr 22, 10	Apr 22, 20
6		51776	$15,000,000	($914,143)	4.895%	Dec 06, 05	Apr 22, 10	Apr 22, 20
7		51777	$15,000,000	($914,143)	4.895%	Dec 06, 05	Apr 22, 10	Apr 22, 20
8		60123	$10,000,000	($991,775)	5.350%	Jul 19, 06	Apr 22, 10	Apr 22, 20
9			$65,000,000	($4,301,618)	4.957%			
10		52078	$25,000,000	($1,132,860)	4.898%	Dec 14, 05	Jul 22, 10	Jul 22, 20
11			$25,000,000	($1,132,860)	4.898%			
12		104955	$25,000,000	$1,037,283	3.910%	Nov 25, 09	Oct 22, 10	Oct 22, 20
13		105646	$15,000,000	$359,512	4.123%	Dec 15, 09	Oct 22, 10	Oct 22, 20
14			$40,000,000	$1,396,795	3.990%			
15	**2011**	104331	$25,000,000	$479,786	4.310%	Nov 12, 09	Jan 24, 11	Jan 22, 21
16		105643	$15,000,000	$348,853	4.260%	Dec 15, 09	Jan 24, 11	Jan 22, 21
17			$40,000,000	$828,639	4.291%			
18		104393	$25,000,000	$419,349	4.408%	Nov 13, 09	Apr 26, 11	Apr 22, 21
19		105644	$10,000,000	$202,329	4.365%	Dec 15, 09	Apr 26, 11	Apr 22, 21
20			$35,000,000	$621,678	4.396%			
21		104454	$25,000,000	$681,595	4.400%	Nov 16, 09	Jul 22, 11	Jul 22, 21
22		106427	$25,000,000	$0	4.650%	Jan 04, 10	Jul 22, 11	Jul 22, 21
23			$50,000,000	$681,595	4.525%			
24		104508	$25,000,000	$739,727	4.420%	Nov 17, 09	Oct 24, 11	Oct 22, 21
25		105696	$15,000,000	$290,548	4.550%	Dec 16, 09	Oct 24, 11	Oct 22, 21
26		105876	$20,000,000	$69,814	4.752%	Dec 22, 09	Oct 24, 11	Oct 22, 21
27			$60,000,000	$1,100,089	4.563%			
28	**2012**	104659	$25,000,000	$738,302	4.500%	Nov 20, 09	Jan 23, 12	Jan 24, 22
29		105410	$15,000,000	$501,224	4.450%	Dec 08, 09	Jan 23, 12	Jan 24, 22
30			$40,000,000	$1,239,526	4.481%			
31		104763	$25,000,000	$778,418	4.530%	Nov 24, 09	Apr 23, 12	Apr 22, 22
32		105697	$10,000,000	$180,888	4.700%	Dec 16, 09	Apr 23, 12	Apr 22, 22
33			$35,000,000	$959,306	4.579%			
34		104765	$25,000,000	$891,888	4.550%	Nov 24, 09	Jul 23, 12	Jul 22, 22
35		106459	$20,000,000	$0	4.935%	Jan 05, 10	Jul 23, 12	Jul 22, 22
36			$45,000,000	$891,888	4.721%			
37		104958	$15,000,000	$528,313	4.600%	Nov 25, 09	Oct 22, 12	Oct 24, 22
38		106277	$15,000,000	($57,971)	5.122%	Dec 29, 09	Oct 22, 12	Oct 24, 22
39			$30,000,000	$470,342	4.861%			
40	**2013**	105043	$10,000,000	$392,453	4.600%	Nov 26, 09	Jan 22, 13	Jan 23, 23
41		105002	$10,000,000	$377,663	4.620%	Nov 26, 09	Jan 22, 13	Jan 23, 23
42			$20,000,000	$770,116	4.610%			
43		105412	$20,000,000	$557,681	4.800%	Dec 08, 09	Apr 22, 13	Apr 24, 23
44			$20,000,000	$557,681	4.800%			
45	**Total**		**$555,000,000**	**$1,850,765**	**4.582%**			

COST OF SHORT-TERM DEBT

1.0 PURPOSE

This evidence provides the details of OPG's annual short-term borrowing and associated costs for the test period determined using the methodology approved by the OEB in EB-2007-0905. It also provides actual short-term debt costs for 2007 - 2009 and budgeted costs for 2010.

2.0 DESCRIPTION OF SHORT-TERM DEBT

The short-term debt component of OPG's capital structure reflects its forecast amount of short-term borrowings, and the cost of capital reflects its forecast short-term borrowing cost.

OPG's short-term debt is comprised of the same two main sources of short-term financing described in EB-2007-0905 at Ex C1-T2-S3. OPG's commercial paper program and accounts receivable securitization program remain its two main sources of short-term financing.

OPG's commercial paper program is used to fund intra-month working capital requirements. OPG expects to continue to use this source of financing in 2011 and 2012. OPG borrowed, on a daily basis, an average of $30.9M in 2007, $1M 2008 and $17.2M in 2009. OPG forecasts that a daily average borrowing of $43M is required to finance OPG's normalized intra-month working capital requirements in the test period.

In addition, the bank credit facility continues to be used primarily as the backstop to the commercial paper program. In the event that OPG is required to draw on the bank credit facility, it provides OPG with the ability to borrow by way of bankers' acceptances if OPG is unable to re-issue its commercial paper in the market place. The bank facility is $1B in size, comprised of a $500M 364-day tranche and a $500M multi-year tranche commencing May 2008 and expiring May 2013 as was discussed in EB-2007-0905. Three years of the five-year tranche remain.

OPG's other primary source of short-term financing is its accounts receivable securitization program with the Royal Bank of Canada, under which it sold $300M of receivables from January 2007 to April 2009, at which point the amount was reduced to $250M. The accounts receivable securitization program is in effect until 2010, but OPG expects to continue this program after 2010. OPG's forecast reflects continued borrowing of $250M under this program throughout the 2011 - 2012 test period.

The $250M is a portion of the month-end accounts receivable balance owing to OPG from the IESO for the prior month (OPG's month-end accounts receivable balances have ranged from $308M to $544M during the period January 2007 to April 2009). The accounts receivable securitization balance of $250M rolls over on a monthly basis and is supported by the amount of the IESO monthly payment. By selling its receivables, OPG is in essence borrowing money in advance of the monthly receipt from the IESO and the interest is the cost of that borrowed money. Under this program OPG continues to service the receivables and pays a short-term cost of funds on a monthly basis to an independent trust.

3.0 SHORT-TERM DEBT COST

As described in EB-2007-0905, OPG's borrowing rate under the commercial paper program is market-based, comprised of a 10 basis point dealer fee and a corporate spread over the bankers' acceptances rate for OPG.

There has been significant credit tightening since August 2007 causing short-term borrowing cost on bankers' acceptances to increase. The indicative corporate spread on OPG's short-term borrowings increased from 3 basis points to 20 basis points in the latter part of 2007. The market has normalized over the 2008 - 2009 period and the spread is currently priced around 5 basis points over bankers' acceptance. OPG's forecast over the test period is based on the current corporate spread of 5 basis points.

OPG has used the Global Insight forecast as the basis for the bankers' acceptances interest rate forecast after adjusting for the spread differential between bankers' acceptances and the yield on treasury securities. For 2010 the bankers' acceptances rate used is 0.46 per cent, for 2011 it is 1.79 per cent and for 2012 it is 3.28 per cent.

The pricing under the bank credit facility is market-based, and subject to OPG's credit rating, the amount drawn and the term of the financing. Amounts are drawn first under the 364-day tranche and then under the multi-year tranche. Based on OPG's current credit rating of A-, if the 364-day tranche is drawn in excess of 66 per cent of the total amount of this tranche ($0.5B), the margin added to the bankers' acceptance rate is 200 basis points (i.e., 2.0 per cent) otherwise the margin is 190 basis points for this tranche. If the multi-year tranche (three year remaining term) is drawn in excess of 50 per cent (i.e., 50 per cent of $0.5B), the margin added to the bankers' acceptance rate is 55 basis points (i.e., 0.55 per cent) otherwise the margin is 50 basis points.

The cost of borrowing under the bank credit facility is more expensive than either OPG's commercial paper or securitization program. OPG did not borrow funds through this facility in 2007, 2008 or 2009 and has not forecast borrowing under this facility in 2010, 2011 or 2012. The bank credit facility is forecast to cost $4M in each of 2010, 2011 and 2012, which is $1.6M lower than the actual cost of $5.6M in 2009. Credit facility costs are expected to be maintained at this level reflecting the new norm in this market. As discussed in EB-2007-0905 Ex. C1-T2-S3, these costs are included with OPG's short term debt costs, as the bank credit facility is required to support OPG's commercial paper program.

The cost of the accounts receivable securitization program, consisting of the banker's acceptance rate for OPG plus a program fee of 0.775 per cent, is forecast to be $6.9M in 2011 and $10.6M in 2012. Although the accounts receivable securitization program is slightly more expensive than OPG's commercial paper program, it represents an alternative form of financing, and a more permanent component of OPG's short-term debt which does not fluctuate month to month.

The cost of borrowing over the bankers' acceptances rate has increased from nil to about 70 basis points on average over the 2007 to 2009 period and the spread is currently priced around 20 basis points over bankers' acceptance. OPG's forecast over the test period is based on the current corporate spread of 20 basis points.

From a liquidity perspective, the availability of different sources of financing provides flexibility in managing short term funding by allowing the borrower to manage use of their overall facilities. The securitization program allows OPG to diversify its source of liquidity at a reasonable cost.

Ex. C1-T1-S3 Table 2 summarizes OPG's forecast company-wide cost of short-term debt.

4.0 ALLOCATION TO REGULATED OPERATIONS

OPG has applied the allocation methodology approved by the OEB in EB-2007-0905. In summary, the ratio of the construction work in progress and non-cash working capital amounts (fuel inventory and materials/supplies) for OPG's regulated operations to the total construction work in progress and non-cash working capital amounts reported in OPG's audited financial statements is used as the basis for allocating company-wide short-term borrowing. This allocation ratio reflects OPG's use of short-term borrowing to finance its working capital requirements and to assist with managing the cash flow variability of capital projects.

For all company-wide, short-term borrowing prior to December 31, 2009, the allocation ratio is determined based on actual year-end values in that year. Consistent with the approach approved in EB-2007-0905, OPG is using the most recent actual audited information available at the time evidence was developed to determine the allocation factor for OPG's short-term debt for 2009 - 2012. OPG has used asset and liability balances from its last audited financial statements as this approach is consistent with the asset values that are readily available, the amounts are independently verified, the approach is simple and transparent. The allocation ratio has changed over the 2007 – 2009 time period, as reflected in Ex. C1-T1-S3 Table 1, owing to the changing relative proportion of construction work in progress ("CWIP") as the Niagara Tunnel project progressed. The 2009 ratio is representative of the ratio going forward.

The 2009 ratio of 64.7 per cent, described in Ex. C1-T1-S3 Table 1, was applied to OPG's short-term debt amount for 2009 - 2012 and the resulting short-term debt cost is reflected in the capitalization and cost of capital evidence provided in Ex. C1-T1-S1 Tables 1 - 4. The 2008 ratio of 56.3 per cent, described in Ex. C1-T1-S3 Table 1, was applied to OPG's short-term debt amount determined in Ex. C1-T1-S3 Table 2 for 2008 and the resulting short-term debt cost is reflected in the capitalization and cost of capital evidence provided in Ex. C1-T1-S1 Table 5. The 2007 ratio of 57.1 per cent, described in Ex. C1-T1-S3 Table 1, was applied to OPG's short-term debt amount determined in Ex. C1-T1-S3 Table 2 for 2007 and the resulting short-term debt cost is reflected in the capitalization and cost of capital evidence provided in Ex. C1-T1-S1 Table 6.

Table 1
Capitalization and Cost of Capital
Allocation of Existing Short-term Debt ($M)

Line No.	Asset	Amount ($M) 2007[1]	2008	2009
		(a)	(b)	(c)
	Company-Wide:			
1	**Adjusted Construction Work-In-Progress (CWIP)**	950.0	1,271.8	1,236.7
2	**Fuel**	604.3	736.0	837.3
3	**Materials/Supplies**	477.9	470.2	520.7
4	**CWIP + Non Cash Working Capital**	2,032.2	2,478.0	2,594.7
	Regulated Operations:			
5	**Adjusted Construction Work-In-Progress (CWIP)**	508.7	681.8	888.1
6	**Fuel[2]**	233.0	300.7	333.0
7	**Materials/Supplies[2]**	419.0	413.4	456.7
8	**CWIP + Non Cash Working Capital**	1,160.7	1,395.9	1,677.8
	Relative Ratio:			
9	**Regulated/Company-Wide Net Fixed Assets**	57.1%	56.3%	64.7%

Notes:
1 Provided for the purpose of the overall weighted average cost of capital at Ex. C1-T1-S1 Table 6.
2 Ex. B2-T5-S1 Table 1 (Regulated Hydroelectric) and Ex. B3-T5-S1 Table 1 (Nuclear).

Numbers may not add due to rounding.

Table 2
Capitalization and Cost of Capital
Summary of OPG's Actual and Forecast Cost of Short-term Debt ($M)

Line No.	Description	2007	2008	2009	2010	2011	2012
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Commercial Paper Amount**[1]	30.9	1.0	17.2	43.0	43.0	43.0
2	**Interest Rate**	4.35%	4.29%	0.31%	0.61%	1.94%	3.43%
3	**Commercial Paper Cost**	1.3	0.0	0.1	0.3	0.8	1.5
4	**A/R Securitization Amount**[1]	300.0	300.0	270.8	250.0	250.0	250.0
5	**Interest Rate**	4.98%	4.10%	1.66%	1.44%	2.77%	4.26%
6	**A/R Securitization Cost**	14.9	12.3	4.5	3.6	6.9	10.6
7	**Total Short-term Debt Amount**[1] (line 1 + line 4)	330.9	301.0	288.0	293.0	293.0	293.0
8	**Effective Interest Rate** ((line 3 + line 6) / line 7)	4.92%	4.10%	1.58%	1.31%	2.64%	4.13%
9	**Short-term Debt Interest Cost**	16.3	12.3	4.6	3.8	7.7	12.1
10	**Facility Cost**	1.3	1.4	5.6	4.0	4.0	4.0
11	**Total Short-term Debt Cost**	17.5	13.7	10.2	7.8	11.7	16.1
	Regulated Portion of Short-Term Debt						
12	**Allocation Factor**[2]	57.1%	56.3%	64.7%	64.7%	64.7%	64.7%
13	**Short Term Debt Amount** (line 7 x line 12)	189.0	169.6	186.2	189.5	189.5	189.5
14	**Short-term Debt Cost** (line 11 x line 12)	10.0	7.7	6.6	5.1	7.6	10.4

Notes:
1 Actual daily weighted average balance for 2008, 2009 and 2010.
Working Capital funding with commercial paper is assumed to be outstanding for the first 20 days of each month.
2 Allocation factor determined at Ex. C1-T1-S3 Table 1.

NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING – BACKGROUND INFORMATION

1.0 PURPOSE

This evidence provides background information regarding OPG's nuclear waste management and decommissioning activities and the financial management of the nuclear waste management and decommissioning liabilities.

2.0 OVERVIEW

The following specific aspects of nuclear waste management and decommissioning are discussed in this exhibit:

- A summary of the process by which nuclear waste is generated at OPG's generating stations, the different nuclear waste types and OPG's general approach to nuclear waste management. OPG's decommissioning responsibilities and role in the management of nuclear wastes at Pickering A and B Generating Stations ("Pickering"), Darlington Generating Station ("Darlington") and the Bruce Generating Station ("Bruce"), operated by Bruce Power L.P. are also summarized (section 2.0).
- The regulatory framework that applies to the financial management of nuclear waste management and decommissioning (section 3.0).
- A description of OPG's financial reference plan for nuclear waste management and decommissioning activities which provides the basis for determining OPG's nuclear liabilities and the current estimated values of these liabilities (section 4.0).

These items provide the necessary context for the subsequent explanation of the recovery of costs associated with the OPG's liabilities for decommissioning its nuclear stations (including Bruce) and nuclear used fuel and low and intermediate level waste management (collectively, the "nuclear liabilities") through the revenue requirement as described in Ex. C2-T1-S2.

2.0 NUCLEAR WASTE GENERATION AND DECOMMISSIONING

2.1 Nuclear Waste Types

In CANDU reactors, when a fuel bundle no longer contains enough fissionable uranium to heat water efficiently, it becomes used fuel and must be replaced.

Used fuel removed from OPG-owned reactors is radioactive and considered to be high level radioactive waste. Materials that have come into close contact with the reactors but which are less radioactive than used fuel, such as reactor components, ion exchange resins, filters used to keep reactor water systems clean and other structural material and reactor equipment, including pressure tubes, are considered to be intermediate level radioactive waste. A third category, low level radioactive waste, consists of materials that are used in connection with station operations such as tools, mop heads, and protective clothing. These items are less radioactive than intermediate level radioactive waste and can generally be handled without radiation shielding.

OPG is responsible for the ongoing, long-term management of all levels of radioactive wastes, including those from the Bruce facilities. As such, references in this exhibit to the nuclear facilities, includes all nuclear facilities owned by OPG (i.e., Pickering, Darlington, and Bruce).

2.2 Management of High Level Radioactive Wastes

Used fuel bundles are temporarily stored in water-filled pools at the nuclear generating stations for a “cooling-off” period of at least ten years, during which time their radioactivity and heat is substantially reduced. After a sufficient “cooling off” period, used fuel can be transferred from the wet bays to above-ground concrete canisters that are stored at each nuclear station site. This is referred to as dry storage.

In June 2007, Natural Resources Canada announced that the Government of Canada accepted a recommendation by the Nuclear Waste Management Organization (“NWMO”) in response to the Nuclear Fuel Waste Act (“NFWA”) for the safe, long-term management of used nuclear fuel. Additional details on the requirements of the NFWA and the work of the NWMO are discussed in section 3.4 of this exhibit.

2.3 Management of Low and Intermediate Level Radioactive Wastes

OPG's low level radioactive waste and intermediate level radioactive waste, collectively ("L&ILW"), is stored primarily at OPG's Western Waste Management Facility. This facility, situated at the Bruce nuclear site, is owned and operated by OPG and operates under licenses issued by the Canadian Nuclear Safety Commission ("CNSC") that are distinct from OPG's and Bruce Power's nuclear generator licenses that are issued by the CNSC.

An agreement has been reached with the Municipality of Kincardine and four surrounding municipalities for OPG to develop a deep geologic repository facility for the long-term placement of L&ILW adjacent to the Western Waste Management Facility. OPG has initiated a federal environmental assessment process in respect of this proposed facility. OPG's plan is for L&ILW to continue to be stored at the current facility while the deep geologic repository facility is planned and developed. The in-service date of the deep geologic repository facility is estimated to be 2018.

2.4 Decommissioning Overview

OPG will also manage radioactive wastes associated with the decommissioning of its nuclear generating stations, including Bruce A and Bruce B Generating Stations, after the end of their useful lives. When a nuclear facility is shut down permanently, the facility is initially placed in safe-store condition to protect the health and safety of workers, the public and the environment. Decommissioning involves activities undertaken to safely eliminate the radiological, chemical, and industrial hazards from the facility in order to release the site for other uses based on approved site release criteria.

OPG's current plans for decommissioning the nuclear generating stations are to remove fuel and heavy water from the reactors and place the station into a safe-store state. Safe-store activities have begun at Pickering A Units 2 and 3. The facility is then stored and monitored for 30 years to allow the residual radioactivity to decay. This will be followed by station dismantling and site restoration over a ten-year period. Used fuel will continue to be stored on site until the long-term management strategy for used fuel is implemented as documented in section 3.2.

As noted earlier, OPG also owns and operates radioactive waste management facilities on the Bruce site and used fuel storage facilities at the Pickering, Darlington and Bruce sites. OPG will decommission these waste facilities when they are permanently shut down. Decommissioning of OPG's radioactive waste management facilities will entail the removal, re-packaging (if required) and transporting of the waste to a long-term facility, dismantling of the facilities and site restoration.

The existing station decommissioning estimates were prepared by a U.S.-based consultant, TLG Services ("TLG"), who prepares a large number of station decommissioning estimates for U.S. utilities and has developed a database on decommissioning costs based on actual experience. TLG has done estimates for 93 of 104 operating U.S. power reactors at 62 sites and for 18 of the 22 permanently shut down U.S. power reactors at 17 sites. They worked with Pickering station staff to update decommissioning estimates for Pickering A with the latest available data based on the work to place Pickering A Units 2 and 3 in safe-store following the decision to not return these units to service.

3.0 REGULATORY FRAMEWORK

3.1 Ontario Nuclear Funds Agreement ("ONFA")

On April 1, 1999, the obligation for nuclear waste management and decommissioning was transferred from the former Ontario Hydro to OPG. The responsibility for funding these liabilities is described in the ONFA Agreement between the Province of Ontario and OPG. A copy of ONFA is available on OPG's website at:
http://www.opg.com/pdf/Nuclear%20Reports%20and%20Publications/Ontario%20Nuclear%20Funds%20Agreement.pdf

ONFA provides for the establishment of a reference plan for nuclear waste management and for decommissioning of stations and other facilities. The reference plan, approved by the

Province, includes cost estimates at a reasonable level of detail as well as assumptions on economics, waste program timing and planned operating lives for stations.

The key provisions of the ONFA are:

- For OPG to establish two segregated funds, including the used fuel fund (to fund future costs of nuclear used fuel waste management) and the decommissioning fund (to fund the future cost of nuclear fixed asset removal and L&ILW management). The used fuel fund includes a trust fund as required by the NFWA and discussed in section 3.4 below.
- For the Ontario Electricity Financial Corporation ("OEFC") to be responsible for funding approximately $2,378M (present value as at April 1, 1999). This amount, representing the nuclear liabilities that Ontario Hydro had accumulated, was included in the decommissioning fund at the time that the agreement became effective.
- For the Province to limit OPG's financial exposure in relation to the cost of used fuel management as explained below.
- For the Province to support financial guarantees to the CNSC for OPG's nuclear waste management and decommissioning liabilities by providing a provincial guarantee as a supplement to accumulated ONFA funds in return for an annual guarantee fee equal to 0.5 per cent of the amount guaranteed, which is reflected in OPG's OM&A costs as explained below.

OPG's contributions to the used fuel fund and the decommissioning fund are determined based on the ONFA Reference Plan cost estimates. These estimates are prepared with the assistance of external consultants and are based on external practices and benchmarks. The ONFA Agreement specifies the timing, circumstances, contents, and approvals required for changes to the Reference Plan. The ONFA Reference Plan must be updated every five years or whenever there is a significant change as determined through the ONFA Agreement. The most recent update to the Reference Plan was submitted by OPG to the Province in November 2006. The Reference Plan was approved by the Province in December 2006 after a detailed review of the submission with the aid of external consultants. OPG's nuclear liabilities are discussed in greater detail in section 4.0 of this exhibit.

A new ONFA Reference Plan is expected to be completed in 2011 to be applicable to the 2012 - 2016 period. Any change resulting from the new ONFA Reference Plan for the 5-year period 2012 - 2016 will be reflected in the Nuclear Liability Deferral Account described in Ex H1-T1-S1 section 6.2.

As part of the ONFA Reference Plan update in 2006, updated nuclear funds contribution profiles were submitted to the Province. The contribution profile of the used fuel fund was updated in 2008 to reflect the settlement of the extraordinary payment required for Bruce fuel obligations. The funding profiles are provided in Attachment 1. Total contributions from both funds are used to determine OPG's unfunded nuclear liability and to support income tax calculations. In accordance with the ONFA, segregated fund contributions are made at the end of each quarter. Contributions continue until the end of individual station lives as assumed within the reference plan.

The Province has significant oversight on funds management and as such provides approval of contributions to segregated funds and fund investment decisions. Ontario Nuclear Funds Agreement funds management is the responsibility of OPG's Treasury Department which uses external fund managers to manage the funds.

Withdrawals by OPG for ONFA-eligible expenditures require the approval of the Province. Disbursements of funds are allowed to address cost for long term programs such as used fuel disposal, L&ILW disposal and decommissioning as discussed in Ex. C2-T1-S2, section 3.1 and reflected in Ex. C2-T1-S2 Tables 1 and 2.

3.2 Provincial Guarantees for Used Fuel

Under the ONFA, the limit to OPG's financial exposure with respect to the cost of long-term management of used fuel was capped at $5.94B (January 1, 1999 present value) for the first 2.23M fuel bundles. OPG is responsible for funding the incremental costs associated with the long-term management of fuel bundles in excess of 2.23M. It is currently estimated that physically, the 2.23M bundle threshold will be reached in 2012.

Under the ONFA, the Province guarantees the rate of return earned in the used fuel fund for the first 2.23M bundles at a specified rate of 3.25 per cent over the change in the Ontario consumer price index. The Province is obligated to make additional contributions to the used fuel fund if this fund earns a rate of return that is less than the rate of return guaranteed by the Province for the first 2.23M bundles. If the return on the assets in the used fuel fund exceeds the Province's guaranteed rate for the first 2.23M bundles, the Province is entitled to the excess.

The same rate of return is used as the target rate of return for the used fuel fund for bundles in excess of 2.23M, although the rate of return is not guaranteed by the Province. Every 5 years, after the update to the ONFA reference plan, the contribution profile is recalculated to reflect the change in contributions necessary in accordance with the terms of the ONFA agreement that in part limit downward adjustment to the contribution profile.

For the decommissioning fund, the rate of return target is presently 5.15 per cent per annum. As defined in ONFA, this consists of a 3.25 per cent real rate of return plus an inflation adjustment. For the 2006 Reference Plan, this inflation adjustment is 1.9 per cent per annum. This rate of return is not guaranteed by the Province; therefore, OPG is required to fund any shortfall between the achieved and target rate of return through additional contributions as part of a renewed reference plan assessment. To the extent the ratio of the decommissioning fund assets exceeds 120 per cent of the decommissioning liabilities, OPG has the option to elect to transfer amounts in excess of 120 per cent. While no such transfer has occurred to date, to the extent a transfer may occur at some point in the future, the transfer of the amounts in excess of 120 per cent would be attributed 50 per cent to the OEFC and 50 per cent to the used fuel fund. As discussed above, the used fuel fund contribution profile is then reassessed to reflect the impact of this transfer from the decommissioning fund.

3.3 Provincial Guarantee to the CNSC

The provincial guarantee provided to the CNSC is intended to supplement accumulated funds in the ONFA nuclear funds to meet the requirements of the CNSC financial guarantee. OPG pays a guarantee fee to the Province for providing this guarantee. This fee is included in the revenue requirement as a centrally-held cost that is directly assigned to the nuclear revenue requirement (see Ex. F4-T4-S1 section 9). The value of the required provincial guarantee was re-evaluated as part of the updated 2008 - 2012 financial guarantee submitted to the CNSC. This submission proposed a provincial guarantee level of $760M for the years 2008 to 2010. Subsequently, OPG proposed an increase of the provincial guarantee to $1,545M to address the funding shortfall as a result of the adverse impacts of the financial markets volatility in 2008. This change was accepted by the CNSC at a hearing in December 2009. The revised provincial guarantee level is now in place to the end of year 2012 and is reflected in OPG's forecast OM&A costs described in Ex. F4-T4-S1.

3.4 Nuclear Fuel Waste Act

The handling and disposal of radioactive material in Canada is subject to federal legislation. The NFWA, administered by Natural Resources Canada, addresses the long-term management of used nuclear fuel.

In response to the NFWA, in 2002, OPG and other Canadian nuclear fuel waste owners incorporated the NWMO. In June 2007, Natural Resources Canada announced that the Government of Canada had accepted the recommendation proposed by the NWMO for long-term management of used fuel. The selected approach described as adaptive-phased management includes the isolation and containment of used nuclear fuel in a separate (from L&ILW) deep geologic repository with an option for initial temporary shallow underground storage. The earliest in-service date for the central facility to support this approach is estimated to be 2035.

Funding for the long-term management of used fuel is shared amongst the Canadian owners of used nuclear fuel, based on the respective quantities of used fuel they generate and the timing for delivery of this fuel to the central repository. Based on current plans, OPG's share of this fuel is approximately 91 per cent. The NFWA requires the nuclear fuel waste owners to establish and make payments into trust funds for the purpose of funding the implementation of the long term management plan. For OPG, the NFWA trust fund is part of the ONFA used fuel fund which is described in section 3.1 of this exhibit.

3.5 Other Legislation

The development and operation of radioactive waste management sites is also subject to federal environment assessment requirements under the *Canadian Environmental Assessment Act*, as well as provincial and federal environmental protection legislation. Of particular note, the transportation of radioactive materials is regulated by both the CNSC and Transport Canada.

4.0 NUCLEAR LIABILITIES

In accordance with Generally Accepted Accounting Principles ("GAAP"), the amount of nuclear liabilities recorded on OPG's balance sheet at any point in time represents the present value of the committed portion of the lifecycle cost estimate in the financial reference plan, where the discount rate is the GAAP determined average accretion rate. This amount is the asset retirement obligation ("ARO"). The committed portion includes the fixed cost components of each program as well as the lifetime variable costs for wastes already generated. As new waste is created, the nuclear liabilities increase by the additional variable cost of such waste. These increases in the liabilities are booked as fuel and depreciation expenses for used fuel and L&ILW, respectively (see Ex. F2-T1-S1 Table 1 and Ex. F4-T1-S2 Table 2). Exhibit C2-T1-S2 explains how costs associated with the nuclear liabilities are recovered through the revenue requirement.

The nuclear liabilities used to determine OPG's contributions to ONFA segregated funds represent the present value of the lifecycle cost estimate in the reference plan where the discount rate is 5.15 per cent.

LIST OF ATTACHMENTS

Attachment 1: Segregated Fund Contribution Schedule

ATTACHMENT 1 – Segregated Fund Contribution Schedule

Table 1 provides the actual contributions made to the Ontario Nuclear Funds by OPG and the Province up until 2007. Table 2 provides the required contributions by OPG to the Used Fuel Fund for the period 2008 to 2036 according to the ONFA contribution schedule approved by the Province on March 7, 2008.

The funding schedules in the attachments are based on the current liability estimates arising from the approved reference plan.

Table 1

Year	Actual ONFA Funds Contributions ($M)			
	Contribution From		**Contribution To**	
	OPG	Province	Used Fuel Fund[1]	Decommissioning Fund
2003	2,090	3,051	1,556	3,585[2]
2004	454		454	
2005	454		454	
2006	454		454	
2007	788		788	

Notes:

(1) All contributions to the Used Fuel Fund were made by OPG

(2) Of the $3,585M contribution to the Decommissioning Fund in 2003, $534 M was made by OPG, the balance of $3,051M was made by the Province.

Table 2

OPG Required Contributions to the Used Fuel Fund

Year	Amended Payment Schedule: due to Bruce Extraordinary Payment ($)
2008	453,883,577
2009	338,789,893
2010	264,053,055
2011	250,483,401
2012	240,035,242
2013	156,641,909
2014	94,061,565
2015	95,730,194
2016	83,594,408
2017	83,401,866
2018	82,867,764
2019	78,593,923
2020	49,293,049
2021	29,094,214
2022	17,048,442
2023	17,048,442
2024	17,048,442
2025	17,048,442
2026	17,048,442
2027	17,048,442
2028	17,048,442
2029	17,048,442
2030	17,048,442
2031	17,048,442
2032	17,048,442
2033	17,048,442
2034	17,048,442
2035	17,048,442
2036	17,048,442

NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING – REVENUE REQUIREMENT TREATMENT OF NUCLEAR LIABILITIES

1.0 PURPOSE

The purpose of this evidence is to explain how nuclear liabilities are treated in determining OPG's revenue requirement and present the forecast amounts for nuclear liabilities included in the revenue requirement.

2.0 OVERVIEW

A summary of the revenue requirement impact of the nuclear liabilities for the prescribed nuclear facilities and the Bruce facilities is provided in Ex. C2-T1-S2 Table 5. The test period revenue requirement impact is $291.3M for the prescribed facilities and $110.3M for the Bruce facilities.

For the 2011 - 2012 test years, OPG proposes to maintain the revenue requirement treatment for nuclear liabilities approved by the OEB in EB-2007-0905 for Pickering, Darlington and the Bruce facilities.[1] OPG is continuing to investigate the impacts of the OEB approved revenue requirement treatment on its ability to fully recover its nuclear liabilities. Based on the results of this investigation, OPG may propose modifications to the existing treatment or an alternative treatment in a future application.

Section 3.0 sets out the approved methodology and how it applies to the revenue requirement respecting the nuclear liabilities. Section 4.0 addresses the changes in the asset retirement obligation, the unamortized asset retirement costs and the segregated fund balances for the period 2008 to 2012.

[1] As explained fully in EX. C1-T1-S1, OPG as the owner of the Bruce facilities is responsible for the management of all levels of nuclear waste generated at the Bruce facilities and for decommissioning. However, because the revenue requirement treatment approved for the Bruce facilities in EB-2007-0905 differs from that approved for Pickering and Darlington, it is discussed in a separate section.

The revenue requirement impact of the nuclear liabilities decreases significantly in the 2010 - 2012 period compared to the historical years as a result of the changes in the asset retirement obligation ("ARO") and depreciation expense associated with the decision to move to the definition phase of the Darlington Refurbishment project. A presentation of the impact of the Darlington Refurbishment project on the nuclear liabilities is provided in Ex. C2-T1-S2 Table 4 and discussed in section 4.1 below.

3.0 APPLICATION OF THE METHODOLOGY FOR RECOVERY NUCLEAR LIABILITIES APPROVED IN EB-2007-0905

3.1 Background

OPG's nuclear liabilities represent the present value of the lifecycle cost of decommissioning and nuclear waste management programs. These lifecycle costs include the fixed cost components of each program as well as the lifetime variable costs for waste already generated. The present value of the committed costs is recorded as an ARO on the balance sheet of OPG.

To the extent that the ARO increases or decreases from changes such as an approved Ontario Nuclear Fund Agreement ("ONFA") Reference Plan or a change in the accounting estimate, an equal amount must be recorded as an increase or decrease in the net book value of the assets to which the retirement obligation relates. This addition to net book value is known as an asset retirement cost ("ARC"). The only exception to this is related to the annual incremental waste to be generated which increases the ARO but is expensed directly in the year and does not impact the ARC.

Asset retirement costs represent a substantial portion of the net book value of the Pickering, Darlington and Bruce nuclear facilities. The ARC is amortized over the useful life of these assets like any other capital cost. This amortization gives rise to depreciation expense.

The ARO is allocated to the station level based on each of the five programs involved in retiring nuclear stations and managing nuclear waste. These five programs are:

decommissioning; used fuel storage; used fuel disposal; low and intermediate level waste ("L&ILW") storage and L&ILW disposal. The methodology for allocating these five programs to the station level's ARO is:

- Decommissioning and Used Fuel Storage programs: The cost estimates for these two programs are prepared at the station level with individual estimates prepared for each station; therefore no allocation is required.
- Used Fuel disposal, L&ILW storage and L&ILW disposal programs: As these three programs involve central facilities, the cost estimates are prepared at the program level. The costs are allocated to stations based on the most up-to-date lifecycle waste volume estimate.

The ARC is recorded to the station level using the same methodologies described above. The allocation of the ARO and ARC as it impacts the prescribed facilities and Bruce facilities is reflected in Ex C2-T1-S2 Table 1 and Table 2.

OPG's contributions to the used fuel fund and the decommissioning fund are determined based on the current ONFA reference plan. The allocation of ONFA liabilities to the station level are based on lifecycle waste volumes for the three programs that involve central facilities discussed above. For the decommissioning and used fuel storage programs, estimates are prepared at the station level. ONFA contribution requirements are calculated at the station levels based on the difference between the station level liabilities and fund balances. Fund balances at the station level represent the cumulative balance of the segregated funds since the inception of ONFA. Cumulative station level fund balances are adjusted for contributions, disbursements and fund returns. The difference between OPG's ARO and segregated fund balances is the unfunded nuclear liability ("UNL").

Continuity schedules showing the opening, closing and average[2] balances for ARO, segregated funds, UNL and ARC are provided in Ex C2-T1-S2 Table 1 (for the prescribed

[2] Averages are only provided for the prescribed facilities as they are required to determine rate base values used in the approved methodology for the prescribed assets only.

facilties) and Table 2 (for the Bruce facilities[3]). Annual changes in these balances are discussed in section 4.0 below.

For the 2011 - 2012 test years, OPG proposes to maintain the revenue requirement treatment for nuclear liabilities approved by the OEB in EB-2007-0905 for Pickering, Darlington and the Bruce facilities. The determination of the revenue requirement arising from the nuclear liabilities for the prescribed facilities and the Bruce facilities is discussed sections 3.2 and 3.3 below. The treatment determined by the OEB in EB-2007-0905 for nuclear liabilities is significantly different from that proposed by OPG in its application. OPG does not present information for 2007, the year prior to OEB regulation, in the Ex. C2-T2-S1 tables as the revenue requirement impact under the methodology in place at that time is not comparable to that in the 2008 to 2012 period.

3.2 Application of the Approved Methodology to the Prescribed Facilities

Under the approved methodology, depreciation expense, variable incremental used fuel costs and variable incremental L&ILW costs related to the revenue requirement impact of OPG's nuclear liabilities are determined in accordance with GAAP.

The approved regulatory approach discussed in section 3.2.4 requires that the return on a portion of the rate base be limited to the average accretion rate on OPG nuclear liabilities.

Each of these components is discussed separately below.

3.2.1 Depreciation Expense

Depreciation on the unamortized ARC is treated in the same manner as the depreciation associated with other capital assets.

[3] Under the approved methodology UNL is used to determine return on rate base. The approved methodology for the Bruce facilities does not include a return on rate base; therefore UNL is not in the continuity schedule for the Bruce facilities.

Nuclear depreciation expense is presented in Ex. F4-T1-S2. A portion of this depreciation expense is attributable to unamortized ARC for each year. For the 2008 to 2012 period, these amounts are shown in Ex C2-T1-S2 Table 1, line 26. The amounts of depreciation expense attributable to unamortized ARC for each year for the 2008 to 2012 period are shown in Ex C2-T1-S2 Table 5, line 1.

3.2.2 Variable Incremental Used Fuel Costs

Nuclear fuel expense is presented in Ex. F2-T5-S1 Table 1. A portion of the nuclear fuel expense is attributable to the present value of the variable costs related to incremental quantities of used fuel generated in each period. The difference between the lifecycle estimate and the amount of committed costs relating to used fuel included in the nuclear liabilities balance represents the variable costs of future fuel waste. Using a present value basis, these variable costs are divided by the forecast number of future fuel bundles to calculate the $/bundle rate. Used fuel expenses are then calculated by applying the $/bundle rate to forecast used fuel generated. Each bundle is charged an equal amount in present value terms. The amount of this expense for each year for the 2008 to 2012 period are shown in Ex C2-T1-S2 Table 5, line 2.

3.2.3 Variable Incremental Low and Intermediate Level Waste Expense

Low and intermediate level waste is a separate component of the depreciation expense presented in Ex. F4-T1-S2. A portion of this depreciation expense is attributable to the present value of the variable costs related to incremental volumes of L&ILW produced in each period. The difference between the lifecycle estimate and the amount of committed costs included in the nuclear liabilities balance represents the variable costs of future waste. Using a present value basis, these variable costs are divided by the L&ILW volume estimates to calculate the $\$/m^3$ rate. Low and intermediate level waste expenses are then calculated by applying the $\$/m^3$ rate to the forecast waste volumes generated. The amount of this expense for the 2008 to 2012 period are shown in Ex C2-T1-S2 Table 5, line 3.

3.2.4 Return on Rate Base

The approved methodology for the prescribed assets recognized that OPG's rate base includes an amount associated with ARC. However, the approved methodology also requires that the return on a portion of the rate base be limited to the weighted average accretion rate of 5.6 per cent (as established in EB-2007-0905). This portion is equal to the lesser of: (i) the forecast amount of the average unfunded nuclear liabilities related to the Pickering and Darlington facilities, and (ii) the average unamortized ARC included in the fixed asset balances for Pickering and Darlington. As seen in Ex C2-T1-S2 Table 5, note 3 the ARC is less than unfunded nuclear liabilities ("UNL"). The remainder of OPG's rate base earns the weighted average cost of capital. For OPG's prescribed assets the average UNL, average unamortized ARC and the determination of the amounts to be receive the accretion rate or the Weighted Average Cost of Capital ("WACC") rate is provided in Ex C2-T1-S2 Table 1.

The approved methodology requires a forecast of the value of the unfunded nuclear liabilities for the test period. As discussed in Ex C2-T1-S1 the target rate of return on these funds is currently 5.15 per cent, which OPG applies in determining its forecast return on its segregated funds.

For the period April 1, 2008 to December 31, 2012 the amount of the average unamortized ARC is less than the amount of the average unfunded nuclear liability. Therefore, the unamortized ARC amount earns the weighted average accretion rate of 5.6 per cent for the period April 1, 2008 to December 31, 2009 and 5.58 per cent for the 2010 to 2012 fiscal years[4]. The resulting amount of earnings calculated by applying the weighted average accretion rate to the average amount of unamortized ARC is shown in Ex. C2-T1-S2 Table 5.

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[4] As discussed in Section 4.1 the Darlington Refurbishment Project results in an increase in the ARO of $293M at an accretion rate of 4.8 percent, reducing the accretion rate of 5.6 percent in EB-2007-0905 marginally to 5.58 percent during the 2010 to 2012 period.

3.3 Application of the Approved Methodology to the Bruce Facilities

As a result of determining that the Bruce facilities were not prescribed facilities, the OEB approved a GAAP approach to determine the net revenue impact for the nuclear liabilities associated with the Bruce facilities. In summary, the difference is that for Bruce facilities the OEB substitutes the net income determinants of accretion expense and earnings on segregated funds in lieu of a return on the unamortized ARC (rate base) used in determining the revenue requirement for prescribed facilities.

Each of the components of the net revenue impact of nuclear liabilities associated with the Bruce facilities is discussed separately below.

3.3.1 <u>Depreciation Expense</u>

Depreciation on the unamortized ARC is treated in the same manner (GAAP basis) as the depreciation associated with other capital assets.

Depreciation expense presented in Ex. G2-T2-S1 Table 5 is a cost component of the calculation of the Bruce Lease net revenues. A portion of this depreciation expense is attributable to the unamortized ARC for each year for the 2008 to 2012 period and is shown in Ex C2-T1-S2 Table 2, line 24. The amounts of depreciation expense attributable to unamortized ARC for each year for the 2008 to 2012 period are shown in Ex C2-T1-S2 Table 5, line 7.

3.3.2 <u>Variable Incremental Used Fuel Costs</u>

Nuclear fuel for Bruce facilities is determined in the same manner (GAAP basis) as described in section 3.2 to determine the nuclear fuel expense for prescribed facilities.

Nuclear fuel expense presented in Ex. G2-T2-S1 Table 5 is a cost component of the calculation of the Bruce Lease net revenues. Used fuel expenses are calculated by applying the $/bundle rate discussed above to forecast used fuel generated. Each bundle is charged an equal amount in present value terms. The amounts of this expense for the 2008 to 2012 period are shown in Ex C2-T1-S2 Table 5, at line 8.

3.3.3 Variable Incremental Low and Intermediate Level Waste Expense

Low and intermediate level waste for Bruce facilities is determined in the same manner (GAAP basis) as described in section 3.2 to determine the L&ILW expense for prescribed facilities.

Low and intermediate level waste presented in Ex. G2-T2-S1 Table 5 is a cost component of the calculation of the Bruce Lease net revenues. The L&ILW expenses are calculated by applying the $/m^3 rate discussed above to forecast L&ILW volumes generated. The amount of this expense for the 2008 to 2012 period are shown in Ex C2-T1-S2 Table 5, line 9.

3.3.4 Accretion Expense

For the April 1, 2008 to 2012 period, accretion expense for Bruce is calculated by applying the weighted average accretion rate to the amount of nuclear liability associated with Bruce in each year as shown in Ex. C2-T1-S2 Table 2. The allocation between Bruce and the prescribed facilities is based on the amounts set out in the most recently approved ONFA Reference Plan as discussed in section 3.1 above. The accretion expense for the Bruce facilities is shown in Ex C2-T1-S2 Table 5, line 10.

3.3.5 Earnings on the Segregated Funds

For the April 1, 2008 to 2012 period, segregated funds earnings are calculated by taking the difference between the opening and closing balances less contributions plus disbursements from each fund each year as shown in Ex. C2-T1-S2 Table 2. The attribution of earnings to Bruce is based on the amounts set out in the most recently approved ONFA Reference Plan. This methodology is applied to both actual earnings and disbursements in 2008 and 2009 as well as forecast amounts for 2010 – 2012. The segregated fund earnings for the Bruce facilities are shown in Ex C2-T1-S2 Table 5, line 11.

3.3.6 Return on Rate Base

For the period January 1, 2008 to March 31, 2008, the unamortized ARC for the Bruce facilities received the same treatment and the same WACC (5.55 per cent) as the prescribed facilities as reflected in the payment amounts established by the Province. The revenue requirement impact is shown in Ex C2-T1-S2 Table 5.

4.0 CHANGES IN ARO, UNAMORTIZED ARC and SEGREGATED FUND BALANCES

The segregated fund balances, ARO and ARC for prescribed facilities and the Bruce facilities are presented in Ex. C2-T1-S2 Tables 1 and 2, respectively for the period 2008 to 2012.

The segregated fund balances in the 2008 to 2009 period reflect the turmoil in the financial markets over 2008 and 2009. Contributions do not change as a result of the Darlington Refurbishment project; rather they continue to be made in accordance with the 2006 ONFA Reference Plan per Ex C2-T1-S1, Attachment 1 until the ONFA reference plan is updated. For 2010 to 2012, OPG has used the target rate of growth of 5.15 per cent on its segregated funds as the rate of earnings the funds are forecast to achieve during that period.

The growth in the ARO over the 2008 to 2012 period is primarily the result of accretion and the impact of the decision on Darlington Refurbishment as of January 1, 2010. The impact of the Darlington Refurbishment project is considered in section 4.1 below.

Depreciation is the primary cause of the declining trend in the ARC balance from 2008 to 2012. The major exception reflects the forecast accounting impact of the Darlington Refurbishment project on January 1, 2010 as discussed in section 4.1.

4.1 Impact of the Darlington Refurbishment Project

A summary of the impacts of the Darlington Refurbishment project on revenue requirement impact of the nuclear liabilities is in Ex. C2-T1-S2 Table 4.

GAAP accounting requires OPG to change the ARO to reflect the recently announced decision to move to the definition phase of the Darlington Refurbishment project.

Refurbishment of the Darlington facility will allow for it to operate with replaced components until the year 2051. The main impacts of the refurbishment decision are: (a) a decrease in the ARO for Darlington decommissioning as the present value of the work reflects the deferral of the decommissioning work for approximately 30 years; and (b) an increase in the cost of used fuel storage and disposal activities to account for the incremental volumes of used fuel to be generated. The net impact is a $293M increase in both ARC and ARO.

An allocation of this incremental ARO/ARC has been made to the stations on the same basis as the balance of the ARO/ARC. The allocation of ARO to stations and the related allocation of ARC amounts are presented in Ex C2-T1-S2 Table 3.

The impact of the change in ARO/ARC results in a reduction in revenue requirement impacts for both the prescribed facilities and the Bruce facilities (the latter through a reduction in the net revenues used to offset the revenue requirement of the prescribed facilities) as presented in Ex C2-T1-S2 Table 4.

The average accretion rate for the ARO liability with this change is 5.58 per cent for the 2010 to 2012 period[5].

[5] The Darlington Refurbishment project results in an increase in the ARO of $293M at an accretion rate of 4.8 percent, reducing the accretion rate of 5.6 percent in EB-2007-0905 marginally to 5.58 percent during the 2010 to 2012 period.

Table 1
Prescribed Facilities - Asset Retirement Obligation, Nuclear Segregated Funds, and Asset Retirement Costs ($M)
Years Ending December 31, 2008, 2009, 2010, 2011 and 2012

Line No.	Description	Note	2008 Actual[1]	2009 Actual	2010 Budget	2011 Plan	2012 Plan
			(a)	(b)	(c)	(d)	(e)
	ASSET RETIREMENT OBLIGATION						
1	**Opening Balance**	2	5,921.0	6,151.2	6,391.2	7,136.8	7,432.8
2	**Darlington Refurbishment Adjustment**	3	0.0	0.0	497.4	0.0	0.0
3	**Adjusted Opening Balance** (line 1 + line 2)		5,921.0	6,151.2	6,888.6	7,136.8	7,432.8
4	**Used Fuel Storage and Disposal Variable Expenses**		19.0	19.2	23.0	26.6	28.5
5	**Low & Intermediate Level Waste Management Variable Expenses**		1.7	3.5	1.1	0.8	0.8
6	**Accretion Expense**		332.2	344.8	381.2	395.9	412.4
7	**Expenditures for Used Fuel, Waste Management & Decommissioning**	4	(122.6)	(129.3)	(157.1)	(127.3)	(126.6)
8	**Consolidation Adjustment**		0.0	1.7	0.0	0.0	0.0
9	**Closing Balance** (line 3 + line 4 + line 5 + line 6 + line 7 + line 8)		6,151.2	6,391.2	7,136.8	7,432.8	7,748.0
10	**Average Asset Retirement Obligation** ((line 3 + line 9)/2)		6,036.1	6,271.2	7,012.7	7,284.8	7,590.4
	NUCLEAR SEGREGATED FUNDS BALANCE						
11	**Opening Balance**	2	4,853.0	4,584.2	5,058.7	5,399.6	5,778.5
12	**Reallocation Adjustment**	5	(23.1)	0.0	0.0	0.0	0.0
13	**Adjusted Opening Balance** (line 11 + line 12)		4,829.9	4,584.2	5,058.7	5,399.6	5,778.5
14	**Earnings (Losses)**		(242.1)	415.5	262.6	280.6	299.7
15	**Contributions**		58.9	124.7	150.2	145.0	140.4
16	**Disbursements**	4	(62.5)	(65.7)	(71.9)	(46.6)	(58.0)
17	**Closing Balance** (line 13 + line 14 + line 15 + line 16)		4,584.2	5,058.7	5,399.6	5,778.5	6,160.7
18	**Average Nuclear Segregated Funds Balance** ((line 13 + line 17)/2)		4,707.0	4,821.5	5,229.2	5,589.1	5,969.6
	UNFUNDED NUCLEAR LIABILITY BALANCE (UNL)						
19	**Opening Balance** (line 3 - line 13)		1,091.1	1,567.0	1,829.9	1,737.2	1,654.3
20	**Closing Balance** (line 9 - line 17)		1,567.0	1,332.5	1,737.2	1,654.3	1,587.3
21	**Average Unfunded Nuclear Liability Balance** ((line 19 + line 20)/2)		1,329.1	1,449.7	1,783.5	1,695.7	1,620.8
	ASSET RETIREMENT COSTS (ARC)						
22	**Opening Balance**	6	1,301.0	1,221.7	1,098.0	1,539.9	1,506.7
23	**Darlington Refurbishment Adjustment**	3	0.0	0.0	475.2	0.0	0.0
24	**Reclassification Adjustment**	7	44.7	0.0	0.0	0.0	0.0
25	**Adjusted Opening Balance** (line 22 + line 23 + line 24)		1,345.7	1,221.7	1,573.1	1,539.9	1,506.7
26	**Depreciation Expense**		(124.0)	(123.8)	(33.2)	(33.2)	(33.2)
27	**Closing Balance** (line 25 + line 26)		1,221.7	1,098.0	1,539.9	1,506.7	1,473.5
28	**Average Asset Retirement Costs** ((line 25 + line 27)/2)		1,283.7	1,159.8	1,556.5	1,523.3	1,490.1
29	**LESSER OF AVERAGE UNL OR ARC** (lesser of line 21 or line 28)		1,283.7	1,159.8	1,556.5	1,523.3	1,490.1

Notes:
1 2008 values are annual amounts.
2 2008 amount per EB-2007-0905 Payment Amounts Order, Appendix A Table 8.
3 Adjustment recorded on January 1, 2010 associated with the changes to the end-of-life date assumptions underlying the ARO calculation, as a result of the approval of the definition phase of the Darlington Refurbishment project.
4 Expenditures incurred by OPG relate to both short-term programs (Used Fuel Storage, L&ILW Storage) and long-term programs (Used Fuel Disposal, L&ILW Disposal and Decommissioning), whereas disbursements from Nuclear Segregated Funds cover long-term programs only.
5 Adjustment in 2008 associated with refinement of attribution of Nuclear Segregated Funds balance to station level, consistent with the ONFA.
6 2008 amount per EB-2007-0905 Undertaking J15.1 Addendum #2, Pg. 1, line 26.
7 Reclassification of amounts from non-ARC portion of PP&E to ARC. There is no impact on the payment amounts set in EB-2007-0905, as the reclassification would not have impacted the forecast depreciation expense for the prescribed facilities (the same service life applies to non-ARC PP&E and ARC) and cost of capital (forecast average UNL was lower than forecast average ARC) used to determine the payment amounts.

Numbers may not add due to rounding.

Table 2
Bruce Facilities - Asset Retirement Obligation, Nuclear Segregated Funds, and Asset Retirement Costs ($M)
Years Ending December 31, 2008, 2009, 2010, 2011 and 2012

Line No.	Description	Note	2008 Actual[1]	2009 Actual	2010 Budget	2011 Plan	2012 Plan
			(a)	(b)	(c)	(d)	(e)
	ASSET RETIREMENT OBLIGATION						
1	**Opening Balance**	2	4,860.0	5,077.8	5,315.0	5,333.9	5,561.0
2	**Darlington Refurbishment Adjustment**	3	0.0	0.0	(204.4)	0.0	0.0
3	**Adjustment to Remove Cobalt Waste Management Provision**	4	(2.4)	0.0	0.0	0.0	0.0
4	**Adjusted Opening Balance** (line 1 + line 2 + line 3)		4,857.6	5,077.8	5,110.7	5,333.9	5,561.0
5	**Used Fuel Storage and Disposal Variable Expenses**		14.0	14.4	16.7	17.0	24.0
6	**Low & Intermediate Level Waste Management Variable Expenses**	5	11.2	4.4	0.9	0.8	0.7
7	**Accretion Expense**		267.4	279.3	282.4	294.5	307.2
8	**Expenditures for Used Fuel, Waste Management & Decommissioning**	6	(72.4)	(62.0)	(76.8)	(85.2)	(85.9)
9	**Consolidation Adjustment**		0.0	1.2	0.0	0.0	0.0
10	**Closing Balance** (line 4 + line 5 + line 6 + line 7 + line 8 + line 9)		5,077.8	5,315.0	5,333.9	5,561.0	5,807.0
11	**Average Asset Retirement Obligation** ((line 4 + line 10)/2)		4,967.7	5,196.4	5,222.3	5,447.4	5,684.0
	NUCLEAR SEGREGATED FUNDS BALANCE						
12	**Opening Balance**	2	4,410.0	4,625.1	5,187.2	5,522.6	5,879.9
13	**Reallocation Adjustment**	7	23.1	0.0	0.0	0.0	0.0
14	**Adjusted Opening Balance** (line 12 + line 13)		4,433.1	4,625.1	5,187.2	5,522.6	5,879.9
15	**Earnings (Losses)**		(183.9)	386.2	268.8	286.2	304.6
16	**Contributions**		395.0	214.1	113.9	105.5	99.7
17	**Disbursements**	6	(19.0)	(38.2)	(47.3)	(34.4)	(31.2)
18	**Closing Balance** (line 14 + line 15 + line 16 + line 17)		4,625.1	5,187.2	5,522.6	5,879.9	6,252.9
19	**Average Nuclear Segregated Funds Balance** ((line 14 + line 18)/2)		4,529.1	4,906.2	5,354.9	5,701.3	6,066.4
	ASSET RETIREMENT COSTS (ARC)						
20	**Opening Balance**	8	1,128.0	1,084.4	1,035.8	825.2	796.8
21	**Darlington Refurbishment Adjustment**	3	0.0	0.0	(182.1)	0.0	0.0
22	**Reclassification Adjustment**	9	5.0	0.0	0.0	0.0	0.0
23	**Adjusted Opening Balance** (line 20 + line 21 + line 22)		1,133.0	1,084.4	853.7	825.2	796.8
24	**Depreciation Expense**		(48.6)	(48.5)	(28.5)	(28.5)	(28.5)
25	**Closing Balance** (line 23 + line 24)		1,084.4	1,035.8	825.2	796.8	768.3
26	**Average Asset Retirement Costs** ((line 23 + line 25)/2))		1,108.7	1,060.1	839.5	811.0	782.6

Notes:

1 2008 values are annual amounts.

2 2008 amount per EB-2007-0905 Payment Amounts Order, Appendix A Table 8

3 Adjustment recorded on January 1, 2010 associated with the changes to the end-of-life date assumptions underlying the ARO calculation, as a result of the approval of the definition phase of the Darlington Refurbishment project.

4 Adjustment in 2008 is to remove the provision related to managing the production and disposal of Cobalt-60. The provision is not part of OPG's obligations for decommissioning, used fuel or low and intermediate-level waste management, and is not within the scope of the liability calculations for the purposes of the ONFA. The provision is not included in subsequent years.

5 Amounts for 2008 and 2009 include expenses ($7.4M in 2008 and $1.3M in 2009) recognized as part of the ARO for processing refurbishment waste received from Bruce Power under a supplemental agreement, as discussed in Ex. G2-T2-S1. In Ex. G2-T2-S1, Table 5, associated payments under this agreement have been netted against these expenses to conform with the presentation in Payment Amounts Order EB-2007-0905 and OPG's external financial statements. The expenses must be shown on a gross basis for ARO continuity purposes, and to reflect appropriately the revenue requirement impact of the Nuclear Liabilities. Amounts for 2010-2012 do not include any expenses related to the supplemental agreement.

6 Expenditures incurred by OPG relate to both short-term programs (Used Fuel Storage, L&ILW Storage) and long-term programs (Used Fuel Disposal, L&ILW Disposal and Decommissioning), whereas disbursements from Nuclear Segregated Funds cover long-term programs only.

7 Adjustment in 2008 associated with refinement of attribution of Nuclear Segregated Funds balance to station level, consistent with the ONFA.

8 2008 amount per EB-2007-0905 Undertaking J15.1 Addendum #2, Pg. 1, line 26.

9 Reclassification of amounts from non-ARC portion of PP&E to ARC. There is no impact on the payment amounts set in EB-2007-0905, as the reclassification would not have impacted the forecast depreciation expense for Bruce stations (the same service life applies to non-ARC PP&E and ARC) used to determine the payment amounts.

Numbers may not add due to rounding.

Table 3

Impact of Darlington Refurbishment Project - Assignment of ARO Adjustment and Allocation of ARC to Nuclear Stations ($M)

Line No.	Description	Pickering A	Pickering B	Darlington	Prescribed Facilities Total	Bruce A	Bruce B	Bruce Facilities Total	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	**Decommissioning Program**	41.8	1.7	(504.9)	(461.5)	0.8	1.5	2.3	(459.1)
2	**Intermediate Level Waste Program**	(66.3)	(73.2)	180.2	40.6	(1.9)	(14.4)	(16.3)	24.4
3	**Low Level Waste Program**	14.7	13.4	51.6	79.7	7.2	(4.8)	2.4	82.1
4	**Used Fuel Disposal Program**	(155.8)	(149.4)	1,108.4	803.2	(168.8)	(104.9)	(273.7)	529.5
5	**Used Fuel Storage Program**	0.8	4.0	30.4	35.3	74.1	6.8	81.0	116.2
6	**ARO Adjustment Assignment to Station Level**	(164.8)	(203.5)	865.7	497.4	(88.7)	(115.7)	(204.4)	293.0
7	**Reallocation of Negative Net Book Value of Stations**[1]	(0.9)	0.6	(22.0)	(22.2)	(12.4)	34.7	22.2	0.0
8	**Asset Retirement Cost Adjustment**	(165.7)	(202.9)	843.7	475.2	(101.1)	(81.0)	(182.1)	293.0

1 Net Book Value of Bruce B at December 31, 2009 is $81.0M. The value of Bruce B, after allocation of $115.7M in negative ARC on January 1, 2010 would be negative $34.7M. Per GAAP, the negative value is to be reallocated to other nuclear facilities. The basis of the reallocation was the proportionate net book value of the ARC by station as at January 1, 2010.

Table 4
Revenue Requirement Impact of Adjustment to Nuclear Liabilities Due To Darlington Refurbishment Project ($M)
Years Ending December 31, 2011 and 2012

Line No.	Description	Note or Reference (for Col. (a) and (b))	With Darlington 2011	With Darlington 2012	Note or Reference (for Col. (c) and (d))	Without Darlington 2011	Without Darlington 2012	(a)-(c)+(b)-(d) Revenue Requirement Impact
			(a)	(b)		(c)	(d)	(e)
	PRESCRIBED FACILITIES							
1	**Depreciation of Asset Retirement Costs**	Note 1, C2-T1-S2 Table 1	33.2	33.2	Note 1, C2-T1-S2 Table 1	123.8	123.8	(181.1)
2	**Used Fuel Storage and Disposal Variable Expenses**	C2-T1-S2 Table 1	26.6	28.5	Note 2	22.6	24.3	8.2
3	**Low & Intermediate Level Waste Management Variable Expenses**	C2-T1-S2 Table 1	0.8	0.8	Note 2	0.8	0.8	0.0
	Return on ARC in Rate Base:							
4	**Accretion Rate**	C1-T1-S1 Tables 1 and 2	85.0	83.1	Note 2, 3	51.1	44.2	72.9
5	**Weighted Average Cost of Capital**	C2-T1-S2 Table 5	0.0	0.0	Note 3	0.0	0.0	0.0
6	**Total Revenue Requirement Impact - Prescribed Facilities**		145.7	145.6		198.3	193.0	(100.0)
	(line 1 + line 2 + line 3 + line 4 + line 5)							
	BRUCE FACILITIES							
7	**Depreciation of Asset Retirement Costs**	Note 1, C2-T1-S2 Table 2	28.5	28.5	Note 1, C2-T1-S2 Table 2	48.5	48.5	(40.2)
8	**Used Fuel Storage and Disposal Variable Expenses**	C2-T1-S2 Table 2	17.0	24.0	Note 2	15.1	21.6	4.2
9	**Low & Intermediate Level Waste Management Variable Expenses**	C2-T1-S1 Table 2	0.8	0.7	Note 2	0.8	0.7	0.0
10	**Accretion**	C2-T1-S2 Table 2	294.5	307.2	Note 2	303.8	316.2	(18.3)
11	**Less: Segregated Fund Earnings (Losses)**	C2-T1-S2 Table 2	286.2	304.6	C2-T1-S2 Table 2	286.2	304.6	0.0
12	**Total Revenue Requirement Impact - Bruce Facilities**		54.5	55.8		82.1	82.5	(54.2)
	(line 7 + line 8 + line 9 + line 10 - line 11)							
13	**Total Revenue Requirement Impact of Adjustment to Nuclear Liabilities Due to Darlington Refurbishment Project**							(154.2)
	(col. (e): line 6 + line 12)							

Notes:

1 The 2009 Depreciation Expense would remain unchanged for 2010 to 2012 in the absence of the changes associated with the Darlington Refurbishment Project.

Facilities	2009	2010	(b)-(a) Annual Impact
	(a)	(b)	(c)
Prescribed	123.8	33.2	(90.6)
Bruce	48.5	28.5	(20.1)

2 "Without Darlington" numbers are derived from a base case calculation of Asset Retirement Obligation (ARO) and Asset retirement Costs (ARC) before the Darlington ARO adjustment, and are presented for illustrative purposes.

3 Revenue Requirement impact of accretion rate without Darlington Refurbishment Project.
If the forecast of unfunded nuclear liabilities (total ARO less segregated funds) is lower than the unamortized ARC, then that difference is assumed to be the funded portion of the unamortized ARC.
The funded portion earns a return at the weighted average cost of capital (WACC). During the test period, the unamortized ARC is less than UNL, so none of the unamortized ARC earns the WACC.

Line No.	Description	(2010 amount from Ex. C2-T1-S2 Table 1, line 22, col. (g)) Asset Retirement Cost Opening Balance	(Ex. C2-T1-S2 Table 1 line 26, col. (f)) Depreciation Expense	(a)-(b) Closing Balance	((a)+(c))/2 Gross Plant Rate Base Amount	Average Accretion Rate	(d) x (e) Pre-Tax Revenue Requirement
		(a)	(b)	(c)	(d)	(e)	(f)
	2010 Budget:						
1	Adjustment for Lesser of UNL or ARC	1,098.0	123.8	974.2	1,036.1	5.60%	58.0
	2011 Plan:						
2	Adjustment for Lesser of UNL or ARC	974.2	123.8	850.4	912.3	5.60%	51.1
	2012 Plan:						
3	Adjustment for Lesser of UNL or ARC	850.4	123.8	726.6	788.5	5.60%	44.2

Numbers may not add due to rounding.

Table 5
Revenue Requirement Impact of OPG's Nuclear Liabilities ($M)
Years Ending December 31, 2008, 2009, 2010, 2011 and 2012

Line No.	Description	Note or Reference	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
			(a)	(b)	(c)	(d)	(e)
	PRESCRIBED FACILITIES						
1	**Depreciation of Asset Retirement Costs**	C2-T1-S2 Table 1	124.0	123.8	33.2	33.2	33.2
2	**Used Fuel Storage and Disposal Variable Expenses**	C2-T1-S2 Table 1	19.0	19.2	23.0	26.6	28.5
3	**Low & Intermediate Level Waste Management Variable Expenses**	C2-T1-S2 Table 1	1.7	3.5	1.1	0.8	0.8
	Return on Rate Base:						
4	**Accretion Rate**	Note 1, C1-T1-S1 Tables 1-5	53.9	65.0	86.9	85.0	83.1
5	**Weighted Average Cost of Capital**	Note 3	17.8	0.0	0.0	0.0	0.0
6	**Total Revenue Requirement Impact**		216.4	211.5	144.2	145.7	145.6
	(line 1 + line 2 + line 3 + line 4 + line 5)						
	BRUCE FACILITIES						
7	**Depreciation of Asset Retirement Costs**	C2-T1-S2 Table 2	48.6	48.5	28.5	28.5	28.5
8	**Used Fuel Storage and Disposal Variable Expenses**	C2-T1-S2 Table 2	14.0	14.4	16.7	17.0	24.0
9	**Low & Intermediate Level Waste Management Variable Expenses**	C2-T1-S2 Table 2	11.2	4.4	0.9	0.8	0.7
10	**Accretion**	Note 2, C2-T1-S2 Table 2	200.6	279.3	282.4	294.5	307.2
11	**Less: Segregated Fund Earnings (Losses)**	Note 2, C2-T1-S2 Table 2	(138.0)	386.2	268.8	286.2	304.6
12	**Return on Rate Base**	Note 4	15.4	0.0	0.0	0.0	0.0
13	**Total Revenue Requirement Impact**		427.6	(39.5)	59.6	54.5	55.8
	(line 7 + line 8 + line 9 + line 10 - line 11 + line 12)						

Notes:

1 Effective April 1, 2008: Lesser of ARC and UNL earns the weighted average accretion rate. Accretion Rate Prior to April 1, 2008 was not used to determine revenue requirement.

2 Return on Rate Base, Accretion, and Segregated Fund Earnings for 2008 are prorated by 9/12 to remove pre-April 1, 2008 amounts.

3 If UNL is less than ARC then the funded ARC earns WACC effective April 1, 2008.
Prior to April 1, 2008 the entire ARC earned WACC. Before April 1, 2008 WACC of 5.55% (55% debt *6% + 45% equity *5%) applied to entire ARC.

Year	ARC ($M) (from C2-T1-S2 Table 1)	UNL ($M) (from C2-1-2 Table 1)	ARC-UNL ($M) (a)-(b)	Annual WACC	Return* ($M) (c)x(d)	WACC Reference
	(a)	(b)	(c)	(d)	(e)	
2008 Pre-April 1	1,283.7	n/a	1,283.7	5.55%	17.8	
2008 Post April 1	1,283.7	1,329.1	(45.3)	5.37%	0.0	Note 4
2009	1,159.8	1,449.7	(289.9)	7.19%	0.0	Note 4
2010	1,556.5	1,783.5	(227.0)	3.94%	0.0	C1-T1-S1 Table 3
2011	1,523.3	1,695.7	(172.4)	7.56%	0.0	C1-T1-S1 Table 2
2012	1,490.1	1,620.8	(130.7)	7.59%	0.0	C1-T1-S1 Table 1

* Return for the prescribed facilities for 2008 Pre-April 1 and for 2008 Post April 1 are prorated by 3/12 and 9/12 respectively.

4 OPG was disallowed the opportunity to earn a return on these assets effective April 1, 2008. OPG earned 5.55% on its average unamortized ARC (per Ex. C2-T1-S2 Table 2) prior to April 1, 2008.

Report to Ontario Power Generation

Technology-Specific Capital Structures: An Assessment

Kathleen C. McShane
President
Foster Associates, Inc.

TABLE OF CONTENTS

I. BACKGROUND

Ontario Power Generation (OPG) retained Foster Associates to conduct a study to determine whether or not separate capital structures could be established for OPG's nuclear and regulated hydroelectric business segments with sufficient rigor to enable the Ontario Energy Board ("OEB" or "the Board") to rely upon the results in establishing OPG's nuclear and regulated hydroelectric payment amounts. The need for the study arose from the findings of the Board in EB-2007-0905 (*Reasons for Decision*, November 3, 2008, "*Decision*") governing the cost of capital for OPG's combined nuclear and hydroelectric operations. In that decision, a single cost of capital was determined for OPG's prescribed assets and attributed to nuclear and hydroelectric operations using a rate base allocation factor. Testimony was presented with respect to technology-specific capital structures during EB-2007-0095, but the Board concluded that the evidence presented was "not sufficiently robust to set separate parameters at this time." However, the Board stated that "there may be merit in establishing separate capital structures for the two businesses as it would enhance transparency and more accurately match costs with the payment amounts" (Page 162). The Board concluded therefore that the question should be further explored in OPG's next proceeding. This report was prepared in response to the Board's directive.[1]

[1] The qualifications of Kathleen C. McShane are found in Appendix F to this report.

II. EXECUTIVE SUMMARY

A. The analysis conducted in this report responds to the Board's directive in EB-2007-0905 to explore the merits of separate capital structures for OPG's regulated hydroelectric and nuclear businesses. The analysis took as its point of departure the Board's general approach to setting the allowed return for utilities under its jurisdiction, that is, establishing a benchmark return on equity ("ROE") and recognizing differences in risk through capital structure. The analysis specifically relied on the parameters that were established in EB-2007-0905, as revised by EB-2009-0084 *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities,* issued December 11, 2009 ("*Report of the Board, 2009*"). Specifically, the analysis accepted as given the 47% common equity ratio adopted by the Board in EB-2007-0905 for OPG's composite regulated hydroelectric and nuclear operations and the benchmark ROE, as revised in the *Report of the Board, 2009*, estimated to be 9.8% based on December 2009 data.

B. The analysis of separate capital structures for the two operations is premised on the following considerations:

1. The relevant cost of capital to be used in setting the allowed return should reflect the opportunity cost principle, that is, the returns that are available from investments of comparable risk;

2. The cost of capital is a function of business risk and financial risk;

3. There is a trade-off between capital structure and cost of equity. As the debt ratio rises, the cost of equity rises. The analysis of appropriate capital structures needs to recognize the trade-off between capital structure and cost of equity. If proxy

firms are to be used in the estimation of capital structures, both their capital structures and associated costs of equity must be taken into account. Higher business risk is not always reflected in the capital structure.

4. The estimation of technology-specific capital structures at which the cost of equity is the same requires a quantitative translation of cost of equity differences of proxy firms into capital structure equivalents. To the extent required by the analysis, the conversion of differences in the cost of equity among proxy samples into capital structure equivalents will be based on the premise that the overall cost of capital is constant across the relevant range of capital structures.

5. The basic principles that should be respected in the estimation of capital structures include:

   (a) The stand-alone principle should be respected;

   (b) The individual capital structures should be compatible with the business risks of the relevant operations;

   (c) The individual capital structures in conjunction with the cost of equity should be compatible with the objective of maintaining financial integrity and creditworthiness, i.e., consistent on a stand-alone basis with maintenance of investment grade credit ratings; and

   (d) The capital structures, in conjunction with the returns on equity, should be comparable on a risk-adjusted basis to the returns adopted for other regulated firms.

C. An assessment of the business risks of OPG's prescribed assets, focusing on changes in the absolute or relative business risks of the regulated hydroelectric and nuclear operations since EB-2007-0905 and changes in the relative business risks that have occurred as a result of the *Decision*, indicates the following:

1. The major change which has occurred since the Board issued its Decision is the passage of the Green Energy and Green Economy Act. From a business risk perspective, the legislation, in conjunction with low demand conditions, increases the dispatch risk of both the regulated hydroelectric and nuclear operations, with the larger impact on the hydroelectric generation operations. The increased dispatch risk that arises from surplus baseload generation translates into increased forecasting risk. The associated impact on the cost of capital for either the hydroelectric or the nuclear operations during the test period is likely to be small, not amenable to quantification and unlikely to materially change the relative business risk of the two regulated operations.

2. As a consequence of the Board's decision, the risks to which the nuclear operations are exposed are higher than was anticipated in the EB-2007-0905 risk assessment. The change in relative risk is largely due to two factors, the Board's decision not to adopt a fixed payment for the nuclear operations and to adopt a different ratemaking treatment for the nuclear liabilities than was proposed by OPG. The adopted ratemaking treatment for the nuclear liabilities has increased the financial risks to which the nuclear operations are exposed.

D. The estimation of the cost of capital, including capital structures, for entities which are not publicly-traded, including segments of firms, requires reference to proxy companies for which capital market data are available. OPG's regulated hydroelectric and nuclear operations are unique. There are no proxy companies with capital market data whose operations are similar to the regulated operations of OPG either on a composite basis or on a technology-specific basis. The lack of comparable firms renders the estimation of the cost of capital for OPG's regulated generation as a whole subject to significant judgment and the isolation of the cost of capital for regulated generation by technology subject to even more judgment.

E. There are no Canadian companies with market data available to serve as proxies for the estimation of technology-specific capital structures. The quantitative analysis therefore focuses on publicly-traded U.S. electric utilities which, while imperfect comparators, provide a pool of potential proxies, particularly for the regulated nuclear operations. However, there are an insufficient number of U.S. electric utilities with significant hydroelectric generation operations from which to isolate the stand-alone cost of capital for regulated hydroelectric operations.

F. To attempt to estimate technology-specific capital structures, a number of recognized empirical approaches for the estimation of the cost of capital for non-traded entities were examined, including the accounting beta, pure play, instrumental beta, residual beta and full information beta approaches. All of the methodologies, with the exception of the pure play approach, are derivatives of the Capital Asset Pricing Model (CAPM). The usefulness of CAPM based models to estimate technology-specific costs of capital is questionable, inasmuch as the principal fundamental difference in risks between the regulated hydroelectric and nuclear operations is attributable to production and operating risks. In principle, the CAPM measures the return requirement for non-diversifiable risks, that is, not company-specific risks, but risks that are attributable to market-wide factors, e.g., inflation, commodity prices, and interest rates. From a CAPM perspective, production and operating risks are company-specific, largely unrelated to capital market or economy-wide events and thus should be largely diversifiable, i.e., reduced or eliminated in a portfolio of investments. The CAPM assumes that these risks are not "priced" by the capital markets.

G. The accounting beta approach entails estimating an accounting analogue of a market beta, where the co-variability of a business's book earnings with those of the equity market composite (that is, the extent to which they move together) over a business cycle serves as a proxy for the market beta. However, as this report and other studies show, there is weak empirical support for a statistically significant relationship between accounting and market betas. From a pragmatic perspective, there are insufficient earnings data available for OPG's regulated hydroelectric and nuclear operations to create accounting betas.

H. The pure play approach entails identifying publicly traded companies operating in the same line of business as the business for which the cost of capital needs to be estimated. There are no publicly traded companies which operate either solely or predominantly in regulated hydroelectric or nuclear generation production.

I. The instrumental beta approach attempts to determine by way of regression analysis the empirical relationships between market betas and risk variables such as volatility of earnings. The quantitative analysis using U.S. electric utilities showed a consistently statistically significant relationship between market betas and only two variables, debt ratings and volatility (standard deviation) of ROEs. There was no empirical relationship observed between market beta and either the proportion of generation relative to wires operations or between market beta and nuclear generation production.

The quantitative estimation of the model suggested that the cost of equity is not very sensitive to the volatility of earnings, suggesting that, even if sufficient data were available, the methodology would not provide a sufficient basis for estimating technology-specific capital structures. In OPG's case, there are an insufficient number of data points to estimate meaningful standard deviations of ROEs. Further, those that are available are not strictly comparable due to the change in regulatory framework. Therefore, the instrumental variables approach does not provide a useful means for estimating technology-specific capital structures.

J. The residual beta approach attempts to extract a beta for a specific operation whose beta is unknown from the observed betas of firms with a limited number of operations including the one for which the residual beta is being estimated. When the betas of the other operations are known and the contributions of each operation to the consolidated performance of the firm are known, in theory, the residual beta of the operation of interest can be extracted from the market betas of the firms.

This methodology was identified as a potentially useful tool to isolate betas for the generation function as a whole and for nuclear generation specifically. The model was not applied to the hydroelectric operations as there are too few utilities with sufficient hydroelectric generation operations. The results of applying the model were inconsistent over time and in some instances incongruous with the expected outcomes. The inconsistent and incongruous results arise in part because the relative betas for various samples were frequently inconsistent with the relative risks, or were too similar to allow the isolation of a meaningful generation or nuclear generation beta. In addition to measurement problems with the betas themselves, the inability of the model to consistently extract meaningful generation or nuclear generation beta may also arise from influences on the cost of capital that are not expressly generation function related (e.g., regulatory climate).

K. The Full Information Beta approach is conceptually similar to the Residual Beta approach. The principal difference is that the full information beta requires only the observed market betas applicable to the consolidated firm and the percentage contribution of each line of business to the consolidated firm. The model uses regression analysis to directly estimate the betas for all the segments of the business. As the Full Information Beta approach is conceptually similar to the Residual Beta approach and uses similar input data, its drawbacks are similar to those of the Residual Beta methodology. From a practical perspective, the lack of proxy companies with significant hydroelectric generation operations limits its application to OPG's regulated nuclear operations. Further, similar to the Residual Beta methodology, the Full Information Beta methodology yielded inconsistent and incongruous results, depending on the time period over which the betas were measured.

L. In summary, five different quantitative methodologies were considered as potential avenues for isolating the cost of capital for OPG's regulated hydroelectric and nuclear generation operations. Four of the five, the exception being the pure play approach, are premised on the CAPM. None of the five proved to be sufficiently robust to serve as a basis for estimating technology-specific costs of capital and thus technology-specific capital structures for OPG's regulated hydroelectric and nuclear prescribed assets.

M. In the absence of a robust empirical method for estimating technology-specific capital structures, the debt rating guidelines of the major debt rating agencies were examined as a potential, albeit subjective, avenue for setting technology-specific capital structures. Standard & Poor's and Moody's debt rating guidelines specify debt ratio ranges for different levels of business risk and debt ratings. Reliance on the guidelines to specify technology-specific capital structures requires the application of significant judgment to estimate the business risk category or implied business risk debt ratings that Standard & Poor's or Moody's would hypothetically apply to each of the regulated hydroelectric and nuclear operations on a stand-alone basis.

The fundamental deficiency of reliance on debt rating agency guidelines for the purpose of establishing technology-specific capital structures is that the guidelines are focused on requirements from a debt investor's perspective, not the equity investor's perspective. There is no direct correlation between the capital structure ratio guidelines published by the rating agencies and the cost of equity. In other words, the adoption of capital structures for two regulated companies in different business risk categories within the ranges suggested by the Standard & Poor's guidelines for those business risk categories does not mean that their costs of equity will be the same. That outcome, however, is the premise of the Board's methodology, i.e., setting a benchmark ROE and adjusting for differences in business risk through capital structure.

N. In the absence of comparable pure play publicly-traded companies, an attempt was made to identify proxy companies that could be viewed as facing reasonably comparable levels of business risk, rather than the specific business risks, faced by each of the regulated hydroelectric and nuclear operations. The costs of capital for the two samples could then be estimated and compared, with the differential in cost of capital used to estimate technology-specific capital structures.

Application of the selection criteria, which included the qualitative business risk categories assigned by Standard & Poor's to each of the regulated companies whose debt it rates, identified nine companies which could be viewed as comparable to the hydroelectric operations, but only three companies which qualified as proxies for the regulated nuclear operations. A sample of three was determined to be too small to permit robust estimates of the cost of capital which could be compared with confidence to cost of capital estimates for the hydroelectric proxy sample.

O. The qualitative assessment of the relative business risks of the hydroelectric and nuclear operations supports the conclusion that the nuclear operations face materially higher business risks than the hydroelectric operations. However, given the constraints of the available market data and the lack of proxy companies that are comparable to each of the two technologies, none of the analyses conducted were able to provide any quantitative insight into reasonable differential capital structures for the two operations. Any specification of technology-specific capital structures would be largely a judgmental exercise and lack any degree of precision. Given the degree of judgment that would be required and the absence of robust parameters upon which to base that judgment, there is no compelling basis for the Board to adopt technology-specific capital structures.

III. RELEVANT CONCLUSIONS OF THE OEB FROM THE EB-2007-0905 *DECISION WITH REASONS*

With respect to the cost of capital (capital structure and ROE) applicable to OPG's regulated operations, in the EB-2007-0905 *Decision*, the Board reached a number of conclusions that are germane to the analysis of technology-specific capital structures.

1. In its conclusion that it intended to further explore the issue of separate capital structures for the two businesses, the Board stated that the inquiry would be limited to the issue of separate capital structures and that it intended to apply the same ROE to both types of generation, consistent with the Board's general approach of setting a benchmark ROE and recognizing risk differences in the capital structure.

   The analysis therefore will focus on the estimation of technology-specific capital structures consistent with a single ROE applicable to both businesses.

2. The Board also noted the following:

   > The Board recognizes that this approach will not alter the overall cost of capital for OPG's prescribed facilities. However, in all other significant respects the specific costs for the hydroelectric and nuclear businesses are used to derive the specific payments for each type of generation. Specific and separate costs of capital for hydroelectric and nuclear would be consistent with the separate nature of these businesses and would provide a more transparent link between the payment amounts for each type of generation and the underlying costs. (*Decision*, page 162)

   The common equity ratio for OPG's prescribed assets was deemed to be 47% equity with an allowed ROE set using the OEB's ROE formula.

The analysis for the purpose of estimating technology-specific capital structures will proceed on the premise that the common equity ratio for OPG's prescribed assets in total will remain at 47% and the allowed ROE for both the prescribed assets in total and the regulated hydroelectric and nuclear assets individually will be based on the OEB's ROE formula.

3. The stand-alone principle is to be respected. Specifically, the Board stated the stand-alone principle is a long-established regulatory principle and, as OPG is operated at arm's length by the provincial government, it should be treated as other provincially-owned utilities regulated by the Board are treated. "In other words, Provincial Ownership will not be a factor to be considered by the Board in establishing capital structure." (*Decision*, page 142)

   The stand-alone principle is equally applicable to the estimation of technology-specific costs of capital and capital structures.[2]

4. In its decision, the OEB stated that the determination of the appropriate capital structure for OPG should be based on a thorough assessment of the risks faced by OPG, the changes in those risks over time and the level of OPG's risk relative to that faced by other utilities. The Board's decision was based on its assessment of OPG's risks, including regulatory and operating risks.

   The focus of this analysis will be on changes in the risks of the two operations which have occurred both since the *Decision* and as a result of the *Decision*.[3]

[2] The stand-alone principle is discussed in further detail in Section V.D.
[3] The trend in business risks of the prescribed hydroelectric and nuclear assets is discussed in Section VI.

IV. REPORT OF THE BOARD ON THE COST OF CAPITAL FOR ONTARIO'S REGULATED UTILITIES

The OEB first adopted a formula-based approach to establishing the cost of capital for Ontario's natural gas utilities in March 1997, expanded to the electricity sector in 1999. The approach adopted used the Equity Risk Premium ("ERP") method for determining the fair rate of return on common equity for those utilities. The Board's approach was reviewed in 2006 and the resulting report, *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, dated December 20, 2006, set out the method to be used for determining the cost of capital for electricity distributors ("2006 Report").

In March 2009, subsequent to issuing its Decision, the Board initiated a consultative process to review the methods by which the cost of capital was established for Ontario's regulated utilities. The decision to initiate a consultative process arose, in part, from concern over the cost of capital parameters arising out of the cost of capital formulation as outlined in the 2006 Report.

In December 2009, the Board issued a policy report, EB-2009-0084, *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, December 11, 2009 ("*Report of the Board, 2009*"), in which it established a new base ROE of 9.75% and refined the automatic adjustment formula.

The base ROE of 9.75% incorporates a risk premium of 550 basis points over a long-term Government of Canada bond yield of 4.25%. Going forward, the refined formula-based ROE is to be calculated as the base ROE + 0.5 X (change in Long Canada Bond Forecast from base year) + 0.5 X (change in the spread of (A-rated Utility Bond Yield – Long Canada Bond Yield) from the spread in the base year).

The revised base ROE represents the same concept as the base ROE it replaced. The revised base ROE is intended to represent the fair return on equity that would be applicable to a benchmark utility, with differences in business risk between a benchmark utility and a specific regulated company reflected in differences in capital structure. Similarly, the refined automatic adjustment mechanism is intended to capture more accurately changes in the cost of equity for a benchmark utility than the formula that it replaced. Given that the revised base ROE and the refined automatic adjustment formula represent the same concepts that were adopted for OPG's prescribed assets in EB-2007-0905, both should be applicable to OPG at the capital structure appropriate to the business risks of the prescribed assets.

For the purpose of the assessment of technology-specific capital structures, the ROE will be based on the revised base ROE established in the December 2009 *Report of the Board* as adjusted using the refined automatic adjustment formula. Based on December 2009 data, the ROE for 2011 is estimated at 9.80%.

V. CONCEPTUAL CONSIDERATIONS

A. RATIONALE FOR SEPARATE CAPITAL STRUCTURES FOR NUCLEAR AND HYDROELECTRIC PRESCRIBED ASSETS

The principal rationale for establishing separate costs of capital for different businesses is the basic economic principle that the cost of capital should reflect the use of funds (i.e., the risk of the investment), in contrast to the source of funds. The relevant cost of capital should recognize the opportunity cost principle, which means that the cost of capital should reflect the return that is available from alternative investments of comparable risk. Using a cost of capital that recognizes the risk of the assets ensures that a scarce resource, capital, is efficiently allocated.

Although there is a valid economic argument in support of separate costs of capital for different functions of a business, regulators frequently rely on a single company-wide capital structure even when faced with considerable differences in risks among functions. To illustrate, the National Energy Board relied on a single capital structure for Westcoast Energy's jurisdictional operations, even though the risks of the company's natural gas mainline and its processing facilities differ significantly.

B. APPROACHES TO RECOGNIZING UTILITY-SPECIFIC DIFFERENCES IN BUSINESS RISK

The overall cost of capital to a firm depends, in the first instance, on business risk. Business risk comprises the fundamental characteristics of the business (e.g., demand, supply and operating factors) that together determine the probability that future returns to investors will fall short of their expected and required returns. Business risk thus relates largely to the assets of the firm. For regulated companies, the business risks also include regulatory risks, i.e., the regulatory framework under which the utility operates. The prevailing regulatory framework effectively represents the current allocation of the fundamental business risks between investors and ratepayers. Regulatory risk can be considered either as a component of business risk or as a separate risk category along with business and financial risk.

The cost of capital is also a function of financial risk. Financial risk refers to the additional risk that is borne by the equity shareholder because the firm is using fixed income securities – debt and preferred shares – to finance a portion of its assets. The capital structure, comprised of debt, preferred shares and common equity, can be viewed as a summary measure of the financial risk of the firm. The use of debt in a firm's capital structure creates a class of investors whose claims on the cash flows of the firm take precedence over those of the equity holder. Since the issuance of debt carries unavoidable servicing costs which must be paid before the equity shareholder receives any return, the potential variability of the equity shareholder's return rises as more debt is added to the capital structure. Thus, as the debt ratio rises, the cost of equity rises.

There are effectively two approaches that can be used to determine a fair return. The first is to assess the fundamental business and regulatory risks of the regulated operations, then establish a capital structure that is compatible with those risks and permits the application of a benchmark cost of equity without any adjustment. This approach can be applied to a spectrum of regulated businesses within a range of combined fundamental business and regulatory risks.

The second approach entails acceptance of a regulated company's actual capital structure for regulatory purposes or deeming a capital structure for a regulated business that adequately protects bondholders but does not necessarily equate the total (business, regulatory and financial) risk of the regulated company to the total risk of the proxy or "benchmark" companies used to estimate the cost of equity. If the total risk of the benchmark or proxy companies is higher or lower than that of the regulated business at the latter's actual or deemed capital structure, an adjustment to the benchmark cost of equity would be required.

Both approaches are equally valid as long as the combination of capital structure and return on equity result in an overall return which satisfies the fair return standard.

In summary, the various components of the cost of capital are inextricably linked; it is impossible to determine if the return on equity for a regulated business is fair and reasonable without reference to the capital structures of both the proxy companies and the specific regulated business to which the allowed return is intended to apply. Similarly, it is impossible to determine if the capital structure for a regulated business is fair and reasonable without reference to the cost of equity of the proxy companies. It is the overall return on capital which must meet the requirements of the fair return standard.

For OPG, in EB-2007-0905, the OEB employed the first approach. The Board applied a benchmark utility cost of equity to OPG's total regulated operations (the prescribed assets), recognizing OPG's higher business risk relative to other regulated Ontario utilities through the capital structure.

For purposes of assessing technology-specific capital structures, the approach taken by the OEB in determining the cost of capital for the total regulated operations of OPG will be followed. As noted above, as set out in EB-2007-0905, this is the approach that the Board expected would be followed.

C. TRADE-OFF BETWEEN COST OF EQUITY AND CAPITAL STRUCTURE

The rationale for the differences in the required return on equity for companies of similar business risk but different financial risk begins with the recognition that the overall cost of capital for a firm is primarily a function of business risk. In the absence of both the deductibility of interest expense for income tax purposes and costs associated with excessive debt (e.g., bankruptcy), the overall cost of capital to a firm would not change when a firm changes its capital structure.[4]

The use of debt creates a class of investors whose claims on the resources of the firm take precedence over those of the equity holder. However, the sum of the available cash flows does not change when debt is added to the capital structure. The available cash flows are now split between debt and equity holders. Since there are fixed debt costs that must be paid before the equity shareholder receives any return, the variability of the equity return increases as debt rises. The higher the debt ratio, the higher the potential volatility of the equity return. Hence, as the debt ratio rises, the cost of equity rises. The higher cost rates of both the debt and equity offset the higher proportion of debt in the capital structure, so that the overall cost of capital does not change.

The deductibility of interest expense for corporate income tax purposes alters the conclusion that the cost of capital is constant across all capital structures. The deductibility of interest expense for income tax purposes means that there is a cash flow advantage to equity holders from the assumption of debt. In the absence of offsetting factors, when interest expense is deductible for corporate income tax purposes, the after-tax cost of capital declines as more debt is used.[5]

[4] The seminal theory, which was premised on no risk to excessive debt, was set out in Franco Modigliani and Merton H. Miller, "The Cost of Capital, Corporation Finance and the Theory of Investment," *American Economic Review*, 48: 261-297 (June 1958).
[5] Franco Modigliani and Merton H. Miller, "Corporate Income Taxes and the Cost of Capital: A Correction," *American Economic Review*, 53: 433-443 (June 1963).

Offsetting some of the advantage of debt at the corporate level are the higher personal tax rates on interest income than on dividend income and capital gains. When personal income tax rates on dividends and capital gains are lower than the personal income tax rate on interest income, all other things equal, investors would prefer firms to use equity rather than debt. If taxes were the only consideration, there are combinations of corporate and personal income taxes at which the corporate tax advantages of using debt are completely offset by the personal tax advantages to holding equity rather than debt.[6]

However, factors other than taxes impact the choice of capital structure. The addition of debt to the capital structure is not risk-free. There is a loss of financial flexibility and an increasing potential for bankruptcy as the debt ratio rises. The result is an increase in the cost of capital as leverage is increased. For example, as the percentage of debt in the capital structure increases, the company's credit rating may decline and its cost of debt will increase. When the loss of financing flexibility and costs of financial distress impair a firm's ability to operate efficiently, e.g., to pursue opportunities to grow the business or even to obtain trade credit as required, the cost of equity and the overall cost of capital will likely increase more than pure theory would indicate.

It is impossible to state with precision whether, within a specific range of capital structures, raising the debt ratio will leave the overall cost of capital unchanged or result in some decline. However, what is indisputable is that the cost of equity does change when the debt ratio changes, increasing when the debt ratio increases and, conversely, decreasing when the debt ratio falls.

In the estimation of appropriate technology-specific capital structures, it must be recognized that higher business risk is not necessarily captured in a more conservative capital structure. The British Columbia Utilities Commission, for example, has traditionally reflected differences in business risk in both capital structure and return on equity. If one were using the allowed returns of other utilities as benchmarks for

[6] The offsetting impacts of lower personal tax rates on equity income compared to interest income were examined in Merton H. Miller, "Debt and Taxes," *The Journal of Finance*, 32: 261-276 (May 1977).

estimating technology-specific capital structures for OPG, it would be necessary to take account of both the capital structure and the incremental equity risk premium adopted for the specific utility in the analysis.

Similarly, if the analysis relies on market data for proxy companies to estimate the appropriate capital structure for a specific operation (where the cost of equity has already been prescribed), both the capital structure and the cost of equity of the proxy companies must be taken into account. To illustrate, assume that the objective is to estimate an appropriate capital structure for regulated generation that is exposed to higher business risks than those of vertically integrated electric utilities but lower than those of merchant generators. Samples of both are used to position the regulated generation operations on a relative business risk basis and then to estimate the appropriate capital structure for regulated generation operations. It would be insufficient to look solely at the comparators' capital structures without also considering their costs of equity. Conversely, it would be insufficient to look solely at the comparators' costs of equity without considering their capital structures. Since merchant generators face higher business risks than vertically integrated utilities, they face a higher overall cost of capital. Merchant generators may also be more highly leveraged (higher debt ratio) than vertically integrated electric utilities. Hence their cost of equity would be higher than that of vertically integrated electric utilities not only due to higher business risk, but also due to higher financial risk.

Failure to account for both business risk and financial risk differences could result in allowing a return on the regulated generation assets which either under or over compensates the equity shareholders for the business risks they face. For any regulated operation, it is the overall return, which reflects both capital structure and return on equity, that must meet the requirements of the fair return standard.[7]

[7] The fair return standard was articulated by the National Energy Board in its RH-2-2004 Phase II decision (and cited by the OEB in its December 2009 *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*) as follows:

A fair or reasonable return on capital should:

The objective of the analysis for this report is to estimate capital structures for each of OPG's regulated hydroelectric and nuclear operations such that (1) the individual capital structures of the two operations reasonably reflect their relative business risks; (2) the overall common equity ratio for the prescribed assets is equal to the 47% adopted in EB-2007-0905; and (3) the cost of common equity is the same for the total regulated operations, the regulated hydroelectric operations and the regulated nuclear operations. To achieve this objective, differences in equity costs among proxy companies must be quantitatively translated into differences in common equity ratios. In this context, the translation will proceed on the premise that the cost of capital is constant across the relevant range of capital structures.

D. PRINCIPLES FOR THE EVALUATION OF CAPITAL STRUCTURES

The following principles should be respected when assessing appropriate capital structures.

1. The Stand-Alone Principle.
2. Compatibility of Capital Structure with Business Risks.
3. Maintenance of Creditworthiness/Financial Integrity.
4. Comparability of Returns

Each of these principles is defined below.

• be comparable to the return available from the application of invested capital to other enterprises of like risk (the comparable investment standard);
• enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and
• permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).

D.1. The Stand-Alone Principle

The stand-alone principle encompasses the notion that the cost of capital incurred by each of each regulated company should be equivalent to that which would be faced if it was raising capital in the public markets on the strength of its own business and financial parameters; in other words, as if it were operating as an independent entity. The cost of capital for the company should reflect neither subsidies given to, nor taken from, other activities of the firm. Respect for the stand-alone principle is intended to promote efficient allocation of capital resources among the various activities of the firm.

As long as capital is raised for a company with multiple operations such as an integrated electric utility, the capital markets will appraise the risk on that basis. An electric utility which, for example, has transmission, distribution and generation operations is likely in fact to be able to operate at a somewhat lower common equity ratio, due to the effect of diversification, than a pure functional "stand-alone" analysis would indicate. It is important to recognize that the application of a “pure” stand-alone approach for rate setting purposes will result in a higher cost of capital than one which reflects the impacts of diversification.

D.2. Compatibility of Capital Structure with Business Risks

The capital structure of a utility should be consistent with the business and regulatory risks of the specific entity for which the capital structure is being set. Business risk is defined and discussed in Section VI.

D.3. Maintenance of Creditworthiness/Financial Integrity

A reasonable capital structure, in conjunction with the returns allowed on the various sources of capital, should provide the basis for stand-alone investment grade debt ratings. In contrast to unregulated companies, public utilities have obligations that require them to raise capital "on demand". Although OPG's regulated operations are not governed by the traditional obligation to serve, its mandate includes continuous improvement of both its regulated nuclear and hydroelectric generation fleet. OPG needs to maintain access to the debt markets on reasonable terms and conditions to carry out its mandate. Consistent with the stand-alone principle, if technology-specific capital structures are to be considered, each should contribute its fair share toward the maintenance of the creditworthiness of the entity which raises capital on their behalf.[8]

D.4. Comparability of Returns

The combination of the adopted capital structure and return on capital for each operation should be comparable on a risk-adjusted basis to the returns adopted for other regulated firms.

[8] A rigid application of the stand-alone and creditworthiness/financial integrity principles would impute to individual operations both the actual cost of debt that that each would be able to obtain on its own and the capital structure that would be required by a potential lender to provide debt capital in the absence of its affiliation with the entity which actually raises the capital on its behalf.

VI. BUSINESS RISK ASSESSMENT OF OPG'S PRESCRIBED ASSETS

A. OVERVIEW

In EB-2007-0905, OPG filed for a capital structure and ROE for its prescribed assets, which as of December 2008 included 6,606 MW of in-service nuclear generating capacity and 3,332 MW of in-service hydroelectric generating capacity. The filed-for capital structure and ROE were premised on the regulatory framework proposed by OPG and an assessment of the business risks to which the prescribed assets would be exposed under that framework. The business risks to which investors in a utility are exposed are those that reflect the basic characteristics of the operating environment and regulatory framework of the utility that can lead to the failure to recover a compensatory return on and/or the return of the capital investment itself. Business risks include market demand, supply, physical/operating and regulatory risks. While different categories of business risk can be identified, the risks are inter-related.

In EB-2007-0905, the Board adopted certain of OPG's proposed ratemaking mechanisms, denied others, and adopted a capital structure and ROE based on its assessment of the business risks to which the prescribed assets would be exposed under the adopted framework. The objective of this section is to assess whether there have been changes in the absolute and relative business risks of the regulated nuclear and hydroelectric operations which have occurred either since the *Decision* or result from the *Decision*.

B. BUSINESS RISKS OF THE COMPOSITE PRESCRIBED ASSETS

B.1. Revenue and Market-Related Risks

Market risks for OPG are defined, in part, by the economy in which it operates. The business risk assessment conducted by Foster Associates in the latter half of 2007 concluded that, while the diversity and strength of the economy are positive for the overall business risk assessment of OPG, the challenges to the manufacturing sector expose the regulated operations to some risk of lower revenues due to decreased demand, both from cyclical declines and long-term demand destruction.

The Ontario economy generally and the manufacturing sector specifically, which accounts for a significant portion of the electricity consumed in the Province,[9] have been relatively hard hit by the global recession. The Ministry of Finance noted in its 2009 *Ontario Economic Outlook and Fiscal Review*:

> the global economic downturn hit Ontario's economy relatively hard compared to other provinces. Manufacturing, especially the auto sector, is a large and important part of Ontario's economy and it has been particularly affected by the recession. Declining U.S. demand caused Ontario auto manufacturing sales to fall by 37 per cent over the first eight months of 2009, compared to the same period in 2008. Ontario's decline in real GDP in 2009 is expected to be significantly larger than Canada's as a whole, and that of all the other provinces except Newfoundland and Labrador.

Electricity demand fell sharply in Ontario in 2009; the IESO reported in its *18-Month Outlook from December 2009 to May 2011* that energy demand dropped 5.7% in 2009. The IESO also predicted that the economic recovery is unlikely to stimulate a significant rebound in electricity demand and that, over the coming months, industrial energy demand will continue to be hampered by the high dollar and rationalization within the manufacturing sector.

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[9] T. Rosemary Yeremian, *Three Perspectives on Energy Demand and the Manufacturing Sector: The Good, the Bad and the Unanticipated*, www.strategicinsights.ca, originally published in IPPSO FACTO Magazine, 2009

The 2007 business risk assessment also pointed to low, but rising, dispatch risk creating surplus baseload generation attributed to OPG's prescribed assets, which are primarily baseload facilities. The Board's decision found that the dispatch risks, described as the risk that baseload generation from OPG's regulated assets will not be dispatched because of economic conditions and/or the presence of generators with lower marginal costs, are low.

Subsequent to the 2008 regulated payments proceeding, the Ontario government passed the Green Energy and Green Economy Act, to position Ontario as a world leader in green energy. The legislation created a Feed-in Tariff program (replacing the previous Renewable Energy Standard Supply Program); the Feed-in Tariff program provides for attractive long-term contractually guaranteed prices for wind, hydroelectric, and biomass projects, designed to attract additional new investment in the renewable energy sector. The development of green energy projects under the Feed-in Tariff program will potentially lead to an increasing occurrence of surplus baseload generation. The adoption of the Green Energy and Green Economy Act and the potential softening of demand support the conclusion that the dispatch risk to which OPG's regulated operations are exposed is rising.

B.2. Production, Operating and Cost Recovery Risks

Production, operating and cost recovery risks include all factors that may result in OPG under recovering a reasonable return on investment and/or a part of the investment itself due to higher than anticipated costs of production, lower than anticipated production or loss of production. As the production, operating and cost recovery risks are largely specific to the generation technology, they are discussed as applicable in the individual hydroelectric and nuclear operations sections below.

C. BUSINESS RISKS OF THE HYDROELECTRIC OPERATIONS

C.1. Revenue and Market-Related Risks

The key revenue risks identified in the 2007 business risk assessment for the hydroelectric operations were the structure of the regulated payments (100% energy based) as compared to the largely fixed cost structure and the dispatch risk, resulting in surplus baseload generation from OPG's prescribed hydroelectric assets, which was assessed as low but rising. With respect to the latter, rising dispatch risk is supported, as noted above, by the passage of the Green Energy and Green Economy Act and low demand conditions. The risk that OPG's regulated baseload facilities will not be dispatched is higher for the hydroelectric operations, as the nuclear production facilities are not designed to ramp up and down, while hydroelectric production can be curtailed by spilling water at the generation facilities.

C.2. Changes in Business Risk since EB-2007-0905

With the exception of a modest increase in dispatch risk during the test period due to the passage of the Green Energy and Green Economy Act and low demand conditions, the business risks faced by OPG's regulated hydroelectric operations remain largely unchanged since EB-2007-0905.

D. BUSINESS RISKS OF THE REGULATED NUCLEAR OPERATIONS

D.1. Revenue and Market-Related Risks

As with the hydroelectric operations, revenue risks of the regulated nuclear operations are partly a function of the payment structure in relation to the cost structure. The cost structure of the nuclear operations is largely fixed, i.e., do not vary directly with changes in production. In EB-2007-0905, OPG proposed a payment structure for the regulated nuclear operations that would recover 25% of the forecast nuclear revenue requirement in a fixed charge. The 2007 business risk assessment was premised on the implementation of the proposed fixed charge, which would have reduced the regulated nuclear operations' revenue risks.

The Board declined to approve OPG's proposed payment structure, instead adopting a 100% energy-based regulated payment. The Board concluded that OPG should be fully incented to produce as accurate a forecast of nuclear production as possible and should be at risk if actual output falls short of forecast. The adoption of a 100% energy-based regulated payment in lieu of a payment that partially recovers the revenue requirement in a fixed charge results in higher revenue risk to the regulated nuclear operations than anticipated in the 2007 business risk assessment and increases the business risk of OPG's nuclear operations relative to that of the hydroelectric operations.

The regulated nuclear operations are, like the regulated hydroelectric operations, facing somewhat higher dispatch risk as a result of the passage of the Green Energy and Green Economy Act and low demand conditions. However, as nuclear generating plants are generally less amenable to ramping up and down in times of increased or decreased demand than hydroelectric generating plants, the dispatch risk attached to surplus baseload generation remains lower for the nuclear operations than for the regulated hydroelectric operations.

D.2. Production, Operating and Cost Recovery Risks

The 2007 business risk assessment concluded that the production/operating risks related to the nuclear assets are significantly higher than those of the hydroelectric generation facilities and higher than those of any other type of generation. Specifically, nuclear technology is more complex than other types of generation and is subject to higher risks of unanticipated costs of repair and loss of production. While the forecast costs and production from the nuclear facilities include a provision for both planned and unplanned outages, the operating environment and the technological characteristics of OPG's nuclear generation fleet are such that the extent of required maintenance, repair or refurbishment is 1) forecast with a higher degree of uncertainty than for other types of generation, 2) can result in materially longer than anticipated outages and more frequent and longer than could be expected forced outages, 3) can result in higher than anticipated costs of repair or remediation, and 4) potentially lead to permanent loss of production either as a result of derating or a premature end of the economic life of the plant.

In this application OPG has adjusted its nuclear production forecast methodology to include an allowance (2 TWh) for major unforeseen events based on its historical experience. While the refinement of the forecasting methodology to better take account of its actual experience reduces the production forecasting risk, OPG had not been fully compensated for that risk, as was made clear in the *Decision.* Specifically, the Board found that the operating risks associated with OPG's regulated assets, particularly the nuclear assets, are significant and further concluded that:

> OPG's regulated nuclear business is riskier than regulated distribution and transmission utilities in terms of operational and production risk, but is less risky than merchant generation (for example, given the risk reduction afforded by some of the deferral and variance accounts). The Board also concludes that it is not appropriate for the shareholder to be compensated for all of the operational risks associated with the regulated nuclear facilities. Under cost of service regulation OPG has the opportunity to forecast production and operating costs and to seek recovery of the associated revenue requirement. The Board concludes that it would not be appropriate for shareholders to be fully compensated for the risk that those forecasts are incorrect given that management controls the development of the forecasts and has some considerable control over the achievement of those forecasts.

In light of the Board's findings regarding compensation for forecasting risk, there is no change in the absolute or relative risk of the hydroelectric and nuclear operations arising from the proposed nuclear production forecasting approach. With no other material changes arising from or since the *Decision*, at this time, there has been no significant change in the relative or absolute production/operating risks of the nuclear and hydroelectric operations.

As regards the risks associated with OPG's responsibility for the decommissioning of the nuclear stations and for the management and disposal of used fuel and the recovery of the associated costs, a discussion of the issues arising from the Board's *Decision* is included in the Regulatory Risks section immediately following.

D.3. Regulatory Risks

In EB-2007-0905 OPG proposed a rate base methodology for the treatment of the nuclear liability costs. Under the proposed methodology, the rate base included net plant inclusive of the unamortized asset retirement cost. The associated deemed capital structure was made up of a deemed equity component appropriate to the business risk of the prescribed assets and a debt component comprised of allocated actual existing and forecast debt plus an amount necessary to equate rate base and capital structure. The weighted average cost of capital would be applied to the deemed capital structure. The Board opted instead for a methodology which accepted the measurement of the rate base as proposed by OPG (net plant measured inclusive of unamortized asset retirement cost) but established the regulated capital structure and allowed return differently from that proposed by OPG. The Board methodology requires that a portion of the rate base attract the average accretion rate on OPG's nuclear liabilities (5.6%). The portion of rate base that attracts the average accretion rate is equal to the lesser of the forecast unfunded nuclear liabilities (UNL) and the unamortized asset retirement cost (ARC). The Board determined that, when the unfunded nuclear liabilities are lower than the unamortized ARC, the portion of rate base that attracts the average accretion rate should be limited to the UNL.

OPG's stand-alone nuclear operations are unique relative to most regulated utilities. First, the nuclear operations comprise nuclear liabilities which were, as of the end of 2008, twice as large as the net nuclear property, plant and equipment. The disparity between the liabilities and the net plant will continue to grow over time, with the result that the accounting earnings of the nuclear operations will increasingly come from the earnings on the associated segregated funds, rather than from the operation of the productive assets themselves. Second, the operations are characterized by relatively high operating leverage.

With respect to the nuclear liabilities, recovery of nuclear liability related costs (the unamortized asset retirement cost) is provided for under the Board's methodology through depreciation and accretion expense at the accretion rate, currently 5.6%. However, the contributions that OPG is required to make under the Ontario Nuclear Funds Agreement (ONFA) are determined based on the costs determined pursuant to the current Reference Plan Update, the target rate of return (the Investing Target Rate) on the segregated funds, currently 5.15%, and the market value of the funds. The market value of the funds is determined by the performance of the capital markets. The methodology for recovery of nuclear liability costs does not take account of the performance of the segregated funds and thus OPG is at risk for the performance of those funds (as they relate to Pickering and Darlington). The capital market experience of 2008, during which the return on the S&P/TSX Composite was – 33%, highlights that risk. While OPG would have also been at risk under its proposed rate base methodology, the requested deemed capital structure and cost of capital were intended to compensate for that risk.

With respect to operating leverage, OPG's nuclear operations currently comprise a relatively small amount of net plant and equity compared to the total revenue requirement.[10] Consequently, they currently face a high degree of operating leverage, that is, earnings are highly sensitive to unanticipated changes in costs or production.[11] A 5% decline in nuclear production would decrease the 2010 return on equity of the nuclear

[10] OPG's Darlington refurbishment project, in conjunction with the proposal to include construction work in progress (CWIP) in rate base, will reduce the operating leverage risk.

[11] The predecessor to the Alberta Utilities Commission recognized the higher risk related to operating leverage in Decision 2002-027 (pages 12-13) for AltaGas Utilities. In that decision the regulator stated, "In addition, AUI has a higher operating leverage arising from contributions. The Board considers that the fact that contributions reduce the gross equity to a value near 27% does result in an element of business risk. The risk stems from the requirement of AUI to be responsible for maintaining the assets, regardless of how they are financed." In that case the higher operating leverage arose from customer contributions, a form of no cost capital related to assets owned by the utility and for which it had all responsibility and liability.

operations on a stand-alone basis by approximately seven percentage points.[12] By comparison, a 5% decline in production by the regulated hydroelectric generating assets would reduce the return on equity for those operations on a stand-alone basis by less than one percentage point.

As a rough estimate of how the nuclear assets compare in terms of operating leverage to other electric utilities, the five year average of expenses before depreciation for U.S. vertically integrated electric utility operating companies was compared to the amount of equity on the balance sheet. The average (2004-2008) ratio of expenses before depreciation to equity is approximately 115%. The corresponding average equity ratio was 48%. By comparison, the 2009 expense before depreciation to equity ratio for OPG's nuclear operations based on amounts approved in EB-2007-0905 was over 200%.[13] For the vertically integrated operating utility companies, a one percentage point increase in expenses would (at the 2010 Federal/Ontario income tax rate of 30.5%) result in an approximately 0.5% reduction in the after-tax return on equity. For OPG's nuclear operations, a 1% increase in total expenses would result in an approximately 1.3% decrease in the after-tax return on equity.[14]

The impact of high operating leverage on the volatility of earnings is magnified by the addition of financial leverage. The higher the operating leverage (the more sensitive earnings before interest and taxes are to changes in revenues or expenses), the more sensitive will be the after-tax earnings at increasing levels of debt. The nuclear liabilities incurred represent a legal obligation which OPG must discharge. As legal obligations, they comprise a form of financial leverage (with the segregated funds similarly akin to a

[12] In contrast to most regulated companies, which have a fixed component of rates, which reflects the fixed nature of their costs, the regulated payments for both nuclear and hydroelectric production are 100% energy-based.
[13] OM&A, fuel/GRC and other taxes of $2,374 and equity of $1,164.
[14] For the composite regulated operations, the sensitivity is materially lower because a significantly larger proportion of the costs of the hydroelectric operations are the cost of capital. In effect, the higher operating leverage of the nuclear operations is counter-balanced by the low operating leverage of the hydroelectric operations. The resulting diversification effect would result in a lower overall cost of capital for the composite operations than indicated by the true stand-alone costs of the two individual operations, although the effect is not quantifiable.

sinking fund), magnifying the sensitivity of the nuclear operations' earnings to changes in revenues and expenses.[15]

The approach adopted by the Board results in a materially lower effective equity ratio for the prescribed assets in 2010 than the 47% approved by the Board. If the lesser of the unamortized ARC or the UNL is included as a form of financing in the capital structure, the equity ratio for the composite prescribed assets is approximately 40%, compared to the 47% equity ratio adopted by the Board. For the nuclear assets on a stand-alone basis, the differential between the 47% approved equity ratio and the effective equity ratio is considerably larger; the equity ratio including the lesser of the ARC or UNL in capital structure is 32%.

Compared to U.S. companies that operate nuclear plants, the impact of the unfunded nuclear liabilities on OPG's effective regulated capital structure is materially greater. In part this is because, in the U.S., the liability for used fuel is borne by the Department of Energy (DOE). Operators of nuclear plants pay a per kWh charge based on production to the DOE to assume the responsibility for high level nuclear waste disposal. In contrast, OPG shares the responsibility of cost increases associated with the disposal of high level nuclear waste up to 2.23 million fuel bundles with the Province and bears the full responsibility for the disposal and cost recovery of used fuel in excess of 2.23 million fuel bundles.

To put the relative impact on OPG's effective capital structure of the nuclear liabilities in some perspective, a comparison can be made with Exelon, the largest operator of regulated nuclear plants in the United States. Exelon's total asset retirement obligations at the end of 2008 were $3.7 billion, or approximately 15% of net plant. In 2010, OPG's asset retirement obligations for Pickering and Darlington are expected to be twice the book value of the plant of the prescribed nuclear assets. Exelon's total investor-supplied capital (short and long term debt, preferred shares and common equity) was

[15] At the end of 2008, the funded liabilities were approximately 130% of the nuclear rate base, meaning that the earnings of the nuclear operations are significantly dependent on the fund earnings, which, in turn, reflect the volatility of the capital markets.

approximately $24 billion at the end of 2008, and its common equity ratio, based on investor-supplied capital, was 45.5%. Its nuclear decommissioning trust funds balance was $5.5 billion. Consequently, since its decommissioning trust funds balance exceeded its total asset retirement obligation, the "effective" equity ratio calculated in the same manner as for OPG above is higher than 45.5%. A similar calculation for Entergy, the second largest operator of nuclear plants in the U.S., would also increase Entergy's "effective" common equity ratio.

Due to the methodology adopted by the Board for the treatment of the nuclear liabilities, the financial leverage of the nuclear assets on a stand-alone basis is higher than it would have been under the rate base methodology proposed by OPG. To illustrate, at the 47% common equity ratio approved by the Board, under the rate base methodology, a 1 TWh reduction in nuclear production would decrease the 2010 return on equity by approximately 2.0 percentage points. Under the adopted methodology, a similar decline in nuclear production would reduce the return on equity by 3.0 percentage points.[16] The increase in the impact on the ROE reflects the relatively small amount of equity underpinning the total revenue requirement, which largely comprises fixed costs.

D.4. Changes in Business Risk since EB-2007-0905

With the exception of a modest increase in dispatch risk due to the passage of the Green Energy and Green Economy Act and low demand conditions, the fundamental business risks faced by OPG's regulated nuclear operations remain largely unchanged since the *Decision*. However, the decision by the Board to deny the proposed 25% fixed portion in the payment amount structure and the methodology adopted by the Board for the treatment of the nuclear liabilities results in higher business and financial risk than anticipated in the 2007 risk assessment.

[16] The reductions in ROE are calculated based on a 2010 nuclear rate base of $3,901 million, a prescribed payment amount of $54.98 per kWh and a combined federal/provincial income tax rate of 30.5%.

E. CHANGE IN RELATIVE RISKS OF THE HYDROELECTRIC AND NUCLEAR OPERATIONS

As indicated in Section VI. A. above, the objective of the business risk analysis was to assess whether there have been changes in the absolute or relative business risks of the regulated nuclear and hydroelectric operations that have occurred since the *Decision* or result from the *Decision*.

The fundamental business risks to which the nuclear operations are exposed are significantly higher than those faced by the regulated hydroelectric operations, as they were when the business risk assessment was performed in EB-2007-0905, primarily due to the higher production and operating risks faced by the nuclear operations and the risk mitigation effect of the Water Conditions Variance Account on the production risks of the regulated hydroelectric operations.

The most significant change that has occurred subsequent to the Board's November 2008 decision in EB-2007-0905 has been the passage of the Green Energy and Green Economy Act and low demand conditions, which has increased the dispatch risk (surplus baseload generation) of both the regulated hydroelectric and nuclear operations. As a result of technological differences, the impact is somewhat greater for the hydroelectric than for the nuclear operations. To some extent, the increased risk of surplus baseload generation can be mitigated through adjustment of the forecast production for purposes of setting the regulated payments. Nevertheless, the forecasting risk associated with surplus baseload generation is higher, particularly for the hydroelectric operations. The associated impact on the cost of capital for either the hydroelectric or the nuclear operations during the test period is likely to be small, not amenable to quantification and unlikely to materially change the relative business risk of the two regulated operations.

With respect to changes in relative risk that result from the *Decision*, the difference in the business risk profiles is greater than was anticipated in EB-2007-0905, largely due to the Board's decision not to adopt the proposed fixed payment for the nuclear operations and to vary the proposed ratemaking treatment of the nuclear liabilities. The ability to quantify those differences in terms of technology-specific capital structures with an acceptable degree of rigour is discussed in the sections of the report which follow.

VII. PRACTICAL OBSTACLES TO THE ESTIMATION OF TECHNOLOGY-SPECIFIC CAPITAL STRUCTURES

The operations of OPG for which the OEB has regulatory oversight are unique: they comprise regulated power production from two separate technologies, nuclear and hydroelectric. The estimation of the cost of capital for OPG's prescribed assets as a whole is a challenge because there are no stand-alone regulated generators with capital market data which can serve as proxies for the estimation of the cost of capital for OPG's prescribed assets as a whole. The absence of proxy companies operating under a framework similar to OPG's renders the initial point of departure, that is, the estimation of the cost of capital for regulated generation as a whole, subject to significant judgment.[17] The isolation of the cost of capital for regulated generation by technology entails even more judgment.[18]

To some extent, the difficulty in specifying technology-specific costs of capital for regulated generation using quantitative tools arises from the diversified nature of regulated companies' asset portfolios. Most publicly-traded electric utilities that own either nuclear or hydroelectric generating assets also have significant investment in other generation technologies (e.g., coal and natural gas) as well as significant investment in "wires" or "pipes" (electric and gas distribution and transmission) assets. To put this in perspective, an analysis of 44 U.S. publicly-traded electric utilities revealed that, on

[17] In the determination of the cost of capital for the Power Purchase Arrangements (PPAs) for the Alberta heritage generating facilities, the Independent Assessment Team engaged by the Province of Alberta noted in its report that there was more room for debate among experts than usual due to the lack of comparators.(Independent Assessment Team, *Cost of Capital in Power Purchase Arrangements*, July 1999, page 7). The same cost of capital was applied to PPAs for coal, natural gas and hydroelectric PPAs.

[18] The FERC, which regulates wholesale electric transmission, estimates the cost of capital by reference to data for vertically integrated electrics. There is no evidence that it has changed the view adopted in 1980, when it stated, "We do not find it intuitive that the risk of supplying transmission service involves lesser risks than the company's diversified business as an integrated utility. Further, to attempt to unbundle the various functions of the electric business of a utility (e.g., production, transmission, etc.) and then apportion an equity return commensurate with the risk of that function would be almost an impossible task." (*Otter Tail Power Co.*, 12 FERC ¶61169, Opinion No. 93, August 15, 1980).

average, approximately 36% of the companies' assets were generation related, 56% were "wires" or "pipes" and 8% were attributable to other operations. On average, the percentages of total assets attributable to nuclear and hydroelectric generating plant were, respectively, approximately 4% and 2%; See Schedule 3. The diversification of the asset portfolios and resulting synergies among wires, pipes and generation and the resulting synergies complicates the quantitative isolation of the cost of capital of regulated generation from that of regulated wires or pipes. Quantitatively estimating generation technology-specific costs of capital adds a further layer of complexity.

An investigation of the allowed returns for utilities indicates that North American regulators have generally ascribed higher costs of capital to electric utilities with generation than to wires utilities. However, there is no empirical evidence that regulators have recognized a distinction among the types of generation operated by utilities in setting the allowed rates of return. From an allowed return perspective, the costs of capital of individual generation technologies are not readily discernible.[19]

As regards direct capital market data for the estimation of technology-specific costs of capital, in Canada, there are only four conventionally structured (corporation) publicly-traded companies in Canada with significant amounts of generation that are either regulated or governed by contractual arrangements which have cost of service characteristics. These are Canadian Utilities Limited, Emera Inc., TransAlta Corporation and TransCanada Corporation. All are relatively diversified and none has any significant amount of hydroelectric capacity. Only TransCanada Corporation owns any nuclear

[19] An analysis of the allowed returns of over 200 U.S. electric utilities over the past 12 years showed that the allowed return on equity increased by approximately six basis points for every one percentage point increase in the percentage of total utility assets attributable to regulated generation. The analysis also accounted for the impact of bond yields, common equity ratio, the regulatory rating for the jurisdiction making the decision and the percentage of regulated generation assets that were nuclear. There was no indication that the operation of nuclear generating assets had an impact on the level of the allowed return on equity. The elimination of the equity ratio and percentage of regulated nuclear asset variables from the analysis indicated that the ROE increased by approximately five basis points for every one percentage point increase in the percentage of utility assets attributable to regulated generation. See Schedule 14.

With respect to hydroelectric generation, there are only three U.S. utilities with significant amounts of hydroelectric generation, Avista, Idaho Power and Portland General Electric. A review of their allowed returns does not suggest that their allowed returns have been significantly different (higher or lower) from those of other electric utilities.

capacity.[20] The diversified nature of the companies, the lack of hydroelectric capacity and, in TransCanada's case, the fact that its nuclear capacity is not regulated, indicate that the market data for these companies would not provide any useful insight into appropriate technology-specific costs of capital for OPG's prescribed assets.

There are several income trusts which have significant hydroelectric capacity (Boralex Power Income Fund, Brookfield Renewable Power Fund, Innergex Power Income Fund). However, reliance on income trusts as proxies is problematic from a cost of capital perspective due to the change in the Income Tax Act announced by the Department of Finance in the 2006 Tax Fairness Plan which will subject the distributions from income trusts to income tax as of 2011. The announced change in the tax law resulted in an immediate sell-off in income trust units. The reaction of the capital markets to the announcement would have an impact on market measures of risk (e.g., beta) that is unrelated to the fundamental operating risks to which the underlying assets of the trusts may be subject.[21] Thus income trusts are not useful proxies for estimating the cost of capital for the OPG's prescribed hydroelectric assets.

[20] Canadian Utilities is a diversified utilities holding company, with investments in electric and gas distribution, electric transmission and gas pipeline operations as well as electric generation. Electric generation accounts for a little over a third of earnings. Approximately 50% of its owned capacity is subject to the Alberta PPAs; close to 85% of total capacity is governed by long-term agreements. Its owned capacity is virtually all coal and gas-fired.

Emera Inc. owns a vertically integrated electric utility subsidiary, Nova Scotia Power, which accounts for approximately two-thirds of net earnings. It also owns a wires-only utility. Approximately 85% of power produced by Nova Scotia Power Inc. is produced by coal, natural gas and oil-fired plants.

Of the generation owned by TransAlta Corporation, approximately 2/3 is governed by long-term contracts (including Alberta PPAs). Less than 10% of the generation owned by TransAlta Corporation, the only one of the three companies which is primarily a generator, is hydroelectric; the hydroelectric plants are mostly peaking plants.

TransCanada Corporation's earnings are approximately 50% derived from its pipeline business and 50% derived from its energy business, which is primarily power generation. TransCanada owns or has rights to the capacity output of approximately 10,900 MW of generating capacity, of which approximately 8,300 MW were in operation at the end of 2008. Approximately 20% of the capacity which it either owns or to which it has rights to the output capacity and which is currently in operation is nuclear (two units of Bruce A and all four units of Bruce B) and 7% is hydroelectric generating capacity.

[21] As a result of the tax change, a number of the income trusts are converting back to conventional corporate structures.

The broader U.S. capital market contains a number of publicly-traded electric utility companies which have nuclear generation operations and thus provide a pool of potential, if imperfect, proxies for quantitatively isolating the cost of capital for OPG's regulated nuclear generation. However, there are only three publicly-traded U.S. utilities with any significant reliance on hydroelectric generation.[22] Of these three, the shares of one (Portland General Electric) have only been trading for three and a half years. A sample of two (Avista Corp. and IdaCorp), both of which have significant regulated assets other than their hydroelectric generating capacity,[23] is insufficient for the purpose of isolating the cost of capital for OPG's prescribed hydroelectric assets.[24]

[22] In general, the U.S. electric utility industry relies to a much lesser degree on hydroelectric generation than Canada. In 2007, only about 6% of the electricity generated in the U.S. was produced by hydroelectric plants.

[23] Approximately 21% and 23% respectively of Avista Corp.'s and IdaCorp's total assets are related to regulated hydroelectric generating capacity.

[24] A key risk that has been identified by Standard & Poor's for these utilities, despite their power cost adjustment mechanisms, is their obligation to buy replacement power when water levels are low. This company-specific risk does not apply to OPG, which has no obligation to provide replacement power if water conditions result in lower production from the prescribed hydroelectric assets.

VIII. EMPIRICAL METHODOLOGIES FOR ASSESSING TECHNOLOGY-SPECIFIC CAPITAL STRUCTURES

A. OVERVIEW

In the absence of separate capital market data for a business, a project or a division, as is the case with OPG's regulated nuclear and hydroelectric operations, indirect means to estimate their separate costs of capital must be employed. The following section describes the various quantitative methodologies that have been developed to estimate the cost of capital for companies, divisions of companies or projects that have no capital market data.

B. ACCOUNTING BETA

An accounting beta is the book earnings analogue of a market or investment risk beta. A market beta is estimated by regressing the stock market returns of a stock (or portfolio of stocks) against the stock market returns of the equity composite. The coefficient (beta) of the regression is a measure of the extent to which a stock's market returns co-vary with those of the market composite. The market beta is, within the context of the Capital Asset Pricing Model, a measure of the stock's systematic risk, where systematic risks are those risks which cannot be diversified away or reduced by holding the stock in a portfolio.

For companies, divisions of companies, or projects that are not publicly traded, market betas are not available. The concept of the accounting beta has been proffered as an alternative when stock market data are not available. An accounting beta measures the covariation in earnings for a non-traded company with the earnings of the equity market composite. The assumption underlying this approach is that the cyclicality of a firm's earnings is a proxy for the systematic risk for which equity investors require compensation in the context of the Capital Asset Pricing Model (CAPM), i.e., the accounting beta is used as a proxy for the market beta. Assume, for example, the change in the earnings of the firm or the division of the firm is 75% of the change in the earnings of the equity market composite. In the application of the CAPM, the beta to be used in estimating the non-traded entity's cost of equity would be 0.75.

There are a number of ways the earnings can be measured, including in dollar terms, returns on assets or returns on equity (ROEs). Other terms for accounting betas, depending on the way they are measured, are earnings betas or ROE betas.

Aswath Damodaran, in *Estimating Risk Parameters*, N.Y.: Stern School of Business, not dated, said of the accounting beta approach:

> While the approach has some intuitive appeal, it suffers from three potential pitfalls. First, accounting earnings tend to be smoothed out relative to the underlying value of the company, resulting in betas that are "biased down", especially for risky firms, or "biased up", for safer firms. In other words, betas are likely to be closer to one for all firms using accounting data. Second, accounting earnings can be influenced by non-operating factors, such as changes in depreciation or inventory methods, and by allocations of corporate expenses at the divisional level. Finally, accounting earnings are measured, at most, once every quarter, and often only once every year, resulting in regressions with few observations and not much power.

Roger Morin, in *New Regulatory Finance*, Vienna, VA: Public Utility Reports, 2006 concluded:

> On the practical side, the Earnings Beta approach requires a sufficient amount of historical accounting data and suffers from the rather arbitrary and numerous allocation and separation decisions of the accounting information. If the historical availability of divisional earnings data is limited, the technique is statistically unreliable.

In *The Search for Value: Measuring the Company's Cost of Capital*, Boston: Harvard Business School Press, 1994 Michael Ehrhardt notes in the chapter devoted to the cost of capital for a division, project or private company:

> There are two schools of thought on estimating systematic risk lacking access to market prices. One is based primarily on accounting data, and the other is based primarily on market data. The accounting-based approaches are used much less frequently than the market-based approaches; therefore, this chapter describes only the market-based approaches.

As an alternative to simply using the accounting beta as a proxy for the market beta, the empirical relationship between the accounting beta and the market beta could be estimated by regressing the accounting betas for a large sample of companies against their market betas to determine the specific relationship between accounting beta and market beta. The resulting regression equation would then be applied to the accounting beta for an untraded firm or division of the firm to solve for its implied market beta.

However, the empirical evidence which has attempted to demonstrate a correlation between the earnings beta and the market beta is weak. For example, William Beaver, Paul Kettler and Myron Scholes, in "The Association Between Market Determined and Accounting Determined Risk Measures", *The Accounting Review*, October 1970 tested seven fundamental variables, including earnings variability, earnings beta, dividend payout, asset growth, liquidity, leverage and size. They concluded:

> The evidence suggests that the accounting *B* [beta] may be subject to a large amount of error and that other accounting measures of risk will have to be introduced in searching for correlates with the market risk measure.

Michael K. Berkowitz, in "Estimating the Market Risk for Nontraded Securities: An Application to Canadian Public Utilities", *International Review of Financial Analysis*, Vol. 7, No. 2, 1998, found that using Canadian data, the relationship between market beta and the accounting, or earnings, beta was either statistically insignificant and or had the opposite sign from what was expected.

C. PURE-PLAY APPROACH

The Pure-Play approach entails identifying publicly-traded companies whose operations are largely in the same line of business as the division for which the cost of capital is being determined. The cost of capital of the pure-play companies are used as a proxy for the beta of the division of the firm. One advantage of this approach is that in principle one can rely on various tests, CAPM, Discounted Cash Flow (DCF) or risk premium tests, applied to pure play companies to estimate the cost of equity for the division. The main disadvantage of this approach is that in the preponderance of cases, there are few firms that operate solely in one industry and that would qualify as pure play proxies for specific projects or divisions of companies. This is particularly problematic in the electric utility business, where there are few, if any, companies that operate in a single function, i.e., regulated distribution, transmission or generation.

An alternative form of this approach is to identify an industry whose business is analogous to the business of interest. For example, suppose the objective were to estimate the cost of capital for the electricity "wires" business. There are a limited number of publicly-traded electric utilities that operate only distribution systems. However, there are a number of publicly-traded natural gas utilities whose cost of capital could potentially serve as a proxy for the cost of capital of the electricity "wires" business. It has been quite common to use gas distributors ("pipes" utilities) to estimate the cost of capital for the "wires" operations of restructured electric utilities in the U.S.

D. INSTRUMENTAL BETA APPROACH

The instrumental beta approach seeks to establish the relationship between the market beta and fundamental accounting and/or operating risk related variables that may explain traded firms' market risk as captured in the market beta. The Beaver, Kettler and Scholes and the Berkowitz articles referenced above are two such studies. The Beaver, Kettler and Scholes study found that earnings variability, dividend payout and asset growth were the best explanators of market betas. Barr Rosenberg and Andrew Rudd, "Corporate

Uses of Beta", in *The Revolution in Corporate Finance*, J.M. Stern and D.H. Chew, eds., N.Y.: Blackwell Publishing, 1987, found that the four best explanators of market betas were earnings variability, growth, size and leverage. Rosenberg and Rudd also documented persistent differences among industries. The Berkowitz study found that growth in assets, leverage and industry designation were the best predictors of market betas.

E. RESIDUAL BETA

The "residual beta" methodology[25] is based on the Capital Asset Pricing Model, which holds that the beta of a portfolio is the market value weighted average of the betas of the investments that make up the portfolio. The notion that the beta of a firm is equal to the weighted average of its divisional betas is a foundation for the "pure play" technique of estimating the betas for individual divisions of a multi-division firm. As stated in Russell J. Fuller and Halbert S. Kerr, "Estimating the Divisional Cost of Capital: An Analysis of the Pure-Play Technique," *Journal of Finance*, December 1981, "it can be shown that the beta for a multidivisional firm approximates the weighted average of its divisional betas". In formula terms, assuming three divisions:

$$\beta_{Stock} = Wgt_{Div1} \times \beta_{Div1} + Wgt_{Div2} \times \beta_{Div2} + Wgt_{Div\,3} \times \beta_{Div3}$$

The residual beta methodology is used to estimate the beta of a division for which there are no pure play proxies. The methodology entails disaggregating the beta of a multi-divisional firm into the betas of its divisions. Its application requires the beta of the firm as a whole and a "pure play" beta for each of the divisions other than the one for which there are no pure play proxies. In the disaggregation of the company beta into the divisional betas, ideally, if known, the weights to be given to each division should be equal to their relative contribution to the operating income of the consolidated entity. Knowing the market beta for the company as a whole, the beta for all but one of the

[25] The residual beta methodology is described in Roger Morin, *New Regulatory Finance*, Vienna, VA: Public Utilities Reports, Inc., 2006.

divisions and the weights of all of the divisions, one can solve for the beta of the remaining division (the residual beta). It is perhaps obvious that the ability to use this methodology is contingent on the availability of "pure play" betas for all divisions other than the one of interest.

F. FULL INFORMATION OR REGRESSION BETA

The Full Information Beta approach uses the betas of firms operating in multiple lines of business to derive the betas for the individual lines of business through a multiple regression approach. Like the Residual Beta approach, it is based on the principle that the investment risk beta of a publicly-traded firm is a weighted average of the betas of the various businesses that it operates. To estimate the beta for a division using the Full Information Beta approach, one would take a sample of companies which operate in multiple divisions, including the one of interest, calculate their individual firm-wide investment risk betas and determine what percentage of each of the company's operations are devoted to their various operations. A cross-sectional regression[26] would then be run, where the observed beta, β_i, of the consolidated firm is the dependent variable and the dependent variables are the weights of the various divisions other than the division of interest.

Where there are three divisions, A, B, and C, for example, the exact equation is as follows:

$$\boldsymbol{\beta_i = \beta_A + (\beta_B - \beta_A) \times \%B + (\beta_C - \beta_A) \times \%C}$$

Where:

β_i is the beta of the consolidated firm

β_A, β_B and β_C are the betas of the three divisions

% B and % C are the weights of the contributions of Divisions B and C to the firm as a whole

[26] A cross-sectional regression is one in which both the independent and dependent variables are associated with a single period of time.

The intercept of the equation, β_A, is the beta of the division of interest, and the two other coefficients represent the difference between the beta of the division of interest and the betas of the other two divisions of the firm.

The Full Information Beta approach is frequently associated with the insurance industry, where the insurance companies are interested in identifying the cost of capital for different lines of their insurance business, particularly for the regulated components (e.g., automobile insurance).

IX. ASSESSMENT OF METHODOLOGIES AND APPLICABILITY TO OPG

A. RELIANCE ON CAPM

With the exception of the "pure play" approach, each of the methodologies described above is a derivative of the Capital Asset Pricing Model. The CAPM relies on the premise that an investor requires compensation for non-diversifiable risks only. From a CAPM perspective, production and operating risks are company-specific, largely unrelated to capital market or economy-wide events. As such, company-specific risks, according to the CAPM, can be diversified away by investing in a portfolio of securities whose expected returns are not perfectly correlated. Therefore, a shareholder requires no compensation to bear company-specific risks.

In the CAPM, non-diversifiable risk is captured in the beta, which, in principle, is a forward-looking (expectational) measure of the volatility of a particular stock or portfolio of stocks, relative to the market. Specifically, the beta is equal to:

$$\frac{\textbf{Covariance}\ (R_E,R_M)}{\textbf{Variance}\ (R_M)}$$

Where:

R_E is the return on an individual stock or portfolio

R_M is the return on the market as a whole

The variance of the market return is intended to capture the uncertainty related to economic events as they impact the market as a whole. The covariance between the return on a particular stock and that of the market reflects how responsive the required return on an individual security is to changes in events that also change the required return on the market. Theoretically, the beta is a forward looking estimate of the contribution of a particular stock to the overall risk of a portfolio. In practice, the beta is a calculation of the historical correlation between the overall equity market, as proxied in Canada by the S&P/TSX Composite, and individual stocks or portfolios of stocks.

Non-diversifiable risks include factors to which all stocks are sensitive in some measure, e.g., inflation, interest rates, economic growth, and oil prices. The sensitivity of specific industries to these factors would be a function of fundamental characteristics industries that are correlated with non-diversifiable risks. For example, stock prices of financial service companies would be sensitive to changes in interest rates; stock prices of oil and gas producers would be sensitive to changes in energy prices; stock prices of manufacturing companies would be sensitive to the ups and downs of the business cycle. For individual stocks, firm-specific characteristics that are correlated with the market-wide factors would influence the sensitivity of those companies' stock prices to market-wide events, muting or magnifying the impacts. For example, the assumption of leverage increases the volatility of a company's earnings stream. All other things equal, higher leverage would magnify the sensitivity of a company's share price to market-wide factors, i.e., increase the beta.

However, the CAPM posits that firm-specific characteristics that are not correlated with market-wide factors are diversifiable and not priced by the capital market. Examples of firm-specific risks that are diversifiable include the impacts of weather, labour strikes, loss of a key customer account (unrelated to macroeconomic factors), system security risks, or changes in government regulations specific to one industry.

In the case of OPG, a key factor that distinguishes the regulated nuclear operations from the regulated hydroelectric operations is operating risks, which in principle should be diversifiable. Consequently, the ability of methodologies derived from the CAPM to capture the difference in risk between the two technologies is, *a priori*, questionable.

Even if one were to accept that, in principle, betas would capture the risks that distinguish the two technologies, there are at least two other factors that call into question the ability of CAPM derived models to accurately capture differences in risk and allow an accurate assessment of the differences in return requirement between the two technologies. These two factors are (1) the instability of measured betas from one time period to the next; and (2) differences in calculated betas depending on the manner in which they are measured.

With respect to the first issue, betas are typically measured over five-year horizons. To illustrate how variable betas can be, even for portfolios of stocks, Schedule 1 sets out betas for the 10 major sectors of the S&P/TSX Composite for the five-year periods ending 1997 to 2008. Schedule 1 shows, for example, that the "raw" five-year betas for the financial sector during that time period ranged from 0.38 to 1.12; betas for the energy sector ranged from 0.17 to 1.44; the range for the utilities sector was -0.25 to 0.55. Schedule 2 sets out adjusted[27] *Value Line* betas for a sample of 28 U.S. electric utilities from 1997 to 2009.[28] Schedule 2 demonstrates that, even when adjusted toward the market mean of 1.0, thus smoothing the period to period fluctuations, the average betas for the sample have ranged from 0.50 to 0.95. The instability of betas from measurement period to measurement period may be problematic for analyses that attempt to measure differences in return requirement for investments exposed to fundamentally different levels of business and/or financial risk.

With respect to differences in calculated betas, there can be significant differences in measured betas depending on the interval over which the change in share price is calculated. Betas calculated using monthly changes in price can differ systematically from betas calculated using weekly changes in prices. There is no "rule" for choosing monthly intervals versus weekly intervals for calculating betas. The principal benefit of weekly betas is the increased number of observations, which mitigates the impact of outlier observations on the measured beta. The benefit of monthly betas is the potential mitigation of non-synchronous trading, which largely affects stocks that are traded

[27] *Value Line* adjusts the "raw" betas toward the market mean beta of 1.0 using a formula which gives two-thirds weight to the "raw" beta and one-third weight to the market mean beta of 1.0. The use of the term adjusted beta throughout this report refers to "raw" betas that have been adjusted to the market mean of 1.0 using these weightings.
[28] The 28 electric utilities represent a sample of utilities with more than one-third of their assets devoted to generation which are used later in the report to attempt to isolate the incremental risk and return requirement associated with electricity generation operations. The selection criteria are described in Appendix A.

relatively infrequently.[29] Table 1 compares the average "raw" beta for the sample of 28 electric utilities (referred to above) calculated using monthly and weekly prices for five-year periods ending 2003 to 2009.

Table 1

	2003	**2004**	**2005**	**2006**	**2007**	**2008**	**10/2009**
Monthly	0.22	0.32	0.44	0.66	0.67	0.62	0.61
Weekly	0.36	0.41	0.55	0.65	0.71	0.67	0.68

Source: Schedules 8 and 9.

While the differences between the average monthly and weekly betas do not appear to be vastly different, the differences are potentially material enough to produce significantly different estimates of the relative risk and return requirements for the different utility sectors.

B. APPLICABILITY OF MODELS TO OPG

B.1. Accounting Beta

While the concept of using an accounting beta to establish the relative risk of the regulated nuclear and hydroelectric generation has some appeal, inasmuch as OPG reports earnings separately for the two operations, there are both conceptual and practical drawbacks which eliminate this approach as a means of estimating technology-specific costs of capital. The broadly applicable drawbacks were discussed above. For OPG, there simply are insufficient data to estimate meaningful accounting betas. The two operations were not subject to regulation prior to 2005, and thus there are no separate earnings data for prior periods. Consequently, the maximum number of observations is five, which is not sufficient for estimating an accounting beta. Further, the regulatory model (as well as the underlying allowed return) changed when OPG became subject to

[29] The non-synchronous trading effect arises when stock prices respond with a lag to economic events. As a result, the returns on a stock at a particular point in time are not "in synch" with those of the market.

OEB regulation in April 2008, rendering the earnings data for 2005-April 2008 not directly comparable to the post April 2008 data.

B.2. Pure Play Approach

Application of the pure play approach to OPG requires identifying publicly-traded companies which operate either solely or predominantly in regulated nuclear and/or hydroelectric generation operations. While, as noted above, this approach has significant appeal, since the estimation of the cost of capital using this approach need not be limited to the Capital Asset Pricing Model, there are no pure play publicly-traded companies operating in the regulated hydroelectric or nuclear generation business. Indeed, there are no pure play companies operating in the regulated generation business more generally. As a result, the pure play approach cannot be relied upon to distinguish the cost of capital for the two technologies.

B.3. Instrumental Beta Approach[30]

The instrumental beta approach entails identifying fundamental factors that explain market betas, and then quantifying the relationship between those factors and the observed market beta. The instrumental beta approach represents a potential methodology for distinguishing between the two technologies on the basis of relative risk. Two avenues of investigation were identified. The first was to determine if there was any evidence that the equity market "priced" nuclear generation exposure, that is, whether there was any identifiable systematic difference in betas arising from reliance on nuclear generation.[31] The second avenue was to determine the extent to which the capital markets priced absolute volatility in earnings inasmuch as the higher operating risks faced by OPG's regulated nuclear operations relative to the regulated hydroelectric operations would be expected to translate into higher year-to-year earnings volatility.

[30] Please see Appendix B for a detailed discussion of the analysis undertaken.
[31] Since hydroelectric generation accounts for a minor portion of virtually all the utilities' asset mix, no attempt was made to estimate the relationship between market betas and reliance on hydroelectric generation.

The usefulness of an instrumental variables model generally as a means of predicting utility betas was initially tested by examining the relationships between recent market betas and the explanatory variables that were found to be relevant in the earlier studies referenced above. Using a sample of 44 U.S. electric utilities[32], the relationships among market betas and the following dependent variables were tested:

- Dividend payout ratio
- Standard deviation of return on equity
- Accounting beta
- Market capitalization (size)
- Average annual growth in assets
- Debt to total capital.

Rather than use a liquidity measure as was done in the Beaver *et al* study, the S&P debt rating was used an additional explanatory variable. Further, an independent variable representing the percentage of nuclear capacity as a percentage of total generation capacity was added.

In contrast to the three studies referenced in Section VII.D, which looked at a cross-section of market sectors, this analysis focused solely on the electric utility industry, with the objective of determining whether or not betas for individual firms within an industry are distinguishable by differences in fundamental factors among firms. Of the eight variables tested, only two, the S&P debt rating and the standard deviation of returns, were statistically different from zero.

As the coefficient on the nuclear capacity variable was not significantly different from zero, two alternative measures of generation were tested to assess whether, in the context

[32] The selection criteria for and identification of the sample of U.S. electric utilities are found in Appendix A.

of the CAPM, the capital market attributed a risk premium to the ownership of generation generally or nuclear generation specifically:

- Percentage of total assets devoted to electric generation
- Nuclear assets as a percentage of total assets

As with the nuclear capacity variable, neither of the coefficients on the other two generation-related variables proved to be significantly different from zero. In other words, for the periods tested, there was no discernible variation in beta values among the 44 electric utilities which could be attributed to the investment in generation assets as a whole or in nuclear assets specifically.

With respect to the two independent variables that were statistically different from zero, the estimated coefficient on the S&P debt rating was highly significant and of the expected sign. As expected, a lower debt rating was associated with a higher beta. While the result suggests, as expected, that debt ratings (and risk to debt holders) and equity risk are positively related, there are no resulting implications for technology-specific capital structures.

The estimated coefficient on the standard deviation of returns on equity was also significantly different from zero. However, while positive, the coefficient was small, indicating relatively little sensitivity of the beta to the annual variability of returns on equity.

To put this in perspective, based on the results of the instrumental variables analysis, the difference between the indicated market beta for a utility with a standard deviation of ROE of 1.0% and the market beta for a utility with a standard deviation of ROE of 13% (plus or minus 6% from the sample mean standard deviation of 7%) is 0.06. Based on the

CAPM, and assuming a market risk premium of 6.75%,[33] the difference in cost of equity arising solely from the difference in variability of returns on equity would be approximately 40 basis points.

In OPG's case, similar to the accounting beta approach, there are insufficient earnings data to attempt to estimate a meaningful standard deviation of ROEs. Given the limited earnings data for OPG, the non-comparability of OPG's annual ROEs due to the change in regulatory framework as well as the relatively small sensitivity of the cost of equity to significant changes in ROE volatility suggested by the quantitative analysis, the instrumental variables approach does not provide a useful basis for the estimation of technology-specific capital structures.

B.4. Residual Beta Approach[34]

As noted above, the residual beta approach entails deriving an estimated beta for a business segment for which there are no pure play proxies from the betas of multi-divisional firms which have operations in that segment. In this case, the ultimate objective was to determine if it is possible, using this model, to distinguish the cost of capital for regulated nuclear generation operations from the cost of capital of regulated distribution ("wires") operations, vertically integrated electric utility and regulated generation generally (i.e., as a function independent of technology).[35]

In applying this model, the first step was the estimation of a residual beta for electric generation operations, independent of technology, for comparison to market betas of distribution utilities and vertically integrated electric utilities. The procedures for conducting the quantitative analysis are described in full in Appendix C. The results of the quantitative analysis are summarized below:

[33] A market risk premium of 6.75% represents the risk premium I would use for purposes of applying the Capital Asset Pricing Model were I estimating the cost of equity for OPG's regulated operations from first principles.
[34] Full discussion of this approach is found in Appendix C.
[35] Since there are so few companies with significant hydroelectric production operations, it was determined that this methodology would not be useful to estimate a stand-alone beta for OPG's regulated hydroelectric operations.

(a) To estimate the residual beta for generation, market betas for two samples of utilities were calculated for five-year periods ending 2006 to 2009 using weekly data, a lower risk distribution ("Wires") utility sample and a higher risk vertically integrated electric ("High Generation") utility sample. The average betas of the two samples for these five-year periods were not significantly different from each other. In two of the four periods tested, the Wires sample beta was actually higher than the High Generation sample beta. Due to the insignificant or incongruous differences in the calculated weekly betas of the two samples, the estimation of a meaningful generation beta from these data using the residual beta methodology was not possible.

(b) Betas were also calculated for the two samples over the same periods, but using monthly, rather than weekly, price changes. In three of the four periods for which betas were calculated, the sample average monthly betas of the High Generation sample were materially higher than the corresponding betas of the Wires sample, but were lower in the remaining period.[36] The application of the residual beta model using monthly unadjusted and adjusted betas suggested that the difference between the betas of pure wires operations and generation was approximately 0.25 to 0.40. Based on these beta differences and an equity market risk premium of 6.75%, the indicated difference in cost of equity between pure wires and generation would be approximately 1.7 to 2.7 percentage points. Since the capital structures, both book value and market value based, of the Wires and High Generation samples used in this analysis were

[36] The material difference in the calculated monthly versus weekly betas underscores the sensitivity of the betas to the choice of price change interval, requiring that caution be applied in interpreting the results of the analysis.

virtually identical, the indicated difference in the equity costs is in principle attributable to differences in business risk.[37]

(c) To isolate a beta specifically for nuclear generation using the residual beta methodology, generation betas must be estimated for two different samples, one with a relatively high proportion of investment in nuclear generation and one with significant generation, but a smaller proportion of nuclear generation. Given the estimated generation betas for the two samples and different proportions of nuclear and other generation, a residual nuclear generation beta can be estimated. From the High Generation sample, a sub-sample of utilities (High Nuclear) with a relatively high proportion of nuclear generation capacity was selected from which a residual generation beta was estimated. The estimated generation betas for the High Nuclear sample (using monthly data) led to nonsensical results in two of the four periods tested (e.g., in one case a negative generation beta). For the two remaining periods (ending 2008 and 2009), the estimated generation betas made intuitive sense (i.e., materially higher residual generation than pure wires betas).

However, when the residual nuclear generation betas were estimated from the generation betas of the High Generation and High Nuclear samples for those two periods, the results were inconsistent. In one period, the estimated nuclear generation beta was significantly higher than the generation betas, but in the other period, the nuclear generation beta was materially lower than the generation betas. The inconsistent results can be traced to the observation that the 2008 betas of the High Nuclear sample were higher than those of the High Generation sample but the two samples' 2009 betas were identical. Since the High Nuclear sample has proportionately both more generation in total and more nuclear generation

[37] The average 2003-2008 book value common equity ratio for the Wires sample was 42.8%; the corresponding equity ratio for the High Generation sample was 42.5%.

than the High Generation sample, identical betas for the samples mathematically will produce lower residual nuclear generation betas.

In light of the inconsistency of the betas and thus the results of the residual beta analysis, DCF estimates of the cost of equity were made for the various samples of companies used in the analysis to determine if other cost of equity models would produce similarly incongruous results. The application of the constant growth model for each year 2006-2009 indicated that, in contrast to the betas, the cost of equity was consistently lowest for the Wires sample, higher for the High Generation sample and highest for the High Nuclear sample. On average from 2006-2009, the indicated constant growth DCF cost of equity for the High Nuclear sample was approximately two percentage points higher than the corresponding cost of equity for the High Generation sample. In turn the DCF cost of equity for the High Generation sample was approximately two percentage points higher than the corresponding cost of equity for the Wires sample. As the forecasts of growth used in the DCF cost estimates for the High Generation and High Nuclear samples may overestimate the rate investors expect in perpetuity, the true differences among the samples' costs of equity are likely smaller than the constant growth DCF model results indicate. Nevertheless, the application of the DCF consistently produces results for the samples that are directionally reasonable; See Appendix C and Schedules 12 and 13.

In summary, theoretically, the Residual Beta approach is a useful tool for estimating the stand-alone cost of capital for operations for which there are no pure play proxy companies. In practice, the application of the model provided little insight into the separate costs of capital for OPG's regulated hydroelectric and nuclear operations. As regards OPG's regulated hydroelectric operations, there are simply an insufficient number of companies to provide a basis for isolating the beta and cost of capital for regulated hydroelectric generation. For OPG's regulated nuclear operations, the calculated betas of the proxy samples used to implement the model have been relatively unstable and the relationships among the sample average betas frequently inconsistent with the expected relationships based on their relative risk.

Other factors which likely complicate the isolation of the technology-specific cost of capital for nuclear operations in the application of the Residual Beta approach include:

a) The cost of capital for regulated operations generally is likely impacted by the regulatory climate in the relevant jurisdiction.[38] The impact of regulatory climate on the overall cost of capital of the companies in the sample would tend to obscure differences among regulated functions and generation technologies.

b) The nuclear generation operations of the companies included in the samples include fully regulated generation as well as unregulated generation. The differing degrees of regulatory protection among companies with nuclear generation capacity complicate the isolation of technology-specific costs of capital.[39]

[38] Regulatory Research Associates Inc. assigns a rating to each of the state regulatory jurisdictions in the U.S. The ratings range from Above Average 1 to Below Average 3 (nine categories in total). The analysis of allowed returns on equity referenced in footnote 8 above indicated a strong relationship between the rating of the regulatory jurisdiction and the level of the allowed ROE, that is, all other things equal, the higher rating assigned to the regulatory jurisdiction, the higher the allowed ROEs were for the utilities in that jurisdiction.

[39] The High Nuclear sample is characterized by a significantly higher proportion of unregulated generation than the High Generation sample. The impact of unregulated generation (and other operations) on the beta was tested by regressing the 2008 and 2009 market betas for a combined sample of the High Generation and Wires utilities against the proportions of their unregulated generation assets (as a percent of the firm's total assets) and their other unregulated assets. The regression suggests that the market beta increases by approximately 0.0032-0.0037 for every one percentage point increase in unregulated generation assets as a percentage of total firm assets. All other things equal, the beta for the High Generation sample, which has approximately 17% of total assets in unregulated generation would be approximately 0.08 lower than the beta of the High Nuclear sample, which on average has approximately 40% of its assets in unregulated generation. The difference in the two samples' cost of equity due to the differences in regulated versus unregulated generation at a market risk premium of 6.75% would be approximately 55 basis points.

The results must be interpreted with caution as the same regressions suggested that there was a negative relationship between the firms' market betas and the proportion of total assets in other unregulated operations. A priori, it was expected that a higher proportion of unregulated assets would have been associated with a higher beta.

B.5. Full Information Beta Approach

Similar to the Residual Beta approach, the Full Information Beta approach is a methodology which attempts to measure betas for separate segments of a firm where the segment betas cannot be separately observed. In contrast to the Residual beta approach, the Full Information Beta approach does not require that any of the individual segment betas be specified in advance. The Full Information Beta methodology requires only the investment risk betas for a relatively large sample of companies and the weights of the contributions of the individual business segments to the consolidated operations of those companies. A cross-sectional regression analysis in which the market betas of each of the sample companies are the dependent variables and the company-specific weights of the various business segments are used for the independent variables allows the estimation of betas for each business segment.

As with the Residual Beta approach, the Full Information Beta approach was applied with the objective of differentiating the cost of capital for OPG's regulated nuclear generation from the cost of capital for distribution utilities, vertically integrated utilities and regulated generation generally. The results of the analysis are provided in more detail in Appendix D.

Similar to the Residual Beta approach, the application of the Full Information Beta approach using monthly market betas for periods ending 2008 and 2009 produced generation betas which were directionally reasonable. The 2008 and 2009 average monthly unadjusted betas for the full sample of 44 gas and electric utilities used in the application of the Full Information Beta approach were 0.56 and 0.55 respectively; the corresponding estimated generation betas were 0.90 and 0.95. The associated nuclear generation betas, although not statistically significant, were higher for both periods than the generation betas, at 1.15 and 1.08 respectively. However, this approach produced implausible results for periods ending 2006 and 2007; the estimated nuclear generation betas were negative.

As with the Residual Beta approach, the Full Information Beta approach represents a potentially useful tool to differentiate the cost of capital for OPG's regulated operations. Its key advantage relative to the Residual Beta approach is the fact that one need not assume the beta for "other" unregulated operations. The methodology directly estimates the betas for all the segments of the business. However, its drawbacks are similar to those of the Residual Beta methodology. From a practical perspective, the lack of proxy companies with significant hydroelectric generation operations limits its application to OPG's regulated nuclear operations. Further, similar to the Residual Beta methodology, the Full Information Beta methodology yielded inconsistent and incongruous results, depending on the time period over which the betas were measured. The possible reasons for the inconsistent and/or incongruous results are the same as those identified above in the discussion of the Residual Beta approach.

B.6. Conclusions from Empirical Methodologies

In this section, five different quantitative methodologies were considered as potential avenues for isolating the cost of capital for OPG's regulated hydroelectric and nuclear generation operations. Four of the five, the exception being the pure play approach are premised on the CAPM. None of the five proved to be sufficiently robust to serve as a basis for estimating technology-specific costs of capital and thus technology-specific capital structures for OPG's regulated hydroelectric and nuclear prescribed assets.

In the case of accounting betas, there are insufficient data points for OPG to estimate an accounting beta. Moreover, empirical analysis demonstrated that the relationship between accounting betas and market betas for Canadian companies was either statistically insignificant or contrary to the expected relationship. Consequently, accounting betas are unlikely to offer a robust approach to estimating technology-specific capital structures even when adequate data points (i.e., earnings over a full business cycle) become available.

With respect to the pure play approach, there are no publicly traded companies whose sole line of business is either regulated hydroelectric or nuclear generation.

The instrumental variables approach indicated that there were only two variables that were statistically significant explanators of market betas, debt ratings and the standard deviation of returns on equity. The former, while supportive of a positive relationship between debt and equity risk, provides no useful insight into separate costs of capital for OPG's regulated hydroelectric and nuclear operations. With respect to the latter, there are insufficient comparable data for OPG's regulated hydroelectric and nuclear operations to estimate meaningful standard deviations of ROEs. Additionally, the relative insensitivity of the cost of equity (and in turn the capital structure) to significant changes in ROE volatility render the results an insufficient basis for setting technology-specific capital structures.

Both the Residual Beta and Full Information Beta methodologies, while conceptually useful tools for estimating technology-specific costs of capital, failed to produce estimates of generation betas or nuclear generation betas that were reasonably consistent over time. The inconsistent and incongruous estimates produced by the two methodologies provide little if any quantitative guidance regarding the cost of capital for OPG's regulated nuclear generation. In addition, the lack of proxy companies with significant hydroelectric operations means that the two methodologies are not practical options for estimating the cost of capital for OPG's regulated hydroelectric operations.

X. DEBT RATING AGENCY GUIDELINES AND TECHNOLOGY-SPECIFIC CAPITAL STRUCTURES

As the empirical methodologies described and applied in the above section provided little perspective on the relative cost of capital and capital structures for OPG's regulated hydroelectric and nuclear operations, more subjective approaches were considered. The debt rating guidelines for regulated company capital structures relied on by Standard & Poor's ("S&P") and Moody's were identified as a potential means of establishing technology-specific capital structures on the basis of differences in business risk.[40]

S&P publishes a matrix of debt rating guidelines that apply to all corporate debt issuers including regulated utilities and power companies. The matrix includes six business risk categories, ranging from "Excellent" to "Vulnerable". Most regulated Canadian companies rated by S&P are in the "Excellent" category. The other categories are "Strong", "Satisfactory", "Fair" and "Weak". In assigning business risk categories to regulated companies, S&P evaluates qualitative factors including regulation, markets, operations, competitiveness and management, with regulation being a critical aspect of utilities' creditworthiness.

The business risk assessment is accompanied by a financial risk assessment. The financial risk assessment includes, but is not limited to, the consideration of three key quantitative credit metrics which include Total Debt/Total Capital. For each of the three metrics, S&P publishes a guideline range associated with six financial risk categories. The lowest financial risk category is "Minimal"; the highest financial risk category is "Highly Leveraged". The table below presents the guideline Total Debt/Capital ranges for each financial risk category. S&P notes that the guideline ranges are intended to represent the level of ranges that have been achieved historically and are expected to consistently continue.

[40] DBRS has published guidelines that do not distinguish by either business risk or investment grade rating category.

Table 2

Financial Risk Profile	Total Debt/Capital (%)
Minimal	Less than 25%
Modest	25-35
Intermediate	35-45
Significant	45-50
Aggressive	50-60
Highly leveraged	Over 60

Source: Standard & Poor's, *Ratings Methodology: Business Risk/Financial Risk Matrix Expanded*, May 27, 2009.

The business and financial risk categories are combined to create a matrix which shows the likely debt rating with a given business risk and financial risk profile, as shown in the table below. For example, a business risk profile of "Excellent" and a financial risk profile of "Significant" correspond to a rating of A-. The indicated range of debt ratios for a "Significant" financial risk profile is 45-50% (corresponding equity ratios of 50-55%). With a "Satisfactory" business risk profile, to achieve the same A- debt rating, the guidelines indicate a financial risk profile of "Minimal", which is associated with a debt ratio below 25% (or equity ratio in excess of 75%).

Table 3

	Financial Risk Profile					
Business Risk Profile	**Minimal**	**Modest**	**Intermediate**	**Significant**	**Aggressive**	**Highly Leveraged**
Excellent	AAA	AA	A	A-	BBB	--
Strong	AA	A	A-	BBB	BB	BB-
Satisfactory	A-	BBB+	BBB	BB+	BB-	B+
Fair	--	BBB-	BB+	BB	BB-	B
Weak	--	--	BB	BB-	B+	B-
Vulnerable	--	--	--	B+	B	CCC+

Source: Standard & Poor's, *Ratings Methodology: Business Risk/Financial Risk Matrix Expanded*, May 27, 2009.

While the S&P guidelines may be useful for assessing the reasonableness of utility capital structures, they provide little or no guidance for the specification of technology-specific capital structures. First, the guidelines govern all industries, not specifically regulated companies, which means that the application of the S&P guidelines to regulated companies generally entails considerable judgment. Second, the determination of the business risk category that S&P would hypothetically assign to each of the hydroelectric and nuclear operations on a stand-alone basis requires further judgment. Third, for a given debt rating, the effect of diversification, while not quantifiable, would permit a lower common equity ratio to be maintained for the composite regulated operations than for the regulated operations on a true stand-alone basis. Fourth, there is no direct connection between the debt rating guidelines and the cost of equity.

The specification of capital structures which equate the costs of equity of the nuclear and hydroelectric operations is the underlying premise of the Board's approach. The adoption of technology-specific capital structures within the debt ratio ranges indicated for given business risk categories would not allow the conclusion to be drawn that the costs of equity were the same for the individual operations.

Moody's has recently revised its ratings guidelines for electric and gas utilities.[41] The Moody's guidelines entail assigning an implied debt rating to each of four factors, regulatory framework, ability to recover costs and earn returns, diversification and financial strength. Each of the factor (and thus implied rating on each of those factors) is assigned a weight. The three business risk factors are assigned a total weight of 60%; financial strength is assigned a weight of 40%. The financial risk factor is further broken down into four quantitative guidelines, including the debt ratio.[42] The debt ratio is assigned 7.5% weight in the determination of the overall debt rating. The weighted

[41] Moody's, *Rating Methodology: Regulated Electric and Gas Utilities*, August 2009.
[42] For example, a debt ratio range of 35%-45% is associated with an A rating; a debt ratio range of 45%-55% is associated with a Baa rating.

average implied rating should be similar to the actual rating (i.e., within one notch) that Moody's assigns.

Although the Moody's guidelines do apply specifically to regulated companies, in contrast to the S&P guidelines, their usefulness for the estimation of technology-specific capital structures is similarly limited. Significant judgment would be required to infer the implied ratings that Moody's would assign on a stand-alone basis to each of the business risk factors. However, as with S&P, while the guidelines provide a perspective on differences in capital structure which may be warranted for different levels of business risk from a debt investor's point of view, they do not address return requirements from an equity investor's perspective. Cost of equity studies are required to address differences in equity return requirements; see Chapter XI below.

XI. RELATIVE COSTS OF CAPITAL OF COMPARABLE UTILITIES

In the absence of proxy regulated companies which operate primarily regulated hydroelectric or nuclear generation operations and thus face the same specific risks as OPG's regulated operations, an alternative is to attempt to select samples of proxy companies that face a relatively comparable level of business risk to OPG's regulated hydroelectric and nuclear prescribed assets. The costs of capital for the two samples would then be estimated and the difference translated into differential common equity ratios for each of the hydroelectric and nuclear operations. For this purpose, two samples of regulated companies are required, one to serve as a proxy for OPG's regulated hydroelectric operations and one to serve as a proxy for the regulated nuclear operations.

There are no universally accepted quantitative measures of total business risk that lend themselves to the selection of proxy companies of similar business risk to OPG's regulated hydroelectric and nuclear operations. Not only are the data for the two operations as regulated entities very limited, the assessment of relative business risk is largely qualitative in nature. S&P's business risk categories were identified as qualitative measures of relative business risk. While the business risk categories assigned to each of the utilities whose debt S&P rates are based on the judgment of the analysts who perform the risk analysis, they are independently determined and widely available to investors.

As noted in Section X above, S&P's corporate rating methodology [43] assigns one of six business risk rating categories to each company that it rates including regulated companies. The lowest business risk category is "Excellent"; the highest business risk category is "Vulnerable." The other business risk categories are "Strong", "Satisfactory", "Fair" and "Weak". The majority of regulated Canadian companies rated by S&P are in

[43] Standard & Poor's, *Ratings Methodology: Business Risk/Financial Risk Matrix Expanded*, May 27, 2009.

the "Excellent" category. OPG on a consolidated basis is assigned a business risk profile score of "Strong" as are Maritime Electric, Nova Scotia Power, and EPCOR Utilities. TransAlta is in the "Satisfactory" category.

To rely on the S&P business risk categories as a selection criterion, the most likely stand-alone business risk category for each of OPG's regulated hydroelectric and nuclear operations must be specified. That specification, in turn, is subject to judgment.

Based on the qualitative business risk assessment of the hydroelectric and nuclear operations and the business risk categories assigned to other Canadian regulated companies, on a stand-alone basis, the likely S&P business risk category for OPG's regulated hydroelectric operations is "Excellent". Consequently, the companies to be selected as proxies for OPG's regulated hydroelectric operations were required to have a business profile score of "Excellent" as well as 90% or more of their total assets devoted to regulated operations.

The regulated nuclear operations would likely be assigned a business risk category of "Satisfactory". The selection criteria for the regulated nuclear operations' proxy sample thus included only companies assigned to the "Satisfactory" business risk category" by S&P, as well as 90% of total assets devoted to wires and electricity generation (both regulated and unregulated) operations.

To further distinguish the two operations, the selection criteria for companies selected as proxies for the regulated nuclear operations were required to have nuclear generation operations, while the proxies for the regulated hydroelectric operations excluded utilities with nuclear operations. The companies in both proxy samples were required to have investment grade debt ratings (BBB- and Baa3 or higher) by both Standard and Poor's and Moody's.

While the application of the selection criteria identified nine companies[44] that met the selection criteria for the hydroelectric proxy sample, only three[45] met the criteria for the nuclear proxy sample. A sample of three is too small to permit measures of the cost of capital that can be compared with those of the proxy hydroelectric sample with any degree of confidence in the robustness of the results.

[44] Avista, Consolidated Edison, Empire District, IdaCorp, MGE Energy, Northeast Utilities, NStar, TECO Energy and Wisconsin Energy.
[45] Ameren, Constellation Energy and PPL Corp.

XII. CONCLUSIONS

A primary objective of reliance on costs of capital that reflect the risks to which the assets are exposed is to ensure that investment capital is efficiently allocated. The estimation of the cost of capital for any business is challenging, requiring significant expert judgment applied to market data. In the case of the separate regulated hydroelectric and nuclear businesses of OPG, the absence of capital market data for companies operating in the same lines of business makes that estimation even more challenging and subject to greater judgment. The results of the application of various empirical models designed to isolate costs of capital for non-traded businesses were not robust and indeed in most cases did not provide significant quantitative insight into the relative costs of capital for the two regulated operations.

While the guideline ranges for debt ratios for different levels of business risk and associated debt ratios provides some guidance on the reasonableness of utility capital structures, they are an insufficient basis for the establishment of technology-specific capital structures. Not only is significant judgment required to assign a business risk category to each of the operations, the guidelines suffer from the fundamental deficiency that they do not address equity investors' return requirements. The adoption of technology-specific capital structures indicated for given business risk categories would not lead to the conclusion that the costs of equity were the same for the individual operations. The determination of capital structures for the two technologies which would equate their costs of equity is the premise of the Board's approach, i.e., the application of a benchmark return on equity with adjustments for differences in business risk in the capital structure.

An attempt to distinguish between the costs of capital of the hydroelectric and nuclear operations by reference to proxy companies facing a reasonably similar level of business risk to the two technologies was not able to identify a large enough sample of companies to serve as a proxy for the nuclear operations. Therefore, it was not possible to estimate technology-specific capital structures by reference to comparable companies.

The qualitative assessment of the relative business risks of the hydroelectric and nuclear operations supports the conclusion that the nuclear operations face materially higher business risks than the hydroelectric operations. However, given the constraints of the available market data and the lack of proxy companies that are comparable to each of the two technologies, none of the analyses conducted were able to provide any quantitative insight into reasonable differential capital structures for the two operations. Any specification of technology-specific capital structures would be largely a judgmental exercise and lack any degree of precision. Given the degree of judgment that would be required and the absence of robust parameters upon which to base that judgment, there is no compelling basis for the Board to adopt technology-specific capital structures.

Appendix A
Selection of Samples for Various Analyses

The various analyses undertaken required the selection of a variety of different company samples. Initially, a large sample of companies, both gas distributors and electric utilities, was selected for which a database of company specific information was created. The company specific information was selected for its usefulness in isolating the cost of capital by function: generation (Gx), distribution and transmission (Dx and Tx) and other as well as within generation by technology (hydroelectric, nuclear and other).

The following steps were taken in establishing the initial database:

- The criteria to create the initial sample of utilities, both electric and gas, for which a database of function-specific and generation-specific information was developed were defined as follows:

  Electric Utilities:

  - Initial universe was comprised of all electric utilities from *Value Line* (59 utilities)
  - From this sample of 59 utilities, nine companies were removed which were either rated below investment grade by S&P or not rated by S&P (50 utilities)
  - From this group of 50 utilities, one company was removed (El Paso Electric) as it did not pay a dividend in 2009
  - Five companies were removed which either had limited corporate history (ITC Holdings, Duke Energy and Portland General Electric) or no meaningful figure

for key variables (CMS Energy and Northwestern Energy), leaving 44 utilities (Schedule 3)

Gas Distributors:

- Initial universe was comprised of all natural gas utilities from *Value Line* (12 utilities)

- Obtained 2008 function-specific information for all companies in samples

Electric Utilities:

- FERC Form 1s – Obtained function-specific asset information for FERC-regulated electric utilities for regulated portions of the companies' operations only (dollars of distribution, transmission and generation in total and of generation by technology)

- Annual Reports and 10-Ks

  - Reviewed business segment data and descriptions of all companies' business segments to determine proportion of total assets related to each of the transmission, distribution and generation (total of regulated and non-regulated) functions and to other unregulated operations

  - Obtained asset and owned capacity data from 10-Ks on type of generation, e.g., hydroelectric, nuclear and other to permit combining regulated and unregulated generation by technology

Gas Distributors:

- o Annual Reports and 10-Ks – Reviewed descriptions of companies' business segments to determine portion of assets related to gas distribution operations

- Combined data from 10-Ks and Form 1s for the electric utilities to create a database which provides total assets broken down by distribution, transmission, total (regulated and unregulated) generation and other, where "other" is all unregulated assets except unregulated generation.

- The data included in the database comprised:

  - o Percentage of each utility's 2008 total assets devoted to each of Generation, Wires (Transmission and Distribution) and Other (remainder). "Other" includes all unregulated assets which are not included in generation assets, e.g. real estate, oil and gas production

  - o Within Generation, the 2008 percentage of owned capacity for hydroelectric, nuclear and other generation, where other generation is primarily from fossil fuel (e.g., coal) facilities

  - o For each of the companies, 2006 function-specific data were also collected, including the 2006 percentage of owned capacity for hydroelectric, nuclear and other generation, to allow for comparisons across time

  - o Betas calculated using weekly price data for the five-year periods ending December 2003 to 2008 and October 2009 and for the same periods using monthly prices, as provided by Standard & Poor's Research Insight

  - o Capital structures, calculated on both book value and market value bases, for the periods covered by the betas

Depending on the analysis to be undertaken, the sample to be utilized was derived from the database developed above. The Instrumental Variables Analysis sample was comprised of all 44 electric utilities referenced above (see Appendix B and Schedule 3). The residual beta and full information beta analysis required the selection of a "wires" sample, a high generation sample, a high nuclear generation sample and a high hydroelectric generation sample. These four samples are described below:

- Wires: Utilities which are predominantly electric or gas distribution (i.e., less than 5% generation assets and more than 80% distribution assets). The sample includes 11 companies, five electric utilities and six gas distributors; See Schedule 5.
- High Generation: Utilities which have a high proportion of generation assets (more than 33% of total assets), with no restrictions on the generation technology (28 companies); See Schedule 4.
- High Nuclear Generation: Utilities which have more than 10% of their assets in nuclear generation. The High Nuclear Generation sample is a sub-set of the High Generation sample; See Schedule 5.
- High Hydroelectric Generation: Utilities which have more than 10% of their assets in hydroelectric generation. The High Hydroelectric Generation sample is a sub-set of the High Generation Sample; See Schedule 5.

In addition, this data base was used for the purpose of selecting two samples to be used as proxies to directly estimate the differences in the cost of capital of OPG's regulated hydroelectric and nuclear operations. The specific criteria for these two samples are listed in Section XI.

Appendix B
Instrumental Variables Analysis

The instrumental variables approach is an alternative to the accounting beta approach for estimating the market beta for a company or division which is not traded. The approach attempts to identify variables that can be used to explain market betas, such as the earnings or accounting beta, growth in assets, leverage, payout ratios, etc. A large sample of companies is used to attempt to specify the relationship between the market beta, i.e., the dependent variable, and the various explanatory or independent variables. Using the coefficients of the resulting regression equation, the market beta for the non-traded entity can be estimated by applying the estimated coefficients from the sample regression to the non-traded entity's values of the various explanatory variables

The sample used in the analysis was comprised of the 44 electric utilities defined in Appendix A for which the following data were collected:

- Research Insight 5-year betas ending 2008. These betas are calculated using 60 months of month-end closing prices (including dividends) for the individual company. The index used in the calculation of the beta is the S&P 500 Index.
- 10-year betas ending 2008 calculated using 120 months of month-end closing prices for the individual company. The index used in the calculation of the beta is the S&P 500 Index.
- The 10-year (1999-2008) standard deviation of annual returns on equity for each company.
- The 10-year accounting beta for each company, where the accounting beta was calculated using 10 years of annual returns on equity for the individual company regressed against the annual returns on equity of the S&P 500.

- Average dividend payout ratio for both the 5 and 10 year periods covered by the betas.
- Average market value for both the 5 and 10 years periods covered by the betas.
- Average debt to total capital for both the 5 and 10 year periods covered by the betas.
- Average (geometric) annual growth in total assets for the 5 and 10 year periods covered by the betas.
- The percentage of total 2008 generating capacity that is nuclear.
- The current S&P debt rating. The rating categories from AA- to BBB- were assigned a numeric value from 1 to 7.

The data for each company in the analysis are provided on Schedule 3.

The regressions estimated included eight explanatory (independent) variables. These variables are listed below along with the *a priori* anticipated relationship between beta and the explanatory variable:

- Standard deviation of return on equity – Higher variability in annual returns as indicated by a higher standard deviation of returns on equity would be expected to be associated with a higher beta, i.e., a positive coefficient.
- Accounting beta – the accounting beta measures the co-variability (the extent to which they move together) of the returns on equity for the firm with the returns on equity of the equity market composite, in this case proxied by the returns on equity of the S&P 500 index. The accounting beta is a proxy for the market beta and thus an indirect measure of the systematic risk faced by the firm. It is expected that the larger is the value of the accounting beta, the higher is the systematic risk and, therefore, the higher the market beta.

- Dividend payout ratio – A higher dividend payout ratio would be expected to signal greater certainty (lower volatility) in the earnings stream (since companies are reluctant to cut dividends). Further, a lower dividend payout ratio suggests that a firm is retaining earnings to finance growth. Higher growth in turn indicates higher risk. A higher dividend payout ratio, all other things equal, should be associated with a lower beta (i.e., the expected value of the coefficient is negative).

- Average market value – All other things equal, larger firms have the benefit of diversification of assets and greater financial resources to weather economic downturns. Therefore, the larger the market value of the firm, the lower is the expected beta.

- Debt to total capital – The higher the debt/capital ratio, the higher is the financial risk. A higher debt/capital ratio would be expected to be associated with a higher beta.

- Average annual asset growth – The greater the proportion of the investor return that is expected to come from uncertain future growth, the higher is the risk that returns will fall short of expectations. High asset growth is effectively the converse of a high dividend payout ratio. Higher growth in assets is expected to be associated with a higher beta.

- Nuclear capacity – *A priori,* it is expected that a higher proportion of nuclear capacity would be associated with relatively higher business risk and a higher beta.

- S&P debt rating – The ratings were assigned a numeric value where a higher value is representative of a lower debt rating. *A priori*, it is expected that the higher the value assigned to the debt rating (i.e., the lower the debt rating), the higher would be the beta.

The dependent variable in each regression was the unadjusted or “raw” beta. The regressions were estimated for both the 5 and 10 year periods.

The following table summarizes the results of the regressions conducted using all eight of the variables; See Schedule 3 for data.

Table B-1

5-Year Regression			**10-Year Regression**		
Regression Statistics			**Regression Statistics**		
Adjusted R^2	0.41		Adjusted R^2	0.39	
Standard Error	0.16		Standard Error	0.14	
Observations	44		Observations	44	
	Coefficients	**t Stat**		**Coefficients**	**t Stat**
Intercept	0.47	2.04	Intercept	0.03	0.15
Dividend Payout	0.00	0.01	Dividend Payout	0.00	-0.22
10-Yr.Standard Deviation of Return	0.01	1.93	10-Yr.Standard Deviation of Return	0.01	2.37
S&P Rating Score	0.10	5.03	S&P Rating Score	0.04	2.33
Nuclear Capacity	-0.28	-0.90	Nuclear Capacity	0.22	0.87
Average Annual Asset Growth	-0.25	-0.55	Average Annual Asset Growth	0.22	0.52
Average Debt /Total Capital	-0.79	-2.03	Average Debt /Total Capital	0.19	0.52
Average Market Value	0.00	1.22	Average Market Value	0.00	-1.84
10-Yr. ROE Beta 2008	0.06	1.60	10-Yr. ROE Beta 2008	0.05	1.57

While the adjusted R^2 of the two equations indicate in both cases that the eight variables in total explain approximately 40% of the variation in betas among companies, the majority of the explanatory variables had estimated coefficients which were not statistically different from zero.

Only the coefficients on the S&P debt rating and standard deviation of returns on equity were significantly different from zero at a 95% confidence level and of the expected sign in both the five-year and ten-year regressions. In both cases the positive sign on the coefficient indicated that an increase in the value of the explanatory variable, that is, a lower debt rating and greater variability in return on equity, would be associated with a higher beta, i.e., greater risk.

With respect to the impact of the debt rating on the beta, the S&P rating values ranged from 1 to 7, equivalent to a range in ratings from AA- to BBB-. The sample average of 5 is equivalent to a BBB+ rating. Based on the results of the 10-year regression above, the market beta for a company with an A rating, (rating value of 3), would be approximately 0.08 lower than the sample average beta. Assuming a market risk premium of 6.75%, the required equity return for an A rated utility would be approximately 55 basis points lower than the required return on a BBB+ rated utility.[46]

With respect to the standard deviation of returns on equity, the coefficient, while positive, was relatively small (approximately 0.008), indicating that the market beta is relatively insensitive to the variability in returns on equity. To put this in perspective, the average standard deviation of the returns on equity of the sample was 7.1%; See Schedule 3. The beta for a company with a standard deviation of returns on equity approximately twice that of the sample average (e.g., 15%) would be approximately 0.06 higher than the sample average beta. The associated difference in cost of equity at a market risk premium of 6.75% would be approximately 0.40%.[47]

A third explanatory variable, the ROE beta, exhibited the expected sign in both regressions, that is, a higher beta was associated with a higher ROE beta; however, the t-statistics were significant at only a 90% confidence level.

Additional regressions were run including only those three independent variables which were of the right sign in both the initial (eight variable) five-year and ten-year regressions and whose coefficients were statistically significant at no less than a 90% confidence level. When estimated using 10-year data, the S&P rating value, standard deviation of returns on equity and the ROE beta were significant at a 95% confidence level and of the expected sign. Using the five-year betas, while all of the independent variables had the expected sign, only the S&P rating was significant.

[46] Equal to the coefficient on the debt rating (0.04) multiplied by the difference in the rating values (3-5) multiplied by the market risk premium (6.75%).
[47] Equal to the coefficient on the standard deviation of returns on equity (0.008) multiplied by the difference in the assumed standard deviation of returns of the subject company and the sample average (15%-7%) multiplied by the market risk premium (6.75%).

The following independent variables were also tested using the data for the 10-year regressions to see if generation more broadly (than nuclear generation alone) or a change in the measurement of nuclear generation made a difference in the regression results. The two variables tested along with the standard deviation of returns, S&P rating value and 10-year ROE beta were:

- Percentage of total assets devoted to electric generation
- Percentage of total assets that is nuclear

Neither of these variables[48] proved to be significantly different from zero in any of the equations at a 90% confidence level.

[48] The values for each company are shown on Schedule 3.

Appendix C
Residual Beta Analysis

The "residual beta" methodology is described in Roger Morin, *New Regulatory Finance*, Vienna, VA: Public Utilities Reports, Inc., 2006. It is based on the Capital Asset Pricing Model, which holds that the beta of a portfolio is the market value weighted average of the betas of the investments that make up the portfolio. The notion that the beta of a firm is equal to the weighted average of its divisional betas is a foundation for the "pure play" technique of estimating the betas for individual divisions of a multi-division firm. As stated in Russell J. Fuller and Halbert S. Kerr, "Estimating the Divisional Cost of Capital: An Analysis of the Pure-Play Technique," *Journal of Finance*, December 1981, "it can be shown that the beta for a multidivisional firm approximates the weighted average of its divisional betas". The pure play technique estimates divisional betas using the betas of proxy firms which operate in the same line of business as the relevant divisions.

The residual beta methodology is used to estimate the beta of a division or line of business for which there are no pure play proxies. The methodology entails disaggregating the betas of multi-divisional firms into the betas of their divisions. Its application requires the betas of the firms as a whole and a "pure play" beta for each of the divisions other than the one for which there are no pure play proxies. If the betas for the consolidated entities are known, the betas for all the divisions but one are known, and the market value weights of each of the divisions are known, the beta for the division for which no pure play proxies exist can be inferred. As the name of the methodology suggests, it is equivalent to the "residual beta." In the disaggregation of the company beta into the divisional betas, in principle, the weights to be given to each division should be equal to their relative contribution to the market value of the firm, whose closest proxy is their contribution to the operating income of the consolidated entity.

In conducting the residual beta analysis, the two objectives were to determine if it was possible to segregate a meaningful beta for the generation function as a whole of electric utilities and then to segregate a meaningful beta for nuclear generation only. To do so, three samples of electric utilities were selected: a sample of electric utilities with a relatively high proportion of investment in generation assets ("High Generation" or "High Gx"); a sample of electric and gas distribution utilities with a relatively high proportion of investment in wires assets ("Wires"); and a sample of electric utilities with a relatively high proportion of investment in nuclear generation assets ("High Nuclear"). The selection of the three samples is described in Appendix A.[49]

The estimation of a generation beta was undertaken in four steps.

STEP 1:

Disaggregate the operations of the High Gx sample into three segments, wires, generation and "other", where "other" represents the assets of the consolidated entity that are neither wires nor generation (regulated and unregulated). For the purpose of this analysis, the percentage of assets was used as a proxy for the relative contribution of each division (or business segment) to the company as a whole. The reason for using assets rather than operating income reflects the fact that electric utilities do not separately report operating income for individual regulated functions (distribution, transmission and generation). The percentages of wires, generation and other assets were calculated at both the end of 2006 and 2008.

STEP 2:

Since betas are a function of both business and financial risk, the capital structures of the Wires and the High Gx samples were compared to estimate the extent to which differences in betas between the initial samples may be due to differences in financial risk rather than business risk.

[49] A sample of utilities with a high proportion of hydroelectric generation was also selected, as per Appendix A. However, because so few publicly-traded U.S. electric utilities have a significant proportion of their total investment in hydroelectric generation assets, the resulting sample comprised only two companies. Thus it was not possible to apply this methodology to estimate the cost of capital for hydroelectric generation.

If there are material differences in financial risk as measured by capital structure, the investment risk betas for the two samples will need to be "delevered", i.e., remove the impact of the capital structure to isolate the business risk or asset betas of the two samples.

As betas are determined by market values, market value as well as book value capital structures were calculated for each of the years 2003 to 2008 (corresponding to the years underlying the sample betas). The book and market value common equity ratios of the the High Gx and Wires samples are shown in Table C-1 below. The average differential between the High Gx and Wires samples' book value common equity ratios was only 0.35% over the entire period and 0.8% at the end of 2008. While the year to year differences between the samples' market value common equity ratios show more variation, on average, the differential was only 0.10%. Given the similarity of the capital structures of the two samples, there is no need to delever the sample betas. Any differences in beta between the samples can be attributed to differences in business risk.

Table C-1

	Book Value Equity Ratios					
	2003	**2004**	**2005**	**2006**	**2007**	**2008**
Wires	38.8%	42.5%	43.3%	44.8%	44.6%	42.9%
High Gx	39.5%	42.0%	42.6%	44.4%	44.2%	42.1%

	Market Value Equity Ratios					
	2003	**2004**	**2005**	**2006**	**2007**	**2008**
Wires	52.0%	55.6%	56.8%	56.1%	57.6%	54.8%
High Gx	46.9%	53.2%	57.5%	59.1%	61.1%	55.7%

Source: Schedules 6 and 7

Step 3:

Estimate a pure wires beta for the "wires" operations of the High Gx sample using the Wires sample.

Knowing the proportion of assets devoted to pure wires and "other", and the betas for the wires sample and that applicable to the other operations, it is possible to solve the following equation for the pure wires beta.

$$\boldsymbol{\beta_{\text{Wires Sample}} = \beta_{\text{Pure Wires}} \text{ x } \%\text{Assets}_{\text{Wires}} + \beta_{\text{Other}} \text{ x } \%\text{Assets}_{\text{Other}}}$$

To estimate the beta for the pure wires operations of the companies in the Wires sample, the beta for the sample's "other" operations was assumed to be equal to the beta for an average risk entity, i.e., equal to 1.0.[50]

Solving for the pure wires beta:

$$\boldsymbol{\beta_{\text{Wires Sample}} = \beta_{\text{Pure Wires}} \text{ x } \%\text{Assets}_{\text{Wires}} + 1.0 \text{ x } \%\text{ Assets}_{\text{Other}}}$$

$$\boldsymbol{\beta_{\text{Pure Wires}} = (\beta_{\text{Wires Sample}} - 1.0 \text{ x } \%\text{ Assets}_{\text{Other}}) / \%\text{ Assets}_{\text{Wires}}}$$

The pure wires betas for various five-year periods are shown in Table C-2 below.

<u>STEP 4:</u>

Using the pure wires beta developed in Step 3, estimate the residual generation ("Gx") beta from the betas of the High Gx sample of companies.

$$\boldsymbol{\beta_{\text{HighGx}} = \beta_{\text{Gx}} \text{ x } \%\text{Assets}_{\text{Gx}} + \beta_{\text{Pure Wires}} \text{ x } \%\text{Assets}_{\text{Wires}} + \beta_{\text{Other}} \text{ x } \%\text{Assets}_{\text{Other}}}$$

Knowing the weights of each of the three segments of the High Gx utilities, the betas of the High Gx firms, the pure wires beta and the "other" beta (assumed, as was the case for the Wires sample, to be 1.0), the residual Gx beta can be estimated. The estimated Gx betas for various

[50] Since the actual proportion of generation assets to total assets for the Wires sample was 0.8% on average, generation assets were included in "Other".

periods are shown in Tables C-2 and C-3 below. The first table presents the results using unadjusted weekly betas and the second table presents the results using adjusted weekly betas.[51]

Table C-2

Calculations Using Unadjusted Weekly Betas				
	Wires Sample Beta	**Pure Wires Beta**	**High Gx Sample Beta**	**Gx Beta**
2006	0.60	0.54	0.64	0.64
2007	0.81	0.77	0.71	0.55
2008	0.68	0.66	0.66	0.64
2009	0.64	0.62	0.69	0.74

Source: Schedules 8 and 10

Table C-3

Calculations Using Adjusted Weekly Betas				
	Wires Sample Beta	**Pure Wires Beta**	**High Gx Sample Beta**	**Gx Beta**
2006	0.73	0.71	0.76	0.76
2007	0.87	0.86	0.81	0.70
2008	0.79	0.77	0.77	0.76
2009	0.76	0.74	0.79	0.83

Source: Schedules 8 and 10

A priori the pure wires beta was expected to be lower than both the High Gx sample beta and the residual Gx beta. The two tables above indicate that, on both an unadjusted and adjusted basis, the pure wires beta was only marginally lower than the High Gx sample beta in two of four cases, marginally higher in one case and materially higher in the fourth case. Since the pure wires betas and the High Gx sample betas were either virtually identical or, in one case, opposite to what one would expect, the resulting residual Gx betas were either very close to or below the pure wires betas, contrary to what would have reasonably been expected.

[51] The betas were adjusted using the following formula: 2/3 ("raw" beta) + 1/3 (market beta of 1.0). *Value Line,* Bloomberg and Merrill Lynch, major sources of financial information for investors, all publish adjusted betas. Their formulas for adjusting the calculated betas are slightly different, but all give approximately two-thirds weight to the "raw" beta of the specific stocks and one-third weight to the market beta of 1.0.

To test the sensitivity of the above results to the choice of a weekly price change interval used to calculate the sample betas, the pure wires and residual Gx betas were also estimated based on betas for the Wires and High Gx samples calculated using a monthly price change interval. Tables C-4 and C-5 below show the results based on both unadjusted and adjusted betas. In three of four cases, the estimated residual Gx betas were materially higher than the pure wires beta as was expected *a priori*. The difference in both the initial sample betas and the indicated residual pure wires and residual Gx betas highlight the sensitivity of beta calculations to the choice of price change interval.

Table C-4

Calculations Using Unadjusted Monthly Betas				
	Wires Sample Beta	Pure Wires Beta	High Gx Sample Beta	Gx Beta
2006	0.40	0.35	0.62	0.82
2007	0.71	0.69	0.66	0.56
2008	0.37	0.33	0.62	0.89
2009	0.31	0.26	0.60	0.91

Source: Schedules 9 and 11

Table C-5

Calculations Using Adjusted Monthly Betas				
	Wires Sample Beta	Pure Wires Beta	High Gx Sample Beta	Gx Beta
2006	0.60	0.57	0.75	0.88
2007	0.81	0.79	0.77	0.70
2008	0.58	0.55	0.74	0.92
2009	0.54	0.51	0.73	0.94

Source: Schedules 9 and 11

Using monthly price changes, the difference between the pure wires and residual Gx betas over the entire 2006 to 2009 period is approximately 0.40 on an unadjusted basis and 0.25 on an adjusted basis. At an equity market risk premium of 6.75%, the difference in the CAPM cost of equity between pure wires and generation based on both the differences in unadjusted and adjusted betas is in the range of approximately 1.7 to 2.7 percentage points.

The sensitivity of the results of the above analysis to the assumption that the "other" operations beta is (and remains constant across time periods) 1.0 was also tested. The sensitivity of the pure wires beta to this assumption is dependent on the weights of "other" assets and pure wires assets for the "wires" sample. The impact of a change in the "other" beta can be estimated as follows:

$$\Delta\, \beta_{\text{Pure Wires}} = -1 \text{ x } \Delta\, \beta_{\text{Other}} \text{ x } (\%\ \text{Assets}_{\text{Other}} \div \%\ \text{Assets}_{\text{Wires}})$$

An increase in the "other" beta from 1.0 to 1.25 results in a decline in the pure wires beta in 2006 and 2007 of -0.021 (based on 2006 asset splits and weekly price changes) and in 2008 and 2009 of -0.015 (using 2008 asset splits and weekly price changes). Since the proportion of "other" assets was relatively small in both 2006 and 2008, the impact on the pure wires beta of the assumption that the "other" beta is 1.0 is relatively minor.

Similarly, the estimated residual Gx betas change in response to a change in the assumed value of the beta assigned to "other" assets. The 2006 and 2007 residual Gx betas both decline by approximately 0.04 and the 2008 or 2009 residual Gx betas both decline by 0.004 if the beta for "other" operations is assumed to be 1.25 rather than 1.0. The impact on the estimated residual Gx beta of the assumption that the beta of the "other" operations is 1.0 is relatively minor.

The possibility that the observed results were due to the weighting of the business segments by assets rather than by operating income or net income was also tested. As noted above, the decision to rely on weights of assets rather than operating income arose from the fact that the companies do not typically break out operating income by utility function. The review of the business segment data suggests that, had operating income been used to assign weights to the functions rather than assets, more weight would have been given to generation because the percentage of operating income from unregulated generation is generally higher than the percentage of assets that is attributable to unregulated generation. The resulting relationships among the High Gx sample and residual pure wires and Gx betas estimated using weekly data would have been more incongruous than indicated when assets were used. In other words, the estimated residual Gx betas would have been lower if operating income had been used for weighting than they were using assets.

In order to assess whether the incongruity in the results of the residual beta model arises from the inability of betas to consistently capture differences in risk and the cost of equity, the constant growth Discounted Cash Flow ("DCF") model was applied to the Wires and High Gx samples. The DCF model was applied for each year 2006 to 2009 to each of the utilities in the two samples using the annual dividend paid, the annual average of the monthly high and low prices, and the annual average of the consensus of analysts' long-term earnings growth rate forecasts. The table below shows the median DCF cost of equity for the two samples for each year 2006-2009.

The application of the constant growth DCF model to the Wires and High Gx samples shows a material difference in the cost of equity from 2006-2009. The annual differences in the samples' median cost of equity range from 1.3 to 2.8 percentage points. On average, the DCF cost of equity of the High Gx sample was approximately 2.2 percentage points higher than the cost of equity of the Wires sample. The differences in the DCF cost of equity between the two samples are reasonably consistent with the indicated differences in the CAPM cost of equity for the two samples estimated using monthly betas.

Table C-6

DCF Cost of Equity (Median)					
	2006	**2007**	**2008**	**2009**	
High Gx	10.1	10.4	11.5	12.2	
Wires	8.4	8.5	9.0	9.9	
Differences In Median	**2006**	**2007**	**2008**	**2009**	**Average**
Wires – High Gx	-1.7	-1.9	-2.5	-2.3	-2.1

Source: Schedules 12 and 13

To attempt to derive a nuclear generation beta, it is necessary to:

1. Derive residual generation (Gx) betas for the High Nuclear sample using the same approach as for the High Generation sample.

2. Using the residual Gx betas for both the High Generation sample (estimated previously) and the High Nuclear sample, solve the following equations simultaneously to arrive at a "nuclear generation" beta:

$$\beta_{GxHigh\ Gx} = \beta_{Nuclear} \text{ x } \%\ Capacity_{Nuclear} + \beta_{Other\ Gx} \text{ x } \%\ Capacity_{Other\ Gx}$$

$$\beta_{Gx\ High\ Nuclear\ Gx} = \beta_{Nuclear} \text{ x } \%\ Capacity_{Nuclear} + \beta_{Other\ Gx} \text{ x } \%\ Capacity_{Other\ Gx}$$

The table below compares the unadjusted residual pure wires betas, the betas for the High Generation and High Nuclear samples and their respective residual Gx betas estimated using monthly data. The table suggests that, while the relative values of the 2008 and 2009 residual Gx betas for the High Generation and High Nuclear samples appear reasonable, the corresponding values for 2006 and 2007 are non-sensical. The non-sensical results are a direct result of the calculated betas for 2006 and 2007 for the High Nuclear sample being very close to (2006) or substantially lower than (2007) the pure wires betas. As a result, it is not possible to derive a meaningful residual nuclear generation beta from the 2006 or 2007 data.

Table C-7

	Wires Sample		**High Gx Sample**		**High Nuclear Sample**	
	Sample Beta	**Pure "Wires" Beta**	**Sample Beta**	**"Gx" Beta**	**Sample Beta**	**"Gx" Beta**
2006	0.40	0.35	0.62	0.82	0.49	0.43
2007	0.71	0.69	0.66	0.56	0.40	-0.22
2008	0.37	0.33	0.62	0.89	0.68	0.98
2009	0.31	0.26	0.60	0.91	0.60	0.88

Source: Schedules 9 and 11

The table below shows the residual nuclear generation betas for 2008 and 2009 estimated using the percentages of nuclear and other generating capacity owned by the utilities in the High Nuclear and High Generation samples, with the corresponding sample betas and residual generation betas.

Table C-8

	High Gx Beta	**High Gx Sample "Gx" Beta**	**High Nuclear Sample Beta**	**High Nuclear Sample "Gx" Beta**	**Residual Nuclear "Gx" Beta**
2008	0.62	0.89	0.68	0.98	1.28
2009	0.60	0.91	0.60	0.88	0.75

The estimated residual nuclear generation betas for the two periods are inconsistent across the two periods, in one case materially higher than the residual beta for "other generation" and in one case materially lower. The apparent inconsistency between the relative 2008 and 2009 nuclear generation betas is a direct result of the fact that the High Nuclear Generation sample betas were higher than the High Generation sample betas for the period ending 2008 but the two samples' betas were identical for the period ending 2009. Since the High Nuclear Generation sample's proportion of generation operations is higher than the High Generation sample's, if the sample betas are identical, the estimated residual generation beta will be lower for the sample with more generation. By extension, since the High Nuclear sample has a higher proportion of nuclear capacity than the High Generation sample, the estimated residual nuclear generation beta will be lower than the estimated "other generation" beta.

A comparison of the book value and market value capital structures of the High Gx and High Nuclear samples shows that the average differential between the book value common equity ratios of the two samples from 2003-2008 was approximately 2.5 percentage points and the market value common equity ratios differed by approximately the same amount, 2.3 percentage points. Consequently different capital structures do not explain the incongruity and inconsistency of the results.

Table C-9

	Book Value Equity Ratios					
	2003	**2004**	**2005**	**2006**	**2007**	**2008**
High Gx	39.5%	42.0%	42.6%	44.4%	44.2%	42.1%
High Nuclear	36.5%	40.7%	39.9%	42.6%	42.3%	37.7%
	Market Value Equity Ratios					
	2003	**2004**	**2005**	**2006**	**2007**	**2008**
High Gx	46.9%	53.2%	57.5%	59.1%	61.1%	55.7%
High Nuclear	49.3%	53.5%	58.1%	60.2%	64.6%	61.8%

Source: Schedules 6 and 7

It bears noting that while the betas of the High Nuclear sample were in some instances inconsistent with the expected values relative to the Wires and High Generation sample (thus leading to incongruous and/or inconsistent residual nuclear-generation betas), the constant growth DCF model consistently produced higher estimated costs of equity for the High Nuclear sample than for the High Generation sample. In turn, as indicated in both Table C-9 above and Table C-10 below, the DCF costs of equity were consistently higher for the High Generation sample than for the Wires sample. The table below summarizes the DCF costs of equity for the three samples for each year 2006-2009. The average difference between the High Nuclear and High Generation sample constant growth DCF costs of equity is two percentage points. The consistently higher DCF results for the High Nuclear Gx sample suggest that the cost of equity is higher for nuclear generation specifically than for generation operations generally.

Given the magnitude of the estimated differences in the estimated costs of equity, however, the comparisons should be interpreted with caution for two reasons. First, the constant growth DCF model cost of equity estimates for the higher growth companies may overestimate their true costs of equity because investors are likely to view the forecast growth rates as unsustainable over the longer term. Second, the High Nuclear sample of companies is characterized by a significantly higher contribution by unregulated generation operations to the consolidated operations than the

High Generation sample. Thus the differential between the two samples' costs of equity may be in part explained by differences in regulatory protection rather than the generation technology.

Table C-10

DCF Cost of Equity (Medians)					
	2006	**2007**	**2008**	**2009**	
High Nuclear	13.1	11.6	14.9	12.8	
High Gx	10.1	10.4	11.5	12.2	
Wires	8.4	8.5	9.0	9.9	
Differences	**2006**	**2007**	**2008**	**2009**	**Average**
High Nuclear – High Gx	3.0	1.2	3.4	0.6	2.0
High Gx– Wires	1.7	1.9	2.5	2.3	2.1

Source: Schedule 12 and 13

Appendix D
Full Information Beta Analysis

The Full Information Beta or Regression Beta approach uses the betas of firms operating in multiple lines of business to derive the betas for the individual lines of business through a multiple regression approach. Similar to the Residual Beta approach, the Full Information Beta approach is based on the principle that the investment risk beta of a publicly-traded firm is a weighted average of the betas of the various businesses that it operates. To estimate the betas of individual divisions of firms using the Full Information Beta approach, cross-sectional regression analysis is applied to a sample of companies in which the dependent variable in the regression is the observed beta, β_i, of the consolidated firm and the independent variables are the weights of the individual firms' business segments.

In this case, the objective was to estimate a nuclear generation beta. The first step was the estimation of a generation beta. The procedure entailed estimation of the following equation:

$$\boldsymbol{\beta_i = \beta_{Gx} + (\beta_{Wires} - \beta_{Gx}) \times \%Assets_{Wires} + (\beta_{Other} - \beta_{Gx}) \times \%Assets_{Other}}$$

The intercept of the equation, β_{Gx}, represents the generation beta, and the two other coefficients represent the difference between the generation beta and the "wires" beta and the difference between the generation beta and the "other" operations beta.

To estimate the generation beta, the unadjusted investment risk betas (based on monthly price changes) for the consolidated operations and the weights (based on assets) of generation, "wires" and "other" operations for a sample of 56 U.S. publicly-traded utilities, both electric and gas utilities, were compiled. The 56 utilities comprise the 44 electric utilities used in the instrumental variables analysis and the 12 gas utilities covered by *Value Line*. Using the equation above, the betas for the 56 utilities and the 2008 weights of the three segments, generation, wires and other operations, regressions were estimated using both five-year betas ending December

2008 October 2009. The average monthly unadjusted betas for the sample of 56 electric and gas utilities for the two periods were 0.56 and 0.55 respectively.

The regression results indicate that the generation (Gx) beta was 0.93 based on five-year betas ending December 2008 and 0.97 based on five-year betas ending October 2009. The betas for "wires" operations were significantly lower at 0.39 and 0.31 respectively based on data ending 2008 and 2009. The beta for "other" operations was 0.56 based on data ending December 2008, but significantly higher, 0.81, based on data ending October 2009. The statistical significance of the Full Information beta results was relatively weak (2008 and 2009 adjusted R^2s of 20% and 30% respectively), but all estimated coefficients, except the coefficient on "other" operations in the October 2009 equation, were significant at a 95% confidence level.

Table D-1

Equation 2008			**Equation 2009**		
Regression Statistics			**Regression Statistics**		
Adjusted R^2	0.20		Adjusted R^2	0.27	
Standard Error	0.21		Standard Error	0.21	
Observations	56		Observations	56	
	Coefficients	**t Stat**		**Coefficients**	**t Stat**
Intercept	0.93	9.53	Intercept	0.97	9.94
Total Wires %	-0.54	-3.85	Total Wires %	-0.66	-4.68
Other %	-0.37	-2.01	Other %	-0.16	-0.89
	Betas			**Betas**	
Gx	0.93		Gx	0.97	
Wires	0.39		Wires	0.31	
Other Operations	0.56		Other Operations	0.81	

In order to isolate a nuclear generation beta, the generation assets of the sample of utilities were split into nuclear generation and all other generation on the basis of their relative capacity. The equation above was expanded to incorporate nuclear generation and all "other" non-nuclear generation as follows:

$$\beta_i = \beta_{Non\text{-}NuclearGx} + (\beta_{Wires} - \beta_{Non\text{-}NuclearGx}) \times \%Assets_{Wires}$$
$$+ (\beta_{Other} - \beta_{Non\text{-}NuclearGx}) \times \%Assets_{Other}$$
$$+ (\beta_{NuclearGx} - \beta_{Non\text{-}NuclearGx}) \times \%Assets_{Nuclear\ Gx}$$

The estimation of the expanded equation using the same sample of 56 utilities and betas ending 2008 and 2009 produced results that were slightly weaker statistically than the first equations. The R^2 was slightly lower in both cases and the estimated coefficient on the additional dependent variable, the percentage of assets that are nuclear assets, was insignificantly different from zero at a 90% confidence level in both the 2008 and October 2009 regression. However, the nuclear generation beta was the highest of the estimated betas.[52]

Table D-2

Equation 2008			Equation 2009		
Regression Statistics			**Regression Statistics**		
Adjusted R^2	0.19		Adjusted R^2	0.26	
Standard Error	0.21		Standard Error	0.21	
Observations	56		Observations	56	
	Coefficients	**t Stat**		**Coefficients**	**t Stat**
Intercept	0.90	7.57	Intercept	0.95	8.02
Total Wires %	-0.51	-3.26	Total Wires %	-0.64	-4.10
Other %	-0.33	-1.61	Other %	-0.14	-0.69
% Gx Nuclear	0.24	0.48	% Gx Nuclear	0.13	0.25
	Betas			**Betas**	
Non-Nuclear Gx	0.90		Non-Nuclear Gx	0.95	
Wires	0.39		Wires	0.31	
Other Operations.	0.57		Other Operations	0.81	
Nuclear Gx	1.15		Nuclear Gx	1.08	

[52] For completeness, the same analysis was performed using monthly betas ending 2006 and 2007 and segment weights as of 2006. However, the analysis, similar to the residual beta analysis conducted using betas and weights for the same period, produced non-sensical results. The application of the full information beta approach resulted in estimated betas ending 2006 and 2007 for nuclear generation that were negative.

Appendix E
Discounted Cash Flow Test

1. CONSTANT GROWTH DCF MODEL

The constant growth model rests on the assumption that investors expect cash flows to grow at a constant rate throughout the life of the stock. The assumption that investors expect a stock to grow at a constant rate over the long-term is most applicable to stocks in mature industries. Growth rates in these industries will vary from year to year and over the business cycle, but will tend to deviate around a long-term expected value.

The constant growth model is expressed as follows:

$$\text{Cost of Equity } (\mathbf{k}) = \frac{\mathbf{D_1}}{\mathbf{P_o}} + \mathbf{g},$$

where,

$\mathbf{D_1}$ = next expected dividend[53]
$\mathbf{P_o}$ = current price
$\mathbf{g}$ = constant growth rate

This model, as set forth above, reflects a simplification of reality. First, it is based on the notion that investors expect all cash flows to be derived through dividends. Second, the underlying premise is that dividends, earnings, and price all grow at the same rate. However, it is likely that, in the near-term, investors expect growth in dividends to be lower than growth in earnings.

The model can be adapted to account for the potential disparity between earnings and dividend growth by recognizing that all investor returns must ultimately come from

[53] Alternatively expressed as D_o (1 + g), where D_o is the most recently paid dividend.

earnings. Hence, focusing on investor expectations of earnings growth will encompass all of the sources of investor returns (e.g., dividends and retained earnings).

The application of the constant growth model relies on the consensus of investment analysts' forecasts of long-term earnings growth compiled by I/B/E/S.

2. APPLICATION OF THE DCF MODEL

The constant growth DCF model was applied to samples of U.S. electric utilities for various periods. The 2009 DCF cost estimates reflect the following inputs to calculate the dividend yield:

(1) the most annualized dividend paid as of October 31, 2009 as D_o; and,

(2) the average of the high and low monthly prices for the period January 1, 2009 to October 31, 2009 as P_o.

For the expected growth rates, the average January to October 2009 I/B/E/S consensus (mean) earnings growth forecasts were used to estimate "g" in the growth component for each utility and to adjust the current dividend yield to the expected dividend yield.

Similar estimates were made for three prior years, 2006-2008, using the average dividend paid during the year as Do, the average of the high and low monthly prices for January to December of each year, and the average of the 12 monthly I/B/E/S consenus growth forecasts.

Appendix F
Qualifications of Kathleen C. McShane

Kathleen McShane is President and senior consultant with Foster Associates, Inc., where she has been employed since 1981. She holds an M.B.A. degree in Finance from the University of Florida, and M.A. and B.A. degrees from the University of Rhode Island. She has been a CFA charterholder since 1989.

Ms. McShane worked for the University of Florida and its Public Utility Research Center, functioning as a research and teaching assistant, before joining Foster Associates. She taught both undergraduate and graduate classes in financial management and assisted in the preparation of a financial management textbook.

At Foster Associates, Ms. McShane has worked in the areas of financial analysis, energy economics and cost allocation. Ms. McShane has presented testimony in more than 200 proceedings on rate of return and capital structure before federal, state, provincial and territorial regulatory boards, on behalf of U.S. and Canadian gas distributors and pipelines, electric utilities and telephone companies. These testimonies include the assessment of the impact of business risk factors (e.g., competition, rate design, contractual arrangements) on capital structure and equity return requirements. She has also testified on various ratemaking issues, including deferral accounts, rate stabilization mechanisms, excess earnings accounts, cash working capital, and rate base issues. Ms. McShane has provided consulting services for numerous U.S. and Canadian companies on financial and regulatory issues, including financing, dividend policy, corporate structure, cost of capital, automatic adjustments for return on equity, form of regulation (including performance-based regulation), unbundling, corporate separations, stand-alone cost of debt, regulatory climate, income tax allowance for partnerships, change in fiscal year end, treatment of inter-corporate financial transactions, and the impact of weather normalization on risk.

Ms. McShane was principal author of a study on the applicability of alternative incentive regulation proposals to Canadian gas pipelines. She was instrumental in the design and preparation of a study of the profitability of 25 major U.S. gas pipelines, in which she developed estimates of rate base, capital structure, profit margins, unit costs of providing services, and various measures of return on investment. Other studies performed by Ms. McShane include a comparison of municipal and privately owned gas utilities, an analysis of the appropriate capitalization and financing for a new gas pipeline, risk/return analyses of proposed water and gas distribution companies and an independent power project, pros and cons of performance-based regulation, and a study on pricing of a competitive product for the U.S. Postal Service. She has also conducted seminars on cost of capital and related regulatory issues for public utilities, with focus on the Canadian regulatory arena.

PUBLICATIONS, PAPERS AND PRESENTATIONS

- *Utility Cost of Capital: Canada vs. U.S.,* presented at the CAMPUT Conference, May 2003.

- *The Effects of Unbundling on a Utility's Risk Profile and Rate of Return*, (co-authored with Owen Edmondson, Vice President of ATCO Electric), presented at the Unbundling Rates Conference, New Orleans, Louisiana sponsored by Infocast, January 2000.

- *Atlanta Gas Light's Unbundling Proposal: More Unbundling Required?* presented at the 24th Annual Rate Symposium, Kansas City, Missouri, sponsored by several commissions and universities, April 1998.

- *Incentive Regulation: An Alternative to Assessing LDC Performance*, (co-authored with Dr. William G. Foster), presented at the Natural Gas Conference, Chicago, Illinois sponsored by the Center for Regulatory Studies, May 1993.

- *Alternative Regulatory Incentive Mechanisms*, (co-authored with Stephen F. Sherwin), prepared for the National Energy Board, Incentive Regulation Workshop, October 1992.

EXPERT TESTIMONY/OPINIONS
ON
RATE OF RETURN AND CAPITAL STRUCTURE

Client	Date
Alberta Natural Gas	1994
AltaGas Utilities	2000
Ameren (Central Illinois Public Service)	2000, 2002, 2005, 2007 (2 cases), 2009 (2 cases)
Ameren (Central Illinois Light Company)	2005, 2007 (2 cases), 2009 (2 cases)
Ameren (Illinois Power)	2004, 2005, 2007 (2 cases), 2009 (2 cases)
Ameren (Union Electric)	2000 (2 cases), 2002 (2 cases), 2003, 2006 (2 cases)
ATCO Electric	1989, 1991, 1993, 1995, 1998, 1999, 2000, 2003
ATCO Gas	2000, 2003, 2007
ATCO Pipelines	2000, 2003, 2007
ATCO Utilities	2008
Bell Canada	1987, 1993
Benchmark Utility Cost of Equity (British Columbia)	1999
Canadian Western Natural Gas	1989, 1996, 1998, 1999
Centra Gas B.C.	1992, 1995, 1996, 2002
Centra Gas Ontario	1990, 1991, 1993, 1994, 1995
Direct Energy Regulated Services	2005
Dow Pool A Joint Venture	1992
Edmonton Water/EPCOR Water Services	1994, 2000, 2006, 2008
Electricity Distributors Association	2009
Enbridge Gas Distribution	1988, 1989, 1991-1997, 2001, 2002
Enbridge Gas New Brunswick	2000
Enbridge Pipelines (Line 9)	2007, 2009
Enbridge Pipelines (Southern Lights)	2007
FortisBC	1995, 1999, 2001, 2004
Gas Company of Hawaii	2000, 2008

Gaz Metropolitain	1988
Gazifère	1993, 1994, 1995, 1996, 1997, 1998
Generic Cost of Capital, Alberta (ATCO and AltaGas Utilities)	2003
Heritage Gas	2004, 2008
Hydro One	1999, 2001, 2006 (2 cases)
Insurance Bureau of Canada (Newfoundland)	2004
Laclede Gas Company	1998, 1999, 2001, 2002, 2005
Laclede Pipeline	2006
Mackenzie Valley Pipeline	2005
Maritimes NRG (Nova Scotia) and (New Brunswick)	1999
MidAmerican Energy Company	2009
Multi-Pipeline Cost of Capital Hearing (National Energy Board)	1994
Natural Resource Gas	1994, 1997, 2006
New Brunswick Power Distribution	2005
Newfoundland & Labrador Hydro	2001, 2003
Newfoundland Power	1998, 2002, 2007, 2009
Newfoundland Telephone	1992
Northland Utilities	2008 (2 cases)
Northwestel, Inc.	2000, 2006
Northwestern Utilities	1987, 1990
Northwest Territories Power Corp.	1990, 1992, 1993, 1995, 2001, 2006
Nova Scotia Power Inc.	2001, 2002, 2005, 2008
Ontario Power Generation	2007
Ozark Gas Transmission	2000
Pacific Northern Gas	1990, 1991, 1994, 1997, 1999, 2001, 2005, 2009
Plateau Pipe Line Ltd.	2007
Platte Pipeline Co.	2002
St. Lawrence Gas	1997, 2002
Southern Union Gas	1990, 1991, 1993
Stentor	1997
Tecumseh Gas Storage	1989, 1990

Telus Québec	2001
Terasen Gas	1992, 1994, 2005, 2009
Terasen Gas (Whistler)	2008
TransCanada PipeLines	1988, 1989, 1991 (2 cases), 1992, 1993
TransGas and SaskEnergy LDC	1995
Trans Québec & Maritimes Pipeline	1987
Union Gas	1988, 1989, 1990, 1992, 1994, 1996, 1998, 2001
Westcoast Energy	1989, 1990, 1992 (2 cases), 1993, 2005
Yukon Electrical Company	1991, 1993, 2008
Yukon Energy	1991, 1993

EXPERT TESTIMONY/OPINIONS
ON
OTHER ISSUES

Client	Issue	Date
Nova Scotia Power	Calculation of ROE	2009
New Brunswick Power Distribution	Interest Coverage/Capital Structure	2007
Heritage Gas	Revenue Deficiency Account	2006
Hydro Québec	Cash Working Capital	2005
Nova Scotia Power	Cash Working Capital	2005
Ontario Electricity Distributors	Stand-Alone Income Taxes	2005
Caisse Centrale de Réassurance	Collateral Damages	2004
Hydro Québec	Cost of Debt	2004
Enbridge Gas New Brunswick	AFUDC	2004
Heritage Gas	Deferral Accounts	2004
ATCO Electric	Carrying Costs on Deferral Account	2001
Newfoundland & Labrador Hydro	Rate Base, Cash Working Capital	2001
Gazifère Inc.	Cash Working Capital	2000
Maritime Electric	Rate Subsidies	2000
Enbridge Gas Distribution	Principles of Cost Allocation	1998
Enbridge Gas Distribution	Unbundling/Regulatory Compact	1998
Maritime Electric	Form of Regulation	1995
Northwest Territories Power	Rate Stabilization Fund	1995
Canadian Western Natural Gas	Cash Working Capital/ Compounding Effect	1989
Gaz Metro/ Province of Québec	Cost Allocation/ Incremental vs. Rolled-In Tolling	1984

5-YEAR PRICE BETAS FOR S&P/TSX SECTOR INDICES

	Consumer Discretionary	Consumer Staples	Energy	Financials	Health Care
1997	0.82	0.62	0.97	0.94	0.60
1998	0.80	0.60	0.85	1.12	1.01
1999	0.73	0.44	0.90	1.00	1.00
2000	0.69	0.23	0.66	0.78	1.09
2001	0.68	0.10	0.49	0.66	0.98
2002	0.73	0.08	0.43	0.66	0.99
2003	0.74	-0.08	0.26	0.38	0.85
2004	0.80	-0.07	0.17	0.39	0.82
2005	0.83	0.07	0.48	0.56	0.72
2006	0.86	0.37	1.03	0.68	0.85
2007	0.73	0.54	1.44	0.51	0.54
2008	0.59	0.32	1.43	0.61	0.48

	Industrials	Information Technology	Materials	Telecommunication Services	Utilities
1997	0.97	1.57	1.32	0.64	0.53
1998	0.93	1.41	1.12	0.92	0.55
1999	0.78	1.55	1.04	1.11	0.30
2000	0.72	1.78	0.74	0.92	0.14
2001	0.82	2.13	0.60	0.94	-0.03
2002	0.86	2.28	0.57	0.93	-0.06
2003	0.91	2.74	0.43	0.83	-0.25
2004	1.05	2.87	0.41	0.58	-0.13
2005	1.13	2.68	0.77	0.74	0.00
2006	1.06	2.07	1.32	0.52	0.25
2007	0.96	1.12	1.45	0.62	0.46
2008	0.81	1.43	1.30	0.55	0.49

Source: TSX Review

HISTORIC VALUE LINE BETAS FOR
HIGH GENERATION U.S. ELECTRIC UTILITY SAMPLE

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
ALLEGHENY ENERGY	0.75	0.70	0.60	0.60	0.60	1.15	1.45	1.60	1.80	2.10	1.40	1.10	0.95
ALLETE INC	0.70	0.60	0.45	0.50	0.45	0.60	0.70	nmf	nmf	0.90	0.95	0.75	0.70
ALLIANT ENERGY CORP	0.55	nmf	nmf	0.55	0.55	0.65	0.70	0.80	0.85	0.95	0.80	0.70	0.70
AMEREN CORP	0.70	0.65	0.50	0.55	0.55	0.60	0.65	0.75	0.75	0.75	0.80	0.80	0.80
AMERICAN ELECTRIC POWER CO	0.70	0.65	0.45	0.55	0.55	0.75	0.95	1.15	1.20	1.35	0.95	0.75	0.70
AVISTA CORP	0.70	0.70	0.50	0.55	0.60	0.65	0.75	0.85	0.90	0.95	1.00	0.85	0.70
CONSTELLATION ENERGY	0.80	0.60	0.55	0.55	0.60	0.75	0.85	0.85	0.95	0.95	0.85	0.75	0.80
DOMINION RESOURCES	0.70	0.55	0.50	0.55	0.50	0.75	0.80	0.85	0.90	1.00	0.75	0.70	0.70
DPL INC	0.75	0.70	0.55	0.55	0.60	0.75	0.80	0.90	1.00	0.95	0.85	0.65	0.60
DTE ENERGY CO	0.80	0.75	0.60	0.60	0.55	0.60	0.60	0.70	0.70	0.75	0.80	0.70	0.75
EMPIRE DISTRICT	0.60	0.60	0.45	0.50	0.45	0.50	0.60	0.70	0.70	0.80	0.85	0.75	0.75
ENTERGY CORP	0.80	0.70	0.50	0.60	0.50	0.60	0.65	0.75	0.80	0.85	0.85	0.75	0.70
EXELON CORP	na	na	na	nmf	nmf	0.70	0.70	0.70	0.75	0.90	0.90	0.90	0.85
FIRSTENERGY CORP	0.80	0.70	0.50	0.55	0.55	0.55	0.75	0.75	0.75	0.80	0.85	0.85	0.80
FPL GROUP	0.75	0.55	0.50	0.45	0.45	0.55	0.65	0.70	0.75	0.85	0.75	0.80	0.75
GREAT PLAINS ENERGY INC	0.75	0.60	0.60	0.60	0.55	0.65	0.70	0.80	0.85	0.95	0.80	0.65	0.75
IDACORP INC	0.70	0.65	0.50	0.50	0.50	0.60	0.75	0.85	0.95	1.00	1.00	0.85	0.70
MGE ENERGY	0.50	0.50	0.50	0.45	0.45	0.50	0.55	0.60	0.70	0.75	0.95	0.70	0.65
PINNACLE WEST CAPITAL CORP	0.75	0.70	0.45	0.45	0.45	0.55	0.70	0.85	0.90	1.00	1.00	0.75	0.75
PPL CORP	0.70	0.55	0.55	0.60	0.70	0.80	0.90	0.95	1.00	0.95	0.90	0.80	0.70
PROGRESS ENERGY INC	0.65	0.50	0.45	0.45	nmf	nmf	0.80	0.80	0.85	0.90	0.85	0.60	0.65
PUBLIC SERVICE ENTRP GRP INC	0.75	0.55	0.50	0.55	0.55	0.70	0.80	0.85	0.90	1.00	0.95	0.85	0.80
SCANA CORP	0.70	0.55	0.45	0.45	0.45	0.55	0.65	0.70	0.75	0.85	0.85	0.70	0.65
SOUTHERN CO	0.70	0.50	0.45	0.50	nmf	nmf	0.60	0.65	0.65	0.70	0.70	0.55	0.55
TECO ENERGY INC	0.70	0.55	0.50	0.50	0.50	0.70	0.80	0.90	0.95	1.05	0.95	0.75	0.85
WESTAR ENERGY INC	0.65	0.55	0.35	0.30	0.35	0.50	0.60	0.75	0.85	0.90	0.85	0.80	0.75
WISCONSIN ENERGY CORP	0.70	0.65	0.45	0.50	0.50	0.55	0.60	0.70	0.70	0.80	0.85	0.65	0.65
XCEL ENERGY INC	na	na	na	nmf	nmf	0.60	0.70	0.80	0.80	0.90	1.05	0.75	0.65
MEAN	**0.71**	**0.61**	**0.50**	**0.52**	**0.52**	**0.65**	**0.74**	**0.82**	**0.88**	**0.95**	**0.89**	**0.76**	**0.73**
MEDIAN	**0.70**	**0.60**	**0.50**	**0.55**	**0.53**	**0.60**	**0.70**	**0.80**	**0.85**	**0.90**	**0.85**	**0.75**	**0.70**

Source: *Value Line*, 4th Quarter issues and Issues 1, 5, and 11 3rd Quarter of 2009

INDIVIDUAL COMPANY RISK DATA FOR 44 U.S. ELECTRIC UTILITIES
USED IN THE INSTRUMENTAL VARIABLES ANALYSIS

	Percent of Total Assets												
	Generation	**Wires**	**Other**	**Nuclear % Capacity**	**Nuclear Assets % of Total Assets [1/]**	**Hydro Assets % of Total Assets [1/]**	**Adjusted 5 Year Betas Ending October 2009 [2/]**	**Common Equity Ratio 2008**	**S&P Debt Rating [3/]**	**S&P Business Profile**	**S&P Financial Profile**	**Moody's Debt Rating [3/]**	**Value Line Safety Rank**
Allegheny Energy	53.1%	46.9%	0.0%	0.0%	0.0%	6.7%	0.98	40%	BBB-	Strong	Aggressive	Ba1	3
ALLETE	54.4%	35.7%	9.9%	0.0%	0.0%	4.5%	0.75	58%	BBB+	Strong	Significant	A2	2
Alliant Energy	33.7%	53.6%	12.6%	0.0%	0.0%	0.2%	0.83	56%	BBB+	Excellent	Significant	Baa1	2
Ameren Corp.	58.3%	36.7%	5.0%	7.5%	4.4%	1.3%	0.90	46%	BBB-	Satisfactory	Significant	Baa3	3
American Electric Power	42.0%	55.8%	2.2%	6.0%	2.5%	0.8%	0.83	37%	BBB	Excellent	Aggressive	Baa2	3
Avista Corp.	38.0%	56.6%	5.4%	0.0%	0.0%	21.2%	0.77	46%	BBB-	Excellent	Aggressive	Baa3	3
Black Hills Corp.	27.2%	47.2%	25.6%	0.0%	0.0%	0.0%	0.89	47%	BBB-	Satisfactory	Significant	Baa3	3
Centerpoint Energy	0.0%	96.6%	3.4%	0.0%	0.0%	0.0%	0.97	16%	BBB	Excellent	Aggressive	Ba1	3
CH Energy Group	2.1%	84.1%	13.8%	0.0%	0.0%	0.0%	0.78	52%	A	Excellent	Intermediate	A3	1
Cleco Corp.	21.2%	78.8%	0.0%	0.0%	0.0%	0.0%	0.77	48%	BBB	Excellent	Aggressive	Baa3	3
Consolidated Edison	4.5%	95.5%	0.0%	0.0%	0.0%	0.0%	0.66	48%	A-	Excellent	Significant	Baa1	1
Constellation Energy	69.7%	30.3%	0.0%	42.8%	29.8%	2.2%	0.80	27%	BBB	Satisfactory	Significant	Baa3	3
Dominion Resources	47.1%	45.4%	7.5%	21.6%	10.2%	3.7%	0.75	36%	A-	Excellent	Significant	Baa2	2
DPL Inc.	68.1%	31.3%	0.6%	0.0%	0.0%	0.0%	0.69	38%	A-	Excellent	Intermediate	Baa1	3
DTE Energy	37.7%	53.3%	9.0%	9.5%	3.6%	2.9%	0.85	40%	BBB	Strong	Significant	Baa2	3
Edison International	29.7%	63.4%	6.9%	17.0%	5.1%	2.5%	0.92	40%	BBB-	Strong	Aggressive	Baa2	3
Empire District Electric	38.8%	60.0%	1.2%	0.0%	0.0%	0.5%	0.76	42%	BBB-	Excellent	Aggressive	Baa2	3
Entergy Corp.	54.3%	44.3%	1.3%	33.3%	18.1%	0.1%	0.73	39%	BBB	Strong	Significant	Baa3	2
Exelon Corp.	41.7%	58.3%	0.0%	67.3%	28.1%	2.7%	0.94	45%	BBB	Strong	Significant	Baa1	1
FirstEnergy Corp.	37.7%	62.3%	0.0%	29.2%	11.0%	1.8%	0.83	37%	BBB	Strong	Significant	Baa3	2
FPL Group	53.9%	37.7%	8.4%	13.8%	7.4%	0.5%	0.82	41%	A	Excellent	Intermediate	A2	1
Great Plains Energy	49.6%	50.4%	0.0%	9.2%	4.6%	0.0%	0.84	44%	BBB	Excellent	Aggressive	Baa3	3
Hawaiian Electric Industries	11.7%	29.8%	58.5%	0.0%	0.0%	0.0%	0.78	42%	BBB	Strong	Significant	Baa2	3
IDACORP, Inc.	43.1%	49.5%	7.4%	0.0%	0.0%	23.0%	0.75	48%	BBB	Excellent	Aggressive	Baa2	3
Integrys Energy Group	14.0%	48.2%	37.9%	0.0%	0.0%	0.5%	0.88	46%	BBB+	Excellent	Aggressive	Baa1	3
MGE Energy	41.3%	58.7%	0.0%	0.0%	0.0%	0.0%	0.71	55%	AA-	Excellent	Intermediate	Aa3	1
Northeast Utilities	3.8%	95.5%	0.6%	0.0%	0.0%	0.2%	0.74	35%	BBB	Excellent	Aggressive	Baa2	3
NSTAR	0.1%	97.5%	2.4%	0.0%	0.0%	0.0%	0.70	37%	A+	Excellent	Intermediate	A2	1
OGE Energy	24.1%	61.0%	14.9%	0.0%	0.0%	0.0%	0.88	44%	BBB+	Strong	Significant	Baa1	2
Otter Tail Corp.	31.4%	28.8%	39.8%	0.0%	0.0%	0.2%	1.05	58%	BBB-	Satisfactory	Significant	Ba1	2
Pepco Holdings	19.4%	70.6%	10.0%	0.0%	0.0%	0.0%	1.01	41%	BBB	Strong	Significant	Baa3	3
PG&E Corp.	10.6%	89.4%	0.0%	33.0%	3.5%	6.0%	0.67	44%	BBB+	Excellent	Significant	Baa1	2
Pinnacle West Capital	38.6%	55.7%	5.8%	17.9%	6.9%	0.0%	0.81	47%	BBB-	Strong	Significant	Baa3	3
PPL Corp.	56.0%	44.0%	0.0%	19.4%	10.8%	4.6%	0.82	37%	BBB	Satisfactory	Significant	Baa2	3
Progress Energy	45.5%	54.5%	0.0%	16.6%	7.5%	0.5%	0.71	42%	BBB+	Excellent	Aggressive	Baa2	2
Public Service Enterprise Group	45.5%	54.5%	0.0%	22.6%	10.3%	0.6%	0.80	46%	BBB	Strong	Significant	Baa2	3
SCANA Corp.	36.9%	50.1%	13.0%	11.1%	4.1%	5.1%	0.74	39%	BBB+	Excellent	Aggressive	Baa2	2
Sempra Energy	11.8%	70.1%	18.1%	14.3%	1.7%	0.0%	0.86	51%	BBB+	Strong	Intermediate	Baa1	2
Southern Co.	50.0%	47.2%	2.9%	8.3%	4.2%	3.2%	0.60	41%	A	Excellent	Intermediate	A3	1
TECO Energy	51.9%	43.7%	4.3%	0.0%	0.0%	0.0%	0.83	38%	BBB	Excellent	Aggressive	Baa3	3
Vectren Corp.	18.9%	60.5%	20.6%	0.0%	0.0%	0.0%	0.76	42%	A-	Excellent	Significant	Baa1	2
Westar Energy	60.0%	40.0%	0.0%	7.9%	4.8%	0.0%	0.82	45%	BBB-	Excellent	Aggressive	Baa1	2
Wisconsin Energy	54.0%	46.0%	0.0%	0.0%	0.0%	0.8%	0.67	41%	BBB+	Excellent	Aggressive	A3	2
Xcel Energy	33.5%	61.1%	5.4%	9.9%	3.3%	1.2%	0.68	44%	BBB+	Excellent	Significant	Baa1	2
Mean	**35.6%**	**56.4%**	**8.1%**	**9.5%**	**4.1%**	**2.2%**	**0.80**	**42.8%**	**BBB+**	**Strong**	**Significant**	**Baa2**	**2**
Median	**38.3%**	**54.0%**	**3.9%**	**0.0%**	**0.0%**	**0.5%**	**0.80**	**42.1%**	**BBB**	**Excellent**	**Significant**	**Baa2**	**3**

1/ Nuclear Assets % of Total Assets = Total Generation % * Nuclear % Capacity; Hydro Assets % of Total Assets = Total Generation % * Hydro % Capacity

2/ Calculated using weekly data against the S&P 500 (260 weeks ending October 2009); adjusted towards the market mean of 1.0.

3/ Rating of CH Energy Group for Central Hudson Gas and Electric; Rating of MGE Energy for Madison Gas and Electric

Source: Company Form 1s and 10-ks; S&P Research Insight; www.yahoo.com; *Value Line Investment Survey* Index December 18, 2009; www.moodys.com
Standard and Poor's, *Issuer Ranking: U.S. Regulated Electric Utilities, Strongest to Weakest* (November 11, 2009).
Standard and Poor's, *Issuer Ranking: U.S. Integrated Utility And Merchant Power Companies, Strongest to Weakest* (November 5, 2009).
Standard and Poor's, *Issuer Ranking: U.S. Natural Gas Distributors and Integrated Gas Companies, Strongest to Weakest* (November 5, 2009).

INDIVIDUAL COMPANY REGRESSION DATA FOR 44 U.S. ELECTRIC UTILITIES USED IN THE INSTRUMENTAL VARIABLE ANALYSIS

	5 Year Research Insight Unadjusted Beta 2008	10 Year Research Insight Unadjusted Beta 2008	10 Year Standard Deviation of ROE	10 Year ROE Beta 2008	5 Year Dividend Payout	10 Year Dividend Payout	5 Year Average Market Value ($ Million)	10 Year Average Market Value ($ Million)	5 Year Average Debt/Total Capital	10 Year Average Debt/Total Capital	5 Year Average Annual Asset Growth	10 Year Average Annual Asset Growth	Nuclear % Capacity	S&P Rating Score
Allegheny Energy	0.96	0.80	18.03	0.00	0.09	0.57	6,366	4,724	66.4%	66.7%	1.2%	4.8%	0.0%	7
ALLETE	0.72	0.43	4.41	-0.11	0.82	0.73	1,220	1,593	38.8%	46.2%	-7.2%	-0.3%	0.0%	5
Alliant Energy	0.59	0.36	5.28	0.07	0.51	0.62	3,737	3,037	41.6%	47.6%	1.1%	5.2%	0.0%	5
Ameren Corp.	0.72	0.31	2.21	0.05	0.88	0.86	9,946	8,032	50.0%	49.3%	9.7%	9.9%	7.5%	7
American Electric Power	0.72	0.43	6.08	0.00	0.53	0.80	15,449	13,379	60.4%	62.7%	4.2%	8.8%	6.0%	6
Avista Corp.	0.69	0.38	3.33	0.11	0.56	0.54	1,048	882	57.2%	57.9%	-0.2%	1.1%	0.0%	7
Black Hills Corp.	1.05	0.62	5.71	-0.12	1.07	0.73	1,217	1,016	49.8%	53.9%	10.4%	19.7%	0.0%	7
Centerpoint Energy	0.83	0.65	37.42	2.68	0.52	0.43	4,514	5,567	85.9%	77.7%	-1.6%	0.3%	0.0%	6
CH Energy Group	0.35	0.22	1.17	0.12	0.82	0.79	765	731	43.0%	41.9%	5.9%	2.8%	0.0%	3
Cleco Corp.	0.67	0.60	8.84	0.21	0.43	0.56	1,308	1,098	48.4%	55.6%	9.1%	8.9%	0.0%	6
Consolidated Edison	0.25	0.00	1.62	-0.20	0.75	0.75	11,659	10,127	50.8%	50.2%	9.8%	8.8%	0.0%	4
Constellation Energy	0.94	0.58	14.37	2.45	0.98	0.73	10,740	8,033	54.9%	55.0%	7.1%	9.3%	42.8%	6
Dominion Resources	0.50	0.34	6.14	-0.46	0.58	0.67	25,471	20,470	61.7%	62.2%	-1.0%	9.2%	21.6%	4
DPL Inc.	0.61	0.50	5.84	-0.37	0.59	0.64	3,026	2,890	64.9%	65.6%	-3.7%	-0.5%	0.0%	4
DTE Energy	0.59	0.20	3.00	0.05	0.65	0.66	7,352	6,807	60.0%	60.7%	3.5%	7.4%	9.5%	6
Edison International	0.80	0.36	23.35	-1.96	0.37	0.32	13,463	9,742	56.0%	68.0%	5.0%	6.1%	17.0%	7
Empire Distric Electric	0.68	0.26	1.78	0.13	1.16	1.15	645	545	53.9%	55.6%	11.2%	10.1%	0.0%	7
Entergy Corp.	0.70	0.22	2.71	-0.15	0.45	0.45	17,287	13,373	54.4%	52.7%	5.1%	4.8%	33.3%	6
Exelon Corp.	0.71	0.31	6.36	-0.57	0.56	0.51	39,339	27,960	57.3%	61.7%	2.7%	14.8%	67.3%	6
FirstEnergy Corp.	0.60	0.27	3.33	-0.10	0.55	0.58	17,060	12,949	57.1%	59.0%	0.4%	6.4%	29.2%	6
FPL Group	0.61	0.35	1.13	-0.07	0.50	0.50	20,116	15,380	56.7%	54.2%	10.7%	14.1%	13.8%	3
Great Plains Energy	0.66	0.57	6.29	0.65	0.93	1.03	2,346	2,014	51.5%	54.7%	16.5%	10.1%	9.2%	6
Hawaiian Electric Industries	0.26	0.13	2.15	0.07	0.98	0.92	2,113	1,757	68.6%	72.6%	0.0%	1.2%	0.0%	6
IDACORP, Inc.	0.37	0.34	4.08	0.11	0.61	0.68	1,439	1,366	51.9%	52.9%	5.3%	5.1%	0.0%	6
Integrys Energy Group	0.48	0.21	2.91	0.32	0.85	0.80	2,729	1,938	50.6%	51.2%	27.2%	25.2%	0.0%	5
MGE Energy	0.26	0.16	1.31	-0.04	0.69	0.74	746	593	45.4%	46.9%	11.9%	10.5%	0.0%	1
Northeast Utilities	0.68	0.50	7.50	-0.44	1.02	0.62	3,679	3,140	62.4%	63.0%	4.3%	3.0%	0.0%	6
NSTAR	0.34	0.26	4.23	0.30	0.64	0.72	3,479	2,932	63.5%	62.8%	5.5%	9.9%	0.0%	2
OGE Energy	0.75	0.37	2.68	0.38	0.60	0.70	2,841	2,288	51.8%	56.7%	7.3%	8.1%	0.0%	5
Otter Tail Corp.	1.20	0.43	3.56	0.33	0.73	0.68	874	757	40.3%	41.9%	11.4%	9.9%	0.0%	7
Pepco Holdings	0.78	0.40	3.93	0.28	0.66	0.70	4,604	3,755	59.9%	61.7%	4.2%	9.5%	0.0%	6
PG&E Corp.	0.50	0.40	34.83	-1.02	0.22	0.41	14,291	10,929	55.0%	60.5%	6.3%	2.1%	33.0%	5
Pinnacle West Capital	0.57	0.36	2.90	0.13	0.76	0.62	4,149	3,769	50.4%	51.9%	4.0%	5.5%	17.9%	7
PPL Corp.	0.62	0.58	5.98	0.71	0.48	0.46	13,198	9,445	60.7%	66.8%	4.6%	8.3%	19.4%	6
Progress Energy	0.49	0.24	1.87	0.05	0.88	0.83	11,584	10,421	56.0%	57.7%	2.7%	13.6%	16.6%	5
Public Service Enterprise Group	0.68	0.39	3.60	-0.05	0.62	0.64	17,031	12,906	62.8%	66.7%	0.7%	4.9%	22.6%	6
SCANA Corp.	0.61	0.32	5.36	-0.29	0.62	0.57	4,572	3,888	56.7%	57.3%	6.4%	8.1%	11.1%	5
Sempra Energy	0.77	0.38	3.25	0.01	0.29	0.35	12,267	8,683	46.1%	51.1%	3.7%	9.7%	14.3%	5
Southern Co.	0.37	-0.16	1.06	0.02	0.71	0.73	27,269	23,491	56.2%	58.0%	6.6%	2.9%	8.3%	3
TECO Energy	0.78	0.43	23.71	-0.55	1.30	1.03	3,302	3,204	68.0%	66.0%	-7.3%	5.5%	0.0%	6
Vectren Corp.	0.24	0.31	1.86	0.16	0.75	0.75	2,098	1,771	58.3%	58.8%	6.7%	20.6%	0.0%	4
Westar Energy	0.60	0.68	8.16	0.64	0.62	1.21	2,160	1,708	54.0%	62.8%	5.4%	-0.7%	7.9%	7
Wisconsin Energy	0.45	0.11	1.60	0.05	0.38	0.49	4,934	3,912	59.0%	61.5%	4.7%	8.9%	0.0%	5
Xcel Energy	0.56	0.56	16.36	1.05	0.65	1.19	8,445	7,592	56.2%	62.3%	4.3%	12.9%	9.9%	5
Mean	**0.62**	**0.37**	**7.07**	**0.11**	**0.67**	**0.69**	**8,224**	**6,605**	**55.8%**	**58.0%**	**5.1%**	**7.9%**	**9.5%**	**5**
Median	**0.61**	**0.36**	**4.00**	**0.05**	**0.63**	**0.68**	**4,543**	**3,828**	**56.1%**	**57.9%**	**4.9%**	**8.2%**	**0.0%**	**6**

Source: Company Form 1s and 10-ks, S&P Research Insight

INDIVIDUAL COMPANY RISK DATA FOR HIGH GENERATION U.S. ELECTRIC UTILITY SAMPLE

	Percent of Total Assets												
	Generation	Wires	Other	Nuclear % Capacity	Nuclear Assets % of Total Assets 1/	Hydro Assets % of Total Assets 1/	Adjusted 5 Year Betas Ending October 2009 2/	Common Equity Ratio 2008	S&P Debt Rating	S&P Business Profile	S&P Financial Profile	Moody's Debt Rating 3/	Value Line Safety Rank
Allegheny Energy	53.1%	46.9%	0.0%	0.0%	0.0%	6.7%	0.98	40%	BBB-	Strong	Aggressive	Ba1	3
ALLETE	54.4%	35.7%	9.9%	0.0%	0.0%	4.5%	0.75	58%	BBB+	Strong	Significant	A2	2
Alliant Energy	33.7%	53.6%	12.6%	0.0%	0.0%	0.2%	0.83	56%	BBB+	Excellent	Significant	Baa1	2
Ameren Corp.	58.3%	36.7%	5.0%	7.5%	4.4%	1.3%	0.90	46%	BBB-	Satisfactory	Significant	Baa3	3
American Electric Power	42.0%	55.8%	2.2%	6.0%	2.5%	0.8%	0.83	37%	BBB	Excellent	Aggressive	Baa2	3
Avista Corp.	38.0%	56.6%	5.4%	0.0%	0.0%	21.2%	0.77	46%	BBB-	Excellent	Aggressive	Baa3	3
Constellation Energy	69.7%	30.3%	0.0%	42.8%	29.8%	2.2%	0.80	27%	BBB	Satisfactory	Significant	Baa3	3
Dominion Resources	47.1%	45.4%	7.5%	21.6%	10.2%	3.7%	0.75	36%	A-	Excellent	Significant	Baa2	2
DPL Inc.	68.1%	31.3%	0.6%	0.0%	0.0%	0.0%	0.69	38%	A-	Excellent	Intermediate	Baa1	3
DTE Energy	37.7%	53.3%	9.0%	9.5%	3.6%	2.9%	0.85	40%	BBB	Strong	Significant	Baa2	3
Empire District Electric	38.8%	60.0%	1.2%	0.0%	0.0%	0.5%	0.76	42%	BBB-	Excellent	Aggressive	Baa2	3
Entergy Corp.	54.3%	44.3%	1.3%	33.3%	18.1%	0.1%	0.73	39%	BBB	Strong	Significant	Baa3	2
Exelon Corp.	41.7%	58.3%	0.0%	67.3%	28.1%	2.7%	0.94	45%	BBB	Strong	Significant	Baa1	1
FirstEnergy Corp.	37.7%	62.3%	0.0%	29.2%	11.0%	1.8%	0.83	37%	BBB	Strong	Significant	Baa3	2
FPL Group	53.9%	37.7%	8.4%	13.8%	7.4%	0.5%	0.82	41%	A	Excellent	Intermediate	A2	1
Great Plains Energy	49.6%	50.4%	0.0%	9.2%	4.6%	0.0%	0.84	44%	BBB	Excellent	Aggressive	Baa3	3
IDACORP, Inc.	43.1%	49.5%	7.4%	0.0%	0.0%	23.0%	0.75	48%	BBB	Excellent	Aggressive	Baa2	3
MGE Energy	41.3%	58.7%	0.0%	0.0%	0.0%	0.0%	0.71	55%	AA-	Excellent	Intermediate	Aa3	1
Pinnacle West Capital	38.6%	55.7%	5.8%	17.9%	6.9%	0.0%	0.81	47%	BBB-	Strong	Significant	Baa3	3
PPL Corp.	56.0%	44.0%	0.0%	19.4%	10.8%	4.6%	0.82	37%	BBB	Satisfactory	Significant	Baa2	3
Progress Energy	45.5%	54.5%	0.0%	16.6%	7.5%	0.5%	0.71	42%	BBB+	Excellent	Aggressive	Baa2	2
Public Service Enterprise Group	45.5%	54.5%	0.0%	22.6%	10.3%	0.6%	0.80	46%	BBB	Strong	Significant	Baa2	3
SCANA Corp.	36.9%	50.1%	13.0%	11.1%	4.1%	5.1%	0.74	39%	BBB+	Excellent	Aggressive	Baa2	2
Southern Co.	50.0%	47.2%	2.9%	8.3%	4.2%	3.2%	0.60	41%	A	Excellent	Intermediate	A3	1
TECO Energy	51.9%	43.7%	4.3%	0.0%	0.0%	0.0%	0.83	38%	BBB	Excellent	Aggressive	Baa3	3
Westar Energy	60.0%	40.0%	0.0%	7.9%	4.8%	0.0%	0.82	45%	BBB-	Excellent	Aggressive	Baa1	2
Wisconsin Energy	54.0%	46.0%	0.0%	0.0%	0.0%	0.8%	0.67	41%	BBB+	Excellent	Aggressive	A3	2
Xcel Energy	33.5%	61.1%	5.4%	9.9%	3.3%	1.2%	0.68	44%	BBB+	Excellent	Significant	Baa1	2
Mean	**47.7%**	**48.7%**	**3.6%**	**12.6%**	**6.1%**	**3.1%**	**0.79**	**42.6%**	**BBB+**	**Excellent/Strong**	**Significant**	**Baa2**	**2**
Median	**46.3%**	**49.8%**	**1.8%**	**8.8%**	**4.1%**	**1.0%**	**0.80**	**41.5%**	**BBB**	**Excellent**	**Significant**	**Baa2**	**3**

1/ Nuclear Assets % of Total Assets = Total Generation % * Nuclear % Capacity; Hydro Assets % of Total Assets = Total Generation % * Hydro % Capacity

2/ Calculated using weekly data against the S&P 500 (260 weeks ending October 2009); adjusted towards the market mean of 1.0.

3/ Rating of MGE Energy for Madison Gas and Electric

Source: Company Form 1s and 10-ks; S&P Research Insight; www.yahoo.com; *Value Line Investment Survey* Index December 18, 2009;www.moodys.com

Standard and Poor's, *Issuer Ranking: U.S. Regulated Electric Utilities, Strongest to Weakest* (November 11, 2009).

Standard and Poor's, *Issuer Ranking: U.S. Integrated Utility And Merchant Power Companies, Strongest to Weakest* (November 5, 2009).

INDIVIDUAL COMPANY RISK DATA FOR WIRES, HIGH NUCLEAR GENERATION, AND HIGH HYDROELECTRIC GENERATION U.S. UTILITY SAMPLES

	Percent of Total Assets												
	Generation	Wires	Other	Nuclear % Capacity	Nuclear Assets % of Total Assets 1/	Hydro Assets % of Total Assets 1/	Adjusted 5 Year Betas Ending October 2009 2/	Common Equity Ratio 2008	S&P Debt Rating 3/	S&P Business Profile	S&P Financial Profile	Moody's Debt Rating 3/	Value Line Safety Rank
WIRES SAMPLE													
CenterPoint Energy	0.0%	96.6%	3.4%	0.0%	0.0%	0.0%	0.97	16%	BBB	Excellent	Aggressive	Ba1	3
CH Energy Group	2.1%	84.1%	13.8%	0.0%	0.0%	0.0%	0.78	52%	A	Excellent	Intermediate	A3	1
Consolidated Edison	4.5%	95.5%	0.0%	0.0%	0.0%	0.0%	0.66	48%	A-	Excellent	Significant	Baa1	1
Laclede Group	0.0%	83.5%	16.5%	0.0%	0.0%	0.0%	0.73	45%	A	Excellent	Intermediate	Baa2	2
Nicor Inc.	0.0%	92.9%	7.1%	0.0%	0.0%	0.0%	0.85	44%	AA	Excellent	Intermediate	na	3
Northeast Utilities	3.8%	95.5%	0.6%	0.0%	0.0%	0.2%	0.74	35%	BBB	Excellent	Aggressive	Baa2	3
Northwest Natural Gas	0.0%	96.0%	4.0%	0.0%	0.0%	0.0%	0.67	45%	AA-	Excellent	Intermediate	A1	1
NSTAR	0.1%	97.5%	2.4%	0.0%	0.0%	0.0%	0.70	37%	A+	Excellent	Intermediate	A2	1
Piedmont Natural Gas	0.0%	96.7%	3.3%	0.0%	0.0%	0.0%	0.74	42%	A	Excellent	Intermediate	A3	2
Southwest Gas	0.0%	96.3%	3.7%	0.0%	0.0%	0.0%	0.90	43%	BBB-	Excellent	Aggressive	Baa3	3
WGL Holdings Inc.	0.0%	90.6%	9.4%	0.0%	0.0%	0.0%	0.75	52%	AA-	Excellent	Intermediate	A2	1
Mean	**1.0%**	**93.2%**	**5.8%**	**0.0%**	**0.0%**	**0.0%**	**0.77**	**41.7%**	**A**	**Excellent**	**Significant**	**Baa1**	**2**
Median	**0.0%**	**95.5%**	**3.7%**	**0.0%**	**0.0%**	**0.0%**	**0.74**	**44.0%**	**A**	**Excellent**	**Intermediate**	**Baa1**	**2**
HIGH NUCLEAR GENERATION SAMPLE													
Constellation Energy	69.7%	30.3%	0.0%	42.8%	29.8%	2.2%	0.80	27%	BBB	Satisfactory	Significant	Baa3	3
Dominion Resources	47.1%	45.4%	7.5%	21.6%	10.2%	3.7%	0.75	36%	A-	Excellent	Significant	Baa2	2
Entergy Corp.	54.3%	44.3%	1.3%	33.3%	18.1%	0.1%	0.73	39%	BBB	Strong	Significant	Baa3	2
Exelon Corp.	41.7%	58.3%	0.0%	67.3%	28.1%	2.7%	0.94	45%	BBB	Strong	Significant	Baa1	1
FirstEnergy Corp.	37.7%	62.3%	0.0%	29.2%	11.0%	1.8%	0.83	37%	BBB	Strong	Significant	Baa3	2
PPL Corp.	56.0%	44.0%	0.0%	19.4%	10.8%	4.6%	0.82	37%	BBB	Satisfactory	Significant	Baa2	3
Public Service Enterprise Group	45.5%	54.5%	0.0%	22.6%	10.3%	0.6%	0.80	46%	BBB	Strong	Significant	Baa2	3
Mean	**50.3%**	**48.4%**	**1.3%**	**33.7%**	**16.9%**	**2.3%**	**0.81**	**38%**	**BBB**	**Strong**	**Significant**	**Baa2**	**2**
Median	**47.1%**	**45.4%**	**0.0%**	**29.2%**	**11.0%**	**2.2%**	**0.80**	**37%**	**BBB**	**Strong**	**Significant**	**Baa2**	**2**
HIGH HYDROELECTRIC GENERATION SAMPLE													
Avista Corp.	38.0%	56.6%	5.4%	0.0%	0.0%	21.2%	0.77	46%	BBB-	Excellent	Aggressive	Baa3	3
IDACORP, Inc.	43.1%	49.5%	7.4%	0.0%	0.0%	23.0%	0.75	48%	BBB	Excellent	Aggressive	Baa2	3
Mean	**40.6%**	**53.1%**	**6.4%**	**0.0%**	**0.0%**	**22.1%**	**0.76**	**47%**	**BBB**	**Excellent**	**Aggressive**	**Baa3**	**3**
Median	**40.6%**	**53.1%**	**6.4%**	**0.0%**	**0.0%**	**22.1%**	**0.76**	**47%**	**BBB**	**Excellent**	**Aggressive**	**Baa3**	**3**

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2/ Calculated using weekly data against the S&P 500 (260 weeks ending October 2009); adjusted towards the market mean of 1.0.

3/ Rating of CH Energy Group for Central Hudson Gas and Electric; Moody's Rating of WGL Holdings for Washington Gas Light

Source: Company Form 1s and 10-ks; S&P Research Insight; www.yahoo.com; *Value Line Investment Survey* Index December 18, 2009; www.moodys.com

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Standard and Poor's, *Issuer Ranking: U.S. Integrated Utility And Merchant Power Companies, Strongest to Weakest* (November 5, 2009).

EQUITY RATIOS FOR HIGH GENERATION U.S. ELECTRIC UTILITY SAMPLE

	Book Value Equity Ratios						Market Value Equity Ratios					
	2003	2004	2005	2006	2007	2008	2003	2004	2005	2006	2007	2008
Allegheny Energy	20.6%	21.2%	29.0%	36.4%	38.3%	40.2%	16.0%	29.4%	49.9%	63.6%	68.4%	64.4%
ALLETE	63.5%	61.7%	60.7%	63.1%	63.7%	57.8%	46.7%	71.2%	77.4%	78.1%	76.9%	67.9%
Alliant Energy	47.5%	47.9%	48.3%	57.7%	58.5%	56.0%	45.7%	51.8%	55.5%	67.4%	70.2%	63.0%
Ameren Corp.	46.9%	48.8%	52.1%	50.1%	47.1%	45.6%	58.3%	59.6%	64.7%	61.9%	58.8%	51.1%
American Electric Power	34.8%	40.2%	42.0%	40.1%	38.5%	36.8%	42.0%	50.3%	53.2%	50.9%	53.6%	46.3%
Avista Corp.	38.9%	38.6%	38.4%	45.0%	46.2%	45.5%	36.5%	41.9%	41.4%	51.5%	52.6%	48.2%
Constellation Energy	42.6%	46.3%	49.3%	46.6%	50.4%	26.7%	49.5%	56.3%	65.7%	66.6%	74.9%	60.4%
Dominion Resources	36.0%	39.2%	35.5%	39.4%	36.0%	36.3%	50.9%	55.2%	57.9%	57.4%	60.2%	58.0%
DPL Inc.	26.6%	32.6%	37.9%	28.3%	34.4%	38.3%	43.2%	53.1%	65.0%	61.6%	66.4%	65.1%
DTE Energy	38.3%	39.4%	39.8%	39.5%	40.8%	40.4%	43.6%	45.5%	47.9%	45.7%	48.3%	42.6%
Empire District Electric	47.2%	48.0%	47.1%	46.5%	48.4%	41.9%	54.6%	57.1%	57.1%	55.7%	58.0%	48.3%
Entergy Corp.	50.5%	50.4%	44.3%	45.8%	40.7%	38.8%	57.7%	61.1%	60.5%	61.4%	64.6%	60.7%
Exelon Corp.	34.9%	40.9%	39.4%	43.2%	42.4%	45.5%	54.2%	63.5%	70.1%	74.7%	77.9%	78.5%
FirstEnergy Corp.	40.1%	42.8%	45.3%	44.0%	43.2%	37.2%	46.8%	53.0%	57.6%	60.1%	62.9%	59.9%
FPL Group	41.0%	43.6%	44.5%	44.6%	43.9%	40.6%	53.3%	56.1%	60.8%	59.1%	64.7%	58.5%
Great Plains Energy	39.4%	45.7%	50.1%	50.1%	50.3%	44.0%	56.6%	63.0%	65.1%	64.0%	62.8%	46.6%
IDACORP, Inc.	42.7%	48.0%	48.2%	49.4%	47.1%	47.8%	45.5%	53.2%	53.0%	57.4%	53.0%	50.0%
MGE Energy	50.9%	57.0%	53.0%	54.8%	53.9%	54.6%	68.4%	71.7%	70.3%	68.9%	67.2%	66.1%
Pinnacle West Capital	45.4%	47.4%	53.2%	51.3%	49.3%	47.0%	48.5%	53.3%	58.7%	56.9%	55.0%	47.0%
PPL Corp.	27.4%	35.1%	37.3%	38.5%	41.1%	36.5%	44.4%	52.9%	59.8%	60.3%	68.0%	64.7%
Progress Energy	40.6%	41.8%	41.7%	47.2%	45.4%	41.9%	48.9%	50.3%	49.4%	55.0%	55.2%	48.0%
Public Service Enterprise Group	28.2%	29.0%	31.7%	36.6%	42.4%	46.0%	40.0%	42.4%	53.2%	58.7%	68.6%	68.6%
SCANA Corp.	38.2%	39.7%	42.1%	43.4%	43.5%	39.3%	49.2%	52.4%	55.7%	55.7%	55.4%	48.4%
Southern Co.	41.2%	41.6%	40.7%	40.6%	41.4%	40.5%	60.9%	60.9%	61.8%	60.4%	61.3%	59.1%
TECO Energy	27.3%	24.3%	28.8%	30.7%	38.7%	37.8%	34.5%	40.6%	47.5%	46.4%	52.9%	51.3%
Westar Energy	30.8%	44.6%	45.7%	46.9%	45.2%	45.2%	33.6%	50.4%	54.2%	53.3%	52.8%	47.5%
Wisconsin Energy	35.0%	40.2%	40.0%	40.1%	41.0%	41.2%	43.1%	50.5%	51.9%	53.3%	55.1%	52.3%
Xcel Energy	43.0%	42.2%	41.6%	43.6%	43.5%	44.0%	45.4%	49.3%	49.5%	51.9%	54.1%	50.6%
Mean	**39.3%**	**42.1%**	**43.1%**	**44.4%**	**44.8%**	**42.6%**	**47.1%**	**53.4%**	**57.7%**	**59.2%**	**61.4%**	**56.2%**
Median	**39.7%**	**42.0%**	**42.1%**	**44.3%**	**43.5%**	**41.5%**	**46.7%**	**53.0%**	**57.3%**	**58.9%**	**60.8%**	**55.1%**
Average of Mean and Median	**39.5%**	**42.0%**	**42.6%**	**44.4%**	**44.2%**	**42.1%**	**46.9%**	**53.2%**	**57.5%**	**59.1%**	**61.1%**	**55.7%**

Source: S&P Research Insight and www.yahoo.com

EQUITY RATIOS FOR WIRES, HIGH NUCLEAR GENERATION, AND HIGH HYDROELECTRIC GENERATION U.S. UTILITY SAMPLES

	Book Value Equity Ratios						Market Value Equity Ratios					
	2003	**2004**	**2005**	**2006**	**2007**	**2008**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**
WIRES SAMPLE												
CenterPoint Energy	13.8%	10.9%	12.7%	14.5%	15.4%	16.0%	18.8%	27.1%	30.8%	31.7%	36.4%	32.2%
CH Energy Group	59.5%	58.3%	56.1%	55.9%	52.8%	51.6%	67.6%	67.4%	64.9%	65.5%	61.4%	56.0%
Consolidated Edison	46.8%	48.7%	46.5%	47.0%	48.9%	48.5%	55.6%	57.9%	56.9%	56.6%	57.9%	52.3%
Laclede Group	36.3%	42.7%	44.8%	40.0%	41.3%	44.5%	48.8%	56.2%	58.9%	54.3%	53.6%	60.0%
Nicor Inc.	41.3%	43.1%	42.0%	50.7%	52.1%	44.0%	57.8%	61.1%	60.7%	69.5%	70.0%	59.3%
Northeast Utilities	33.5%	32.7%	34.8%	39.7%	38.0%	35.1%	31.9%	34.1%	39.5%	44.5%	49.3%	41.5%
Northwest Natural Gas	46.4%	48.6%	47.2%	48.1%	47.4%	45.3%	55.1%	58.7%	60.2%	61.1%	64.9%	61.8%
NSTAR	35.3%	37.0%	34.0%	34.4%	35.9%	36.8%	48.7%	51.6%	50.4%	52.1%	54.6%	53.3%
Piedmont Natural Gas	38.3%	52.6%	51.9%	47.0%	46.3%	41.9%	55.7%	68.2%	68.9%	65.7%	65.4%	62.4%
Southwest Gas	33.0%	33.6%	34.4%	38.9%	41.0%	43.5%	36.7%	38.5%	41.5%	48.1%	50.6%	48.0%
WGL Holdings Inc.	49.2%	52.4%	56.0%	52.2%	53.6%	51.7%	60.5%	64.4%	68.6%	63.9%	65.6%	62.6%
Mean	**39.4%**	**41.9%**	**41.8%**	**42.6%**	**43.0%**	**41.7%**	**48.8%**	**53.2%**	**54.7%**	**55.7%**	**57.2%**	**53.6%**
Median	**38.3%**	**43.1%**	**44.8%**	**47.0%**	**46.3%**	**44.0%**	**55.1%**	**57.9%**	**58.9%**	**56.6%**	**57.9%**	**56.0%**
Average of Mean and Median	**38.8%**	**42.5%**	**43.3%**	**44.8%**	**44.6%**	**42.9%**	**52.0%**	**55.6%**	**56.8%**	**56.1%**	**57.6%**	**54.8%**
HIGH NUCLEAR GENERATION SAMPLE												
Constellation Energy	42.6%	46.3%	49.3%	46.6%	50.4%	26.7%	49.5%	49.5%	49.5%	49.5%	49.5%	49.5%
Dominion Resources	36.0%	39.2%	35.5%	39.4%	36.0%	36.3%	50.9%	55.2%	57.9%	57.4%	60.2%	58.0%
Entergy Corp.	50.5%	50.4%	44.3%	45.8%	40.7%	38.8%	57.7%	61.1%	60.5%	61.4%	64.6%	60.7%
Exelon Corp.	34.9%	40.9%	39.4%	43.2%	42.4%	45.5%	54.2%	63.5%	70.1%	74.7%	77.9%	78.5%
FirstEnergy Corp.	40.1%	42.8%	45.3%	44.0%	43.2%	37.2%	46.8%	53.0%	57.6%	60.1%	62.9%	59.9%
PPL Corp.	27.4%	35.1%	37.3%	38.5%	41.1%	36.5%	44.4%	52.9%	59.8%	60.3%	68.0%	64.7%
Public Service Enterprise Group	28.2%	29.0%	31.7%	36.6%	42.4%	46.0%	40.0%	42.4%	53.2%	58.7%	68.6%	68.6%
Mean	**37.1%**	**40.5%**	**40.4%**	**42.0%**	**42.3%**	**38.1%**	**49.1%**	**53.9%**	**58.4%**	**60.3%**	**64.5%**	**62.8%**
Median	**36.0%**	**40.9%**	**39.4%**	**43.2%**	**42.4%**	**37.2%**	**49.5%**	**53.0%**	**57.9%**	**60.1%**	**64.6%**	**60.7%**
Average of Mean and Median	**36.5%**	**40.7%**	**39.9%**	**42.6%**	**42.3%**	**37.7%**	**49.3%**	**53.5%**	**58.1%**	**60.2%**	**64.6%**	**61.8%**
HIGH HYDROELECTRIC GENERATION SAMPLE												
Avista Corp.	38.9%	38.6%	38.4%	45.0%	46.2%	45.5%	36.5%	41.9%	41.4%	51.5%	52.6%	48.2%
IDACORP, Inc.	42.7%	48.0%	48.2%	49.4%	47.1%	47.8%	45.5%	53.2%	53.0%	57.4%	53.0%	50.0%
Mean	**40.8%**	**43.3%**	**43.3%**	**47.2%**	**46.7%**	**46.7%**	**41.0%**	**47.5%**	**47.2%**	**54.4%**	**52.8%**	**49.1%**
Median	**40.8%**	**43.3%**	**43.3%**	**47.2%**	**46.7%**	**46.7%**	**41.0%**	**47.5%**	**47.2%**	**54.4%**	**52.8%**	**49.1%**
Average of Mean and Median	**40.8%**	**43.3%**	**43.3%**	**47.2%**	**46.7%**	**46.7%**	**41.0%**	**47.5%**	**47.2%**	**54.4%**	**52.8%**	**49.1%**

Source: S&P Research Insight and www.yahoo.com

WEEKLY BETAS FOR HIGH GENERATION U.S. ELECTRIC UTILITY SAMPLE

	5 Year Unadjusted Weekly Betas Ending:							5 Year Adjusted Weekly Betas Ending:						
	Dec-03	Dec-04	Dec-05	Dec-06	Dec-07	Dec-08	Oct-09	Dec-03	Dec-04	Dec-05	Dec-06	Dec-07	Dec-08	Oct-09
Allegheny Energy	0.59	0.68	0.97	1.26	1.12	0.93	0.97	0.72	0.79	0.98	1.17	1.08	0.95	0.98
ALLETE	0.43	0.55	0.62	0.65	0.90	0.64	0.63	0.62	0.70	0.75	0.77	0.93	0.76	0.75
Alliant Energy	0.33	0.38	0.52	0.72	0.70	0.72	0.74	0.56	0.59	0.68	0.82	0.80	0.81	0.83
Ameren Corp.	0.31	0.32	0.41	0.42	0.55	0.84	0.85	0.54	0.54	0.61	0.62	0.70	0.90	0.90
American Electric Power	0.38	0.44	0.58	0.77	0.79	0.78	0.74	0.59	0.62	0.72	0.85	0.86	0.86	0.83
Avista Corp.	0.58	0.71	0.75	0.66	0.95	0.67	0.65	0.72	0.80	0.83	0.77	0.97	0.78	0.77
Constellation Energy	0.41	0.42	0.65	0.70	0.81	0.47	0.70	0.61	0.62	0.77	0.80	0.87	0.65	0.80
Dominion Resources	0.30	0.30	0.46	0.51	0.55	0.60	0.62	0.53	0.53	0.64	0.67	0.70	0.73	0.75
DPL Inc.	0.53	0.59	0.77	0.82	0.79	0.57	0.53	0.68	0.73	0.84	0.88	0.86	0.71	0.69
DTE Energy	0.26	0.27	0.34	0.48	0.55	0.71	0.78	0.51	0.51	0.56	0.66	0.70	0.81	0.85
Empire District Electric	0.31	0.42	0.55	0.56	0.68	0.64	0.64	0.54	0.61	0.70	0.71	0.79	0.76	0.76
Entergy Corp.	0.25	0.29	0.47	0.51	0.73	0.63	0.59	0.50	0.53	0.64	0.68	0.82	0.75	0.73
Exelon Corp.	0.16	0.17	0.35	0.47	0.70	0.96	0.91	0.44	0.44	0.56	0.65	0.80	0.98	0.94
FirstEnergy Corp.	0.23	0.22	0.39	0.56	0.72	0.75	0.74	0.49	0.48	0.59	0.71	0.81	0.83	0.83
FPL Group	0.26	0.27	0.41	0.51	0.54	0.75	0.74	0.51	0.52	0.60	0.68	0.69	0.83	0.82
Great Plains Energy	0.37	0.43	0.51	0.62	0.49	0.67	0.76	0.58	0.62	0.67	0.75	0.66	0.78	0.84
IDACORP, Inc.	0.49	0.56	0.66	0.79	0.82	0.64	0.63	0.66	0.71	0.77	0.86	0.88	0.76	0.75
MGE Energy	0.32	0.42	0.53	0.70	0.97	0.60	0.56	0.55	0.61	0.68	0.80	0.98	0.74	0.71
Pinnacle West Capital	0.40	0.48	0.65	0.77	0.63	0.64	0.71	0.60	0.65	0.76	0.85	0.75	0.76	0.81
PPL Corp.	0.42	0.46	0.61	0.62	0.71	0.74	0.72	0.61	0.64	0.74	0.75	0.80	0.83	0.82
Progress Energy	0.29	0.34	0.43	0.60	0.59	0.61	0.56	0.52	0.56	0.62	0.73	0.73	0.74	0.71
Public Service Enterprise Group	0.35	0.38	0.58	0.68	0.76	0.72	0.71	0.57	0.59	0.72	0.79	0.84	0.81	0.80
SCANA Corp.	0.35	0.41	0.53	0.61	0.64	0.59	0.61	0.57	0.61	0.69	0.74	0.76	0.73	0.74
Southern Co.	0.06	0.05	0.19	0.29	0.42	0.42	0.41	0.37	0.37	0.46	0.53	0.61	0.61	0.61
TECO Energy	0.40	0.49	0.76	0.89	0.90	0.66	0.75	0.60	0.66	0.84	0.92	0.94	0.78	0.83
Westar Energy	0.43	0.48	0.65	0.72	0.72	0.72	0.73	0.62	0.65	0.77	0.81	0.81	0.81	0.82
Wisconsin Energy	0.27	0.36	0.41	0.48	0.67	0.58	0.51	0.51	0.57	0.60	0.66	0.78	0.72	0.68
Xcel Energy	0.50	0.54	0.68	0.81	0.60	0.55	0.53	0.66	0.69	0.79	0.88	0.73	0.70	0.69
Mean	**0.36**	**0.41**	**0.55**	**0.65**	**0.71**	**0.67**	**0.68**	**0.57**	**0.61**	**0.70**	**0.77**	**0.81**	**0.78**	**0.79**
Median	**0.35**	**0.42**	**0.54**	**0.64**	**0.70**	**0.65**	**0.70**	**0.57**	**0.61**	**0.69**	**0.76**	**0.80**	**0.77**	**0.80**
Average of Mean and Median	**0.35**	**0.41**	**0.54**	**0.64**	**0.71**	**0.66**	**0.69**	**0.57**	**0.61**	**0.70**	**0.76**	**0.81**	**0.77**	**0.79**

Source: www.yahoo.com

MONTHLY BETAS FOR HIGH GENERATION U.S. ELECTRIC UTILITY SAMPLE

	5 Year Unadjusted Monthly Betas Ending:							5 Year Adjusted Monthly Betas Ending:						
	Dec-03	Dec-04	Dec-05	Dec-06	Dec-07	Dec-08	Oct-09	Dec-03	Dec-04	Dec-05	Dec-06	Dec-07	Dec-08	Oct-09
Allegheny Energy	0.73	0.92	1.07	1.35	1.37	0.96	0.90	0.82	0.95	1.05	1.23	1.25	0.97	0.94
ALLETE	0.26	0.33	0.40	0.89	1.18	0.72	0.70	0.51	0.55	0.60	0.92	1.12	0.81	0.80
Alliant Energy	0.23	0.34	0.39	0.79	0.72	0.59	0.57	0.49	0.56	0.60	0.86	0.81	0.73	0.71
Ameren Corp.	0.07	0.17	0.28	0.37	0.68	0.72	0.71	0.38	0.44	0.52	0.58	0.79	0.81	0.81
American Electric Power	0.27	0.40	0.62	0.97	0.94	0.72	0.56	0.51	0.60	0.74	0.98	0.96	0.81	0.71
Avista Corp.	0.21	0.40	0.62	0.56	1.26	0.69	0.76	0.47	0.60	0.75	0.71	1.17	0.79	0.84
Constellation Energy	0.38	0.43	0.53	0.55	0.50	0.94	1.09	0.58	0.62	0.69	0.70	0.67	0.96	1.06
Dominion Resources	0.25	0.30	0.34	0.51	0.27	0.50	0.50	0.50	0.53	0.56	0.67	0.51	0.66	0.67
DPL Inc.	0.44	0.52	0.72	0.89	0.94	0.61	0.59	0.62	0.68	0.82	0.93	0.96	0.74	0.73
DTE Energy	-0.02	0.08	0.26	0.53	0.69	0.59	0.71	0.32	0.39	0.50	0.69	0.79	0.73	0.81
Empire District Electric	0.02	0.14	0.31	0.65	0.86	0.68	0.76	0.34	0.42	0.54	0.77	0.90	0.79	0.84
Entergy Corp.	-0.04	0.00	0.15	0.25	0.44	0.70	0.64	0.30	0.34	0.43	0.50	0.62	0.80	0.76
Exelon Corp.	0.08	0.08	0.35	0.27	0.46	0.71	0.58	0.39	0.39	0.57	0.51	0.64	0.81	0.72
FirstEnergy Corp.	0.08	0.07	0.20	0.47	0.41	0.60	0.52	0.39	0.38	0.47	0.64	0.61	0.74	0.68
FPL Group	0.21	0.29	0.22	0.52	0.49	0.61	0.64	0.47	0.52	0.48	0.68	0.66	0.74	0.76
Great Plains Energy	0.51	0.63	0.54	0.83	0.81	0.66	0.79	0.67	0.75	0.69	0.89	0.87	0.77	0.86
IDACORP, Inc.	0.32	0.43	0.68	0.94	0.80	0.37	0.41	0.55	0.62	0.79	0.96	0.87	0.58	0.61
MGE Energy	0.10	0.22	0.29	0.51	0.75	0.26	0.30	0.40	0.48	0.53	0.67	0.84	0.51	0.53
Pinnacle West Capital	0.24	0.32	0.63	0.89	0.63	0.57	0.62	0.49	0.54	0.75	0.92	0.75	0.71	0.74
PPL Corp.	0.55	0.65	0.79	0.56	0.26	0.62	0.52	0.70	0.77	0.86	0.70	0.51	0.74	0.68
Progress Energy	0.10	0.22	0.31	0.62	0.70	0.49	0.41	0.40	0.48	0.54	0.75	0.80	0.66	0.61
Public Service Enterprise Group	0.23	0.33	0.49	0.61	0.34	0.68	0.56	0.49	0.55	0.66	0.74	0.56	0.78	0.71
SCANA Corp.	0.15	0.26	0.40	0.50	0.40	0.61	0.57	0.44	0.51	0.60	0.67	0.60	0.74	0.71
Southern Co.	-0.46	-0.47	-0.49	-0.06	0.34	0.37	0.34	0.02	0.02	0.00	0.29	0.56	0.58	0.56
TECO Energy	0.23	0.35	0.49	0.71	0.78	0.78	0.89	0.49	0.57	0.66	0.80	0.85	0.85	0.92
Westar Energy	0.72	0.86	0.93	1.14	0.61	0.60	0.62	0.81	0.90	0.95	1.09	0.74	0.73	0.75
Wisconsin Energy	-0.08	0.06	0.02	0.18	0.56	0.45	0.38	0.28	0.37	0.35	0.45	0.71	0.64	0.59
Xcel Energy	0.55	0.68	0.78	1.45	0.60	0.56	0.44	0.70	0.79	0.86	1.30	0.73	0.71	0.62
Mean	**0.22**	**0.32**	**0.44**	**0.66**	**0.67**	**0.62**	**0.61**	**0.48**	**0.55**	**0.63**	**0.77**	**0.78**	**0.75**	**0.74**
Median	**0.23**	**0.32**	**0.40**	**0.58**	**0.66**	**0.61**	**0.59**	**0.49**	**0.55**	**0.60**	**0.72**	**0.77**	**0.74**	**0.72**
Average of Mean and Median	**0.23**	**0.32**	**0.42**	**0.62**	**0.66**	**0.62**	**0.60**	**0.49**	**0.55**	**0.61**	**0.75**	**0.77**	**0.74**	**0.73**

Source: S&P Research Insight

WEEKLY BETAS FOR WIRES, HIGH NUCLEAR GENERATION, AND HIGH HYDROELECTRIC GENERATION U.S UTILITY SAMPLES

	5 Year Unadjusted Weekly Betas Ending:							5 Year Adjusted Weekly Betas Ending:						
	Dec-03	Dec-04	Dec-05	Dec-06	Dec-07	Dec-08	Oct-09	Dec-03	Dec-04	Dec-05	Dec-06	Dec-07	Dec-08	Oct-09
WIRES SAMPLE														
CenterPoint Energy	0.24	0.31	0.56	0.58	0.89	0.97	0.96	0.49	0.54	0.71	0.72	0.93	0.98	0.97
CH Energy Group	0.36	0.44	0.48	0.57	0.92	0.71	0.67	0.58	0.63	0.65	0.71	0.94	0.80	0.78
Consolidated Edison	0.23	0.25	0.29	0.39	0.48	0.50	0.50	0.49	0.50	0.53	0.59	0.65	0.66	0.67
Laclede Group	0.35	0.41	0.54	0.75	1.02	0.68	0.60	0.57	0.61	0.69	0.84	1.02	0.78	0.74
Nicor Inc.	0.57	0.64	0.81	1.13	0.92	0.77	0.78	0.71	0.76	0.87	1.08	0.94	0.85	0.85
Northeast Utilities	0.29	0.36	0.44	0.54	0.60	0.66	0.62	0.53	0.57	0.63	0.69	0.74	0.77	0.75
Northwest Natural Gas	0.23	0.34	0.46	0.54	0.83	0.54	0.51	0.49	0.56	0.64	0.69	0.89	0.70	0.68
NSTAR	0.37	0.39	0.42	0.49	0.55	0.59	0.56	0.58	0.59	0.62	0.66	0.70	0.73	0.70
Piedmont Natural Gas	0.38	0.42	0.52	0.61	0.77	0.61	0.60	0.59	0.62	0.68	0.74	0.85	0.74	0.74
Southwest Gas	0.54	0.61	0.66	0.64	0.87	0.85	0.86	0.69	0.74	0.77	0.76	0.91	0.90	0.91
WGL Holdings Inc.	0.37	0.43	0.52	0.63	0.78	0.68	0.63	0.58	0.62	0.68	0.75	0.85	0.78	0.75
Mean	**0.36**	**0.42**	**0.52**	**0.62**	**0.79**	**0.69**	**0.66**	**0.57**	**0.61**	**0.68**	**0.75**	**0.86**	**0.79**	**0.78**
Median	**0.36**	**0.41**	**0.52**	**0.58**	**0.83**	**0.68**	**0.62**	**0.58**	**0.61**	**0.68**	**0.72**	**0.89**	**0.78**	**0.75**
Average of Mean and Median	**0.36**	**0.41**	**0.52**	**0.60**	**0.81**	**0.68**	**0.64**	**0.57**	**0.61**	**0.68**	**0.73**	**0.87**	**0.79**	**0.76**
HIGH NUCLEAR GENERATION SAMPLE														
Constellation Energy	0.41	0.42	0.65	0.70	0.81	0.47	0.70	0.61	0.62	0.77	0.80	0.87	0.65	0.80
Dominion Resources	0.30	0.30	0.46	0.51	0.55	0.60	0.62	0.53	0.53	0.64	0.67	0.70	0.73	0.75
Entergy Corp.	0.25	0.29	0.47	0.51	0.73	0.63	0.59	0.50	0.53	0.64	0.68	0.82	0.75	0.73
Exelon Corp.	0.16	0.17	0.35	0.47	0.70	0.96	0.91	0.44	0.44	0.56	0.65	0.80	0.98	0.94
FirstEnergy Corp.	0.23	0.22	0.39	0.56	0.72	0.75	0.74	0.49	0.48	0.59	0.71	0.81	0.83	0.83
PPL Corp.	0.42	0.46	0.61	0.62	0.71	0.74	0.72	0.61	0.64	0.74	0.75	0.80	0.83	0.82
Public Service Enterprise Group	0.35	0.38	0.58	0.68	0.76	0.72	0.71	0.57	0.59	0.72	0.79	0.84	0.81	0.80
Mean	**0.30**	**0.32**	**0.50**	**0.58**	**0.71**	**0.69**	**0.71**	**0.54**	**0.55**	**0.67**	**0.72**	**0.81**	**0.80**	**0.81**
Median	**0.30**	**0.30**	**0.47**	**0.56**	**0.72**	**0.72**	**0.71**	**0.53**	**0.53**	**0.64**	**0.71**	**0.81**	**0.81**	**0.80**
Average of Mean and Median	**0.30**	**0.31**	**0.48**	**0.57**	**0.71**	**0.71**	**0.71**	**0.53**	**0.54**	**0.66**	**0.71**	**0.81**	**0.80**	**0.81**
HIGH HYDROELECTRIC GENERATION SAMPLE														
Avista Corp.	0.58	0.71	0.75	0.66	0.95	0.67	0.65	0.72	0.80	0.83	0.77	0.97	0.78	0.77
IDACORP, Inc.	0.49	0.56	0.66	0.79	0.82	0.64	0.63	0.66	0.71	0.77	0.86	0.88	0.76	0.75
Mean	**0.53**	**0.63**	**0.70**	**0.73**	**0.89**	**0.66**	**0.64**	**0.69**	**0.75**	**0.80**	**0.82**	**0.93**	**0.77**	**0.76**
Median	**0.53**	**0.63**	**0.70**	**0.73**	**0.89**	**0.66**	**0.64**	**0.69**	**0.75**	**0.80**	**0.82**	**0.93**	**0.77**	**0.76**
Average of Mean and Median	**0.53**	**0.63**	**0.70**	**0.73**	**0.89**	**0.66**	**0.64**	**0.69**	**0.75**	**0.80**	**0.82**	**0.93**	**0.77**	**0.76**

Source: www.yahoo.com

MONTHLY BETAS FOR WIRES, HIGH NUCLEAR GENERATION, AND HIGH HYDROELECTRIC GENERATION U.S UTILITY SAMPLES

	5 Year Unadjusted Monthly Betas Ending:							5 Year Adjusted Monthly Betas Ending:						
	Dec-03	Dec-04	Dec-05	Dec-06	Dec-07	Dec-08	Oct-09	Dec-03	Dec-04	Dec-05	Dec-06	Dec-07	Dec-08	Oct-09
WIRES SAMPLE														
CenterPoint Energy	0.54	0.69	0.81	1.19	1.24	0.83	0.74	0.69	0.79	0.88	1.13	1.16	0.89	0.83
CH Energy Group	0.15	0.28	0.23	0.35	0.77	0.35	0.40	0.44	0.52	0.49	0.56	0.85	0.57	0.60
Consolidated Edison	-0.14	-0.05	0.00	0.14	0.39	0.25	0.27	0.24	0.30	0.33	0.43	0.59	0.50	0.51
Laclede Group	0.05	0.14	0.18	0.51	0.92	0.11	0.02	0.37	0.43	0.45	0.68	0.95	0.41	0.35
Nicor Inc.	0.31	0.43	0.55	0.91	0.85	0.37	0.33	0.54	0.62	0.70	0.94	0.90	0.58	0.55
Northeast Utilities	0.40	0.43	0.44	0.43	0.69	0.68	0.49	0.60	0.62	0.63	0.62	0.80	0.79	0.66
Northwest Natural Gas	-0.19	0.01	0.04	0.14	0.74	0.36	0.25	0.21	0.34	0.36	0.43	0.83	0.57	0.50
NSTAR	0.22	0.28	0.34	0.48	0.63	0.34	0.25	0.48	0.52	0.56	0.66	0.75	0.56	0.50
Piedmont Natural Gas	-0.04	0.13	0.28	0.35	0.58	0.06	0.18	0.31	0.42	0.52	0.57	0.72	0.37	0.45
Southwest Gas	0.14	0.28	0.25	0.21	0.55	0.65	0.70	0.43	0.52	0.50	0.48	0.70	0.77	0.80
WGL Holdings Inc.	0.08	0.22	0.21	0.27	0.69	0.24	0.21	0.39	0.48	0.47	0.51	0.79	0.49	0.47
Mean	**0.14**	**0.26**	**0.30**	**0.45**	**0.73**	**0.39**	**0.35**	**0.43**	**0.50**	**0.54**	**0.64**	**0.82**	**0.59**	**0.57**
Median	**0.14**	**0.28**	**0.25**	**0.35**	**0.69**	**0.35**	**0.27**	**0.43**	**0.52**	**0.50**	**0.57**	**0.80**	**0.57**	**0.51**
Average of Mean and Median	**0.14**	**0.27**	**0.27**	**0.40**	**0.71**	**0.37**	**0.31**	**0.43**	**0.51**	**0.52**	**0.60**	**0.81**	**0.58**	**0.54**
HIGH NUCLEAR GENERATION SAMPLE														
Constellation Energy	0.38	0.43	0.53	0.55	0.50	0.94	1.09	0.58	0.62	0.69	0.70	0.67	0.96	1.06
Dominion Resources	0.25	0.30	0.34	0.51	0.27	0.50	0.50	0.50	0.53	0.56	0.67	0.51	0.66	0.67
Entergy Corp.	-0.04	0.00	0.15	0.25	0.44	0.70	0.64	0.30	0.34	0.43	0.50	0.62	0.80	0.76
Exelon Corp.	0.08	0.08	0.35	0.27	0.46	0.71	0.58	0.39	0.39	0.57	0.51	0.64	0.81	0.72
FirstEnergy Corp.	0.08	0.07	0.20	0.47	0.41	0.60	0.52	0.39	0.38	0.47	0.64	0.61	0.74	0.68
PPL Corp.	0.55	0.65	0.79	0.56	0.26	0.62	0.52	0.70	0.77	0.86	0.70	0.51	0.74	0.68
Public Service Enterprise Group	0.23	0.33	0.49	0.61	0.34	0.68	0.56	0.49	0.55	0.66	0.74	0.56	0.78	0.71
Mean	**0.22**	**0.27**	**0.41**	**0.46**	**0.38**	**0.68**	**0.63**	**0.48**	**0.51**	**0.60**	**0.64**	**0.59**	**0.78**	**0.75**
Median	**0.23**	**0.30**	**0.35**	**0.51**	**0.41**	**0.68**	**0.56**	**0.49**	**0.53**	**0.57**	**0.67**	**0.61**	**0.78**	**0.71**
Average of Mean and Median	**0.23**	**0.28**	**0.38**	**0.49**	**0.40**	**0.68**	**0.60**	**0.48**	**0.52**	**0.59**	**0.66**	**0.60**	**0.78**	**0.73**
HIGH HYDROELECTRIC GENERATION SAMPLE														
Avista Corp.	0.21	0.40	0.62	0.56	1.26	0.69	0.76	0.47	0.60	0.75	0.71	1.17	0.79	0.84
IDACORP, Inc.	0.32	0.43	0.68	0.94	0.80	0.37	0.41	0.55	0.62	0.79	0.96	0.87	0.58	0.61
Mean	**0.27**	**0.41**	**0.65**	**0.75**	**1.03**	**0.53**	**0.59**	**0.51**	**0.61**	**0.77**	**0.83**	**1.02**	**0.69**	**0.72**
Median	**0.27**	**0.41**	**0.65**	**0.75**	**1.03**	**0.53**	**0.59**	**0.51**	**0.61**	**0.77**	**0.83**	**1.02**	**0.69**	**0.72**
Average of Mean and Median	**0.27**	**0.41**	**0.65**	**0.75**	**1.03**	**0.53**	**0.59**	**0.51**	**0.61**	**0.77**	**0.83**	**1.02**	**0.69**	**0.72**

Source: S&P Research Insight

CONSTANT GROWTH DCF COSTS OF EQUITY FOR HIGH GENERATION U.S. ELECTRIC UTILITY SAMPLE

	2006	2007	2008	2009
Allegheny Energy	na	na	na	na
ALLETE	12.52	9.13	9.70	12.41
Alliant Energy	8.92	8.79	10.41	11.67
Ameren Corp.	10.94	10.65	11.01	9.92
American Electric Power	7.55	8.79	10.40	9.73
Avista Corp.	8.17	7.75	8.07	11.22
Constellation Energy	15.57	15.93	19.18	17.96
Dominion Resources	15.06	11.38	12.33	12.75
DPL Inc.	11.20	11.42	14.60	13.91
DTE Energy	9.62	10.41	11.38	9.67
Empire District Electric	na	na	na	na
Entergy Corp.	11.88	11.41	14.89	13.80
Exelon Corp.	13.05	11.56	11.84	10.98
FirstEnergy Corp.	8.99	11.42	12.72	12.84
FPL Group	11.05	11.78	13.11	13.59
Great Plains Energy	8.03	9.01	13.70	11.46
IDACORP, Inc.	8.17	8.85	10.12	9.81
MGE Energy	na	na	na	na
Pinnacle West Capital	11.07	9.89	10.80	12.20
PPL Corp.	13.48	15.35	18.20	17.55
Progress Energy	9.19	9.56	12.09	12.22
Public Service Enterprise Group	10.18	16.65	16.51	10.66
SCANA Corp.	8.94	9.10	10.20	10.94
Southern Co.	9.44	9.66	10.16	11.19
TECO Energy	10.95	8.26	11.28	15.73
Westar Energy	9.06	9.86	9.85	10.20
Wisconsin Energy	10.08	10.58	11.80	12.51
Xcel Energy	9.21	10.43	11.49	12.30
Mean	**10.49**	**10.70**	**12.23**	**12.29**
Median	**10.08**	**10.41**	**11.49**	**12.20**

Note: Allegheny Energy was removed because they did not have consistent dividend history.
Empire District Electric and MGE Energy were removed because they did not have consistent IBES history.

Source: www.yahoo.com, S&P Research Insight

YEARLY PRICES AND DIVIDENDS FOR HIGH GENERATION U.S. ELECTRIC UTILITY SAMPLE

	Average Monthly High/Low Prices				Yearly Dividends			
	2006	2007	2008	2009	2006	2007	2008	2009
Allegheny Energy	na	na	na	na	na	na	na	na
ALLETE	45.86	45.32	39.17	29.84	1.45	1.64	1.72	1.76
Alliant Energy	34.53	40.43	33.93	25.66	1.15	1.27	1.40	1.50
Ameren Corp.	51.61	52.10	40.91	25.67	2.54	2.54	2.54	1.54
American Electric Power	36.80	46.40	38.93	29.26	1.50	1.58	1.64	1.64
Avista Corp.	22.52	22.26	20.18	17.40	0.57	0.60	0.69	0.84
Constellation Energy	58.53	87.49	67.08	26.32	1.51	1.74	1.91	0.96
Dominion Resources	38.37	43.92	41.81	32.76	1.38	1.46	1.58	1.75
DPL Inc.	27.15	29.14	25.30	23.16	1.00	1.04	1.10	1.14
DTE Energy	42.61	48.75	40.14	32.25	2.08	2.12	2.12	2.12
Empire District Electric	na	na	na	na	na	na	na	na
Entergy Corp.	76.15	107.44	102.17	74.31	2.16	2.58	3.00	3.00
Exelon Corp.	57.91	73.51	73.36	49.42	1.60	1.76	2.03	2.10
FirstEnergy Corp.	54.23	65.60	68.24	42.87	1.80	2.00	2.20	2.20
FPL Group	43.99	61.93	58.82	53.15	1.50	1.64	1.78	1.89
Great Plains Energy	29.60	30.34	23.76	15.99	1.66	1.66	1.66	0.83
IDACORP, Inc.	35.29	34.01	30.22	26.20	1.20	1.20	1.20	1.20
MGE Energy	na	na	na	na	na	na	na	na
Pinnacle West Capital	43.34	44.14	34.01	30.02	2.03	2.10	2.10	2.10
PPL Corp.	32.37	45.33	43.37	30.65	1.10	1.22	1.34	1.38
Progress Energy	44.32	48.25	41.96	37.16	2.42	2.44	2.46	2.48
Public Service Enterprise Group	32.85	42.51	39.50	30.77	1.14	1.17	1.29	1.33
SCANA Corp.	40.03	40.78	37.44	32.65	1.68	1.76	1.84	1.88
Southern Co.	34.00	36.31	36.10	31.17	1.53	1.60	1.66	1.75
TECO Energy	16.17	16.91	16.27	12.10	0.76	0.78	0.80	0.80
Westar Energy	22.81	25.92	22.21	18.80	1.00	1.08	1.16	1.20
Wisconsin Energy	42.07	46.85	44.51	42.15	0.92	1.00	1.08	1.35
Xcel Energy	19.99	22.50	19.96	18.56	0.88	0.91	0.94	0.98
Mean	**39.32**	**46.32**	**41.57**	**31.53**	**1.46**	**1.55**	**1.65**	**1.59**
Median	**38.37**	**44.14**	**39.17**	**30.02**	**1.50**	**1.60**	**1.66**	**1.54**

Note: Allegheny Energy was removed because they did not have consistent dividend history.
Empire District Electric and MGE Energy were removed because they did not have consistent IBES history.

Source: www.yahoo.com, S&P Research Insight

YEARLY AVERAGE IBES GROWTH AND EXPECTED DIVIDEND YIELD FOR HIGH GENERATION U.S. ELECTRIC UTILITY SAMPLE

	Average Monthly IBES Growth Rates				Expected Dividend Yield			
	2006	2007	2008	2009	2006	2007	2008	2009
Allegheny Energy	na	na	na	na	na	na	na	na
ALLETE	9.07	5.32	5.08	6.15	3.45	3.81	4.61	6.26
Alliant Energy	5.41	5.48	6.03	5.50	3.50	3.31	4.38	6.17
Ameren Corp.	5.73	5.50	4.52	3.70	5.20	5.14	6.49	6.22
American Electric Power	3.34	5.20	5.93	3.91	4.21	3.58	4.46	5.82
Avista Corp.	5.50	4.94	4.50	6.10	2.67	2.81	3.57	5.12
Constellation Energy	12.67	13.67	15.89	13.81	2.90	2.26	3.30	4.15
Dominion Resources	11.07	7.79	8.24	7.03	3.99	3.58	4.09	5.72
DPL Inc.	7.25	7.58	9.83	8.57	3.95	3.84	4.77	5.34
DTE Energy	4.53	5.81	5.79	2.90	5.09	4.60	5.59	6.77
Empire District Electric	na	na	na	na	na	na	na	na
Entergy Corp.	8.79	8.79	11.61	9.38	3.09	2.61	3.28	4.42
Exelon Corp.	10.01	8.95	8.83	6.46	3.04	2.61	3.00	4.52
FirstEnergy Corp.	5.49	8.13	9.20	7.33	3.50	3.30	3.52	5.51
FPL Group	7.39	8.90	9.79	9.70	3.66	2.88	3.32	3.90
Great Plains Energy	2.29	3.36	6.27	5.98	5.74	5.66	7.42	5.49
IDACORP, Inc.	4.61	5.14	5.92	5.00	3.56	3.71	4.21	4.81
MGE Energy	na	na	na	na	na	na	na	na
Pinnacle West Capital	6.12	4.90	4.36	4.87	4.96	4.99	6.44	7.33
PPL Corp.	9.75	12.32	14.66	12.48	3.73	3.02	3.54	5.06
Progress Energy	3.54	4.29	5.88	5.20	5.65	5.27	6.21	7.02
Public Service Enterprise Group	6.48	13.53	12.83	6.07	3.70	3.12	3.68	4.59
SCANA Corp.	4.55	4.59	5.03	4.90	4.39	4.51	5.16	6.04
Southern Co.	4.72	5.04	5.31	5.27	4.72	4.62	4.85	5.92
TECO Energy	5.97	3.51	6.09	8.55	4.98	4.74	5.18	7.18
Westar Energy	4.48	5.46	4.40	3.59	4.58	4.39	5.45	6.61
Wisconsin Energy	7.72	8.27	9.15	9.01	2.36	2.31	2.65	3.50
Xcel Energy	4.60	6.13	6.47	6.67	4.61	4.30	5.02	5.63
Mean	**6.44**	**6.90**	**7.66**	**6.72**	**4.05**	**3.80**	**4.57**	**5.56**
Median	**5.73**	**5.50**	**6.09**	**6.10**	**3.95**	**3.71**	**4.46**	**5.63**

Note: Allegheny Energy was removed because they did not have consistent dividend history.
Empire District Electric and MGE Energy were removed because they did not have consistent IBES history.

Source: www.yahoo.com, S&P Research Insight, I/B/E/S

CONSTANT GROWTH DCF COSTS OF EQUITY FOR WIRES AND HIGH NUCLEAR GENERATION U.S. UTILITY SAMPLES

	2006	2007	2008	2009
WIRES SAMPLE				
CenterPoint Energy	na	na	na	na
CH Energy Group	na	na	na	na
Consolidated Edison	8.52	8.27	8.93	8.95
Laclede Group	na	na	na	na
Nicor Inc.	7.82	7.35	8.85	9.56
Northeast Utilities	12.17	13.61	11.86	12.70
Northwest Natural Gas	9.41	8.11	8.30	8.91
NSTAR	9.50	10.42	10.83	11.11
Piedmont Natural Gas	8.23	8.73	10.18	11.46
Southwest Gas	5.69	9.23	9.05	10.32
WGL Holdings Inc.	8.29	7.95	8.75	8.91
Mean	**8.70**	**9.21**	**9.59**	**10.24**
Median	**8.40**	**8.50**	**8.99**	**9.94**
HIGH NUCLEAR GENERATION SAMPLE				
Constellation Energy	15.57	15.93	19.18	17.96
Dominion Resources	15.06	11.38	12.33	12.75
Entergy Corp.	11.88	11.41	14.89	13.80
Exelon Corp.	13.05	11.56	11.84	10.98
FirstEnergy Corp.	8.99	11.42	12.72	12.84
PPL Corp.	13.48	15.35	18.20	17.55
Public Service Enterprise Group	10.18	16.65	16.51	10.66
Mean	**12.60**	**13.38**	**15.10**	**13.79**
Median	**13.05**	**11.56**	**14.89**	**12.84**

Note: CenterPoint Energy, CH Energy Group, and Laclede Group were removed because they did not have consistent IBES history.

Source: www.yahoo.com, S&P Research Insight

YEARLY PRICES AND DIVIDENDS FOR WIRES AND HIGH NUCLEAR GENERATION U.S. UTILITY SAMPLES

	Average Monthly High/Low Prices				Yearly Dividends			
	2006	2007	2008	2009	2006	2007	2008	2009
WIRES SAMPLE								
CenterPoint Energy	na	na	na	na	na	na	na	na
CH Energy Group	na	na	na	na	na	na	na	na
Consolidated Edison	45.72	47.90	41.09	38.61	2.30	2.32	2.34	2.36
Laclede Group	na	na	na	na	na	na	na	na
Nicor Inc.	42.87	44.99	39.76	34.06	1.86	1.86	1.86	1.86
Northeast Utilities	22.13	29.78	25.39	22.51	0.73	0.78	0.83	0.95
Northwest Natural Gas	37.13	45.92	46.24	42.73	1.39	1.44	1.52	1.66
NSTAR	30.76	34.25	32.79	31.83	1.21	1.30	1.40	1.50
Piedmont Natural Gas	25.22	25.83	27.60	24.67	0.96	1.00	1.04	1.08
Southwest Gas	31.35	33.62	27.95	22.90	0.82	0.85	0.89	0.95
WGL Holdings Inc.	30.53	32.88	32.92	32.19	1.35	1.37	1.41	1.47
Mean	**33.21**	**36.90**	**34.22**	**31.19**	**1.33**	**1.36**	**1.41**	**1.48**
Median	**31.06**	**33.93**	**32.86**	**32.01**	**1.28**	**1.33**	**1.40**	**1.49**
HIGH NUCLEAR GENERATION SAMPLE								
Constellation Energy	58.53	87.49	67.08	26.32	1.51	1.74	1.91	0.96
Dominion Resources	38.37	43.92	41.81	32.76	1.38	1.46	1.58	1.75
Entergy Corp.	76.15	107.44	102.17	74.31	2.16	2.58	3.00	3.00
Exelon Corp.	57.91	73.51	73.36	49.42	1.60	1.76	2.03	2.10
FirstEnergy Corp.	54.23	65.60	68.24	42.87	1.80	2.00	2.20	2.20
PPL Corp.	32.37	45.33	43.37	30.65	1.10	1.22	1.34	1.38
Public Service Enterprise Group	32.85	42.51	39.50	30.77	1.14	1.17	1.29	1.33
Mean	**50.06**	**66.54**	**62.22**	**41.02**	**1.53**	**1.70**	**1.91**	**1.82**
Median	**54.23**	**65.60**	**67.08**	**32.76**	**1.51**	**1.74**	**1.91**	**1.75**

Note: CenterPoint Energy, CH Energy Group, and Laclede Group were removed because they did not have consistent IBES history.

Source: www.yahoo.com, S&P Research Insight

YEARLY AVERAGE IBES GROWTH AND EXPECTED DIVIDEND YIELD FOR WIRES AND HIGH NUCLEAR GENERATION U.S. UTILITY SAMPLES

	Average Monthly IBES Growth Rates				Expected Dividend Yield			
	2006	2007	2008	2009	2006	2007	2008	2009
WIRES SAMPLE								
CenterPoint Energy	na	na	na	na	na	na	na	na
CH Energy Group	na	na	na	na	na	na	na	na
Consolidated Edison	3.32	3.27	3.06	2.67	5.20	5.00	5.87	6.28
Laclede Group	na	na	na	na	na	na	na	na
Nicor Inc.	3.34	3.08	3.98	3.89	4.48	4.26	4.86	5.67
Northeast Utilities	8.60	10.73	8.33	8.15	3.56	2.89	3.52	4.56
Northwest Natural Gas	5.47	4.82	4.85	4.83	3.95	3.29	3.45	4.07
NSTAR	5.35	6.38	6.29	6.11	4.15	4.04	4.54	5.00
Piedmont Natural Gas	4.26	4.68	6.18	6.79	3.97	4.05	4.00	4.67
Southwest Gas	3.00	6.53	5.68	5.93	2.69	2.69	3.36	4.39
WGL Holdings Inc.	3.72	3.64	4.29	4.15	4.58	4.31	4.46	4.76
Mean	**4.63**	**5.39**	**5.33**	**5.32**	**4.07**	**3.82**	**4.26**	**4.92**
Median	**3.99**	**4.75**	**5.27**	**5.38**	**4.06**	**4.05**	**4.23**	**4.72**
HIGH NUCLEAR GENERATION SAMPLE								
Constellation Energy	12.67	13.67	15.89	13.81	2.90	2.26	3.30	4.15
Dominion Resources	11.07	7.79	8.24	7.03	3.99	3.58	4.09	5.72
Entergy Corp.	8.79	8.79	11.61	9.38	3.09	2.61	3.28	4.42
Exelon Corp.	10.01	8.95	8.83	6.46	3.04	2.61	3.00	4.52
FirstEnergy Corp.	5.49	8.13	9.20	7.33	3.50	3.30	3.52	5.51
PPL Corp.	9.75	12.32	14.66	12.48	3.73	3.02	3.54	5.06
Public Service Enterprise Group	6.48	13.53	12.83	6.07	3.70	3.12	3.68	4.59
Mean	**9.18**	**10.46**	**11.61**	**8.94**	**3.42**	**2.93**	**3.49**	**4.85**
Median	**9.75**	**8.95**	**11.61**	**7.33**	**3.50**	**3.02**	**3.52**	**4.59**

Note: CenterPoint Energy, CH Energy Group, and Laclede Group were removed because they did not have consistent IBES history.

Source: www.yahoo.com, S&P Research Insight, I/B/E/S

Regressions of Allowed Return on Equity for 210 Electric Utility Cases 1998-2009

Regression Statistics		
Adjusted R Square	0.581	
Standard Error	0.478	
Observations	210	
	Coefficients	t Stat
% Regulated Generation	0.593	3.018
Moodys A Rated Yield Lagged	0.442	8.931
Common Equity Ratio Authorized	0.021	3.199
State Regulatory Rating	-0.187	-7.936
% Utility Generation Nuclear	-0.131	-1.606

Regression Statistics		
Adjusted R Square	0.557	
Standard Error	0.492	
Observations	210	
	Coefficients	t Stat
% Regulated Generation	0.523	2.725
Moodys A Rated Yield Lagged	0.426	8.679
State Regulatory Rating	-0.225	-10.440