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Request IR-1:

Reference: Introduction DE-03, page 5 and page 15 on discussing the rate stabilization plan

a) Please provide a simple financial forecast in an Excel file covering the period until the end of the fixed cost recovery deferral period (FCRDP) 2023. The file should contain full linkages (Excel equations etc) linking the different parts of the financial statements. The format should include:

   a. The full rate base separating the FCRDP from other working capital items, property plant and equipment (gross less accumulated depreciation) and other rate base assets.
   b. The liability structure including, deemed common equity, deemed long term debt and other liabilities;
   c. The annual operating revenue and annual expenses including deferred items that link directly to the FCRDP and depreciation of the rate base assets and deferred charges;
   d. A cash flow statement (changes in financial position) that shows which items in the revenue requirement and expenses are non-cash items
   e. A capital cost schedule that shows how the financial structure translates into annual costs for debt and equity, and which is then tied directly into the capital costs in the income statement.

b) The Excel financial model should show all the direct linkages (equations) that tie the balance sheet, income statement and cash flow statements together to allow sensitivity analysis with respect to key financial parameters such as the allowed ROE, debt cost, depreciation rate etc. and the assumptions underlying the forecast should be explicit and verifiable.

c) Please provide the major credit metrics that flow from the financial statements on an annual basis, including but not limited to others that NSPI might deem relevant

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(please show how the ratios are calculated and tie them in with the data in the financial statements and confirm they are standard definitions):

- **i. Funds flow to interest coverage**
- **ii. Funds flow to debt**
- **iii. Debt total capital**
- **iv. EBIT interest coverage**
- **v. FCRD and all other deferred charges to total assets**

d) In the financial statement please provide a simple discussion of the tax status of NSPI and how taxes have been calculated.

e) Note the objective is not a full 11 year forecast but a simple model of NSPI's finances to capture the key credit metrics and the impact of changes in financial structure and how they interact with the deferred charges.

Response IR-1:

(a-b) NS Power does not have a simple financial forecast in Excel that provides the requested information to 2023.

(c) Please refer to Partially Confidential Attachments 1 and 2 for the requested information for the years 2011 to 2014. The funds from operations (FFO) ratios are the standard metrics used by credit rating agencies. NS Power does not have a simple financial model that captures the key credit metrics and the impacts of changes in financial structure and deferred charges for years outside those attached.

(d-e) NS Power is a taxable Canadian corporation with a permanent establishment in Nova Scotia, Canada. It pays corporate income tax on its taxable income at the combined Federal and Nova Scotia provincial income tax rate. In 2012 and years forward, the combined Federal and Nova Scotia provincial income tax rate is 31 percent. Please refer to OE-10 – OE-11 of the Application.

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In addition, NS Power pays Part VI.1 tax at a rate of 40 percent on preferred dividends paid. With respect to NS Power's accounting for taxes, please refer to Attachment 3.

(M$)	Actual 2011	Forecast 2012	Present Rates 2013	Present Rates 2014	Proposed Rates 2013	Proposed Rates 2014
Funds From Operations Interest Coverage Metric:	3.5x	2.9x	2.7x	3.0x	3.3x	3.3x
Adjusted Funds From Operations	$ 328.9	[redacted]	$ 255.1	$ 314.6	$ 345.0	$ 362.2
Long-Term Interest	114.9	[redacted]	125.2	129.5	124.5	126.4
Short-Term Interest	3.3	[redacted]	8.7	13.1	9.2	14.7
Total	447.1	[redacted]	389.1	457.3	478.7	503.3
Adjusted Interest Expense	$ 129.1	[redacted]	$ 144.6	$ 152.5	$ 144.3	$ 151.0
Funds From Operations Debt Metric:	13.4%	10.0%	9.6%	11.6%	13.0%	13.4%
Adjusted Funds From Operations	$ 328.9	[redacted]	$ 255.1	$ 314.6	$ 345.0	$ 362.2
Adjusted Debt	$ 2,448.5	[redacted]	$ 2,659.0	$ 2,711.4	$ 2,657.9	$ 2,708.7
Total Debt:						
Long-Term Debt	$ 1,707.5	[redacted]	$ 1,910.4	$ 1,890.5	$ 1,860.2	$ 1,840.2
Current Portion of Long-Term Debt	0.1	[redacted]	-	70.0	-	70.0
Short-Term Debt	317.5	[redacted]	315.3	313.9	364.4	361.4
Total Debt	2,025.1	[redacted]	2,225.7	2,274.3	2,224.6	2,271.6
Adjustments:						
Operating leases	$ 6.7	[redacted]	$ 6.7	$ 6.7	$ 6.7	$ 6.7
Intermediate hybrids reported as equity	66.1	[redacted]	66.1	66.1	66.1	66.1
Postretirement benefit obligations	289.1	[redacted]	289.1	289.1	289.1	289.1
Asset retirement obligations after tax	61.5	[redacted]	71.4	75.1	71.4	75.1
Total Adjustments	423.4	[redacted]	433.3	437.1	433.3	437.1
Adjusted Total Debt	$ 2,448.5	[redacted]	$ 2,659.0	$ 2,711.4	$ 2,657.9	$ 2,708.7
Interest Expense:						
Interest Expense	$ 114.2	[redacted]	$ 133.7	$ 142.8	$ 133.4	$ 141.2
Total Interest Expense	114.2	[redacted]	133.7	142.8	133.4	141.2
Adjustments:						
Operating Leases	$ 0.3	[redacted]	$ 0.3	$ 0.3	$ 0.3	$ 0.3
AFUDC	8.4	[redacted]	4.3	3.2	4.3	3.2
Intermediate Hybrids reported as equity	4.0	[redacted]	4.0	4.0	4.0	4.0
Post-Retirement Benefit Obligations	2.3	[redacted]	2.3	2.3	2.3	2.3
Total Adjustments	14.9	[redacted]	10.9	9.8	10.9	9.8
Adjusted Interest Expense	$ 129.1	[redacted]	$ 144.6	$ 152.5	$ 144.3	$ 151.0
Funds From Operations:						
Net Cash provided by Operating Activities	$ 271.4	[redacted]	$ 314.0	$ 297.8	$ 403.9	$ 345.5
Change in FAM Regulatory Asset	14.3	[redacted]	(28.2)	-	(28.2)	-
Re-classification of Working-Capital Cash Flow Changes	35.8	[redacted]	(42.2)	4.1	(42.2)	4.1
Total Net Cash provided by Operating Activities	$ 321.5	[redacted]	$ 243.6	$ 302.0	$ 333.5	$ 349.6
Adjustments:						
Operating Leases	1.1	[redacted]	1.1	1.1	1.1	1.1
Intermediate Hybrids reported as equity	(4.0)	[redacted]	(4.0)	(4.0)	(4.0)	(4.0)
AFUDC	(8.4)	[redacted]	(4.3)	(3.2)	(4.3)	(3.2)
Asset Retirement Obligation	(0.6)	[redacted]	(0.6)	(0.6)	(0.6)	(0.6)
Post-Retirement Benefit Obligations	19.3	[redacted]	19.3	19.3	19.3	19.3
Total Adjustments	$ 7.5	[redacted]	$ 11.5	$ 12.6	$ 11.5	$ 12.6
Adjusted Funds From Operations	$ 328.9	[redacted]	$ 255.1	$ 314.6	$ 345.0	$ 362.2

Notes:
* Based on NSPI Forecast; Legal entity financials
* Historical metrics based on published S&P reports
* Estimated metrics based on current understanding of S&P adjustment methodology
* When insufficient detail exists to produce an adjustment, the 2011 adjustment has been used in its place (includes op. leases, post retirement benefits, and fx gains/(losses)

(M$)	Actual 2011	Forecast 2012	Present Rates 2013	Present Rates 2014	Proposed Rates 2013	Proposed Rates 2014
Debt-to-Total Capital	56%	59%	59%	59%	59%	59%
Debt	1,933.3	[redacted]	2,108.0	2,150.9	2,107.0	2,148.3
Short-term debt	225.7	[redacted]	197.6	190.4	246.8	238.1
Current portion of long term debt	-	[redacted]	-	70.0	-	70.0
Long-term debt	1,707.6	[redacted]	1,910.4	1,890.5	1,860.2	1,840.2
Preferred shares	132.2	[redacted]	132.2	132.2	132.2	132.2
Common shares	1,034.7	[redacted]	1,034.7	1,034.7	1,034.7	1,034.7
Retained earnings	369.7	[redacted]	307.5	332.8	308.6	335.4
Total capitalization	3,469.9	[redacted]	3,582.4	3,650.6	3,582.5	3,650.6
EBIT interest coverage	1.7x	2.1x	1.2x	1.7x	2.1x	2.1x
Earnings before interest and taxes	232.7	[redacted]	180.2	251.4	310.5	318.9
Interest and other expenses	135.8	[redacted]	146.4	152.0	146.1	150.5
FCRD and deferred charges to total assets	5%	4%	3%	2%	3%	2%
Deferred charges and credits	172.1	[redacted]	91.7	63.0	91.7	63.0
Total rate base	3,470.0	[redacted]	3,582.5	3,650.6	3,582.5	3,650.6

Notes:
* Based on NSPI Forecast; Regulated entity financials

COST OF OPERATIONS
INCOME TAXES - 5900

POLICY

01 Income tax expense should be categorized as current or deferred income tax expense as appropriate.

02 The Company uses the applicable enacted tax rate when measuring current and deferred income tax expense.

03 The Company follows the flow-through method of accounting for investment tax credits ("ITC's"). ITC's are recorded in the year earned as a reduction to income tax expense to the extent that realization of such benefit is more likely than not.

04 The Company recognizes deferred income tax assets (liabilities) as appropriate. To the extent deferred income taxes are expected to be recovered from or returned to customers in future rates, the Company will recognize a deferred regulatory asset (liability)[1]

05 The Company will recognize a deferred regulatory asset (liability) related to FAM. Deferred income tax expense (benefit) and a corresponding deferred income tax (liability) asset related to the FAM will be recognized based on the enacted income tax rate(s) for the period(s) when the FAM regulatory asset (liability) is expected to reverse.

FEDERAL INCOME TAXES

06 The Company is subject to federal income tax at prescribed rates applied to taxable income.

PROVINCIAL INCOME TAXES

07 The Company is subject to provincial income tax at prescribed rates applied to taxable income.

TAX ON LARGE CORPORATIONS

08 The Company is subject to a provincial capital tax ("PCT") at prescribed rates applied to taxable capital.

PART VI.1 TAX

09 The Company is subject to Part VI.1 tax at a prescribed rate applied to preferred share dividends paid. The Company receives a tax deduction equal to a prescribed multiple of the Part VI.1 tax.

1 FASB ASC 980-740-25-2

NOVA SCOTIA POWER
An Emera Company

PROCEDURES

10 A monthly income tax provision is recorded by multiplying the Company's effective combined federal and provincial income tax rate forecasted for the year (calculated without inclusion of the forecasted FAM adjustment) by the net earnings before tax for the period. The monthly income tax provision with respect to FAM is based on the actual FAM adjustment for the period multiplied by the enacted tax rate.

11 The Company prepares an estimate of its taxable capital using a forecasted year-end balance sheet. The taxable capital forecast is then multiplied by the enacted tax rate to determine the PCT expense for the year. The PCT estimate is prorated based upon days to determine the amount to accrue each month.

12 The net Part VI.1 tax is calculated using enacted rates and recorded as an additional cost (recovery) of the preferred share dividend. It is reclassified to current income tax expense for external reporting purposes. The monthly Part VI.1 tax expense is based on the amount of preferred dividends declared in the month. The monthly Part VI.1 tax deduction is based on the annual forecasted Part VI.1 deduction prorated based upon the total preferred dividends declared in a month.

13 The Company currently follows the policy of claiming sufficient capital cost allowance and cumulative eligible capital (the tax system's equivalent of depreciation and amortization), to minimize taxable income.

14 Federal and provincial income taxes are included in general ledger account 086 - Income Tax Expense and Provincial Capital Tax is included in account 067. The net Part V1.1 tax is included in general ledger account 786 – Tax on Preferred Dividends.

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Request IR-2:

Reference: Evolution from Crown Corporation status, DE-03, page 12

a) **Please indicate the terms under which NSPI ceased to become a Crown and ownership was transferred to the private sector. In particular, were there any specific agreements that NSPI would not be at risk for stranded assets?**

b) **When the NSUARB approves NSPI's capital expenditures has it ever explicitly indicated that its approval indicates that if these assets become stranded then NSPI will be made whole?**

c) **Further to b), please indicate any such expressions by the Board that stranded asset risk is a ratepayer rather than a shareholder risk.**

d) **In industry comments (TD Securities and RBC September 20, 2011) on the 2011 settlement, they indicate that the lower ROE is offset by the reallocation of Port Hawkesbury costs to other ratepayers so the "settlement is neutral to shareholders." Did NSPI or Emera indicate to analysts that it might not be allowed to reallocate these costs? If yes, does NSPI agree that its risk reduction is of equivalent value to the lower ROE? If not, can NSPI indicate whether or not this risk was mentioned in public filings by either NSPI or Emera?**

e) **On page 37 NSPI states "Due to this, the fixed system costs that would have been previously recovered from Bowater, must be recovered from remaining customers". Please indicate what justifies "must"; has the Board explicitly indicated in any decision that cost can be reallocated in the way that NSPI claims?**

f) **Please indicate whether in NSPI's judgment both *U.S.* and Canadian utilities are protected from stranded costs.**

Response IR-2:

(a) The terms under which NS Power ceased to be a Crown corporation are contained within the *Nova Scotia Power Privatization Act* 1992, c.8, s.1 and through an Initial Public Offering and Secondary Offering dated July 29, 1992. Please refer to Attachment 1 for a copy of the Prospectus dated July 29, 1992. There were no specific agreements that NS Power would not be at risk for stranded costs.

(b-c) The Board's capital work order approval and rate decisions have reflected the Board's recognition that NS Power is entitled to recovery of its prudently incurred investments. Examples include:

(i) On May 11, 2011, the Board approved the 2010 Depreciation Study Settlement Agreement. Paragraph 3 of the Settlement Agreement approved through the Board's Order states:

> 3. NSPI is entitled to full recovery of and a return on the prudently incurred investment in its regulated assets regardless of the depreciation methodology employed from time to time.[1]

(ii) On September 10, 2007, NS Power requested that prior to commencing the Trenton 5 Baghouse and Replace Generator projects: 1. Trenton 5 be fully recovered (depreciated) by 2015 or; 2. If item 1 is not tenable, and Trenton 5 is prematurely closed, the Company would be assured that it would fully recover its investment in accordance with a reasonable depreciation schedule determined by the Board. On September 18, 2007, the Board provided its decision stating:

> With respect to item 1 above, the Board is not prepared to agree to approve an accelerated depreciation schedule based on "ongoing dialogue with federal government officials" absent some new regulation which would support

[1] NSPI 2010 Depreciation Study, UARB Order, NSUARB-NSPI-P-891, May 11, 2011.

> a change in depreciation rates. If government regulations change, the Board will reconsider the matter.
>
> With respect to item 2 above, the Board notes that it is the role of NSPI's Board to make decisions with respect to its business, including capital expenditures. Business decisions, by their nature, have an element of uncertainty in them. NSPI is rewarded for that uncertainty by the risk premium component of the approved return on equity.
>
> Having said that, the Board would point out that no capital project pre-approved by the Board has ever subsequently been found to be imprudent, nor has the cost of an approved project ever been stranded.[2]

(iii) On January 23, 2001, the Board approved the retirement work order for the Glace Bay Generating Station, including treatment for recovery of the undepreciated costs of the plant which the Board stated that it accepted were "incurred as a cost of providing service and as such are properly recoverable from customers". [3]

(iv) Per the provisions of the *Public Utilities Act*, NS Power's capital investments require Board approval in advance of being undertaken. Beginning two years ago, the Board convenes a public hearing for approval of NS Power's annual capital budget, the Annual Capital Expenditure Plan. For larger individual capital projects the Board typically convenes a separate public hearing to vet the Company's capital application.

Through these hearings the Board provides all interested parties with an opportunity to review the Company's justification for the capital projects it proposes to undertake in order to serve customers and meet legislated requirements. The Board's approval of a capital project following these processes

[2] NSPI Work Orders CI #25210 Trenton 5 Baghouse Addition and CI #28552 Trenton 5 Replace Generator, UARB Decision, P-128.06, September 18, 2007.
[3] NSPI-Work Orders – 1) Retire Glace Bay Generating Station 2) Retire 1S Seaboard Substation, UARB Decision, P-500, January 23, 2001.

NON-CONFIDENTIAL

reinforces the Company's expectation that the costs of these prudently incurred costs will be recovered from its customers.

d) No. Based on the settlement agreement approved by the Board, recovery would begin in 2013.[4] NS Power advised that the process of setting the final deferred amount would occur during a rate application or the FAM process in 2012. Please refer to Attachment 2 for a copy of NS Power's Annual Information Form which includes statements about the Settlement Agreement for the 2012 General Rate Application. Please also refer to NS Power's comments in its Management Discussion & Analysis provided as OP-01, Attachment 1 to NS Power's Application.

e) In the 2012 General Rate Application Decision, the Board approved the 2012 GRA Settlement Agreement, which states:

> b. Any amount of unrecovered NPB contribution to non-fuel costs net of non-fuel variable O&M, will be deferred for later recovery from all customers beginning in 2013.[4]

f) NS Power understands that, in both countries, a fundamental premise of the regulatory compact is that utilities are to have rates established for them which provide opportunity for recovery of their prudently incurred costs. To NS Power's knowledge, no UARB consultant has testified and recommended that a capital or regulatory asset that was approved in advance in accordance with the Public Utilities Act should be subsequently stranded and recovery by the utility be denied in whole or in part.

[4] NSPI 2012 General Rate Application, UARB Decision, NSUARB-NSPI-P-892, November 29, 2011.

This prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities commission or similar authority in Canada has in any way passed upon the merits of the securities offered hereunder and any representation to the contrary is an offence.

Initial Public Offering and Secondary Offering July 29, 1992

Nova Scotia Power Inc.
$851,346,660
85,134,666 Common Shares
(including 23,180,935 Common Shares represented by Instalment Receipts)

To privatize the business being carried on by Nova Scotia Power Corporation, the Province of Nova Scotia (the "Province") will implement a reorganization (the "Reorganization") prior to the closing of this offering by which the business operated by Nova Scotia Power Corporation ("Old NSP") will be transferred to Nova Scotia Power Inc. ("New NSP"), the issuer of the common shares offered hereby (the "Common Shares"). **Completion of the Reorganization will impact New NSP in several ways.** Refer to "New NSP".

After giving effect to the Reorganization, the Province will own 20,134,666 Common Shares, representing 100% of the outstanding Common Shares of New NSP. After completion of this offering the Province will have sold pursuant to this prospectus all of its 20,134,666 Common Shares and New NSP will have issued from treasury 65,000,000 Common Shares. New NSP will not receive any part of the proceeds of the sale of Common Shares by the Province. The Province's Common Shares are not being offered on an instalment basis. **There may be limits upon the enforceability of statutory rights of action against the Province and its agents.** Refer to "Purchasers' Statutory Rights". **The Common Shares are not guaranteed in any manner by the Province.** Refer to "New NSP — Relationship with the Province of Nova Scotia".

There are restrictions on ownership and, in certain circumstances, voting of the Common Shares. There are provisions for the enforcement of these restrictions. Refer to "Restrictions on Ownership and Voting and Other Restrictions". For certain basic investment considerations associated with ownership of Common Shares and for other considerations which may be material to an investment decision, refer to "Investment Considerations".

The offering price for the Common Shares has been determined by negotiation among New NSP, the Province and the Underwriters. The Toronto and Montreal stock exchanges have conditionally approved the listing of the Common Shares and the Instalment Receipts, subject to New NSP fulfilling all of the requirements of such exchanges on or before October 25, 1992 including distribution to a minimum number of public shareholders.

FOR ELIGIBLE NOVA SCOTIA RESIDENTS ONLY

Eligible Nova Scotia residents who applied on or before July 24, 1992 may purchase Common Shares offered by New NSP pursuant to this prospectus on an instalment basis. Individuals and certain corporations and other entities resident in Nova Scotia are eligible to purchase between a minimum of 25 Common Shares and a maximum of 5,000 Common Shares on an instalment basis. Prior to payment of the final instalment, the Common Shares purchased on an instalment basis will be represented by an Instalment Receipt and the Common Shares will be registered in the name of Montreal Trust Company of Canada (the "Custodian"). The first instalment of $6.00 per Common Share is payable on closing of this offering which is expected to occur on or about August 12, 1992 and the final instalment of $4.00 per Common Share is payable on or before August 12, 1993. As soon as practicable after payment of the final instalment, the registered holder of an Instalment Receipt will receive a certificate representing the underlying Common Shares. **If a registered holder of an Instalment Receipt does not pay the final instalment when due, the Common Shares represented by the registered holder's Instalment Receipt may be reacquired in full satisfaction of the registered holder's obligations or may be sold with the registered holder remaining liable for any deficiency.** Refer to "Eligible Nova Scotia Residents" and "Details of the Offering — Eligible Nova Scotia Residents Only".

In the opinion of counsel, the Common Shares, including the Common Shares represented by Instalment Receipts, will be eligible for investment under certain statutes. Refer to "Eligibility for Investment".

The purchase price of $10.00 per Common Share exceeds the pro forma net tangible book value per Common Share as at March 31, 1992 by $1.47 or 14.7% of the price. Refer to "Dilution".

Price: $10.00 per Common Share

	Offering Price	Underwriters' Fees	Net Proceeds to New NSP (1)	Net Proceeds to the Province
Nova Scotia				
Per Common Share: First Instalment	$ 6.00	$ 0.3875	$ 5.6125	—
Final Instalment	$ 4.00	$ —	$ 4.0000	—
Total	$ 10.00	$ 0.3875	$ 9.6125	—
Canada				
Per Common Share	$ 10.00	$ 0.4500	$ 9.5500	$ 9.5500
Total Offering (2)	$851,346,660	$36,861,791	$622,198,809	$192,286,060

(1) Before deducting expenses of issue estimated at $7 million to be paid by New NSP, including a facilitation fee to be paid by New NSP to the Underwriters with respect to the payment of the final instalment. Refer to "Plan of Distribution".

(2) This offering includes Common Shares, including Common Shares represented by Instalment Receipts, to be purchased by employees under the Employee Initial Share Purchase Plan (the "Plan"). The Underwriters will receive a fee from New NSP of approximately $35,000, with respect to the sale of these securities. Each employee is entitled to receive an interest-free loan from New NSP of up to $5,000 to purchase securities under the Plan. Refer to "Employee Initial Share Purchase Plan".

The Underwriters, as principals, conditionally offer 85,134,666 Common Shares ($851,346,660), subject to their prior sale, if, as and when issued by New NSP or sold by the Province, as the case may be, and accepted by the Underwriters in accordance with conditions contained in the Underwriting Agreement referred to under "Plan of Distribution" and subject to the approval of certain legal matters by Cox Downie and McInnes Cooper & Robertson on behalf of New NSP, by Stewart McKelvey Stirling Scales on behalf of the Underwriters and by Patterson Kitz on behalf of the Province.

Subscriptions will be received subject to rejection or allotment in whole or in part and the right is reserved to close the subscription books at any time without notice. The closing of this offering is expected to occur on or about August 12, 1992, but not later than August 28, 1992.

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EXPLANATORY NOTES

After proclamation of the Nova Scotia Power Privatization Act (the "Privatization Act") and before the closing of this offering, the business operated by Nova Scotia Power Corporation, a Crown corporation, will be transferred to Nova Scotia Power Inc., a company incorporated under the Companies Act (Nova Scotia) and reorganized under the Privatization Act. Refer to "New NSP".

"New NSP" means Nova Scotia Power Inc. as it will exist following the Reorganization. When referring to events prior to the Reorganization, "Old NSP" means Nova Scotia Power Corporation, which will continue after the Reorganization under the name "Nova Scotia Power Finance Corporation", and includes its subsidiaries which will continue to remain subsidiaries of Old NSP after the Reorganization. "Nova Scotia Power" or "NSP" is used to describe the operations of Old NSP before the Reorganization and New NSP after the Reorganization where the distinction between the two corporations is not of significance.

The disclosure in this prospectus is presented as if the Reorganization had been completed, unless the context otherwise requires. The completion of this offering is conditional upon completion of the Reorganization.

Certain defined terms are found in the "Glossary". All currency amounts in this prospectus are stated in Canadian dollars unless otherwise indicated.

PROSPECTUS SUMMARY

This is a summary only and is qualified by the more detailed information and financial statements appearing elsewhere in this prospectus.

Nova Scotia Power

Nova Scotia Power generates, transmits and distributes electricity in Nova Scotia. NSP's system is province-wide and provides approximately 94% of the generation, 99% of the transmission and 95% of the distribution of electric power throughout Nova Scotia. NSP is regulated by the Board of Commissioners of Public Utilities (the "PUB") pursuant to the Public Utilities Act (Nova Scotia). NSP's revenues for the year ended March 31, 1992 were $673.7 million and at that date its assets were $2,322.7 million and its liabilities were $2,211.3 million.

Reorganization

Until completion of this offering, New NSP will be wholly-owned by the Province. To facilitate the privatization of the business being carried on by Nova Scotia Power, the Province will implement the Reorganization prior to the closing of this offering by which the business operated by Old NSP will be transferred to New NSP.

Completion of the Reorganization referred to above will impact NSP in several ways, including matters relating to regulation, taxation and debt restructuring. Refer to "New NSP" and "Business of Nova Scotia Power".

The Offering

Issue:	65,000,000 Common Shares ($650,000,000) offered by New NSP and 20,134,666 Common Shares ($201,346,660) offered by the Province.
Price:	$10.00 per Common Share.
Dividend Policy:	The board of directors of New NSP has established an initial policy of paying quarterly dividends of $0.1875 ($0.75 per annum) per Common Share. It is expected that the first dividend will be payable on November 16, 1992. This initial policy will be reviewed from time to time in light of New NSP's net income, its financial position and other factors considered relevant by the board of directors. New NSP's future net income will be directly affected by rates approved by the PUB. Refer to "Dividend Policy", "Business of Nova Scotia Power — Rate Regulation" and "Investment Considerations".
Use of Proceeds:	The net proceeds from the sale of the Common Shares offered hereby by New NSP will be used to reduce short-term and long-term indebtedness. New NSP will not receive any part of the proceeds of the sale of Common Shares by the Province. Refer to "Use of Proceeds" and "New NSP — Debt Restructuring".
Dilution:	The purchase price of $10.00 per Common Share exceeds the pro forma net tangible book value per Common Share at March 31, 1992 by $1.47 or 14.7% of the price. Refer to "Dilution".
Instalment Basis in Nova Scotia:	Eligible Nova Scotia residents who applied on or before July 24, 1992 may purchase Common Shares offered by New NSP pursuant to this prospectus on an instalment basis. Individuals and certain corporations and other entities resident in Nova Scotia are eligible to purchase between a minimum of 25 Common Shares and a maximum of 5,000 Common Shares on an instalment basis. Expressions of interest to purchase Common Shares on an instalment basis will be given priority over other investors if this offering is over-subscribed. Prior to payment of the final instalment, the Common Shares purchased on an instalment basis will be represented by an Instalment Receipt and the Common Shares will be registered in the name of the Custodian. The first instalment of $6.00 per Common Share is payable on closing of this offering which is expected to occur on or about August 12, 1992 and the final instalment of $4.00 per Common Share is payable on or before August 12, 1993. Registered holders of Instalment Receipts will be entitled, in the manner set forth in the Instalment Receipt and Pledge Agreement described herein, to participate fully in dividends and to vote

at meetings in proportion to the number of Common Shares represented by such Instalment Receipts and to receive periodic reports and other materials in like manner as if they were the registered holders of the Common Shares. As soon as practicable after payment of the final instalment, the registered holder of an Instalment Receipt will receive a certificate representing the underlying Common Shares. **If a registered holder of an Instalment Receipt does not pay the final instalment when due, the Common Shares represented by the registered holder's Instalment Receipt may be reacquired in full satisfaction of the registered holder's obligations or may be sold with the registered holder remaining liable for any deficiency. Refer to "Eligible Nova Scotia Residents" and "Details of the Offering — Eligible Nova Scotia Residents Only".**

Principal Shareholder: After giving effect to the Reorganization, the Province will own 20,134,666 Common Shares, representing 100% of the outstanding Common Shares of New NSP. After completion of this offering the Province will have sold pursuant to this prospectus all of its Common Shares.

Investment Considerations

Before purchasing Common Shares, prospective investors should consider the following factors, in addition to those discussed elsewhere in this prospectus. Refer to "Investment Considerations".

The Common Shares are not guaranteed in any manner by the Province. Unlike a bond or term deposit, the Common Shares do not entitle the holder to the return of the offering price. The price of the Common Shares will fluctuate in response to market forces. Unlike interest on a bond or term deposit, Common Shares do not entitle the holder to dividends unless and until declared by the board of directors of New NSP. The amount of any declared dividend will depend on the dividend policy established by the board of directors from time to time. Refer to "Dividend Policy".

Ownership and Voting Restrictions

As required by the Privatization Act, the Articles of Association of New NSP provide that no person, together with associates thereof, may subscribe for, have transferred to that person, hold, beneficially own or control, otherwise than by way of security only, or vote, in the aggregate, voting shares of New NSP to which are attached more than 15% of the votes attached to all outstanding voting shares of New NSP other than voting shares held by the Province. Non-residents of Canada may not subscribe for, have transferred to them, hold, beneficially own or control, otherwise than by way of security only, or vote, in the aggregate, voting shares of New NSP to which are attached more than 25% of the votes attached to all outstanding voting shares of New NSP other than voting shares held by the Province. Votes cast by non-residents on any resolution at a meeting of shareholders will be prorated so that such votes will not constitute more than 25% of the total number of votes cast. The only outstanding voting shares of New NSP are the Common Shares.

As required by the Privatization Act, the Articles of Association of New NSP contain provisions for the enforcement of these restrictions, including provisions for suspension of voting rights, forfeiture of dividends, prohibitions against share transfer, compulsory sale of shares, redemption and suspension of other shareholder rights. The board of directors of New NSP may require shareholders to furnish statutory declarations as to matters relevant to enforcement of the restrictions.

Regulation

Nova Scotia Power is a public utility as defined in the Public Utilities Act (Nova Scotia) and will continue to be subject to regulation under the Act by the PUB. The Act gives the PUB broad general supervisory powers over NSP's operations and its expenditures. The ultimate decision as to whether a given capital or operating expenditure will be borne by customers and the timing and any conditions of such cost recovery rests with the PUB. If recovery of any expenses of NSP were delayed or disallowed, NSP's net income would be adversely affected. Rates charged by NSP to its customers are subject to PUB approval and net income will be directly affected by the rates approved by the PUB. In approving rates, the PUB will allow a just and reasonable rate of return for NSP. Generally speaking, the PUB sets a rate of return equal to the return investors could expect on an investment of comparable risk elsewhere in the economy. The future rate of return will be influenced by interest rates. Refer to "Business of Nova Scotia Power — Rate Regulation".

Debt Restructuring Arrangements

As part of the Reorganization, New NSP will issue to Old NSP approximately $2,245 million of interest-bearing debt instruments the amounts, terms and conditions of which will correspond to the publicly-held debt of Old NSP, most of which is guaranteed by the Province. Pursuant to a debt restructuring arrangement between New NSP and Old NSP, New NSP will agree to repay, redeem or defease all of the approximately $2,245 million of interest-bearing debt instruments by December 31, 1997. New NSP expects the PUB to permit costs incurred in connection with such arrangement to be recovered through rates, although there is no assurance of this.

Taxation

Due to the combined effect of the federal income tax rebate under the Public Utilities Income Tax Transfer Act (Canada) and a provincial income tax exemption under the Privatization Act, New NSP will be subject to income tax at substantially reduced effective rates. The continuance of the federal rebate and provincial exemption is subject to future government policy.

Selected Financial Information

The selected financial information set forth below, other than with respect to the pro forma forecast data, forecast data, pro forma balance sheet data and operating data and balance sheet data as at March 31, 1988 through 1990, has been derived from the Consolidated Financial Statements and should be read in conjunction with such statements and related notes included in this prospectus. Refer to "Management Discussion and Analysis" for selected balance sheet data for the years 1988, 1989 and 1990. The selected financial information with respect to the pro forma forecast data, forecast data and the pro forma balance sheet data should be read in conjunction with the Pro Forma Forecasted Statement of Operations, the Forecasted Statement of Operations, the Pro Forma Balance Sheet and related notes included in this prospectus.

	Pro Forma Forecast Twelve Months Ending December 31, 1992 (1)	Forecast Nine Months Ending December 31, 1992 (1)	Year Ended March 31				
			1992	1991	1990	1989	1988
	(unaudited)	(millions except Earnings Per Share)					
Income Statement Data:							
Total Revenue	$724.6(2)	$507.7(2)	$673.7	$635.6	$602.1	$549.9	$509.7
Income Before Interest and Income Taxes	244.1	158.6	212.4	190.5	172.9	143.6	124.1
Net Income (Loss)	95.3	37.6	46.3	24.0	21.0	(11.4)	(27.7)
Pro Forma Forecasted Earnings Per Share	1.12	—	—	—	—	—	—

(1) New NSP changed its fiscal year end from March 31 to December 31 as part of the Reorganization. The audited Forecast of the operating results of NSP for its nine month fiscal period ending December 31, 1992 assumes the Reorganization is completed on August 10, 1992 and this offering is completed on August 12, 1992. The unaudited Pro Forma Forecast illustrates twelve complete months of operating results after giving effect to the Reorganization and this offering as if they had occurred on January 1, 1992. The excess of the Pro Forma Forecast net income of $95.3 million over the nine month Forecast net income of $37.6 million is attributable to (i) actual net income for the three month period ended March 31, 1992 of $23.6 million and (ii) pro forma adjustments to the net income for the seven month and ten day period ending August 10, 1992 of $35.1 million for interest savings resulting from the reduction of indebtedness with the net proceeds of this offering of $615 million and $1.0 million for additional net federal taxes. Refer to "Forecast (Nine Months)" and "Pro Forma Forecast (Twelve Months)".

(2) Total Revenue for the twelve month pro forma forecast and nine month forecast periods include federal tax rebates of $29.9 million and $10.2 million, respectively. Refer to "Forecast (Nine Months)" and "Pro Forma Forecast (Twelve Months)".

Assumptions used in the preparation of the forecast, although considered reasonable by NSP at the time of preparation, may be proven to be incorrect. The actual results achieved during the forecast period will vary from the forecast and the variations may be material.

	Pro Forma as at March 31, 1992 (1)	As at March 31				
		1992	1991	1990	1989	1988
	(unaudited)	(millions)				
Balance Sheet Data:						
Total Assets	$2,322.7	$2,322.7	$1,989.1	$1,715.9	$1,594.2	$1,509.1
Total Debt (2)	1,402.9	2,017.9	1,783.4	1,554.7	1,463.4	1,377.0
Equity	726.4	111.4	65.1	41.1	20.1	31.6

(1) The pro forma balance sheet data is unaudited and is based upon the financial information in the March 31, 1992 balance sheet after giving effect to the Reorganization and this offering as if they had occurred on March 31, 1992. Refer to "Pro Forma Balance Sheet".

(2) Includes long-term notes payable, net of sinking funds, and bank indebtedness.

	Year Ended March 31				
	1992	1991	1990	1989	1988
Operating Data:					
Electric Energy Sales (GW.h)	8,681	8,674	8,445	8,056	7,438
Nameplate Capacity at End of Year (MW)	2,129	1,964	1,964	1,964	1,964

GLOSSARY

The following terms are used in this prospectus with the following meanings:

BTU	— (British Thermal Unit) The amount of heat needed to raise the temperature of one pound of water by one degree Fahrenheit. BTUs are used by NSP as a measure of the thermal energy content of various energy sources.
Common Shares	— Common shares of New NSP.
CPI	— Consumer Price Index prepared by Statistics Canada.
Defeasance	— A debtor irrevocably sets aside cash or other assets to be used solely for satisfying scheduled payments of both interest and principal of a specific obligation and the possibility that the debtor will be required to make future payments with respect to that debt is remote. In this circumstance, the debt is extinguished or defeased even though the debtor is not legally released from being liable for the debt. Old NSP will follow this method in defeasing its public debt. Alternatively, defeasance occurs if a debtor is legally released from the debt and it is probable that the debtor will not be required to make future payments with respect to that debt under any guarantees. New NSP will follow this method in defeasing its debt to Old NSP. In either case, defeasance of a debt allows a debtor to remove the debt from its balance sheet, although the notes to the balance sheet disclose the defeasance and the amount of the debt defeased.
Demand Side Management	— Influencing customer use of electricity to produce desired changes in the pattern and volume of customer demand or Load.
Devco	— Cape Breton Development Corporation, a federal Crown corporation and a supplier of coal to NSP.
Firm Peak Demand	— The largest amount of electric energy consumed in a one hour period that occurs on the system from customers that NSP is required to serve. Demand from customers whose service can be interrupted or reduced is excluded from this calculation.
Gigawatt (GW)	— 1,000 MW or 1,000,000 kW.
Gigawatt Hour (GW.h)	— 1,000,000 kW.h.
Instalment Receipt	— An instrument evidencing beneficial ownership of the number of Common Shares specified therein and the right to receive the legal title to such number of Common Shares upon payment of the final instalment.
Kilovolt (kV)	— 1,000 Volts.
Kilowatt (kW)	— 1,000 Watts.
Kilowatt Hour (kW.h)	— Amount of energy consumed by a Load or produced by a generator of one kilowatt (kW) operating for one hour.
Load	— The quantity of electricity consumption measured as either the energy consumed over a given period of time (kW.h or GW.h) or the rate of energy consumption (kW). Load also refers to a device that consumes electric energy.
Load Forecast	— The future Load forecasted by NSP to be supplied by its system during a particular year, including the energy estimated to be consumed in that year and the expected Firm Peak Demand during that year.
Megawatt (MW)	— 1,000 kW or 1,000,000 Watts.
Nameplate Capacity	— Amount of electrical power output for which a generator was designed and is normally the amount marked on the nameplate of the electrical generator.
Nova Scotia	— The territory of Nova Scotia.
Peaking Capacity	— Generating capacity which, because of its cost or limited energy production capability, as is the case with some hydroelectric installations, is normally operated only to provide power during maximum Load periods.

Privatization Act	— Nova Scotia Power Privatization Act, which is subject to proclamation on or before the closing of this offering.
PUB	— The Board of Commissioners of Public Utilities, established pursuant to the Public Utilities Act (Nova Scotia).
Reorganization	— The reorganization of NSP as described under the heading "New NSP".
Tonne (t)	— 1,000 kilograms (a metric ton), 1 tonne = 2,204.6 pounds.
Underwriters	— RBC Dominion Securities Inc., Richardson Greenshields of Canada Limited, ScotiaMcLeod Inc., Wood Gundy Inc., Burns Fry Limited, Midland Walwyn Capital Inc., Nesbitt Thomson Inc., Gordon Capital Corporation, Lévesque Beaubien Geoffrion Inc. and J.D. Mack Limited.
Volt (V)	— The unit of measurement of the force that causes electricity to flow. Electrical force measured in Volts is analogous to water pressure measured in pounds per square inch.
Watt (W)	— Metric unit of power, or the rate at which energy is consumed, 746 Watts = 1 horsepower.

ELIGIBLE NOVA SCOTIA RESIDENTS

Eligible Nova Scotia residents who applied on or before July 24, 1992 may purchase Common Shares offered by New NSP pursuant to this prospectus on an instalment basis. Individuals and certain corporations and other entities resident in Nova Scotia are eligible to purchase between a minimum of 25 Common Shares and a maximum of 5,000 Common Shares on an instalment basis. Expressions of interest to purchase Common Shares on an instalment basis will be given priority over other investors if this offering is over-subscribed. Prior to payment of the final instalment, a holder's beneficial ownership of the Common Shares purchased on an instalment basis will be represented by an Instalment Receipt and the Common Shares will be registered in the name of the Custodian. The first instalment of $6.00 per Common Share is payable on closing of this offering which is expected to occur on or about August 12, 1992 and the final instalment of $4.00 per Common Share is payable on or before August 12, 1993.

"Eligible Nova Scotia resident" means:

(a) an individual whose principal place of residence is in Nova Scotia;

(b) a corporation, society or non-profit organization which has, and on June 30, 1992 had, its head office or principal place of business in Nova Scotia;

(c) an estate or trust if one or more of the beneficiaries is, and on June 30, 1992 was, an eligible Nova Scotia resident as described in paragraph (a); or

(d) a registered retirement savings plan, deferred profit sharing plan, registered pension plan or registered retirement income fund if one or more of the beneficiaries or annuitants of the plan or fund is an eligible Nova Scotia resident as described in paragraph (a).

A confirmation of the number of Common Shares allotted to each eligible Nova Scotia resident expressing interest will be sent by mail on or about August 4, 1992.

ELIGIBILITY FOR INVESTMENT

In the opinion of Cox Downie, counsel for New NSP and Stewart McKelvey Stirling Scales, counsel for the Underwriters, the Common Shares, including the Common Shares represented by Instalments Receipts, at the date of issue, will be eligible investments, without resort to the so-called "basket" provisions but subject to general investment provisions for:

(a) certain insurers incorporated or organized under the *Insurance Act* (Ontario) and insurers incorporated by or under the laws of the Province of Alberta whose investment powers are governed by the *Insurance Act* (Alberta);

(b) the funds of pension plans registered under the *Pension Benefits Standards Act, 1985* (Canada), the *Pension Benefits Act* (Nova Scotia), *The Pension Benefits Act* (Manitoba), *The Pension Benefits Act* (Saskatchewan) and the *Employment Pension Plans Act* (Alberta);

(c) trustees whose investment powers are governed by the *Trustee Act* (Nova Scotia) (1) and the *Trustee Act* (Alberta);

(d) funds governed by the *Provincial Finance Act* (Nova Scotia) (1); and

(e) the Caisse de dépôt et placement du Québec.

In the opinion of such counsel, subject to the compliance with the prudent investment standards and general investment provisions of the statutes referred to below (and, where applicable, the regulations thereunder) and, in certain cases, subject to the satisfaction of additional requirements relating to investment or lending policies or goals and, in certain cases, the filing of such policies or goals, the Common Shares, including the Common Shares represented by Instalment Receipts, at the date of issue, will not be precluded as investments for:

(a) funds received as deposits by loan corporations or trust corporations registered under the *Trust and Loan Companies Act* (Canada), the *Trust and Loan Companies Act* (Nova Scotia), *an Act respecting trust companies and savings companies* (Québec) and the *Loan and Trust Corporations Act* (Ontario) (in the last case without resort to the so-called "basket" provisions);

(b) insurance companies registered under the *Insurance Companies Act* (Canada);

(c) insurers (other than mutual associations, guaranty fund corporations or professional corporations) governed by *an Act respecting insurance* (Quebec);

(d) financial institutions as defined in and authorized to carry on business under the *Financial Institutions Act* (British Columbia);

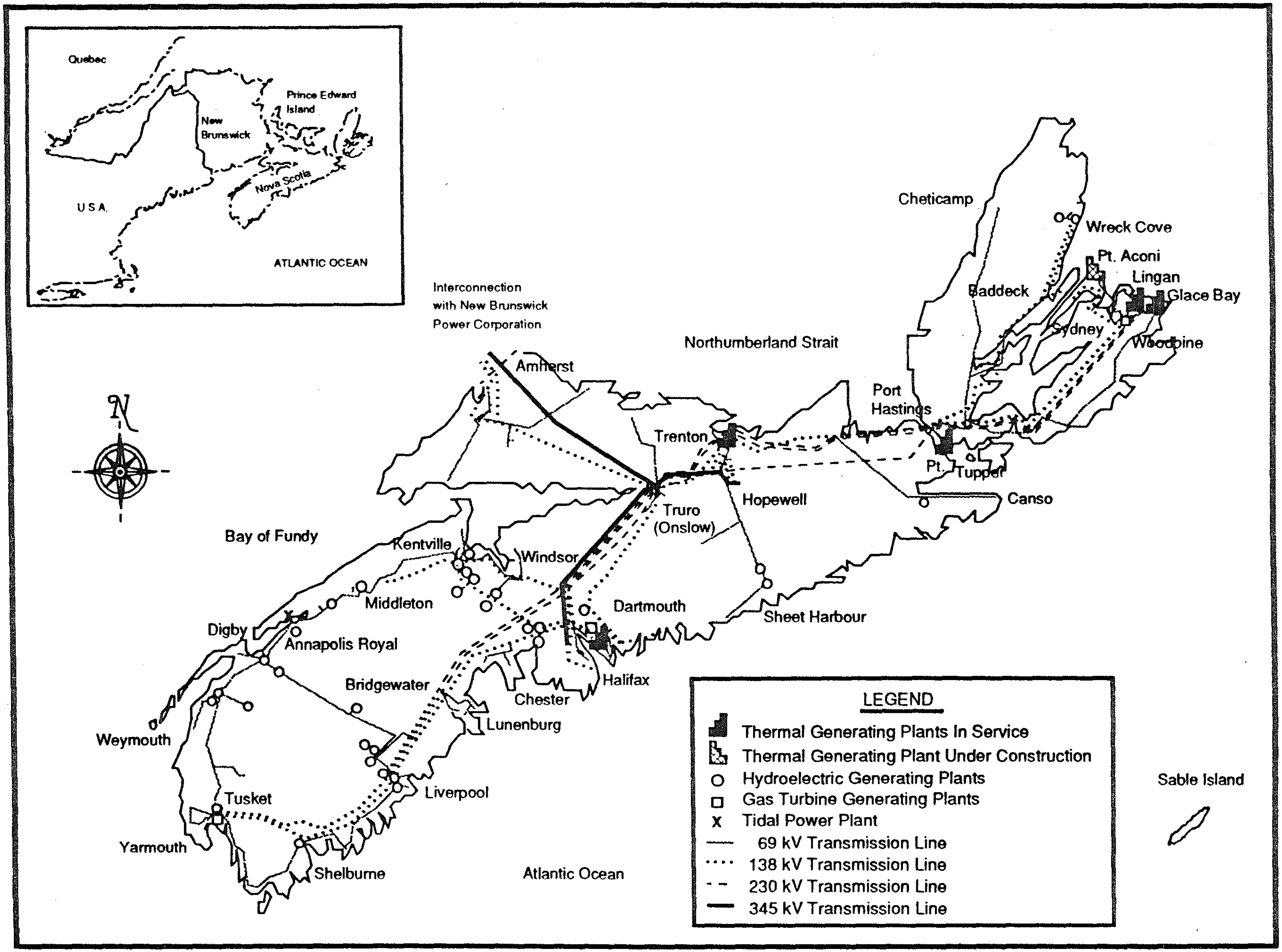
(e) pension plans registered under the *Supplemental Pension Plans Act* (Quebec) and the *Pension Benefits Act* (Ontario); and

(f) trustees whose investment powers are governed by the *Trustees Act* (New Brunswick) and *The Trustee Act* (Manitoba).

In the opinion of McInnes Cooper & Robertson, tax counsel for New NSP, and Stewart McKelvey Stirling Scales, counsel for the Underwriters, the Common Shares, including the Common Shares represented by Instalment Receipts, will, if, as and when listed on a prescribed stock exchange, be qualified investments under the *Income Tax Act* (Canada) for trusts governed by registered retirement savings plans, registered retirement income funds and deferred profit sharing plans and may be held in such plans, subject to the terms of the particular plan.

(1) The opinion assumes the proclamation of the Privatization Act, which as enacted amends the investments eligible under the Trustee Act (Nova Scotia) and the Provincial Finance Act (Nova Scotia) to include the Common Shares.

MAP OF NOVA SCOTIA - MAJOR FACILITIES OF NOVA SCOTIA POWER



BUSINESS OF NOVA SCOTIA POWER

Overview

Nova Scotia Power generates, transmits and distributes electricity in Nova Scotia. NSP's system is province-wide and its operations include approximately 94% of the generation, 99% of the transmission and 95% of the distribution of electric power throughout Nova Scotia. NSP is regulated by the Board of Commissioners of Public Utilities (the "PUB") pursuant to the Public Utilities Act (Nova Scotia). At March 31, 1992 NSP served approximately 361,400 residential customers, 33,700 commercial and industrial customers and 5,500 unmetered service accounts. Seven municipal electric distribution systems which purchase their electric power requirements from NSP in turn served approximately 10,000 additional customers.

For the year ended March 31, 1992, Nova Scotia Power's revenue totalled $673.7 million, of which $665.1 million was electric revenue. In that year, 42.8% of the electric revenue billed was derived from residential customers (Domestic Service class), 52.7% from commercial (General Service class) and industrial customers (Industrial Power class), and the remaining 4.5% from municipalities and unmetered services. For that year, electric energy sales were 8,681 GW.h. During the five years ended March 31, 1992, NSP's electric revenue and the volume of electric energy sales have grown at compound annual rates of 6.9% and 4.4% respectively.

Area Served

Nova Scotia is the most populous of the four Atlantic Provinces of Canada and covers 52,840 square kilometres (20,402 square miles). As reported by Statistics Canada, Nova Scotia's population is estimated at 903,700 at December 1991, or 3.3% of Canada's population. The largest urban concentration in the Atlantic Provinces, and the largest financial and commercial service centre, is Nova Scotia's Halifax-Dartmouth metropolitan area with an estimated population of 316,600 at June 1991.

As reported by Statistics Canada, Nova Scotia's gross domestic product at market prices ("GDP") grew from $13.031 billion in 1986 to $17.017 billion in 1990, the most recent year for which statistics are available, representing a compound annual growth rate of 6.8% (2.6% in constant 1986 dollars), compared to a rate for Canada as a whole over the same period of 7.4% (3.1% in constant 1986 dollars). Nova Scotia's GDP for 1990 was 2.5% of Canada's GDP. Statistics Canada's preliminary estimate of Canada's GDP for 1991 increased by 1.1% over Canada's GDP for 1990 (a decline of 1.5% in constant 1986 dollars).

Operations

At March 31, 1992, Nova Scotia Power operated four coal-fired, one heavy fuel oil-fired, 34 hydroelectric and three gas turbine generating plants with a total Nameplate Capacity of 2,129 MW. Coal-fired, heavy fuel oil-fired and gas turbine units account for more than 80% of NSP's total Nameplate Capacity. The largest single unit presently in service, a coal-fired unit, has a Nameplate Capacity of 160 MW. The gas turbine units, with a total Nameplate Capacity of 180 MW, together with the two 100 MW Wreck Cove hydroelectric units ("Wreck Cove"), provide Peaking Capacity. Gross investment in generating facilities as at March 31, 1992 was $1,576 million. Since 1978 NSP has commissioned 227 MW of hydroelectric capacity and 932 MW of dual-fired capacity (coal or heavy fuel oil). Construction is under way of a 165 MW coal-fired generating station at Point Aconi ("Point Aconi"). Upon its completion, NSP expects to defer the in-service date of any additional generating capacity until after the year 2000. Refer to "Capital Expenditures" and "Environmental Protection".

Energy Sources

NSP relies on several energy sources for its electric energy generation: coal, heavy fuel oil, hydroelectric energy and light fuel oil (gas turbine). In addition, NSP purchases electric energy from New Brunswick Power Corporation ("NB Power"). The following table sets forth the Nameplate Capacity of NSP's electric generating facilities at

March 31, 1992 and the percentage of total electric energy generated and purchased for the year ended March 31, 1992 by type of energy source:

	Nameplate Capacity (MW)	Percentage of Total Capacity	Percentage of Total Electric Energy Generated and Purchased
Coal	1,218 (1)	57.2%	64.7%
Heavy Fuel Oil	350	16.4	23.0
Hydroelectric	381	17.9	10.8
Light Fuel Oil (Gas Turbine)	180	8.5	0.1
Purchased Power	—	—	1.4
	2,129	100.0%	100.0%

(1) Approximately 1,062 MW of coal-fired capacity or 50% of NSP's Nameplate Capacity can also be fuelled by heavy fuel oil, subject to minimum purchase requirements for coal, and oil delivery and storage constraints. At March 31, 1992 essentially all of this dual-fired capacity was being fuelled by coal mined in Nova Scotia.

The following table sets forth certain information in respect of coal and heavy fuel oil consumed by NSP for the fiscal years shown:

	Year Ended March 31				
	1992	1991	1990	1989	1988
Coal					
Tonnes Consumed (thousands)	2,393	2,118	2,352	2,068	2,133
Average Cost per Tonne	$70.77	$70.95	$67.33	$75.62	$72.20
Cost per Million BTUs	$2.74	$2.70	$2.58	$2.90	$2.80
Total Cost (millions)	$169	$150	$158	$156	$154
Heavy Fuel Oil					
Barrels Consumed (thousands)	3,497	3,618	3,366	3,162	2,088
Average Cost per Barrel	$14.67	$18.74	$18.09	$14.71	$20.19
Cost per Million BTUs	$2.32	$2.97	$2.87	$2.33	$3.21
Total Cost (millions)	$51	$68	$61	$46	$42

For May 1992, the average cost per tonne of coal was approximately $69.53 and the average cost per barrel of heavy fuel oil was approximately $13.96.

Compared with oil, coal as an energy source for NSP is more stable in terms of price, due to NSP's long-term contracts. However, much of Nova Scotia coal is relatively high in sulphur content, resulting in emissions of sulphur dioxide into the atmosphere. NSP has adopted preventive measures to comply with environmental regulation of sulphur dioxide emissions. Refer to "Environmental Protection".

Coal is obtained from mines located in Nova Scotia principally under contracts with Cape Breton Development Corporation, a federal Crown corporation ("Devco") and Westray, a division of Curragh Inc. ("Westray"). Devco supplies coal pursuant to a long-term contract that began in 1978. In the year ended March 31, 1992, Devco supplied 87.5% of NSP's total coal purchases. NSP is Devco's principal customer for coal. The Devco contract provides for renegotiation of certain terms including price and quantities at approximately five-year intervals. The current price interval, which began April 1, 1989 and ends March 31, 1995, has annual adjustments to reflect changes in the CPI. Following the expiry of the current price interval, coal prices will be renegotiated every five years until the contract expires in 2010. If the parties cannot agree on price, the contract provides that price will be arbitrated. The Province and NSP, by letter to the federal department responsible for Devco, the Department of Industry, Science and Technology, have agreed, subject to quality and price, that NSP will buy all its coal requirements for existing and future coal-fired plants in Cape Breton and for future coal-fired plants in mainland Nova Scotia (except the Trenton generating station ("Trenton")) from Devco under this contract. Although Devco has announced that it plans to close its Lingan mine in 1993, NSP expects that sufficient quantities of coal will still be available to support NSP's anticipated coal-fired generating capacity. In its February 1992 budget, the federal government proposed a study of the privatization of Devco. NSP expects that privatization of Devco, if it occurs, will not adversely affect its contract with Devco and the long-term supply of coal to NSP.

Under the Westray contract Westray agreed to supply 700,000 tonnes per annum of low-sulphur coal to Trenton with annual adjustments in price reflecting changes in the CPI until March 31, 1996, and with coal prices to be renegotiated every five years until the termination of the contract on March 31, 2006. The mining accident on May 9, 1992 at the Westray coal mine suspended coal supplies from this source. NSP will be able to continue operating Trenton by using existing coal inventory, other sources of coal and heavy fuel oil at costs which NSP expects will not exceed those under the Westray contract.

Heavy fuel oil is used primarily at the Tufts Cove generating station ("Tufts Cove"). It is also used in small quantities as back up fuel at coal-fired plants. Heavy fuel oil is supplied to NSP by Imperial Oil Limited under two contracts which terminate on March 31, 1993. More than half of this oil is supplied by Imperial Oil Limited's refinery in Dartmouth, Nova Scotia. NSP is the principal customer of this refinery for heavy fuel oil. The price per barrel is determined by formulas based upon referenced market prices for heavy fuel oil. During the fall of 1992, NSP intends to call for tenders for its heavy fuel oil purchases after the expiry of the current contracts.

Both the coal and the oil contracts have minimum purchase requirements. Each year NSP must purchase a minimum of 1,773,000 tonnes of coal from Devco and 2,290,000 barrels of heavy fuel oil from Imperial Oil Limited. To the extent possible while meeting the minimum purchase requirements of the contracts, NSP adjusts its electric energy generation between coal and oil to minimize fuel costs and emissions.

Hydroelectric capacity is used primarily to provide Peaking Capacity. The 200 MW plant at Wreck Cove provides most of NSP's hydroelectric Peaking Capacity. Hydroelectric capacity is also used to adapt to moment to moment changes in demand for electric energy. Although these are the most valuable uses for hydroelectric capacity, it is also used to reduce fuel costs by displacing coal and oil-fired generation. NSP has a 19 MW hydroelectric plant at Annapolis which harnesses the tides of the Bay of Fundy. Because its generation depends on the timing of the tides, it is used mainly to displace coal and oil-fired generation. NSP has concluded that there is little untapped non-tidal hydroelectric potential remaining in Nova Scotia.

The gas turbine plants, fuelled by light fuel oil, provide Peaking Capacity, and emergency capacity when other parts of NSP's system are temporarily out of service. Because their fuel is relatively expensive compared to coal or heavy fuel oil, their use is kept to a minimum.

The Privatization Act and the Public Utilities Act (Nova Scotia) prohibit NSP from constructing a generating plant that utilizes nuclear energy. NSP has no present plans to use nuclear energy to generate electricity, although its possible use as an alternative source of energy will continue to be monitored.

Nova Scotia Power's system is connected with that of NB Power, providing an inter-provincial power grid for the pooling of reserve capacity and the purchase and sale of energy pursuant to an interconnection agreement with NB Power. The interconnection has a normal capacity of 300 MW, allowing approximately 15% of NSP's Nameplate Capacity to be replaced, and an emergency capacity of 450 MW. The interconnection agreement is designed to provide both participants with emergency or cost advantageous power, subject to the requirements of the supplier. During the five years ended March 31, 1992, NSP purchased 1,585.5 GW.h of electric energy from NB Power, representing 3.8% of the total electric energy sold by NSP during the period, and sold 303.5 GW.h of electric energy to NB Power, representing 0.7% of total electric energy sales during the period. Refer to "Operating Statistics".

This inter-provincial grid is connected with the power systems in Prince Edward Island, Québec and the State of Maine. Through this grid NSP is connected to the New England Power Pool and the rest of the interconnected North American systems. The grid enhances the cost effectiveness, efficiency, reserve capacity and reliability of its participating power systems.

Generating Facilities

The following table sets forth Nova Scotia Power's generating facilities, their Nameplate Capacity and the fiscal year placed in service:

Generating Station — Unit No.	Nameplate Capacity (MW)	In Service (Fiscal Year)
THERMAL		
Coal-Fired		
Glace Bay — 3-7 (1)	96	1951-67
Glace Bay — 2 (2)	20	1992
Lingan — 1	150.5	1979
Lingan — 2	150.5	1980
Lingan — 3	150.5	1983
Lingan — 4	150.5	1984
Point Tupper — 2 (3)	150	1988
Trenton — 3-4 (1)	40	1955-59
Trenton — 5	150	1969
Trenton — 6	160	1992
Heavy Fuel Oil-Fired		
Tufts Cove — 1 (4)	100	1965
Tufts Cove — 2	100	1972
Tufts Cove — 3	150	1976
Gas Turbine		
Burnside (4 units)	97	1976
Tusket (1 unit)	23	1971
Victoria Junction (2 units)	60	1975
HYDROELECTRIC		
Wreck Cove (2 stations) (5)	204.3	1978-82
Eastern Shore (3 stations)	14	1924-48
Halifax Area (4 stations)	11	1922-85
Annapolis Valley (10 stations)	50	1929-68
Annapolis Tidal Power Station	19	1984
Western (14 stations)	83	1929-83
	2,129.3	

(1) These coal-fired plants burn coal only; the remainder can also burn heavy fuel oil, subject to minimum purchase requirements for coal, and oil delivery and storage constraints. This dual-fired capacity provides some security if coal supplies are interrupted.

(2) In 1992 Glace Bay Unit No. 2 returned to service after being moved from the closed Water Street plant and renovated.

(3) In 1988 Point Tupper Unit No. 2 returned to service after extensive renovations to convert from oil-fired to coal-fired generation.

(4) Tufts Cove Unit No. 1 has a Nameplate Capacity of 100 MW. Due to furnace vibrations its maximum capacity at present is 84 MW. NSP is in the process of assessing this problem.

(5) Includes a 4 MW station at Gisborne and a 300 kW wind turbine.

NSP has no plans to retire any of these generating plants before the year 2000. For the two years ended March 31, 1991 and March 31, 1992, maintenance and operating costs associated with the generating system were $46.8 million and $51.1 million respectively.

NSP is constructing a 165 MW coal-fired generating station at Point Aconi. Point Aconi will use a circulating fluidized bed boiler. Compared to conventional pulverized coal plants, this technology is designed to achieve a 90% reduction in sulphur dioxide emissions and a 65-75% reduction in nitrogen oxide emissions, two of the major contributors to acid rain. Refer to "Environmental Protection". Point Aconi is expected to be in service before the end of 1993. The prime contractor for Point Aconi is Mitsui & Co. (Point Aconi) Limited, whose contract provides for guarantees of completion and performance covering design, materials, workmanship, emissions control and operating characteristics. The guarantors of these obligations are Mitsui & Co., (Canada) Ltd. and Mitsui & Co., Ltd. of Japan. Other contracts provide for related works, including a cooling water intake system, an ash disposal area and a highway extension.

Point Aconi is located on a 52 hectare site bounded on the north by the Atlantic Ocean (the source of cooling water), on the south by an abandoned coal mine (the ash disposal site), and on the east by Devco's Prince coal mine (the principal fuel source for the station). The site is designed for a total of three generating units, although only the first 165 MW unit is being constructed.

The total estimated cost of Point Aconi is approximately $516 million, of which approximately $437 million represents the generating station and its related works. Part of this cost is infrastructure to accommodate the two additional generating units which may be built on this site. The approximately $79 million remaining is required to extend NSP's transmission system to connect Point Aconi to the rest of the system, including substations.

Transmission and Distribution

Nova Scotia Power maintains a transmission and distribution system to deliver electricity from its generating plants to its customers. NSP's total gross investment in transmission and distribution facilities at March 31, 1992 was $1,103 million.

The transmission system primarily transports bulk electricity at high voltages (69 kV or above) from the generating plants to distribution supply substations. Some customers who are consumers of large amounts of electricity, including some industrial customers and municipalities, are served directly from the transmission system. NSP's transmission system consists of approximately 5,100 km of transmission lines and 233 substations connected solely to transmission lines, representing a gross investment at March 31, 1992 of $459 million. Approximately 1,625 km of these transmission lines are designed for operation at 69 kV, 1,825 km at 138 kV, 1,320 km at 230 kV and 330 km at 345 kV. Several transmission lines have been constructed in anticipation of increased future demands and are presently operated at voltages lower than their designed rating.

A decade ago the mainstay of the transmission system had been the 69 kV and 138 kV network. The more recent 230 kV system was constructed to provide access to additional capacity and to meet growing demand, as well as to improve reliability and to link new generating plants to the various Load centres. Major 230 kV substations at Lingan, Port Hastings, Brushy Hill and Onslow were installed as part of the 230 kV network. The 345 kV transmission lines connect the Onslow substation to New Brunswick, to Halifax (Lakeside substation) and to Hopewell. The 345 kV transmission lines will be extended from Hopewell to Sydney (Woodbine substation) in 1993 as part of the Point Aconi project.

The distribution system begins at the distribution supply substations, which are connected to transmission lines, and delivers electricity to all NSP's remaining customers. The distribution system consists of 388 distribution supply substations and over 24,000 km of distribution lines, representing a gross investment of $644 million at March 31, 1992. Approximately 31% of the distribution lines operate at 25 kV, 63% at 12 kV and 6% at 4 kV. The 4 kV distribution lines are converted to either 12 kV or 25 kV when they reach the end of their useful lives.

For each of the years ended March 31, 1991 and March 31, 1992, maintenance and operating costs associated with the transmission and distribution systems were $40.3 million and $40.9 million respectively.

System Operations and Planning

Nova Scotia Power's control centres coordinate and control the electric generation and transmission facilities, with the goal of providing a reliable and secure supply while maintaining economy of operations. Because of the high degree of security and reliability required in the generation, transmission and distribution of electric energy, NSP's control centres are linked to the generating plants and other key parts of the system by an extensive, private voice and data communications network, which includes a microwave system, a fibre optic system and a mobile radio system. The principal control centre, located at Ragged Lake near Halifax, was built in 1987 at a cost of approximately $12 million.

To provide reliable service, Nova Scotia Power plans to maintain over time a generating capacity in excess of Firm Peak Demand so as to result in a probability of having insufficient generating capacity to meet Firm Peak Demand not greater than one day in ten years. This is a system design criterion commonly employed by power systems throughout North America. Accordingly, in NSP's system, given its predominance of coal and oil-fired generating plants, and the diversity of generating plants, NSP plans to satisfy this criterion by maintaining a generation reserve margin in the range of 20% of Firm Peak Demand. The following table sets forth NSP's Firm Peak Demand and percentage reserve based on Nameplate Capacity for each of the years shown:

	Year Ended March 31				
	1992	**1991**	**1990**	**1989**	**1988**
		(MW except for percentage reserve)			
Nameplate Capacity (1)	2,129	1,964	1,964	1,964	1,964
Firm Peak Demand	1,685	1,694	1,627	1,513	1,508
Percentage Reserve	26.4%	15.9%	20.7%	29.8%	30.2%

(1) The actual generating capability can differ from the Nameplate Capacity in any given year. The total demonstrated net generating capability of NSP's generating units operating under normal conditions in 1991 exceeded Nameplate Capacity by 45 MW.

Because of the long lead times needed for the construction of new generating plants and their associated transmission lines, Nova Scotia Power is required to forecast Firm Peak Demand years into the future. Each year NSP prepares a new Load Forecast. NSP's Load Forecasts have been revised to reflect a trend towards reduced growth in energy usage. The 1991 forecast, the most recent available, indicates Firm Peak Demand growth at a reduced rate from the forecast prepared the year before. The 1991 forecast indicates a Firm Peak Demand for the year 2000 of 2,090 MW, down 5% from the 1990 forecast for the year 2000. A major reason for the reduction in forecast growth is a reduction in the forecast economic growth over this period.

The adoption of NSP's Demand Side Management program, which is expected to reduce the forecast growth by 175 MW by the year 2000, combined with the reduction in Load growth, is expected to enable NSP to defer the addition of new generating capacity, following the completion of Point Aconi, until after the year 2000. The implementation of NSP's Demand Side Management program is subject to PUB approval. The addition to the system of up to 60 MW of independent power generation will extend this deferral period further.

Nova Scotia Power belongs to the Northeast Power Coordinating Council, a body whose primary role is promoting the reliability of thc interconnected power systems throughout the northeastern United States and eastern Canada. In 1991 the Council completed its most recent evaluation of NSP's system and concluded that it conforms with the requirements of the Council's criteria for the design and operation of interconnected power systems.

Nova Scotia Power's head office administration is located in Scotia Square, Halifax, in approximately 200,000 square feet of office space leased from Halifax Developments Limited on a long-term lease expiring in 2011.

Operating Statistics

The following table shows certain information concerning the operations of NSP:

	Year Ended March 31				
	1992	1991	1990	1989	1988
			(GW.h)		
Electric Energy Generated and Purchased:					
Generated (Net)	9,313.8	8,907.0	9,169.8	8,439.4	7,655.5
Purchased	136.4	510.6	137.5	295.2	515.2
	9,450.2	9,417.6	9,307.3	8,734.6	8,170.7
Losses & Internal Use	769.0	743.3	862.0	678.3	732.8
Total Electric Energy Sold	8,681.2	8,674.3	8,445.3	8,056.3	7,437.9
			(GW.h)		
Energy Sales Billed:					
Domestic Service	3,324.4	3,267.9	3,206.8	3,049.9	2,782.6
General Service(1)	2,390.6	2,356.0	2,291.7	2,185.5	2,030.8
Industrial Power	2,641.0	2,758.0	2,390.4	2,380.5	2,227.2
Municipalities	252.9	244.7	242.7	235.9	223.1
Unmetered Services	86.2	84.4	82.2	79.0	76.2
Total In-Province Billed Energy Sales	8,695.1	8,711.0	8,213.8	7,930.8	7,339.9
Increase (Decrease) in Unbilled Sales	(18.4)	(43.4)	(10.3)	104.4	68.6
Grid Sales	4.5	6.7	241.8	21.1	29.4
Total Electric Energy Sales	8,681.2	8,674.3	8,445.3	8,056.3	7,437.9
Electric Revenue Billed:			(millions)		
Domestic Service	$ 284.4	$ 266.2	$ 253.2	$ 226.3	$ 208.6
General Service(1)	207.6	196.9	186.6	171.1	159.7
Industrial Power	142.6	139.2	119.4	113.1	105.4
Municipalities	15.0	14.0	13.5	12.2	11.5
Unmetered Services	14.6	13.8	12.8	11.6	11.2
Total In-Province Electric Revenue	664.2	630.1	585.5	534.3	496.4
Increase (Decrease) in Unbilled Revenue	0.7	(2.3)	3.0	6.3	4.4
Grid Sales	0.2	0.2	7.3	2.7	1.9
Total Electric Revenue	$ 665.1	$ 628.0	$ 595.8	$ 543.3	$ 502.7
Average Unit Revenue per kW.h Billed:			(cents)		
Domestic Service	8.6	8.1	7.9	7.4	7.5
General Service(1)	8.7	8.4	8.1	7.8	7.9
Industrial Power	5.4	5.0	5.0	4.8	4.7
Municipalities	5.9	5.7	5.6	5.2	5.2
Unmetered Services	16.9	16.4	15.6	14.7	14.7
All Classifications Combined	7.7	7.2	7.1	6.7	6.8
Number of Employees at End of Year:	2,435	2,556	2,483	2,460	2,420
Number of Customers at End of Year:	400,626	395,577	389,370	381,507	373,594

(1) General Service applies to customers who are not eligible for industrial, municipal or domestic rates. It includes primarily a variety of commercial customers.

Capital Expenditures

New plant construction, improvements and extensions must be approved by the PUB, except for Point Aconi Unit No. 1 which was exempted by legislation. The following table shows gross capital expenditures made during the five years ended March 31, 1992 and planned capital expenditures to December 31, 1993, by which time the construction of Point Aconi is scheduled to be completed:

	Year and Nine Months Ending December 31, 1993	Year Ended March 31 1992	1991	1990	1989	1988
			(MW)			
Increase in Nameplate Capacity	165	165	—	—	—	150
	(unaudited)		(millions)			
Generating Facilities	$153.5	$268.6	$196.8	$121.0	$ 35.3	$ 36.3
Transmission Facilities	65.6	48.8	64.8	34.6	17.5	13.5
Distribution & Other Facilities	141.5	72.7	67.7	61.2	53.9	53.1
Total	$360.6	$390.1	$329.3	$216.8	$106.7	$102.9

Property retirements and sales of fixed assets, which offset capital expenditures in part, totalled $63.7 million for the five year period ended March 31, 1992. Property retirements and sales of fixed assets in the aggregate for the one year and nine month period ending December 31, 1993 are estimated to be $23.6 million.

Projected additions to generating capacity for the year and nine month period ending December 31, 1993 will consist of one coal-fired thermal unit of 165 MW capacity under construction at Point Aconi. The total estimated cost of Point Aconi is $516 million, of which $366 million was included in the capital expenditures for the three fiscal years ended March 31, 1992.

Rate Regulation

Nova Scotia Power is a public utility as defined in the Public Utilities Act (Nova Scotia) and will continue to be subject to regulation under that Act by the PUB.

The Act gives the PUB broad general supervisory powers over NSP's operations and its expenditures. Rates in each of the rate classes under which NSP serves its customers are subject to PUB approval, as are its overall return on rate base and the regulations under which NSP provides its service. Issues of equity securities by NSP, including this offering, are not subject to PUB approval. Issues of debt securities by NSP are not subject to PUB approval unless secured by NSP's assets.

The Act provides that NSP shall be entitled to earn annually such return on its rate base as the PUB deems "just and reasonable". This return is in addition to any expenses the PUB may allow as "reasonable and prudent". In determining a "just and reasonable" return, the PUB may consider such factors as the cost of attracting capital, encouraging efficient operation of the utility, ensuring fairness to investors and providing relatively stable and predictable rates. Of these factors, the cost of attracting capital is the basic test of fair return. Rates must be adequate to assure confidence in the financial soundness of a utility and to maintain and support its credit and enable the utility to raise necessary capital. Generally speaking, the PUB sets a rate of return equal to the return investors could expect to receive on an investment of comparable risk elsewhere in the economy. For this reason, the rate of return allowed will be influenced by prevailing interest rates.

"Reasonable and prudent" expenses are those undertaken by New NSP which the PUB judges are necessarily incurred in connection with the operation of New NSP. New NSP is required to seek prior approval of capital expenditures as discussed below and it expects to continue Old NSP's practice of annual review of operating expenditures by the PUB as part of its rate applications. These two measures minimize the risk of expenses being disallowed. If recovery of any expenses of New NSP were delayed or disallowed, New NSP's net income would be adversely affected.

NSP has applied for revisions to its rates in each of the last four years. The PUB approved average rate increases of approximately 6.3% effective April 1, 1989, 2.5% effective April 1, 1990, and 5% effective April 1, 1991. In its March 3, 1992 decision, the PUB approved NSP's request for an average rate increase of approximately 2.1% effective April 1, 1992. This decision provides for 1.15 times interest coverage and an 11.14% return on rate base. Interest coverage is calculated for regulatory purposes by adding income before interest expense and before income taxes to interest capitalized and then dividing by the sum of interest expense and interest capitalized. Return on rate base is calculated by dividing the excess of operating revenue over operating expense by the rate base. The PUB has set the next rate hearing for January 12, 1993 to determine rates to be effective April 1, 1993.

The PUB is required to fix and determine a rate base for NSP. The rate base includes net utility plant in service, an allowance for materials and supplies and an allowance for working capital and such other matters as the PUB deems appropriate. The net utility plant in service consists of the utility plant at its original cost less accumulated depreciation. In its decision dated March 3, 1992, the PUB accepted a rate base for NSP's next fiscal year of $1,887 million.

In its decision dated March 19, 1991, the PUB ordered NSP to structure its future rate applications to bring all of its rates within a revenue to cost ratio of 0.95 to 1.05 within five years. The revenue to cost ratio of a class of customers is the ratio of revenue contributed by that class to the cost imposed on the system by the class. In order to achieve this revenue to cost ratio range, the rate classes whose contributions are below 0.95 (principally the Domestic Service class) must have a proportionately higher increase to improve their ratios, while those above 1.05 (principally the General Service and certain Industrial classes) must have a proportionately lower increase. In its March 3, 1992 decision, the PUB approved increases to rates of between 1.5% and 3.5%. This brings classes within a revenue to cost ratio range of 0.92 to 1.11. Further differential increases will be required in future in order to comply with the PUB's order.

NSP must seek approval from the PUB for all capital expenditures in excess of $25,000 unless approved by the PUB in an annual capital expenditure program. The Public Utilities Act (Nova Scotia) and the Privatization Act allow expenditures related to Point Aconi Unit No. 1 currently under construction to be made without PUB approval.

The PUB also prescribes rates respecting depreciation. The PUB's last major review of depreciation rates was in an order dated January 23, 1989. The PUB has set a hearing date of December 1, 1992 for the next review of depreciation rates. Depreciation rates are generally reviewed every four years. NSP must also seek approval from the PUB for changes in accounting policies.

In October 1990, the PUB approved a pricing methodology and rates to apply to the purchase by NSP of electricity from independent power producers. The rates will apply to a maximum of 50 MW of purchased power from individual projects not in excess of 10 MW. The rates are based on NSP's avoided costs, which are the costs NSP avoids by not having to build capacity to generate this purchased power. In January 1991, NSP requested proposals for independent power production to provide a total of 50 MW. NSP received a total of 22 separate proposals totalling approximately 160 MW. Contracts for 14 of these projects with a maximum aggregate capacity of 60 MW were signed as of June 30, 1992. The projects include hydroelectric, methane gas, municipal solid waste, wood/heavy fuel oil (80% wood), and wood-fired generation. All projects were scheduled to be in service by December 1, 1994, but NSP has requested that the PUB delay the in-service date for several projects because the independent power producers need additional time to complete their projects. Certain projects needing approval from environmental authorities could be delayed for up to two years beyond the proposed in-service date.

Employee Relations

Nova Scotia Power had 2,435 regular employees at March 31, 1992. Of these, 1,271 are represented by three union locals: 1,174 members of the International Brotherhood of Electrical Workers ("IBEW"), Local 1928, 33 members of the Canadian Brotherhood of Rail Transport and General Workers ("CBRT & GW"), Local 610, and 64 members of the CBRT & GW, Local 507. Labour relations have been satisfactory for more than fifteen years, with the last strike being a legal strike in 1975. NSP has adopted a pay equity program and implemented an employment equity policy of making its workforce generally representative of the diversity of the Nova Scotia population.

A provincial wage restraint program for public and quasi-public employees, including NSP's employees, became effective in May 1991. The program provided generally that employees would not receive a contractual or negotiated wage increase within the two year period following the first scheduled wage increase subsequent to May 14, 1991. The Privatization Act provides that the two year period will be shortened for NSP's employees so that it will end on April 1, 1993, at which time all collective agreements are eligible for renegotiation and NSP's non-union employees are eligible for salary reviews.

Before the Reorganization, Nova Scotia Power's employees were covered by a pension plan for provincial public servants (the "Superannuation Plan"). For the year ended March 31, 1992, NSP's employer contributions to the Superannuation Plan were $5.7 million. As part of the Reorganization, NSP's portion of the assets of the Superannuation Plan attributable to its active employees, together with the liability to pay pensions to those employees, will be transferred to a new pension plan (the "NSP Pension Plan"), which is required by the Privatization Act to provide the same benefits to employees as the Superannuation Plan for their past service with Old NSP, and benefits for their service with New NSP no less advantageous than the level of benefits provided by the Superannuation Plan at the time the Privatization Act is proclaimed. Future contributions to the NSP Pension Plan will be made equally by both New NSP and its employees.

According to a preliminary actuarial valuation prepared by W.F. Morneau & Associates Limited for funding purposes as at March 31, 1992, the portion of the Superannuation Plan's assets for NSP's active employees was valued at $120.0 million and the unfunded liability of that portion of the Superannuation Plan was $20.7 million. This actuarial unfunded liability is intended to be funded by New NSP over a period not exceeding 30 years. The additional annual pension plan contribution required by New NSP towards funding this liability is $1.2 million.

NSP's employees who are retired immediately before the Reorganization and former employees who are entitled to deferred benefits, will continue to be covered by the Superannuation Plan. New NSP will remain liable for the actuarial unfunded liability of these retired and former employees under the Superannuation Plan. The preliminary actuarial estimate of this unfunded liability for funding purposes as at March 31, 1992 is $7.8 million.

NSP also provides pension benefits to employees of utilities acquired by NSP over the years, in addition to those which are payable under the existing plans for the employees of these acquired utilities, for years of service prior to acquisition. The pension expense for these plans for the year ended March 31, 1992 totalled $1.7 million. NSP also supports early retirement incentive programs and has other pension obligations which for the year ended March 31, 1992 totalled $1.5 million.

NSP provides additional benefits under statutory programs (Unemployment Insurance and Canada Pension Plan) and non-statutory programs. Some of these costs are shared equally between the employee and NSP, and some are fully paid by NSP. For the year ended May 31, 1992, the amount to be paid by NSP into non-statutory programs was $3.0 million, including group life, accidental death and dismemberment, supplemental health, dental care and long-term disability insurance. After the Reorganization, employees' benefits will be substantially the same as before the Reorganization.

Environmental Protection

Nova Scotia Power is committed to conducting its business in a manner which is respectful and protective of the environment and in compliance with environmental regulations. NSP has established an internal environmental review program to evaluate its environmental performance and verify its compliance with environmental regulations. NSP is in material compliance with current environmental regulations.

Nova Scotia Power is subject to environmental regulation at both the federal and provincial levels. At the federal level, future generating plants may require environmental impact assessments. Federal legislation also affects NSP's operations and its handling of by-products or waste.

The Province regulates the environment by means of legislation requiring environmental assessments for construction and modification of generating stations and other facilities, permits for facilities generating or emitting wastes and compliance with regulations governing dangerous goods and hazardous waste management.

New generating units require provincial environmental assessments. NSP recognizes that compliance with these procedures requires longer lead times in planning projects and additional costs of construction. Provincial legislation also requires NSP to obtain environmental permits for its generating stations. All required permits are in place for NSP's generating stations. Permits can be varied, suspended or cancelled on such terms and conditions as the provincial Minister of the Environment may prescribe.

Environmental assessments or permits may also be required for the decommissioning of closed plants. NSP has commissioned a study to determine the method and cost of decommissioning its Water Street plant in Halifax, which stopped generating electricity in 1981 and steam in 1987. Point Tupper Unit No. 1 stopped generating in 1985. There are no plans at present to decommission this site and the cost of decommissioning this site is not currently known. NSP closed its Maccan generating station in April 1992. The cost of decommissioning this site is estimated to be approximately $3.5 million, including modifications to NSP's transmission system caused by the closing of this site.

International bilateral and multilateral air quality agreements have the potential to influence both the present and future means of energy generation in Nova Scotia. In February 1988, the federal and provincial governments entered into the Canada-Nova Scotia Acid Rain Reduction Agreement which sets objectives for the reduction of emissions of sulphur dioxide. NSP has committed to the Province to not emit more than 145,000 tonnes of sulphur dioxide per year after 1994. In 1990 and 1991, NSP's sulphur dioxide emissions were approximately 143,000 tonnes and 141,000 tonnes respectively. With the growth in NSP's Load, measures are required to maintain NSP's emission commitment.

In 1990 Nova Scotia Power adopted a 20 year atmospheric emission management program to address sulphur dioxide and nitrogen oxide emissions. This program has as its cornerstone the circulating fluidized bed combustion technology being installed at Point Aconi. Compared to a conventional pulverized coal plant, Point Aconi is designed to achieve a 90% reduction in sulphur dioxide emissions and a 65-75% reduction in nitrogen oxide emissions. By allocating higher sulphur coal to Point Aconi, NSP expects to use lower sulphur coal at other coal-fired generating stations, resulting in reduced overall sulphur dioxide emissions and leaving room for Load growth while still meeting NSP's emissions commitment. The balance of the program involves the use of lower sulphur heavy fuel oil at Tufts Cove and low sulphur coal at Trenton. Because of the May 9, 1992 accident at the Westray mine, NSP may not be able to obtain low sulphur coal from that source. However, by using other fuels at Trenton NSP expects to meet its commitment to emit less than 145,000 tonnes of sulphur dioxide per year after 1994.

Carbon dioxide emissions, which arise from the burning of all fossil fuels, such as coal and oil, also raise environmental concerns. Carbon dioxide is one of the heat-trapping greenhouse gases which may contribute to global warming. At present, there are no environmental regulations restricting carbon dioxide emissions. As part of its mandate to test the reasonableness of all expenditures in order to assure equitable rates, the PUB directed NSP to complete and NSP filed with the PUB a least-cost plan for meeting the forecast electrical load to the year 2025, assuming environmental laws are put in place restricting carbon dioxide emissions to various levels. The PUB has recognized that laws restricting carbon dioxide emissions, if put in place, may force NSP to reduce the power it generates at its existing coal and oil burning plants and to build new plants solely to meet the more stringent environmental laws, with the associated cost burden passed on to customers through rates.

Prior to the 1980s polychlorinated biphenyls ("PCBs") were commonly used in the electric utility industry. In response to increased regulatory activity, NSP decided in the mid-1980s to remove from service all equipment containing concentrated PCBs. Virtually all of NSP's inventory of concentrated PCBs, with the exception of small amounts including those contained in street light capacitors, was destroyed by high temperature incineration outside Canada in 1988 and 1989. From 1986 to 1990 NSP decontaminated virtually all of its mineral oil containing low concentrations of PCBs (generally below 500 parts per million) by means of a mobile unit. Since that time, as small amounts of PCBs are removed from NSP's system, including those contained in street light capacitors, they are stored or disposed of in accordance with applicable regulations.

Combustion of coal and heavy fuel oil generates a certain quantity of residual ash. In power generation, this residue is collected in the form of bottom ash and fly ash. Bottom ash, which is heavy and falls to the bottom of the furnace, is removed and landfilled. Fly ash, which is light and would be carried out of the stacks if not removed from the flue gases, is mostly landfilled, although NSP has made efforts to re-use fly ash. In 1990 NSP sold 17,400 tonnes of its fly ash for use as a concrete additive. Many concrete suppliers in Nova Scotia sell concrete containing fly ash from NSP's coal-fired plants. Fly ash was substituted for 20% of the cement in concrete used in the construction of Trenton Unit No. 6 and Point Aconi. Total ash can range from 5% to 20% of the amount of coal burned. NSP has installed electrostatic precipitators in all coal-burning units built or modernized since 1976. They remove 99.5% or more of fly ash. Oil contains only about 0.1% ash, but its fly ash tends to be more acidic than that from coal. To reduce this acidity, Tufts Cove, NSP's sole generating station designed to burn heavy fuel oil only, has been fitted with magnesium hydroxide addition units, which neutralize the corrosive nature of fly ash.

Hydroelectric generating stations can create barriers for migratory fish and affect the movement of resident fish. NSP has been working with fisheries officials to improve the passage of fish around NSP's hydroelectric stations. To protect fish habitat, NSP also maintains minimum flows of water below dams in specified rivers.

NSP controls the growth of vegetation along its transmission and distribution system, partly by cutting and partly by selective ground level application of approved herbicides. In keeping with guidelines established by the provincial Department of the Environment, herbicides are not applied in watersheds or in buffer zones around water courses.

Transmission and distribution lines also raise possible environmental questions due to the low frequency electric and magnetic fields surrounding them. There are no regulations in Canada with respect to these fields. However, as part of its criteria in the selection of transmission corridors, NSP preferentially locates them away from populated areas where feasible. At the stipulation of the provincial Department of the Environment, NSP followed regulations applicable in the State of Florida in designing its most recent transmission facilities.

NSP prepares estimates of its capital and operating expenditures for environmental purposes, although it is a matter of judgement whether certain expenditures are incurred for environmental purposes. The following table sets forth NSP's estimated capital and operating expenditures incurred for environmental purposes for each of the years shown:

	Year Ended March 31		
	1992	1991	1990
		(millions)	
Capital Expenditures	$30	$21	$14
Operating Expenditures	4	4	3

As societal and regulatory standards evolve, NSP expects both capital and operating expenditures for environmental purposes to increase.

As with other capital expenditures, those required to meet environmental laws have to be approved by the PUB if they exceed $25,000, either as part of an annual capital expenditure program or separately. Expenses of a non-capital nature would be reviewed by the PUB as part of NSP's revenue requirement. The PUB has permitted NSP to undertake required environmental expenditures and to recover those expenditures through rates. Management of NSP expects that the cost of future required environmental expenditures will continue to be recovered through rates. In its March 3, 1992 decision, the PUB confirmed that it will approve all costs associated with environmental compliance required by law within the rates customers pay for electricity. The PUB has indicated, however, that it would be unlikely to force customers to bear environmental costs to achieve environmental standards higher than those set by law.

Taxation

New NSP will be subject to Canadian federal income tax of general application. The 1992 general federal tax rate applicable to NSP is 38% which is abated to 28%. The federal government also levies a large corporation tax at a rate of 0.2% of taxable capital employed in Canada in excess of $10 million.

Under the Public Utilities Income Tax Transfer Act (Canada) and regulations to be made under enabling provisions in the Privatization Act, 95% of the federal corporation income tax paid in the future by New NSP to Revenue Canada, Taxation under Part I of the Income Tax Act (Canada) and 95% of the large corporation tax paid under Part I.3 in respect of its electric utility operations will be rebated by the federal government to the Province and by the Province to New NSP. The total amount of annual rebates to be paid by the federal government under this legislation until March 31, 1996 has been frozen at the level of rebates in the federal government's 1989-90 fiscal period. If the total amount to be rebated would exceed the 1989-90 level, the rebated portion would fall below 95%. New NSP's management expects the rebate for its 1992 fiscal year to be at the 95% level. By virtue of the Privatization Act, New NSP is exempt from provincial income tax in respect to its income from its electric utility operations. The continuance of the federal rebate, the provincial payment of the rebate and the provincial exemption are subject to future government policy.

New NSP is subject to provincial sales and other taxes. By virtue of the Privatization Act, New NSP will pay annual grants to municipalities of Nova Scotia, in lieu of all municipal taxation other than deed transfer tax. The annual grants will increase with the Nova Scotia sub-index of the CPI, using Old NSP's 1992 payment of $5 million as a base.

Land Use Planning

New NSP is not subject to land use planning laws with respect to its transmission and distribution facilities or building inspection laws with respect to its generating, transmission and distribution systems. New NSP will be required to comply with land use planning laws with respect to its future generating facilities.

MANAGEMENT DISCUSSION AND ANALYSIS

The following management discussion and analysis should be read together with NSP's consolidated financial statements included in this prospectus. Its purpose is to provide supplemental analysis and background material to provide an enhanced understanding of Nova Scotia Power's business, operations and prospects for the future.

Introduction

Nova Scotia Power is the principal supplier of electricity in Nova Scotia. The following historical results relate to NSP before the Reorganization. While the business activities of NSP will be continued after the Reorganization, future financial results will reflect the recapitalization of NSP described under "New NSP".

Selected Financial Information

Five Year Summary

	Year Ended March 31				
	1992	1991	1990	1989	1988
	(millions unless otherwise indicated)				
Electric Revenue	$ 665.1	$ 628.0	$ 595.8	$ 543.3	$ 502.7
Fuel for Generation	224.6	220.8	225.1	206.2	199.1
Operation, Maintenance and General Expense	154.7	140.2	134.7	127.8	116.4
Depreciation	73.2	63.2	60.0	58.9	52.6
Interest	166.1	166.5	151.9	155.0	151.8
Net Income (loss)	46.3	24.0	21.0	(11.4)	(27.7)
Total Assets	2,322.7	1,989.1	1,715.9	1,594.2	1,509.1
Total Debt (1)	2,017.9	1,783.4	1,554.7	1,463.4	1,377.0
Equity	111.4	65.1	41.1	20.1	31.6
Additions to Fixed Assets	390.1	329.3	216.8	106.7	102.9
Average Rate Increase Effective at Beginning of Fiscal Year	5.0%	2.5%	6.3%	—	—

(1) Total interest-bearing debt net of sinking funds.

Two Year Summary by Quarter (Unaudited)

	Year Ended March 31							
	1992				1991			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(millions)							
Electric Revenue	$156.0	$143.0	$171.3	$194.8	$146.5	$135.6	$163.1	$182.8
Net Income (Loss)	16.5	(5.3)	11.5	23.6	9.7	(8.5)	3.7	19.1

Results of Operations

Net income has improved significantly from a loss of $27.7 million in fiscal 1988 to a profit of $24.0 million in fiscal 1991 and $46.3 million in fiscal 1992. Three of the most important factors in this improvement are rate increases, increases in electric energy sales and the decline of coal and heavy fuel oil prices. Firstly, NSP had no rate increases between 1983 and 1989 in order to stabilize rates and bring rates closer to those in other provinces. The six years without a rate increase to April 1, 1989 resulted in losses in fiscal 1988 and 1989. Since April 1, 1989 NSP has applied to the PUB for and has received rate increases annually. Secondly, the volume of electric energy sales has increased 16.7% over the five years ended March 31, 1992 from 7,437.9 GW.h in fiscal 1988 to 8,674.3 GW.h in fiscal 1991 and 8,681.2 GW.h in fiscal 1992. Thirdly, over the five years ended March 31, 1992, the price of coal, NSP's primary energy source, declined by 2.1% and the price of heavy fuel oil declined by 27.7%.

Revenue

Electric revenue increased from $502.7 million in fiscal 1988 to $628.0 million in fiscal 1991 and $665.1 million in fiscal 1992. The increase in electric revenue reflects both increases in the volume of electric energy sales and rate increases.

The following table shows the electric revenue increases over the five year period resulting from increases in volumes of energy sales and from rate increases:

	Year Ended March 31				
	1992	1991	1990	1989	1988
			(millions)		
Increase from Volume	$ 4	$16	$25	$41	$27
Increase from Rate Increases	33	16	28	—	—
Total Increase	$37	$32	$53	$41	$27

The percentage change in volume of electric energy sales for the five year period are set forth in the following table:

	Year Ended March 31				
	1992	1991	1990	1989	1988
	(increase (decrease) in GW.h)				
Domestic (Residential)	2.6%	1.6%	2.6%	10.1%	5.6%
Industrial	(3.5)	13.7	0.3	7.0	6.1
General Service	1.3	2.1	3.4	8.0	5.5

The percentage increase in Domestic and General Service energy sales has declined over the period, largely due to economic conditions. The sizable percentage increase in Industrial energy sales for 1991 over 1990 was due mainly to the expansion of two major customers.

In addition to volume increases, rate increases also resulted in increased electric revenue. The 6.3% average rate increase on April 1, 1989, being the first since April 1, 1983, was set by the PUB in part to build equity. The April 1, 1990 average increase was held to 2.5% in order to lessen the effect on customers of the then forthcoming introduction of the 7% federal goods and services tax. The 5% average rate increase April 1, 1991 and the 2.1% average rate increase April 1, 1992 were also required in part in accordance with the PUB's policy of increasing NSP's equity.

Expenses

The cost of fuel for generation. NSP's largest single expense, increased from $199.1 million in fiscal 1988 to $220.8 million in fiscal 1991 and $224.6 million in fiscal 1992. The volume of coal consumed remained relatively constant over the five years while the consumption of heavy fuel oil has increased from 2.1 million barrels in 1988 to 3.6 million barrels in 1991 and 3.5 million barrels in 1992 due to increased demand for electrical energy and due to favourable heavy fuel oil prices at various periods of time. There are minimum purchase requirements in all fuel contracts. Within these constraints and oil delivery and storage constraints, NSP adjusts its purchases between these two main energy sources to minimize fuel expense.

The average annual price of coal per million BTUs declined by 2.1% over the five year period ended March 31, 1992. Coal prices declined in fiscal 1990 following the renegotiation of the Devco contract in 1989, reflecting lower world energy prices at the time of renegotiation. Increases in the years before and after 1990 result from increases in CPI, as provided in the Devco contract. The increase in 1992 was lower than CPI because NSP negotiated oil-equivalent prices on quantities purchased above the minimum stipulated in the Devco contract. The average cost per million BTUs of heavy fuel oil has fluctuated over the five years and was at its lowest level in 1992. The following table sets forth the average cost per million BTUs of coal and heavy fuel oil purchased by NSP for the fiscal years shown:

	Year Ended March 31				
	1992	1991	1990	1989	1988
Coal	$2.74	$2.70	$2.58	$2.90	$2.80
Heavy Fuel Oil	2.32	2.97	2.87	2.33	3.21

Operating, maintenance and general expense increased from $116.4 million in fiscal 1988 to $140.2 million in fiscal 1991 and $154.7 million in fiscal 1992. This increase has been influenced by the rate of inflation and additional costs due to new generating units at existing thermal generating stations moderated by NSP's efforts to control costs and increase productivity. In this regard, during this five year period the number of employees increased by only 0.6% while energy sales volume increased by 16.7%.

In fiscal 1992 NSP introduced *Power Smart,*[1] a Demand Side Management program, which increased operating, maintenance and general expense by $1.8 million in fiscal 1992. *Power Smart* is expected to improve customer education and, subject to PUB approval, will provide incentives to customers to use energy more efficiently. This is expected to defer the need for new generating plants further into the future and is expected ultimately to lead to lower overall rate increases.

Depreciation expense increased from $52.6 million in fiscal 1988 to $63.2 million in fiscal 1991 and $73.2 million in fiscal 1992. The addition of generating units at Point Tupper in fiscal 1988 and at Trenton in fiscal 1992, as well as transmission and distribution additions and other general property additions, has caused depreciation expense to increase.

Interest expense increased from $151.8 million in fiscal 1988 to $166.5 million in fiscal 1991 and $166.1 million in fiscal 1992. Interest costs have been influenced by additional borrowings to finance NSP's construction program, changing foreign exchange rates and fluctuations in interest rates on new borrowings.

Notwithstanding additional borrowings, interest expense for fiscal 1992 was virtually unchanged due to favourable rates on long-term borrowings and steadily declining short-term borrowing rates.

Risk Management

Nova Scotia Power has managed its financial risks by maintaining the majority of its debt in medium and long-term fixed-rate Canadian dollar denominated debt to minimize the impact of interest and exchange rate fluctuations. NSP has utilized a small portion of floating interest rate Canadian and fixed interest rate U.S. dollar denominated debt for the purpose of minimizing cost of funds. Sinking fund provisions, in the same currency as the debt, are maintained on most medium and long-term debt issues and as a result provide for their orderly repayment as well as a hedge against adverse foreign exchange exposure. At March 31, 1992, NSP had U.S. $353.4 million of long-term debt denominated in U.S. dollar funds in excess of sinking funds that are exposed to exchange fluctuations.

NSP expects to consume 1.9 million barrels of heavy fuel oil during the six month period ending December 31, 1992. The price of heavy fuel oil is subject to fluctuations in the world price of crude oil, the relationship of heavy fuel oil price to crude oil price and the U.S. dollar exchange rate. Based upon the projected consumption in this six month period, a one dollar change in the price of heavy fuel oil would result in a $1.9 million change in fuel costs. In order to partially offset the effect of changing world oil prices, in fiscal 1992 NSP began using oil swap agreements wherein NSP swapped a portion of its floating price heavy fuel oil for fixed price heavy fuel oil to protect a portion of heavy fuel oil purchases against price increases. As at June 30, 1992, NSP had outstanding agreements equal to approximately 26% of its heavy fuel oil requirements for the six month period ending December 31, 1992.

NSP carries insurance covering loss or damage to its properties and against public liability, as well as boiler and machinery insurance, fleet auto insurance and insurance for aircraft and data processing equipment.

Environmental Matters

Canada and the Province each have enacted legislation to address environmental protection and other environmental matters. For the year ended March 31, 1992, capital expenditures for environmental plant and equipment were estimated at approximately 8% of total capital expenditures and operating and maintenance charges

[1]*Power Smart* is a trademark of British Columbia Hydro and Power Authority and is used by NSP with permission.

for environmental purposes were estimated at approximately 4% of the total operating and maintenance charges. Most future capital projects will be subject to provincial environmental assessments and perhaps federal environmental assessments, which will require longer lead times in planning projects and may result in additional costs of construction, operation and maintenance. Furthermore, growing concern for the environment could result in additional legislation which may increase expenditures for environmental compliance. Refer to "Business of Nova Scotia Power — Environmental Protection".

Capital Expenditures

During the five fiscal years ended March 31, 1992 NSP incurred capital expenditures of $1,146 million, $658 million on generating facilities, $179 million on transmission facilities and $309 million on distribution and other facilities. Point Aconi, together with the associated transmission line, is forecast to cost approximately $516 million. Of the forecasted cost of Point Aconi and associated transmission line, $366 million has been expended to March 31, 1992.

Financing

NSP's gross short-term and long-term debt was $2,414.6 million ($2,017.9 million net of sinking funds) at the end of fiscal 1992 as compared to $2,229.1 million ($1,783.4 million net of sinking funds) at the end of fiscal 1991 and $1,955.1 million ($1,554.7 million net of sinking funds) at the end of fiscal 1990. The increase in 1992 over 1991 consisted of new long-term debt of $366.9 million partially offset by repayments and retirements. In April 1991 NSP issued U.S. $300 million of 9.40% debentures due 2021 ($347 million Canadian at time of issue). This was followed by an issue in July 1991 for $19.9 million of 9% Savings Bonds, due 1996. These financings were undertaken to repay short-term notes payable and thereby reduce NSP's exposure to fluctuations in short-term interest rates. NSP's net cash requirements for long-term debt, sinking fund contributions and maturities were $191.4 million in fiscal 1992, which consisted of maturities of $284.9 million, sinking fund contributions of $18.4 million and sinking fund withdrawals of $111.9 million.

At March 31, 1992 short-term borrowings totalled $161.5 million. Old NSP issued short-term promissory notes to the Province for the majority of short-term borrowing requirements, utilizing the Province's commercial paper program.

Old NSP was able to undertake long-term borrowings with a guarantee of the Province at interest rates which were lower than the rates at which Old NSP would have been able to borrow without such a guarantee.

Outlook

This discussion should be read in conjunction with the forecasted statement of operations. Refer to "Forecast (Nine Months)" and "Pro Forma Forecast (Twelve Months)".

The primary foundation upon which most plans of NSP are built is the Load Forecast of what its customers' energy needs are forecast to be. Electric energy consumption, being an integral part of the production of most goods and services, is affected by economic activity, as well as changes in population, efficiency of electric energy consumption, competitive alternatives and prices.

Seasonality affects NSP's sales and profitability. NSP sales and related production change significantly over the course of a year due to the marked difference in temperatures and daylight hours between summer and winter. Monthly energy sales in 1991 ranged from below 700 GW.h in the summer months to over 1,000 GW.h in the winter months. Costs, other than fuel expense, do not vary to any major extent due to sales volume changes. The significant variation in sales revenues makes the winter months more profitable than the spring and autumn months, while the summer months are the least profitable. In order to assess NSP's profitability, a full year of operations must be reviewed. The first financial reporting period of New NSP after the Reorganization is the summer period, the period of lowest sales volume and historically the least profitable part of the year.

Fuel costs for the nine months ended December 31, 1992 are forecast to be $168.0 million assuming coal prices increase 3.8% and heavy fuel oil prices increase 7.0% over those in Old NSP's fiscal 1992.

Operating, maintenance and general expense in the short-term will be subject to general inflation except for wage rates which are expected to remain substantially the same until April 1, 1993 due to the wage freeze legislation as amended by the Privatization Act. An early retirement incentive program in fiscal 1992 reduced the number of employees by 157 which will favourably affect this category of expense in the future. Included in this category of expense for the nine months ending December 31, 1992 is $2.3 million for Demand Side Management.

Interest expense will decrease in the nine months ending December 31, 1992 due to the net proceeds of this offering being used to reduce long-term and short-term debt. Offsetting the interest savings will be the anticipated dividends to be paid to shareholders.

New NSP will be subject to federal income tax, estimated to be $10.7 million in 1992. New NSP expects the major portion of it, being 95% or $10.2 million, to be refunded to NSP through the Province pursuant to the Public Utilities Income Tax Transfer Act (Canada) and the Privatization Act.

New NSP will continue to be subject to regulation by the PUB, which has broad general supervisory powers over New NSP's operations and its expenditures and establishes rates charged to its customers. Refer to "Business of Nova Scotia Power — Rate Regulation".

NSP expects to spend $360.6 million in capital expenditures in the twenty-one months ending December 31, 1993, including $150 million on Point Aconi and associated transmission facilities. After Point Aconi is completed in late 1993, capital expenditures are expected to decline because NSP expects to defer construction of further generating plants until after the year 2000.

Working capital and bridge financing requirements will continue to be met through the use of short-term borrowings. New NSP intends to fund its short-term requirements through a commercial paper program. To date no commercial paper is outstanding. New NSP has received a provisional rating of A (low) for its future senior long-term debt issues, R-1 (low) for its commercial paper program and Pfd-2 for its future senior preferred share issues from the Dominion Bond Rating Service and A (low) for long-term debt, A-1 for its commercial paper program and P-2 (low) for preferred shares from the Canadian Bond Rating Service. These ratings are conditional on the completion of this offering. Based on the provisional ratings for long-term debt and current market conditions, New NSP expects to be able to have access to the capital markets to meet its capital requirements. However, there is no assurance of this.

As part of the Reorganization, New NSP will issue to Old NSP notes in the principal amount and having substantially the same terms and conditions as the approximately $2,245 million principal amount of the long-term public debt of Old NSP. The payments of principal and interest on such public debt of Old NSP, other than debt held by the federal government and the Province, is guaranteed by the Province. Pursuant to the debt restructuring arrangements between New NSP and Old NSP, New NSP will agree to repay, redeem or defease the notes issued by it to Old NSP by December 31, 1997. To the extent that such repayment, redemption or defeasance is not financed out of the net proceeds of this offering, further equity issues or cash flow from operations, New NSP expects to arrange new debt financing. Refer to "New NSP — Debt Restructuring".

New NSP's gross capital expenditures are estimated to be $698 million for the five years ending December 31, 1996, as follows:

	Year Ending December 31				
	1996	1995	1994	1993	1992
	(unaudited — millions)				
Generating Facilities	$ 6	$ 7	$ 10	$ 44	$116
Transmission Facilities	9	24	25	18	50
Distribution Facilities	64	64	59	60	56
Other	14	17	17	18	20
Total	$93	$112	$111	$140	$242

New NSP expects to fund the major portion of these capital expenditures by cash flow from operations. Financing flexibility may be provided by reductions in discretionary capital expenditures. New NSP will not be able to borrow with the credit backing of the Province.

New NSP will have access to the equity capital markets. The increase in New NSP's equity resulting from this offering will improve its financial strength and flexibility. In addition, New NSP intends to undertake a further equity offering in the short-term, most likely in the form of an issue of preferred shares.

NEW NSP

Background

New NSP was incorporated under the Companies Act (Nova Scotia) on July 13, 1984 and reorganized under the Privatization Act, and is wholly owned by the Province. Its registered and head office is located at Scotia Square, 1894 Barrington Street, P.O. Box 910, Halifax, Nova Scotia, B3J 2W5.

New NSP has no material assets or liabilities. Its business history and financial statements are not material to this offering or to the business and financial prospects of New NSP after the Reorganization.

Old NSP was created by legislation as a Crown entity of the Province in 1919 to operate as an electric utility under the name "Nova Scotia Power Commission" ("NSP Commission"). NSP Commission expanded over a number of years by creating its own generating capacity, acquiring municipal and other local electric utilities and acquiring Eastern Light & Power Company, Limited in 1967 and Nova Scotia Light and Power Company, Limited in 1972. NSP Commission was continued as a Crown corporation by legislation in 1973 under the name "Nova Scotia Power Corporation".

The Privatization Act provides for the Reorganization of Old NSP and New NSP in order to facilitate this offering of the Common Shares of New NSP. The Reorganization will take place prior to the closing of this offering. The terms of the Reorganization are contained in the Privatization Act and certain agreements to be executed between Old NSP and New NSP including the asset transfer agreement, the matching notes agreement, the sinking funds notes agreement and the debt restructuring agreement.

Asset Transfer

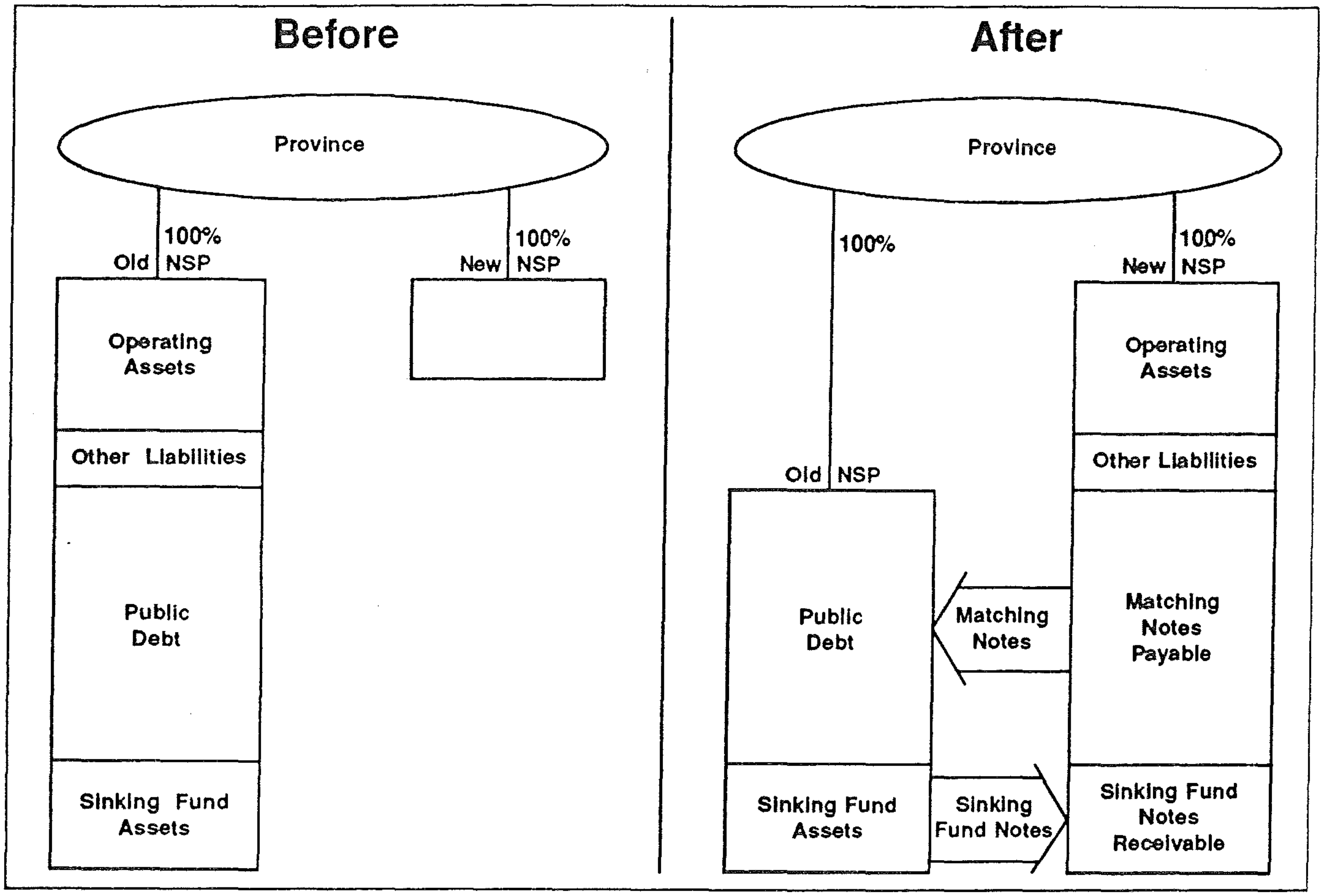
The asset transfer agreement will provide that all of the assets held by Old NSP, except the sinking fund assets in respect of the public debt of Old NSP, will be transferred to New NSP. Old NSP will retain the sinking fund assets in respect of each series of public debt having a sinking fund. Old NSP will issue notes (the "Sinking Fund Notes") to New NSP for each such series of public debt retained by Old NSP. Each Sinking Fund Note will be in a principal amount equal to the current book value of the sinking fund assets to which it relates and will bear interest at a rate equal to the yield earned by Old NSP on such sinking fund assets. Interest will be paid on maturity of the Sinking Fund Note. In consideration for the transfer of the assets and the issuance of the Sinking Fund Notes:

(a) At the direction of Old NSP, New NSP will deliver 20,134,666 Common Shares to the Minister of Finance of the Province;

(b) New NSP will issue notes to Old NSP (the "Matching Notes"), in the principal amount and having substantially the same terms and conditions as the approximately $2,245 million principal amount of long-term public debt of Old NSP, including debt held by the Government of Canada, (the "Public Debt Instruments"); and

(c) New NSP will assume all other liabilities and commitments of Old NSP, actual, accrued, contingent or otherwise, including short-term debt due to the Province of approximately $409 million.

The following diagram shows Old NSP and New NSP before and after this asset transfer:



The asset transfer agreement will also provide that New NSP will indemnify Old NSP and the Province against all assumed liabilities and commitments of Old NSP.

The Privatization Act vests in Old NSP title to all its real estate for which it has a deed purporting to convey a fee simple estate, subject only to registered mortgages, judgments and easements. Any person who claims an interest in this real estate who has not been compensated is limited to making a claim for compensation against Old NSP under the Expropriation Act (Nova Scotia). Any monetary claims made against Old NSP will be the ultimate responsibility of New NSP under its indemnity to Old NSP. New NSP also has the power to expropriate real estate with the approval of the Province.

Matching Notes

The matching notes agreement will provide that the terms and conditions of each of the Matching Notes issued by New NSP to Old NSP will be substantially the same as the terms and conditions of each of the Public Debt Instruments, including obligations as to principal and interest. The total amount of the Public Debt Instruments of Old NSP which will be mirrored by the Matching Notes of New NSP is approximately $2,245 million. Of this amount approximately $370 million matures on or before December 31, 1997 and approximately $1,875 million matures after December 31, 1997 and before February 26, 2031. Of this latter amount approximately $504 million may be redeemed prior to December 31, 1997. If New NSP defaults under the matching notes agreement, Old NSP may declare the Matching Notes to be immediately due and payable.

The sinking funds notes agreement will require New NSP to lend to Old NSP amounts equal to the sinking fund contributions required by Old NSP under the terms of the Public Debt Instruments. New NSP will advance such amounts to Old NSP from time to time and such amounts shall be added to the amounts outstanding by Old

NSP to New NSP under the Sinking Fund Notes, which are unsecured. Subject to the defeasance arrangements described below, upon maturity of a Public Debt Instrument to which the sinking fund assets relate and following repayment by New NSP of the related Matching Note, Old NSP shall deliver the sinking fund assets to New NSP in full satisfaction of the related Sinking Fund Note. Any such repayment is subject to Old NSP's right to offset any amount in default under or in respect of the matching notes agreement or the sinking funds notes agreement. Such sinking fund assets are expected to have a value equal to the principal and accrued interest of the Sinking Fund Note. In the event of a shortfall or default, New NSP's recourse under the Sinking Fund Note will be limited to the sinking fund assets.

New NSP will manage the sinking fund assets retained by Old NSP together with future contributions advanced by New NSP to Old NSP. All costs associated with such management shall be for the account of New NSP.

Debt Restructuring

The debt restructuring agreement will provide that New NSP will, on or before December 31, 1997:

(a) repay the Matching Notes of approximately $370 million maturing on or before December 31, 1997;

(b) redeem the Matching Notes of approximately $504 million callable on or before December 31, 1997; and

(c) defease the remaining approximately $1,371 million of Matching Notes maturing after December 31, 1997.

The repayment, redemption or defeasance of the Matching Notes by New NSP will allow Old NSP to repay, redeem or defease the related Public Debt Instruments, which in turn will discharge or defease the Public Debt Instruments and the obligations thereunder.

To defease such debt, New NSP will deliver to a custodian a portfolio of federal or provincial debt securities or certain federally or provincially guaranteed debt securities (the "Defeasance Assets"), to provide for payment of the principal and interest of the Matching Notes, and in turn, the Public Debt Instruments to the satisfaction of the auditors of New NSP and Old NSP. If the auditors of Old NSP determine that there is a deficiency in the Defeasance Assets, New NSP will transfer or assign additional Defeasance Assets to the custodian to remove the deficiency. Defeasance of the Matching Notes and the Public Debt Instruments will allow New NSP and Old NSP to fully remove such debt from their balance sheets although the notes to their balance sheets disclose the amount of the defeasance. New NSP will indemnify Old NSP in respect of any shortfall if the Defeasance Assets fail to discharge the principal and interest obligations of the Matching Notes.

New NSP will agree to defease, on a cumulative basis, Matching Notes maturing after December 31, 1997 of at least $200 million by December 31, 1993, $500 million by December 31, 1994, $900 million by December 31, 1995, $1,150 million by December 31, 1996 and the total, approximately $1,371 million by December 31, 1997 (the "Defeasance Schedule").

The debt restructuring agreement will provide for additional interest to be paid by New NSP to Old NSP with respect to the Matching Notes which New NSP fails to defease in accordance with the Defeasance Schedule. The amount of additional interest depends on the credit rating for long term debt of New NSP from time to time and is computed on a daily basis on the principal amount of the Matching Notes which New NSP fails to defease in accordance with the Defeasance Schedule. Based on New NSP's current provisional credit rating of A (low) for long-term debt, the additional interest payable by New NSP until such Matching Notes are defeased will be 0.5% per annum during the first 90 day period; 1% per annum during the subsequent 90 day period, escalating by 0.25% per annum for each 90 day period thereafter; provided that such additional interest shall not at anytime prior to December 31, 1997, exceed 2.5% per annum and thereafter shall not exceed 3.5% per annum.

However, until December 31, 1997, should there be a determination that debt market conditions during a 90 day period were such that it would have been imprudent for a company with a credit rating similar to that of New NSP to issue long-term debt ("Adverse Debt Market Conditions"), the Defeasance Schedule will be extended for a period of 90 days and no additional interest will be payable by New NSP during the extension period. Should Adverse Debt Market Conditions prevail during such extension period, the Defeasance Schedule will be extended for further 90 day periods, so long as such Adverse Debt Market Conditions prevail. In no event shall such extensions of the Defeasance Schedule extend beyond March 31, 1998. Notwithstanding an extension, New NSP is obligated to correct the failure to achieve defeasance in accordance with the Defeasance Schedule as soon as the

Adverse Debt Market Conditions cease. The determination as to whether Adverse Debt Market Conditions exist is made by two advisers, one appointed by Old NSP and one appointed by New NSP. If they cannot agree, they select a third adviser as arbitrator, whose decision is final.

Where the Matching Notes and related Public Debt Instruments are fully defeased by the delivery of Defeasance Assets, Old NSP will deliver the sinking fund assets in respect of the defeased Public Debt Instruments to New NSP in satisfaction of the related Sinking Fund Note. Alternatively, New NSP may tender as part of the Defeasance Assets cash equal to the value of the Sinking Fund Note, or the Sinking Fund Note, provided New NSP can demonstrate to the satisfaction of Old NSP that there is no material adverse effect on Old NSP. If cash is tendered and accepted, such cash shall be used by Old NSP to retire the Sinking Fund Note and Old NSP shall include the sinking fund assets as Defeasance Assets.

New NSP will manage the Defeasance Assets transferred by New NSP to the custodian to defease the Matching Notes. New NSP must ensure that all public debt payments are made on time and collect all receipts on the Defeasance Assets to cover those payments. Management will be passive unless deficiencies occur. All costs associated with such management shall be for the account of New NSP.

Depending upon interest rates prevailing at the time of defeasance of the Matching Notes, New NSP may incur costs in relation to such defeasance. Such costs may include but may not be limited to (i) the difference between the cost to New NSP of acquiring the Defeasance Assets and the principal amount of the Matching Notes, (ii) fees and other issuance costs incurred by New NSP in respect of new debt arranged by New NSP for the purpose of acquiring the Defeasance Assets, and (iii) brokerage and other transaction costs incurred by New NSP in acquiring the Defeasance Assets. Further, New NSP may incur additional interest expense in respect of new debt arranged to defease the Matching Notes.

Based on current interest rates, which are lower than the weighted average interest rate of the Matching Notes, and assuming that New NSP arranges new debt financing for the purpose of acquiring Defeasance Assets, New NSP estimates that, once all of the Matching Notes are defeased by 1997, the costs referred to in (i) to (iii) above would be approximately $287 million, which would result in a net increase in New NSP's debt of that amount. If interest rates during the period in which the Matching Notes are defeased decrease compared with current rates, these estimated costs and net increase in debt will be larger, other assumptions being equal. For example, if interest rates decrease by 1%, the costs and net increase in debt would be approximately $453 million. Conversely, if interest rates during the period increase, these estimated costs and increase in net debt will be smaller or net debt may even decrease, other assumptions being equal. A 1% increase in interest rates would reduce the costs and net increase in debt to approximately $146 million.

For each Matching Note, New NSP expects to amortize the costs referred to in (i) and (iii) above over the remaining life of such Matching Note and the costs referred to in (ii) above over the life of the new debt arranged. Based on current interest rates and assuming that New NSP arranges new debt financing for the purpose of acquiring the Defeasance Assets, New NSP estimates that such amortized costs, after allowing for reduced interest expense, may be approximately $1 million in 1993 increasing to approximately $12 million by 1997. If interest rates decrease by 1%, the annual costs by 1997 would increase to approximately $15 million. A 1% increase in interest rates would reduce the annual costs to approximately $8 million. After 1997, as each series of Matching Notes which has been defeased is repaid, these annual costs will reduce. New NSP expects the PUB to permit these costs of defeasance to be recovered through rates, and to permit the amortization of the costs as described, although there is no assurance of this. Refer to "Business of Nova Scotia Power — Rate Regulation" and "Investment Considerations — Regulation".

In estimating these costs and resulting net increase in debt, New NSP has made a number of assumptions which are based on current market conditions. Actual costs will vary from these estimates and the variations may be material. In estimating the costs referred to in (ii) and (iii) above, New NSP has assumed issuance costs of 1.0% of the cost to New NSP of new debt arranged and transaction costs of 0.5% of the cost of acquiring the Defeasance Assets. In estimating the costs referred to in (i) above, New NSP has assumed that it will pay on average an interest rate on the new debt arranged which is 0.4% higher than the interest rate earned on the Defeasance Assets of similar maturity. New NSP has assumed that it will issue debt with an average term of approximately 10 years, compared to the 24 year average term of the Matching Notes being defeased, to take advantage of the lower interest rates currently available for shorter terms, estimated at 0.88% for debt denominated in Canadian dollars and 1.06% for debt denominated in United States dollars. The average term of all the Matching Notes is 17 years.

Until the Defeasance Schedule is completed, New NSP has agreed that it will not create a subsidiary or parent company or sell any material asset without the consent of Old NSP.

Relationship with the Province of Nova Scotia

After giving effect to the Reorganization, the Province will own 20,134,666 Common Shares, representing 100% of the outstanding Common Shares of New NSP. After completion of this offering the Province will have sold pursuant to this prospectus all of its Common Shares. **The Common Shares are not guaranteed in any manner by the Province.**

INVESTMENT CONSIDERATIONS

Prospective investors should consider the following factors, in addition to those discussed elsewhere in this prospectus, before purchasing Common Shares.

The Common Shares are not guaranteed in any manner by the Province. Unlike a bond or term deposit, the Common Shares do not entitle the holder to the return of the offering price. The price of the Common Shares will fluctuate in response to market forces. Unlike interest on a bond or term deposit, Common Shares do not entitle the holder to dividends unless and until declared by the board of directors of New NSP. The amount of any declared dividend will depend on the dividend policy established by the board of directors from time to time, Refer to "Dividend Policy".

Ownership, Voting and Other Restrictions

As required by the Privatization Act, the Articles of Association of New NSP provide that no person, together with associates thereof, may subscribe for, have transferred to that person, hold, beneficially own or control, otherwise than by way of security only, or vote, in the aggregate, voting shares of New NSP to which are attached more than 15% of the votes attached to all outstanding voting shares of New NSP other than voting shares held by the Province. Non-residents of Canada may not subscribe for, have transferred to them, hold, beneficially own or control, otherwise than by way of security only, or vote, in the aggregate, voting shares of New NSP to which are attached more than 25% of the votes attached to all outstanding voting shares of New NSP other than voting shares held by the Province. Votes cast by non-residents on any resolution at a meeting of shareholders will be prorated so that such votes will not constitute more than 25% of the total number of votes cast. The only outstanding voting shares of New NSP are the Common Shares.

As required by the Privatization Act, the Articles of Association of New NSP contain provisions for the enforcement of these restrictions, including provisions for suspension of voting rights, forfeiture of dividends, prohibitions of share transfer, compulsory sale of shares, redemption and suspension of other shareholder rights. The board of directors of New NSP may require shareholders to furnish statutory declarations as to matters relevant to enforcement of the restrictions.

The Articles of Association of New NSP also include provisions prohibiting New NSP from selling, transferring or otherwise disposing of all or substantially all of its assets to any one person or group of associated persons or to non-residents, otherwise than by way of security only in connection with the financing of New NSP.

For a more detailed description of these restrictions refer to "Restrictions on Ownership and Voting and Other Restrictions".

Absence of Previous Market for Common Shares

There has been no previous market for the Common Shares. The offering price for the Common Shares has been determined by negotiation among New NSP, the Province and the Underwriters. Refer to "Plan of Distribution".

Regulation

Nova Scotia Power is a public utility as defined in the Public Utilities Act (Nova Scotia) and will continue to be subject to regulation under the Act by the PUB. The Act gives the PUB broad general supervisory powers over NSP's operations and its expenditures. The ultimate decision as to whether a given capital or operating expenditure will be borne by customers and the timing and any conditions of such cost recovery rests with the PUB. If recovery of any expenses of NSP were delayed or disallowed, NSP's net income would be adversely affected. Rates charged by NSP to its customers are subject to PUB approval and net income will be directly affected by the rates approved by the PUB. In approving rates, the PUB will allow a just and reasonable rate of return for NSP. Generally speaking, the PUB sets a rate of return equal to the return investors could expect on an investment of comparable risk elsewhere in the economy. The future rate of return will be influenced by interest rates. Refer to "Business of Nova Scotia Power — Rate Regulation".

Debt Restructuring Arrangements

As part of the Reorganization, New NSP will issue to Old NSP approximately $2,245 million of interest-bearing debt instruments the amounts, terms and conditions of which will correspond to the publicly held debt of Old NSP, most of which is guaranteed by the Province. Pursuant to a debt restructuring arrangement between New NSP and Old NSP, New NSP will agree to repay, redeem or defease by December 31, 1997 all of the approximately $2,245 million of interest-bearing debt instruments. Based on current interest rates and assuming that New NSP arranges new debt financing for the purpose of acquiring the Defeasance Assets, New NSP estimates that amortized costs, after allowing for reduced interest expense, may be approximately $1 million in 1993 increasing to approximately $12 million by 1997. After 1997, as each series of public debt which has been defeased is repaid, these annual costs will reduce. If interest rates during the period in which the Matching Notes are defeased increase compared with current rates, these estimated costs may decrease. Conversely, if interest rates during this period decrease, these estimated costs may increase. New NSP expects the PUB to permit such costs to be recovered through rates, although there is no assurance of this. Refer to "New NSP — Debt Restructuring".

Based on its provisional credit ratings and current market conditions, New NSP expects to be able to have access to the capital markets in order to meet its debt restructuring obligations, although there is no assurance of this.

Taxation

Due to the combined effect of the federal income tax rebate under the Public Utilities Income Tax Transfer Act (Canada) and a provincial income tax exemption under the Privatization Act, New NSP will be subject to income tax at substantially reduced effective rates. The continuance of the federal rebate and provincial exemption is subject to future government policy. Refer to "Business of Nova Scotia Power — Taxation".

CONSOLIDATED CAPITALIZATION

The following table sets forth the consolidated capitalization of Old NSP at March 31, 1992 and at June 30, 1992 and of New NSP at June 30, 1992 after giving effect to the Reorganization and this offering, assuming net proceeds to New NSP of $615 million.

	Outstanding as at March 31, 1992	Outstanding as at June 30, 1992	Outstanding as at June 30, 1992 after giving effect to the Reorganization and this offering
		(unaudited)	(unaudited)
		(millions except Common Shares)	
Long-Term Debt	$2,153.9	$2,157.9	$2,154.6 (1)
Debt Payable Within One Year (2)	253.0	332.5	(106.9) (3)
Less: Sinking Funds (4)	(396.7)	(412.8)	(585.1) (5)
TOTAL DEBT	2,010.2	2,077.6	1,462.6
SHAREHOLDERS' EQUITY (6)			
Preferred Shares			
First Preferred Shares (authorized: unlimited)	—	—	—
Second Preferred Shares (authorized: unlimited)	—	—	—
Common Shares (authorized: unlimited)	—	—	650.0 (7) (8) (85,134,666 shares)
Contributed Surplus (9)	13.3	13.3	—
Retained Earnings (9)	98.1	98.1	76.4 (7) (8)
TOTAL SHAREHOLDERS' EQUITY	111.4	111.4	726.4
TOTAL CAPITALIZATION	$2,121.6	$2,189.0	$2,189.0

Notes:

(1) Refer to "Use of Proceeds", item (b).

(2) This amount includes the current portion of long-term debt of $70.2 million (June 30, 1992 — $69.3 million), notes payable to the Province of $161.5 million (June 30, 1992 — $242.0 million) and sinking fund instalment payments of $21.3 million (June 30, 1992 — $21.2 million).

(3) Refer to "Use of Proceeds", items (a) and (c). Short-term indebtedness held by the Province is expected to increase from $242.0 million as of June 30, 1992 to approximately $409.4 million as of August 10, 1992. Included in this increase is $14.6 million to be borrowed to repay long-term debt maturing in July 1992.

(4) See Note 6 to the Consolidated Financial Statements of Old NSP (Historical).

(5) Refer to "Use of Proceeds", item (d).

(6) Old NSP has no share capital. References to share capital apply only to New NSP after the Reorganization.

(7) Pursuant to the asset transfer agreement described under "New NSP — Asset Transfer", Common Shares to be issued pursuant to the Reorganization will be issued for nominal consideration and the balance of shareholders' equity will be allocated to contributed surplus in the amount of $13.3 million and retained earnings in the amount of $98.1 million.

(8) The total proceeds to New NSP from this offering of $650 million will be credited to common shares and Underwriters' fees and estimated expenses of issue totalling $35 million will be charged to contributed surplus ($13.3 million) and retained earnings ($21.7 million). New NSP will receive the full amount of the final instalment of the Instalment Receipts from the Province on the Closing Date. Refer to "Plan of Distribution".

(9) As at March 31, 1992.

USE OF PROCEEDS

The net proceeds to New NSP from this offering estimated to be approximately $615.0 million, after deduction of the Underwriters' fees and the estimated costs of issue, will be used to:

(a) repay short-term indebtedness held by the Province of approximately $409.4 million;

(b) repay long-term indebtedness held by the Province of approximately $3.3 million;

(c) retire long-term indebtedness maturing November, 1992, of $30.0 million; and

(d) purchase long-term public debt of Old NSP and other Defeasance Assets for sinking fund or defeasance purposes with the balance of the net proceeds of approximately $172.3 million.

Until the portion of the net proceeds described in (c) and (d) is utilized, it will be invested in short-term interest-bearing securities. The net proceeds to New NSP include $92.7 million paid by the Province to New NSP to purchase the right to receive the aggregate amount of the final instalment for all Instalment Receipts. New NSP will not receive any part of the proceeds of the sale of Common Shares by the Province. Refer to "Plan of Distribution".

DILUTION

The following table shows the dilution based upon the unaudited pro forma net tangible book value per Common Share of NSP as at March 31, 1992, after giving effect to the Reorganization, both before and after giving effect to this offering:

Offering price		$10.00
Pro forma net tangible book value per Common Share before this offering	$5.53	
Change in pro forma net tangible book value per Common Share attributable to this offering (1)	3.00	
Pro forma net tangible book value per Common Share after this offering		8.53
Dilution to subscribers		$ 1.47
Percentage dilution in relation to the offering price		14.7%

(1) After deducting the Underwriters' fees payable by New NSP and expenses of the issue.

DIRECTORS AND OFFICERS

Directors of New NSP

The following table shows certain information concerning the directors of New NSP:

Name and Municipality of Residence	Age	Principal Occupation
LOUIS R. COMEAU Halifax, Nova Scotia	51	President and Chief Executive Officer Nova Scotia Power Inc.
SIR J. GRAHAM DAY London, England	59	Chairman Cadbury Schweppes plc London, England (soft drink and confectionary company)
MARC DE LOGÈRES New York, New York	66	International Business Consultant New York, New York
THOMAS R. HALL (1) Port Hastings, Nova Scotia	62	President and General Manager Stora Forest Industries Limited Port Hawkesbury, Nova Scotia (pulp and paper products)

Name and Municipality of Residence	Age	Principal Occupation
JOSEPH A. F. MACDONALD, QC (2) Halifax, Nova Scotia	49	Partner McInnes Cooper & Robertson Halifax, Nova Scotia (barristers and solicitors)
M. EDWARD MACNEIL Sydney River, Nova Scotia	56	International Representative International Brotherhood of Electrical Workers Sydney, Nova Scotia (labour union)
DEREK OLAND (1) Halifax, Nova Scotia	53	President and Chief Operating Officer Moosehead Breweries Limited Dartmouth, Nova Scotia (brewers)
DR. ELIZABETH PARR-JOHNSTON Halifax, Nova Scotia	52	President and Vice-Chancellor Mount Saint Vincent University Halifax, Nova Scotia
KENNETH C. ROWE Halifax, Nova Scotia	57	Chairman, President and Chief Executive Officer IMP Group Limited Halifax, Nova Scotia (aerospace, aviation, hotel, and marine industries)
ROSEMARY SCANLON (1) Brooklyn, New York	52	Chief Economist Port Authority of New York and New Jersey New York, New York
PAUL D. SOBEY (1) New Glasgow, Nova Scotia	35	President, Chief Executive Officer and Director Atlantic Shopping Centres Limited Stellarton, Nova Scotia (real estate)

(1) Member of Audit Committee.

(2) Chairman.

Eight of the directors were appointed as directors of New NSP by the Province in April 1992. The President and Chief Executive Officer and the Chairman were previously appointed and Marc de Logères was appointed in July 1992. Each of the directors has held the principal occupation set forth above for the past five years except for (a) Sir J. Graham Day who, prior to May 1989, was Chairman of Rover Group Holdings plc, (b) Marc de Logères who, prior to September 1991, was President, Chief Executive Officer and Director of Michelin Corporation, (c) Dr. Elizabeth Parr-Johnston who, prior to July 1991, was a management consultant with E. Parr-Johnston & Associates and, prior to September 1990, was Manager, Products Strategic Systems and Manager, Information Technology, Information and Computing with Shell Canada Limited and (d) Paul D. Sobey who, prior to October 1989, was Executive Vice-President, Finance of Atlantic Shopping Centres Limited.

The term of office of the directors named above ends at the close of business of the first annual shareholders' meeting, following this offering. Thereafter the directors are elected annually to serve until New NSP's next meeting of shareholders or until their successors are elected.

The Articles of Association of New NSP provide that the number of directors of New NSP will be a minimum of eleven and a maximum of thirteen. The Articles of Association also provide that the nominees for election as directors at each annual meeting of shareholders shall consist of:

(i) the chief executive officer and, if considered appropriate, one other senior officer of New NSP; and

(ii) the balance being nominees who are independent from both New NSP and the Province.

Executive Officers of New NSP

The following table shows certain information concerning the executive officers of New NSP:

Name and Municipality of Residence	Position	Age	Served as an Officer of Old NSP Since	Years of Electric Utility Industry Experience
LOUIS ROLAND COMEAU .... Halifax, Nova Scotia	President and Chief Executive Officer	51	1983	13
WILLIAM LEO FRASER .... Halifax, Nova Scotia	Vice-President Human Resources and Corporate Services	57	1985	20
GERALD DOUGLAS LETHBRIDGE Dartmouth, Nova Scotia	Vice-President Engineering and Production	54	1985	33
TERRANCE FRANCIS MACDONALD Bedford, Nova Scotia	Vice-President Planning and Environment	46	1987	23
GARY KENDALL OICKLE .... Bedford, Nova Scotia	Vice-President and Chief Financial Officer	41	1990	2
SHERRY ELLEN PORTER........ Halifax, Nova Scotia	Vice-President Public Affairs	37	1992	—
RICHARD JOSEPH SMITH .... Halifax, Nova Scotia	Secretary and General Counsel	40	1987	14
LEONARD JOHN SWEETT .... Halifax, Nova Scotia	Vice-President Customer Services and Energy Management	58	1979	36

Each of the executive officers has been actively engaged for more than five years in the affairs of Old NSP in various managerial and executive capacities except Mr. Oickle who, before January 1, 1990 was Vice-President Finance and Administration for Clearwater Fine Foods Inc., an international seafood company, with head office in Bedford, Nova Scotia, and Ms. Porter who, before May 25, 1992 was Director of Corporate Affairs for Sobeys Inc., before March 1991 was Regional Director, Atlantic, for the Canadian Council of Grocery Distributors and before February 1989 was Marketing Manager, North America for National Sea Products Limited.

REMUNERATION OF DIRECTORS AND EXECUTIVE OFFICERS

For the year ended March 31, 1992, the only directors of New NSP were also officers of Old NSP and did not receive compensation in their capacity as directors of New NSP. In April 1992 all but three of the current directors of New NSP were appointed by the Province. A fee and reimbursement of expenses arrangement is expected to be established for the directors of New NSP.

New NSP has eight executive officers, being the same executive officers as Old NSP. The annualized aggregate compensation paid by Old NSP and to be paid by New NSP to these executive officers for the year ending December 31, 1992, based upon current amounts, is $916,152. The provincial wage restraint program freezes executive compensation at current levels until April 1, 1993, as it does for all employees. Other compensation for this period received and to be received by the executive officers, including personal benefits, will not exceed $80,000. The personal benefits for executive officers include the full cost of life, accident, medical and dental insurance plans with increased levels of coverage from those of other employees.

One executive officer has a supplementary pension arrangement which, when added to New NSP's regular pension, is designed to provide the officer from age 65 with 70% of the average of the officer's last five years' salary, the limit for a pensioner with full years of service.

DESCRIPTION OF SHARE CAPITAL

The authorized share capital of New NSP consists of an unlimited number of Common Shares without par value, an unlimited number of First Preferred Shares, issuable in series ("First Preferred Shares"), and an unlimited number of Second Preferred Shares, issuable in series ("Second Preferred Shares"). In accordance with the Privatization Act and the Memorandum and Articles of Association of New NSP, the class conditions of the First Preferred Shares and the Second Preferred Shares will be established by resolution of the board of directors. After giving effect to the Reorganization described under the heading "New NSP", there will be 20,134,666 Common Shares issued and outstanding, all of which will be held by the Province and all of which are being offered pursuant to this prospectus. No First Preferred Shares or Second Preferred Shares will be issued and outstanding at the closing of this offering.

The following is a summary of the material provisions to be attached to these classes of shares.

Common Shares

Subject to the limitations described under the heading "Restrictions on Ownership and Voting and Other Restrictions", the holders of Common Shares are entitled to one vote per Common Share on all matters to be voted on by the shareholders and are entitled to receive such dividends as may be declared by the board of directors. The Common Shares rank junior to the rights of the holders of all First Preferred Shares and Second Preferred Shares that may be outstanding with respect to the payment of dividends and in the distribution of assets or return of capital of New NSP in the event of liquidation, dissolution or winding up of New NSP. The holders of Common Shares are entitled to participate equally, on a share for share basis, with respect to the payment of dividends and in the distribution of the remaining property and assets of New NSP in the event of liquidation, dissolution or winding up of New NSP, whether voluntary or involuntary, or any other distribution of the property and assets or return of capital of New NSP among its shareholders for the purpose of winding-up its affairs.

First Preferred Shares

The following is a summary of the material attributes of the First Preferred Shares as a class.

Issuable in Series

The First Preferred Shares may be issued from time to time in one or more series in such numbers and with such designations, rights, privileges, restrictions and conditions as the board of directors of New NSP determines by resolution.

Voting Rights

Subject to the provisions of the Companies Act (Nova Scotia), as from time to time amended, supplemented or replaced, the holders of the First Preferred Shares of each series shall not be entitled as such to receive notice of or to attend any meeting of shareholders of New NSP or to vote at any such meeting unless New NSP from time to time fails to pay, in the aggregate, eight quarterly dividends on any series of the First Preferred Shares on the dates on which the same should be paid according to the terms thereof whether or not consecutive, whether or not such dividends have been declared and whether or not there are any monies of New NSP properly applicable to the payment of dividends. Thereafter, but only so long as any such dividends remain in arrears, the holders of the First Preferred Shares of each series upon which dividends are in arrears as aforesaid shall be entitled to receive notice of and to attend all meetings of shareholders of New NSP at which directors are to be elected and to vote for the election of two directors out of the total number of directors elected at such meeting. Such entitlement to vote shall be exercised together with holders of shares of:

(a) all other series of the First Preferred Shares,

(b) all series of the Second Preferred Shares, and

(c) all other classes or series of classes of shares of New NSP, whether presently authorized or authorized in the future,

having the right to vote in similar circumstances. In any instance where the holders of First Preferred Shares are entitled to vote, each such holder shall have one vote for each First Preferred Share held. Nothing contained in the First Preferred Share provisions shall be deemed to limit the right of New NSP from time to time to increase or decrease the number of its directors in accordance with the procedures prescribed by the Articles of Association of New NSP.

Ranking and Priority of First Preferred Shares

The First Preferred Shares of each series rank on a parity with the First Preferred Shares of every other series and are entitled to a preference over the Second Preferred Shares, the Common Shares and any other shares ranking junior to the First Preferred Shares whether presently authorized or authorized in the future with respect to the payment of dividends and the distribution of the remaining property and assets or return of capital of New NSP in the event of the liquidation, dissolution or winding-up of New NSP, whether voluntary or involuntary, or any other distribution of the property and assets or return of capital of New NSP among its shareholders for the purpose of winding-up its affairs.

Amendments

The class provisions attaching to the First Preferred Shares may be deleted, varied, modified or amended with the prior approval of the holders of the First Preferred Shares as a class given in writing by all holders of the First Preferred Shares outstanding or by at least two-thirds of the votes cast at a meeting or adjourned meeting of the holders of such shares duly called for that purpose and at which a quorum is present, in addition to any other approval required by the Companies Act (Nova Scotia), as from time to time amended, supplemented or replaced.

Second Preferred Shares

The following is a summary of the material attributes of the Second Preferred Shares as a class.

Issuable in Series

The Second Preferred Shares may be issued from time to time in one or more series in such numbers and with such designations, rights, privileges, restrictions and conditions as the board of directors of New NSP determines by resolution.

Voting Rights

Subject to the provisions of the Companies Act (Nova Scotia), as from time to time amended, supplemented or replaced, the holders of the Second Preferred Shares of each series shall not be entitled as such to receive notice of or to attend any meeting of shareholders of New NSP or to vote at any such meeting unless New NSP from time to time fails to pay, in the aggregate, eight quarterly dividends on any series of the Second Preferred Shares on the dates on which the same should be paid according to the terms thereof whether or not consecutive, whether or not such dividends have been declared and whether or not there are any monies of New NSP properly applicable to the payment of dividends. Thereafter, but only so long as any such dividends remain in arrears, the holders of the Second Preferred Shares of each series upon which dividends are in arrears as aforesaid shall be entitled to receive notice of and to attend all meetings of shareholders of New NSP at which directors are to be elected and to vote for the election of two directors out of the total number of directors elected at such meeting. Such entitlement to vote shall be exercised together with holders of shares of:

(a) all series of the First Preferred Shares,

(b) all other series of the Second Preferred Shares, and

(c) all other classes or series of classes of shares of New NSP, whether presently authorized or authorized in the future,

having the right to vote in similar circumstances. In any instance where the holders of Second Preferred Shares are entitled to vote, each such holder shall have one vote for each Second Preferred Share held. Nothing contained in the Second Preferred Share provisions shall be deemed to limit the right of New NSP from time to time to increase or decrease the number of its directors in accordance with the procedures prescribed by the Articles of Association of New NSP.

Ranking and Priority of Second Preferred Shares

The Second Preferred Shares of each series rank on a parity with the Second Preferred Shares of every other series and are entitled to a preference over the Common Shares and any other shares ranking junior to the Second

Preferred Shares whether presently authorized or authorized in the future with respect to the payment of dividends and the distribution of the remaining property and assets or return of capital of New NSP in the event of the liquidation, dissolution or winding-up of New NSP, whether voluntary or involuntary, or any other distribution of the property and assets or return of capital of New NSP among its shareholders for the purpose of winding up its affairs.

Amendments

The class provisions attaching to the Second Preferred Shares may be deleted, varied, modified or amended with the prior approval of the holders of the Second Preferred Shares as a class given in writing by all holders of the Second Preferred Shares outstanding or by at least two-thirds of the votes cast at a meeting or adjourned meeting of the holders of such shares duly called for that purpose and at which a quorum is present, in addition to any other approval required by the Companies Act (Nova Scotia), as from time to time amended, supplemented or replaced.

RESTRICTIONS ON OWNERSHIP AND VOTING AND OTHER RESTRICTIONS

The Privatization Act requires that the Articles of Association of New NSP include certain restrictions including restrictions on the ownership and voting of voting shares of New NSP, both on an individual basis and on the basis of Canadian residence. "Voting shares" include Common Shares whether or not purchased on an instalment basis. The Privatization Act also contains provisions for the enforcement of the individual and non-resident ownership restrictions. In addition, the ability of non-residents of Canada to vote the Common Shares and any other voting shares which might subsequently be issued may, under certain circumstances, be restricted.

With regard to the application of the Privatization Act to Common Shares purchased on an instalment basis, refer to "Details of the Offering — Eligible Nova Scotia Residents Only — Ownership Restrictions".

The following is a summary of such restrictions in New NSP's Articles of Association and is not intended to be, nor should it be construed to be, legal advice to any particular purchaser. Prospective purchasers should, therefore, consult their own legal advisers with respect to their particular circumstances.

Individual Ownership Restriction

No person, together with associates thereof, may hold, beneficially own or control, directly or indirectly, otherwise than by way of security only, in the aggregate voting shares to which are attached more than 15% of the votes that may ordinarily be cast to elect directors of New NSP, calculated without including votes that may be cast by or on behalf of the Province. This restriction does not apply to the Province.

A person is an associate of another person if:

(a) one is a corporation of which the other is an officer or director;
(b) one is a corporation that is controlled by the other or by a group of persons of which the other is a member;
(c) one is a partnership of which the other is a partner;
(d) one is a trust of which the other is a trustee;
(e) both are corporations controlled by the same person;
(f) both are members of a voting trust that relates to voting shares of New NSP;
(g) both, in the reasonable opinion of the directors of New NSP, are parties to an agreement or arrangement a purpose of which is to require them to act in concert with respect to their interests, direct or indirect, in New NSP or are otherwise acting in concert with respect to those interests; or
(h) both are at the same time associates, within the meaning of any of (a) to (g), of the same person;

provided that:

(1) if a person who would otherwise be an associate of another person submits to New NSP a statutory declaration stating that (A) no voting shares held or to be held by the declarant are or will be, to the declarant's knowledge, held in the right of, for the use or benefit of or under the control of, any other person of which the declarant would otherwise be an associate, and (B) the declarant is not acting and will not act in concert with any such other person with respect to their interests, direct or indirect, in New NSP, the declarant and that other person are not associates so long as the directors of New NSP are

satisfied that the statements in the declaration are being complied with and that there are no other reasonable grounds for disregarding the declaration;

(2) two corporations are not associates pursuant to (h) above by reason only that under (a) above each is an associate of the same individual; and

(3) where the directors of New NSP are of the reasonable opinion that any person holds, beneficially owns or controls voting shares to which are attached not more than the lesser of (A) two one-hundreths of one per cent of the votes that may ordinarily be cast to elect directors of New NSP, and (B) 10,000 such votes, that person is not an associate of anyone else and no one else is an associate of that person.

Non-Resident Ownership Restriction

Non-residents of Canada may not hold, beneficially own or control, directly or indirectly, otherwise than by way of security only, in the aggregate voting shares to which are attached more than 25% of the votes that may ordinarily be cast to elect directors of New NSP, calculated without including votes that may be cast by or on behalf of the Province.

"Non-resident of Canada" means

(a) an individual, other than a Canadian citizen, who is not ordinarily resident in Canada;

(b) a corporation incorporated, formed or otherwise organized outside Canada;

(c) a foreign government or an agency thereof;

(d) a corporation controlled by non-residents as defined in any of (a) to (c);

(e) a trust (A) established by a non-resident as defined in (b) to (d), other than a trust for the administration of a pension fund for the benefit of individuals a majority of whom are residents, or (B) in which non-residents as defined in (a) to (d) have more than 50% of the beneficial interest; or

(f) a corporation that is controlled by a trust described in (e);

but does not include a mutual company to which subsection 427(5) of the Insurance Companies Act (Canada) applies or a company or foreign company to which subsection 427(6) of that Act applies.

If one or more joint holders of, beneficial owners of or persons controlling voting shares is a non-resident of Canada, the voting shares are deemed to be held, beneficially owned or controlled, by such non-resident.

Non-Resident Voting Restriction

If the directors determine that on any motion at a shareholders' meeting more than 25% of the votes cast, in person or by proxy, have been cast in respect of voting shares held, beneficially owned or controlled, directly or indirectly, by non-residents of Canada, all votes cast in respect of such non-resident voting shares on that motion shall be proportionately adjusted so that such votes cast equal 25% of all votes cast on that motion.

Enforcement

The board of directors of New NSP may at any time require holders of or subscribers for voting shares and certain other persons to furnish statutory declarations as to residence, ownership of voting shares and certain other matters relevant to the enforcement of the restrictions. New NSP is precluded from accepting any subscription for, issuing or registering a transfer of any voting shares if a contravention of the individual or non-resident ownership restrictions would result.

The board of directors of New NSP is entitled to determine whether contraventions of the individual and non-resident ownership restrictions have occurred. If the board of directors of New NSP determines that a person is in contravention of the individual ownership restriction, New NSP shall not accept a subscription for shares from or issue or register any transfer of voting shares to that person or any associate of that person. The contravening shareholder may not exercise the voting rights attached to any of its voting shares and New NSP shall not pay any dividends or make any other distributions with respect to the voting shares held in contravention of the restriction, or, if the contravention was intentional, with respect to any of the voting shares held by such shareholder. New NSP shall also send to the contravening shareholder a notice requiring it to sell the shares held in contravention of the restriction within a specified period of not less than 45 days. Unless, within the time specified in such notice the contravening shareholder sells or otherwise disposes of the shares held in contravention or provides New NSP with satisfactory evidence that the shareholder is not in contravention of the restriction, New NSP may suspend the voting and all other rights attached to the voting shares of the shareholder (other than the right to transfer such shares) and may sell or redeem the shares held in contravention of the restriction. Any sale will be made through a stock exchange or, if the shares are not then listed, in such manner as the board of directors may determine. Voting shares may be redeemed after a reasonable attempt has been made to sell the shares or after the directors have determined that a sale would have adverse consequences to New NSP or its shareholders. The redemption price would be the average closing price of the voting shares over the previous ten trading days on which a board lot of voting shares has traded on the principal stock exchange on which the voting shares are listed or a price determined by the directors if the requisite trading of voting shares has not occurred. In the event of the sale or redemption of voting shares by New NSP, the contravening shareholder is entitled to the net proceeds of the sale or redemption, without interest and less administrative costs, upon the surrender of the relevent share certificate.

If the board of directors of New NSP determines that there has been a contravention of the non-resident ownership restriction, New NSP shall make a public announcement to that effect and shall not accept a subscription for voting shares from a non-resident, issue any voting shares to a non-resident or register any transfer of voting shares from a resident to a non-resident. Provided that the directors have determined that to do so would be practicable and would not be unfairly prejudicial, New NSP shall also send a notice to non-resident shareholders, chosen in inverse order to the order of acquisition or registration of voting shares, by lot or by such other method determined by the directors, requiring them to sell sufficient voting shares so as to eliminate the contravention of the ownership restriction within a specified period of not less than 60 days. If the shareholders receiving such notice have not sold sufficient shares or provided New NSP with satisfactory evidence that they are not in contravention of the restriction, New NSP may sell or redeem the shares held in contravention in the same way as described above.

Interpretation

For purposes of the foregoing restrictions:

(a) the ownership restrictions do not apply with respect to shares held by underwriters solely for the purpose of distributing the shares to the public, or by any person who provides centralized facilities for the clearing of trades in securities and is acting in relation to trades in the shares solely as an intermediary in the payment of funds or the delivery of securities or both;

(b) "control" means control in any manner that results in control in fact and, without limiting the generality of the foregoing,

  (i) a body corporate is deemed to be controlled by a person if (A) securities of the body corporate to which are attached more than 50% of the votes that may be cast to elect directors are held, otherwise than by way of security only, by or for the benefit of that person, and (B) the votes attached to those securities are sufficient to elect a majority of the directors of the body corporate; and

  (ii) a partnership or unincorporated organization is deemed to be controlled by a person if an ownership interest therein representing more than 50% of the assets thereof is held, otherwise than by way of security only, by or for the benefit of that person;

(c) "corporation" includes a body corporate, partnership and unincorporated organization; and

(d) "voting share" means a share carrying a voting right under all circumstances or under some circumstances that have occurred and are continuing, and includes a security currently convertible into such a share and currently exercisable options and rights to acquire such a share or such a convertible security.

Other Restrictions

The Memorandum and Articles of Association of New NSP also include provisions requiring New NSP to maintain its head office and principal executive offices in Nova Scotia, and prohibiting New NSP from selling, transferring or otherwise disposing of all or substantially all of its assets, in one transaction or several related transactions, to any one person or group of associated persons or to non-residents of Canada, otherwise than by way of security only in connection with the financing of New NSP.

DIVIDEND POLICY

The board of directors of New NSP has established an initial policy of paying quarterly dividends of $0.1875 ($0.75 per annum) per Common Share. It is expected that the first dividend will be payable with respect to the Common Shares on November 16, 1992.

This initial policy will be reviewed from time to time in light of New NSP's net income, its financial position and other factors considered relevant by the board of directors. New NSP's future net income will be directly affected by rates approved by the PUB. Refer to "Business of Nova Scotia Power — Rate Regulation" and "Investment Considerations".

After completion of this offering, New NSP will consider creating a dividend reinvestment and share purchase plan pursuant to which holders of Common Shares will be entitled to acquire additional Common Shares through the reinvestment of dividends or optional cash payments.

DETAILS OF THE OFFERING

National Offering

The national offering consists of a total of 61,953,731 Common Shares which are being offered in each of the provinces of Canada, including Nova Scotia. Of these Common Shares, 41,819,065 are being offered by New NSP and 20,134,666 are being offered by the Province.

Eligible Nova Scotia Residents Only

In addition to any Common Shares available pursuant to the national offering described above, eligible Nova Scotia residents, defined in "Eligible Nova Scotia Residents", who applied on or before July 24, 1992, may purchase Common Shares offered by New NSP pursuant to this prospectus on an instalment basis. Eligible Nova Scotia residents were entitled to apply to purchase between a minimum of 25 and a maximum of 5,000 Common Shares on an instalment basis.

An eligible Nova Scotia resident may acquire beneficial ownership of up to 5,000 Common Shares purchased on an instalment basis, including registrations in the name of his or her registered retirement savings plan or registered retirement income fund. For the purposes of calculating a person's limit, when an Instalment Receipt is jointly purchased by more than one person, each person will be considered to have purchased the number of Common Shares represented by the Instalment Receipt divided by the number of joint purchasers. An estate or trust of which one or more of the beneficiaries is, and on June 30, 1992 was, an eligible Nova Scotia resident may purchase Common Shares on an instalment basis, but for limit calculation purposes, each such eligible Nova Scotia resident is deemed to beneficially own the number of Common Shares so purchased by the trust divided by the number of beneficiaries. Each registered pension plan ("RPP") and deferred profit sharing plan ("DPSP") may acquire up to 5,000 Common Shares on an instalment basis if one or more of the beneficiaries is an eligible Nova Scotia resident. The Common Shares acquired on an instalment basis by a RPP or DPSP are not attributable to the individuals participating in such plans and will not be taken into account in determining the amount of such individual's holdings.

Prior to receipt by New NSP of full payment, beneficial ownership of the Common Shares purchased on an instalment basis will be represented by Instalment Receipts. The first instalment of $6.00 per Common Share is payable on closing of this offering which is expected to occur on or about August 12, 1992 (but not later than August 28, 1992) and the final instalment of $4.00 per Common Share is payable on or before August 12, 1993 (the "Final Instalment Date").

The following is a summary of the material attributes and characteristics of the Instalment Receipts. Reference is made to the instalment receipt and pledge agreement ("Instalment Receipt and Pledge Agreement") to be dated the date of the closing of this offering, among New NSP, the Underwriters and the Custodian for a complete statement of the attributes and characteristics of the Instalment Receipts and the rights and obligations of holders thereof. Refer to "Material Contracts".

The Instalment Receipt and Pledge Agreement provides that legal title to the Common Shares sold on an instalment basis will be held by the Custodian following payment of the initial instalment pursuant to the Underwriting Agreement and until the purchase price due to the Custodian has been fully paid by payment of the final instalment due on the Final Instalment Date. Each eligible Nova Scotia resident who purchases Common Shares offered hereby on an instalment basis, by acceptance of the offer constituted by this prospectus, agrees that the Common Shares purchased on an instalment basis shall be delivered at closing to the Custodian to be held upon the terms of the Instalment Receipt and Pledge Agreement. Each holder of an Instalment Receipt agrees to be bound by the terms of the Instalment Receipt and Pledge Agreement including the obligation to pay the final instalment and such other amounts provided for therein.

Instalments

Instalment Receipts will be issued to eligible Nova Scotia resident purchasers who pay the initial instalment and who are entered by the Custodian in the register of holders of Instalment Receipts to be maintained by the Custodian. Instalment Receipts will be transferable by the Custodian at its principal corporate trust offices in Halifax, Montreal, Toronto, Winnipeg, Calgary and Vancouver.

An Instalment Receipt will evidence the fact that the initial instalment has been paid in respect of the number of Common Shares specified therein (the "Underlying Shares") and the right of the registered holder thereof, subject to compliance with the provisions of the Privatization Act, and the Instalment Receipt and Pledge Agreement, to become the registered holder of the Underlying Shares upon payment in full of the final instalment. Upon registration of the transfer of an Instalment Receipt, the transferee will acquire the transferor's rights and become subject to the obligations of a registered holder under the Instalment Receipt and Pledge Agreement and the transferor will cease to have any further rights thereunder. No transfer of an Instalment Receipt tendered for registration after August 12, 1993 will be accepted for registration.

The Instalment Receipt and Pledge Agreement will require the Custodian to mail to the registered holders of Instalment Receipts, as determined on a date being not more than 14 days before the date of mailing, a notice of the Final Instalment Date, the amount of the final instalment and the liability of holders set out below under "Liability for Instalments" not more than 60 days and not less than 30 days prior to the Final Instalment Date. This agreement will also require the Custodian to advertise this notice twice in three newspapers. The first advertisement must be published not more than 120 days and not less than 90 days prior to the Final Instalment Date and the second not more than 30 days and not less than 15 days prior to the Final Instalment Date. The three newspapers are the Report on Business section of a weekday national edition of The Globe and Mail, a newspaper of wide circulation in Nova Scotia and a daily French language newspaper of wide circulation in the Province of Québec. Payment of the final instalment is required when due whether or not a registered holder receives a notice of the Final Instalment Date from the Custodian. Subject to compliance with the provisions of the Privatization Act and the Instalment Receipt and Pledge Agreement, as soon as practicable after timely payment of the final instalment, presentation and surrender of the relevant Instalment Receipt(s), the Underlying Shares will be registered in the name of the registered holder of the Instalment Receipt without additional charge.

A holder of an Instalment Receipt will be entitled to make payment of all, but not less than all, of the final instalment and thereby become, as soon as practicable after presentation and surrender of the Instalment Receipt, the registered holder of the Underlying Shares at any time prior to the Final Instalment Date.

Liability for Instalments

The Underwriters will hypothecate and pledge the Underlying Shares represented by Instalment Receipts purchased by eligible Nova Scotia residents on an instalment basis to secure payment of the final instalment. If payment of the final instalment is not received when due, the Instalment Receipt and Pledge Agreement will provide that the Common Shares then held as security under the Instalment Receipt and Pledge Agreement may, at the option of any assignee of the right to receive the final instalment pursuant to the Instalment Receipt and Pledge Agreement and upon compliance with applicable law, be acquired by the assignee in satisfaction of all obligations of the registered holder of an Instalment Receipt. Refer to "Plan of Distribution". The Instalment Receipt and Pledge Agreement will further provide that New NSP may, and, if in excess of 95% of the total amount owing in respect of final instalments has been paid, shall, direct the Custodian to sell the Underlying Shares in the open market and remit to the registered holder of the relevant Instalment Receipt the proceeds of such sale after deducting therefrom the amount of the final instalment together with the holder's pro rata portion of the costs of such sale and an administrative charge of $0.50 per Underlying Share, subject to a minimum charge of $25.00. **The Instalment Receipt and Pledge Agreement will provide that the foregoing sale by the Custodian shall not limit any other remedies available to New NSP against such holder of Instalment Receipts in the event the proceeds of such sale**

are insufficient to cover the amount of the final instalment and such costs and administrative charge and, accordingly such holder shall remain liable to New NSP for any such deficiency. A late payment charge of $0.25 per Underlying Share will be payable by registered holders of Instalment Receipts at the time of payment of the final instalment when payment of the final instalment is received after the close of business on August 12, 1993 but before the close of business on August 19, 1993, but late payment will be permitted only if the average closing price of the Common Shares on The Toronto Stock Exchange for each of the trading days on which there was a closing price falling within the ten days immediately preceding the Final Instalment Date is greater than $4.00.

The Province will, at the closing of this offering purchase New NSP's right to receive the aggregate amount of the final instalment and has taken an assignment of New NSP's rights under the Instalment Receipt and Pledge Agreement, and an assignment of New NSP's rights under an indemnity agreement. Pursuant to the indemnity agreement, the Underwriters or their assignee agree to indemnify New NSP or its assignee, the Province, to the extent that the holders of Instalment Receipts do not pay the final instalment. Upon payment under the indemnity agreement, the Underwriters or their assignee will acquire the right to pursue the remedies against holders of Instalment Receipts described above. Refer to "Plan of Distribution".

Ownership Restrictions

The Privatization Act requires that the Articles of Association of New NSP include certain restrictions including restrictions on the ownership and voting of voting shares of New NSP, both on an individual basis and on the basis of Canadian residence. "Voting shares" include Common Shares whether or not purchased on an instalment basis, and therefore include Instalment Receipts. The Privatization Act also contains provisions for the enforcement of the individual and non-resident ownership restrictions. In addition, the ability of non-residents of Canada to vote the Common Shares and any other voting shares which might subsequently be issued may, under certain circumstances, be restricted. Refer to "Restrictions on Ownership and Voting and Other Restrictions".

In addition, Instalment Receipts may not, under the terms of the Instalment Receipt and Pledge Agreement, be sold or transferred to, or purchased or owned by, a non-resident of Canada. The Custodian will refuse to register any non-resident of Canada as the registered holder of an Instalment Receipt. Declarations may be required from time to time from registered holders of Instalment Receipts in respect of the name of the beneficial holder of such Instalment Receipts.

Rights and Privileges

The Instalment Receipt and Pledge Agreement confers or imposes upon registered holders of Instalment Receipts the same rights, privileges and limitations as are conferred or imposed upon registered holders of Common Shares, except for certain rights and privileges which are limited under the Instalment Receipt and Pledge Agreement in order to protect the value of the security held by the Custodian in respect of the obligation of the registered holder to pay the final instalment and except where the exercise of such rights and privileges would not be practicable. Subject to compliance with the Privatization Act and with the provisions of the Instalment Receipt and Pledge Agreement, registered holders of Instalment Receipts will be entitled to dividends and distributions on the Underlying Shares and to exercise all voting rights in respect of the Underlying Shares represented by such Instalment Receipts and to receive periodic reports and other materials in like manner as if they were the registered holders of the Underlying Shares.

In particular, the Instalment Receipt and Pledge Agreement will contain the following provisions:

(a) dividends on Common Shares which are payable in cash (other than Excess Dividends, as defined below) shall be remitted to persons who, on the applicable dividend record date in respect of Common Shares, are registered holders of the Instalment Receipts representing such Common Shares. "Excess Dividends" means the amount, if any, by which the aggregate of all cash dividends and Proceeds (as defined below) paid in respect of a Common Share in any calendar quarter commencing July 1, 1992 exceeds $0.25 per calendar quarter calculated on a cumulative basis;

(b) if New NSP declares and pays Excess Dividends payable in cash, such Excess Dividends will be applied in reduction of the final instalment payable on the Underlying Shares in respect of which the Excess Dividends were paid. Any amount by which the Excess Dividend exceeds the amount of the final instalment shall be paid to the registered holders of the Instalment Receipts;

(c) If New NSP distributes to all, or substantially all, of the holders of its Common Shares, dividends payable solely in shares of New NSP ("Stock Dividends"), such Stock Dividends shall be registered in the name of the Custodian and held by the Custodian as security for the obligation of the registered holders of Instalment Receipts to pay the final instalment and, upon payment of the final instalment, shall be registered in the name of the registered holders of the Instalment Receipts together with the Underlying Shares;

(d) If New NSP issues or distributes securities, options, rights or warrants to purchase securities, securities convertible into or exchangeable for securities, property or other assets, whether of New NSP or of any other corporation, distributed or issued by New NSP to all, or substantially all, of the holders of Common Shares, not including cash dividends, Stock Dividends and securities, cash or other property issued or delivered pursuant to any event referred to in paragraph (e) below but including dividends paid in respect of shares of New NSP received as Stock Dividends and property distributed by New NSP in the event of the liquidation, dissolution or winding-up of New NSP or any other distribution of the assets of New NSP among its shareholders for the purpose of winding-up its affairs (collectively "Distributed Property"), the Custodian will as promptly as commercially reasonable sell, on behalf of the registered holders of Instalment Receipts, such Distributed Property attributable to the Underlying Shares. The Custodian shall remit pro rata to the registered holders of the Instalment Receipts the net proceeds ("Proceeds") from such sale unless such Proceeds together with any other cash dividends exceed the threshold of Excess Dividends, in which case such excess amount shall be applied in reduction pro rata of the final instalment on the Underlying Shares. Any amount by which such excess amount exceeds the amount of the final instalment shall be paid to the registered holders of the Instalment Receipts; and

(e) If there is any subdivision, consolidation, reclassification or other change of the Common Shares; a reorganization, amalgamation, arrangement, merger or sale of assets affecting New NSP or to which it is a party; a transfer of all or substantially all of the assets of New NSP; or other similar transaction as a result of which the holders of Common Shares shall be entitled to receive securities, cash or other property in exchange for, in conversion of, or in respect of such Common Shares (an "Arrangement"), the Instalment Receipts shall thereafter represent the right to be registered as the holder of the Underlying Shares as modified by the Arrangement or the securities, property or cash so exchanged, converted or substituted for the Underlying Shares and such securities, property or cash will form part of the security held by the Custodian for the obligation of the registered holders of Instalment Receipts to pay the final instalment.

Charges of Custodian

Registered holders of Instalment Receipts will not be liable for charges and expenses of the Custodian except for any costs for selling Underlying Shares for which the final instalment is not paid and any taxes, duties and other governmental charges which may be payable as described under the heading "Taxation and Compliance with Laws" below. New NSP will pay all charges and expenses of the Custodian other than the amounts described above payable by the registered holders of Instalment Receipts.

Amendment

Apart from corrective changes which do not materially prejudice the registered holders of Instalment Receipts as a group (which may be made without consent of such holders), the Instalment Receipt and Pledge Agreement may not be amended without the affirmative vote of the registered holders of Instalment Receipts entitled to not less than two-thirds of the Common Shares represented by such Instalment Receipts represented and voting at a meeting duly called for the purpose. The procedures for the meeting will be substantially similar to those governing meetings of holders of the Common Shares.

Taxation and Compliance with Laws

The Custodian may require registered holders of Instalment Receipts from time to time to furnish such information and documents as may be necessary or appropriate to comply with any fiscal or other laws relating to Underlying Shares or to the rights and obligations represented by Instalment Receipts. The registered holder of Instalment Receipts and not the Custodian shall be responsible for any taxes, duties, governmental charges or expenses which are or may become payable in respect of the Underlying Shares or Instalment Receipts. In this regard, the Custodian shall be entitled to deduct or withhold from any payment or other distribution required or contemplated by the Instalment Receipt and Pledge Agreement such money or property, in respect of any taxes, duties or other governmental charges or expenses required by applicable law to be withheld or paid, and to withhold delivery of Underlying Shares until satisfactory provision for payment is made.

CERTAIN CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

In the opinion of McInnes Cooper & Robertson, tax counsel to New NSP, and Stewart McKelvey Stirling Scales, counsel to the Underwriters, the following summary presents fairly the principal Canadian federal income tax considerations under the *Income Tax Act* (Canada) (the "Tax Act") generally applicable to a person who purchases Common Shares, including Common Shares purchased on an instalment basis, pursuant to this prospectus and who, for purposes of the Tax Act, (i) holds such shares as capital property, (ii) deals at arm's length with New NSP, with the Province and with the Underwriters, and (iii) is or is deemed to be resident in Canada. This summary is based upon the current provisions of the Tax Act and the regulations thereunder, publicly announced proposed amendments thereto and counsels' understanding of the current administrative policies and practices of Revenue Canada, Taxation. This summary is not exhaustive of all possible Canadian federal income tax considerations and does not deal with provincial, territorial or foreign income tax legislation or considerations and does not take into account or anticipate any possible changes in law, or the administration thereof, whether by legislative, governmental or judicial action, except for publicly announced specific proposed amendments to the Tax Act.

This summary is of a general nature only and is not intended to be, nor should it be construed to be, legal or tax advice to any particular purchaser. Prospective purchasers should consult their own tax advisers with respect to their particular circumstances.

Dividends

Dividends (including Excess Dividends) received on a Common Share, including a Common Share represented by an Instalment Receipt, will be subject to taxation as dividends received from a taxable Canadian corporation. The normal gross-up and dividend tax credit rules will apply to dividends received by an individual and dividends received by a corporation normally will be deductible in computing its taxable income. Certain corporations may be liable to pay a 25 per cent refundable tax under Part IV of the Tax Act in respect of such dividends. The entirety of all dividends (including Excess Dividends) received by the Custodian under the Instalment Receipt and Pledge Agreement in respect of a Common Share represented by an Instalment Receipt shall be treated as having been received by the registered holder of the Instalment Receipt at the time of the receipt thereof by the Custodian irrespective of whether such dividends are remitted by the Custodian to the registered holder of the Instalment Receipt.

Disposition

Upon the disposition or deemed disposition of a Common Share, including a Common Share represented by an Instalment Receipt, a holder will realize a capital gain (or capital loss) to the extent that the proceeds of disposition are greater than (or less than) the aggregate of the adjusted cost base of the Common Share to the holder and any reasonable costs of disposition. In this regard, the adjusted cost base to a holder of a Common Share represented by an Instalment Receipt acquired pursuant to this prospectus will include the aggregate of all amounts paid or payable by the holder for such Common Share, including the amount of the final instalment, and the proceeds of disposition of a Common Share represented by an Instalment Receipt will include the amount of any liability to pay the final instalment which has been assumed by the transferee upon the disposition.

A capital gain realized by a holder who is an individual (other than most trusts) and who is resident in Canada throughout the year in which the individual disposes of a Common Share, including a Common Share represented by an Instalment Receipt, may be eligible for the $100,000 cumulative lifetime capital gains exemption, subject to the limitations and restrictions contained in the Tax Act. In particular, the ability of an individual to claim the exemption from tax in respect of capital gains realized in a particular taxation year will be restricted by the individual's "cumulative net investment loss" as defined in the Tax Act at the end of the year.

If there is a failure to pay the final instalment in respect of a Common Share represented by an Instalment Receipt in accordance with the Instalment Receipt and Pledge Agreement, the holder of the Instalment Receipt may be subject to special rules in the Tax Act relating to mortgage foreclosures and relating to the settlement or extinguishment of debts.

The full amount of capital gains less the portion in respect of which the lifetime capital gains exemption is claimed must be included in a Canadian resident individual's adjusted taxable income for the purposes of computing such individual's liability under the Tax Act for the alternative minimum tax.

PLAN OF DISTRIBUTION

Under an agreement (the "Underwriting Agreement") dated July 29, 1992 among RBC Dominion Securities Inc., Richardson Greenshields of Canada Limited, ScotiaMcLeod Inc., Wood Gundy Inc., Burns Fry Limited, Midland Walwyn Capital Inc., Nesbitt Thomson Inc., Gordon Capital Corporation, Lévesque Beaubien Geoffrion Inc. and J.D. Mack Limited (collectively, the "Underwriters"), the Province and New NSP, New NSP and the Province have agreed to sell and the Underwriters have severally agreed to purchase on August 12, 1992, or on such other date not later than August 28, 1992, as may be agreed upon (the "Closing Date"), subject to the terms and conditions stated in the Underwriting Agreement, all but not less than all of 85,134,666 Common Shares, including Common Shares represented by Instalment Receipts, ($851,346,660) offered hereby.

The Underwriting Agreement provides that it is a condition of the closing of this offering that the Privatization Act be proclaimed and the Reorganization be completed on or before the Closing Date. After giving effect to the Reorganization, the Province will own 20,134,666 Common Shares, representing 100% of the outstanding Common Shares of New NSP. After completion of this offering the Province will have sold pursuant to this prospectus all of its Common Shares.

All of the Common Shares will be offered at a price of $10.00 per Common Share. The price per Common Share is, with respect to Common Shares not sold on an instalment basis, payable to New NSP and the Province by the Underwriters against delivery of the Common Shares. The $10.00 per Common Share is, with respect to Common Shares sold on an instalment basis, payable in instalments consisting of a first instalment of $6.00 per Common Shares payable to New NSP by the Underwriters against delivery of the Common Shares and a final instalment of $4.00 per Common Share payable August 12, 1993 by the registered holders of the Instalment Receipts.

Pursuant to an indemnity agreement (the "Indemnity Agreement") to be dated the date of the closing of this offering, the Underwriters have agreed to indemnify New NSP to the extent that the holders of Instalment Receipts do not pay the final instalment. For this indemnity, New NSP will pay the Underwriters a facilitation fee of one percent of the aggregate amount of the final instalment for all Instalment Receipts (the "Receivable").

Pursuant to a sale and assignment of receivable agreement (the "Sale Agreement") to be dated the date of the closing of this offering, the Province has agreed to purchase the Receivable on the Closing Date at 100% of the amount of the Receivable. No fees will be charged by the Province to New NSP for this purchase. New NSP has also agreed to assign to the Province its rights under the Indemnity Agreement.

In addition to the facilitation fee, the Underwriting Agreement provides for the payment to the Underwriters of a fee of $0.3875 per Common Share sold on an instalment basis and $0.45 per Common Share for all other Common Shares sold by New NSP and the Province for various services relating to the sale of their respective Common Shares. The Underwriters will also receive a fee from New NSP of approximately $35,000 with respect to Common Shares purchased by employees under the Employee Initial Share Purchase Plan. Certain out-of-pocket expenses in connection with this offering are payable by New NSP.

The obligations of the Underwriters under the Underwriting Agreement are several and not joint and may be terminated at their discretion on the basis of their assessment of the state of the financial markets and may also be terminated upon the occurrence of certain stated events. The Underwriters are, however, obligated to take up and pay for all of the Common Shares to be purchased by the Underwriters if any of such Common Shares are purchased. In the event of default by an Underwriter, the commitments of non-defaulting Underwriters may be increased.

Pursuant to policy statements of the Ontario Securities Commission and the Commission des valeurs mobilières du Québec, the Underwriters may not, throughout the period of distribution under this prospectus, bid for or purchase the Common Shares. The foregoing restriction is subject to certain exceptions, as long as the bid or purchase is not engaged in for the purpose of creating actual or apparent active trading in or raising the price of the Common Shares. These exceptions include a bid or purchase permitted under the by-laws and rules of The Toronto Stock Exchange and the Montreal Exchange relating to market stabilization and passive market making activities. In connection with this offering and subject to the foregoing, the Underwriters may over-allot or effect transactions which stabilize or maintain the market price of the Common Shares at levels other than those which might otherwise prevail in the open market. Such transactions, if commenced, may be discontinued at any time.

The Underwriters may form distribution groups consisting of other investment dealers for the purpose of distributing the Common Shares.

New NSP has agreed to indemnify the Province, the Underwriters and the directors, officers and employees of the Underwriters against certain liabilities.

Except in connection with any dividend reinvestment and share purchase plan that may be adopted, New NSP has agreed with the Underwriters that for a period commencing on the date hereof and ending on the 181st day after the closing of this offering, New NSP shall not, without the prior written consent of the Underwriters, issue, sell or agree to issue or sell any Common Shares or any security that is convertible into or exchangeable for Common Shares within such period, or agree to do so or publicly announce the intention to do so.

The offering price for the Common Shares has been determined by negotiation among New NSP, the Province and the Underwriters.

EMPLOYEE INITIAL SHARE PURCHASE PLAN

Under the Employee Initial Share Purchase Plan (the "Plan") eligible participants are permitted to acquire Common Shares, including Common Shares represented by Instalment Receipts, up to an aggregate price of $50,000 under this offering by subscription. Shares purchased pursuant to the Plan are included in determining the maximum 5,000 Common Shares an eligible Nova Scotia resident may purchase. NSP's current regular full-time, regular part-time and term employees are eligible to participate. Employees may also purchase Common Shares, including Common Shares represented by Instalment Receipts, outside the Plan.

Participants may pay for their Common Shares, including Common Shares represented by Instalment Receipts subscribed for under the Plan in cash or, at their option, by way of non-interest bearing loan to a maximum of $5,000 from New NSP repayable over 24 months by payroll deduction. Common Shares, including Common Shares represented by Instalment Receipts purchased by a participant under the Plan by way of non-interest bearing loan will be issued at the closing of this offering, but will be held by the escrow agent of the Plan until the loan has been repaid. Participants will be able to vote their shares and receive dividends while their Common Shares, including Common Shares represented by Instalment Receipts are held in escrow.

If all of NSP's employees participated in the Plan and received the maximum loan of $5,000, approximately $13.1 million of loans would be advanced.

LEGAL MATTERS

The matters referred to under "Eligibility for Investment" and certain other legal matters in connection with this offering will be passed upon on behalf of New NSP by Cox Downie and McInnes Cooper & Robertson and on behalf of the Underwriters by Stewart McKelvey Stirling Scales. Certain legal matters in connection with this offering will be passed upon on behalf of the Province by Patterson Kitz.

MATERIAL CONTRACTS

Except for contracts made in the ordinary course of business, the only material contracts entered into by New NSP within the past two years or to be entered into by New NSP on or before the closing of this offering are:

1. The Instalment Receipt and Pledge Agreement referred to under the heading "Details of the Offering — Eligible Nova Scotia Residents Only";
2. The Underwriting Agreement described under the heading "Plan of Distribution";
3. The Sale Agreement described under the heading "Plan of Distribution";
4. The Indemnity Agreement described under the heading "Plan of Distribution";

5. The asset transfer agreement providing for transfer of assets, assumption of liabilities and other matters described under the heading "New NSP — Asset Transfer";
6. The matching notes agreement and the sinking funds notes agreement between New NSP and Old NSP in respect of notes issued by New NSP and Old NSP described under the heading "New NSP — Matching Notes";
7. The debt restructuring agreement between New NSP and Old NSP described under the heading "New NSP — Debt Restructuring".

Copies of these agreements or drafts thereof may be inspected at the offices of NSP at Scotia Square, 1894 Barrington Street, P.O. Box 910, Halifax, Nova Scotia, B3J 2W5 and at the offices of Davies, Ward & Beck, Suite 4400, 1 First Canadian Place, Toronto, Ontario, M5X 1B1, during ordinary business hours during the period of distribution of the Common Shares offered hereby and for a period of 30 days thereafter.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of New NSP are Ernst & Young, 13th Floor, 1959 Upper Water Street, Halifax, Nova Scotia, B3J 2Z1.

The Transfer Agent and Registrar for the Common Shares will be Montreal Trust Company of Canada at its principal offices located in Halifax, Montreal, Toronto, Winnipeg, Calgary and Vancouver.

PURCHASERS' STATUTORY RIGHTS

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities within two business days after receipt or deemed receipt of a prospectus and any amendment. In several provinces, securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, damages where the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, but such remedies must be exercised by the purchaser within the time limit prescribed by the securities legislation of his or her province. Certain remedies, including statutory rights for rescission or damages, may not be enforceable against the Province or its agents. The purchaser should refer to any applicable provisions of the securities legislation of his or her province for the particulars of these rights or consult with a legal adviser.

FORECAST (NINE MONTHS)

The following Forecasted Statement of Operations and Summary of Significant Forecast Assumptions (the "Forecast") for Nova Scotia Power was prepared by its management in July 1992 and approved by the board of directors on July 6, 1992. The Forecast will be reviewed quarterly by the management of NSP to identify significant changes resulting from events that occur after the Forecast is issued. During the nine month forecast period ending December 31, 1992, each financial report issued to the shareholders will contain either a statement that there is no significant change to be made to the Forecast or an updated forecast accompanied by explanations of significant changes.

The Forecast has been prepared in accordance with the presentation and disclosure standards for forecasts established by The Canadian Institute of Chartered Accountants. The Forecast reflects management's present judgment as to the most probable industry and economic conditions and NSP's intended course of action under these circumstances.

The reader is cautioned that assumptions used in the preparation of the Forecast, although considered reasonable by NSP at the time of preparation, may be proven to be incorrect. The actual results achieved during the forecast period will vary from the Forecast and the variations may be material.

Auditors' Report on Financial Forecast

To The Directors of
NOVA SCOTIA POWER INC.

The accompanying financial forecast of Nova Scotia Power consisting of the forecasted statement of operations for the nine months ending December 31, 1992 has been prepared by management using assumptions with an effective date of July 3, 1992.

We have examined the support provided by management for the assumptions, and the preparation and presentation of this forecast. Our examination was made in accordance with the applicable Auditing Guideline issued by The Canadian Institute of Chartered Accountants. We have no responsibility to update this report for events and circumstances occurring after its date.

In our opinion:

— as at the date of this report, the assumptions developed by management are suitably supported and consistent with the plans of Nova Scotia Power, and provide a reasonable basis for the forecast;

— this forecast reflects such assumptions; and

— this forecast complies with the presentation and disclosure standards for forecasts established by The Canadian Institute of Chartered Accountants.

Since this forecast is based on assumptions regarding future events, actual results will vary from the information presented and the variations may be material. Accordingly, we express no opinion as to whether this forecast will be achieved.

Ernst & Young

Halifax, Canada
July 29, 1992

(Signed) ERNST & YOUNG
Chartered Accountants

Financial Forecast

NOVA SCOTIA POWER

FORECASTED STATEMENT OF OPERATIONS

(After Giving Effect to the Reorganization as of August 10, 1992 and This Offering as of August 12, 1992)
For the Four Months and Ten Days of NOVA SCOTIA POWER CORPORATION (Old NSP)
and the Four Months and 21 days of NOVA SCOTIA POWER INC. (New NSP) Ending December 31, 1992

	Old NSP Four Months and Ten Days ending Aug. 10, 1992	New NSP One Month and 21 Days ending Sept. 30, 1992	New NSP Three Months ending Dec. 31, 1992	Nine Months ending Dec. 31, 1992
	(millions except per share amounts)			
Revenue				
Electric	$228.7	$ 83.5	$179.5	$491.7
Federal Tax Rebate	—	1.9	8.3	10.2
Other	3.0	0.9	1.9	5.8
	231.7	86.3	189.7	507.7
Cost of Operations				
Fuel for Generation	75.0	27.5	65.5	168.0
Power Purchased	0.9	0.3	0.9	2.1
Operating, Maintenance and General	55.9	23.7	37.6	117.2
Grants in Lieu of Taxes	1.7	0.7	1.3	3.7
Depreciation	27.7	10.8	19.6	58.1
	161.2	63.0	124.9	349.1
Income Before Interest and Income Taxes	70.5	23.3	64.8	158.6
Interest	64.0	16.5	29.8	110.3
Income Before Income Taxes	6.5	6.8	35.0	48.3
Income Taxes	—	2.0	8.7	10.7
Net Income	$ 6.5	$ 4.8	$ 26.3	$ 37.6
Earnings per Share		$ 0.06	$ 0.31	

Summary of Significant Forecast Assumptions

The reader is cautioned that assumptions used in the preparation of the Forecast, although considered reasonable by NSP at the time of preparation, may be proven to be incorrect. The actual results achieved during the forecast period will vary from the Forecast and the variations may be material.

The following significant assumptions with an effective date of July 3, 1992 form an integral part of the Forecast and, in the opinion of management, include all significant assumptions upon which it is based. During the forecast period, each financial report issued to the shareholders will contain either a statement that there is no significant change to be made to the Forecast or an updated forecast accompanied by explanations of significant changes.

1. The Reorganization is completed on August 10, 1992 and this offering is completed on August 12, 1992. The net proceeds to New NSP from this offering of $615 million are received on August 12, 1992 in full and are applied to reduce short-term and long-term indebtedness of NSP. This results in an annualized interest saving of $57.3 million of which $22.2 million is included in the four month and 21 day forecast period to December 31, 1992 and $35.1 million is as set out in the pro forma adjustment to the seven month and 10 day period ending August 10, 1992 in the pro forma forecasted statement of operations. This interest saving is calculated by applying an assumed average annual interest rate of 9.3% to the assumed reduction of $615 million of indebtedness of NSP.

2. The forecasted statement of operations is prepared in accordance with the accounting policies expected to be used during the forecast period, which are the same as those used by Old NSP in its most recent audited consolidated financial statements. Refer to summary of significant accounting policies in the consolidated financial statements of Old NSP.
3. There are no material changes in the assets, liabilities, operations or product of New NSP from that of Old NSP other than those disclosed herein.
4. New NSP changes its fiscal year end from March 31 to December 31.
5. New NSP is a taxable Canadian corporation and as such is subject to federal tax. New NSP pays federal income tax of 28% of net income before income taxes and large corporations tax of 0.2% of taxable capital. Of these taxes, 95% is refunded under the Public Utilities Income Tax Transfer Act (Canada) and the Privatization Act. New NSP is exempt from provincial income tax. Refer to Note 2 of "Pro Forma Forecast (Twelve Months)".
6. The average number of Common Shares issued and outstanding for the one month and 21 day period ending September 30, 1992 and the three month period ending December 31, 1992 is 85,134,666 shares.
7. The following operating assumptions are made:
   (a) Energy sales volumes increase 1.8% for the nine months ending December 31, 1992 over the volume for the same nine months of fiscal 1992 of Old NSP.
   (b) Sales are based on rates approved by the PUB effective April 1, 1992, which represented an average 2.1% increase over fiscal 1992 of Old NSP.
   (c) The cost of coal increases 3.8% over the contracted price for fiscal 1992 of Old NSP. The price of heavy fuel oil increases 7.0% over the average price for fiscal 1992 of Old NSP.
   (d) Operating, maintenance and general expense are based on historical trends and changes in expenses required to support the level of revenue assumed during the forecast period, including 3.0% inflation where applicable.
   (e) Depreciation rates remain unchanged from those used in fiscal 1992 by Old NSP.
   (f) The weighted average interest rate on net indebtedness is 10.8% per annum.
   (g) The average exchange rate is one dollar U.S. equals $1.18 Canadian.

COMPILATION REPORT

To the Directors of
NOVA SCOTIA POWER INC.:

We have reviewed, as to compilation only, the accompanying pro forma forecasted statement of operations of Nova Scotia Power for the twelve months ending December 31, 1992 which has been prepared for inclusion in this prospectus. In our opinion, the pro forma forecasted statement of operations has been properly compiled to give effect to the proposed transactions and the assumptions described in the notes thereto.

Ernst & Young

Halifax, Canada
July 29, 1992

(Signed) ERNST & YOUNG
Chartered Accountants

PRO FORMA FORECAST (TWELVE MONTHS)

NOVA SCOTIA POWER

PRO FORMA FORECASTED STATEMENT OF OPERATIONS

For the Twelve Months Ending December 31, 1992
(Unaudited — Refer to "Compilation Report")

	Historical Three Months ended March 31, 1992	Forecasted Nine Months ending Dec. 31, 1992 (1)	Pro Forma Adjustments (Note 2)	Pro Forma Forecasted Year ending Dec. 31, 1992
		(millions except per share amount)		
Revenue				
Electric	$194.8	$491.7		$686.5
Federal Tax Rebate	—	10.2	$ 19.7	29.9
Other	2.4	5.8		8.2
	197.2	507.7		724.6
Cost of Operations				
Fuel for Generation	66.9	168.0		234.9
Power Purchased	1.0	2.1		3.1
Operating, Maintenance and General	40.8	117.2		158.0
Grants in Lieu of Taxes	1.3	3.7		5.0
Depreciation	21.4	58.1		79.5
	131.4	349.1		480.5
Income Before Interest and Income Taxes	65.8	158.6		244.1
Interest	42.2	110.3	(35.1)	117.4
Income Before Income Taxes	23.6	48.3		126.7
Income Taxes	—	10.7	20.7	31.4
Net Income	$ 23.6	$ 37.6		$ 95.3
Earnings per Share (Note 3)				$ 1.12

Notes to Pro Forma Forecasted Statement of Operations

The unaudited pro forma forecasted statement of operations has been prepared by management. In the opinion of management, this statement includes all adjustments necessary for fair presentation. The statement gives effect to the proposed Reorganization of Old NSP and New NSP and the sale and issue of Common Shares described in this prospectus as if they had occurred on January 1, 1992. The purpose of this statement is to illustrate twelve complete months of operating results under the proposed capital structure of New NSP and therefore reflect a complete energy cycle for the business. The major impact is interest savings of $35.1 million reflecting the application of issue proceeds to reduce indebtedness of NSP during the seven month and ten day period ending August 10, 1992.

1. The pro forma forecasted statement of operations includes actual results of Old NSP for the three months ended March 31, 1992 which form part of the audited financial statements for the year ended March 31, 1992. The forecasted amounts for the nine months ending December 31, 1992 include the forecasted results of operations for (i) Old NSP for the four months and ten days ending August 10, 1992 and (ii) New NSP for the four months and 21 days ending December 31, 1992.
2. The pro forma adjustments restate the operating results of Old NSP for the seven month and ten day period ending August 10, 1992 to reflect (i) interest savings of $35.1 million calculated as if $615 million of indebtedness had been repaid on January 1, 1992 with the issue proceeds; and (ii) additional net federal tax adjustment of $1.0 million calculated as follows:

	(millions)
Income for the three months ended March 31, 1992	$23.6
Forecast income for the four months and ten days ending August 10, 1992 (1)	6.5
Interest savings for the seven months and ten days ending August 10, 1992	35.1
Adjusted income before income taxes	$65.2
Income tax expense adjustment ($65.2 million multiplied by the combined income and capital tax rate of 31.7%)	$20.7
Less federal tax rebate adjustment (95%)	19.7
Net federal tax adjustment for the seven months and ten days ending August 10, 1992	$ 1.0

3. Earnings per share is calculated assuming an average number of Common Shares issued and outstanding during the twelve month period ending December 31, 1992 of 85,134,666.

(1) For more information refer to "Forecast (Nine Months)".

COMPILATION REPORT

To the Directors of
NOVA SCOTIA POWER INC. :

We have reviewed, as to compilation only, the accompanying pro forma balance sheet of Nova Scotia Power Inc. as at March 31, 1992 which has been prepared for inclusion in this prospectus. In our opinion, the pro forma balance sheet has been properly compiled to give effect to the proposed transactions and the assumptions described in the notes thereto.

Ernst & Young

Halifax, Canada
July 29, 1992

(Signed) ERNST & YOUNG
Chartered Accountants

NOVA SCOTIA POWER INC.

PRO FORMA BALANCE SHEET
March 31, 1992
(millions)

(Unaudited — Refer to "Compilation Report")

ASSETS

Fixed Assets	
Property, Plant & Equipment in Service	$2,430.3
Less Accumulated Depreciation	731.8
	1,698.5
Construction Work in Progress	402.6
	$2,101.1
Current Assets	
Cash	0.1
Accounts Receivable	67.9
Unbilled Revenue	45.9
Inventories at Cost	69.3
Prepaid Expenses	2.2
	185.4
Deferred Charges less Amortization	36.2
	$2,322.7

LIABILITIES AND EQUITY

Long-Term Notes Payable — Old NSP	$1,395.2
Current Liabilities	
Bank Indebtedness	7.7
Accounts Payable and Accrued Charges	118.5
Customers' Deposits and Accrued Interest	2.3
Accrued Interest on Long-Term Debt	72.6
	201.1
Shareholders' Equity	
Common Shares	650.0
Retained Earnings	76.4
	726.4
	$2,322.7

Refer to accompanying Notes to Pro Forma Balance Sheet.

Approved by the Board:

(Signed) J. A. F. MACDONALD
Director

(Signed) K. C. ROWE
Director

Notes to Pro Forma Balance Sheet

The unaudited pro forma balance sheet has been prepared by management from the audited consolidated financial statements of Old NSP. In the opinion of management, this pro forma balance sheet includes all adjustments necessary for fair presentation. The pro forma balance sheet gives effect to the proposed Reorganization of Old NSP and New NSP and the sale and issue of Common Shares described in this prospectus as if they had occurred on March 31, 1992.

1. Reorganization

The Privatization Act provides for the reorganization of Old NSP and New NSP in order to facilitate this offering of the Common Shares of New NSP.

Pursuant to the Reorganization, which will take place prior to the closing of this offering, all of the assets held by Old NSP, except the sinking fund assets in respect of the public debt of Old NSP, will be transferred to New NSP. Old NSP will retain the sinking fund assets in respect of each series of public debt having a sinking fund and will issue notes (the "Sinking Fund Notes") to New NSP for each such series of public debt retained by Old NSP. Each Sinking Fund Note will be in a principal amount equal to the present book value of the sinking fund assets to which it relates and will bear interest at a rate equal to the yield earned by Old NSP on such sinking fund assets. In consideration for the transfer of the assets and the issuance of the Sinking Fund Notes:

(a) At the direction of Old NSP, New NSP will deliver 20,134,666 Common Shares of New NSP to the Minister of Finance of the Province;

(b) New NSP will issue notes to Old NSP in the principal amount and having substantially the same terms and conditions as the approximately $2,245.4 million principal amount of the long-term public debt of Old NSP, including debt held by the Government of Canada; and

(c) New NSP will assume all other liabilities and commitments of Old NSP, actual, accrued, contingent or otherwise, including short-term debt due to the Province.

For more information refer to "New NSP".

2. Accounting Policies

The pro forma balance sheet has been prepared in accordance with the accounting policies used by Old NSP in the consolidated financial statements. The pro forma balance sheet should be read in conjunction with the consolidated financial statements included in this prospectus.

3. Pro Forma Adjustments

The pro forma balance sheet is based upon the financial information in the March 31, 1992 balance sheet of Old NSP after giving effect to transactions proposed to occur on August 10 and 12, 1992 and reflects the:

(a) transfer of assets of Old NSP to New NSP: $2,322.7 million;

(b) issue by Old NSP to New NSP of Sinking Fund Notes for each series of public debt having a sinking fund, the principal amounts of which will equal the present book value of the sinking fund assets of Old NSP to which they relate;

(c) issue of notes by New NSP to Old NSP in the principal amount and having substantially the same terms and conditions as the long-term public debt of Old NSP, including debt held by the Government of Canada: $2,245.4 million;

(d) assumption by New NSP of the other liabilities of Old NSP, including short-term debt due to the Province of $161.5 million: $362.6 million;

(e) delivery by New NSP of Common Shares to the Minister of Finance of the Province for Old NSP's equity: credited as to retained earnings $111.4 million(1) and to common shares a nominal $1; and

(f) reduction by New NSP of indebtedness of $615 million with the net proceeds to New NSP from this offering consisting of $650 million credited to common shares less $35 million of Underwriters' fees and estimated expenses of issue charged to contributed surplus ($13.3 million) and retained earnings ($21.7 million).

(1) The net assets and equity at August 10, 1992 is anticipated to increase over the March 31, 1992 amounts by $6.5 million, being the forecasted income for the four month and ten day period ending August 10, 1992, as disclosed in the nine month forecasted statement of operations. This will increase the equity to $117.9 million. Refer to "Forecast (Nine Months)".

AUDITORS' REPORTS

To the Board of Directors
Nova Scotia Power Corporation (Old NSP)

We have audited the consolidated balance sheet of Old NSP as at March 31, 1992, and the consolidated statements of operations and retained earnings and changes in cash position for the year then ended. These financial statements are the responsibility of Old NSP's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Old NSP as at March 31, 1992 and the results of its operations and the changes in its financial position for the year then ended in accordance with generally accepted accounting principles.

Ernst & Young

(Signed) ERNST & YOUNG
Chartered Accountants

Halifax, Canada
April 30, 1992

To the Board of Directors
Nova Scotia Power Corporation (Old NSP)

We have audited the consolidated balance sheet of Old NSP as at March 31, 1991, and the consolidated statements of operations and retained earnings and changes in cash position for each of the years in the four year period ended March 31, 1991. These financial statements are the responsibility of Old NSP's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Old NSP as at March 31, 1991 and the results of its operations and the changes in its financial position for each of the years in the four year period ended March 31, 1991 in accordance with generally accepted accounting principles.

Peat Marwick Thorne

(Signed) PEAT MARWICK THORNE
Chartered Accountants

Halifax, Canada
May 31, 1991

CONSOLIDATED FINANCIAL STATEMENTS OF OLD NSP (HISTORICAL)

NOVA SCOTIA POWER CORPORATION (OLD NSP)

CONSOLIDATED BALANCE SHEETS

	March 31 1992	March 31 1991
	(millions)	
ASSETS		
Fixed Assets — Note 5		
Property, Plant and Equipment in Service	$2,430.3	$2,068.4
Less Accumulated Depreciation	731.8	677.0
	1,698.5	1,391.4
Construction Work in Progress	402.6	392.8
	2,101.1	1,784.2
Current Assets		
Cash	0.1	0.2
Accounts Receivable	67.9	64.9
Unbilled Revenue	45.9	45.2
Inventories at Cost	69.3	69.7
Prepaid Expenses	2.2	2.3
	185.4	182.3
Deferred Charges less Amortization	36.2	22.6
	$2,322.7	$1,989.1
LIABILITIES AND EQUITY		
Long-Term Debt — Note 6	$1,757.2	$1,566.1
Current Liabilities		
Bank Indebtedness	7.7	14.7
Accounts Payable and Accrued Charges	118.5	71.5
Customers' Deposits and Accrued Interest	2.3	2.0
Accrued Interest on Long-Term Debt	72.6	65.7
Debt Payable Within One Year	253.0	202.6
	454.1	356.5
Deferred Credits	—	1.4
Equity		
Contributed Surplus	13.3	13.3
Retained Earnings	98.1	51.8
	111.4	65.1
	$2,322.7	$1,989.1

Commitments — Note 7
Subsequent Event — Note 9

Refer to accompanying Notes to Consolidated Financial Statements

Approved by the Board:

(Signed) J. A. F. MACDONALD
Director

(Signed) L. R. COMEAU
Director

NOVA SCOTIA POWER CORPORATION (OLD NSP)

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended March 31				
	1992	1991	1990 (millions)	1989	1988
Revenue					
Electric	$665.1	$628.0	$595.8	$543.3	$502.7
Other	8.6	7.6	6.3	6.6	7.0
	673.7	635.6	602.1	549.9	509.7
Cost of Operations					
Fuel for Generation	224.6	220.8	225.1	206.2	199.1
Power Purchased	3.8	15.9	4.6	8.6	12.7
Operating, Maintenance and General	154.7	140.2	134.7	127.8	116.4
Grants in Lieu of Taxes	5.0	5.0	4.8	4.8	4.8
Depreciation	73.2	63.2	60.0	58.9	52.6
	461.3	445.1	429.2	406.3	385.6
Income before Interest	212.4	190.5	172.9	143.6	124.1
Interest (Note 3)	166.1	166.5	151.9	155.0	151.8
Net Income (Loss)	$ 46.3	$ 24.0	$ 21.0	$(11.4)	$(27.7)

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

	Year Ended March 31				
	1992	1991	1990 (millions)	1989	1988
Balance at Beginning of Year	$51.8	$27.8	$ 6.8	$18.2	$30.8
Net Income (Loss)	46.3	24.0	21.0	(11.4)	(27.7)
	98.1	51.8	27.8	6.8	3.1
Appropriation From Rate Stabilization Reserve (Note 4)	—	—	—	—	15.1
Balance at End of Year	$98.1	$51.8	$27.8	$ 6.8	$18.2

Refer to accompanying Notes to Consolidated Financial Statements

NOVA SCOTIA POWER CORPORATION (OLD NSP)

CONSOLIDATED STATEMENTS OF CHANGES IN CASH POSITION

	Year Ended March 31				
	1992	1991	1990	1989	1988
			(millions)		
Operating Activities:					
Net Income (Loss)	$ 46.3	$ 24.0	$ 21.0	$ (11.4)	$ (27.7)
Items Not Requiring an Outlay of Funds:					
Depreciation	73.2	63.2	60.0	58.9	52.6
Amortization of Deferred Charges	5.5	11.0	3.0	10.6	7.7
Working Capital Changes	51.0	6.2	(8.9)	(2.9)	3.0
Cash Provided By Operating Activities	176.0	104.4	75.1	55.2	35.6
Financing Activities:					
Proceeds From Long-Term Debt Less Discount	524.3	361.4	394.1	209.8	149.7
Repayment of Long-Term Debt	(350.6)	(72.3)	(278.3)	(55.1)	(38.4)
Sinking Fund Redemptions (Payments)	93.4	(20.9)	(15.9)	(16.4)	(15.4)
Earnings on Sinking Funds	(46.1)	(35.6)	(32.2)	(29.8)	(26.1)
Cash Provided By Financing Activities	221.0	232.6	67.7	108.5	69.8
Investing Activities:					
Fixed Asset Expenditures	(390.1)	(329.3)	(216.8)	(106.7)	(102.9)
Increase (Decrease) in Cash Position	6.9	7.7	(74.0)	57.0	2.5
Cash Position (Deficiency) at Beginning of Year	(14.5)	(22.2)	51.8	(5.2)	(7.7)
Cash Position (Deficiency) at End of Year	$ (7.6)	$ (14.5)	$ (22.2)	$ 51.8	$ (5.2)

The components of cash are cash less bank indebtedness.

Refer to accompanying Notes to Consolidated Financial Statements

NOVA SCOTIA POWER CORPORATION (OLD NSP)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

The major accounting policies of Nova Scotia Power Corporation (Old NSP) are presented below to assist the reader in analyzing the consolidated financial statements. These financial statements have been prepared using generally accepted accounting principles the more significant of which are as follows.

Consolidation

The consolidated financial statements include the accounts of Old NSP and its wholly-owned subsidiaries, Nova Scotia Light and Power Company, Limited and Eastern Light & Power Company, Limited.

Regulation

Old NSP has no share capital and is a Crown corporation of the Province of Nova Scotia which is engaged in the production and sale of electric energy, and is regulated by the Board of Commissioners of Public Utilities for the Province of Nova Scotia (PUB) pursuant to the Public Utilities Act. Old NSP is subject to examination of its accounting policies and practices by the PUB; these accounting policies and practices are similar to those being used by other companies in the utility industry.

Revenue

Old NSP records an estimate of revenue for service rendered but not billed to customers.

Property, Plant and Equipment

The property, plant and equipment of Old NSP are recorded at original cost net of contributions in aid of construction. Expenditures for additions, replacements and improvements, which are comprised of direct labour, material, engineering, and related overhead costs, are capitalized whereas repairs and maintenance are charged to operations. Interest on funds used during construction is capitalized monthly at an interest rate which represents the effective cost of capital determined at the preceding fiscal year end. For property, plant and equipment replaced or renewed, the original cost plus removal cost (excluding future removal and site restoration costs) less salvage is charged to accumulated depreciation.

The excess of Old NSP's investment over the book value of subsidiaries and acquired power utilities was $30.2 million. This amount is being amortized on a straight-line basis over terms ranging from 11-30 years. At March 31, 1992, the unamortized value included in the fixed assets of Old NSP was $6.0 million (1991 — $6.9 million).

Depreciation is provided for by Old NSP on the straight-line method, based on the estimated remaining service lives of its depreciable assets. The estimated average service lives for the major categories of plant in service are summarized as follows:

Functions	Average Life in Years
Generation:	
Hydro	62.0
Steam	32.3
Gas Turbine	28.7
Transmission	42.9
Distribution	30.8
General Plant	12.7

Changes in the estimated service lives of fixed assets and in the significant assumptions underlying the estimates of fixed asset removal costs are subject to periodic review. Such changes are implemented on a remaining service life basis from the year the changes can be first reflected in electric service rates. Depreciation expense for the year ended March 31, 1992 includes $0.9 million ($1.1 million for the years ended

NOVA SCOTIA POWER CORPORATION (OLD NSP)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

March 31, 1990 and 1991, $1.2 million for the years ended March 31, 1988 and 1989) representing amortization of the excess of investment over book value of acquired utilities.

Provisions are made for future removal and site restoration costs of thermal generating stations. These provisions are included in depreciation expense and are recorded as a liability as at March 31, 1992 of $8.6 million (1991 — $4.5 million).

Foreign Currency Translation

Foreign currency amounts are translated into Canadian funds substantially in accordance with the temporal method of foreign currency translation, whereby assets and liabilities so denominated are categorized as monetary or non-monetary items as follows:

(a) Monetary items:

Cash, other current assets and liabilities, sinking funds and long-term debt are converted to Canadian dollars at the rate of exchange prevailing at the balance sheet date. The resulting differences between the translation at the original transaction date and the balance sheet date that relates to long-term debt less sinking funds are shown on the balance sheet under deferred charges. All other exchange differences are charged to operations.

Deferred costs are amortized to operations over the remaining life of the debt issue or the period over which the related sinking fund will retire the debt issue, whichever is less.

(b) Non-monetary items:

Fixed assets originally acquired in foreign currencies are translated to Canadian dollars at historical exchange rates.

(c) Revenue and expense items, including interest expense on long-term debt, are reflected in operations at the rate of exchange on the date of the transaction together with any other exchange gains or losses realized from transactions affecting current operations.

Financing Costs

Financing costs are deferred and amortized on a straight-line basis over the life of the debt to which they apply.

Income Tax

Old NSP is a Crown corporation of the Province of Nova Scotia and accordingly is not subject to income taxes.

Sinking Funds

Sinking funds, including those in foreign currencies, consist of securities and cash held by Old NSP and trustees for the redemption of certain debt issues. Old NSP may satisfy its annual sinking fund obligations by purchasing bonds of Old NSP on the open market at any time prior to the due date.

2. Electric Revenue

Electric service is provided to the Province of Nova Scotia and its agencies at the appropriate class rates as approved by the PUB.

NOVA SCOTIA POWER CORPORATION (OLD NSP)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

3. Interest

	Year Ended March 31				
	1992	1991	1990	1989	1988
			(millions)		
Interest on Long-Term Debt	$250.9	$205.0	$194.1	$174.7	$168.3
Amortization of Financing Costs	3.7	2.1	3.4	2.8	2.3
Interest on Short-Term Debt	5.7	16.7	4.9	2.8	0.6
Foreign Exchange Costs	2.7	11.2	2.7	10.6	20.0
	263.0	235.0	205.1	190.9	191.2
Less					
Interest Charged to Construction	41.1	26.9	9.8	2.9	9.6
Sinking Fund Earnings	46.1	35.6	32.2	29.8	26.1
Other Investment Income	9.7	6.0	11.2	3.2	3.7
	96.9	68.5	53.2	35.9	39.4
	$166.1	$166.5	$151.9	$155.0	$151.8

4. Rate Stabilization Reserve

In fiscal 1980, Old NSP established a rate stabilization reserve to protect customers from increases in the cost of electric service. Appropriations from the reserve were made to retained earnings to offset operating losses until the reserve was depleted in fiscal 1988.

5. Fixed Assets

	1992		
	Property, Plant and Equipment in Service	Accumulated Depreciation	Construction Work in Progress
		(millions)	
Generating Stations			
Steam and Gas Turbine	$ 980.0	$284.8	$335.2
Hydro	260.2	79.7	0.8
Transmission	414.4	116.7	44.8
Distribution	635.6	200.4	8.4
General Plant	140.1	50.2	13.4
	$2,430.3	$731.8	$402.6

	1991		
	Property, Plant and Equipment in Service	Accumulated Depreciation	Construction Work in Progress
		(millions)	
Generating Stations			
Steam and Gas Turbine	$ 723.6	$262.5	$331.6
Hydro	257.8	76.1	0.2
Transmission	372.1	106.7	39.7
Distribution	594.1	187.7	5.9
General Plant	120.8	44.0	15.4
	$2,068.4	$677.0	$392.8

NOVA SCOTIA POWER CORPORATION (OLD NSP)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

6. Long-Term Debt (1)

	1992	1991
	(millions)	
Bonds and Debentures	$1,810.6	$1,657.1
Notes		
Province of Nova Scotia	164.8	74.1
Government of Canada	34.8	37.5
	2,010.2	1,768.7
Less Payable Within One Year	253.0	202.6
	$1,757.2	$1,566.1

(1) Amounts shown are net of sinking fund balances.

Bonds, debentures and notes payable, which are guaranteed by the Province of Nova Scotia, are expressed in Canadian dollars at balance sheet date. A number of the bond and debenture issues are redeemable prior to maturity at the option of Old NSP. Bonds, debentures and notes are summarized by years of maturity and by currency in which they are payable in the following table:

	1992				1991	
Years of Maturity	Principal Outstanding			Weighted Average Coupon Rate	Principal Outstanding	Weighted Average Coupon Rate
	Canadian	Foreign	Total	%	Total	%
	(millions)				(millions)	
1992					$ 226.2	
1993	$ 283.8	$ —	$ 283.8		122.3	
1994	12.1	—	12.1		12.5	
1995	14.7	4.5	19.2		19.4	
1996	103.7	—	103.7		103.7	
1997	23.7	47.6	71.3		—	
1-5 Years	438.0	52.1	490.1	9.96	484.1	11.00
6-10 Years	281.4	35.7	317.1	9.70	313.4	9.61
11-15 Years	449.8	—	449.8	11.63	559.4	11.21
16-20 Years	3.7	89.2	92.9	9.54	91.5	9.52
21-25 Years	350.0	—	350.0	11.09	350,3	11.09
26-30 Years	150.0	357.0	507.0	9.65	215.7	10.25
31-40 Years	200.0	—	200.0	11.00	200.0	11.00
	1,872.9	534.0	2,406.9	10.63	2,214.4	10.75
Less Sinking Funds	283.2	113.5	396.7		445.7	
	$1,589.7	$420.5	$2,010.2		$1,768.7	
Currency Payable:						
Canadian Dollars			$1,589.7		$1,626.7	
United States Dollars			420.5		78.0	
Swiss Francs			—		64.0	
			$2,010.2		$1,768.7	

NOVA SCOTIA POWER CORPORATION (OLD NSP)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The portion of the long-term maturities of principal which has not already been provided for by sinking funds, and additional sinking fund requirements, including those in foreign currencies translated to Canadian currency at March 31, 1992 and 1991 are as follows:

	1992	1991
	(millions)	
1992	$ —	$202.6
1993	253.0	108.4
1994	33.4	27.0
1995	36.0	30.9
1996	109.8	118.1
1997	45.0	—
	477.2	487.0

7. Commitments

At March 31, 1992, Old NSP was constructing generation, transmission and other facilities estimated to cost approximately $656 million of which approximately $454 million has been expended and an additional $58 million has been committed under contract. The remaining $144 million is estimated to be committed and spent in future years in order to complete the construction program.

8. Pension Plans

Regular employees of Old NSP are covered by the Public Service Superannuation Plan of the Province of Nova Scotia, which is a defined benefit multi-employer plan under which contributions are made equally by Old NSP and the employees. Contributions to this plan of $4.3 million, $4.6 million, $5.0 million, $5.5 million and $5.7 million for the years ended March 31, 1988 to 1992 respectively were expensed (See Note 9).

Old NSP provides pension benefits to employees of acquired utilities, additional to those which are payable under the existing plans for years of service prior to acquisition. Pension expense for these plans totalled $1.5 million, $2.1 million, $2.0 million, $1.6 million and $1.7 million for the years ended March 31, 1988 to 1992, respectively. Based on the most recent actuarial valuations completed as of December 31, 1989, extrapolations of both the present value of the accrued pension benefits, and the market value of the net assets available to provide for these benefits are as disclosed in the following table.

	1992	1991
	(millions)	
Accrued Benefits	$56.3	$58.0
Pension Fund Assets	41.9	39.4
Unfunded Pension Liability	$14.4	$18.6

9. Subsequent Event

On January 9, 1992 the Province of Nova Scotia announced its decision to privatize the operations of Old NSP. Legislation introduced by the Province of Nova Scotia on April 16, 1992 provides for a reorganization to give effect to the creation of a public company ("New NSP") to carry on the operations of Old NSP.

NOVA SCOTIA POWER CORPORATION (OLD NSP)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Under the planned privatization, the assets of Old NSP, except for the sinking fund assets in respect of the public debt of Old NSP, will be transferred to New NSP. Old NSP will retain the sinking fund assets in respect of each series of public debt having a sinking fund and will issue notes (the "Sinking Fund Notes") to New NSP for each series of public debt retained by Old NSP. Each Sinking Fund Note will be in a principal amount equal to the present book value of the sinking fund assets to which it relates. In consideration for the transfer of the assets and the issuance of the Sinking Fund Notes:

a) At the direction of Old NSP, New NSP will deliver Common Shares to the Minister of Finance of the Province of Nova Scotia;

b) New NSP will issue notes to Old NSP in the principal amount and having substantially the same terms and conditions as the principal amount of the public debt of Old NSP, including debt held by the Government of Canada; and

c) New NSP will assume all other liabilities and commitments of Old NSP.

New NSP will issue, pursuant to a public offering, shares to the public. Old NSP will continue to be a wholly-owned Crown corporation of the Province of Nova Scotia.

DEBT BY ISSUE (HISTORICAL)
(Unaudited)

The following table sets forth details of the long-term debt of Old NSP:

Series	Date of Issue	Date of Maturity	Interest Rate	At March 31, 1992	Call and Other Provisions (1)
			Debentures		
AD	Aug. 10, 1982	Aug. 10, 1992	16.750%	$ 73,430,000	Non-callable
E	Nov. 15, 1972	Nov. 15, 1992	8.125	30,000,000	(b)
J	May 1, 1974	May 1, 1994	8.375	4,521,621	Non-callable (e) (2)
K	Jul. 1, 1974	Jul. 1, 1994	9.500	948,000	(f)
AL	Oct. 24, 1990	Oct. 24, 1995	11.850	100,000,000	Non-callable
D	Mar. 15, 1972	Mar. 15, 1997	7.750	47,596,000	(d) (2)
D002	Jul. 7, 1987	Jul. 7, 1997	10.250	9,573,500	Non-callable (h)
G	Jul. 15, 1973	Jul. 15, 1998	8.125	35,697,000	(d) (2)
X	Dec. 21, 1978	Dec. 21, 1998	10.000	50,000,000	(g)
Z	Jan. 4, 1980	Jan. 4, 2000	11.250	50,000,000	(a)
M	Mar. 1, 1976	Mar. 1, 2001	10.000	50,000,000	(a)
O	Oct. 21, 1976	Oct. 21, 2001	9.750	50,000,000	(a)
P	Nov. 1, 1976	Nov. 1, 2001	9.750	5,000,000	(a)
Q	Feb. 22, 1977	Feb. 22, 2002	9.250	50,000,000	(a)
R	Feb. 22, 1977	Feb. 22, 2002	9.250	5,000,000	(a)
S	Jul. 21, 1977	Jul. 21, 2002	9.250	50,000,000	(a)
T	Jul. 21, 1977	Jul. 21, 2002	9.250	5,000,000	(a)
U	Dec. 1, 1977	Dec. 1, 2002	9.450	15,000,000	(a)
AE	Dec. 1, 1982	Dec. 1, 2002	13.500	100,000,000	(b)
V	Jan. 10, 1978	Jan. 10, 2003	9.375	50,000,000	(a)
AF	Dec. 20, 1983	Dec. 20, 2003	12.500	75,000,000	(b)
AG	Feb. 14, 1985	Feb. 14, 2005	12.125	100,000,000	(c)
AA	Jul. 15, 1980	Jul. 15, 2005	11.500	50,000,000	(a)
W	Jun. 1, 1978	Jun. 1, 2008	9.625	89,242,500	(d) (2)
AH	Nov. 15, 1988	Nov. 15, 2012	10.875	150,000,000	Non-callable
AJ	Apr. 27, 1989	Apr. 27, 2014	11.250	200,000,000	Non-callable
AK	Jan. 10, 1990	Jan. 10, 2020	10.250	150,000,000	Non-callable
AN	Apr. 1, 1991	Apr. 1, 2021	9.400	356,970,000	Non-callable (2)
AM	Feb. 26, 1991	Feb. 26, 2031	11.000	200,000,000	Non-callable
				2,152,978,621	

Non-Callable Savings Bonds (3)

Series	Date of Issue	Date of Maturity	Interest Rate	At March 31, 1992
SB02	July 7, 1987	July 7, 1992	9¼%	14,595,700
SB03	Aug. 8, 1988	Aug. 8, 1993	9½	8,643,800
SB04	Aug. 8, 1989	Aug. 8, 1994	10	11,168,900
SB05	July 8, 1991	July 8, 1996	9	19,925,700
				54,334,100

Long-Term Callable Notes Payable to the Government of Canada (4)

Series	Years of Loans	Years of Maturity	Interest Rate	At March 31, 1992
1 to 55	1961 to 1972	1996 to 2012	5 - 10.258%	34,793,192

Long-Term Non-Callable and Short-Term Notes Payable to the Province (5)

Long-Term Notes Payable

Series	Date of Maturity	Interest Rate	At March 31, 1992
6W-1	Nov. 30, 1992	9.168%	150,017
6W	Nov. 30, 1993	9.168	138,768
7D	Nov. 30, 1993	7.710	208,392
CP14	Nov. 30, 1995	8.550	224,974
CP15	Nov. 30, 1995	10.000	291,982
7L	Nov. 30, 1996	9.650	174,242
CP16	Nov. 30, 1997	9.450	899,420
7J	Nov. 30, 1997	9.750	364,648
7S	Nov. 30, 1998	10.350	859,905
			3,312,348
Short-Term Notes Payable			161,500,000
			164,812,348
Total Debt			$2,406,918,261

(1) Call and Other Provisions

(a) Redeemable as a whole five years prior to maturity at par plus accrued interest.

(b) Redeemable as a whole two years prior to maturity at par plus accrued interest.

(c) Redeemable as a whole three years prior to maturity at par plus accrued interest.

(d) Redeemable in whole, or in part by lot, fifteen years after date of issue at various declining premiums to par in the last year prior to maturity.

(e) Redeemable in whole or in part at the option of the holder, eight years prior to maturity at par.

(f) Redeemable at the option of the holder 13 years prior to maturity or any year thereafter at par; redeemable at the option of Old NSP in whole or in part by lot in amounts of $1,000,000 or multiples thereof, 10 years after the date of issue at various declining premiums to July 1, 1991 and thereafter at par to maturity.

(g) Redeemable, at any time, on or after December 21, 1993, in whole but not in part, at the option of Old NSP at various declining premiums to par two years prior to maturity.

(h) Not redeemable prior to maturity except in the event of death of the holder.

(2) Denominated in U.S. dollars as follows:

Series D	U.S.	$ 40,000,000
Series G		30,000,000
Series J		3,800,000
Series W		75,000,000
Series AN		300,000,000
	U.S.	$448,800,000

The Canadian dollar equivalent at March 31, 1992 totals $534,027,121.

(3) Savings bonds are redeemable in whole or in part at the option of the holder upon presentation to the Registrar 30 days prior to each annual interest payment date, or at any time in the event of death of the holder.

(4) Under an agreement dated February 20, 1958 between the Government of Canada and the Province, Northern Canada Power Commission, a federal agency, made available to Old NSP long-term financing, as set forth above, for the construction of coal-fired thermal generating stations and high voltage transmission facilities. The notes are repayable in equal annual instalments on March 31, which include principal and interest.

(5) Notes payable to the Province are repayable in equal annual instalments which include both principal and interest.

CERTIFICATE OF NEW NSP

Dated: July 29, 1992

The foregoing constitutes full, true and plain disclosure of all material facts relating to the securities offered by this prospectus as required by Part 7 of the Securities Act (British Columbia), by Part 8 of the Securities Act (Alberta), by Part XI of The Securities Act (Saskatchewan), by Part VII of The Securities Act (Manitoba), by Part XV of the Securities Act (Ontario), by Section 13 of the Securities Act (New Brunswick), by the Securities Act (Nova Scotia), by Part II of the Securities Act (Prince Edward Island) and by Part XIV of The Securities Act, 1990 (Newfoundland), and the respective regulations thereunder. This prospectus does not contain any misrepresentation likely to affect the value or the market price of the securities to be distributed, within the meaning of the Securities Act (Québec).

(Signed) LOUIS R. COMEAU
Chief Executive Officer

(Signed) GARY K. OICKLE
Chief Financial Officer

On behalf of the Board of Directors

(Signed) J. A. F. MACDONALD
Director

(Signed) K. C. ROWE
Director

CERTIFICATE OF THE UNDERWRITERS

Dated: July 29, 1992

To the best of our knowledge, information and belief, the foregoing constitutes full, true and plain disclosure of all material facts relating to the securities offered by this prospectus as required by Part 7 of the Securities Act (British Columbia), by Part 8 of the Securities Act (Alberta), by Part XI of The Securities Act (Saskatchewan), by Part VII of The Securities Act (Manitoba), by Part XV of the Securities Act (Ontario), by Section 13 of the Securities Act (New Brunswick), by the Securities Act (Nova Scotia), by Part II of the Securities Act (Prince Edward Island) and by Part XIV of The Securities Act, 1990 (Newfoundland), and the respective regulations thereunder. To our knowledge, this prospectus does not contain any misrepresentation likely to affect the value or the market price of the securities to be distributed, within the meaning of the Securities Act (Québec).

RBC DOMINION SECURITIES INC.

By: DEREK BROWN

RICHARDSON GREENSHIELDS OF CANADA LIMITED	SCOTIAMcLEOD INC.	WOOD GUNDY INC.
By: GEORGE RATNER	By: DONALD A. CARMICHAEL	By: DAVID G. LEITH
BURNS FRY LIMITED	MIDLAND WALWYN CAPITAL INC.	NESBITT THOMSON INC.
By: A. FLETCHER MCLAUGHLIN	By: ROBERT H. GRIMARD	By: M. MICHAEL MACKASEY
GORDON CAPITAL CORPORATION	LÉVESQUE BEAUBIEN GEOFFRION INC.	J.D. MACK LIMITED
By: DOUGLAS E. TURNBULL	By: ROBERT A. PETERS	By: J. DAVID MACK

The following includes the names of all persons having an interest, either directly or indirectly, to the extent of not less than 5% in the capital of:

RBC DOMINION SECURITIES INC.: RBC Dominion Securities Limited, a majority-owned subsidiary of a Canadian chartered bank;

RICHARDSON GREENSHIELDS OF CANADA LIMITED: wholly-owned by Richardson Greenshields Limited;

SCOTIAMCLEOD INC.: a wholly-owned subsidiary of a Canadian chartered bank;

WOOD GUNDY INC.: a wholly-owned subsidiary of The CIBC Wood Gundy Corporation, a majority-owned subsidiary of a Canadian chartered bank;

BURNS FRY LIMITED: wholly-owned by Burns Fry Holdings Corporation;

MIDLAND WALWYN CAPITAL INC.: a wholly-owned subsidiary of Midland Walwyn Inc.;

NESBITT THOMSON INC.: wholly-owned by The Nesbitt Thomson Corporation Limited;

GORDON CAPITAL CORPORATION: Gordon Investment Corporation, N. W. Baker, J. R. Connacher, G. H. Eberts, R. A. Fung, J. N. Green and R. Li;

LÉVESQUE BEAUBIEN GEOFFRION INC.: a wholly-owned subsidiary of Lévesque, Beaubien and Company Inc., a majority-owned subsidiary of a Canadian chartered bank; and

J.D. MACK LIMITED: J. David Mack, David K. Beazley, Bruce E. Clarke, Morton J. Small and Laurie B. Stevens.

Nova Scotia Power Inc.

Nova Scotia Power Incorporated

2011 Annual Information Form

March 29, 2012

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NOTE: The information presented in this Annual Information Form is as of December 31, 2011, unless otherwise specified.

DEFINITIONS

For convenience, terms used throughout this 2011 Annual Information Form of Nova Scotia Power Incorporated shall have the following meanings:

"AIF" means this 2011 Annual Information Form of NSPI;

"Bangor Hydro" means Bangor Hydro Electric Company, an electric utility company incorporated under the laws of the State of Maine and a wholly-owned subsidiary of Emera;

"Board" means the Board of Directors of NSPI;

"CEA" means the Canadian Electricity Association;

"CEO" means the President and Chief Executive Officer of NSPI:

"CFO" means the Chief Financial Officer of NSPI;

"CGAAP" means Canadian Generally Accepted Accounting Principles from time to time approved by the Canadian Institute of Chartered Accountants, or any successor institute;

"CRA" means Canada Revenue Agency;

"Capital Plan" means NSPI's Annual Capital Expenditure Plan filed annually with the UARB;

"Company" means NSPI;

"Computershare" means Computershare Trust Company of Canada;

"DBRS" means the credit rating agency Dominion Bond Rating Service Limited;

"DSM" means demand side management;

"Directors" means the directors of NSPI;

"EMS" means environmental management systems;

"ENSC" means Efficiency Nova Scotia Corporation;

"Emera" means Emera Incorporated, a company incorporated under the laws of the Province of Nova Scotia and the parent company of NSPI;

"FAM" means the fuel adjustment mechanism established by the UARB;

"GHG" means greenhouse gases;

"GWh" means gigawatt hours;

"IFRS" means International Financial Reporting Standards;

"IPPs" means independent power producers;

"IRP" means the Integrated Resource Plan filed with the UARB in 2007 and updated in November 2009;

"ISO 14001" means the international standard developed by the International Organization for Standardization on environmental management. For more information see www.iso.org;

"KV" means the amount of electric potential measured in kilovolts;

"LED" means light-emitting diode;

"MD&A" means NSPI's Management's Discussion and Analysis for the fiscal year ended December 31, 2011, a copy of which is available electronically at www.sedar.com under NSPI's profile;

"MMBTU" means one million British thermal units;

"MRCCR" means NSPI's Management Resources, Compensation and Corporate Responsibility Committee;

"MW" means the amount of power measured in mega-watts;

"Market Price" has the meaning as set out in the section entitled "Capital Structure – Series D First Preferred Shares";

"NPCC" means Northeast Power Coordinating Council, Inc.;

"NPNS" means normal purchase and normal sale;

"NSPI" means Nova Scotia Power Incorporated, an electric utility company incorporated under the laws of the Province of Nova Scotia and a wholly-owned subsidiary of Emera;

"NewPage" means NewPage Port Hawkesbury Corp., a company incorporated under the laws of the Province of Nova Scotia;

"OpenHydro" means OpenHydro Group Limited, a company incorporated under the laws of Ireland;

"Officers" means the executive officers of NSPI;

"Order" means a cease trade order, an order similar to a cease trade order or an order that denies a company access to any exemption under securities legislation that is in effect for a period of more than thirty (30) consecutive days;

"Province" means the Province of Nova Scotia and includes, when the context requires, the provincial government of Nova Scotia, and "provincial" refers to Nova Scotia;

"*Public Utilities Act*" means the *Public Utilities Act* (Nova Scotia);

"RES" means the Province of Nova Scotia's Renewable Energy Standards, viewable at www.gov.ns.ca/energy/renewables/renewable-energy-standard;

"RESL" means Renewable Energy Services Ltd.;

"ROE" means return on equity;

"Rating Agencies" means collectively, DBRS and S&P, and a "Rating Agency" means one of the Rating Agencies;

"S&P" means the credit rating agency Standard & Poor's, a division of The McGraw-Hill Companies, Inc.;

"SEC" means the U.S. Securities and Exchange Commission;

"Series D First Preferred Shares" means the 5.90% cumulative redeemable first preferred shares, series D of NSPI;

"Stock Option Plan" means the Senior Management Stock Option Plan of Emera;

"TSX" means The Toronto Stock Exchange;

"UARB" means the Nova Scotia Utility and Review Board, a regulator of NSPI;

"U.S." means the United States of America;

"USD $" means U.S. dollar(s);

"USGAAP" means the accounting principles which are recognized as being generally accepted and which are in effect from time to time in the U.S. as codified by the Financial Accounting Standards Board, or any successor institute;

All amounts are in Canadian dollars ("CAD") except where otherwise stated.

Reference to "including" or "includes" means "including (or includes) but is not limited to" and shall not be construed to limit any general statement preceding it to the specific or similar items or matters immediately following it.

INTRODUCTION

NSPI is an electricity generation, transmission and distribution company with approximately $3.9 billion of assets providing service to 493,000 customers in the Province of Nova Scotia. NSPI operates as a monopoly in its service territory. The essential nature of the services provided, the monopoly position, and the regulated market structure mean that NSPI can generally be expected to produce stable earnings streams within regulated ranges.

For more information on the business operations of NSPI, see "Description of the Business" below.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING INFORMATION

This AIF, including the documents incorporated herein by reference, contains "forward-looking information" within the meaning of Canadian Securities laws and "forward-looking statements" within the meaning of the *United States Private Securities Litigation Reform Act* of 1995 (collectively, "forward-looking information"). The words "anticipates", "believes", "budget", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words.

The forward-looking information in this AIF, including the documents incorporated by reference, includes statements which reflect the current view with respect to NSPI's objectives, plans, financial and operating performance, business prospects and opportunities. The forward-looking information reflects NSPI management's current beliefs and is based on information currently available to NSPI's management and should not be read as a guarantee of future events, performance or results, and will not necessarily be accurate indications of whether, or the times of which, such events, performance or results will be achieved.

The forward-looking information in this AIF, including the documents incorporated herein by reference, includes statements regarding: NSPI's earnings and cash flow; the growth and diversification of NSPI's business and earnings base; NSPI's expected compliance with the regulation of its operations; NSPI's environmental initiatives and expected compliance with federal and provincial standards; the completion of announced acquisitions; the expected timing of regulatory decisions; forecasted gross capital expenditures; the nature, timing and costs associated with certain capital projects; the expected impacts on NSPI of challenges in the global economy; estimated energy consumption rates; expectations related to annual operating cash flows; the expectation that NSPI will continue to have reasonable access to long-term capital in the near to medium terms; expected debt maturities and repayments; expectations about increases in interest expense and/or fees associated with credit facilities; and no material adverse credit rating actions being expected in the near term.

The forecasts and projections that make up the forward-looking information are based on reasonable assumptions which include: the receipt of applicable regulatory approvals and requested rate decisions; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major events; the continued ability to maintain transmission and distribution systems to ensure their continued performance; no severe and prolonged downturn in economic conditions; sufficient liquidity and capital resources; the continued ability to hedge exposures to fluctuations in interest rates, foreign exchange rates and commodity prices; no significant variability in interest rates; the continued competitiveness of electricity pricing when compared with other alternative sources of energy; the continued availability of commodity supply; the absence of significant changes in government energy plans and environmental laws that may materially affect the operations and cash flows of NSPI; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; no material decrease in market energy sales prices; favourable labour relations; and sufficient human resources to deliver service and execute the capital program.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ from current expectations include: commodity price and availability risk; foreign exchange risk; commercial relationship risk; labour risk; credit risk; weather; interest rate risk; environmental risks; operational risks; capital market risks including economic conditions, cost of financing, capital resources and liquidity risk; and construction and development risks. For additional information with respect to NSPI's risk factors, reference should be made to the section of this AIF entitled "Risk Factors".

Readers are cautioned not to place undue reliance on forward-looking information as actual results could differ materially from the plans, expectations, estimates or intentions and statements expressed in the forward-looking information. All forward-looking information in this AIF and in the documents incorporated herein by reference is qualified in its entirety by the above cautionary statements and, except as required by law, NSPI undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise.

CORPORATE STRUCTURE

Name and Incorporation

NSPI was incorporated on July 13, 1984 pursuant to the *Companies Act (*Nova Scotia). NSPI's principal, head and registered office is located at 1223 Lower Water Street, Halifax, Nova Scotia, B3J 3S8.

NSPI is the largest operating subsidiary of Emera, a company incorporated under the laws of Nova Scotia. NSPI and its predecessor companies have been producing and supplying electricity in Nova Scotia for more than 80 years.

Intercorporate Relationship

NSPI is the primary electricity supplier in Nova Scotia and is a subsidiary of Emera, a Canadian energy and services company.

GENERAL DEVELOPMENT OF THE BUSINESS

The following discussion summarizes key developments in NSPI's business and operations over the last three completed financial years.

UARB Decision on 2012 Fuel Adjustment Mechanism

On December 19, 2011, the UARB approved NSPI's customer rates associated with the 2012 FAM adjustment related to the recovery of prior period fuel costs. The recovery of these costs began January 1, 2012. The approved customer rates seek to recover $69.0 million of prior years' unrecovered fuel costs in 2012.

2012 General Rate Application

On November 29, 2011, the UARB announced its decision regarding NSPI's general rate application. NSPI filed a general rate application on May 13, 2011 requesting an average 7.3% rate increase across all customer classes effective January 1, 2012. In September 2011, NSPI and certain of its customer representatives announced a proposed settlement regarding 2012 electricity rates being increased on average by 5.1% which was subject to UARB approval. Rates were approved by the UARB based on a 9.2% ROE, applied to a 37.5% common equity component with a target earnings range of 9.1% to 9.5% on maximum actual equity of 40%.

NewPage Port Hawkesbury Corp.

On September 9, 2011, NewPage, NSPI's largest customer, was granted creditor protection under the *Companies' Creditors Arrangement Act* (Nova Scotia). On September 7, 2011, NewPage Group Inc., NewPage's parent company, commenced a voluntary case under Chapter 11 of the United States Bankruptcy Code. NewPage has suspended operations and is actively seeking a buyer for its Port Hawkesbury, Nova Scotia operations. In light of the uncertainty inherent in this situation, the general rate application decision discussed above under the heading "2012 General Rate

Application" provides for any unrecovered non-fuel electric charges in 2012 related to this customer to be deferred and recovered beginning in 2013. NewPage was also responsible for the engineering, procurement and construction of a 60 MW biomass facility 100% owned by NSPI but located at the mill site. NSPI is proceeding with this project and has assumed full project management responsibilities. For more information, see "Renewable Energy Projects – Port Hawkesbury Biomass Project" below.

Deferral of Certain Tax Benefits relating to Renewable Energy Projects

On July 21, 2011, the UARB approved an agreement that NSPI reached with stakeholders regarding a tax deferral of $14.5 million of tax benefits related to renewable energy projects previously approved by the UARB on December 23, 2010. Pursuant to the agreement, the deferral of the tax benefits was applied against the FAM effective January 1, 2011 and reduced the amount of the FAM balance outstanding, with the reduction applied to the amount that will otherwise be recovered from customers in 2012.

Depreciation Settlement

On May 11, 2011, the UARB approved changes to NSPI's depreciation rates following NSPI's completion of a depreciation study and a settlement agreement with stakeholders. The overall impact on the average depreciation rate is not material. The new depreciation rates are effective January 1, 2012 following approval of the 2012 general rate application referred to above.

History of FAM Rate Adjustments to December 31, 2011

The UARB established the FAM for NSPI in December 2007. The FAM took effect on January 1, 2009, and includes a formal regulatory process to make annual rate adjustments starting in 2010 that reflect actual increases or decreases in the cost of fuel during the previous year. The FAM allows NSPI to recover all prudently incurred fuel costs from customers.

On November 13, 2009, NSPI asked the UARB to approve a reduction in the fuel costs customers would pay in 2010 under the FAM. The UARB approved the request on December 9, 2009, as a result of which residential customers saw a rate decrease of 1.4% starting January 1, 2010. For commercial customers, the decrease ranged from 1.4 to 2.1%, and 2.0 to 3.3% for industrial customers, depending on rate class. The total rebate to customers was $22 million.

On November 12, 2010, NSPI asked the UARB to approve an increase in the fuel costs customers would pay in 2011 under the FAM. The UARB approved the request on December 8, 2010, deferring recovery of 2010 FAM costs over a three year period. As a result of the UARB's decision, residential customers saw a rate increase of 3.6% starting January 1, 2011. For commercial customers, the increase ranged from 3.7 to 5.3 %, and 4.8 to 6.8 % for industrial customers, depending on rate class. The total increased recovery from customers was $30.5 million in 2011.

On December 8, 2010, the UARB allowed NSPI to set its 2011 base cost of fuel and its recovery of unrecovered fuel related costs as submitted in NSPI's November, 2010 filing. The recovery of these costs began January 1, 2011. The UARB approved the recovery of these costs by NSPI over three years, with 50% of the deferred costs to be recovered in 2011, 30% in 2012 and 20% in 2013. The decision resulted in an average rate increase of approximately 4.3% for customers in 2011. Pursuant to the FAM's Plan of Administration, NSPI is entitled to the unrecovered balance of fuel related costs.

The rate changes noted above relate only to those affected by the FAM. The net change in rates experienced by customers is also affected by changes in DSM charges and general rates.

Environmental Regulations – Canada

Greenhouse Gas

On August 19, 2011, Environment Canada announced proposed regulations for a new national GHG framework for the electricity sector in Canada. These proposed regulations would apply to new coal-fired electricity generation units and existing coal-fired electricity generation units once they have reached the end of their deemed economic life. These proposed regulations are expected to be published in 2012. On March 19, 2012 the governments of Canada and Nova Scotia announced that they are working towards an equivalency agreement on coal-fired electricity GHG regulations to avoid duplication of efforts to control GHG emissions. An equivalency agreement would see the provincial rules take precedence over the federal rules, as long as the provincial regulations achieve an equivalent environmental outcome. Nova Scotia's existing GHG regulations require reductions of 25% in GHG emissions in the electricity sector by 2020. The Province plans to develop additional, increasingly stringent milestones between 2020 and 2030 to match the federal targets. NSPI is reviewing the implications of this federal framework and its alignment with its current operating plans under existing Nova Scotia regulations.

Environmental Regulations – Nova Scotia

Biomass Cap

On April 11, 2011, the Nova Scotia government announced that the cap on the annual amount of new forest biomass that can be used to generate electricity will be lowered by 30% to 350,000 dry tonnes per year. NSPI's 60 MW Port Hawkesbury biomass project is not affected by this announcement.

Renewable Electricity Plan

On October 15, 2010, the Province of Nova Scotia enacted regulations under the *Electricity Act* (Nova Scotia) related to the Province's Renewable Electricity Plan. These regulations established the requirement that 25% of electricity must be supplied from renewable sources by 2015. These regulations build on previously legislated requirements for 2011 and 2013 by adding an additional 5% for 2015. Amendments to the *Electricity Act*, and the regulations, provided for the appointment of an independent renewable electricity administrator to conduct the procurement of at least 300 GWh of energy from IPPs to meet the 2015 standard.

On May 19, 2011, the government of Nova Scotia amended the *Electricity Act* (Nova Scotia) to facilitate the eligibility of energy from the Lower Churchill Project in Labrador as a resource for meeting Nova Scotia's renewable electricity targets. The amendment requires regulations to be developed that increase the percentage of renewable energy in the generation mix from the planned 25% in 2015 to 40% by 2020.

Mercury Emissions

On July 22, 2010, the government of Nova Scotia asked NSPI to develop a plan of staged mercury emission reductions for its generation facilities for the period of 2010 to 2020 and meet an annual cap of 35 kg beginning in 2020.

LED Streetlight Legislation

On May 19, 2011, the Province of Nova Scotia passed legislation making LED lighting mandatory on Nova Scotia's roads and highways. This legislation builds on previous initiatives focused on energy efficiency and environmental responsibility. The cost to convert to LED lighting Province-wide is estimated to be in the range of $100 million. NSPI's related capital costs will be subject to UARB review and approval.

Renewable Energy Projects

Port Hawkesbury Biomass Project

On October 14, 2010, the UARB approved NSPI's $208.6 million capital work order application for the Port Hawkesbury biomass project. NSPI will develop this 60 MW co-generating facility in Port Hawkesbury, Nova Scotia. The project was originally planned with NSPI to own the facility while NewPage would engineer, procure, construct and operate the plant as well as supply the fuel. NewPage's circumstances have since changed (see "General Development of the Business - NewPage Port Hawkesbury Corp."), as a result of which NSPI has assumed full project management responsibilities for the project. This project is expected to be in operation in 2013 and supply approximately 3% of the Province of Nova Scotia's total electricity needs.

Point Tupper Wind Project

In November 2009, to satisfy NSPI's requirements under the Province's 2011 RES, NSPI signed a project operating agreement with RESL, an IPP, regarding the construction and operation of a 22 MW wind farm in Richmond County, Nova Scotia. NSPI has a 49% interest in the wind farm, with RESL constructing, managing, operating and maintaining the site. In order to facilitate the project's advancement, NSPI provided a limited guarantee for the indebtedness of RESL. The guarantee is up to $23.5 million. NSPI holds a first ranking security interest in the assets of RESL and all future assets of the project owned by RESL. NSPI had previously signed a power purchase agreement with RESL relating to the wind farm, which was one of the power purchase agreements NSPI signed with IPPs to meet provincial regulations. On June 14, 2010, the UARB approved NSPI's $27.8 million capital work order for the Point Tupper Wind project. The project went into service in August 2010.

Digby Wind Project

On May 28, 2010, NSPI purchased wind generation assets under development for the 30 MW Digby Wind Project from a subsidiary of Emera for $30.1 million. This project went into service in December 2010. On March 9, 2011, the UARB approved a capital work order for the project, which included a substation, network upgrades and interconnection costs, in the total amount of $79.8 million. The project should supply approximately 1% of Nova Scotia's electricity requirements.

Nuttby Mountain Wind Project

In April 2009, NSPI purchased the development rights for a proposed 22 turbine, 51 MW wind farm located at Nuttby Mountain, Nova Scotia. The Nuttby Mountain project represented one of the power purchase agreements NSPI had signed with IPPs previously. The Nuttby Mountain project development rights were owned by EarthFirst Nuttby Inc., a subsidiary of EarthFirst Canada Inc. The development rights included land leases and transmission interconnection rights as well as provincial environmental approval. As a result of the purchase by NSPI, this particular power purchase agreement is no longer in effect. The UARB approved the development of this project as a capital work order on November 30, 2009 at a cost of $120 million.

Construction of the wind farm commenced in early December 2009, with 22 wind turbines fully operational and generating up to 51 MW by the end of December, 2010. This project should produce approximately 1.5% of Nova Scotia's electricity requirements.

Nova Scotia Renewable Energy Standard Regulation

On October 9, 2009, the RES, which was established by the Nova Scotia government in January 2007 for the purpose of increasing the percentage of renewable energy in the Nova Scotia generation mix, was amended. Pursuant to the amendment, the target date for 5% of electricity to be supplied from the post-2001 sources of renewable energy, owned by IPPs, was extended from 2010 to 2011. The target for 2013, which requires an additional 5% of renewable energy from either IPPs or NSPI, is unchanged.

Return on Equity Decision

In January 2010, NSPI reached an agreement with stakeholders on its calculation of ROE. The agreement establishes that NSPI will continue to use actual capital structure, actual equity and actual net earnings to calculate actual annual regulated ROE. The agreement further provides NSPI with flexibility in amortizing the pre-2003 income tax regulatory asset, allowing NSPI to recognize additional amortization amounts in current periods and reducing amounts in future periods. The agreement was approved by the UARB. In connection with its November 29, 2011 general rate decision (see "General Development of the Business – General Rate Application" above), the UARB set, as a condition, that NSPI will maintain its average regulated annual common equity at a level no higher than 40%.

Integrated Resource Plan Filed with UARB

On November 30, 2009, NSPI filed an update to its IRP at the request of the UARB. The IRP is a stakeholder driven long range planning tool used to develop various plans for meeting Nova Scotia's electricity requirements. The IRP update process was completed by NSPI, working jointly with UARB staff and consultants, and with stakeholders representing residential customers, industry, government, and environmental organizations.

The 2009 update to the IRP update reflects changes in assumptions about the economy, the environment, fuel pricing and electricity demand based on stakeholder consensus. The 2009 update follows the direction of the 2007 IRP, identifying three areas important to Nova Scotia's resource planning over the next 25 years, namely:

1. Conservation and energy efficiency programs;

2. Renewable energy sources such as wind, hydro, and biomass; and

3. Continued investments in NSPI's existing facilities.

The 2009 update uses a 25-year load forecast to model the long-term electricity demand for Nova Scotia. Based on these forecasts, various scenarios are developed to help determine the ways to meet that demand in a cost-effective, environmentally and regulatory-compliant manner. NSPI continued construction of the Tufts Cove Generating Station waste heat recovery project in 2011, which was a key element of the IRP. This project involved the conversion of two natural gas fired generators from simple cycle to combined cycle by installing a turbine to capture waste heat, producing 50 megawatts of new generation.

In-Stream Tidal Demonstration Project

In September 2009, NSPI and OpenHydro, an Irish renewable energy company that designs and manufactures marine turbines for harnessing energy from tidal currents, announced a project to deploy a 1 MW tidal turbine in the Bay of Fundy, Nova Scotia. This 10 metre in-stream tidal turbine was installed on November 12, 2009. The testing focuses on the environmental impact, deployment and recovery, subsea gravity base position stability, durability of the turbine as well as its energy production capability. NSPI has invested $3 million in the project. The project with OpenHydro is part of NSPI's long term approach to explore cleaner, greener energy sources.

Due to damage to the in-stream tidal turbine, the turbine was recovered in December 2010 and is currently undergoing engineering analysis.

Emera, NSPI's parent company, owns an 8.2% equity interest in OpenHydro.

NSPI Energy Conservation and Efficiency Programs

In October 2010, ENSC assumed administration of the electricity conservation and efficiency programs formerly managed by NSPI. ENSC is a corporation created by the Government of Nova Scotia to administer certain energy conservation and efficiency programs.

Throughout 2011 ENSC managed the program submitted by NSPI and approved by the UARB in 2010. ENSC submitted its first DSM plan in 2011. In its second DSM plan filing dated February 27, 2012, ENSC has requested approval of a multi-year plan for the period 2013-2015 with forecast spending of $42.3 to $45.1 million annually.

The cost of the DSM programs are recovered from NSPI customers. Rates to cover the costs of the programs are adjusted annually following approval by the UARB.

2009 Rate Decision

On May 27, 2008, NSPI filed an application with the UARB requesting an increase in electricity rates effective January 1, 2009. In September, 2008, NSPI reached a settlement agreement with stakeholders on its 2009 rate application. The UARB approved the settlement agreement in November 2008 which included an average rate increase of 9.4% for most customer segments effective January 1, 2009. The settlement agreement included a FAM, also effective January 1, 2009. The first rate adjustment under the FAM, which was effective January 1, 2010, was approved by the UARB on December 9, 2009. The UARB oversees the FAM, including the review of fuel costs, contracts and transactions. With the implementation of the FAM, NSPI's regulated ROE range was established as 9.1% to 9.6%, with 9.35% used to set rates.

Financing Activity

On May 21, 2010, NSPI filed a short form base shelf prospectus related to the issuance of up to

$500,000,000 in debt securities, including medium term notes and debentures. On June 9, 2010, NSPI filed a prospectus supplement which, together with the base shelf prospectus, provided for the issuance of up to an aggregate of $500,000,000 medium term notes. On June 15, 2010, NSPI made its first issue of medium term notes under this shelf prospectus, representing $300,000,000 5.61% Series X notes maturing on June 15, 2040.

On July 15, 2010, NSPI filed an amended and restated base shelf prospectus, amending and restating the shelf prospectus described above, which increased the amount of debt securities available for issue under the shelf program back to up to $500,000,000 in debt securities.

On May 13, 2011, NSPI filed Amendment No. 1 to the amended and restated base shelf prospectus which increased the amount of debt securities available for issue under the shelf program to $800,000,000 in debt securities, and filed Amendment No. 1 to the prospectus supplement to increase the aggregate principal amount of medium term notes offered from time to time under the shelf program to $800,000,000.

On March 6, 2012, NSPI made its second issue of medium term notes under the shelf program, representing $250,000,000 4.15% Series Y Notes maturing on March 6, 2042.

NSPI has established the following available credit facilities:

	Matures	Maximum Amount (*millions of dollars*)
Short-term		
Operating Credit facility, including support for commercial paper program	June 25, 2015	$500.00[1]

Note:
(1) In 2011, the operating credit facility was decreased from $600 million to $500 million and the maturity was extended from June 2013 to June 2015. As of March 15, 2012, $197.4 million was drawn down, leaving $302.6 million available under the facility.

Transition to USGAAP

In 2008, the Canadian Institute of Chartered Accountants announced that CGAAP for publicly accountable enterprises would be replaced by IFRS for fiscal years beginning on or after January 1, 2011. Due primarily to the continued uncertainty around the applicability of a rate-regulated accounting standard under IFRS, NSPI's Board approved the transition to USGAAP instead of IFRS. The adoption of USGAAP was made on a retrospective basis with restatement of prior periods' financial statements to reflect USGAAP requirements in effect at that time.

NSPI transitioned to USGAAP on January 1, 2011 and restated the 2010 comparative period for the 2011 financial statements.

On July 15, 2010, NSPI filed a shelf registration statement with the SEC under the U.S. *Securities Act of 1933*, as amended, to register certain of its investment grade securities. As a result of the registration, NSPI became subject to reporting obligations under U.S. securities laws.

On December 12, 2011, NSPI filed with the SEC, to remove from registration all unsold debt securities as of that date. NSPI also filed to terminate its reporting obligations under Section 15(d) of the *United States Securities Exchange Act of 1934*, as amended and is no longer subject to reporting obligations under U.S. securities laws. NSPI intends to continue preparing its financial statements in accordance with USGAAP.

Changes in Business Expected During the Current Year

Economic Environment

NSPI will continue to pursue investments related to the transformation of the energy industry to lower emissions and comply with renewable energy standards. This will also include improvement to the transmission system.

Environmental Legislation

NSPI is subject to environmental regulations as set by both the Province of Nova Scotia and the Government of Canada. The Company continues to work with officials at both levels of government so as to comply with these regulations in an integrated way.

Operations

NSPI anticipates earning a regulated ROE within its allowed range in 2012. NSPI continues to implement its strategy, which is focused on regulated investments in renewable energy and system reliability projects with an annual capital expenditure plan approximately $330 million in 2012. NSPI expects to finance its capital expenditures with funds from operations and debt.

DESCRIPTION OF THE BUSINESS

General

NSPI is the primary electricity supplier in Nova Scotia, providing electricity generation, transmission and distribution services in the Province of Nova Scotia to approximately 493,000 customers. The Company owns 2,374 MW of generating capacity. Approximately 52% of NSPI's generating capacity is coal-fired. Natural gas and/or oil comprise another 28% of capacity; hydro and wind production provide approximately 20%. In addition, NSPI has contracts to purchase renewable energy from IPPs. These IPPs own 229 MW, increasing to 259 MW in 2012, of wind and biomass fuelled generation capacity. A further 83 MW of renewable capacity is being built directly or purchased under long-term contracts by NSPI, expected to be in service by the end of 2013. NSPI also owns approximately 5,000 kilometres of transmission facilities and approximately 26,000 kilometres of distribution facilities. The Company has a workforce of approximately 1,900 people.

NSPI is a public utility as defined in the *Public Utilities Act* and is subject to regulation under the *Public Utilities Act* by the UARB. The *Public Utilities Act* gives the UARB supervisory powers over NSPI's operations and expenditures. Electricity rates for NSPI's customers are also subject to UARB approval. NSPI is not subject to a general annual rate review process, but rather participates in hearings from time to time, which may be at NSPI's or the UARB's request. Since January 2009, NSPI has been operating with a FAM for fuel expense recovery, which is subject to UARB review and approval.

In 2009, the UARB approved the FAM allowing NSPI to recover fluctuating fuel expenses from customers through annual fuel rate adjustments. Differences between actual fuel costs and amounts recovered from customers through electricity rates in a year are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in a subsequent year.

Electric sales volume is primarily driven by general economic conditions, population and weather.

Electricity rates change as new regulatory decisions are implemented. Residential and commercial electricity sales are seasonal in Nova Scotia, with Q1 and Q4 the strongest periods, as a result of colder weather, and fewer daylight hours in the winter season. Electric revenues as of December 31, 2011 were $1,209.7 million compared to $1,167.3 million as of December 31, 2010. For more information describing the revenue generated for the three years ended December 2011, December 2010 and December 2009, see the "Electric Revenue" and "Electric Margin" sections of the MD&A.

Changes to base electricity rates, if any, take place separately from FAM adjustments. There was no increase in the base electricity rate in 2011, nor was there an increase in 2010. There was an average rate increase of 5.1% effective January 1, 2012.

NSPI distinguishes revenues related to recovery of fuel costs from revenues related to the recovery of non-fuel costs because the FAM enables NSPI to seek recovery of fuel costs through regularly scheduled rate adjustments. Differences between actual fuel costs and amounts recovered from customers through electricity rates in a period are deferred to FAM regulatory asset or liability, and are recovered from or returned to customers in a subsequent period. Consequently, fuel revenues and fuel costs do not have a material effect on NSPI's electric margin or net income, with the exception of the incentive component of the FAM, whereby NSPI retains or absorbs 10% of the over or under recovered amount to a maximum of $5 million. As an outcome of the 2012 general rate application, due to uncertainty regarding the load for NewPage (see "NewPage Port Hawkesbury Corp."), the incentive component of the FAM will not operate in 2012.

For the year ended December 31, 2011, actual fuel costs were more than amounts recovered from customers. The difference has been accrued as a FAM regulatory asset.

NSPI has recognized a future income tax expense related to the FAM based on NSPI's applicable statutory income tax rate. The FAM regulatory asset or liability includes amounts recognized as a fuel adjustment and associated interest included in financing charges. As at December 31, 2011, future income tax liability related to FAM was $29.0 million (December 31, 2010 - liability of $29.2 million).

Area Served

Nova Scotia is the most populous of the four Atlantic provinces of Canada and covers 55,284 square kilometres of land and freshwater. As reported by Statistics Canada, Nova Scotia's population was estimated at 945,400 as of July 1, 2011, or 2.74 % of Canada's population.

Energy Sources

NSPI's energy sources for its electric energy generation are coal, petroleum coke, natural gas, heavy fuel oil, hydroelectric energy, light fuel oil (gas turbine), biomass and wind. NSPI also purchases electric energy from neighbouring markets outside Nova Scotia and IPPs in Nova Scotia.

NSPI's percentage of solid fuel generation decreased to approximately 57 % in 2011, down from 64% in 2010 and 68 % in 2009. Economic dispatch of the generating fleet brings the lowest cost options on stream first, such that the incremental cost of production increases as sales volume increases. Historically, solid fuels have had the lowest per unit fuel cost, after hydro and NSPI-owned wind, which have no fuel cost component. Natural gas, oil, and purchased power have the next lowest fuel cost, depending on the relative pricing of each. During 2011, natural gas represented a higher percentage of the annual energy requirement than prior years as economic dispatch favored natural gas for much of the year. Additionally, the introduction of new renewable generation has decreased coal consumption.

The average unit fuel costs decreased in 2011 compared to 2010 primarily due to decreased natural gas prices and increased hydro and wind production.

The average unit fuel costs increased in 2010 compared to 2009 primarily due to higher priced imported coal and solid fuel commodity mix related to emission compliance.

Comparative costs of fuel sources fluctuate from year to year. For information describing the percentage of total electric energy generated by fuel source and for information related to the cost of electricity generation, see the “Fuel for Generation and Purchased Power (including affiliates)” section of the MD&A.

Transmission and Distribution

NSPI transmits and distributes electricity from its generating stations to its customers. NSPI's transmission system consists of approximately 5,000 km of transmission lines, including major substations at Lingan, Woodbine, Port Hastings, Hopewell, Onslow, Brushy Hill, and Bridgewater connected to the transmission and distribution system. The distribution system consists of approximately 26,000 km of distribution lines which includes distribution supply substations.

System Operations and Generation

The NSPI system control centre, located in Halifax, co-ordinates and controls the electric generation and transmission facilities with the goal of providing a reliable and secure electricity supply while maintaining economy of operations. The system control centre is linked to the generating stations and other key parts of the system by the Supervisory Control and Data Acquisition system, a voice and data communications network.

Through an interconnection agreement with Énergie NB Power, NSPI's system has access to other regional power systems and the rest of the interconnected North American bulk power systems. This interconnection of power systems enhances the cost effectiveness, efficiency, reserve capacity and reliability of all participating power systems. The interconnection agreement also provides both utilities with an alternative source of power, subject to availability and the requirements of the supplier.

NSPI is a member of the NPCC, a body whose primary role is promoting the reliability of the interconnected power systems throughout the northeastern U.S. and eastern Canada. NSPI's system complies with NPCC criteria for the design and operation of interconnected power systems.

NSPI has the following generating facilities:

- Four solid-fuel generating stations located at:
    - Lingan 4 units with a combine output of 612MW
    - Point Tupper 1 unit with an output of 152MW
    - Trenton 2 units with a combine output of 307MW
    - Point Aconi 1 unit with an output of 172MW;

- One natural gas/heavy fuel oil fired facility located at:
    - Tufts Cove
        - 3 units dual fired with either HFO or gas with a combine output of 321MW

        - 3 units in combined cycle fired on gas with a combined output of 148MW;

- Three gas turbine facilities located at:
    - Burnside 4 units with a combined output of 132MW
    - Tusket 1 unit with an output of 24MW
    - Victoria Junction 2 units with a combined output of 66MW;

- 33 hydro plants located on 17 river systems throughout Nova Scotia, including Wreck Cove, the Halifax area, the Annapolis Valley and western Nova Scotia with a total combine output of 397MW;

- 20 wind turbines at Digby Wind project with an output of 30 MW;

- 22 wind turbines at Nuttby Mountain Wind project with an output of 51MW; and

- a 49% interest in Point Tupper Wind project (11 wind turbines, 6 of which are owned by NSPI).

NSPI also contracts with IPPs.

With the exception of Point Aconi, all of NSPI's solid-fuel-fired generating stations can also burn heavy fuel oil, subject to oil delivery and storage constraints. This dual-fired capacity provides some security if solid-fuel supplies are interrupted.

New Head Offices

The principal, head and registered offices of NSPI relocated, effective in the fall of 2011, to 1223 Lower Water Street, Halifax, Nova Scotia, B3J 3S8.

Regulatory Matters

Electricity Rates & Return on Equity. NSPI is regulated under a cost of service model, with rates set to cover prudently incurred costs of providing electricity service to customers, and provide an appropriate return to investors. NSPI's target regulated ROE range for 2011 was 9.1% to 9.6%, based on an actual regulated common equity component of up to 40% of average regulated capitalization. The 2012 general rate decision adjusted the 2012 ROE range to 9.1% to 9.5%.

For further details, see "Deferral of Certain Tax Benefits relating to Renewable Energy Projects", "General Rate Application", "Depreciation Settlement", "UARB Decision on Fuel Adjustment Mechanism and Status of December 31, 2010", "Return on Equity Decision", "FAM Rate Adjustments", and "2009 Rate Decision" under the heading "General Development of the Business" above.

Capital Expenditures. The *Public Utilities Act* allows NSPI to file a Capital Plan with the UARB for approval. Items for which the Board has withheld its approval and items not included in capital projects which exceed $250,000, require UARB approval. The 2011 Capital Plan was approved by the UARB on June 23, 2011.

Capital expenditures for 2011 were approximately $320 million (2010 - $550 million). Significant capital expenditures included the Port Hawkesbury biomass project, construction of a 138 KV transmission line, the construction completion of the Lower Water Street corporate offices and the replacement of the substation at Lower Water Street.

NSPI continues to implement its strategy, which is focused on regulated investments in renewable energy and system reliability projects with a total capital program budget of approximately $330 million in 2012 ($320 million in 2011).

NSPI's rate base includes regulated assets and liabilities, an allowance for materials and supplies and an allowance for working capital. The net utility plant in service consists of the utility plant at its original cost less accumulated depreciation.

The UARB prescribes depreciation rates and regulated accounting policies. Depreciation rates are reviewed periodically. Following completion of a depreciation study and a negotiated agreement with stakeholders, in 2003 the UARB approved a $20 million increase in annual depreciation expense, to be phased in over four years beginning in 2004. Following the deferral of the phase-in of depreciation rates, the UARB, in its November 5, 2008 decision, approved the third stage of the phase-in effective January 1, 2009. A new depreciation study was filed with the UARB on October 29, 2010 resulting in a settlement agreement for depreciation rates, which became effective on January 1, 2012. See “General Development of the Business - Depreciation Settlement”.

Employee Relations

NSPI had approximately 1,900 employees on December 31, 2011, approximately 52% of whom are unionized. There have been no labour disruptions since 1975. NSPI has a collective agreement with approximately 1,000 unionized employees, which will expire on March 31, 2012.

Environmental Matters

NSPI is subject to regulation by federal, provincial and municipal authorities with regard to environmental matters. NSPI continues to work with officials at all levels of government so as to comply with these regulations in an integrated way. NSPI is in material compliance with current environmental regulations.

In mid 2009, the Province of Nova Scotia set GHG emission limits covering the period from 2010 to 2020. This makes Nova Scotia the first jurisdiction in Canada to have "hard caps” for GHG emissions. The GHG regulation requires a reduction of 25% from 2010 levels by the year 2020.

In June, 2010, the Federal Department of Environment announced its intentions for a new national GHG framework for the electricity sector. In August 2011, Environment Canada announced proposed regulations for a new national framework for the electricity sector in Canada. These proposed regulations would apply to new coal-fired electricity generation units and existing coal-fired electricity generation units once they have reached the end of their deemed economic life. Nova Scotia's existing GHG regulations require reductions in NSPI's emissions similar to the intentions of the federal framework. In March 2012, the governments of Canada and Nova Scotia announced that they are working towards an equivalency agreement to avoid duplication of efforts to control GHG emissions. An equivalency agreement would see the provincial rules take precedence over the federal rules, as long as the provincial regulations achieve an equivalent environmental outcome. Nova Scotia’s existing GHG regulations require reductions of 25% in GHG emissions in the electricity sector by 2020. The Province plans to develop additional, increasingly stringent milestones between 2020 and 2030 to match the federal targets. NSPI is reviewing the implications of this federal framework and its alignment with NSPI’s current operating plans under existing Nova Scotia regulations.

The provincial regulations for renewable energy require 25% of the energy to be produced from renewable sources by 2015, including the 17% which exists currently in Nova Scotia.

NSPI has completed the installation of mercury abatement systems at seven of its solid fuel generating units located at three generating stations to ensure compliance with environmental regulations which became effective on January 1, 2010. NSPI will use a combination of fuel mix and the abatement systems to comply with the mercury regulations.

Over the last several years, NSPI has been working on a plan to enable it to meet or exceed new government air emission targets. While the government's regulation for GHG emissions is aggressive, it is in line with the Company's planning. NSPI is fully engaged to achieve this target, and is working cooperatively with government and other stakeholders to meet Nova Scotia's RES and the GHG emission limits.

All required permits are in place for NSPI's generating stations. These permits are generally for a ten year period but can be subject to review, variation, or suspension by the Minister of Environment (Nova Scotia).

The UARB has authorized required environmental expenditures and the recovery of those expenditures through rates. The UARB has confirmed that it will approve costs associated with environmental compliance required by law within the rates customers pay for electricity.

For further information, see the "Developments", "Canadian Environmental Regulations", "Nova Scotia Provincial Environmental Regulations", and "Business Risks – Changes in Environmental Legislation" sections of the MD&A and "Risk Factors – Environment" in this AIF.

Taxation

See the "Deferral of Certain Tax Benefits Decision", "Provincial Grants and Taxes", and "Income Taxes" sections of the MD&A.

Risk Factors

NSPI's risk management practices are overseen by the Board. Daily and periodic reporting of relevant metrics are performed by a centralized risk management group which is independent of all operations.

NSPI's risk management activities are focused on those areas that most significantly impact profitability and quality of earnings and cash flow. These risks include exposure to commodity prices, foreign exchange, interest rates, credit risk, and regulatory risk. The UARB approved the implementation of a FAM effective January 1, 2009, reducing the utility's exposure to fuel price volatility and by providing a mechanism for NSPI to recover actual fuel costs. The FAM mitigates the risk to NSPI's net earnings associated with fluctuations in commodity prices and foreign exchange.

The following is a summary of the significant risk factors identified by NSPI:

<u>Regulatory Risk</u>

NSPI faces risk with respect to the recovery of costs and investments in a timely manner. As a regulated, cost-of-service utility with an obligation to serve, NSPI must obtain regulatory approval to change general electricity rates and riders. Costs and investments can be recovered after and once the UARB has approved recovery in adjustments to rates or riders, which normally requires a public hearing process.

During public hearing processes, consultants and customer representatives scrutinize the Company's costs, actions and plans, and the UARB determines whether to allow recovery and to adjust rates based upon NSPI's evidence and any contrary evidence from other hearing participants. The Company manages this regulatory risk through transparent regulatory disclosure, ongoing stakeholder consultation and multi-party engagement on aspects such as utility operations, rate filings and capital plans. The Company employs a collaborative regulatory approach through technical conferences and negotiated settlements.

<u>Commodity Price Risk</u>

A large portion of the Company's annual fuel requirement is subject to fluctuation in commodity market prices. Fuel contracts may be exposed to broader global conditions which may include impacts on delivery reliability and price, despite contracted terms. NSPI seeks to manage this risk through the use of financial hedging instruments and physical contracts and utilizes a portfolio strategy for fuel procurement with a combination of long, medium, and short-term supply agreements. It also provides for supply and supplier diversification. The strategy is designed to reduce the effects from market volatility through agreements with staggered expiration dates, volume options and varied pricing mechanisms. The adoption and implementation of the FAM, effective January 1, 2009, has further helped NSPI manage this risk.

Coal/Petroleum Coke. A substantial portion of NSPI's coal and petroleum coke supply comes from international suppliers, which are contracted at or near the market prices prevailing at the time of contract. NSPI entered into fixed-price and index price contractual arrangements with several suppliers as part of the fuel procurement portfolio strategy. All index priced contractual arrangements are matched with a corresponding financial instrument to fix the price. The approximate percentage of coal and petroleum coke requirements contracted at December 31, 2011 is as follows:

2012 - 94%
2013 - 32%
2014 - 15%

Heavy Fuel Oil. NSPI manages exposure to changes in the market price of heavy fuel oil through the use of swaps, options, and forward contracts. For 2012 and 2013, NSPI currently has no heavy fuel oil hedging requirements due to favourable natural gas pricing and the forecast that it will not burn a material amount of heavy fuel oil.

Natural Gas. NSPI has entered into multi-year contracts to purchase approximately 38,400 MMBTU of natural gas per day in 2012, and 20,100 MMBTU of natural gas per day in 2013. Volumes exposed to market prices are managed using financial instruments where the fuel is required for NSPI's generation; and the balance is sold against market prices when available for resale. As at December 31, 2011, amounts of natural gas volumes that have been economically and/or financially hedged are approximately as follows:

2012 – 83%
2013 – 31%

Foreign Exchange Risk

NSPI enters into foreign exchange forward and swap contracts to limit the exposure of currency rate fluctuations on fuel purchases. Currency forwards are used to fix the CAD cost to acquire USD, reducing exposure to currency rate fluctuations.

The risk due to fluctuations of the CAD against the USD for fuel purchases is measured and managed. In 2012, NSPI expects approximately 63% of its anticipated net fuel costs to be denominated in USD.

Forward contracts to buy USD $256.0 million were in place at December 31, 2011 at a weighted average rate of $0.99, representing 81% of 2012's USD requirements. Forward contracts to buy USD $752.0 million in 2013 through 2016 at a weighted average rate of $1.01 were in place at December 31, 2011. These contracts cover 60% of anticipated USD requirements in these years. As at December 31, 2011, there were no fuel-related foreign exchange swaps outstanding.

Commercial Relationships Risk

For the year ended December 31, 2011, NSPI's five largest customers contributed approximately 13.3 % (2010 – 14.7 %) of electric revenues. The loss of a large customer could have a material effect on NSPI's operating revenues. NSPI works to mitigate this risk through the regulatory process.

NSPI's largest customer was granted creditor protection under the Companies' Creditors Arrangement Act (Canada) (the "CCCA"), and suspended operations in September 2011. This customer contributed approximately 6.0 % (2010 – 7.9 %) of NSPI's electric revenues for the year ended December 31, 2011. NSPI is working to recover an outstanding receivable owing from this customer through the CCAA claims process, including a claim for set-off against amounts owing from NSPI to the customer that exceeds the amount receivable. The 2012 general rate decision, approved by the UARB, provides for any unrecovered non-fuel electric charges in 2012 related to this customer to be deferred and recovered beginning in 2013.

Labour Risk

Certain NSPI employees are subject to a collective labour agreement which will expire on March 31, 2012. Approximately 52 % of NSPI's full-time employees and term employees are represented by a local union affiliated with the International Brotherhood of Electrical Workers. NSPI seeks to manage this risk through ongoing discussions with the union.

Credit Risk

NSPI is exposed to credit risk with respect to amounts receivable from customers. Credit assessments are conducted on all new customers and deposits are requested on any high risk accounts. NSPI is also exposed to credit risk with counterparties to its derivatives. Credit risk is the potential loss from a counterparty's non-performance under an agreement. NSPI manages credit risk with policies and procedures for counterparty analysis, exposure measurement, and exposure monitoring and mitigation.

Weather Risk

Shifts in weather patterns affect electric sales volumes and associated revenues with increased volatility in the winter months attributed to heating loads. Extreme weather events generally result in increased operating costs associated with restoring power to customers. NSPI responds to significant weather event related outages according to its Emergency Services Restoration Plan.

Interest Rate Risk

The Company utilizes a combination of fixed and variable rate debt financing for operations and capital expenditures resulting in an exposure to interest rate risk. The Company seeks to manage interest rate risk through a portfolio approach that includes the use of fixed and floating rate debt with staggered maturities. The Company will, from time to time, issue long-term debt or enter into interest rate hedging contracts to limit its exposure to fluctuations in floating interest rate debt. Floating-rate debt is estimated to represent approximately 16 % of total debt in 2012. The Company has no interest rate hedging contracts outstanding as at December 31, 2011.

Environment

NSPI is subject to regulation by federal, provincial and municipal authorities with regard to environmental matters. Changes to climate change and air emissions standards could adversely affect utility operations.

Corporate Environmental Governance. NSPI is committed to operating in a manner that is respectful and protective of the environment, and in full compliance with legal requirements and Company policies. NSPI has implemented this policy through the development and application of EMS.

Implementation of EMS has provided a systematic focus on environmental issues so risks are identified and managed proactively. All areas of NSPI's business continued initiatives commenced in 2010 to reduce potential environmental risks and associated costs. Activities included reducing air emissions, protecting water resources, and continued management of polychlorinated biphenyl (or PCB) contaminated electrical equipment.

Conformance with legislative and Company requirements are verified through a comprehensive environmental audit program. There were no significant environmental or regulatory compliance issues identified during the 2011 audits. Plans are in place to promptly address any audit findings and continually improve the environmental management of NSPI's operations.

Oversight of environmental matters is carried out by the Board of Directors of NSPI or committees of the Board with specific environmental responsibilities. In addition, an Environmental Council, made up of senior NSPI employees, with working accountability for environmental matters, continues to guide the implementation of programs that address key environmental issues. In addition to programs involving employees, the EMS procedures include planning, implementing and monitoring of contractors' performance.

NSPI's IRP includes current environmental requirements and assumptions on future regulations as constraints on possible generation plans. This allows the development of revised generation plans for the future. NSPI stakeholders were engaged in the assumptions and the scenarios to be modelled. The results of the planning activities can be found on the NSPI website at www.nspower.ca.

In 2007, NSPI was audited by the CEA to verify the quality of its environmental reporting and management systems. The auditor from the CEA concluded that NSPI had "robust programs, environmental leadership and a strong, mature EMS". In 2011, a review of NSPI's EMS by an accredited ISO 14001 auditor determined that the EMS was strong, focused with engaged staff and would be considered ISO 14001 equivalent.

Regulatory. NSPI produces its electrical energy from approximately 57% from coal and petroleum coke and 20% from natural gas and/or oil. As such, it is subject to regulation with respect to air pollutants and GHG emissions. NSPI operates under a cost-of-service regulation model. Accordingly, all prudently incurred costs, including those capital and operating costs associated with meeting present and future environmental liabilities, will be recovered in rates collected from customers. Installed generating capacity will differ from energy produced because NSPI economically dispatches from the lowest cost generation first.

NSPI is subject to environmental regulation as set by both Canadian and Nova Scotia governments. NSPI is in material compliance with all current environmental regulations. All required permits are in place for NSPI's generating stations. These permits are generally for a ten year period but can be subject to review, variation, or suspension by the Minister of Environment of Nova Scotia.

Climate Change and Air Emissions

Greenhouse Gas Emissions

NSPI has stabilized, and in recent years, reduced GHG emissions. This has been achieved by energy efficiency and conservation programs, increased use of natural gas and the addition of new renewable energy sources to the generation portfolio.

GHG emissions from NSPI facilities have been capped beginning in 2010 through to 2020. The regulations allow for multi-year compliance periods recognizing the variability in electricity supply sources and demand. Over the decade, the caps will be achieved by a combination of additional renewable generation, import of non-emitting energy, and energy efficiency and conservation.

In 2011, Environment Canada announced proposed regulations for a new national carbon dioxide framework for the electricity sector in Canada. These proposed regulations would apply to new coal-fired electricity generation units; and existing coal-fired electricity generation units that have reached the end of their deemed economic life. These proposed regulations are expected to be published in 2012. In March, 2012 the governments of Canada and Nova Scotia announced that they are working towards an equivalency agreement on coal-fired electricity GHG regulations to avoid duplication of efforts to control GHG emissions. An equivalency agreement would see the provincial rules take precedence over the federal rules, as long as the provincial regulations achieve an equivalent environmental outcome. Nova Scotia's existing GHG regulations require reductions of 25% in GHG emissions in the electricity sector by 2020. The Province plans to develop additional, increasingly stringent milestones between 2020 and 2030 to match the federal targets. NSPI is reviewing the implications of this federal framework and its alignment with its current operating plans under existing Nova Scotia regulations.

Renewable Energy

The Province of Nova Scotia has established targets with respect to the percentage of renewable energy in NSPI's generation mix. The target date for 5% of electricity to be supplied from post-2001 sources of renewable energy, owned by independent power producers, was extended to 2011 from 2010. The target for 2013, which requires an additional 5% of renewable energy, is unchanged.

In May, 2011 the Nova Scotia Government approved *The Electricity Act* (Amended) to facilitate the eligibility of energy from the Lower Churchill Project in Labrador as a resource for meeting Nova

Scotia's renewable electricity targets. The amendment requires regulations to be developed that increase the percentage of renewable energy in the generation mix from the planned 25% in 2015, to 40% by 2020.

Mercury, Nitrogen Oxide and Sulphur Dioxide Emissions

NSPI completed a capital program to add sorbent injection to each of the seven pulverized fuel coal units in 2010 at a cost of $17.3 million. This was put in place to address planned reductions in mercury emissions limits.

Any mercury emission above 65 kg, between 2010 and 2013, must be offset by lower emissions in the 2014 to 2020 period.

NSPI completed its capital program of retrofitting low nitrogen oxide combustion firing systems on six of its seven pulverized fuel coal units in early 2009 at a cost of $23.3 million. NSPI now meets the nitrogen oxide emission cap of 21,365 tonnes per year established by the Nova Scotia Government effective 2010. These investments, combined with the purchasing of low sulphur coal, allows NSPI to meet the provincial air quality regulations.

NSPI will meet ever-reducing sulphur dioxide emission cap requirements through the use of a blend of net lower sulphur content solid fuel.

Compared to historical levels, NSPI will have reduced mercury emissions by 60% effective 2014, nitrogen oxide by 40% effective 2009 and sulphur dioxide by 50% effective 2010.

<u>Capital Markets</u>

NSPI generates cash through its regulated operations. It has a diversified customer base by both sales volume and revenue among residential, commercial, industrial and other customers. Circumstances that could affect the Company's ability to generate cash include economic downturns, the loss of one or more large customers, and regulatory decisions affecting customer rates.

Volatility in the global capital markets can increase the cost, and affect the timing, of the issuance of long-term capital by the Company. While the cost of borrowing may increase, the Company expects to continue to have reasonable access to capital in the future. Based on current funds available and expected cash from operations, NSPI believes it has sufficient funds available to finance its projected capital expenditures and operations. However, if cash flow from operations is lower than expected or capital costs exceed current estimates, or if NSPI incurs major unanticipated expenses related to development or maintenance of its existing assets, it may be required to seek additional capital to maintain, and/or adjust, its planned expenditures levels.

<u>Construction and Development</u>

The development, construction and future operation of electricity generation, transmission and distribution, gas transmission and power facilities can be affected adversely by changes in government policy and regulation, environmental concerns, increases in capital and construction costs, construction delays, increases in interest rates and competition in the industry. In the event that any one of these factors emerges, the actual results may vary materially from projections, including projections of costs, power production, future revenue and earnings. The construction and development of NSPI's transmission and distribution projects and their future operations are subject to changes in the policies and laws of Canadian federal and provincial governments, including regulatory approvals and regulations relating to the environment, land use, health, conflicts of interest with other parties and other matters beyond the direct control of NSPI. Changes in operating legislation may be in a manner which adversely affects NSPI through the imposition of restrictions on its business activities or by the introduction of regulations that increase NSPI's operating costs thereby affecting NSPI. Income tax laws relating to NSPI may be changed in a manner which adversely affects shareholders.

CAPITAL STRUCTURE

The authorized capital of NSPI consists of an unlimited number of Common Shares, all without nominal or par value, and an unlimited number of First Preferred Shares and Second Preferred Shares. The Preferred Shares rank in priority to the Common Shares. All of the outstanding Preferred Shares and Common Shares of NSPI are fully paid and non-assessable. The outstanding Series D First Preferred Shares are listed on the TSX under the symbol NSI.PR.D. All of the Common Shares of NSPI are owned directly or indirectly by Emera. The Common Shares carry one vote per share and, subject to the prior rights of holders of the Preferred Shares, each Common Share entitles the holder to share rateably in any dividends or other distributions to the shareholders. The Preferred Shares do not carry the right to vote except in certain circumstances.

NSPI's issued share capital as at December 31, 2011 is comprised of the following:

Common Shares (117.2 million, 100% owned directly or indirectly by Emera)	$1,034,659,099
Series D First Preferred Shares (5.4 million issued and outstanding)	$132,246,011

Common Shares Issued To Emera

A total of 5,000,000 common shares were issued to Emera and an affiliate under common control of Emera on March 30, 2011 at a price of $10.00 per common share.

Series D First Preferred Shares

NSPI has issued and outstanding 5.4 million Series D First Preferred Shares. Each Series D First Preferred Share is entitled to a $1.475 (5.90%) per share per annum fixed cumulative preferential dividend, as and when declared by the NSPI Board, accruing from the date of issue and payable quarterly on the fifteenth day of January, April, July and October of each year. Subject to the provisions of the *Companies Act* (Nova Scotia), on and after October 15, 2015, Series D First Preferred Shares are redeemable by NSPI on prior notice, in whole or in part, at $25.00 per Series D First Preferred Share, plus accrued and unpaid dividends.

Subject to the approval of the TSX, commencing October 15, 2015, NSPI also has the option to exchange the Series D First Preferred Shares into that number of Emera common shares determined by dividing $25.00, together with accrued and unpaid dividends, by the greater of $2.00 and 95% of the weighted average trading price of the Emera common shares on the TSX for the Market Price, being the twenty trading days ending on the last trading day on or before the fourth trading day immediately prior to the time of exchange.

On and after January 15, 2016, upon sixty-five days' prior notice and prior to any dividend payment date, each Series D First Preferred Share will be exchangeable, at the option of the holder, into that number of Emera common shares determined by dividing $25.00, together with accrued and unpaid dividends, by the greater of $2.00 and the Market Price. This exchange right of the holder is subject to the right of NSPI to redeem for cash on the exchange date, or cause the holders to sell on the exchange date to substitute purchasers found by NSPI, all or any part of such Series D First Preferred Shares, on the payment of $25.00 per share, together with accrued and unpaid dividends.

Share Ownership Restrictions

Pursuant to the *Nova Scotia Power Privatization Act* (Nova Scotia), the articles of association of NSPI provide that no person, together with associates thereof, may subscribe for, have transferred to that person, hold, beneficially own or control, directly or indirectly, otherwise than by way of security only, in the aggregate, voting shares of NSPI to which are attached more than 15% of the votes that may ordinarily be cast to elect directors, other than votes that may be so cast by or on behalf of Emera. Non-residents of Canada may not subscribe for, have transferred to them, hold, beneficially own or control, directly or indirectly, otherwise than by way of security only, or vote, in the aggregate, voting shares of NSPI to which are attached more than 25% of the votes that may ordinarily be cast to elect directors. Votes cast by non-residents on any resolution at a meeting of common shareholders of Emera will be pro-rated so that such votes will not constitute more than 25% of the total number of votes cast.

NSPI's articles of association contain provisions for the enforcement of these constraints on share ownership, including provisions for suspension of voting rights, forfeiture of dividends, prohibitions of share transfer and issuance, compulsory sale of shares and redemption, and suspension of other shareholder rights.

Ratings

NSPI has the following credit ratings by the Rating Agencies[1]:

	DBRS		S&P	
	2011	2010	2011	2010
Corporate	N/A	N/A	BBB+	BBB+
Senior unsecured debt	A (low)	A (low)	BBB+	BBB+
Preferred Shares	Pfd-2 (low)	Pfd-2 (low)	P-2 (low)	P-2 (low)
Commercial paper	R-1 (low)	R-1 (low)	A-1 (low)	A-1 (low)

Note:
(1) Ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities. The credit ratings assigned by the Rating Agencies are not recommendations to buy, sell or hold securities inasmuch as such ratings do not comment as to relevant price or suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a Rating Agency in the future if in its judgment circumstances so warrant.

Dominion Bond Rating Service Limited

Dominion Bond Rating Service Limited's ("DBRS") credit ratings are on a long term debt rating scale that ranges from AAA to D, representing the range from highest to lowest quality of such rated securities. The "A" rating is the third highest rating category out of a total of ten categories employed by DBRS. Debt instruments that are rated in the A category by DBRS are considered by DBRS to be of a good credit quality. The capacity for repayment is substantial, but of lesser credit quality than

AA rated instruments. Securities in this category may be vulnerable to future events, but qualifying negative factors are considered manageable. The assignment of a "(high)" or "(low)" designation indicates relative standing of such category.

The rating of Pfd-2 (low) from DBRS with respect to NSPI's preferred shares is characterized as "satisfactory credit quality" and is the second highest of six available rating categories.

The rating of R-1 (low) from DBRS with respect to NSPI's commercial paper is characterized as "good credit quality" and is the third highest of ten available rating categories.

Standard & Poor's

Standard & Poor's ("S&P") credit ratings are on a long term debt rating scale that ranges from AAA to D, representing the range from highest to lowest quality of such rated securities. A rating of BBB by S&P is the fourth highest of ten major categories. According to the S&P rating system, an obligor with debt securities rated BBB has adequate capacity to meet its financial commitments. However, adverse economic conditions or changing circumstances are more likely to lead to weakened capacity of the obligor to meet its financial commitments. The addition of a plus (+) or minus (-) designation after a rating indicates the relative standing within a particular rating category.

The rating of P-2 (Low) from S&P with respect to NSPI's preferred shares corresponds to S&P's debt rating scale criteria for BBB-.

The rating of A-1 (Low) from S&P with respect to NSPI's commercial paper indicates the obligor's capacity to meet its financial commitment on the obligation is strong.

DIVIDENDS

Any dividend payments are at the Directors' discretion based upon earnings and capital requirements and such other factors as the Directors may consider relevant.

Each Series D First Preferred Share is entitled to a $1.475 per share per annum fixed cumulative preferential cash dividend, as and when declared by the Board, accruing from the date of issue and payable quarterly on the 15th day of January, April, July and October of each year.

During the last three completed fiscal years, the Directors approved payment of the following dividends on its shares that were outstanding on December 31, 2011:

Series D First Preferred Shares			
Fiscal Year	Record Date	Date Paid	Dividend (per share)
2011	October 3, 2011	October 17, 2011	0.36875
	June 30, 2011	July 15, 2011	0.36875
	April 1, 2011	April 15, 2011	0.36875
	December 31, 2011	January 15, 2011	0.36875
2010	September 30, 2010	October 15, 2010	0.36875
	June 30, 2010	July 15, 2010	0.36875
	April 1, 2010	April 15, 2010	0.36875
	December 31, 2009	January 15, 2010	0.36875
2009	October 1, 2009	October 15, 2009	0.36875
	June 1, 2009	July 15, 2009	0.36875
	January 1, 2009	January 15, 2009	0.36875

NSPI paid dividends on its common shares which are held, directly and indirectly, by Emera, as follows: in 2011 - $25 million; in 2010 - $100 million; and in 2009 - $126 million.

MARKET FOR SECURITIES

Trading Price and Volume

NSPI's Common Shares are directly and indirectly owned by Emera and are not publicly traded. NSPI's Series D First Preferred Shares are listed and posted for trading on the TSX under the symbol "NSI.PR.D". The trading volume for the Series D First Preferred Shares and their high and low price for each month of 2011 are set out below:

Series D First Preferred Shares			
2011	High	Low	Volume
January	28.25	27.55	132,118
February	28.57	27.42	81,372
March	28.39	27.76	15,530
April	28.28	27.60	106,922
May	28.05	27.65	15,660
June	28.13	27.50	41,548
July	27.80	27.52	52,687
August	27.99	27.00	34,984
September	27.90	26.67	25,996
October	29.00	27.56	20,597
November	28.50	27.56	79,448
December	28.20	27.80	24,189

Prior Sales

A total of 5,000,000 common shares were issued to Emera and an affiliate under common control of Emera in 2011. See "Capital Structure – Common Shares Issued to Emera" above.

TRANSFER AGENT AND REGISTRAR

Computershare acts as NSPI's transfer agent and registrar. The registers of transfers of securities of NSPI are located at Computershare's principal offices in Vancouver, Calgary, Toronto, Montreal and Halifax.

DIRECTORS AND OFFICERS

Directors

The following information is provided for each Director of NSPI as of December 31, 2011:

Name & Municipality of Residence	Director Since(1)	Principal Occupations During Past Five Years
Wesley G. Armour(2)(3) Moncton, New Brunswick	2005	President and Chief Executive Officer of Armour Transportation Systems, which provides trucking,

Name & Municipality of Residence	Director Since(1)	Principal Occupations During Past Five Years
Canada		warehousing, and courier services in Atlantic Canada.
Robert R. Bennett Halifax, Nova Scotia Canada	2008	President and Chief Executive Officer since June 2008. From September 2007 to June 2008, Executive Vice-President, Revenue and Sustainability of NSPI. From September 2005 to June 2007, President and Chief Operating Officer of Bangor Hydro. From January 2005 to September 2005, Vice President and General Manager of Bangor Hydro. From June 3, 2002 to January 2005, General Manager Transmission & Distribution Asset Management of Bangor Hydro.
J. Lee Bragg(2)(3) Fall River, Nova Scotia Canada	2010	Chief Executive Officer of Eastlink, a cable and communication company, and its associated communications companies since 1999. Prior to 1999, held various management positions with the Bragg Group of Companies.
R. Irene d'Entremont, C.M.(2)(3)(5) Yarmouth, Nova Scotia Canada	1995	President of ITG Information Management Inc., business and management services consultants.
James D. Eisenhauer(2) (4) Lunenburg, Nova Scotia Canada	2008	President and Chief Executive Officer of ABCO Group Limited, which has holdings in manufacturing and distribution activities.
Christopher G. Huskilson Wellington, Nova Scotia Canada	2004	President and Chief Executive Officer of Emera since November 2004. Chair of Bangor Hydro, a Director of NSPI and Chair or Director of a number of other Emera affiliated companies. Since 1980 held a number of positions within NSPI and its predecessor, Nova Scotia Power Corporation.
Raymond E. Ivany (2) (3) Wolfville, Nova Scotia Canada	2011	President and Vice Chancellor of Acadia University since April 2009. From 2007 to 2009 Chair of the Worker's Compensation Board of Nova Scotia. Former principal of Ivany and Associates, a consulting firm, from 2005 to 2009.
John T. McLennan(2)(3) Mahone Bay, Nova Scotia Canada	2005	Chair of the Board of Emera since May 2009. Former Chair of the Board of NSPI from May 2006 to May 6, 2009. Director of Chorus Aviation Inc. and Amdocs Ltd. Former Vice-Chair and Chief Executive Officer of Allstream Inc. (formerly AT&T Canada).

Name & Municipality of Residence	Director Since(1)	Principal Occupations During Past Five Years
Marie C. Rounding(2)(3)(6) Toronto, Ontario Canada	2007	Counsel to Gowling Lafleur Henderson LLP, and member of the National Energy and Infrastructure Industry Group. Former President and Chief Executive Officer of the Canadian Gas Association from 1998 to 2003. Former Chair of the Ontario Energy Board from 1992 to 1998.
Elaine S. Sibson(2)(3) Halifax, Nova Scotia Canada	2010	Currently Chair of the Workers' Compensation Board of Nova Scotia. Fellow of the Institute of Chartered Accountants and a Tax Partner in PricewaterhouseCoopers LLP and its predecessor Coopers & Lybrand until 2007. Served on the Board of PricewaterhouseCoopers LLP from 2004 through 2006.

Notes:
(1) Denotes the year the individual became a Director of NSPI. Directors are elected for a one year term which expires at the termination of NSPI's annual general meeting.
(2) Member of the Audit, Nominating and Corporate Governance Committee.
(3) Member of the MRCCR.
(4) Chairman of the Board since May 2, 2011.
(5) Chair of the MRCCR.
(6) Chair of the Audit, Nominating and Corporate Governance Committee.

As of December 31, 2011, no Directors of NSPI own common or preferred shares of NSPI.

NSPI has an Audit, Nominating and Corporate Governance Committee and the MRCCR. The membership of each of these Committees is indicated above.

Audit, Nominating and Corporate Governance Committee

The Audit, Nominating and Corporate Governance Committee of the Company is composed of the following eight members, all of whom are independent Directors: Marie C. Rounding (Chair), Wesley G. Armour, J. Lee Bragg, R. Irene d'Entremont, James D. Eisenhauer, John T. McLennan, Elaine S. Sibson, and Raymond E. Ivany. The responsibilities and duties of the Committee are set out in the Committee's current Charter, a copy of which is attached as Appendix "B" to this AIF.

The Directors believe that the composition of the Committee reflects a high level of financial literacy and experience. Each member of the Committee has been determined by the Board to be "independent" and "financially literate" as such terms are defined under Canadian securities laws. The Directors have made these determinations based on the education and breadth and depth of experience of each member of the Committee. The following is a description of the education and experience of each member of the Committee that is relevant to the performance of her or his responsibilities as a member of the Audit Committee.

Name of Audit Committee Member	Experience and Education Related to Audit Committee Duties
Marie C. Rounding, Committee Chair since 2009	Counsel to Gowling Lafleur Henderson LLP, a leading Canadian law firm, where she is a member of the National Energy and Infrastructure Industry Group. Former President and Chief Executive Officer of the Canadian Gas Association. Prior to that, served over six years as Chair of the Ontario Energy Board, the

Name of Audit Committee Member	Experience and Education Related to Audit Committee Duties
	quasi-judicial body that regulates that province's electricity and natural gas sectors. Former Chair of the Canadian Association of Members of Public Utility Tribunals (CAMPUT). Director of Ontario Power Generation Inc. Member of Independent Review Committees for investment funds managed by Sentry Investments Inc. and Vertex One Asset Management Inc. Graduated from the Directors Education Program and Financial Literacy Program, both jointly sponsored by the Institute of Corporate Directors, and the Rotman School of Management Corporate Governance College. Designated an Institute-certified director, ICD.D.
Wesley G. Armour	President and Chief Executive Officer of Armour Transportation Systems, which provides trucking, warehousing, and courier services in Atlantic Canada. 40 years of experience in the transportation industry, and Past President and a current Director of the Atlantic Provinces Trucking Association, as well as Past President, Past Chairman of the Board and a current Director of the Canadian Trucking Alliance. Served as treasurer for the Canadian Trucking Association and the Atlantic Provinces Trucking Association. Graduated from the Saint John Institute of Technology (Business Administration).
J. Lee Bragg	Chief Executive Officer of Eastlink Group of Companies. EastLink has more than 1,500 employees providing a range of communications, entertainment, television and advertising services to residential, business and public sector customers. With over 450,000 subscribers across Canada, Eastlink is the fifth largest cable company in Canada and is the only privately held company operating in all Canadian provinces. Prior to entering the cable business, Mr. Bragg held various management positions with the Bragg Group of Companies, the parent company of Eastlink.
R. Irene d'Entremont, C.M.	President of ITG Information Management Inc., business and management services consultants. Past President of M.I.T. Electronics Inc. of Yarmouth, Nova Scotia, a research and development company in the manufacturing of electronics products for the marine industry. Held several directorships, including having served as a Director of the Atlantic Canada Opportunities Agency, Marine Atlantic Inc., the Nova Scotia Advisory Board of Colleges and Universities, and Nova Scotia Business Development Corporation where she chaired the Finance Committee. Member of the Law Commission of Canada from 2000 to 2006. Served on the Board of the Aerospace and Defence Industries Association of Nova Scotia since 2004. Served as President of the Yarmouth Chamber of Commerce, Chair of the Nova Scotia Chamber of Commerce, Chair of the Atlantic Provinces Chamber of Commerce, and has been a member of the Canadian Chamber of Commerce. From 1999 to 2002, served as a member of the Revenue Canada E-Commerce Technical Advisory Committee. In 1995, received an Honorary Doctor of Commerce Degree from Saint Mary's University in Halifax. From 1994-2000, served on Revenue Canada Advisory Board.

Name of Audit Committee Member	Experience and Education Related to Audit Committee Duties
James D. Eisenhauer	President and Chief Executive Officer of ABCO Group Limited, which has holdings in manufacturing and distribution activities. He is a Professional Engineer and Fellow of the Institute of Chartered Accountants of Nova Scotia. From 1974 to 1978, staff accountant with Clarkson Gordon (now Ernst & Young) in Halifax. Has been a member of the Board of Nova Scotia Business Inc. since 2005, and Chair since November 2010. Member of the Board of Composites Atlantic Limited since 1993 (and its predecessor Cellpack Aerospace since 1987). Also on the Board of Atlantic Industries Limited and chairs its Audit Committee.
John T. McLennan	Former Vice-Chair and Chief Executive Officer of Allstream Inc. (formerly AT&T Canada), a telecommunications company. Former President and Chief Executive Officer of Bell Canada, and before that he was President of Bell Ontario from 1993 to 1994. From 1990 to 1993, President and Chief Executive Officer of BCE Mobile Communications Inc. Former President and Chief Executive Officer at Cantel Inc. and founder and former President of Jenmark Consulting Inc. Former Executive Vice President of Mitel Communications Inc. Currently sits on the board of directors of Chorus Aviation Inc. and Amdocs Ltd. Holds a Bachelor of Science, Master of Science and Honorary Doctorate of Science degrees from Clarkson University in New York.
Elaine S. Sibson	Fellow of the Institute of Chartered Accountants and a Tax Partner in PricewaterhouseCoopers LLP and its predecessor Coopers & Lybrand from 1974 to 2007. Served on the Board of PricewaterhouseCoopers LLP from 2004 through 2006. Served on the executive committee of the Canadian Tax Foundation from 2001 to 2005 and served for four years as Treasurer of a hospital. A graduate of the Institute of Corporate Directors and current Chair of the Atlantic Chapter. A past Chair of the Canadian tax Foundation. Sits on the Board of the Atlantic Institute of Market Studies.
Raymond E. Ivany	President and Vice Chancellor of Acadia University. Former Chair of the Workers' Compensation Board of Nova Scotia. Former President and Chief Executive Officer of the Nova Scotia Community College and Executive Vice President of the University College of Cape Breton. Served on several community boards and committees, including as board member of the Greater Halifax Partnership from 2002 to 2005, member of Premier's Fiscal Management Task Force from 2000 to 2001, and participant on the National Roundtable on the Environment and Economy from 1999 to 2002.

Audit and Non-Audit Services Pre-Approval Process

The Committee is responsible for the oversight of the work of the external auditors. As part of this responsibility, the Committee is required to pre-approve the audit and non-audit services performed by the external auditors in order to assure that they do not impair the external auditors' independence from the Company. Accordingly, the Committee has adopted an Audit and Non-Audit Pre-Approval Policy, which sets forth the procedures and the conditions pursuant to which services proposed to be performed by the external auditors may be pre-approved.

Unless a type of service has received the pre-approval of the Committee it will require specific pre-approval by the Committee if it is to be provided by the external auditors. Any proposed services exceeding the pre-approved cost levels or budgeted amounts will also require specific pre-approval by the Committee.

The Committee considers whether the provision of any service raises an issue regarding the independence of the external auditors.

Auditors' Fees

The aggregate fees billed by Grant Thornton LLP, the Company's external auditors, during the fiscal years ended December 31, 2011 and 2010 respectively, were as follows:

Service Fee	2011	2010
Audit Fees	$428,197	$234,350
Audit-related Fees	$49,400	$356,690
Tax Fees	$22,400	$11,500
All Other Fees	Nil	Nil
Total	$499,997	$602,540

Audit-related Fees for NSPI relate to services associated with French translation.

Tax Fees are for tax compliance on corporation income tax returns.

Officers

The Officers of NSPI as of December 31, 2011 were as follows:

Name and Municipality of Residence	Position with NSPI	Five Year History with NSPI
Robert R. Bennett Halifax, Nova Scotia Canada	President and Chief Executive Officer	Since June 2008. From September 2007 to June 2008, Executive Vice-President, Revenue and Sustainability. From September 2005 to June 2007, President and Chief Operating Officer of Bangor Hydro. From January 5, 2005 to September 2005, Vice President and General Manager of Bangor Hydro and prior to that he served as General Manager Transmission & Distribution Asset Management of Bangor Hydro.
Barbara Meens Thistle Halifax, Nova Scotia Canada	Vice President, Human Resources	Since November 25, 2011. From November 2011 to the present, Chief Human Resources Officer for Emera. From 2009 to

Name and Municipality of Residence	Position with NSPI	Five Year History with NSPI
		2011, General Manager, Human Resources for NSPI. Prior to 2009, National Director, Human Resources for Eastlink and prior to that, she was the Chief Human Resources Officer at BC Hydro.
Judy A. Steele Halifax, Nova Scotia Canada	Chief Financial Officer	Since May 16, 2011. Prior to May 2011, Vice President Finance of Emera Energy Inc. From 1999 to May 2007, held managerial and executive positions with Emera's businesses.
Robin B. McAdam Halifax, Nova Scotia Canada	Executive Vice President Strategic Business & Customer Services	Since December 5, 2011. From January 2009 to December, 2011, Executive Vice President Sustainability. From 2007 to January 2009, President of Emera Brunswick Pipeline Company Ltd. Director of Emera Brunswick Pipeline Company Ltd. After joining Emera in 1998 and until 2007, Robin worked on various M&A initiatives and greenfield development projects for Emera-affiliated companies.
Mark W. Savory Lower Sackville, Nova Scotia Canada	Vice President, Technical and Construction Services	Since October 2008. From February 2008 to October 2008, Vice President, Engineering and Construction of Emera. From July 2006 to February 2008, Director, Asset Management with Emera. From December 2003 to July 2006, Director, Control Centre, NSPI.
Richard J. Smith Halifax, Nova Scotia Canada	Vice President, Corporate Insurance and Asset Protection	Since September 2008. Prior to September 2008, Corporate Secretary and held other offices since 1992.
Stephen D. Aftanas Halifax, Nova Scotia Canada	Corporate Secretary	Since September 2008. From June 2007 to September 2008, Associate Corporate Secretary. From March 2006 to June 2007, Associate General Counsel. Prior to March 2006, Senior Solicitor.

Name and Municipality of Residence	Position with NSPI	Five Year History with NSPI
Alan C. Richardson (1) Lower Sackville, Nova Scotia Canada	Vice President, Integrated Customer Services	Since October 2008. From February 2008 to October 2008, Vice President Engineering and Construction of Emera. From July 2006 to February 2008, Director, Asset Management with Emera.
J. Rene Gallant Halifax, Nova Scotia Canada	Vice President, Regulatory Affairs	Since May 2, 2011. From September 2007 to May 2011, General Manager Regulatory Affairs. From October 2005 to September 2007, Regulatory Counsel.

Notes:
(1) Effective January 1, 2012, Mr. Richardson resigned from NSPI and became the Vice President, Strategy and Innovation for Emera.

No Directors or Officers own preferred shares of NSPI. All of NSPI's common shares are held directly or indirectly by Emera. No insider of NSPI has an interest in transactions material to NSPI.

Certain Proceedings

To the knowledge of the Company, none of the Directors or Officers of the Company:

1. are, as at the date of this AIF, or have been, within ten years before the date of this AIF, a director, chief executive officer or chief financial officer of any company that:

    (a) was subject to an Order that was issued while the Director was acting in the capacity as director, chief executive officer or chief financial officer; or

    (b) was subject to an Order that was issued after the Director ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer of chief financial officer;

2. with the exception of Mr. McLennan as set forth below, are, as at the date of this AIF, or have been within ten years before the date of this AIF, a director or executive officer of any company that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangements or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or

3. have, within the ten years before the date of this AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the proposed nominee.

John T. McLennan was the Chief Executive Officer of AT&T Canada when AT&T Canada filed for protection under the Companies' Creditors Arrangement Act (Canada) on October 15, 2002.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

To the knowledge of NSPI, there are no legal proceedings that individually or together could potentially involve claims against NSPI for damages totalling 10% or more of the current assets of NSPI, exclusive of interest and costs.

NO INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than Emera, which is the sole direct and indirect holder of the common shares of NSPI, none of the following persons or companies, namely (a) a Director or Officer of NSPI; (b) a person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over, more than 10% of any class or series of NSPI's outstanding voting securities, or (c) an associate or affiliate of any person or company named in (a) or (b), had a material interest in any transaction involving NSPI within NSPI's last three completed financial years or during the current financial year that has materially affected or will materially affect NSPI.

MATERIAL CONTRACTS

NSPI has no material contracts other than those entered into in the ordinary course of its business.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The MD&A for the financial year ended December 31, 2011 is incorporated herein by reference.

EXPERTS

Interest of Experts

Grant Thornton LLP are the external auditors of NSPI. Grant Thornton LLP reports that they are independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Nova Scotia.

ADDITIONAL INFORMATION

Additional Information relating to NSPI may be found on SEDAR at www.sedar.com or upon request to the Corporate Secretary, NSPI, P.O. Box 910, Halifax, N.S., B3J 2W5, telephone (902) 428-6096 or fax (902) 428-6171:

At any time, NSPI will provide to any person upon request to the Corporate Secretary, a copy of the Emera Group of Companies' Standards for Business Conduct, which is intended to be a code of ethics for the purpose of the *Sarbanes-Oxley Act of 2002.*

APPENDIX "A" – AUDIT COMMITTEE CHARTER

NOVA SCOTIA POWER INCORPORATED
AUDIT COMMITTEE
CHARTER

PART I
MANDATE AND RESPONSIBILITIES

<u>*Committee Purpose*</u>

There shall be a committee of the Board of Directors (the "Board") of Nova Scotia Power Inc. ("NSPI") which shall be known as the Audit Committee (the "Committee"). The Committee shall assist the Board in discharging its oversight responsibilities concerning:

- *the integrity of NSPI's financial statements;*
- *NSPI's internal control systems;*
- *the internal audit and assurance process;*
- *the external audit process;*
- *NSPI's compliance with legal and regulatory requirements; and*
- *any other duties set out in this Charter or delegated to the Committee by the Board.*

1. Financial Reporting

   a) The Committee shall be responsible for reviewing and recommending to the Board for approval:

      (i) the audited annual financial statements of NSPI, all related Management's Discussion and Analysis, and earnings press releases;

      (ii) any documents containing NSPI's audited financial statements; and,

      (iii) the quarterly financial statements, all related Management's Discussion and Analysis, and earnings press releases.

   b) The Committee shall satisfy itself that adequate procedures are in place for the review of public disclosure of financial information.

2. External Auditors

   a) The Committee shall evaluate, approve and recommend to the Board the external auditor to be nominated for the purpose of preparing or issuing the auditor's report or performing other audit, review, or attest services for NSPI, and if the shareholders authorize the Board to do so, the compensation of such external auditors. The

Committee shall not recommend the same external auditor as is being recommended for Emera Inc.

b) Once appointed, the external auditor shall report directly to the Committee, and the Committee shall oversee the work of the external auditor concerning the preparation or issuance of the auditor's report or the performance of other audit, review or attest services for NSPI.

c) The Committee shall be responsible for resolving disagreements between management and the external auditor concerning financial reporting.

d) The Committee shall review the independence of the external auditor and shall make recommendations to the Board on appropriate actions to be taken which the Committee deems necessary to protect and enhance the independence of the external auditor.

3. Non-Audit Services

a) The Committee shall be responsible for reviewing and pre-approving all non-audit services to be provided to NSPI by the external auditor.

b) The Committee shall be permitted to establish specific policies and procedures concerning the performance of non-audit services by the external auditor so long as the requirements of applicable legislation are satisfied.

c) In accordance with policies and procedures established by the Committee, and applicable legislation, the Committee may delegate the pre-approval of non-audit services to a member of the Committee or a sub-committee thereof.

4. Oversight and Monitoring of Audits

a) The Committee shall review with the external auditor, the internal auditors and Management the audit function generally, the objectives, staffing, locations, co-ordination, reliance upon Management and internal audit and general audit approach and scope of proposed audits of the financial statements of NSPI, the overall audit plans, the responsibilities of Management, the internal auditors and the external auditor, the audit procedures to be used and the timing and estimated budgets of the audits.

b) The Committee shall meet periodically with the internal auditors to discuss the progress of their activities and any significant findings stemming from internal audits and any difficulties or disputes that arise with Management and the adequacy of Management's responses in correcting audit-related deficiencies.

c) The Committee shall discuss with the external auditor any difficulties or disputes that arose with Management or the internal auditors during the course of the audit and the adequacy of Management's responses in correcting audit-related deficiencies.

d) The Committee shall review with Management the results of internal and external audits.

e) The Committee shall take such other reasonable steps as it may deem necessary to satisfy it that the audit was conducted in a manner consistent with applicable legal requirements and auditing standards of applicable professional or regulatory bodies.

5. Oversight and Review of Accounting Principles and Practices

The Committee shall, as it deems necessary, oversee, review and discuss with Management, the external auditor and the internal auditors:

a) the quality, appropriateness and acceptability and degree of conservatism of NSPI's accounting principles and practices used in its financial reporting, changes in NSPI's accounting principles or practices and the application of particular accounting principles and disclosure practices by Management to new transactions or events;

b) all significant financial reporting issues and judgments made in connection with the preparation of the financial statements, including the effects of alternative methods within generally accepted accounting principles on the financial statements and any "second opinions" sought by Management from an independent auditor with respect to the accounting treatment of a particular item;

c) disagreements between Management and the external auditor or the internal auditors regarding the application of any accounting principles or practices;

d) any material change to NSPI's auditing and accounting principles and practices as recommended by Management, the external auditor or the internal auditors or which may result from proposed changes to applicable generally accepted accounting principles;

e) the effect of regulatory and accounting initiatives on NSPI's financial statements and other financial disclosures;

f) any reserves, accruals, provisions, estimates or Management programs and policies, including factors that affect asset and liability carrying values and the timing of revenue and expense recognition, that may have a material effect upon the financial statements of NSPI;

g) the use of special purpose entities and the business purpose and economic effect of off-balance sheet transactions, arrangements, obligations, guarantees and other relationships of NSPI and their impact on the reported financial results of NSPI;

h) any legal matter, claim or contingency that could have a significant impact on the financial statements, NSPI's compliance policies and any material reports, inquiries or other correspondence received from regulators or governmental agencies and the manner in which any such legal matter, claim or contingency has been disclosed in NSPI's financial statements;

i) the treatment for financial reporting purposes of any significant transactions which are not a normal part of NSPI's operations.

6. Hiring Policies

The Committee shall be responsible for reviewing and approving NSPI's hiring policy concerning partners or employees, as well as former partners and employees, of the present or former external auditors of NSPI.

7. Pension Plans

The Committee shall exercise oversight of the pension plans in accordance with the Pension Governance Framework adopted by NSPI.

8. Oversight of Finance Matters

a) Appointments of key financial executives involved in the financial reporting process of NSPI, including the Chief Financial Officer, shall require the prior review of the Committee.

b) The Committee shall receive and review material tax policies and tax planning initiatives, tax payments and reporting and any pending tax audits or assessments. The Committee shall discuss NSPI's compliance with tax and financial reporting laws and regulations when and if issues arise.

c) The Committee shall meet periodically with Management to review and discuss NSPI's major financial risk exposures and the policy steps Management has taken to monitor and control such exposures, including the use of financial derivatives and hedging activities. The Committee shall identify with Management the principal business risks, determine risk tolerance, and approve risk management policies.

d) The Committee shall review any investments or transactions that could adversely affect the well-being of NSPI which the internal or external auditor, or any officer of NSPI, may bring to the attention of the Committee.

9. Internal Controls

In order to discharge its responsibility, pursuant to NSPI's Articles of Association, to ensure that appropriate internal control procedures (financial or otherwise) are in place, the Committee shall, as it deems necessary, exercise oversight of:

a) the adequacy and effectiveness of the Company's internal accounting and financial controls and the recommendations of Management, the external auditor and the internal auditors for the improvement of accounting practices and internal controls;

b) any material or significant weaknesses in the internal control environment;

c) management's compliance with the Company's processes, procedures and internal controls; and

d) the practices and procedures adopted to support Management's assurance on the underlying controls reflected in the CEO/CFO certificates required under applicable securities regulations, In exercising such oversight, the Committee shall review and discuss each of the foregoing with Management, the external auditor and the internal auditor.

10. Internal Auditor

a) The chief internal auditor shall report directly to the Committee. The Committee shall approve the appointment of the internal auditor.

b) The Committee shall review the terms of engagement of the internal auditors. The Committee will be consulted with respect to the compensation payable to, and the appointment, replacement, or termination of, the chief internal auditor.

c) The Committee shall review the annual internal audit plan.

d) The Committee shall obtain from the internal auditors and review summaries of the significant reports to Management prepared by the internal auditors, or the actual reports if requested by the Committee, and Management's responses to such reports.

e) The Committee shall, as it deems necessary, communicate with the internal auditors with respect to their reports and recommendations, the extent to which prior recommendations have been implemented and any other matters that the internal auditor brings to the attention of the Committee.

f) The Committee shall, annually or more frequently as it deems necessary, evaluate the internal auditors including their activities, organizational structure and qualifications and effectiveness.

12. Complaints

The Committee shall ensure that procedures exist relating to the receipt, retention, and treatment of complaints which may be received concerning accounting, internal accounting controls, or auditing matters, and in particular, the Committee shall review procedures concerning the confidential, anonymous submission of concerns by NSPI's employees relating to questionable accounting or auditing matters.

13. Other Responsibilities

The Committee shall:

(a) review any investment issues or policies which may arise from time to time until a committee is established by the Board to specifically deal with such issues;

(b) pursuant to NSPI's Articles of Association, perform such other duties and exercise such powers as may be directed or delegated to the Committee by the Board;

(c) receive confirmation of compliance with the Nova Scotia Utilities and Review Board ("UARB") Code of Conduct Guidelines as may be in place from time to time, including receiving copies of any independent report from third parties on same;

(d) Annually, review insurance programs.

14. Risk Oversight

The Committee shall oversee NSPI's risk management by reviewing:

(a) the annual identification and assessment of the principal risks of NSPI, including, without limitation, the major financial risk exposures (such as the use of derivative instruments and hedging activities);

(b) the process for ongoing monitoring and reporting of the principal risks of NSPI;

(c) the effectiveness of NSPI's mitigation response to its principal risks;

(d) the alignment of risk management with NSPI's risk tolerance, its strategy, and its organizational objectives, including capital and resources allocation.

15. The Committee shall oversee NSPI's risk management governance by:

(a) reviewing the documentation of the allocation of roles, responsibility and accountability for NSPI's risk management;

(b) reviewing the disclosure and communication of NSPI's principal risks and management of those risks.

16. Limitation on Authority

Nothing articulated herein is intended to assign to the Committee the Board's responsibility to oversee NSPI's compliance with applicable laws or regulations or to expand applicable standards of liability under statutory or regulatory requirements for the Directors or the members of the Committee.

PART II
COMPOSITION

17. Composition

(a) NSPI's Articles of Association require that the Committee shall be comprised of no less than three directors, each of whom shall be independent, as defined for purposes of service as an audit committee member under applicable securities laws and the rules of any stock exchange on which the Company's securities are listed for trading.

(b) The Board shall appoint members to the Committee who are financially literate, as required by applicable legislation, which at a minimum requires that Committee members have the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by NSPI's financial statements.

(c) Committee members shall be appointed at the Board meeting following the election of Directors at NSPI's annual shareholders' meeting and membership may be based upon the recommendation of the Nominating and Corporate Governance Committee.

(d) Pursuant to NSPI's Articles of Association, the Board may appoint, remove, or replace any member of the Committee at any time, and a member of the Committee shall cease to be a member of the Committee upon ceasing to be a Director. Subject to the foregoing, each member of the Committee shall hold office as such until the next annual meeting of shareholders after the member's appointment to the Committee.

(e) The Secretary of the Committee shall advise NSPI's internal and external auditors of the names of the members of the Committee promptly following their election.

PART III
COMMITTEE PROCEDURE

18. Meetings

(a) Meetings of the Committee may be called by the Chair or at the request of any member or any member of the Board. The Committee shall meet at least quarterly.

(b) The timing and location of meetings of the Committee, and the calling of and procedure at any such meeting, shall be determined from time to time by the Committee.

(c) NSPI's internal and external auditors shall be notified of all meetings of the Committee and shall have the right to appear before and be heard by the Committee.

(d) NSPI's internal or external auditors may request the Chair of the Committee to consider any matters which the internal or external auditors believe should be brought to the attention of the Committee or the Board.

19. Separate Sessions

The Committee Chair shall meet periodically with the Chief Financial Officer, the head of the internal audit function (if other than the Chief Financial Officer) and the external auditor in separate executive sessions to discuss any matters that the Committee or each of these groups believes should be discussed privately and such persons shall have access to the Committee to bring forward matters requiring its attention. However, the Committee shall also meet periodically without Management present.

20. Quorum

Two members of the Committee present in person, by teleconferencing, or by videoconferencing, or by a combination thereof, will constitute a quorum.

21. Chair

Pursuant to NSPI's Articles of Association, the Committee shall choose one of its members to act as Chair of the Committee, which person shall not be the Chair of Emera Inc.'s Audit Committee. In selecting a Committee Chair, the Committee may consider any recommendation made by the Nominating and Corporate Governance Committee.

22. Secretary and Minutes

Pursuant to NSPI's Articles of Association, the Corporate Secretary of NSPI shall act as the Secretary of the Committee. NSPI's Articles of Association require that the Minutes of the Committee be in writing and duly entered into NSPI's records, and the Minutes shall be circulated to all members of the Committee. The Secretary shall maintain all Committee records.

23. Board Relationships and Reporting

The Committee shall:

(i) Review on an annual basis the Committee's Charter;

(ii) Oversee the appropriate disclosure of the Committee's Charter as well as other information concerning the Committee which is required to be disclosed by applicable legislation in NSPI's Annual Information Form and any other applicable disclosure documents; and

(iii) Report to the Board at the next following board meeting on any meeting held by the Committee, and as required, regularly report to the Board on Committee activities, issues, and related recommendations.

24. Powers

The Committee shall:

(a) examine and consider such other matters, and meet with such persons, in connection with the internal or external audit of NSPI's accounts, which the Committee in its discretion determines to be advisable;

(b) have the authority to communicate directly with the internal and external auditors;

(c) have the right to inspect all records of NSPI or its affiliates and may elect to discuss such records, or any matters relating to the financial affairs of NSPI with the officers or auditors of NSPI and its affiliates; and

(d) review any investments or transactions that could adversely affect the well-being of NSPI which the internal or external auditor, or any officer of NSPI, may bring to the attention of the Committee.

25. Experts and Advisors

The Committee may, in consultation with the Chairman of the Board, engage and compensate any outside adviser that it determines necessary in order to carry out its duties.

PART IV
ANNUAL SCHEDULE

The timetable on the following pages outlines the Committee's annual schedule of activities.

	Q1	Q2	Q3	Q4	As Needed
1. Financial Reporting a) The Committee shall be responsible for reviewing and recommending to the Board for approval: (i) the audited annual financial statements of NSPI, all related Management Discussion and Analysis, and earnings press releases;	√				
(ii) any documents containing NSPI's audited financial statements; and,	√				
(iii) the quarterly financial statements, all related Management Discussion and Analysis, and earnings press releases.	√	√	√	√	
b) The Committee shall satisfy itself that adequate procedures are in place for the review of public disclosure of financial information and the Committee shall assess the adequacy of these procedures.	√	√	√	√	
2. External Auditors a) The Committee shall evaluate, approve and recommend to the Board the external auditor to be nominated for the purpose of preparing or issuing the auditor's report or performing other audit, review, or attest services for NSPI, as well as the compensation of such external auditors. The Committee shall not recommend the same external auditor as is being recommended for Emera Inc.	√				
b) Once appointed, the external auditor shall report directly to the Committee, and the Committee shall oversee the work of the external auditor concerning the preparation or issuance of the auditor's report or the performance of other audit, review or attest services for NSPI.	√	√	√	√	
c) The Committee shall be responsible for resolving disagreements between management and the external auditor concerning financial reporting.					√
d) The Committee shall review the independence of the external auditor and shall make recommendations to the Board on appropriate actions to be taken which the Committee deems necessary to protect and enhance the independence of the external auditor.	√	√	√	√	

	Q1	Q2	Q3	Q4	As Needed
3.Non-Audit Services a) The Committee shall be responsible for reviewing and pre-approving all non-audit services to be provided to NSPI, by the external auditor.	√	√	√	√	
b) The Committee shall be permitted to establish specific policies and procedures concerning the performance of non-audit services by the external auditor so long as the requirements of applicable legislation are satisfied.	√	√	√	√	
c) In accordance with policies and procedures established by the Committee, and applicable legislation, the Committee may delegate the pre-approval of non-audit services to a member of the Committee or a sub-committee thereof.	√	√	√	√	
4.Oversight and Monitoring of Audits a) The Committee shall review with the external auditor, the internal auditors and Management the audit function generally, the objectives, staffing, locations, co-ordination, reliance upon Management and internal audit, and general audit approach and scope of proposed audits of the financial statements of NSPI, the overall audit plans, the responsibilities of Management, the internal auditors and the external auditor, the audit procedures to be used and the timing and estimated budgets of the audits.	√	√	√	√	
b) The Committee shall meet periodically with the internal auditors to discuss the progress of their activities and any significant findings stemming from internal audits and any difficulties or disputes that arise with Management and the adequacy of Management's responses in correcting audit-related deficiencies.	√	√	√	√	
c) The Committee shall discuss with the external auditor any difficulties or disputes that arose with Management or the internal auditors during the course of the audit and the adequacy of Management's responses in correcting audit-related deficiencies.	√	√	√	√	
d) The Committee shall review with Management the results of internal and external audits.	√	√	√	√	
e) The Committee shall take such other reasonable steps as it may deem necessary to satisfy it that the audit was conducted in a manner consistent with applicable legal requirements and auditing standards of applicable professional or regulatory bodies.					√
5.Oversight and Review of Accounting Principles and Practices The Committee shall, as it deems necessary, oversee, review and discuss with Management, the external auditor and the internal auditors: a) the quality, appropriateness and acceptability and degree of	√	√	√	√	

	Q1	Q2	Q3	Q4	As Needed
conservatism of NSPI's accounting principles and practices used in its financial reporting, changes in NSPI's accounting principles or practices and the application of particular accounting principles and disclosure practices by Management to new transactions or events;					
b) all significant financial reporting issues and judgments made in connection with the preparation of the financial statements, including the effects of alternative methods within generally accepted accounting principles on the financial statements and any "second opinions" sought by Management from an independent auditor with respect to the accounting treatment of a particular item;	√	√	√	√	
c) disagreements between Management and the external auditor or the internal auditors regarding the application of any accounting principles or practices;	√	√	√	√	
d) any material change to NSPI's auditing and accounting principles and practices as recommended by Management, the external auditor or the internal auditors or which may result from proposed changes to applicable generally accepted accounting principles;	√	√	√	√	
e) the effect of regulatory and accounting initiatives on NSPI's financial statements and other financial disclosures;	√	√	√	√	
f) any reserves, accruals, provisions, estimates or Management programs and policies, including factors that affect asset and liability carrying values and the timing of revenue and expense recognition, that may have a material effect upon the financial statements of NSPI;	√	√	√	√	
g) the use of special purpose entities and the business purpose and economic effect of off-balance sheet transactions, arrangements, obligations, guarantees and other relationships of NSPI and their impact on the reported financial results of NSPI;	√	√	√	√	
h) any legal matter, claim or contingency that could have a significant impact on the financial statements, NSPI's compliance policies and any material reports, inquiries or other correspondence received from regulators or governmental agencies and the manner in which any such legal matter, claim or contingency has been disclosed in NSPI's financial statements;	√	√	√	√	
i) the treatment for financial reporting purposes of any significant transactions which are not a normal part of NSPI's operations.	√	√	√	√	
6.Hiring Policies The Committee shall be responsible for reviewing and approving NSPI's hiring policy concerning partners or employees, as well as former partners and employees, of the present or former external					√

	Q1	Q2	Q3	Q4	As Needed
auditors of NSPI.					
7.Pension Plans The Committee shall exercise oversight of the pension plans in accordance with the Pension Governance Framework adopted by NSPI.		√			
8.Oversight of Finance Matters a) Appointments of key financial executives involved in the financial reporting process of NSPI, including the Chief Financial Officer, shall require the prior review of the Committee.					√
b) The Committee shall receive and review material tax policies and tax planning initiatives, tax payments and reporting and any pending tax audits or assessments. The Committee shall discuss NSPI's compliance with tax and financial reporting laws and regulations when and if issues arise.	√				√
c) The Committee shall meet periodically with Management to review and discuss NSPI's major financial risk exposures and the policy steps Management has taken to monitor and control such exposures, including the use of financial derivatives and hedging activities. The Committee shall identify with Management the principal business risks, determine risk tolerance, and approve risk management policies.	√	√	√	√	
d) The Committee shall review any investments or transactions that could adversely affect the well-being of NSPI which the internal or external auditor, or any officer of NSPI, may bring to the attention of the Committee.					√
9.Internal Controls In order to discharge its responsibility, pursuant to NSPI's Articles of Association, to ensure that appropriate internal control procedures (financial or otherwise) are in place, the Committee shall, as it deems necessary, exercise oversight of, review and discuss with Management, the external auditor and the internal auditors: a) the adequacy and effectiveness of the Company's internal accounting and financial controls and the recommendations of Management, the external auditor and the internal auditors for the improvement of accounting practices and internal controls;	√	√	√	√	
b) any material or significant weaknesses in the internal control environment, including with respect to computerized information system controls and security; and	√	√	√	√	
c) management's compliance with the Company's processes, procedures and internal controls.	√	√	√	√	
d) the practices and procedures adopted to support Management's assurance on the underlying controls reflected in the CEO/CFO certificates required under applicable securities regulations,	√	√	√	√	

	Q1	Q2	Q3	Q4	As Needed
10.Internal Auditor a) The chief internal auditor shall report directly to the Committee. The Committee shall approve the appointment of the internal auditor.	√	√	√	√	
b) The Committee shall review the terms of engagement of the internal auditors. The Committee will be consulted with respect to the compensation payable to, and the appointment, replacement, or termination of, the chief internal auditor. c) The Committee shall review the annual internal audit plan				√	
d) The Committee shall obtain from the internal auditors and review summaries of the significant reports to Management prepared by the internal auditors, or the actual reports if requested by the Committee, and Management's responses to such reports.	√	√	√	√	
e) The Committee shall, as it deems necessary, communicate with the internal auditors with respect to their reports and recommendations, the extent to which prior recommendations have been implemented and any other matters that the internal auditor brings to the attention of the Committee.	√	√	√	√	
f) The Committee shall, annually or more frequently as it deems necessary, evaluate the internal auditors including their activities, organizational structure and qualifications and effectiveness.				√	
12.Complaints The Committee shall ensure that procedures exist relating to the receipt, retention, and treatment of complaints which may be received concerning accounting, internal accounting controls, or auditing matters, and in particular, the Committee shall be responsible for the establishment of procedures concerning the confidential, anonymous submission of concerns by NSPI's employees relating to questionable accounting or auditing matters.					√
13.Other Responsibilities The Committee shall: (a) review any investment issues or policies which may arise from time to time until a committee is established by the Board to specifically deal with such issues; and					√
(b) pursuant to NSPI's Articles of Association, perform such other duties and exercise such powers as may be directed or delegated to the Committee by the Board.					√
(c) receive confirmation of compliance with the Nova Scotia Utilities and Review Board ("UARB") Code of Conduct Guidelines as may be in place from time to time, including receiving copies of any independent report from third parties on same					√

	Q1	Q2	Q3	Q4	As Needed
(d) Annually review insurance program			√		
514. Risk Oversight The Committee shall oversee NSPI's risk management by reviewing: (a) the annual identification and assessment of the principal risks of NSPI, including, without limitation, the major financial risk exposures (such as the use of derivative instruments and hedging activities); (b) the process for ongoing monitoring and reporting of the principal risks of NSPI; (c) the effectiveness of NSPI's mitigation response to its principal risks; (d) the alignment of risk management with NSPI's risk tolerance, its strategy, and its organizational objectives, including capital and resources allocation.			√		
15. The Committee shall oversee NSPI's risk management governance by: (a) reviewing the documentation of the allocation of roles, responsibility and accountability for NSPI's risk management; (b) by reviewing the disclosure and communication of NSPI's principal risks and management of those risks.				√	

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Request IR-3:

Reference: FAM DE-03, page 30, pages 50 on and Analyst reports

a) **DBRS indicated (November 26, 2010) that the introduction of the FAM is expected to reduce earnings volatility in the long term, while S&P upgraded NSPI from BBB to BBB+ in part due to FAM. Please confirm that this is because the FAM covers not just the risk of fuel price volatility but other risks associated with plant efficiencies, shutdowns and outages.**

b) **For each year since NSPI ceased to be a crown corporation include a table of the following: The rate base, deemed equity component, allowed ROE for revenue requirement purposes and net income, actual ROE and net income. For each year where there was a deviation of more than 1% from the allowed ROE indicate the major drivers in this deviation.**

c) **Further to (b), if NSPI had a FAM during the period in (b) above would this have affected the deviation of actual from allowed in a material way? If so please indicate the extent of the deviation since 2006 to determine the magnitude of the risk reduction.**

Response IR-3:

(a) DBRS and S&P have provided their full comments in their publications. It would be inappropriate for NS Power to speculate beyond that. Please refer to OP-12 Confidential Attachment 3 of this Application and OP-12 Confidential Attachment 3 of the 2012 GRA for copies of reports received from DBRS and S&P.

(b) Please refer to Attachment 1.

NON-CONFIDENTIAL

(c) NS Power is not able to determine whether having a FAM during the period prior to 2009 would have affected the deviation of actual from allowed ROE.

Nova Scotia Power Inc.
Years Ended December 31st
Millions of Dollars

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Average regulated equity	$761.4	$789.7	$820.9	$849.6	$877.5	$901.6	$926.9	$947.8	$966.7	$1,029.1	$1,101.8	$1,104.9	$1,085.6	$1,121.2	$1,123.6	$1,128.2	$1,220.0	$1,263.5	$1,362.3
Average regulated capitalization (Ratebase)	$2,538.2	$2,618.1	$2,674.9	$2,930.7	$2,733.2	$2,712.3	$2,679.7	$2,751.7	$2,835.7	$2,833.5	$2,844.9	$2,872.3	$2,885.9	$2,857.6	$2,823.3	$2,794.1	$2,903.6	$3,158.8	$3,407.7
Average actual regulated common equity	30%	30%	31%	29%	32%	33%	35%	34%	34%	36%	39%	38%	38%	39%	40%	40%	42%	40%	40%
Regulated earnings	$91.5	$94.0	$94.8	$90.0	$92.7	$85.4	$103.2	$103.7	$105.1	$106.0	$115.3	$110.8	$94.7	$107.3	$103.0	$109.6	$111.8	$121.3	$131.3
Regulated return on equity	**12.0%**	**11.9%**	**11.5%**	**10.6%**	**10.6%**	**9.5%**	**10.8%**	**10.9%**	**10.9%**	**10.3%**	**10.5%**	**10.0%**	**8.7%**	**9.6%**	**9.2%**	**9.7%**	**9.2%**	**9.6%**	**9.6%**
Regulated ROE Band	11.5%-12%	11.5%-12%	11.5%-12%	10.5%-11.0%	10.5%-11.0%	10.5%-11.0%	10.5%-11.0%	10.5%-11.0%	10.5%-11.0%	9.9%-10.4%	10.5%-11.0%	10.5%-11.0%	9.3%-9.8%	9.3%-9.8%	9.3%-9.8%	9.3%-9.8%	9.1%-9.6%	9.1%-9.6%	9.1%-9.6%

Notes:
1) NSPI reported Return on Equity and Regulated Capitalizaton using the simple average method for years 2002-2005.
2) Since 2006, NSPI reports Return on Equity and Regulated Capitalization using the five quarter average method.
3) In 1999, there was a $3.1M gain on the sale of Enercom shares to NS Power Holdings Inc. This one time gain is not included in the return on common equity calculation.
4) NSPI was below the band in 2005 due to the Q4 2005 agreement with its supplier on pricing for natural gas under an existing long-term natural gas agreement that resulted in a larger than forecasted fuel expense being recorded in Q4 2005.

Request IR-4:

Reference: Business Risk: Ms. McShane's testimony Appendix H, pages 7-13

a) **Please indicate the last time that NSPI filed business risk testimony by a business risk expert, apart from a financial cost of capital witness.**

b) **Please file the last two testimonies filed by Ms. McShane where she discusses NSPI's business risk.**

c) **Ms. McShane makes no assessment as to whether NSPI's business risk has increased or decreased over the last five years. Please indicate both the views of Ms. McShane and NSPI as to whether there has been a material change in business risk since the last time a formal business risk assessment was made or 2005 whichever is latest.**

Response IR-4:

(a) The assessment of a utility's cost of capital is inextricably tied to an assessment of the utility's business risk. The cost of capital experts the Company has engaged have had the expertise in business risk analysis required to estimate the utility's cost of capital.

(b) For Ms. McShane's last two testimonies that included a detailed discussion of NS Power business risk, filed April 2011 and July 2005, please refer to Attachment 1 and Attachment 2.

(c) Ms. McShane considers that NS Power's business risks have risen in the past five years. The minor reduction in business risk which resulted from the adoption of the FAM effective January 1, 2009 (and was balanced by a 0.2 percent reduction in NS Power's Return on Equity) has been more than offset by the challenges that have arisen as a result of Nova Scotia energy policy and related legislation and regulations as well as the weak economy.

In NS Power's view, the FAM has not operated to reduce business risk as was anticipated. NS Power has experienced increased scrutiny of management's decisions and actions, increased involvement and influence of UARB consultants in what were formerly operational aspects of the business, allegations of imprudence, and lengthened time for recovery of fuel costs from what NS Power had understood when the FAM was adopted.

Other business risks have also increased in the past five years, including risks relating to:

- NS Power's fossil fuel based generating units which must now be operated in a different fashion due to the need to balance wind generation and utilize different fuel blends;

- The rapid increase in the cost of our major input: coal which reached our customers on a delayed basis. This has placed upward pressure on rates which is meeting with customer and political resistance;

- Changes in government policy relating to emissions which complicates fuel buying and fuel use and handling as we deal with a number of coal types and must manage those inventories effectively. Blending fuels and managing dispatch while balancing wind so as to optimize economics and also meet regulatory requirements has added to the complexity of the business and thus the risk;

- The requirement for renewable generation, including non-utility owned generation procured under Power Purchase Agreements, requiring new long term commitments whether in rate base or via contract. These long-term commitments are for hundreds of millions of dollars and thus inherently increase risk;

- The steady reduction in local natural gas supply coincident with the fall in gas price which has complicated the procurement of gas at a time when the Federal Government policy approach is migrating to dictate increased substitution of natural gas for coal;

- The steady reduction in load as a result of both economic factors and Demand Side Management programs which affects the ability to recover fixed costs;

- Increased political and regulatory risk associated with the execution of significant and complicated capital investments in combination with the dramatically increased level of regulatory activity associated with fuel, major capital projects and the Annual Capital Expenditure Plan. This was reinforced in S&P's recent negative credit action on NS Power;[1]

- The reduction in the credit-worthiness of major customers and suppliers due to the world-wide economic downturn and ongoing financial market turmoil and manifesting itself in a soft local economy;

- The impact of more volatile weather on system maintenance and reliability;

- Human resources and succession planning as a result of the resource boom in other parts of the country drawing skilled personnel away from this labour market;

- Regulatory oversight of affiliate transactions.

[1] OP-12 Confidential Attachment 3, page 37 of the Application

In virtually all aspects of utility operation and management, business risk has increased since 2005.

Please also refer to Booth IR-2, Attachment 2, at pages 20-26 for a discussion of NS Power risk factors and risk management.

OPINION

ON

CAPITAL STRUCTURE

AND

RETURN ON EQUITY

FOR

NOVA SCOTIA POWER INC.

Prepared by

KATHLEEN C. McSHANE

FOSTER ASSOCIATES, INC.

April 2011

TABLE OF CONTENTS

I. INTRODUCTION AND CONCLUSIONS

A. INTRODUCTION

My name is Kathleen C. McShane and my business address is 4550 Montgomery Avenue, Suite 350N, Bethesda, Maryland 20814. I am President of Foster Associates, Inc., an economic consulting firm. I hold a Masters in Business Administration with a concentration in Finance from the University of Florida (1980) and am a Chartered Financial Analyst (1989).

I have testified on issues related to cost of capital and various ratemaking issues on behalf of electric utilities, local gas distribution utilities, pipelines and telephone companies in more than 200 proceedings in Canada and the U.S., including the Nova Scotia Utility and Review Board (NSUARB). My professional experience is provided in Appendix E.

I have been requested by Nova Scotia Power Inc. (NSPI) to provide an expert opinion on the reasonableness of its 37.5% deemed common equity ratio and to recommend a fair ROE for the 2012 test year.

B. CONCLUSIONS

My principal conclusions are as follows:

(1) While global capital markets and economies have improved substantially since the height of the financial crisis, significant risks to the capital markets and economies remain. These include:

- (a) Sovereign debt concerns in several countries;
- (b) Financial fragility associated with the weak global economic recovery;
- (c) Global imbalances;
- (d) The potential for excessive risk-taking behaviour arising from a prolonged period of exceptionally low interest rates in major advanced economies; and

(e) High leverage of Canadian households.

(3) With respect to business risk, as a vertically integrated electric utility with significant electricity generation assets, NSPI faces higher business risk than the typical Canadian electric or gas utility, whose operations are focused largely in "wires" or "pipes".

(4) NSPI's 37.5% common equity ratio is lower than the Canadian utility sector averages, both allowed and actual. NSPI's higher business risk relative to its Canadian peers' has not been offset by lower financial risk, i.e., by a thicker common equity ratio.

(5) With both higher business risk and a lower common equity ratio than its Canadian peers', NSPI's total risk is higher than that of the average risk Canadian utility. As a result, the fair return on equity for NSPI is higher than that applicable to the typical, average risk Canadian utility.

(6) The fair return for NSPI for 2012 is 10.625% (mid-point of a range of 10.25% to 11.0%), based on the following:

(a) A forecast long-term Government of Canada bond yield of 4.5% for 2012;

(b) A "bare-bones" cost of equity of 10.0% based on the equity risk premium tests, summarized in the Table below:

Table 1

Risk Premium Test	**Cost of Equity**
Risk-Adjusted Equity Market	9.5%
Discounted Cash Flow-Based	9.5-10.0%
Historic Utility	10.5%-11.0%

(c) A "bare-bones" cost of equity of 9.5% based on the application of the discounted cash flow test to a sample of U.S. electric utilities and a sample of Canadian utilities. The results of the various models applied to the two samples are as follows:

Table 2

	Constant Growth		
	Analysts' EPS Forecasts	**Sustainable Growth**	**Three-Stage Model**
U.S. Electric Utilities	9.8%	9.3%	9.5%
Canadian Utilities	10.0%	N/A	8.7%

(d) An allowance for financing flexibility in a range of 0.50% to 1.4%. The lower end of the range represents the minimum required to notionally allow the utilities to maintain the market value of their investment at a small premium to book value. The upper end of the range represents full recognition of the disparity between the levels of financial risk in the market value capital structures and utility book value capital structures.

(e) The equity risk premium tests and discounted cash flow tests together indicate a "bare-bones" cost of equity for NSPI of 9.75%. The addition of an allowance for financing flexibility in the range of 0.50% to 1.4% results in a fair return on equity of 10.7%, the mid-point of a range of approximately 10.25% to 11.2%.

II. FAIR RETURN STANDARD

The requirements to meet the fair return standard arise from legal precedents[1] which are echoed in numerous regulatory decisions across North America.[2] A fair return gives a regulated utility the opportunity to:

(1) earn a return on investment commensurate with that of comparable risk enterprises;
(2) maintain its financial integrity; and,
(3) attract capital on reasonable terms.

The legal precedents make it clear that the three requirements are separate and distinct. Moreover, none of the three requirements is given priority over the others. The fair return standard is met only if all three requirements are satisfied. In other words, the fair return standard is only satisfied if the utility can attract capital on reasonable terms and conditions, its financial integrity can be maintained ***and*** the return allowed is comparable to the returns of enterprises of similar risk.

A fair return on the capital provided by investors not only compensates the investors who have put up, and continue to commit, the funds necessary to deliver service, but benefits all stakeholders, including ratepayers. A fair and reasonable return on the capital invested provides the basis for attraction of capital for which investors have alternative investment opportunities.

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[1] The principal court cases in Canada and the U.S. establishing the standards include *Northwestern Utilities Ltd.* v. *Edmonton (City)*, [1929] S.C.R. 186; *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia,(262 U.S. 679, 692 (1923))*; and, *Federal Power Commission v. Hope Natural Gas Company (320 U.S. 591 (1944))*.

[2] The three requirements were summarized by the National Energy Board (RH-2-2004, Phase II) as follows:

> The Board is of the view that the fair return standard can be articulated by having reference to three particular requirements. Specifically, a fair or reasonable return on capital should:
> - be comparable to the return available from the application of the 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).

The three requirements were reiterated in the *Reasons for Decision, Trans Québec and Maritimes Pipelines Inc., RH-1-2008, March 2009* (pages 6-7).

A fair return preserves the financial integrity of the utility, that is, it permits the utility to maintain its creditworthiness, as demonstrated by the level of its credit metrics and debt ratings. Fair compensation on the capital committed to the utility provides the financial means to pursue technological innovations and build the infrastructure required to support long-term growth in the underlying economy.

An inadequate return, on the other hand, undermines the ability of a utility to compete for investment capital. Moreover, inadequate returns act as a disincentive to expansion, potentially degrading the quality of service or depriving existing customers from the benefit of lower unit costs that might be achieved from growth. In short, if the utility is not provided the opportunity to earn a fair and reasonable return, it may be prevented from making the requisite level of investments in the existing infrastructure in order to reliably provide utility services for its customers.

III. TRENDS IN ECONOMIC AND CAPITAL MARKET CONDITIONS

The following section is intended to provide a review of the trends and changes in the economy and the capital markets since the UARB last reviewed NSPI's allowed ROE and capital structure UARB in detail during the Company's 2005 rates proceeding.

At close of record in the 2005 rates proceeding (January 2005), the Canadian economy was growing moderately and expected to strengthen. Real GDP growth in Canada was an estimated 2.7% in 2004 and expected to improve slightly to 3.0% in 2005. Corporate profits were robust, having risen 18% in 2004. Inflation was relatively tame, with CPI inflation in 2004 under 2.0%.

At the end of 2004, the yields on 10-year and 30-year Canada bonds were 4.3% and 4.8% respectively. Long-term corporate bond yields were approximately 5.75%; A-rated utility bond yields were also approximately 5.75%. Spreads between corporate bond yields and government bond yields were relatively low. Credit spreads were relatively low; the spread between long-term A-rated utility and government bond yields was under 100 basis points.

The equity market (as represented by the S&P/TSX Composite Index) was performing well. From the market trough of the "dot.com" market sell-off (early fourth quarter 2002) to the end of 2004, the S&P/TSX Composite had risen by over 55%.

With the strength in the economy, rising oil prices and an appreciating Canadian dollar, monetary stimulus was being withdrawn by the Bank of Canada by raising its key policy rate (the overnight rate). The Bank of Canada, in its December 2004 *Financial System Review*, noted that the removal of monetary stimulus was expected to entail modest upward movement in interest rates. Consensus Economics, *Consensus Forecasts*, December 2004, anticipated a rise in l0-year Government of Canada bond yields from 4.3% to 5.1% 12 months hence. The challenges to the household sector and some governments (particularly emerging countries) of high debt burdens, along with rising interest rates, were considered to pose some risks to the global financial system, but the BOC considered that borrowers were well positioned overall to deal with higher borrowing costs.

In that economic environment, the UARB rendered Decision NSUARB-NSPI-P-881 (March 25, 2005), in which it approved an ROE for NSPI of 9.3% to 9.8% (mid-point of 9.55%).

The UARB briefly reviewed NSPI's cost of capital again in the context of the 2006 rates proceeding, at which time the Company was requesting to retain its previously approved ROE.

At the time of that proceeding, economic growth in Canada had remained robust. GDP increased at an annual rate of close to 3.0% in 2005 and was expected to continue at approximately the same rate in 2006. With the economy operating at capacity, the Bank of Canada had continued to raise its key policy interest rate. By the end of 2005, the overnight rate had been increased four times (from 2.25% to 3.25%) since September 2004.

In its October 2005 *Monetary Policy Report*, the Bank of Canada noted that:

(1) business credit conditions had remained advantageous for borrowers, both in Canada and globally;

(2) in financial markets, corporate bond yields and credit spreads had remained low for both investment-grade and non-investment grade borrowers;

(3) the narrow credit spreads reflected healthy corporate balance sheets, continued investor demand for higher yielding securities, and a high level of liquidity in global financial markets; and

(4) easy access to capital markets was indicated by the robust growth in the gross issuance of corporate bonds.

At the end of 2005, the yields on 10-year and 30-year Canada bonds were 4.0% and 4.05% respectively. Government bond yields, despite strong economic growth, had declined to levels below where they had been a year earlier and levels considerably lower than had been anticipated. The relatively low level of government bond yields globally was attributed to the high level of savings relative to investment requirements.

Long-term corporate bond yields had fallen to just over 5%; A-rated utility bond yields were at similar levels. As the Bank of Canada's October 2005 *Monetary Policy Report* noted, spreads between corporate bond yields and government bond yields remained low. In fact, the spread between long-term A-rated utility and government bond yields had not changed materially from the prior year.

Equity markets continued to prove robust; the S&P/TSX composite delivered a total return of 24% in 2005.

In its December 2005 *Financial System Review*, the Bank of Canada noted that the "globally, benign macroeconomic conditions" marked by solid economic growth and low interest rates indicated that the possibility of a shock having a significant negative impact on the Canadian financial system was small. Further, it noted that global financial markets had proved themselves resilient to increased uncertainty resulting from higher energy prices and a possible increase in inflation.

The Company's proposal to maintain its previously approved ROE was unopposed by intervenors and was approved by the UARB in its March 10, 2006 Decision NSUARB-NSPI-P-882.

In its 2007 rates proceeding, NSPI again proposed to retain its previously approved ROE range of 9.3% to 9.8%.

In the intervening year between the 2006 and 2007 rate proceedings, the Bank of Canada's assessment of risks to the financial markets had remained relatively unchanged. In its June 2006 *Financial System Review*, page 3, the Bank noted that while "there continues to be a small risk that the adjustment of global imbalances could slow the growth of the global economy appreciably and increase volatility in financial markets significantly [t]his risk may, however, be lower than previously thought." In its December 2006 *Review*, the Bank noted "the global economic outlook continues to be favourable."

As a result of the continued favourable conditions in the economy and financial markets throughout 2006, the Bank of Canada continued tightening its policy interest rates; increasing the overnight rate four times to 4.25%. At the end of 2006, yields on 10-year and 30-year Canada bonds were 4.08% and 4.14% respectively, little changed from a year previously. In the corporate market, yields on long-term corporate bonds and A-rated utility bonds were virtually identical at 5.2%, and little changed from the end of the prior year.

The Canadian equity markets turned in another exceptional performance in 2006, with the total return on the S&P/TSX Composite Index exceeding 17%.

In the 2007 rates proceeding, NSPI reached a negotiated settlement, approved by the UARB in Decision NSUARB-NSPI-P-886, dated February 5, 2007.

On December 10, 2007, the UARB conditionally approved the establishment of a fuel adjustment mechanism (FAM), as had been proposed, effective January 1, 2009. In its subsequent application for rates (for test year 2009), NSPI requested an ROE of 9.35%, reflecting a reduction of 0.20% from the previously approved ROE. The requested ROE was a component of the framework agreement for the establishment of the FAM that had been signed by various stakeholders.

Between the time of the February 2007 and November 2008 rates decisions, capital markets deteriorated significantly.

Through the first half of 2007, the economy remained strong and financial market developments, in the words of the Bank of Canada (*Financial System Review*, June 2007), "have also been largely favourable. Although there was a brief period of volatility in financial markets in February/March, this volatility has subsided, and risk premiums have since contracted towards the historically low levels observed prior to that period." The Bank of Canada's *Monetary Policy Report Update*, July 2007, referenced a Canadian economy operating above its output potential, strong employment growth and domestic demand, supported by firm commodity prices, and robust economic growth outside North America. According to the Bank, expectations for policy rates in many economies had generally moved up; higher reported longer-term interest rates reflected the expectations of higher real interest rates, consistent with the outlook for continued strong global economic growth.

By the end of July 2007, the Bank of Canada had increased the overnight rate once more, to 4.5%, for eight increases in total since the beginning of 2005. Long-term Canada bond yields had begun to creep up during the first half of 2007, reaching their highest level (4.66%) in over two years in mid-June. At the end of June 2007, with the long-term Canada bond yielding 4.5% and long-term corporate and A-rated utility bonds yielding 5.75% and 5.66% respectively, spreads had moved up only modestly.

Nevertheless, some signs of the upcoming upheaval in the capital markets were already evident in the Bank of Canada's June 2007 *Financial System Review*:

> The exception [to the favourable market conditions] has been the U.S. subprime mortgage market, where a combination of weakness in the housing market and questionable underwriting practices at some institutions contributed to a decline in the credit quality of some U.S. mortgages and certain related credit market instruments.

The Bank pointed to the historically narrow credit spreads on risky assets, and the possibility that low real interest rates may have triggered a widespread search for yield, and an increasing risk appetite, which had contributed to the prevailing low spreads. The Bank expressed some concern that market risk was underpriced, and that a large macroeconomic shock could result in a rapid rise in risk premiums, leading to a widespread and significant decline in asset prices.

In August 2007, the asset-backed commercial paper market locked up, as concerns increased about the quality of the underlying assets in these structured products. In its December 2007 *Financial System Review*, the Bank of Canada announced that the sudden repricing of risk that it had previously considered a possibility had materialized. The Bank noted that risk spreads had widened, volatility in financial markets had increased, and liquidity in the markets for some structured products had evaporated. There was a flight to quality assets; yields on both short and long-term government securities had dropped significantly. Corporate/government bond yield spreads widened and equity markets fell significantly.

In an effort to ease the pressure on credit markets, the Bank dropped its overnight rate to 4.25% in December 2007. As investors fled to safe government securities, yields on 10-year and 30-year Canada bonds had fallen back to 4.0% and 4.1% respectively. In the investment grade corporate debt market, yields had remained virtually unchanged since mid-year, resulting in a widening of spreads. At the end of 2007, the spread between A-rated utility bonds and 30-year Canada bond yields had reached just under 140 basis points.

While the 2007 year-over-year return on the S&P/TSX Composite was close to 10%, equity market volatility had increased materially. During the second half of 2007, the Implied

Volatility Index ("MVX") averaged above 19, close to 40% higher than its 2005-mid-2007 average of 14.[3]

By mid-2008, strains in global credit markets had both broadened and deepened. Aggressive interest rate cuts by the U.S. Federal Reserve, as well as by other major central banks, were undertaken in an effort to stem the liquidity crisis in the global financial system. Between December 2007 and April 2008, the Bank of Canada had cut its overnight rate four times from 4.5% to 3.0%. Between September 2007 and April 2008, the U.S. Federal Reserve had cut the federal funds rate six times, from 4.75% to 2.0%. In addition to policy rate reductions, application of fiscal stimulus began. However, despite these efforts, the crisis in global financial markets intensified, as large financial institutions in the U.S. and Europe collapsed (or nearly collapsed), most notably Lehman Brother in September 2008.

At the end of October 2008, just prior to the UARB's issuance of Decision NSUARB-NSPI-P-888 approving the agreed-to 9.35% ROE, 10-year and 30-year Canada bond yields stood at approximately 3.75% and 4.25%, respectively. However, both long-term corporate bond yields and A-rated utility bonds had risen to 7.6%, increases of almost 200 basis points and 215 basis points, respectively, in ten months, resulting in spreads with long-term Canada bonds of close to 335 basis points.

Between mid-June and the end of October 2008, the S&P/TSX Composite Index had dropped by over a third. During October 2008, the implied market volatility index soared, averaging in excess of 60, over three times its beginning of year level. In November 2008, the MVX hit an all time high of 88.

The crisis in the financial markets spread to real economic activity, triggering a severe global recession. In 4th quarter 2008, the Canadian economy was in recession, although the official

[3] The MVX, introduced by the Montreal Stock Exchange in 2002, was a measurement of the market expectation of stock market volatility over the next month. It was described as a good proxy of investor sentiment for the Canadian equity market: the higher the index, the greater the risk of market turmoil. A rising index reflects the heightened fears of investors for the coming month. The MVX was replaced by a somewhat different measure of implied volatility, called the VIXC, in October 2010. The VIXC still measures market expectation of stock market volatility over the next month.

announcement by the Bank of Canada did not occur until late January 2009. Real GDP growth in Canada for all of 2008 was only 0.5%, with fourth quarter 2008 posting a 3% annualized quarter-over-quarter drop in real growth. The first quarter 2009 decline was more severe, at over 7% quarter-over-quarter (annualized), the largest quarterly decline recorded since comparable data were first recorded in 1961.

By the end of March 2009, the Bank of Canada had cut its overnight rate five additional times, from 3.0% in April 2008 to 0.50% by the end of March, continuing its efforts to restore liquidity, investor and consumer confidence and economic growth. Consistent with negative economic growth, low inflation and investor risk aversion, yields on 10-year and 30-year Canada bonds had declined to 2.8% and 3.6%, respectively. While the absolute yields on long-term corporate bonds had fallen slightly from their January peak, the March 2009 month-end yield of 7.4% reflected a spread with long-term Canada bonds of 380 basis points. A-rated utility bonds were yielding 6.8% (spread of 320 basis points).

During the last months of 2008 and early 2009, the long-term debt market, even for highly rated entities, was essentially closed. Between the end of August 2008 and mid-February 2009, no regulated utility raised any debt in Canada with a term longer than nine years. In December 2008 and January 2009, NSPI raised five-year debt at unprecedented spreads of 400 and 390 basis points respectively over the corresponding term Canada bond.

Through the early part of 2009, equity markets continued to spiral downward. The S&P/TSX Composite hit its trough in early March, having lost 50% of its value since hitting a peak in June 2008.

By mid-year, the massive stimulus programs and monetary policy initiatives implemented globally began to bear fruit. In early June 2009, Finance Minister Jim Flaherty announced that there were cautious signs that the Canadian economy had stabilized. Since that time there has been continued improvement in both the capital markets and the real economies, both in Canada and globally.

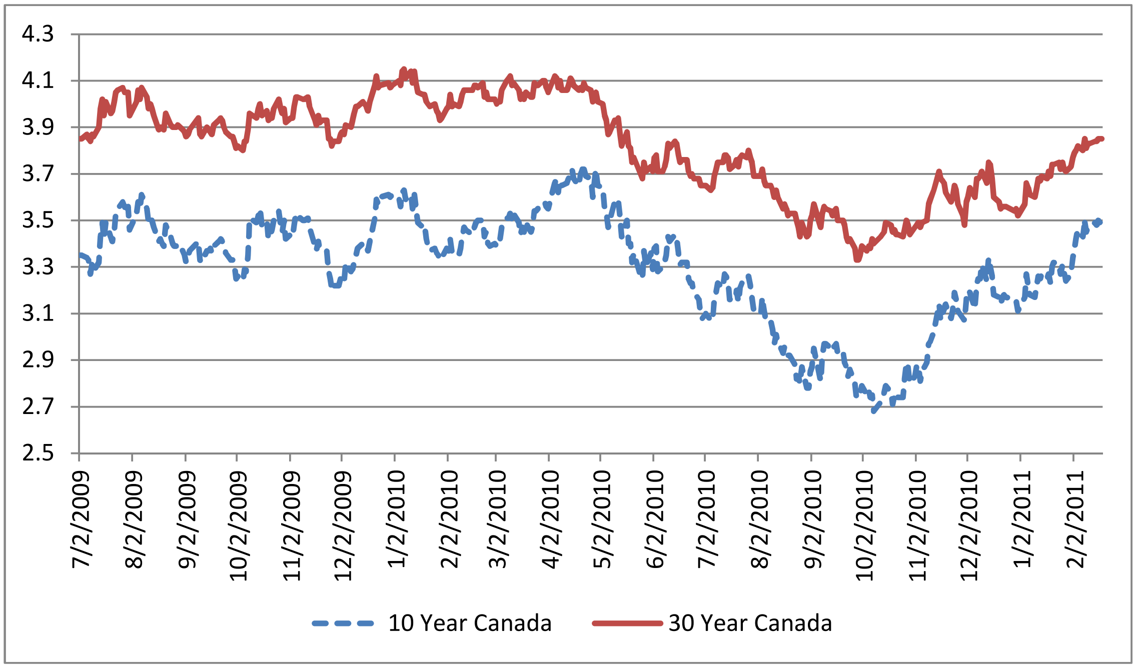
The Canadian economy was declared to be officially out of recession in July 2009. The recovery from the recession started modestly in the third quarter of 2009, and then gained momentum. Real GDP growth rates in 4Q 2009 and 1Q 2010 were 4.9% and 5.4% respectively. After having decreased its target overnight rate 10 times between December 2007 and April 2009 (from 4.75% to 0.25%), the Bank of Canada began to implement increases as the economy appeared to strengthen. The most recent of three increases, to 1.0%, occurred in early September 2010.

However, in October 2010, the Bank of Canada announced that the economic outlook for Canada had changed and it now expected growth to be more muted than previously forecasted. Since that announcement, the Bank has implemented no further changes to the target overnight rate. At 1.0%, the target overnight rate is still lower than at any time prior to the crisis.

Three-month Treasury bill yields, which follow the target overnight rate, have risen from a low of 0.16% in February 2010 to just under 1% at the end of February 2011. The most recent Consensus Economics, *Consensus Forecasts* (February 2011) anticipates an increase of slightly more than 1% (to 2.2%) in three-month Treasury bond yields over the next year. Even with the expected increase to a 2.2% yield, the three-month Treasury bill would be well below long-range levels that would be likely to prevail. Since 1961, the three-month Treasury bill yield on average has exceeded the rate of CPI inflation by 2.2%. With inflation expected to average 2.0% from 2013-2020, Treasury bill yields can reasonably be expected to average approximately 4.0%, 300 basis points above their current level.

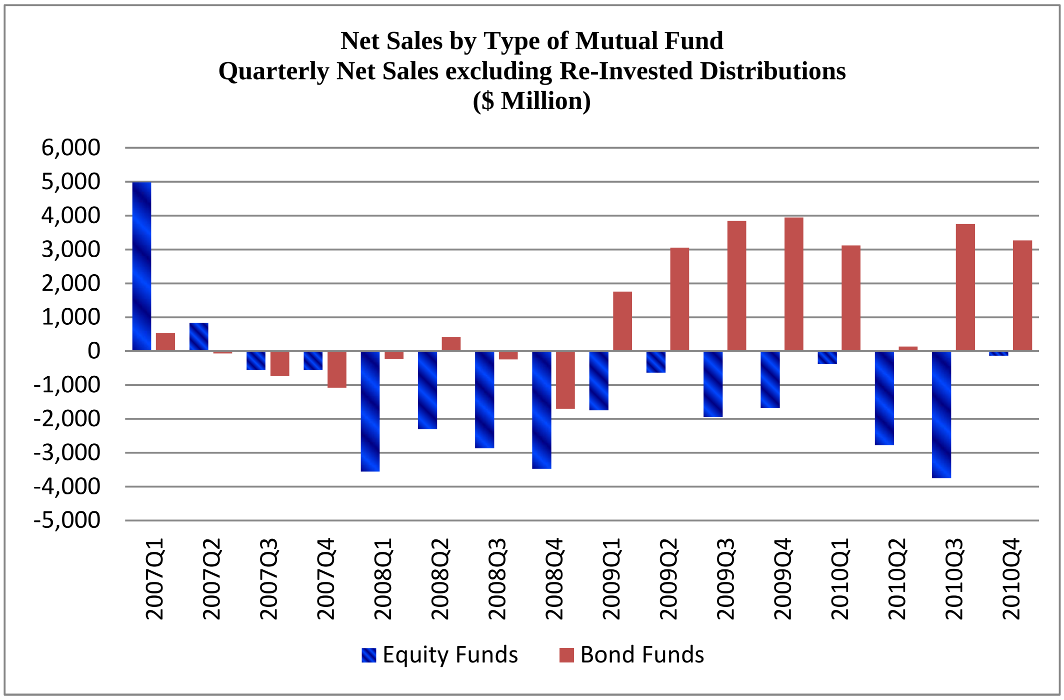
Yields on 10-year and 30-year Government of Canada bonds were relatively flat from the end of June 2009 (approximately the end of the recession) until the end of April 2010, averaging 3.5% and 4.0% respectively. As the outlook for global economic growth tempered, coupled with the sovereign debt crisis in Europe, yields fell. The 30-year Canada bond yield hit a trough of 3.3% at the end of September 2010, the lowest yield observed on long-term Government of Canada bonds since the mid-1950s. Although there has been a gradual uptrend in yields since that time, as shown in Chart 1 below, a subdued recovery in Canada and the other advanced economies, low inflation (expected to be 2.3% and 2.1% in 2011 and 2012 respectively), flows of capital into bonds during 2010 and geopolitical disruptions in the first quarter of 2011 have held 30-year Canada yields below 4%.

Chart 1



With respect to flows of capital into bonds, data compiled by the Investment Funds Institute of Canada (IFIC) show that Canadian investors put a net $10.2 billion into bond mutual funds during 2010, a further $26.1 billion into balanced (debt and equity) funds, while withdrawing a net $7.0 billion from equity mutual funds. Data compiled by Statistics Canada (*Canada's International Transactions in Securities*, December 2010) show that net purchases of Canadian bonds by foreign investors totaled $96 billion in 2010, accounting for close to 85% of net inflows into Canadian securities by foreign investors. Chart 2 below demonstrates by reference to flows into and out of mutual funds that bond funds have, since first quarter 2009, experienced significant inflows, while flows to equity funds have remained largely negative.

Chart 2



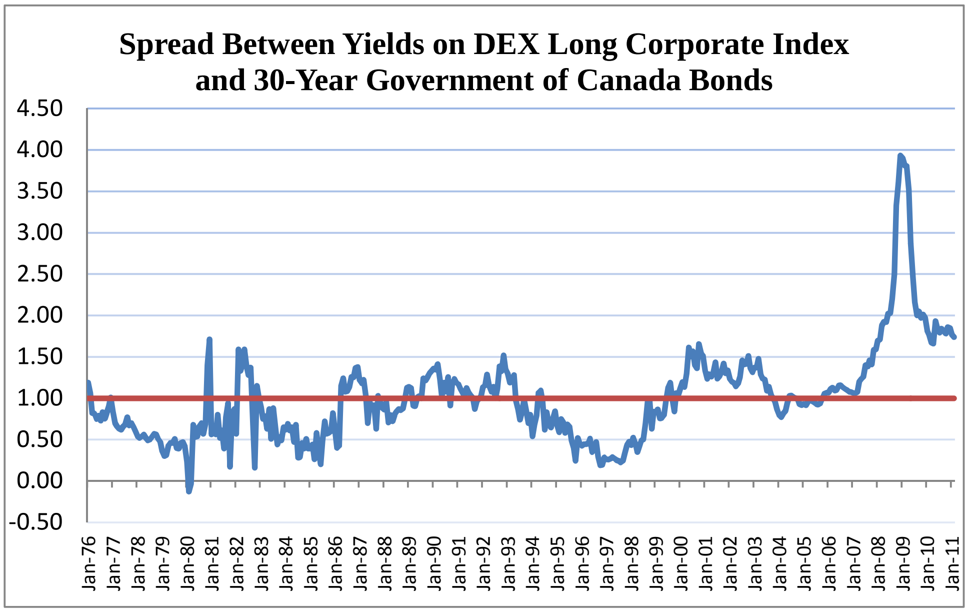
Source: IFIC

At the end of February 2011, the yields on 10-year and 30-year Government of Canada bonds were 3.3% and 3.7% respectively. The March 2011 Consensus Economics, *Consensus Forecasts* anticipates that the 10-year Canada bond yield will reach 3.9% within 12 months; the corresponding long-term Canada bond yield, based on recent (early March 2011) spreads, would be approximately 4.4%.

Spreads on long-term corporate debt have generally continued to narrow since the end of June 2009, although the downward trend was partially reversed in May 2010 with the onset of the sovereign debt crisis in Europe. The spread between the yield on the DEX Long Corporate Index and the 30-year Canada bond fell from 250 basis points at the end of June 2009 to 165 basis points in April 2010, jumping to close to 195 basis points in May 2010. At the end of February 2011, the spread was 174 basis points. As shown in Chart 3 below, despite the significant flows of funds into bonds (both corporate and government) during 2010, spreads remain higher than prior to the financial crisis. The 174 basis point spread observed at the end of

February 2011 compares to a long-term average of 1.0%[4] inclusive of the higher spreads experienced during the financial crisis and of approximately 0.85% up until the beginning of 2007.

Chart 3



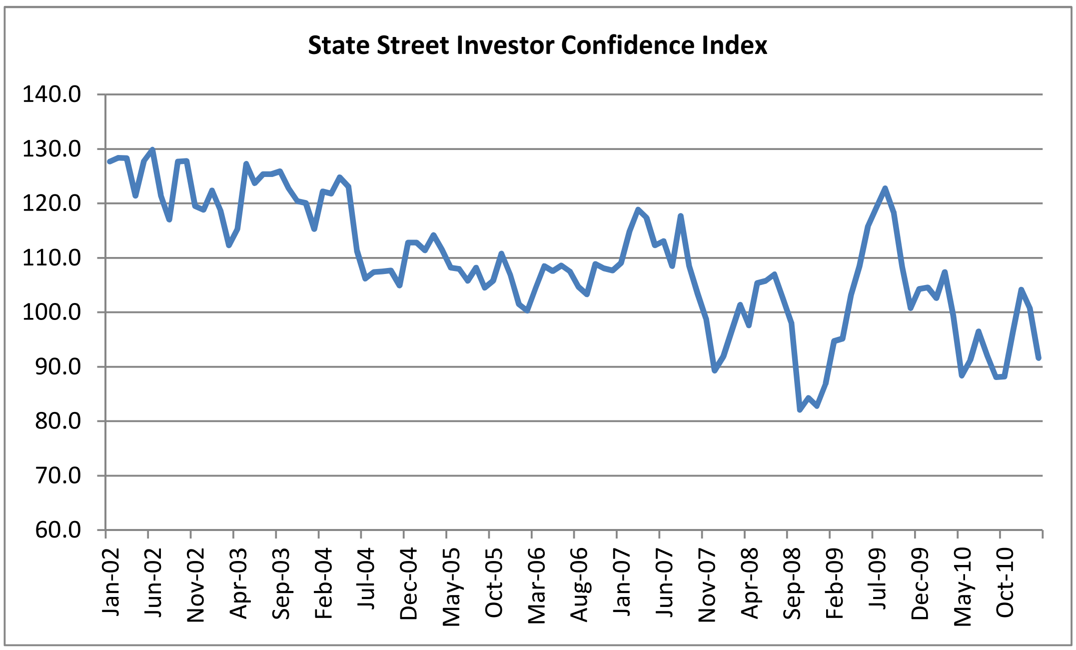
Spreads between long-term Canadian A rated utility bonds narrowed to 140 basis points in April 2010, but then spiked to almost 175 basis points during the height of the sovereign debt crisis in May. At the end of the February 2011, the spread had dipped to just above 140 basis points, still well above the 115 basis point average experienced during the five-year period (2003-2007) prior to the onset of the financial crisis.

Since the end of the recession (from end of June 2009), the equity markets have been fueled by the low interest rate environment, with low borrowing costs helping to boost corporate profits. Pre-tax corporate profits are estimated to have increased 17% in 2010, after declining by 33% in 2009. The S&P/TSX index ended 2010 approximately 15% higher than at the end of 2009, but still over 10% below its 2008 peak. While the expected volatility of the equity market has declined significantly since the worst of the financial crisis, from the beginning of 2010 to the

[4] Measured since 1976 when the yield on the benchmark long-term Government of Canada bond first became available.

end of February 2011, expected volatility has been higher on average than pre-crisis (2004-2007 average) levels. Further, global investor confidence levels remain lower than pre-crisis. Chart 4 below shows global investor confidence levels from January 2002 to late February 2011. The investor confidence levels portrayed in the Chart reflect a quantitative measure of the actual and changing levels of risk contained in investment portfolios representing about 15% of the world's tradable assets.

Chart 4



Source: www.statestreet.com

In October 2010, as noted above, the Bank of Canada announced that the economic outlook for Canada had changed and that a more gradual recovery was expected than had previously been the case. Actual growth in 2010 was 3.1%, the result of a sharp decline in the rate of growth during the second and third quarters of the year, followed by a somewhat higher than expected rate in the fourth quarter. While recovery is expected to continue in 2011 and 2012, the rates of growth are anticipated to lower than in 2010, and relatively modest in the context of recovery from recession. Consensus Economics (March 2011) forecasts growth in 2011 and 2012 at 2.9% and 2.7%. The Bank of Canada's January 2011 *Monetary Policy Report*, prepared prior to the release of the fourth quarter economic performance, anticipated somewhat lower growth rates, at 2.4% and 2.8% for 2011 and 2012 respectively.[5]

The relatively modest pace of growth expected reflects a combination of domestic factors (high household debt, which limits consumer spending) and international factors (e.g., the weak labour and residential real estate markets in the U.S., the strained balance sheets of banks and governments in Europe and austerity programs, and constraints on export growth arising from a combination of tempered growth abroad, the high Canadian dollar and relatively weak productivity).

The facts that (1) Canada fared relatively well compared to other advanced economies during the worst of the financial crisis; (2) economic recovery is underway globally; and (3) capital markets are on materially more solid ground than they were during the depths of the crisis do not mean that it is "business as usual." However, the global economies and capital markets have still not fully recovered and there remain significant risks that there could be a material reversal, of which certain bumps along the way have been constant reminders. The nature of most of these risks, like the financial crisis itself, underscores the extent to which economies and capital markets globally are inter-twined.

The most recent Bank of Canada *Financial System Review*, December 2010, page 2, summed up those risks as follows:

(1) Sovereign debt concerns in several countries;
(2) Financial fragility associated with the weak global economic recovery;
(3) Global imbalances;
(4) The potential for excessive risk-taking behaviour arising from a prolonged period of exceptionally low interest rates in major advanced economies; and
(5) High leverage of Canadian households.

[5] Neither the Consensus Forecast nor the Bank of Canada's forecast would have incorporated the potential impact on economic growth of the crisis in Japan.

With respect to the first, as the Bank of Canada's June 2010 *Financial System Review* concluded:

> While the Canadian financial system has continued to function well in the face of adverse spillovers from Europe, it is vulnerable to renewed stress in the event of a recurrence of severe tensions in global markets. For example, heightened concerns over sovereign debt could lead to higher borrowing costs and/or more rapid tightening of fiscal policy in some European countries, potentially hampering the global economic recovery. In turn, increased uncertainty over global economic prospects could trigger a severe worldwide retrenchment from risky investments. This may lead to market turmoil globally, and possibly even to forced asset sales and liquidity shortages for some institutions. These developments could materially impair the asset quality, capital positions, and funding liquidity of financial institutions, and undermine confidence more generally. Through these indirect channels, sovereign risk could have an impact on the global financial system that is disproportionate to the direct exposure of banks to sovereign debt.

In the December 2010 *Financial System Review*, the Bank of Canada rated the risk to the Canadian financial system from global sovereign debt as high and higher than it was in June 2010.

With respect to financial fragility associated with the weak global recovery, the Bank of Canada noted the more subdued economic recovery than it had anticipated six months earlier, given in part the shift of governments from fiscal stimulus to fiscal consolidation. The Bank noted that, while banks around the world had made substantial progress in repairing their balance sheets, they remain unusually strained and face challenges stemming from the weaknesses in the macroeconomic environment, particularly the labour and real estate markets in Europe and the United States. The Bank concluded that risks arising from the financial fragility associated with a weak global economic recovery were elevated and had increased since they were assessed six months earlier.[6]

[6] The Bank's assessment occurred prior to the onset of political upheaval in Egypt, Libya and other countries in the Middle East, and the crisis in Japan, which could threaten the global recovery in 2011.

In a similar vein, in its October 2010 *Global Financial Stability Report*, the International Monetary Fund stated:

> Despite the ongoing economic recovery, the global financial system remains in a period of significant uncertainty. The baseline scenario is for balance sheets to strengthen gradually as the economy recovers, and as further progress is made in addressing legacy problems in key banking systems. However, substantial downside risks remain. Mature market governments face the difficult challenge of managing a smooth transition to self-sustaining growth, while stabilizing debt burdens under low and uncertain economic prospects. Without further bolstering of balance sheets, banking systems remain susceptible to funding shocks that could intensify deleveraging pressures and place a further drag on public finances and the recovery.

Global imbalances refer to imbalances between savings and investment in the world economies, as reflected in the significant distortions among current account balances, e.g., the large and persistent current account deficit in the U.S. and surplus in China. In its December 2010 *Financial System Review*, the Bank of Canada noted the recent widening of global current account imbalances, warning that the larger they grow, the greater the magnitude of future adjustments required to resolve them. A disorderly resolution, which would be characterized by a sharp adjustment in exchange rates and risk premiums for a wide range of assets, could create significant stresses on financial institutions.

In addition to highlighting concerns with the large current account deficit of the U.S. and the surplus of China, the Bank cited the increasing capital flows to emerging economies since mid-2009. The capital flows (e.g. via funds which invest in emerging market equity and debt) to emerging economies had been putting upward pressure on their currencies and raising concerns about those economies' potential to contribute to excessive credit growth and asset price bubbles. Reaction to capital inflows in some cases has taken the form of tightened controls on capital inflows in an attempt to thwart upward pressure on their currencies. The Bank cited the heightened tensions in currency markets that had been experienced during the prior six months and the increased risk of real and financial protectionism.

The Bank opined that those heightened tensions and the related risks associated with global imbalances could result in a more protracted and difficult global recovery, causing further stress in the financial system. It determined that the risk of market turmoil resulting from global imbalances was high and had risen since its last assessment.

With respect to the potential for excessive risk-taking behaviour, the Bank referred to the extended period of extraordinarily low interest rates in the advanced economies, and that, while such levels are required to stimulate the economies, they may lead to excessive credit creation and undue risk risk-taking in the quest for higher returns. For example, the Bank noted the pressure faced by insurance companies and pension funds to meet their obligations to policyholders and beneficiaries, which could promote risk-taking behaviour. The Bank judged the risk of such behaviour endangering financial stability in Canada in the near-term to be moderate.

Finally, the Bank expressed concern with the growth in household credit, which leaves individuals vulnerable to adverse economic shocks. The risk faced is a transmission to the broader financial system of a decline in the credit quality of loans to individuals as a result of deterioration in economic conditions. The decline in credit quality, in turn, would lead to tighter credit conditions, to further deterioration in real economic activity, and to financial instability. The Bank considered the risk of a system-wide disturbance resulting from financial stress in the household sector to be elevated and somewhat higher than it had been six months previously.

Although there will always be systemic risks to the economy and the financial markets, the breadth and level of those risks far exceeds those envisioned prior to the onset of the financial crisis.[7]

[7] A comparison of the Bank of Canada's December 2006 and 2010 *Financial System Reviews* confirms this.

IV. TRENDS IN UTILITY ALLOWED RETURNS

A. CANADA

At the time of NSPI's 2005 rates proceeding, the vast majority of Canadian utilities were subject to automatic ROE adjustment formulas that changed the allowed ROEs annually by 75% to 80% of the change in forecast long-term Canada bond yields. Most of the formulas had been in place since the mid to late 1990s.[8] The Albert Energy and Utilities Board (now the Alberta Utilities Commission) was the last of the regulators to adopt a formula (2004), although the ROEs they had adopted over the prior decade had followed the formula trends fairly closely. Of the major provincial and federal energy utility regulators, only the UARB, the New Brunswick Energy and Utilities Board and the Island Regulatory and Appeals Commission have not adopted automatic adjustment formulas.[9]

Supported by the fiscal restraint of the Federal government, the achievement and maintenance of low levels of inflation, and the high levels of savings, forecast long-term Government bond yields declined by approximately 375 basis points between late 1994 (when automatic formulas were first adopted) and the beginning of 2005. With many Canadian utilities subject to formulas tied to government bond yields over some or all of that period, the average allowed ROE had fallen by approximately 265 basis points. When the UARB set NSPI's allowed ROE in March 2005, the approved ROE of 9.55% was marginally higher than the industry average of 9.5%.

Over the next several years, as long-term Canada bonds continued to decline, the formula-driven allowed ROEs followed suit. By 2008, the industry average allowed ROE in Canada had dropped to approximately 8.8%.

[8] British Columbia Utilities Commission, 1994; National Energy Board, 1995; Public Utilities Board of Manitoba, 1995; Ontario Energy Board, 1997; Public Utilities Board of Commissioners of Newfoundland and Labrador, 1998; and Régie de l'énergie du Québec, 1999.

[9] The Rate Review Panel in Saskatchewan does not regulate the ROE of the Crown-owned utilities. New Brunswick Power is not rate base/rate of return regulated. A formula was proposed by intervenors for Enbridge Gas New Brunswick in its 2010 cost of capital proceeding, but the NB Board did not address the issue in its decision.

The evidence that the formulas were producing returns that did not meet the fair return standard had been mounting for some time.

As long ago as December 2001, CIBC World Markets Report entitled "*Pipelines and Utilities: Time to Lighten Up*", stated, in reference to the then recent formulaic reduction in Newfoundland Power's allowed return (from 9.59% to 9.05% year over year):

> The magnitude of the reduction in the case of Newfoundland Power illustrates the flaw in using a brief snapshot of existing rates rather than a forecast of rates that are expected to persist during the upcoming year. More importantly, however, it shows the shortcoming of the formula approach itself. Mechanically tying allowed returns on equity to long bond yields is an approach that is simple for regulators to apply; however, in recent years, with a steady decline in bond yields, it has produced-allowed returns that are out of sync with the cost of capital, and returns that are being achieved with comparable nonregulated companies or regulated returns that are achievable in the U.S.

At the time of the report, the allowed returns for Canadian utilities were approximately 9.6%, compared to just over 11% for U.S. utilities.

In its June 2006 *Canadian Hydrocarbon Transportation System* report, the National Energy Board (NEB) reported that a number of analysts felt that the ROE generated by the NEB formula and by other Canadian regulators' formulas "were a little too low" and not supportive of dividend growth or credit metrics. A number of analysts commented that where they had "Buy" recommendations on utility stocks, the recommendations tended to reflect the prospects of the unregulated operations. Analysts also commented that companies had reduced costs and taken other steps to improve profitability and dividend growth for several years, and wondered how long that could continue. The 2007 Report expressed similar views.[10] Some market participants expressed concern that the stand-alone pipelines might have difficulty attracting capital given low ROEs. Others felt the regulated entities would be able to attract capital, but that the terms under which they did so would be more costly than for the consolidated entity. In addition, the report stated:

[10] The NEB did not consult with analysts for the purpose of their 2008 report, in light of its then ongoing cost of capital proceeding for TransQuébec and Maritimes Pipeline.

> Many analysts expressed support for a formulaic approach to determining ROEs because of the transparency, stability and predictability that this method provides. However, a number expressed the view that the ROE resulting from the formula was too low, and contend that they are much lower than regulated ROEs in the U.S. and U.K. While views ranged widely on this issue, some felt that the typically lower ROEs in Canada were not justified by the differences in risk for Canadian companies compared to FERC-regulated pipelines. Some parties suggested it was time for the Board to revisit the ROE Formula.

In *Pipelines/Gas & Electric Utilities*, dated December 7, 2006, Karen Taylor, then equity analyst for BMO Capital Markets, concluded, "We believe on a collective basis, that the allowed returns as established by the formulas highlighted above [referring to the NEB, EUB,[11] BCUC and OEB[12] formulas] are confiscatory and likely violate the Fair Return Standard."[13]

With the unambiguous divergence between the trends in long-term government bond yields on the one hand and utility bond yields and the market cost of equity on the other during 2008 led other investment analysts to the conclusion that the formula had broken. In RBC Capital Markets' January 16, 2009 *Industry Comment* entitled "Allowed ROEs: The Formula Is Broken, but Will Regulators Fix It?", analyst Robert Kwan commented:

> With higher equity risk premiums and higher long bond yields for Energy Infrastructure companies that are trading at levels close to the allowed ROEs, it appears that the formula is broken. Forgetting the magnitude of change, it appears that the formula is producing a result that is directionally incorrect (i.e., ROEs declining yet corporate bond yields and equity risk premiums are rising).

Mr. Kwan recommended from a risk/reward perspective:

> We would focus on companies with the least exposure to the formula.

A February 23, 2009 report by Macquarie Research entitled *ROE Formula May Finally Bite the Dust* concluded that government bond yields bear little resemblance to any private company's cost of capital. The report also concluded that:

[11] Alberta Energy and Utilities Board, now the Alberta Utilities Commission.
[12] Ontario Energy Board.
[13] Studies commissioned by the Canadian Gas Association and the Canadian Energy Pipeline Association published in 2008 also came to the conclusion that the ROEs produced by the automatic adjustment formulas did not meet the fair return standard.

> Lack of comparability between allowed utility ROEs and returns on similar investments is driving the emerging capital access problem. In support of the argument the comparability criterion is not being met, utility customers and their expert witnesses like to point out that allowed returns for U.S. utilities are considerably higher than allowed returns in Canada. No matter how we slice the data, we concur with this opinion.

On March 19, 2009 the National Energy Board released its cost of capital decision for TransQuébec and Maritimes Pipeline (TQM). In that decision, the NEB expressed the view that:

> there have been significant changes since 1994 in the financial markets as well as in general economic conditions. More specifically, Canadian financial markets have experienced greater globalization, the decline in the ratio of government debt to GDP has put downward pressure on Government of Canada bond yields, and the Canada/US exchange rate has appreciated and subsequently fallen. In the Board's view, one of the most significant changes since 1994 is the increased globalization of financial markets which translates into a higher level of competition for capital. When taken together, the Board is of the view that these changes cast doubt on some of the fundamentals underlying the RH-2-94 Formula as it relates to TQM.

The NEB also noted that:

> The RH-2-94 Formula relies on a single variable which is the long Canada bond yield. In the Board's view, changes that could potentially affect TQM's cost of capital may not be captured by the long Canada bond yields and hence, may not be accounted for by the results of the RH-2-94 Formula. Further, the changes discussed above regarding the new business environment are examples of changes that, since 1994, may not have been captured by the RH-2-94 Formula. Over time, these omissions have the potential to grow and raise further doubt as to the applicability of the RH-2-94 Formula result for TQM for 2007 and 2008.

The NEB adopted a new cost of capital methodology for TQM, which instead of specifying separate capital structure and ROE components, expressed the allowed return as an overall after-tax return. The NEB provided calculations of the ROE implied at different capital structures to facilitate comparisons with the "traditional" capital structure/ROE approach. The implicit ROE at TQM's proposed common equity ratio of 40% was 9.7%, which represented an increase in the

ROE of approximately 1.0% to 1.25% relative to the NEB's formula results for the same years for which TQM's cost of capital was set.[14]

Following its decision for TQM specifically, the NEB rescinded its RH-2-94 decision which adopted the automatic adjustment formula.[15] Since the NEB's recission of the formula, Foothills Pipe Lines, Nova Gas Transmission and Westcoast Energy have all reached negotiated settlements with their shippers, all of which included allowed ROEs of 9.7% on 40% common equity ratios.

BMO Capital Markets analyst George Lazarevski in *Pipelines and Utilities* (March 30, 2009) stated:

> We applaud the NEB for acknowledging that the RH-2-94 formula is no longer applicable given the changes in business risk, financial markets and economic conditions. In particular, the globalization of financial markets made it difficult for Canadian operators to compete for capital with such low ROE.

On April 24, 2009, Scotia Capital commented:

> The turmoil in financial markets over the last 18 months has had a material knock-on effect on a sector typically seen as a safe haven from adverse equity market volatility and valuations. Energy utilities across Canada have seen their regulated returns on equity squeezed by falling Government of Canada bond yields, even as the real-world cost of equity capital has risen dramatically.
>
> Beginning with the National Energy Board in early 1995, Canadian energy regulators have largely adopted formula-based annual adjustments to utilities' allowed return on equity. These formula have been based on the capital asset pricing model. A base "risk-free" rate, represented by long Canada bond yields, is augmented by an equity risk premium, chosen to represent the business and financial risk of the utilities. The NEB's formula was created in 1994 and 1995, when Canada long bond yields reached over 9% at times, due to a range of factors, including ratings downgrades, large public sector deficits, and bearish domestic and international market sentiment towards Canadian government debt.

[14] The NEB also noted that the ATWACC that it had adopted for TQM resulted in an effective ROE of 11.2% on the 32% common equity ratio recommended by the principal intervenor, the Canadian Association of Petroleum Producers.

[15] National Energy Board, *Reasons for Decision, Multi-Client, RH-R-2-94*, October 2009. It is of note that the NEB's decision was for years 2007 and 2008 and was rendered independently of the financial crisis.

> As Canada's public sector reformed its finances, long Canada yields have come down, gradually but steadily, since early 1995. This led to a gradual decline in utility allowed ROEs, which has been a challenge for equity holders, and a challenge for utility management to offset by trying to "over-earn" the regulatory target, which is used to set rates.
>
> The onset of economic and financial market turmoil in late 2007 led to a further, more rapid decline in Canada yields, mimicking the global flight to the safety of top-quality sovereign debt, and reflecting widespread investor aversion to risk of all kinds. This triggered a decrease in Canadian utility regulators' formula-driven ROEs, to unprecedented low levels. However, utility bond spreads, and their cost of equity capital, were rising.
>
> Very recently, the NEB recognized these adverse and undesirable results, in what we view as a very significant Decision in the case of Trans Québec & Maritimes Pipeline. The NEB varied from its formula, which it had applied virtually universally to utilities in its jurisdiction since 1995. The ROE relief was material, lifting TQM's ROE from the formula-set 8.46% and 8.71% in 2007 and 2008 (on the NEB's deemed equity capitalization of 30%) to roughly 11.6% to 11.8%, based on the same capital structure and the embedded cost of debt.[16]

In addition to the NEB, in 2009, the AUC, the BCUC, the OEB, the Newfoundland and Labrador Board, and the Régie, each reviewed the automatic adjustment ROE formulas. While each of the decisions came to somewhat different conclusions regarding the appropriate level of ROE, the cost of equity tests to be accorded most weight and the validity of the formula, all of the decisions increased the allowed ROEs above the level that the automatic adjustment formulas would have produced.

In November 2009, the AUC adopted an allowed ROE of 9.0% for 2010 and on an interim basis for 2011 for all the utilities under its jurisdiction and implemented a 2% across-the-board increase in allowed common equity ratios, subject to some company-specific adjustments.[17] The AUC has instituted a proceeding to set the final allowed ROE for 2011 and to review the utilities' capital structures.

[16] Stephen Dafoe, "Falling Canada Yields and Utility ROEs", *Capital Points*, ScotiaBank Group, April 24, 2009.
[17] For example, the AUC allowed a 3 percentage point increase in common equity ratio for the two electricity transmission utilities that were embarking on major capital build programs.

In December 2009, the Régie adopted a 2010 ROE for Gaz Métro of 9.2%, compared to an ROE of 8.64% which would otherwise have been adopted under the Régie's automatic adjustment formula. The Régie renewed its automatic adjustment mechanism effective for Gaz Métro's 2011 test year. Due to the decline in forecast long-term Canada bond yields subsequent to the December 2009 decision, Gaz Métro's allowed ROE for 2011 will be 9.09%. The corresponding ROE at the forecast 4.5% long-term Canada bond yield for 2012 would be 9.35%.

In its December 2009 decision for Newfoundland Power, the NL PUB set the allowed ROE for 2010 at 9.0% (on a common equity ratio of 44.7% and assuming a forecast long-term Canada bond yield of 4.5%) and later adopted a formula that was quite similar to its previous formula, i.e., it changes the allowed ROE by 80% of the change in long-term Canada bond yields. For 2011, due to the lower forecast long-term Canada bond yield compared to the yield on which the 9.0% ROE was premised, the 2011 ROE is 8.38%. At the forecast long-term Canada bond yield of 4.5% for 2012, the allowed ROE would be 9.0%.

In its December 2009 decision, the BCUC eliminated its automatic adjustment mechanism.[18] In so doing the Commission found the following:

> The Commission Panel agrees that a single variable is unlikely to capture the many causes of changes in ROE and that in particular the recent flight to quality has driven down the yield on long-term Canada bonds, while the cost of risk has been priced upwards.
>
> In the Commission Panel's opinion, reliance on CAPM by Canadian regulatory agencies has also contributed to the divergence between Canadian and US allowed ROEs. In light of the limited weight given by the Commission Panel to CAPM in determining the ROE for TGI [Terasen Gas] for 2010, it would seem inconsistent to retain the adjustment mechanism.

The BCUC set the allowed ROE for Terasen Gas, designated the benchmark utility, effective July 1, 2009 at 9.50%, compared to 8.47% for the first six months of 2009, on a common equity ratio of 40%. The corresponding ROEs effective July 1, 2009 for the smaller gas utilities, Terasen Gas (Vancouver Island), Terasen Gas (Whistler) and Pacific Northern Gas (three

[18] British Columbia Utilities Commission, *In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc., and Return on Equity and Capital Structure, Decision*, December 19, 2009.

divisions) were in the range of 9.9% to 10.15%, 40 to 65 basis points point higher than the ROE for the benchmark utility, on equity ratios of 40% to 45%. The allowed ROE for FortisBC, the only investor-owned fully integrated electric utility in Canada other than NSPI, is 9.9% on 40% common equity. There has been no further action taken to change these approved ROEs.

In its, *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, EB-2009-0084, December 11, 2009, the Ontario Energy Board ("OEB"), in its assessment of the automatic adjustment formula, concluded that:

> The existing formula approximates this relationship [between interest rates and the equity risk premium] using a linear specification. The Board is of the view that it is unreasonable to conclude that the current formula correctly specifies this relationship, based on the passage of time, changes in financial and circumstances generally, and the empirical analyses provided by participants to the consultation and the discussion at the consultation itself. However, the Board is of the view that its current formulaic approach for determining the equity cost of capital should be reset and refined, not otherwise abandoned or subject to wholesale change.
>
> The events that unfolded earlier this year that triggered this review effectively illustrated that the Board's approach needs to be refined to reduce the sensitivity of the formula to changes in government bond yields due to monetary and fiscal conditions that do not reflect changes in the utility cost of equity. The Board concludes that the current approach could be more robust and better guide the Board's discretion in applying the FRS [Fair Return Standard]. The Board notes that while the current formula today produces results similar to that in 2008, it does not address the observed behaviour of the formula during the financial crisis – lowering the allowed ROE when the amount and price of risk in the market was increasing.

The OEB also recognized that:

> In its 1997 Draft Guidelines, the Board determined that the difference between the LCBF for the current test year and the corresponding rate for the immediately preceding year should be multiplied by a factor of 0.75 to determine the adjustment to the allowed ROE. In that same document, however, the Board noted that there was a significant difference of opinion concerning the relationship between interest rates and the ERP and that ratios contained in the evidence from generic rate of return proceedings in other Canadian jurisdictions ranged from 0.5:1 to 1:1.5. Moreover, the Board notes that the selection of the 0.75 adjustment factor is described in the 1997 Draft Guidelines as "admittedly somewhat arbitrary."

The OEB reset the benchmark allowed ROE at a forecast long-term Canada bond yield of 4.25% and an approximately 140 basis point spread of A-rated utility bond yields over long Canada bond yields, at 9.75%, and confirmed the equity ratio applicable to the electricity distribution utilities at 40%. Under the previous formula, the benchmark allowed ROE would have been 8.41%. The most recent ROE that has been officially adopted by the OEB by the application of the revised formula was for Hydro One Transmission (9.66%, for rates effective January 1, 2011, on an equity ratio of 40%, based on a forecast long-term Canada bond yield of 3.94%). Based on the forecast of long-term Canada bond yields of 4.5% for 2012 (discussed in Section VII.C.2) and current A-rated utility spreads, the OEB's revised formula would produce an allowed ROE of approximately 9.8%.

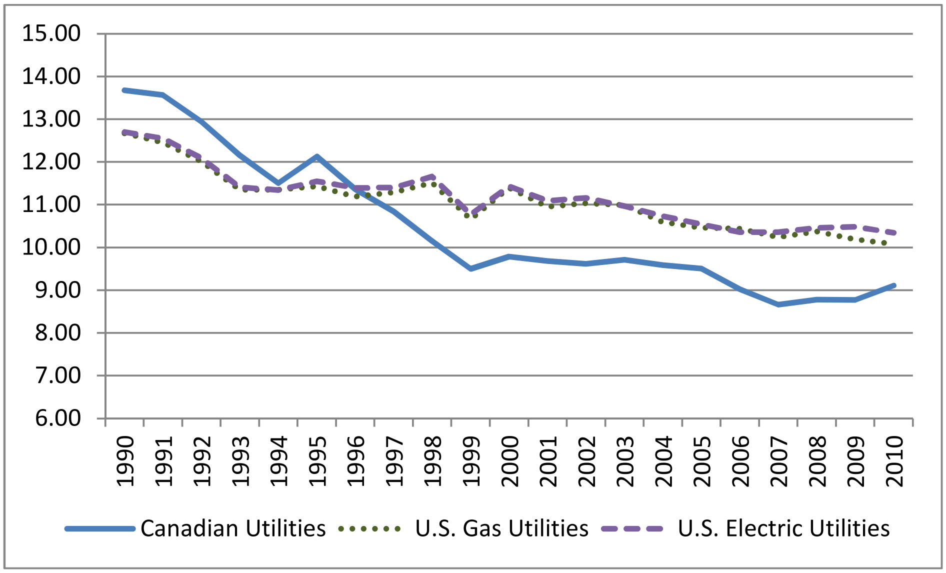
In July 2010, IRAC approved Maritime Electric's requested ROE of 9.75% for 2010 and 2011 on 40% equity and declined to adopt an automatic adjustment formula as proposed by the Consumer Advocate's expert witness, stating that it "sees little value in placing greater emphasis on a formula approach at a time when that approach is either being abandoned, altered or deviated."

Taking into account (1) the expectation that interest rates are expected to rise to 4.5% by 2012 and (2) recognizing that the AUC is in the process of setting the final ROE for 2011, the level of ROEs allowed in Canada is not materially different on average than it was in 2005 (when the UARB established the 9.55% ROE for NSPI) and is materially higher than the average ROE adopted for 2009 (the year for which the UARB approved a 9.35% ROE for NSPI).

B. UNITED STATES

Chart 5 below shows that the ROEs approved for Canadian utilities and those approved for electric and gas utilities in the U.S. were relatively comparable until approximately 1996. As the automatic formulas continued to operate as initially constructed, a significant gap between the allowed ROEs emerged, a gap which has persisted through 2009. Between 1996 and 2010, Canadian allowed ROEs have averaged close to 1.2 percentage points lower than the allowed returns of U.S. gas and electric utilities. Over the same period (1996-2010), the average yield on long-term government bonds in the two countries was virtually identical (5.2% in both countries).

Chart 5



Source: Schedule 2, page 3 of 3

To a large extent the difference in the allowed returns stems from (1) the weight given to the Capital Asset Pricing Model in Canadian regulatory jurisdictions, which, due to its construction, results in the allowed ROEs tracking long-term Canada bonds closely and (2) the use of automatic adjustment formulas in Canada, which, because they are premised on a high degree of sensitivity of the utility cost of equity to changes in long-term government bond yields, have resulted in a larger decline in allowed ROEs in Canada versus the U.S.

The average returns allowed for U.S. electric utilities in 2010 was 10.34% (on an average common equity ratio of 48.5%) and for U.S. electric and gas utilities together, 10.24% (on an average common equity ratio of 48.6%).

V. ANALYTICAL FRAMEWORK

A. RELATIONSHIP BETWEEN CAPITAL STRUCTURE AND ROE

The analysis starts with the proposition that the fair return (which in this context encompasses both capital structure and ROE) for NSPI should be determined on a stand-alone basis. The stand-alone principle encompasses the notion that the cost of capital incurred by ratepayers should be equivalent to that which would be faced by the utility raising capital in the public markets on the strength of its own business and financial parameters. Respect for the stand-alone principle is intended to promote efficient allocation of capital resources and avoid cross-subsidies. The stand-alone principle has been respected by virtually every Canadian regulator in setting both regulated capital structures and allowed ROEs.

The overall cost of capital to a firm depends, in the first instance, on business risk. Business risk relates largely to the assets of the firm. The business risk of a utility is the risk of not earning a compensatory return on the invested capital and of a failure to recover the capital that has been invested.

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 uses debt to finance a portion of its assets. The capital structure, comprised of debt 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.

Simply put, as the debt ratio rises, so do the costs of debt and equity. For a given level of business risk, the return on equity that would be fair and reasonable at a common equity ratio of 40% would be lower than the return on equity that would be fair and reasonable at a common equity ratio of 30%.

There are effectively two approaches that can be used to determine a fair rate of return on rate base. The first is to assess the "subject" utility's business risks, then establish a capital structure that (1) is compatible with its business risks; (2) would permit it to achieve a stand-alone investment grade debt rating; and (3) would approximately equate the level of the specific utility's total (business and financial) risk to that of the proxies (or benchmarks) used to estimate the cost of equity. This approach permits the application of the proxy companies' cost of equity to the subject utility without adjustment.

The second approach relies on acceptance of the utility's actual or proposed deemed capital structure for regulatory purposes. The actual or deemed capital structure then becomes the key measure of the utility's financial risks. The utility's level of total risk (business plus financial) is then compared against that faced by the proxy firms used to estimate the ROE requirement. If the total risk of the proxy or "benchmark" sample is higher or lower than that of the subject utility, an adjustment to their cost of equity would be required when setting the subject utility's allowed ROE.

Both of these approaches have been taken by regulators in Canada. The first approach has been utilized by the Alberta Utilities Commission (AUC), the National Energy Board (NEB) and the Ontario Energy Board (OEB). The second approach has been used by the British Columbia Utilities Commission (BCUC), the Régie de l'énergie (Régie), and the OEB.[19]

In summary, the various components of the cost of capital are inextricably linked; it is impossible to determine if the return on equity is fair without reference to the capital structure of the utility. Thus, the determination of a fair return must take into account all of the elements of the cost of capital, including the capital structure and the cost rates for each of the types of financing. It is the overall return on capital which must meet the requirements of the fair return standard.

[19] Historically, the OEB used both capital structure and ROE to recognize differences in business risk among utilities. More recently, it has adopted the same ROE for the utilities it regulates, adjusting for differences in business risk in the capital structure.

Both approaches used by Canadian regulators are equally valid as long as the combination of capital structure and return on equity result in an overall return which satisfies all three fair return standards. The advantage of the second approach is that it is, in principle, compatible with the philosophy that the capital structure, within a reasonable range, is appropriately a decision for management, because management is in the best position to assess its business risks, financing requirements and access to debt and equity capital. For NSPI, the second approach has been adopted for the estimation of the fair return.

B. SELECTION OF PROXY COMPANIES

The cost of equity, as estimated using tests applied to proxy companies, reflects the composite of those proxy companies' business, regulatory and financial risks. In principle, the cost of equity estimated by reference to a sample of companies is applicable to a specific utility without adjustment only if the magnitude of the total risks of the sample and the specific utility is comparable.

In Canada, there are only seven investor-owned publicly-traded companies whose operations are largely regulated.[20] These companies are relatively heterogeneous in terms of both operations[21] and size.[22] The relatively small and heterogeneous universe of publicly-traded Canadian regulated companies means that it is impossible to select a sample that would be considered directly comparable in total risk to any specific Canadian utility.

While market data for the Canadian utilities provide a perspective on the fair return for a benchmark utility, a more accurate assessment can be made by relying also on a sample of comparable risk U.S. utilities drawn from a much broader universe and selected using criteria designed to (1) identify companies that are of relatively similar risk to NSPI and (2) produce a large enough sample of companies to ensure reliable cost of equity test results.

[20] Canadian Utilities Limited, Emera Inc., Enbridge Inc., Fortis Inc., Pacific Northern Gas, TransCanada Corporation and Valener Inc. (formerly Gaz Métro LP).

[21] Their operations span all the major utility industries, including electricity distribution, transmission and power generation, natural gas distribution and transmission, and liquids pipeline transmission, as well as unregulated activities in varying proportions of their consolidated activities.

[22] Ranging from an equity market capitalization of approximately $110 million (Pacific Northern Gas) to $26 billion (TransCanada).

U.S. regulated companies represent a reasonable point of departure for the selection of a sample of proxies from which to estimate the cost of equity for NSPI. The operating (or business) environments are similar, the regulatory model in the U.S. is similar to the Canadian model, Canadian and U.S. capital markets are significantly integrated and the cost of capital environment is similar. Nevertheless, not all utilities in the U.S. would be considered of similar risk to NSPI, just as not all utilities in the U.S. would be similar to each other. Consequently, a proxy sample was selected according to criteria specifically designed to identify utilities of similar risk to NSPI. The selection criteria are set out in Appendix B.

VI. BUSINESS AND FINANCIAL RISK OF NSPI

A. BUSINESS RISK

1. Conceptual Considerations

Business risk is a function of the fundamental characteristics of a utility (e.g., demand, supply and operating factors). Regulatory risk can be considered either as a component of business risk or as a separate risk category along with business and financial risk. Regulatory risk relates to the framework that determines how the fundamental risks are allocated between the utility's customers and its investors. The regulatory framework is dynamic: it is subject to change as a result of shifts in underlying fundamental risk factors including the competitive environment, energy policy, and regulatory philosophy.

Business risks have both short-term and longer-term aspects. The capital structure and fair return on equity should reflect both short- and long-term risks. Short-term business risks relate primarily to year-to-year variability in earnings due to the combination of fundamental underlying economic factors and the existing regulatory framework. Long-term risks are important because utility assets are long-lived. Long-term business risks comprise factors that may negatively impact the long-run viability of the utility and impair the ability of the shareholders to fully recover their invested capital and a compensatory return thereon. As utilities represent capital-intensive investments with very limited alternative uses, whose committed capital is recovered over an extended period of time, it is the long-term risks that are of primary concern to the investor. Moreover, utility stocks are not typically purchased as short-term investments.

Since utilities are generally regulated on the basis of annual revenue requirements, there is a tendency to downplay longer-term risks, essentially on the grounds that the regulatory framework provides the regulator an opportunity to compensate the shareholder for the longer-term risks when they are experienced. This premise may not hold. First, competitive conditions may forestall higher return rewards when the risk materializes. Second, no regulatory board can bind a successor board and thus guarantee that investors will be compensated for longer-term risks in the event they are incurred in the future. Thus, while annual volatility in earnings is a risk factor, longer-term risks are critical elements of the business risk profile of a regulated utility and the determination of a reasonable capital structure and a fair overall return.

2. <u>Overview of NSPI</u>

NSPI is an integrated electric utility providing over 95% of the electricity generated, transmitted and delivered in the Province of Nova Scotia to approximately 490 thousand residential, commercial and industrial customers. Total assets at the end of 2010 were close to $4 billion. The percentage of customers and sales to each customer class are summarized below.

Table 3

	Customers	**Sales (GWh)**
Residential	90.5%	36.2%
Commercial	7.1%	27.0%
Industrial	0.5%	34.1%
Other	1.9%	2.7%

The proportions of total property, plant and equipment (net of general plant) attributable to each of the three main functions are as follows:

Table 4

Function	Percentage of PP&E
Generation	68%
Transmission	11%
Distribution	21%

3. Electricity Market Structure in Nova Scotia

NSPI owns and operates a vertically integrated (transmission, distribution and generation) electric utility. It is one of only two investor-owned electric utilities in Canada (FortisBC being the other) which own and operate regulated facilities that generate more than a third of the power consumed by their customers. There is a limited wholesale market for eligible market participants (the province's six municipally-owned electric utilities) and an Open Access Tariff, which provides for non-discriminatory access to NSPI's transmission system, allowing the eligible market participants to import power from outside the province and for competitive suppliers to import and export power into and out of the province.

NSPI retains the obligation to serve, including the obligation to ensure that adequate power is available to its domestic customers, either through construction, ownership and operation of generation or by contracting for power. This obligation is in contrast to the obligations held by, for example, the electricity distributors in Ontario or Alberta. In Ontario, the distribution utilities have no obligation to ensure the availability of power. In Alberta, the distribution utilities have the supplier of last resort function only if the retailers who have been designated the supplier of last resort default on their commitment.

4. NSPI's Market

NSPI serves a relatively small economy; the 2009 Nova Scotia GDP of $34 billion represents approximately 2.25% of the total GDP of Canada. The economy is a mix of resource-based industries (e.g., energy and forestry related) and service-based, as Nova Scotia serves as a regional service hub for Atlantic Canada. The province's economy depends on trade, with more than 50% of its GDP directly attributed to the export of goods and services to the U.S. and other Canadian provinces.[23]

The significant service-related segments of the Nova Scotia economy helped the province to weather the recession relatively well. Nova Scotia experienced one of the lowest percentage declines in GDP in Canada in 2009. However, the resource-based export industries were hard hit. The value of provincial exports declined by almost 25% in 2009, of which energy exports accounted for over 60% of the decline.[24] The energy industry in Nova Scotia remained weak in 2010; the decline in the value of energy exports was close to 40%, due to steep declines in off-shore natural gas production and low natural gas prices. With weak demand abroad, the forestry and forest products industry also experienced significant declines during both 2008 and 2009, resulting in a seven-year stretch averaging approximately 12% per year. The drop of 7% posted by the manufacturing industries in 2009 marked the fifth consecutive year of decline for this sector. The poor performance of industry in Nova Scotia during the recession is reflected in NSPI's 2009 sales volumes. Industrial electricity consumption fell by 12% in 2009; total consumption declined by 4%.

Consistent with a shallower recession, the first year of economic recovery in Nova Scotia was more muted. Real economic growth lagged the rest of Canada (real GDP growth of 1.8% in Nova Scotia versus 3.1% for Canada) during 2010. Strongest growth among industry sectors is expected to be posted by the forestry and forest products industry, with growth in agriculture, the fisheries, and the oil and gas industry all remaining in negative territory. The oil and gas industry is expected to remain weak until the Deep Panuke project begins production at the end

[23] Standard and Poor's, *Nova Scotia Power Inc.*, December 30, 2010.
[24] Foreign Affairs and International Trade Canada, *Canada's State of Trade: Trade and Investment Update – 2010*, page 78, available at www.international/gc/ca/economist-ecnomiste/performance.

of 2011. Although industrial consumption of electricity rebounded last year, it remained below its 2005 peak.

Over the next two years (2011-2012), growth is expected to remain slow. The Conference Board of Canada's *Provincial Outlook*, Winter 2011, anticipates that government austerity measures, limited residential and non-residential investment spending and restrained consumer spending will slow the economic recovery. The Conference Board forecasts that growth in the province during 2011 and 2012, at 1.6% and 1.8% respectively, will lag well behind the rest of Canada (2.7% and 2.0%), despite the significant bump expected from the oil and gas sector in 2012 with the commencement of production from Deep Panuke.[25]

Over the longer-term, demographic factors are expected to be the key constraint on growth. The Conference Board of Canada's *Provincial Outlook 2010* forecasts that Nova Scotia will rank next to last in long-term growth from 2009-2030. The expected annual growth rate of 1.1% over this period (compared to Canada's 2.0%) reflects a deceleration over time, as the population ages, net outmigration occurs, consumer spending shifts away from durable goods to services, and slowing growth in domestic industries, most notably mining (oil and gas) and construction.

5. <u>Electricity Supply</u>

NSPI produces close to 90% of the power that it sells and purchases the remainder under power purchase contracts with independent power producers (IPPs) of renewable energy. NSPI's year-end 2010 owned generating capacity of 2,368 MW was comprised of the following technologies (by percentage):

[25] Other private sector economic forecasters anticipate similar outcomes.

Table 5

Technology	Percent of Capacity (MW)
Coal	52.5%
Dual Fired	14.8%
Natural Gas	12.8%
Hydroelectric	16.7%
Wind	3.2%

The IPPs with which NSPI has contracts own 186 MW of wind and biomass capacity, increasing to 226 MW in 2011. An additional 85 MW of renewable capacity expected to be in service by the end of 2012 is either being build directly by NSPI or will be purchased from IPPs by NSPI pursuant to long-term contracts.

Currently, approximately 83% of the power delivered by NSPI is produced from fossil fuels (64% from coal). The Government of Nova Scotia has taken a leadership role in combating climate change, through the reduction of greenhouse gas (GHG) emissions and other air pollutant emissions and the adoption of an energy strategy that will transition from coal-fired electricity production to electricity produced from renewable resources.

In August 2009, the Government of Nova Scotia issued Greenhouse Gas Emissions Regulations made under the *Environment Act*. Under those regulations, NSPI is subject to caps on GHG emissions. The targets require a reduction in GHG by NSPI of 25% by 2020 from 2009 levels. Failure to meet the caps can result in penalties of up to $500,000 per day. NSPI is also subject to increasingly stringent caps on sulphur dioxide, nitrous dioxide and mercury emissions.

The Government of Nova Scotia first legislated renewable energy targets in 2007 as part of the *Environmental Goals and Sustainability Prosperity Act*, committing to obtaining 18.5% of the province's electricity needs from renewable sources (hydroelectric, wind, tidal, solar, and biomass) by 2013. Renewable Energy Standard Regulations were adopted under the *Electricity Act* (Nova Scotia), which implemented the rules for achievement of the specified requirements, including potential penalties for non-compliance (up to $500,000 per day). In April 2010, the government released a more aggressive plan (the Renewable Electricity Plan), which would legislate obtaining 25% of the province's electricity needs from renewable resources by 2015 and established an objective of 40% by 2020. Amendments to the Renewable Energy Standard Regulations made under the *Electricity Act* in October 2010 implemented the 2015 requirement. The UARB has recognized that the Renewable Energy Standard, which will require an additional 600 to 750 GWh of renewable energy projects between 2010 and 2015, will be a significant challenge for NSPI.[26]

6. <u>Regulation</u>

NSPI's cost of service framework is similar to that of other North American utilities. Like most other vertically integrated utilities in North America, NSPI is able to recover from customers the difference between its forecast and actual fuel costs through a fuel adjustment mechanism (FAM). NSPI's FAM was conditionally approved by the UARB in Order NSUARB-P-887 (December 2007). Decision NSUARB-NSPI-P-888 (November 2008) approved the implementation of the FAM, effective January 1, 2009, with the Board having satisfied itself that the prerequisites specified in its December 2007 Order had been fulfilled.

The adoption of the FAM was viewed positively by the debt rating agencies. In its November 2010 debt rating report for NSPI, DBRS commented that "The Fuel Adjustment Mechanism (FAM) which took effect on January 1, 2009, now allows for 100% fuel cost pass through, which in turn has reduced regulatory risk and volatility in NSPI's earnings." In its September 2009 report, Standard & Poor's upgraded NSPI from BBB to BBB+, in part due to the adoption of the FAM. Its December 2009 report concluded that "the utility's risk profile has improved with the introduction of a fuel-adjustment mechanism (FAM), which will result in pass through of fuel costs into rates."

[26] Nova Scotia Utility and Review Board, *In the Matter of an Application by Nova Scotia Power Incorporated for approval of capital work order CI# 39029, Port Hawkesbury Biomass Project, at a cost of $208.6 million* (NSUARB-P-128.10), page 37.

In December 2010, in Decision NSUARB-P-887(2), the Board determined that the 2011 FAM amounts should be recovered over a three-year period, 50% in 2011, 30% in 2012 and 20% in 2013. DBRS responded:

> While DBRS understands that according to the FAM Plan of Administration, the UARB reserves the right to intervene where it believes an increase is not acceptable nor in the public's interest, the current decision to defer recovery is not favourable for NSPI. While the deferred amount ($53 million) is sizable, DBRS recognizes that under the FAM, NSPI will recover all its fuel costs (including carrying charges) from its customers over the deferral period and, as such, does not view the decision as having a material impact on NSPI's liquidity nor on the current ratings of A (low), R-1 (low) and Pfd-2 (low). However, DBRS will monitor future FAM filings, noting that a deferral significant enough to have a material effect on NSPI's liquidity could affect the ratings, particularly in a period of high capital requirements.

S&P also commented as follows:

> An energy cost deferral mechanism, which the Nova Scotia Utility and Review Board (UARB) approved during a December 2010 rate case decision, somewhat weakens the FAM, in our view. While the UARB recognized that energy costs should increase by NSPI's requested amount, it ordered the recovery of the energy cost increase to be spread over multiple years.
>
> We believe that in a period of rising fuel costs, there is now a greater likelihood of a sustained use of an energy cost deferral mechanism to minimize customer rate shock. As a result, a growing deferral balance might put pressure on the ratings because it could increase cash flow volatility and place greater demands on working capital. NSPI's ability to earn a return on the deferral while it remains on the asset side of its balance sheet offsets the adverse effect a deferral balance could have on the company's credit profile, in our view.

In both cases, the potential for the FAM deferral to pressure NSPI's ratings appears to be a function of the relative size of the amount deferred. In NSPI's case the amount deferred represents approximately 4.5% of 2010 revenues. A relatively larger deferral, however, from DBRS' perspective, clearly could pressure NSPI's debt rating. As regards S&P's perspective, a comparison between its views regarding NSPI and Maritime Electric Company Limited (MECL) indicates that, if the FAM deferral were to grow relative to NSPI's total revenues, NSPI's ratings could come under pressure. With respect to MECL, which had accumulated a large (relative to total revenues) deferral account related to incurred but unrecovered energy costs, S&P stated. "

> We have some concern with the use of an energy cost adjustment mechanism (ECAM) under the existing regulations. In the most recent approved rate order in July 2010, the regulator recognized that the base rate for energy costs should increase and also directed MEC to file a business case analysis with respect to the utility's continued involvement with the Point Lepreau and Dalhousie generating facilities. **Nevertheless, the regulator's desire to minimize rate shock for electricity users is slowing MEC's commodity cost recovery and putting pressure on the rating.** (emphasis added) The ECAM is designed to smooth out the cost of volatile produced and purchased energy costs; in theory, high energy costs are not be immediately passed through but are deferred and then recovered on a rolling12-month basis. However, since 2006, the cost of energy has consistently exceeded the level built into the base rate for consumers. This has caused the deferral balance to rise well beyond our expectations (various rate deferral balances were approximately C$57 million at the end of 2009, or more than 40% of annual revenues). The 2009 regulatory deferral balance was equivalent to about 29% of the year's FFO generation. The adverse effect the deferral balance has on the Maritime Electric's credit profile is **somewhat offset** in our opinion by the company's ability to earn a return on the deferral while it remains on the asset side of its balance sheet. (emphasis added)[27]

With respect to capital projects, as noted by DBRS, "Each project must receive approval from the Nova Scotia Utility and Review Board (UARB) before NSPI can proceed to ensure that the investment will be included in the rate base."[28] This requirement is materially the same in other Canadian jurisdictions. Costs incurred in the construction of each project are, as in other jurisdictions, subject to a prudence review. On an ongoing basis, projects completed and placed into service are subject to risks that costs incurred for maintenance capital, operating expenses and fuel (for generation projects) will not be recoverable in rates.

With respect to how the capital markets view regulatory risk overall in Nova Scotia compared to regulatory risk in other Canadian jurisdictions, the only third party comparisons of which I am aware have been provided by two debt rating agencies, S&P and Moody's.[29] In its most recent debt rating report for NSPI, S&P commented that "In our opinion, NSPI's specific regulatory environment was somewhat less favorable than others in Canada. However, the direction of recent rulings has generally been more favorable. In particular, we viewed the FAM

[27] Standard and Poor's, *Maritime Electric Co. Ltd.*, September 1, 2010.
[28] DBRS, *Nova Scotia Power Inc.*, November 26, 2010.
[29] DBRS has not, to my knowledge, ever provided any comparative assessment. Its commentary on NSPI's regulatory risk in its most recent full debt rating report, issued in November 2010, prior to Decision NSUARB-P-887(2), was specific to Nova Scotia. DBRS found that "NSPI still faces some regulatory risk with respect to the timeliness and certainty of full cost recovery, even though the implementation of the FAM will help to alleviate this. It is expected that the difference between the costs included in rates and the actual costs of fuel will be deferred and refunded to or collected from customers in the subsequent year."

implementation as a positive development that materially reduces the risk associated with volatile hydrocarbon prices."[30] In its last report on NSPI prior to its discontinuation of the debt ratings, Moody's ratings for NSPI on its two regulatory risk factors were the same as the average for other Canadian utilities that it rates.[31] Moody's quantitative methodology for rating electric and gas utilities worldwide considers four main factors: regulatory framework (25% weight); ability to recover costs and earn returns (25% weight); diversification (10% weight); and financial strength and liquidity (40% weight). On the two factors related to regulatory environment, regulatory framework and ability to recover costs and earn returns, Moody's rated NSPI "A", the same average rating that it has accorded other Canadian utilities that it rates.[32]

7. Capital Expenditures

In its most recent debt rating report (November 25, 2010), DBRS noted that NSPI's capital expenditures had increased significantly and estimated that NSPI would spend close to $1 billion over the next several years in addition to maintenance capital (approximately $400 million per year) in order to meet the renewable energy targets, to improve system reliability and to comply with new environmental standards. In 2010 alone, NSPI incurred over $0.5 billion in capital expenditures, largely related to investments in renewable energy projects.

The over $0.5 billion in capital expenditures in 2010 and the anticipated approximately $400 million per year over the next several years represent more than two and a half times the average annual investment in plant, property and equipment of under $150 million made by NSPI during the prior five years (2005-2009).

8. Relative Business Risk of NSPI

Even with the FAM in place, as an integrated utility with more than 50% of its rate base invested in generation assets, NSPI faces higher business risks than the typical regulated Canadian utility.

[30] Standard and Poor's, *Nova Scotia Power Inc.*, December 30, 2010.
[31] Moody's, *Nova Scotia Power Inc.*, November 17, 2009.
[32] Moody's rates electric and gas utilities operating in the provinces of Alberta, British Columbia, Ontario and Newfoundland and Labrador.

The average business risk profile ranking[33] assigned to Canadian electric and gas utilities by Standard & Poor's is "Excellent", the top category on its business risk ranking scale; NSPI is assigned a business ranking of "Strong".[34] The regulated operations of the majority of the Canadian utilities listed on Schedule 3 are largely "wires" or "pipes" operations (distribution and transmission) that inherently face less business risk than an integrated electric utility (i.e., with generation). Generation operations are exposed to higher operating and capital recovery risks than a "wires only" or "pipes only" business. Of the major capital intensive utility functions, generation is the one that is not necessarily a natural monopoly; the electric "wires" and gas distribution "pipes" are unlikely to ever be duplicated. Integrated utilities retain the obligation to ensure adequate generation capacity; "wires" utilities do not have that obligation nor do they have the same level of cost recovery risks as generation (fuel cost disallowances, operating risk or stranded costs).

While generation is riskier than transmission or distribution, within the generation function, there are different levels of business risk associated with different types of generation. The generation assets of FortisBC, the only other Canadian investor-owned truly integrated electric utility[35], are relatively low risk hydro-electric plants. Its purchased power also is primarily generated by hydroelectric plants. In contrast, NSPI's existing generation assets are concentrated in higher risk coal/petroleum coke facilities. NSPI's higher risk relative to FortisBC arises from:

(1) Risks related to the availability and costs of fuel and replacement costs of power if the plants are not operating. Hydroelectric generation facilities do not incur fuel costs.[36] Even with the FAM, NSPI is exposed through the FAM's incentive mechanism to the risk of under-recovering its actual fuel costs and to the risk of cost disallowance.

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[33] There are six S&P business risk profile rankings, ranging from "Excellent" to "Vulnerable".
[34] S&P raised NSPI's business risk profile ranking from "Satisfactory" to "Strong" in December 2009 following implementation of the FAM.
[35] Maritime Electric and Newfoundland Power have some generation assets, but remain largely distribution utilities. Other investor-owned Canadian utilities have significant generating assets, but the generating assets are not regulated.
[36] Due to its arrangements with BC Hydro (BC Hydro dispatches FortisBC's plants in exchange for power entitlements), FortisBC does not face any risk related to water availability.

(2) The lower probability that FortisBC's low cost hydroelectric facilities will be replaced by alternative generating sources, which results in lower long-term competitive and stranded cost risk for FortisBC than for NSPI.

(3) The higher environmental risk (e.g., costs of environmental compliance) associated with NSPI's coal/petroleum coke facilities, as compared to FortisBC's hydroelectric plants.

(4) NSPI's renewable energy resource requirements arising from the Renewable Energy Standard Regulation.

(5) NSPI's requirements to reduce greenhouse gas (GHG) emissions and other air pollutants. While FortisBC, as a British Columbia utility, also operates in a province governed by an aggressive climate change strategy, its sources of power supply, as noted above, are predominantly hydroelectric.

B. FINANCIAL RISK

As discussed in Chapter V, financial risk is the additional risk borne by the equity shareholder because the firm uses debt to finance a portion of its assets. The capital structure, comprised of debt and common equity, can be viewed as a summary measure of the financial risk of the firm. Credit metrics are also an important indicator of the level of financial risk. The firm's debt ratings are a further indicator of the level of financial risk, as debt ratings incorporate an overall assessment of the firm's business and financial risk, from the perspective of the bond investor.

NSPI is proposing to maintain the 37.5% common equity ratio that has previously been adopted for rate setting purposes. It is also requesting in this proceeding to continue to calculate its annual earnings on the basis of its actual capital structure up to a maximum common equity ratio of 40% as directed by the UARB in approving the January 2010 ROE Settlement Agreement.

NSPI's 37.5% common equity ratio used for rate setting purposes is at the low end of the scale for regulated Canadian utilities. Of the investor-owned electric utilities in Canada, only the electric transmission utilities in Alberta, which are of materially lower business risk than NSPI, have allowed equity ratios lower than 37.5%. The typical common equity ratio allowed for rate setting purposes for electricity distribution utilities, which are also of lower business risk than NSPI is 40%, with a range of 39% (Alberta taxable electricity distributors) to close to 45% (Newfoundland Power) ; (see Schedule 2 page 1 of 3). The average common equity ratio for regulated electric and gas utilities in Canada used for ratesetting purposes is approximately 40%, higher than NSPI's 37.5%; (see Schedule 2 page 1 of 3). The median actual year-end 2009 common equity ratio for investor-owned utilities with rated debt was 41%, higher than NSPI's forecast test-year actual common equity ratio of 37.5%.

With respect to credit metrics, three credit metrics that debt rating agencies look to in their assessment of financial risk are: Earnings before Interest and Taxes (EBIT) Interest Coverage, Funds from Operations (FFO)[37] to Total Debt, and FFO Interest Coverage.[38] The latter two are important because bond investors are more concerned about cash flows available to meet interest payments than earnings *per se*. As summarized in Table 6 below, NSPI's three-year average EBIT Interest Coverage, FFO to Debt Ratio and FFO Interest Coverage Ratio have been marginally higher than the medians for investor-owned Canadian utilities with rated debt. DBRS expects the credit metrics to weaken during the capital build cycle, i.e., while capital expenditures are being incurred but before the projects are included in rate base.

Table 6

	EBIT Coverage	**FFO Interest Coverage (2007-2009)**	**FFO/Debt**
NSPI	2.4X	3.2X	15.8%
Investor-owned Utility Median	2.3X	3.2X	14.5%

Source: Schedule 6 page 1 of 2

[37] Funds from Operations Funds from operations are equal to net income plus or minus non-cash items. The principal non-cash items include depreciation and amortization, future income taxes and the equity component of AFUDC.
[38] Funds from Operations plus Interest divided by Interest.

Despite slightly higher credit metrics than achieved by the investor-owned utility sector overall, NSPI's debt ratings have been lower than average. NSPI's DBRS rating is A (low), one notch lower than the investor-owned Canadian utility median of A. Its S&P rating is BBB+, one notch lower than the investor-owned utility median of A-.[39]

The lower debt ratings stem from higher business risk as compared to NSPI's Canadian peers, which has not been offset by lower financial risk (i.e., a higher common equity ratio and materially stronger credit metrics).

NSPI's higher business risk, lower regulated and actual common equity ratios, and lower debt ratings compared to its Canadian peers translate into both a higher cost of debt and a higher cost of equity. The higher cost of equity, in turn, means that NSPI's allowed ROE needs to be set at a level in excess of those awarded its Canadian peer in order to meet the three requirements of the fair return standard. While all of the three requirements of the fair return standard (comparability of returns, ability to attract capital, and maintenance of financial integrity and creditworthiness) are equally important, NSPI is embarking on a significant capital program that will require consistent access to the capital markets. A fair ROE that recognizes NSPI's higher business risk but relatively modest common equity ratio will provide a foundation for ensuring the Company's ability to attract capital on reasonable terms and conditions.

VII. FAIR RETURN ON EQUITY FOR NSPI

A. CONCEPTUAL CONSIDERATIONS

1. <u>Importance of Multiple Tests</u>

The key to determining the fair return on equity (i.e., ensuring that all three requirements of the fair return standard are met) is reliance on multiple tests. There are three different types of tests that have traditionally been used to estimate the fair return on equity: equity risk premium

[39] Before NSPI's Moody's ratings were withdrawn at the request of the Company in March 2010, its rating was Baa1, one notch lower than the median rating of A- for all Canadian utilities rated by Moody's.

(including, but not limited to, the Capital Asset Pricing Model), discounted cash flow and comparable earnings tests. Each of the tests is based on different premises and brings a different perspective to the fair return on equity. None of the individual tests is, on its own, a sufficient means of ensuring that all three requirements of the fair return standard are met; each of the tests has its own strengths and weaknesses. Individually, each of the tests can be characterized as a relatively inexact instrument; no single test can pinpoint the fair return.[40] Moreover, different tests may be more or less reliable depending on prevailing economic and capital market conditions.[41] These considerations not only emphasize the importance of reliance on multiple tests, but also of benchmarking, or testing the reasonableness of the test results themselves against other relevant information.

Each test has its own set of pros and cons. The discounted cash flow test directly measures utility return expectations. It is subject to an ongoing debate around the accuracy of investment analysts' forecasts as the measure of investor expectations of growth. The comparable earnings test explicitly recognizes that the objective of regulation is to emulate competition and measures returns on the same original cost basis on which utilities are regulated. It is subject to concerns around selection criteria and whether the results are representative of economic returns. The theoretical Capital Asset Pricing Model, framed in an elegant, simple construct, and, on the surface, with only three components, easy to apply, has an intuitive appeal. Nevertheless, it also has its own set of challenges, which are summarized below.

The focus on the challenges of the theoretical CAPM is not to suggest that other tests are necessarily superior, but because Canadian regulators have, in recent years, tended to favour CAPM in their estimation of the allowed ROEs, although recently with clearer recognition of its

[40] For example, Bonbright states, "No single or group test or technique is conclusive. Therefore, it is generally accepted that commissions may apply their own judgment in arriving at their decisions." (James C. Bonbright, Albert L. Danielsen, David R. Kamerschen, *Principles of Public Utility Rates*, 2nd Ed., page 317, Arlington, VA.: Public Utility Reports, Inc., March 1988).

[41] For example, see Federal Communications Commission, Report and Order 42-43, CC Docket No. 92-133 (1995).

> Equity prices are established in highly volatile and uncertain capital markets... Different forecasting methodologies compete with each other for eminence, only to be superseded by other methodologies as conditions change... In these circumstances, we should not restrict ourselves to one methodology, or even a series of methodologies, that would be applied mechanically. Instead, we conclude that we should adopt a more accommodating and flexible position.

shortcomings and the various adjustments to the "classic" model that may be required.[42] The challenges in the application of the CAPM include:

(1) The CAPM attempts to measure, within the context of a diversified portfolio, what return an equity investor should require, in contrast to the return that the investor does require or what returns are actually available to investments of comparable risk.

(2) The size of the market risk premium cannot be directly observed and is subject to a wide divergence of opinion. While historic risk premiums may provide a perspective on the size of the expected forward-looking market risk premium, historic results are sensitive to

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[42] The British Columbia Utilities Commission (BCUC) and the Ontario Energy Board (OEB), in their 2009 utility cost of capital reviews, recognized the challenges of the CAPM, the need for adjustments, and the need to consider the results of multiple tests.

The BCUC noted:

> that CAPM is based on a theory that can neither be proved nor disproved, relies on a market risk premium which looks back over nine decades and depends on a relative risk factor or beta. The fact that the calculated beta for PNG (considered by Dr. Booth to be the most risky utility in Canada) was 0.26 in 2008 causes the Commission Panel to consider that betas conventionally calculated with reference to the S&P/TSX are distorted and require adjustment.
>
> The Commission Panel will give weight to the CAPM approach, but considers that the relative risk factor should be adjusted in a manner consistent with the practice generally followed by analysts so that it yields a result that accords with common sense and is not patently absurd. (BCUC, *Order G-158-09, In the Matter of Terasen Gas Inc. Terasen Gas (Vancouver Island) Inc. Terasen Gas (Whistler) Inc. and Return on Equity and Capital Structure Decision*, December 16, 2009, page 45).

The OEB stated:

> The Board's current formulaic approach for determining ROE is a modified Capital Asset Pricing Model methodology, and in his written comments, Dr. Booth recommended that this practice be continued. Dr. Booth recommended that "the Board base its fair ROE on a risk based opportunity cost model, with overwhelming weight placed on a CAPM estimate".
>
> This view was not shared by other participants in the consultation, who asserted that the Board should use a wide variety of empirical tests to determine the initial cost of equity, deriving the initial ERP [equity risk premium] directly by examining the relationship between bond yields and equity returns, and indirectly by backing out the implied ERP by deducting forward-looking bond yields from ROE estimates…
>
> The Board agrees that **the use of multiple tests to directly and indirectly estimate the ERP is a superior approach to informing its judgment than reliance on a single methodology**. In particular, the Board is concerned that CAPM, as applied by Dr. Booth, does not adequately capture the inverse relationship between the ERP and the long Canada bond yield. As such, the Board does not accept the recommendation that it place overwhelming weight on a CAPM estimate in the determination of the initial ERP. (OEB, *EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities,* December 11, 2009, pages 45-46)

the country from which the data are drawn and the time period over which they are measured.

(3) The market risk premium is not a fixed quantity; it changes with investor experience and expectations. It would be higher, for example, when investors perceive that the risk of the equity market has increased relative to that of the government bond market and vice versa. However, the model does not readily allow estimation of changes in the size of the market risk premium as economic or capital market conditions (e.g., interest rates) change. The typical application of the CAPM relies heavily on long-term average achieved equity risk premiums in conjunction with a current or forecast risk-free rate.[43] The typical application of the model captures the change in interest rates, but does not capture how the risk premium changes when interest rates change. The need to capture and measure changes in the relative risk of the so-called risk-free security introduces a further complication in the application of the CAPM, particularly as the changes impact the measurement of the equity market risk premium.

(4) The achieved equity market risk premium in Canada is significantly influenced by historic behaviour of the long-term Government of Canada bond. The radical change in Canada's fiscal performance over the past decade has contributed to a steady decline in long-term government bond yields and a corresponding increase in total returns achieved by investors in long-term government securities. As a result, the achieved equity market risk premiums in Canada have been squeezed by the performance of the government bond market. The low prevailing and forecast long-term Government of Canada bond yields relative to both the historic yields and total returns on those securities indicate that the historic yields and returns on long-term Government of Canada bonds overstate the forward looking risk-free rate.

[43] Theoretically, an underlying premise of the CAPM is that the risk-free rate is uncorrelated with the return on the market. In other words, the assumption is that there is no relationship between the risk-free rate and the equity market return (i.e., the risk-free rate has a zero beta). However, the application of the model frequently assumes that the equity market return is highly correlated with the risk-free rate, that is, the equity market return and the risk-free rate move in tandem. Consequently the application of the test frequently proceeds on an assumption directly in conflict with an underlying premise of the model itself.

(5) The objective of using the CAPM (as with any cost of equity model) is to estimate the returns that investors expect or require. Empirical tests of the model have shown in some cases that the model underestimates the returns for low beta stocks and overestimates them for high beta stocks and in other cases that there is no relationship between beta and return.

The challenges associated with the CAPM are of a sufficient magnitude to warrant the conclusion that it is not inherently superior to other approaches to the estimation of a fair return, particularly in light of the adjustments to the theoretical CAPM necessary to apply it to the utility industry.

All approaches to estimating a fair return require significant judgment in their application, the extent of which depends on the prevailing state of the capital markets. Any individual cost of equity model implicitly ascribes simplicity to a cost whose determination is inherently complex. No single model is powerful enough on its own to produce "the number" that will meet the fair return standard. Only by applying a range of tests along with informed judgment can adherence to the fair return standard be ensured.[44]

2. Distinction between Market and Book Values for Fair ROE Determination

Discounted cash flow and equity risk premium models represent conceptually different ways that investors might approach estimating the return they require on the market value of an equity investment. While the discounted cash flow (DCF) and risk premium tests estimate the return

[44] I am strongly of the view that the comparable earnings test is the only test which measures returns in a manner compatible with the base (original cost) to which they are applied. However, I also recognize that the comparable earnings test is the most controversial, not only in terms of its applicability to the estimation of a fair return, but in terms of its application (e.g., criteria for selection of comparables, period over which returns should be measured, need for adjustments for relative risk. In order to limit the issues relevant to the estimation of a fair return, I have applied risk premium and discounted cash flow tests only. However, if the comparable earnings test is to be omitted, the determination of the allowed ROE needs to recognize that market-based costs of equity relate to market value capital structures, not the book value capital structure to which the cost of equity is applied. See Section VII.E. for a full discussion. The application of the comparable earnings test, conducted in the same manner as I previously presented to the UARB, indicates, in isolation, a fair return in the range of 12.5% to 13.0%. In that context, the ROE that I recommend for NSPI is conservative.

required on the market value of common equity, regulatory convention applies that return to the book value of the assets included in rate base. The determination of a fair return on book equity needs to recognize that distinction.

In simple terms, assume that the cost of equity for a company whose stock value is $200 is 10%. That means that investors require a return, in dollar terms, of $20. If the book value of the stock is $100, and the 10% cost of equity is applied to the $100 book value rather than the $200 market value, the resulting return in dollar terms is only $10, or half that which investors require.

The proxy companies used for the purpose of estimating the cost of equity have market-to-book ratios of 1.5 X (U.S. sample) to 2.0X (Canadian sample), well in excess of the market-to-book ratio of 1.0 that conceptually would equate the return on book value (in dollar terms) to the return estimated by reference to the market-based DCF or equity risk premium tests.

When the allowed return is applied to an original cost book value, a market-derived cost of attracting capital must be converted to a fair and reasonable return on book equity so that the stream of dollar earnings on book value equates to the investors' dollar return requirements on market value. Failure to make such a conversion will produce an allowed level of earnings that contravenes the fair return standard and will discourage utilities from making investments in critical infrastructure.

B. SELECTION OF COMPARABLE UTILITIES

To ensure comparability with NSPI, only electric utilities categorized by the Edison Electric Institute (EEI) as regulated or mostly regulated utilities were selected. Further, the selection was limited to electric utilities whose operations are focused in states whose electric utility industry is not restructured or where restructuring has been suspended, retail choice is limited to large customers, and the preponderance of customers and load receive a bundled (distribution, transmission and generation) service.

The selected electric utilities are in Standard & Poor's "Strong" or "Excellent" business risk category, with a sample median of "Excellent". The typical Canadian utility[45] has an "Excellent" business risk ranking; NSPI is ranked "Strong"; i.e., of higher business risk than the typical Canadian utility and of higher business risk than the typical utility in the proxy U.S. electric utility sample from S&P's perspective. The U.S. electric utilities are rated no lower than BBB/Baa by both Standard & Poor's and Moody's. The median S&P debt rating of the U.S. electric utility sample is BBB+, identical to NSPI. The median Moody's rating for the U.S. electric utility sample is Baa1; NSPI's Moody's rating was also Baa1 before it was withdrawn by the Company in March 2010 (Schedules 3 and 12).

The median *Value Line* Safety rank of the U.S. electric utility sample is 2 (Schedule 12); the Safety ranks of both of the two Canadian regulated companies covered by *Value Line* (TransCanada Corp. and Enbridge Inc.) are also 2.[46] In comparison to NSPI, the U.S. utilities have higher common equity ratios (lower financial risk).[47] The average common equity ratio of the sample of U.S. electric utilities (based on the average of the last four quarters ending September 2010) was approximately 45% (Schedule 12), compared to NSPI's deemed common equity ratio for ratesetting purposes of 37.5%, the forecast actual common equity ratio of 37.5% in 2012 and the 40% common equity ratio on which the Company is allowed to earn.

C. EQUITY RISK PREMIUM TESTS

1. <u>Conceptual Underpinnings</u>

An equity risk premium test is derived from the basic concept of finance that there is a direct relationship between the level of risk assumed and the return required. Since an investor in

[45] Standard & Poor's assigns a business risk ranking to each of the companies it rates. There are six business risk categories, ranging from "Excellent" to "Vulnerable". All of the utilities in the proxy sample of U.S. utilities have an "Excellent" business profile, as do the majority of Canadian utilities whose debt is rated by S&P.

[46] The Safety rank represents Value Line's assessment of the relative total risk of the stocks. The ranks range from "1" to "5", with stocks ranked "1" and "2" most suitable for conservative investors. The most important influences on the Safety rank are the company's financial strength, as measured by balance sheet and financial ratios, and the stability of its price over the past five years.

[47] In isolation, the difference in financial risk between a common equity ratio of 50% and a common ratio of 40% is equivalent to a difference in cost of equity of approximately 0.75% to 1.25% at the prevailing utility costs of debt and equity and Canadian income tax rates.

common equity takes greater risk than an investor in bonds, the former requires a premium above bond yields in compensation for the greater risk. Equity risk premium tests are a measure of the market-related cost of attracting capital, i.e., a return on the market value of the common stock, not the book value.

Equity risk premium tests, similar to the other tests used to arrive at a fair return, are forward-looking, that is, they are intended to estimate investors' future equity return requirements. The magnitude of the differential between the required/expected return on equities and the risk-free rate is a function of investors' willingness to take risks and their views of such key factors as inflation, productivity and profitability. Because equity risk premium tests are forward-looking, historic risk premium data need to be evaluated in light of prevailing economic/capital market conditions. If available, direct estimates of the forward-looking risk premium should supplement estimates of the risk premium made using historic data as the point of departure.

2. <u>Risk-Free Rate</u>

The application of equity risk premium tests require a forecast of the risk-free rate to which the equity risk premium is applied. Reliance on a long-term government bond yield as the risk-free rate recognizes (1) the administered nature of short-term rates; and (2) the long-term nature of utility assets to which the equity return is applicable.

In the application of the equity risk premium tests, the long-term Government of Canada bond yield expected to prevail during the 2012 test year was utilized. The most recent publicly-available interest rate forecasts expect the 30-year Canada bond to yield approximately 4.5% during 2012.[48] As the economy strengthens, long-term Canada bond yields are expected to rise. Over the longer-term (2013-2020), the 10-year Canada bond yield is expected to average close to 5.0%.[49] The corresponding 30-year Canada bond yield, assuming that the spread reverts to its historical long-term average of 0.30% as the yield curve flattens, would be approximately 5.25%.

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[48] The forecasts were provided by BMO Capital Markets, CIBC World Markets, Desjardins, National Bank, Royal Bank of Canada, Scotia Bank Group and TD Securities.

[49] Consensus Economics issues long-term forecasts twice annually, in April and October. Consensus Economics, *Consensus Forecasts*, October 2010 anticipates the 10-year Canada bond yield to average approximately 5.0% from

3. <u>Risk-Adjusted Equity Market Risk Premium Test</u>

3.a. <u>Conceptual and Empirical Considerations</u>

The risk-adjusted equity market risk premium approach to estimating the required equity risk premium for a benchmark utility entails (1) estimating the equity risk premium for the equity market as a whole; (2) estimating the relative risk adjustment; and (3) applying the relative risk adjustment to the equity market risk premium, to arrive at the required equity risk premium for a benchmark utility. The cost of equity is thus estimated as:

$$\text{Risk-Free Rate} + \left\{ \text{Relative Risk Adjustment} \times \text{Market Risk Premium} \right\}$$

The risk-adjusted equity market risk premium test is a variant of the Capital Asset Pricing Model (CAPM). The CAPM attempts to measure, within the context of a diversified portfolio, what return an equity investor should require (in contrast to what the investor does require). Its focus is on the minimum return that will allow a company to attract equity capital.

In the CAPM, risk is measured using the beta. 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 returns, as proxied in Canada by the returns on S&P/TSX Composite, and the returns on individual stocks or portfolios of stocks.

The CAPM, framed in an elegant, simple construct, has an intuitive appeal. However, in addition to its restrictive premises, the CAPM does have disadvantages that caution against placing principal reliance on it for purposes of determining a fair return on equity. The disadvantages are summarized in Section VII A. above.

2013 to 2020. The spread between 10- and 30-year Canada bond yields has historically averaged approximately 0.30%.

3.b. Equity Market Risk Premium

3.b.(i) Overview

The estimation of the expected/required market risk premium from achieved market risk premiums is premised on the notion that investors' return expectations and requirements are linked to their past experience. Basing calculations of achieved risk premiums on the longest periods available reflects the notion that it is necessary to reflect as broad a range of event types as possible to avoid overweighting periods that represent "unusual" circumstances. On the other hand, the objective of the analysis is to assess investor expectations in the current economic and capital market environment. Consequently, the analysis of historic returns and risk premiums focused on the post-World War II period (1947-2010)[50] as well as on longer periods. My analysis of historic returns and risk premiums was based on the Canadian experience as well as on the U.S. experience as a relevant benchmark for estimating the equity risk premium from the perspective of Canadian investors. The U.S. experience is relevant given the close relationship between the two economies, the fact that the U.S. has historically been the single largest alternative destination for Canadian portfolio investment (See Appendix A, page A-14) and the similarity between historical Canadian and U.S. equity market returns and equity return volatility.

3.b(ii) Historic Returns and Risk Premiums

Table 7 below summarizes the achieved equity and government bond returns and the corresponding experienced risk premiums for Canada and the U.S.[51]

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[50] Key structural economic changes have occurred since the end of World War II, including:

1. The globalization of the North American economies, which has been facilitated by the reduction in trade barriers of which GATT (1947) was a key driver;
2. Demographic changes, specifically suburbanization and the rise of the middle class, which have impacted on the patterns of consumption;
3. Transition from a resource-oriented/manufacturing economy to a service-oriented economy;
4. Technological change, particularly in the areas of telecommunications and computerization, which have facilitated both market globalization and rising productivity.

[51] The equity and bond market returns in Table 7 represent arithmetic averages of achieved returns. Appendix A explains the rationale for using arithmetic, rather than compound, or geometric averages for the purpose of estimating the expected return from historic returns.

Table 7

Period	Stock Return	Bond Total Returns	Bond Income Returns	Risk Premium Over Bond Total Returns	Risk Premium Over Bond Income Returns
Canada					
1924-2010	11.7%	6.5%	6.0%	5.2%	5.6%
1947-2010	12.1%	6.9%	6.8%	5.2%	5.3%
U.S.					
1926-2010	11.9%	5.9%	5.2%	6.0%	6.7%
1947-2010	12.5%	6.3%	5.9%	6.2%	6.6%

Source: Schedule 7.

The raw data show that, on average, equity returns in Canada have averaged approximately 11.75% to 12.0%, compared to average bond returns of approximately 6.0% to 7.0% (income returns[52]) and 6.5% to 7.0% (total returns), resulting in average achieved risk premiums in the range of approximately 5.25% to 5.5%. The slightly lower achieved equity risk premium relative to bond income returns achieved during the post-World War II period reflects a slightly higher average equity return relative to the longer period, which was more than offset by higher bond income returns.

The corresponding raw data for the U.S. indicate average equity market returns of approximately 12.0% to 12.5%, corresponding to average bond returns of approximately 6.0% to 6.25% and an achieved equity risk premium above 6.5%.

3.b.(iii) Canadian Equity and Government Bond Returns

To assess whether there has been a trend in the underlying returns which generate the achieved risk premiums, the returns and risk premiums for each decade over the period 1931 to 2010 were examined and are presented in Table 8 below.

[52] The bond income return reflects only the coupon payment portion of the total bond return. As such, the income return represents the riskless component of the total government bond return. The bond income return is similar to the bond yield.

Table 8

10-YEAR AVERAGE CANADIAN MARKET RETURNS					
	Canadian Stock Returns	**Canadian Bond Total Returns**	**Canadian Risk Premium Over Bond Total Returns**	**Canadian Bond Income Returns**	**Canadian Risk Premium Over Bond Income Returns**
1931-1940	5.6%	5.7%	-0.1%	3.8%	1.9%
1941-1950	16.7%	3.1%	13.6%	2.9%	13.8%
1951-1960	12.3%	1.1%	11.1%	3.9%	8.4%
1961-1970	10.2%	4.4%	5.9%	5.9%	4.3%
1971-1980	15.5%	4.1%	11.3%	8.9%	6.5%
1981-1990	8.6%	13.8%	-5.2%	11.6%	-3.0%
1991-2000	13.8%	12.9%	1.0%	7.5%	6.4%
2001-2010	8.7%	7.4%	1.3%	4.6%	4.1%

Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2009*; *TSX Review*.

Table 8 indicates a clear pattern in bond returns, reflecting:

(1) rising bond yields in the 1950s through the mid-1980s, which produced capital losses on bonds and low bond total returns;

(2) high total bond returns and yields in the 1980s, reflecting the high rates of inflation; and,

(3) high bond total returns in the 1990s and the 2000s, relative to income returns, reflecting the secular decline in long-term government bond yields, which resulted in capital gains and total bond returns, well in excess of the concurrent bond yields.[53]

In contrast to the pattern in bond returns, Table 8 does not indicate a discernible pattern in equity market returns.[54]

[53] The long-term Government of Canada bond yield is equivalent to an estimate of the expected return on the bond.
[54] Slope coefficients of trend lines fitted to the annual equity return data for the periods 1924-2010 and 1947-2010 are estimated at 0.00 for both periods.

However, further analysis of the historical data indicates, as shown in Table 9 below, that, historically, lower bond income returns have been associated with higher achieved risk premiums.

Table 9

	Averages for the Period: 1924-2010			Averages for the Period: 1947-2010		
Bond Income Returns:	**Equity Returns**	**Bond Income Returns**	**Risk Premium**	**Equity Returns**	**Bond Income Returns**	**Risk Premium**
Below 5%	13.1%	3.7%	9.5%	15.0%	3.6%	11.5%
Below 6%	11.5%	4.2%	7.3%	12.2%	4.4%	7.8%
Below 7%	11.7%	4.3%	7.3%	12.5%	4.6%	7.8%
Below 8%	12.1%	4.6%	7.6%	13.1%	5.0%	8.1%
Below 9%	11.1%	5.0%	6.2%	11.5%	5.5%	6.0%
All Observations	11.7%	6.0%	5.6%	12.1%	6.8%	5.3%

Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2009; TSX Review*.

Table 9 above indicates that, except at the lowest levels of long-term Government of Canada bond income returns, average equity returns were in the range of approximately 11.5% to 12.5% during the two periods. Further, at bond income returns below 8%, the equity risk premium averaged approximately 7.5% to 8.0%. Only when the highest levels of bond income returns are included do the average achieved equity risk premiums drop to approximately 6% and then to 5.0% to 5.5%. In other words, the historical data indicate that the equity risk premium has varied with bond yields, i.e., higher risk premiums at lower levels of bond yields and vice versa.

The forecast long-term Canada bond yield for 2012 is approximately 4.5%, approximately 1.5 percentage points lower than the long-term average bond income return and 2.25 percentage points lower than the post-World War II average bond income return. Over the longer-term, based on the Consensus Economics, *Consensus Forecasts,* October 2010, the long-term Government of Canada bond is anticipated to yield approximately 5.25%. Although *Consensus Forecasts* expect yields to rise, the anticipated average yield going forward is still well below the average income and bond returns achieved historically. While the longer-term forecast of the long-term (30-year) Government of Canada bond yield of approximately 5.25% lies within the range of yields that have been associated with average achieved equity risk premiums of approximately 6.0% to 6.25%, the 2012 forecast long-term Government of Canada bond yield (4.5%) suggests an equity risk premium, based on historical risk premiums at similar levels of interest rates, in the range of 7.25% to 8.0%.

3.b(iv) Comparison of Canadian and U.S. Returns and Risk Premiums

A comparison of the returns in Canada and the U.S. over the longer-term and the post-World War II period shows that the equity market returns in the two countries have been similar. On average the achieved equity market returns in the two countries have been in the approximate range of 11.75% to 12.5% (see Table 7 above).

Despite relatively similar equity market returns, the achieved risk premium in Canada has been approximately 1.3% to 1.5% lower than in the U.S. The difference in the equity market returns accounts for only 0.2% to 0.4% of the difference in the observed risk premiums. The preponderance of the difference is attributable to higher bond returns historically in Canada. Over the period 1926-1997, the difference between long-term government bond yields in Canada and the U.S. averaged close to 100 basis points.

With the vastly improved economic fundamentals in Canada (e.g., lower inflation, balanced budgets), the risk of investing in Canadian government bonds (relative to equities) declined and the differential between Canadian and U.S. government bond yields that existed historically fell. Between 1998 and 2010, the average yield on 10-year Government of Canada bonds was only slightly higher (+6 basis points) than the corresponding average yield on 10-year U.S. Treasury bonds. The corresponding differential between the yields on the long-term (30-year) government bonds was -13 basis points. As indicated above, the yields (and expected returns) on long-term Government of Canada bonds are expected to be in the approximate range of 4.5% to 5.25% in the near-term (2012) and longer-term (2013-2020) respectively, which compares to approximately 5.0% to 5.5% for the U.S.[55]

[55] Blue Chip *Financial Forecasts*, February 1, 2011for 2012 and December 1, 2010 for the longer term.

With respect to the relative risk of the two equity markets, the historic annual volatility in the two markets over the longer-term has been quite similar. The Table below compares the average arithmetic equity market returns and the corresponding standard deviations, as well as the compound (geometric) average returns from 1926-2010 and post-World War II (1947-2010) for the two countries.

Table 10

	Canada			United States		
	Arithmetic Average	**Standard Deviation**	**Compound Average**	**Arithmetic Average**	**Standard Deviation**	**Compound Average**
1926-2010	11.5%	18.9%	9.8%	11.9%	20.4%	9.9%
1947-2010	12.1%	17.0%	10.8%	12.5%	17.5%	11.0%

Source: Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2009*, Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2010 Yearbook*, www.standardandpoors.com, *TSX Review*.

To put the differences in the relative risk of the two markets in perspective over these two time periods, it is useful to compare the differences between the arithmetic and compound average returns in the two markets. The difference between the arithmetic and compound average returns is approximately equal to one-half of the variance in the annual returns. The variance in the arithmetic average returns in turn is equal to the standard deviation squared. The larger the difference between the arithmetic and compound averages, the more volatility there has been in the annual returns. For the longer period, 1926-2010, the difference in the arithmetic and compound average returns in Canada was 1.7%; the corresponding difference in the U.S. was 2.0%, a difference between the two of approximately 0.3%. During the post-World War II period, the difference in Canada was 1.3%; in the U.S. it was 1.5%, a difference of 0.2%. The two differentials between the Canadian and U.S. arithmetic and compound average returns can be interpreted as the difference in equity return required for the difference in volatility between the two markets. In other words, based on the longer period, the equity market return required would be 0.30% higher in the U.S. than in Canada and based on the post-World War II period, the equity market return required would be 0.2% higher in the U.S. than in Canada. In both cases, the differences are *de minimus*.

Since the beginning of the financial crisis (August 2007) to the end of February 2011, the two markets have exhibited similar volatility; the standard deviations of weekly price changes in the two countries have been virtually identical.

Table 11

Standard Deviations of Weekly Price Changes		
	S&P/TSX Composite (Canada)	**S&P 500 (United States)**
01/08/07-28/02/11	3.4%	3.5%
18/08/08-28/02/11	3.8%	3.8%

Source: www.yahoo.com

With similar government bond yields in the two countries for more than a decade, the U.S. historic equity market risk premium is a relevant benchmark for the estimation of the forward-looking equity market risk premium for Canadian investors. Further, bond yields in Canada are expected to be similar to, or lower than, the bond income returns underpinning the achieved equity risk premiums in the U.S. Given the similarity of achieved equity market returns in the two countries, and the expected lower bond returns in Canada compared to both the historical bond returns in Canada and in the U.S., the achieved U.S. equity risk premium of no less than 6.5% represents a conservative estimate of the forward-looking equity risk premium for the Canadian market.

3.b.(v) Impact of Inflation on Equity Market Returns[56]

Theoretically, the expected return on equity should be equal to the sum of the real risk-free cost of capital, the expected rate of inflation and an equity risk premium. Thus, the question arises whether the forward-looking equity nominal (inclusive of inflation expectations) market return

[56] The 1998-2002 equity market “bubble and bust” spawned a number of studies of the equity market risk premium that have speculated that the U.S. market risk premium will be lower in the future than in the past. The speculation stems in part from the hypothesis that the magnitude of the achieved risk premiums is due to an increase in price/earnings (P/E) ratios. That is, the historic U.S. equity market returns reflect appreciation in the value of stocks in excess of that supported by the underlying growth in earnings or dividends. The increase in P/E ratios, it has been argued, reflects a decline in the rate at which investors are discounting future earnings, i.e., a lower cost of capital. I analyzed the trends in P/E ratios and equity market returns and determined that there is no indication that rising P/E ratios during the bull market of the 1990s resulted in average equity market returns that are unsustainable going forward. The analysis is summarized in Appendix A.

should differ from the historic nominal returns due to differences in the historic versus expected rates of inflation. On average, historically, the actual rate of consumer price (CPI) inflation in both Canada and the U.S. has been higher than the expected rate of inflation. The arithmetic average CPI rate of inflation from 1926-2010 in Canada was 3.1%; the corresponding rate of inflation in the U.S. was also 3.1%. The most recent consensus long-term (2011-2020) forecast of CPI inflation for Canada is 2.0%; for the U.S., it is 2.1%.[57] The lower forecast rate of inflation compared to the historical rate of inflation might suggest that expected nominal equity returns would be lower than they have been historically.

However an analysis of nominal equity returns, rates of inflation and real returns on equity shows that real equity returns have generally been higher when inflation was lower. Table 12 below summarizes the nominal and real rates of equity market returns historically at different levels of CPI inflation.

Table 12

	Canada			U.S.		
Inflation Range	**Nominal Equity Return**	**Average Rate of Inflation**	**Real Equity Return**	**Nominal Equity Return[1/]**	**Average Rate of Inflation[1/]**	**Real Equity Return[1/]**
Less than 1%	15.7%	-1.4%	17.0%	13.2%	-2.0%	15.2%
1-3%	13.0%	1.9%	11.1%	18.4%	2.0%	16.4%
3-5%	4.8%	4.1%	0.7%	6.2%	3.6%	2.6%
Over 5%	12.5%	9.2%	3.3%	7.0%	8.2%	-1.2%
Avg. 1924-2010	11.7%	3.0%	8.6%	11.9%	3.1%	8.8%

[1/] U.S. data are calculated over the period 1926-2010

Source: Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2009;* www.federalreserve.gov; Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2010 Yearbook;* www.standardandpoors.com; www.statscan.ca; *TSX Review*.

The observed negative relationship between the real equity return and the rate of inflation does not support a reduction to the historic nominal equity rates of return for expected lower inflation for the purpose of estimating the future equity risk premium. The average nominal equity returns in Canada were approximately 11.7% over the longer-term and 12.1% since the end of World War II.

[57] Consensus Economics, *Consensus Forecasts*, October 2010.

3.b.(vi) Equity Market Risk Premium

Given the absence of any material upward or downward trend in the nominal historic equity market returns over the longer-term, the P/E ratio analysis[58], and the observed negative relationship between real equity returns and inflation, a reasonable expected value of the equity market return is a range of 11.5% to 12.0%, based on Canadian equity market returns and supported by U.S. equity market returns. The expected return on long-term Canada bonds, based on both the near-term (2012) and the longer-term forecasts of the 30-year Canada bond yield, is in the range of 4.5% to 5.25%. The resulting expected equity market risk premium is approximately 6.75% to 7.0%. An analysis of Canadian equity risk premiums in conjunction with bond income returns indicates that an equity risk premiums of 7.25% to 8.0% has been associated with a bond income return of approximately 4.5%, i.e., similar to the forecast 2012 Government of Canada bond yield. The achieved equity risk premium in the U.S. supports a lower bound on the estimate of the market equity risk premium for Canada at the forecast levels of bond returns of no less than 6.5%. Therefore, a reasonable estimate of the expected value of the equity market risk premium at the forecast 2012 long-term Government bond yield is thus in the range of 6.5% to 8.0%, or approximately 7.25% (equivalent to an equity market return of 11.75% at the 2012 forecast 4.5% long-term Canada bond yield).

3.c. <u>Relative Risk Adjustment</u>

3.c.(i) Overview

The market risk premium result needs to be adjusted to recognize the relative risk of a benchmark utility. The theoretical CAPM holds that equity investors only require compensation for risk that they cannot diversify by holding a portfolio of investments. In the simple, one risk variable CAPM, the non-diversifiable risk is captured in beta.

[58] The P/E ratio analysis is included in Appendix A.

Impediments to reliance on beta as the sole relative risk measure, as the CAPM indicates, include:

(1) The assumption that all risk for which investors require compensation can be captured and expressed in a single risk variable;

(2) The only risk for which investors expect compensation is non-diversifiable equity market risk; no other risk is considered (and priced) by investors; and,

(3) The assumption that the observed calculated betas (which are simply a calculation of how closely a stock's or portfolio's price changes have mirrored those of the overall equity market) are a good measure of the relative return requirement.

(4) Use of beta as the relative risk adjustment allows for the conclusion that the cost of equity capital for a firm can be lower than the risk-free rate, since stocks that have moved counter to the rest of the equity market could be expected to have betas that are negative. Gold stocks, for example, which are regarded as a quintessential counter-cyclical investment, could reasonably be expected to exhibit negative betas. In that case, the CAPM would posit that the cost of equity capital for a gold mining firm would be less than the risk-free rate, despite the fact that, on a total risk basis, the company's stock could be very volatile.

(5) While investors can diversify their portfolios, the stand-alone utility to which the allowed return is applied cannot.

Thus, a risk measurement that reflects those considerations is relevant for estimating the benchmark utility equity risk premium.

3.c.(ii) Total Market Risk

These considerations support focusing on total market risk, as well as on beta, to estimate the relative risk adjustment for a benchmark utility. The absence of an observable relationship between "raw" betas and the achieved market returns on equity in the Canadian market[59] provides further support for reliance on total market risk to estimate the relative risk adjustment.

The standard deviation of market returns is the principal measurement of total market risk. To estimate the relative total risk of a benchmark utility, the S&P/TSX Utilities Index was used as a proxy. The standard deviations of monthly total market returns for each of the 10 major Sectors of the S&P/TSX Index, including the Utilities Index, were calculated over five-year periods ending 1997 through 2010 (Schedule 8).

To translate the standard deviation of market returns into a relative risk adjustment, utility standard deviations must be related to those of the overall market. The relative market volatility of Canadian utility stocks was measured by comparing the standard deviations of the Utilities Index to the simple mean and median of the standard deviations of the 10 Sectors. Schedule 8 shows the ratios of the standard deviations of the Utilities Index to those of the 10 S&P/TSX Sectors. The ratio of the standard deviation of the Utilities Index to the mean and median standard deviations of the 10 major Sector Indices suggests a relative risk adjustment for a Canadian utility in the range of 0.55-0.85, with a central tendency of approximately 0.65-0.70.

3.c.(iii) Historic Raw Betas of Canadian Utilities

Schedule 11 summarizes the "raw"[60] betas calculated using monthly changes in price[61] for individual publicly-traded Canadian regulated pipeline, gas distribution and electric utility

[59] See Appendix A.
[60] The term "raw" means that the beta is simply the result of a single variable ordinary least squares regression.
[61] The use of price betas for utilities has been criticized on the grounds that the exclusion of dividends from the calculated betas overestimates the betas. A comparison of price and total return (including dividends) for Canadian utilities showed that there was no material difference between the two.

companies, the TSE Gas/Electric Index, and the S&P/TSX Utilities Sector[62] using monthly price data calculated over five-year periods ending 1993 through 2010.

As Schedule 11 indicates, there was a significant decline in the calculated "raw" five-year betas of the individual regulated Canadian companies between 1993-1998 and 1999-2005 (from approximately 0.50-0.60 to 0.0 and slightly negative). Following an increase in 2007 to 0.50, the "raw" monthly betas for the individual regulated Canadian company betas again declined in 2008 to approximately 0.25 and have remained at that level through the end of 2010.[63]

The observed levels and pattern of the calculated "raw" utility betas in 1999-2010 can be traced to four factors: (1) the technology sector bubble and subsequent bust; (2) the dominance in the TSE 300 of two firms during the early part of the "bubble and bust" period, Nortel Networks and BCE; (3) the greater sensitivity of utility stock prices than the equity market composite to rising and falling interest rates (e.g., during the equity market "bubble" of 1999 and early 2000 and during the first half of 2006); and (4) the more extreme price changes of the market as a whole during the financial crisis and the subsequent market recovery.[64] Over the longer term (1970-2010), the "raw" beta of the Utilities Index calculated using total returns has been close to 0.50, as indicated in Table 13 below.

[62] The S&P/TSX Utilities Sector was created in 2002 (with historic data calculated from year-end 1987), when the TSE 300 was revamped to create the S&P/TSX Composite. The Utilities Sector was essentially an amalgamation of the former TSE 300 Gas/Electric and Pipeline sub-indices. In May 2004, the pipelines were moved to the Energy Sector.

[63] 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. The table below shows that, for the five large publicly-traded Canadian utilities, whose shares are regularly traded, the median five-year beta ending December 2010 calculated using weekly price changes was twice as higher as the corresponding median beta calculated using monthly price changes.

	Canadian Utilities	**Emera**	**Enbridge**	**Fortis**	**TransCanada**	**Median**
Weekly	0.39	0.40	0.49	0.50	0.44	0.44
Monthly	0.06	0.21	0.32	0.16	0.39	0.21

[64] Schedule 9 shows that utilities were not the only companies whose betas were negatively impacted by the technology sector bubble and subsequent market decline. To illustrate, the 60-month beta ending 1997 of the Consumer Staples Sector was 0.62; the corresponding betas ending 2003 and 2004 were -0.08 and -0.07 respectively. In contrast, over the same periods, the beta of the Information Technology Sector rose from 1.57 to 2.87.

3.c.(iv) Canadian Regulated Company Returns and "Raw" Betas

The equity betas of traded regulated Canadian company shares and of the utility index explain a relatively small percentage of the actual achieved market returns over time. A regression of the monthly returns on the TSX Utilities Index against the returns on the TSX Composite, for example, over the period 1970-2010[65] shows the following:

Table 13

Monthly TSX Utilities Index Return	=	0.0059 +	0.47	{ Monthly TSE Composite Return }
t-statistic	=		13.8	
R^2	=	28%		

The relationship quantified in the above equation suggests a long-term utility beta of 0.47. However, the R^2, which measures how much of the variability in utility stock prices is explained by volatility in the equity market as a whole, is only 28%. That means 72% of the monthly volatility in share prices remains unexplained.[66]

Since utility shares are interest sensitive, the regression was expanded to capture the impact of movements in long-term Canada bond prices on utility returns. The addition of monthly long-term Canada bond returns to the analysis indicates the following:

[65] The Monthly TSX Utilities Index Returns are comprised of the monthly returns on the TSE Gas & Electric Index for period January 1970 to April 2003 and the monthly returns on the S&P/TSX Utilities Index for the period May 2003 to December 2010.

[66] As shown in Schedule 11, page 2 of 2, the R^2s of the monthly betas for individual Canadian utilities calculated over five-year periods ending 2004 to 2010 have been extremely low, averaging less than 10%. The low R^2s indicate that very little of the volatility in the utility share prices is explained by the volatility in the equity market composite. It bears noting that, while the 2006-2010 "raw" beta of Canadian Utilities Limited, at 0.06, is the lowest of the individual Canadian utilities, its absolute price volatility, measured by the standard deviation of monthly price changes, was the highest of the group.

Table 14

Monthly TSX Utilities Index Return	=	0.0026 + .41	{ Monthly TSE Composite Return }	+ .47	{ Monthly Long Canada Bond Return }
t-statistics	=	12.4		8.5	
R^2	=	37%			

When government bond returns are added as a further explanatory variable, somewhat more of the observed volatility in utility stock prices is explained (37% versus 28%). The second regression equation suggests that utility shares have had approximately 40% of the volatility of the equity market and approximately 47% of the volatility of the bond market, the latter consistent with utility common stocks' interest sensitivity. Nevertheless, the equation still leaves more than half of the utility shares' volatility unexplained. To provide some perspective, the average actual annual return for the index from 1970-2010 was 12.9%. Of this average annual return, just over 3.0 percentage points was explained neither by volatility in the equity market nor by the long-term government bond market.[67] The persistent large unexplained component of the achieved utility return should be recognized in the estimation of the relative risk adjustment.

By solving the regression equation (including the intercept) in Table 14, using current estimates of the market return and the long-term Canada bond return, the expected utility return can be estimated. At an expected annual equity market return of 11.5%-12.0% (as developed above), an annual 30-year Canada bond return of 5.25% (equal to the forecast long range expected yield of 5.25%), and the equation intercept (equal to the annual historical average "unexplained" utility return of 3.2 percentage points), the indicated expected utility return is 10.5%.[68] Alternatively, the prospective "unexplained" component of the utility return can be estimated to be in the same proportion to the total utility return as was the case historically (approximately 25%[69]). In this case, the expected utility return is 9.7%.[70] The average of the two utility return estimates is

[67] The unexplained component of the achieved return is represented by the intercept in the equation. The intercept of 0.0026 (or 0.26%) is a monthly return, which when annualized, equals 3.2%.
[68] 10.5% = 3.2% + (0.41*11.75%) + (0.47*5.25%).
[69] 3.2%/12.9% ≈ 25%.
[70] 9.7% = ((0.41*11.75%) + (0.47*5.25%))/ (1-25%).

10.1%; the corresponding utility risk premium above the forecast long-term Canada bond yield of 5.25% is 4.8%. The indicated market risk premium using the same equity market return estimate of 11.75% and long-term Canada bond return of 5.25% is 6.5%. The resulting utility relative risk adjustment is 0.74.[71]

3.c.(v) Use of Adjusted Betas

From the calculated "raw" betas, the inference can readily be made that regulated companies are less risky than the equity market composite, which by construction has a beta of 1.0. The more difficult task is determining how the "raw" beta translates into a relative risk adjustment that captures utility investors' return requirements. In order to arrive at a reasonable relative risk adjustment, the normative ("what should happen") CAPM needs to be integrated with what has been empirically observed ("what does or has happened"). Empirical studies have shown that stocks with low betas (less than the equity market beta of 1.0) have achieved returns higher than predicted by the single variable (i.e., equity beta) CAPM. Conversely, stocks with betas higher than the equity market beta of 1.0 have achieved lower returns than the model predicts.[72]

The use of betas that are adjusted toward the equity market beta of 1.0, rather than the calculated "raw" betas, is a partial recognition of the observed tendency of low (high) beta stocks to achieve higher (lower) returns than predicted by the simple CAPM. Adjusted historical betas are a standard means of estimating expected betas, and are widely disseminated to investors by investment research firms, including Bloomberg, *Value Line* and Merrill Lynch. All three of these firms use a similar methodology to adjust "raw" betas toward the equity market beta of 1.0. Their methodologies give approximately 2/3 weight to the calculated "raw" beta and 1/3 weight to the equity market beta of 1.0.

The following Table compares recent reported Bloomberg betas (calculated using three years of weekly prices)[73] for the five major Canadian utilities to calculated "raw" weekly betas for a

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71 $\frac{10.1\% - 5.25\%}{11.75\% - 5.25\%} = 0.74$

72 See Appendix A, page A-21.

73 Retrieved from www.bloomberg.com on January 13, 2011.

similar three-year period. The Bloomberg betas suggest that the relative risk adjustment based solely on the most recent Canadian regulated company betas would be approximately 0.60. The application of the same adjustment formula used by Bloomberg to the long-term calculated "raw" beta of approximately 0.50 for the TSX Utilities Index shown in Table 13 above results in a relative risk adjustment of 0.67.[74]

Table 15

Company	"Raw" Beta	Bloomberg Beta
Canadian Utilities Ltd.	0.37	0.55
Emera Inc.	0.41	0.63
Enbridge Inc.	0.46	0.54
Fortis Inc.	0.51	0.62
TransCanada Corp.	0.42	0.60
Median	**0.42**	**0.60**

Source: www.yahoo.com and www.bloomberg.com.

A comparison of the reported *Value Line* betas[75] to the "raw" calculated betas for the sample of U.S. electric utilities relied upon in the application of the discounted cash flow (DCF) and DCF-based risk premium tests shows a similar relationship. While the "raw" calculated weekly betas for the five-year period ending December 27, 2010 averaged approximately 0.59[76], the 4th Quarter 2010 betas reported by the widely disseminated *Value Line* averaged approximately 0.70 for the sample (Schedule 12).

[74] Adjusted beta = 0.67 x "Raw" Beta + 0.33 x Market Beta of 1.0.
[75] *Value Line* uses a five-year horizon and a weekly price change interval.
[76] The calculations of the sample betas are sensitive to the period over which the betas are calculated, the price interval chosen to estimate the betas as noted above (e.g., weekly versus monthly) and the market index selected (e.g., S&P 500 versus the NYSE Index). The betas calculated using monthly data are systematically lower than the betas calculated using weekly data for the U.S. electric utility sample.

3.c.(vi) Relative Risk Adjustment

A summary of the results of the preceding analysis is set out in the Table below:

Table 16

Relative Risk Indicator	Relative Risk Factor
Total Market Risk (Standard Deviations)	0.65-0.70
Relative Historic Returns and Betas: Canadian Utilities	0.74
Recent Adjusted Beta: Canadian Utilities	0.60
Long-term Adjusted Beta: Canadian Utilities Index	0.67

These results support a relative risk adjustment for an average risk Canadian utility in the approximate range of 0.65-0.70. For NSPI, which is of higher risk than the average Canadian utility, the relevant relative risk adjustment would be, conservatively, at the upper end of the range, i.e., at 0.70. A 0.70 relative risk adjustment is equivalent to the recent average adjusted beta for the U.S. electric utility sample.

3.d. Equity Risk Premium and Cost Of Equity

The equity market risk premium was previously estimated to be in the range of 6.5% to 8.0% (mid-point of approximately 7.25%) at the 2012 forecast yield of 4.5% for long-term Government of Canada bonds. At an equity market risk premium of 7.25% and a relative risk adjustment of 0.70, the indicated equity risk premium for NSPI is approximately 5.0%. The corresponding cost of equity at the 2012 forecast long-term Canada bond yield of 4.5% is approximately 9.5%.

4. DCF-Based Equity Risk Premium Test

4.a. Overview

The Discounted Cash Flow-Based ("DCF-Based) Equity Risk Premium Test estimates the utility equity risk premium as the difference between the DCF cost of equity and yields on long-term government bonds.

The DCF-based equity risk premium test estimates the equity risk premium directly for regulated companies by analyzing regulated company equity return data. In contrast, the risk-adjusted equity market risk premium test discussed above estimates the required utility equity risk premium indirectly. The DCF-based risk premium test was applied to a sample of U.S. electric utilities.[77] The DCF-based risk premium test was applied to the sample of U.S. electric utilities only because its application requires a consistent time series of long-term growth rate forecasts, which is not available for Canadian utilities.

4.b. Construction of the Constant Growth DCF-Based Equity Risk Premium Test

The constant growth DCF model was used to construct a monthly series of expected utility returns for each of the utilities in the sample from 1995-2010.[78] The monthly DCF cost of equity for each utility was estimated as the sum of the utility's I/B/E/S mean earnings growth forecast (published monthly) **(g)** and the corresponding expected monthly dividend yield **(DY_e)**. The dividend yield **(DY)** was calculated as the most recent quarterly dividend paid, annualized, divided by the monthly closing price. The expected dividend yield was then calculated by adjusting the monthly dividend yield for the I/B/E/S mean earnings growth forecast **(DY_e=DY*(1+g))**. The individual utilities' monthly DCF estimates **(DY_e + g)** were then averaged to produce a time series of monthly DCF estimates **(DCFs)** for the sample. The monthly equity risk premium **(ERP)** for the sample was calculated by subtracting the corresponding 30-year Treasury yield **(TY)** from the average DCF cost of equity **(ERPs=DCFs–TY)** (Schedule 13, page 1 of 4). The monthly sample average constant growth ERPs were used to estimate the regression equations found on Schedule 13, page 2 of 4.

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[77] The selection criteria for the sample of U.S. electric utilities to which the DCF-Based Equity Risk Premium Test was applied are found in Appendix B.
[78] The analysis comprises the full period over which automatic ROE adjustment formulas for setting allowed ROEs were (and in some cases continue to be) in effect in Canada. The period for the analysis was chosen in part to test the validity of the relationship between interest rates and the equity risk premium on which most of the automatic ROE adjustment formulas have been based.

4.c. Constant Growth DCF-Based Equity Risk Premium Test Results

For the sample of U.S. electric utilities, the DCF-based equity risk premium test indicates that the average 1995-2010 equity risk premium was 5.0%, corresponding to an average long-term government bond yield of 5.3%. The data also show that the risk premium averaged 2.4% when long-term government bond yields were 7.0% or higher and 5.9% when long-term government bond yields were below 5.0%.

The Table below sets out the observed utility equity risk premium at various levels of long-term government bond yields based on the results of the 1995-2010 analysis.

Table 17

Government Bond Yield	Below 4.0%	4.0%-5.0%	5.0%-6.0%	6.0%-7.0%	Above 7.0%
Utility Equity Risk Premium	7.4%	5.7%	5.1%	3.4%	2.4%

Source: Schedule 13, page 1 of 4.

The data indicate that the utility equity risk premium is higher at lower levels of interest rates than it is at higher levels of interest rates, i.e., there is an inverse relationship between long-term government bond yields and the utility equity risk premium.

A key advantage of the DCF-based risk premium test is that it can be used to test the relationship between the cost of equity (or risk premiums) and interest rates (and/or other variables).[79] In the application of this test, the relationships between the utility risk premiums and long-term government bond yields and between utility risk premiums, long-term government bond yields and the spread between the yields on long-term utility and government bond yields have been examined.

[79] Of the three equity risk premium tests, the DCF-based equity risk premium test is the only one that lends itself to explicitly estimating the relationship between utility equity risk premiums (or the utility cost of equity) and interest rates.

The single independent variable regression analysis used monthly 30-year government bond yields as the independent variable and the corresponding utility equity risk premiums as the dependent variable. The analysis for this specific sample indicated that, for each 100 basis point change in the long-term government bond yield, the utility equity risk premium moved in the opposite direction by approximately 125 basis points, or alternatively, expressed in cost of equity terms, the ROE is lower at higher levels of long-term government bond yields. This incongruous result is due in part to the rising estimated costs of equity during the early 2000s, even as long-term government bond yields were falling, as industry restructuring and consolidation gave rise to forecasts of higher earnings growth. (Schedule 13, page 1 of 4) It is also due in part to the fact that factors other than long-term government bond yields are determinants of the cost of equity.

To capture the impact of other factors, corporate bond yield spreads were incorporated into the analysis. The magnitude of the spread between corporate bond yields and government bond yields is frequently used as a proxy for changes in investors' risk perception or willingness to take risk. Various empirical studies have shown that there is a positive correlation between corporate yield spreads and the equity risk premium.[80] In the two independent variable regression analysis, government bond yields and the spread between long-term Baa-rated utility and government bond yields were both used as independent variables and the utility equity risk premium was the dependent variable. The two independent variable analysis indicates that, while the utility risk premium has been negatively related to the level of government bond yields, it has been positively related to the spread between utility bond yields and government bond yields.

Specifically, the analysis showed that the utility equity risk premium increased or decreased by slightly more than 90 basis points when the government bond yield decreased or increased by 100 basis points and increased or decreased by approximately 12 basis points for every 10 basis point increase or decrease in the long-term Baa utility/government bond yield spread (Schedule 13, page 2 of 4).

[80] Examples include: Chen, N. F., R. Roll and S. A. Ross, 1986, "Economic Forces and the Stock Market", *Journal of Business*, 59, pages 383-403 and Harris, R.S. and F.C. Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts", Summer 1992, *Financial Management*, pages 63-70.

During 2010, the spread between yields on NSPI's long-term bonds and 30-year Government of Canada bond yields was approximately 165 basis points. At a forecast long-term Government of Canada bond yield of 4.50% and a long-term utility/government bond yield spread of 165 basis points, the two independent variable DCF-based equity risk premium model indicates an equity risk premium of approximately 5.4%. The corresponding utility cost of equity is approximately 9.9% (Schedule 13, page 2 of 4).

The two independent variables (the government bond yield and the utility/government bond yield spread) can be collapsed into a single independent variable, the long-term Baa-rated utility bond yield. When the long-term Baa-rated utility bond yield was used as the sole independent variable and the equity risk premium is measured as the DCF cost of equity minus the corresponding Baa-rated utility bond yield, the resulting relationship was:

Risk Premium Over Baa Utility Bond Yield = 7.3 - 0.58 Baa Utility Bond Yield

In other words, the analysis indicated that the utility cost of equity rose and fell by approximately 40% of the change in the long-term Baa-rated utility bond yield (Schedule 13, page 2 of 4). The combination of the forecast long-term Government of Canada bond yield of 4.5% and a utility bond yield spread of 1.65% equates to a utility cost of debt of 6.15%. The resulting utility risk premium over a utility bond yield is 3.7% and the corresponding cost of equity, similar to the two independent variable approach, is 9.9% (Schedule 13, page 2 of 4).

4.d. Three-Stage DCF-Based Equity Risk Premium Test and Results

The reliability of the relationships estimated using the constant growth model was tested using a three-stage DCF model. The construction of the monthly three-stage DCF cost of equity estimates is described in Appendix C. The use of the three-stage model, which assumes that, in the long run, earnings growth for the utility sample will converge to the long-term rate of growth in the economy, effectively lessens the volatility of the monthly growth rates utilized in the analysis.[81]

Using monthly three-stage estimates of the DCF cost of equity, the average equity risk premium above long-term Treasury bond yields was 4.9% at an average long-term Treasury bond yield of 5.3% (Schedule 13, page 3 of 4). With three-stage DCF cost of equity estimates, the single independent variable regression analysis indicates that, for each 100 basis point change in the long-term government bond yield, the utility equity risk premium moved in the opposite direction by approximately 71 basis points. The two independent variable (long-term government bond yields and utility/government bond yield spreads) showed that the utility equity risk premium increased or decreased by approximately 50 basis points when the government bond yield decreased or increased by 100 basis points and increased or decreased by approximately seven basis points for every ten basis point increase or decrease in the utility/government bond yield spread (Schedule 13, page 4 of 4).[82]

The indicated utility equity risk premiums and costs of equity based on the three-stage DCF model are summarized in the Table below.

Table 18

Regression Model	Long-term Government Bond Yield	Utility/ Government Bond Yield Spread	Equity Risk Premium	Cost of Equity
Single Independent Variable	4.5%	N/A	5.5%	10.0%
Two Independent Variables	4.5%	1.65%	5.1%	9.6%

[81] The standard deviation of the sample average monthly I/B/E/S growth rates is approximately 1.2; the standard deviation of the monthly implied growth rates utilized in the three-stage DCF-based risk premium analysis is approximately 0.5.

[82] When the two independent variables were collapsed into a single independent variable, the long-term A-rated utility bond yield and the equity risk premium was measured as the DCF cost of equity minus the corresponding A-rated utility bond yield, the resulting relationship was:

Equity Risk Premium Over Baa-Rated Utility Bond Yield = 6.1% - 0.43 Baa-Rated Utility Bond Yield

At a Baa-rated utility bond yield of 6.15%, the indicated equity risk premium over the utility bond yield is 3.5% and the utility cost of equity is 9.6% (Schedule 13, page 4 of 4).

As an alternative test of the relationships, quarterly ROEs allowed for U.S. utilities were used as a proxy for the utility cost of equity to test the sensitivity of the utility cost of equity to changes in long-term government bond yields and utility/government bond yield spreads. The average allowed ROEs can be viewed as a measure of the utility cost of equity as they represent the outcomes of multiple rate proceedings across multiple jurisdictions, which in turn reflect the application of various cost of equity tests by parties representing both the utility and ratepayers.

Initially, the risk premiums indicated by the quarterly allowed ROEs from 1995 to 2010 were regressed against long-term Treasury bond yields lagged by six months.[83] The result indicated that the utility equity risk premium increased or decreased by approximately 60 basis points for every one percentage point decrease or increase in long-term government bond yields. When long-term Baa-rated utility/government bond yield spreads were added as a second independent variable, the analysis indicated that (1) the utility equity risk premium increased (decreased) by approximately 50% of the decrease (increase) in long-term Treasury bond yields; and (2) the risk premiums increased or decreased by approximately 20 basis points for every one percentage point increase or decrease in the long-term Baa-rated utility/government bond yield spread (Schedule 14, page 2 of 2).[84] At a forecast long-term Canada bond yield of 4.5% and a utility bond yield spread of 1.65%, the allowed ROE analysis indicates a utility risk premium of 5.9% and a cost of equity of 10.4%.

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[83] The government bond yields and the spread variables were lagged by six months behind the quarter of the ROE decisions to take account of the fact that the dates of the decisions will lag the period covered by the market data on which the ROE decisions would have been based.

[84] The regression is:

7.90 - 0.52 x 6 Months Lagged 30 Year Treasury Yield + 0.19 x 6 Months Lagged Spread

Collapsing the two independent variables into a single variable, long-term Baa-rated bond yields, and regressing those yields against the risk premiums indicated by the quarterly allowed ROEs, the analysis indicated that the risk premiums over utility bond yields have decreased (increased) by approximately 59 basis points for every one percentage point increase (decrease) in the Baa-rated utility bond yield.

4.e. DCF-Based Equity Risk Premium Test Results

The Table below summarizes the relationships among equity risk premiums, long-term government bond yields and utility/government bond yield spreads for the various models and the resulting equity risk premiums and costs of equity at a forecast long-term Canada bond yield of 4.5% and a long-term utility/government bond yield spread of 1.65%.

Table 19

	Coefficients		Equity Risk Premium	Cost of Equity
	Government Bond	**Bond Yield Spread**		
DCF Constant Growth				
Single Variable	-1.25	n/a	6.0%	10.5%
Two Variable	-0.92	1.16	5.4%	9.9%
DCF Three-Stage Growth				
Single Variable	-0.71	n/a	5.5%	10.0%
Two Variable	-0.50	0.72	5.1%	9.6%
Allowed ROEs				
Single Variable	-0.58	n/a	6.0%	10.5%
Two Variable	-0.52	0.19	5.9%	10.4%

Note: "Single Variable" refers to the regression analysis applied only to the long-term government bond yield and "Two Variable" refers to the addition of the spread variable to the regression analysis.

While the indicated sensitivities of the models to changes in long-term government bond yields vary, they support the conclusion that the utility cost of equity does not vary with (or track) long-term government bond yields to the extent that has frequently been assumed.

Specifically, the analysis demonstrates that the utility cost of equity is materially less sensitive to long-term government bond yields than has been assumed by the automatic ROE adjustment formulas previously relied upon (e.g., AUC, BCUC, National Energy Board (NEB), OEB), and in some cases continue to be relied upon (Newfoundland and Labrador PUB and Régie de l'énergie) by regulators in Canada. Those formulas assume that the utility cost of equity increases/decreases by 75-80 basis points for every one percentage increase/decrease in the long-term Government of Canada bond yield. By comparison the two-variable three stage model indicates that the utility cost of equity increases/decreases by only 50 basis points for every one percentage point increase/decrease in long-term Government bond yields.

I have not given any explicit weight to the allowed ROE analysis in deriving an estimate of the utility cost of equity from the DCF-based risk premium test. However, that analysis supports provides further support for the conclusion that the utility cost of equity does not track government bond yields nearly to the extent that has been frequently assumed.

Given the incongruous results of the single variable DCF constant growth model, my DCF-based risk premium estimates focus on the two-variable constant growth model and the three-stage model results. These three models indicate that the utility equity risk premiums and returns on equity at a long-term Canada bond yield of 4.5% and a utility/government bond yield spread of 1.65% are, respectively, approximately 5.0% to 5.5% and 9.5% to 10.0%.

5. <u>Historic Utility Equity Risk Premium Test</u>

5.a. <u>Overview</u>

The historic experienced returns for utilities provide an additional perspective on a reasonable expectation for the forward-looking equity risk premium for a benchmark utility. Similar to the DCF-based risk premium test, this test estimates the cost of equity for regulated companies directly by reference to return data for regulated companies. Reliance on achieved equity risk premiums for utilities as an indicator of what investors expect for the future is based on the proposition that over the longer term, investors' expectations and experience converge. The more stable an industry, the more likely it is that this convergence will occur.

5.b. <u>Historic Returns and Risk Premiums</u>

As shown in Table 20 below, over the longest term available (1956-2010),[85] the average achieved utility (gas and electric combined) equity risk premiums in Canada were 4.5% and 4.8% in relation to total and income returns for long-term Government of Canada bonds

[85] The longest period for which Canadian utility index data are available from the Toronto Stock Exchange.

respectively.[86] For U.S. electric utilities, the corresponding 1947-2010 average achieved risk premiums were 4.5% and 4.9%. For U.S. gas utilities, the corresponding average historic equity risk premiums in relation to total and income returns on bonds over the entire post-World War II period (1947-2010) were 5.6% and 5.9% respectively.

Table 20

	Utility Equity Returns	Bond Total Returns	Bond Income Returns	Risk Premium Over: Bond Total Returns	Risk Premium Over: Bond Income Returns
Canadian Utilities	12.2%	7.7%	7.4%	4.5%	4.8%
U.S. Electric Utilities	10.8%	6.3%	5.9%	4.5%	4.9%
U.S. Gas Utilities	11.8%	6.3%	5.9%	5.6%	5.9%

Source: Schedule 15.

5.c. <u>Trends in Equity Returns and Bond Returns</u>

Similar to the risk premiums for the market composite, the magnitude of achieved utility risk premiums is a function of both the equity returns and the bond returns. An analysis of the underlying data indicates there has been no secular upward or downward trend in the utility equity returns. Trend lines fitted to the historic utility equity returns for each of the three utility indices are flat (Schedule 15, pages 2 and 3 of 3). The historical average utility returns in both Canada and the U.S. have clustered in the range of 11.0-12.0%. However, the achieved government bond returns (total and income) in Canada over the period of analysis, at 7.4% to 7.7%, were materially higher than the yields on long-term Canada bonds forecast for both the near-term (4.5%) and over the longer-term (5.25%). With no change in the utility equity market return (i.e., a utility equity market return of 11.0% to 12.0%), the indicated utility risk premium at the forecast 2012 long Canada bond yield of 4.5% is approximately 6.5%. At the long-range expected return on long-term Canada bonds of 5.25%, the indicated utility equity risk premium is approximately 6.25%. Based on both estimates of the long-term Canada bond yield, the indicated utility risk premium is in the range of 6.25% to 6.5%.

[86] Based on the Gas/Electric Index of the TSE 300 from 1956 to 1987 and on the S&P/TSX Utilities Index from 1988-2010.

An alternative way of interpreting the historical utility return data is the recognition of the inverse relationship between utility equity risk premiums and government bond yields demonstrated in the DCF-based equity risk premium analysis, including the analysis of allowed ROE. That analysis supports the conclusion that the utility equity risk premium changes by approximately 50% of the change in long-term government bond yields.

Table 21 below derives estimates of the utility equity risk premium at the 2012 forecast long-term Canada bond yield from the historical averages by applying the 50% sensitivity factor to the difference between the historical average bond income returns and the 4.5% Government of Canada bond yield forecast for 2012.

Table 21

		Canadian Utilities	**U.S. Electric Utilities**	**U.S Gas Utilities**
Equity Returns	(1)	12.2%	10.8%	11.8%
Bond Income Returns	(2)	7.4%	5.9%	5.9%
Risk Premium (RP)	(3) = (1) – (2)	4.8%	4.9%	5.9%
2012 Forecast Long-Term Canada Bond Yield (LCBY)	(4)	4.5%	4.5%	4.5%
Change in Bond Yield/Return	(5) = (4) – (2)	-2.9%	-1.4%	-1.4%
Change in Equity RP	(6) = – (5) X 50%	1.5%	0.7%	0.7%
Equity Risk Premium at 4.5% LCBY	(7) = (3) + (6)	6.25%	5.6%	6.6%

Source: Schedule 15.

At a forecast 2012 long-term Canada bond yield of 4.5% and a 50% sensitivity factor between utility equity risk premiums and long-term government bond yields, the indicated utility equity risk premium derived from historical averages is in the approximate range of 5.5% to 6.5% (mid-point of 6.0%).

5.d. Historic Utility Equity Risk Premium Test Results

The two perspectives indicate a utility equity risk premium of approximately 6.0% to 6.5%. At the forecast 2012 long-term Canada bond yield of 4.5% and a utility risk premium of 6.0% to 6.5%, the indicated utility cost of equity is approximately 10.5% to 11.0%.

6. Cost of Equity Based on Equity Risk Premium Tests

The estimated utility costs of equity based on the three equity risk premium methodologies are as follows:

Table 22

Risk Premium Test	Cost of Equity
Risk-Adjusted Equity Market	9.5%
DCF-Based	9.5%-10.0%
Historic Utility	10.5%-11.0%

The three equity risk premium tests indicate a utility cost of equity of approximately 10.0%.

D. DISCOUNTED CASH FLOW TEST[87]

1. Conceptual Underpinnings

The discounted cash flow approach proceeds from the proposition that the price of a common stock is the present value of the future expected cash flows to the investor, discounted at a rate that reflects the risk of those cash flows. The DCF model is a positive model; that is, it deals with "what is" as opposed to "what should be". The DCF test allows the analyst to directly estimate the utility cost of equity, in contrast to the Capital Asset Pricing Model (CAPM), which estimates the cost of equity model indirectly. The DCF model is widely used to estimate the utility cost of equity for the purpose of establishing the allowed ROE.

[87] See Appendix C for a more detailed discussion.

In simplest terms, the DCF cost of equity 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[88]
$\mathbf{P_o}$ = current price
$\mathbf{g}$ = expected growth in dividends

There are multiple versions of the discounted cash flow model available to estimate the investor's required return on equity, including the constant growth model and multiple period models to estimate the cost of equity. 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. Similarly, a multiple period model rests on the assumption that growth rates will change over the life of the stock.

2. <u>Application of the DCF Test</u>

2.a. <u>DCF Models</u>

To estimate the DCF cost of equity, both the constant growth model and a multiple stage (three-stage) model were used. In both cases, the discounted cash flow test was applied to a sample of U.S. electric utilities that are intended to serve as a proxy for NSPI, as well as to a sample of Canadian utilities.

2.b. <u>Growth Estimates</u>

The growth component of the DCF model is an estimate of what investors expect over the longer-term. For a regulated utility, whose growth prospects are tied to allowed returns, the estimate of growth expectations is subject to circularity because the analyst is, in some measure, attempting to project what returns the regulator will allow, and the extent to which the utilities will exceed or fall short of those returns. To mitigate that circularity, it is important to rely on a

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

sample of proxies, rather than the subject company. When the subject company does not have traded shares, a sample of proxies is required.[89]

Further, to the extent feasible, one should rely on estimates of longer-term growth readily available to investors, rather than superimpose on the analysis one's own view of what growth should be. The constant growth model was applied to the U.S. sample using two estimates of long-term growth. The first estimate reflects the consensus of investment analysts' long-term earnings growth forecasts drawn from four sources: I/B/E/S (First Call), Reuters, *Value Line* and Zacks. The second is an estimate of sustainable growth. The sustainable growth rate represents the growth in earnings that a utility can expect to achieve as a result of the ROE it is expected to earn and the proportion of the ROE it reinvests plus incremental earnings growth achievable as a result of external equity financing. The development of the sustainable growth rates is explained in detail in Appendix C.

In the application of the DCF test, the reliability of the analysts' earnings growth forecasts as a measure of investor expectations has been questioned by some Canadian regulators. The issue of reliability arises because of the documented optimism of analysts' forecasts historically. However, as long as investors have believed the forecasts, and have priced the securities accordingly, the resulting DCF costs of equity are an unbiased estimate of investors' expected returns. That proposition can be tested indirectly. Three such tests are described in Appendix C. These tests indicate that the consensus of analysts' long-term earnings growth forecasts is not an upwardly biased estimate of investor expectations.

[89] In addition, any cost of equity estimate that relies on data for a single company only is subject to measurement error.

3. Results of the DCF Model

3.a. Results for the Sample of U.S. Electric Utilities

The two constant growth models applied to the U.S. electric utility sample indicate a cost of equity of approximately 9.3% to 9.8% (Schedules 16 and 17).

The three-stage model is based on the premise that investors expect the growth rate for the utilities to be equal to the analysts' forecasts (which are five year projections) for the first five years, but, in the longer-term to migrate to the expected long-run rate of nominal growth in the economy. The three-stage DCF model is fully described in Appendix C. The three-stage model applied to the sample of U.S. electric utilities indicates a cost of equity of approximately 9.5% (Schedule 18).

3.b. Results for the Sample of Canadian Utilities

The constant growth and three-stage DCF models were also applied to a sample of Canadian utilities with publicly-traded shares and for which long-term growth rate forecasts were available from I/B/E/S (First Call) and Bloomberg.[90] The application of the constant growth model to a sample of five Canadian utilities indicated a cost of equity in the range of 9.5% to 10.5% (mid-point of 10.0%). The cost of equity developed using the three-stage model indicates a cost of equity in the range of 8.5% to 8.8% (mid-point of 8.7%) (Schedules 19 and 20).

3.c. DCF Cost of Equity

The Table below summarizes the results of the DCF models applied to both the U.S. electric utility sample and the Canadian utility sample.

[90] Long-term earnings growth forecasts were available from each of these two sources for Canadian Utilities Limited, Emera Inc., Enbridge Inc., Fortis Inc., and TransCanada Corporation. There are no widely available estimates of long-term expected returns on equity and earnings retention rates from which to make forecasts of sustainable growth.

Table 23

	Constant Growth		
	Analysts' EPS Forecasts	**Sustainable Growth**	**Three-Stage Model**
U.S. Electric Utilities	9.8%	9.3%	9.5%
Canadian Utilities	10.0%	N/A	8.7%

Source: Schedules 16-20.

The two DCF models applied to the sample of U.S. electric utilities and to the sample of Canadian utilities support a cost of equity for NSPI of approximately 9.5%.

E. ALLOWANCE FOR FINANCING FLEXIBILITY[91]

The equity risk premium tests (Section VII.C) and discounted cash flow tests (Section VII.D) indicate a "bare-bones" cost of equity for NSPI in the range of 9.5% (Discounted Cash Flow) to 10.0% (Equity Risk Premium), or approximately 9.75%. The financing flexibility allowance is an integral part of the cost of capital as well as a required element of the concept of a fair return. The allowance is intended to cover three distinct aspects: (1) flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) recognition of the "fairness" principle.

In the absence of an adjustment for financial flexibility, the application of a "bare-bones" cost of equity to the book value of equity, if earned, in theory, limits the market value of equity to its book value. The fairness principle recognizes the ability of competitive firms to maintain the real value of their assets in excess of book value and thus would not preclude utilities from achieving a degree of financial integrity that would be anticipated under competition. The market/book ratio of the S&P/TSX Composite averaged 2.1 times from 1995-2010; the corresponding average market/book ratio of the S&P 500 was 3.1 times.[92]

[91] See Appendix D for a more complete discussion.
[92] The market to book ratio of the S&P 500 includes the Utilities. The market to book ratio of the S&P Industrials alone has been higher.

At a minimum, the financing flexibility allowance should be adequate to allow a regulated company to maintain its market value, notionally, at a slight premium to book value, i.e., in the range of 1.05-1.10. At this level, a utility would be able to recover actual financing costs, as well as be in a position to raise new equity (under most market conditions) without impairing its financial integrity. A financing flexibility allowance adequate to maintain a market/book in the range of 1.05-1.10 is approximately 50 basis points.[93] As this financing flexibility adjustment is minimal, it does not fully address the comparable returns standard.

The cost of capital, as determined in the capital markets, is derived from market value capital structures. The cost of equity has been estimated using samples of proxy companies with a lower level of financial risk, as reflected in their market value capital structures, than the financial risk reflected in the corresponding book value capital structure. Regulatory convention applies the allowed equity return to a book value capital structure. When the market value equity ratios of the proxy utilities are well in excess of their book value common equity ratios, the failure to recognize the higher level of financial risk in the book value capital structure relative to the financial risk of the proxy samples of utilities, as recognized by equity investors, results in an underestimation of the cost of equity.

Utilities are entitled to the opportunity to earn a return that meets the fair return standard, namely one that provides the utility an opportunity to earn a return on investment commensurate with that of comparable risk enterprises, to maintain its financial integrity and to attract capital on reasonable terms. What must be fair is the overall return on capital. The recognition in the allowed return on equity of the impact of financial risk differences between the market value capital structures of the proxy companies and the ratemaking capital structure is required to ensure that the opportunity to earn a return commensurate with that of comparable risk enterprises. A full recognition of the disparity between the levels of financial risk in the market value capital structures and utility book value capital structures warrants an adjustment to the "bare bones" cost of equity of approximately 140 basis points (See Appendix D).

[93] Based on the DCF model as shown in Appendix D, footnote 2.

A reasonable adjustment for financing flexibility to the “bare bones” cost of equity estimated solely by reference to market-based tests (that is, without reference to the comparable earnings test) would be the mid-point of the indicated range of 50 to 140 basis points. The addition of an allowance for financing flexibility of 50 to 140 basis points to the “bare-bones” return on equity estimate of 9.75% for NSPI, derived from the equity risk premium and DCF tests, results in an estimate of the fair return on equity for 2012 of 10.7%, the mid-point of a range of approximately 10.25% to 11.2%.[94]

F. FAIR ROE FOR NSPI

The fair return for NSPI for 2012 is 10.7% (mid-point of a range of 10.25% to 11.2%), based on the following:

(1) A forecast long-term Government of Canada bond yield of 4.5% for 2012;
(2) A “bare-bones” cost of equity of 10.0% based on the equity risk premium tests;
(3) A “bare-bones” cost of equity of 9.5% based on the application of the discounted cash flow tests;
(4) A “bare-bones” cost of equity for NSPI of 9.75%, based on both the equity risk premium tests and discounted cash flow tests;
(5) An allowance for financing flexibility in a range of 0.50% to 1.4%;
(6) A fair return on equity of 10.7%, the mid-point of a range of approximately 10.25% to 11.2%.

[94] The recommended ROE compares to an average of the most recent allowed ROEs for the U.S. electric utility sample of approximately 10.5%, based on decisions rendered between 2007 and 2010; see Appendix B.

OPINION

ON

CAPITAL STRUCTURE
AND
RETURN ON EQUITY

FOR

NOVA SCOTIA POWER INC.

APPENDICES

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APPENDICES

APPENDIX A

RISK-ADJUSTED EQUITY MARKET RISK PREMIUM TEST

1. CONCEPTUAL UNDERPINNINGS OF THE CAPITAL ASSET PRICING MODEL

The Capital Asset Pricing Model (CAPM) is a theoretical, formal model of the equity risk premium test which posits that the investor requires a return on a security equal to:

$$R_F + \beta(R_M - R_F),$$

Where:

R_F	=	risk-free rate
β	=	covariability of the security with the market (M)
R_M	=	return on the market.

The model is based on restrictive assumptions, including:

a. Perfect, or efficient, markets exist where,

(1) each investor assumes he has no effect on security prices;

(2) there are no taxes or transaction costs;

(3) all assets are publicly traded and perfectly divisible;

(4) there are no constraints on short-sales; and,

(5) the same risk-free rate applies to both borrowing and lending.

b. Investors are identical with respect to their holding period, their expectations and the fact that all choices are made on the basis of risk and return.

The CAPM relies on the premise that an investor requires compensation for non-diversifiable risks only. Non-diversifiable risks are those risks that are related to overall market factors (e.g., interest rate changes, economic growth). 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:

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

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.

The CAPM is a normative model, that is, it estimates the equity return that an investor **should** require under the restrictive assumptions outlined above, based on the relative systematic risk of the stock.

2. RISK-FREE RATE

a. The theoretical CAPM assumes that the risk-free rate is uncorrelated with the return on the market. In other words, the assumption is that there is no relationship between the risk-free rate and the equity market return (i.e., the risk-free rate has a zero beta). However, the application of the model frequently assumes that the return on the market is highly correlated with the risk-free rate, that is, that the equity market return and the risk-free rate move in tandem.

b. The theoretical CAPM calls for using a risk-free rate, whereas the typical application of the model in the regulatory context employs a long-term government bond yield as a proxy for the risk-free rate. Long-term government bond yields may reflect various factors that render them problematic as an estimate of the "true" risk-free rate, including:

(1) The yield on long-term government bonds reflects the impact of monetary and fiscal policy; e.g., the potential existence of a scarcity premium. The Canadian federal government was in a surplus position from 1997/1998 to 2007/2008 (ten years), which reduced its financing requirements.[1] In 2008/2009, despite a budget deficit, the federal debt/GDP ratio stood at 29%, its lowest level since 1980/81, and well below the 1995/1996 peak of 68%. In 2009, Government of Canada bonds accounted for approximately one-quarter of total Canadian dollar bonds outstanding[2], compared to almost half in 1996.[3] However, the demand for long-term government securities by institutions that are "buy and hold" investors and that match the duration of their assets and liabilities (e.g., pension funds and insurance companies) has not declined. Thus, there is a potential for the prices of

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[1] Following a budget deficit of $55.6 billion in fiscal year 2009/2010 and an anticipated deficit of $40.5 billion 2010/2011, the Federal government's 2011 Budget anticipates budget deficits for all fiscal years through 2014/2015. A small surplus ($4.2 billion) is projected for 2015/2016. Federal debt to GDP is expected to peak at approximately 35% in 2011/12, declining to its pre-recession level in 2015/2016. (Department of Finance, *Next Phase of Canada's Economic Action Plan*, March 23, 2011)
[2] Includes provincial, municipal, corporate, foreign issuer, and term securitization bonds.
[3] Statistics Canada, www.statcan.gc.ca

long-term government bonds to incorporate a scarcity premium reflecting an imbalance between demand and supply.

(2) Yields on long-term government bonds may reflect shifting degrees of investors' risk aversion; e.g., "flight to quality". An increase in the equity risk premium arising from a reduction in bond yields due to a "flight to quality" is not likely to be captured in the typical application of the CAPM which focuses on a long-term average market risk premium. Particularly in periods of capital market upheaval, e.g., the "Asian contagion" in the fall of 1998, during the technology sector sell-off beginning in mid-2000, the post 9/11 period, the wake of the subprime mortgage crisis commencing in late 2007, and the sovereign debt crisis in Europe, investors shifted to the safe haven of government securities perceived as default-free, pushing down government bond yields and increasing the required equity risk premium. The typical application of the CAPM, which relies heavily on long-term average achieved equity risk premiums, captures the lower government bond yields, but not the corresponding increase in the equity risk premium.

(3) Long-term government bond yields are not risk-free; they are subject to interest rate risk. The size of the equity market risk premium at a given point in time depends in part on how risky long-term government bond yields are relative to the overall equity market. Changes in the risk of the "risk-free" security introduce further complexity to the application of the CAPM, particularly as the changes impact the measurement of the equity market risk premium.

c. The radical change in Canada's fiscal performance since the mid-1990s contributed to a steady decline in long-term government bond yields and a corresponding increase in total returns achieved by investors in long-term government securities. As a result, the achieved equity market risk premiums in Canada measured using total bond returns were squeezed by the performance of the government bond market. The low prevailing and forecast long-term Government of Canada bond yields relative to the historical total returns on those securities indicate that the historical returns on long-term Government of Canada bonds overstate the forward looking risk-free rate. The estimate of the equity market risk premium using historical data as a point of departure needs to recognize the much higher government bond returns historically than the forecast risk-free rate.

d. Total returns on government bonds include capital gains and losses resulting from changes in interest rates over time. The income return on government bonds, in contrast, reflects only the coupon payment portion of the total bond return. As such, the income return represents the riskless component of the total government bond return. In principle, using the bond income return in the calculation of historical risk premiums more accurately measures the historical equity risk premium above a true risk-free rate.

3. USE OF ARITHMETIC AVERAGES OF HISTORIC RETURNS TO ESTIMATE THE EXPECTED EQUITY MARKET RISK PREMIUM

a. Rationale for the Use of Arithmetic Averages

In Robert F. Bruner, Kenneth M. Eades, Robert S. Harris, and Robert C. Higgins, "Best Practices in Estimating the Cost of Capital: Survey and Synthesis", *Financial Practice and Education*, Spring/Summer 1998, pp. 13-28, the authors found that 71% of the texts and tradebooks in their survey supported use of an arithmetic mean for estimation of the cost of equity. One such textbook, Richard A. Brealey, Stewart C. Myers and Franklin Allen, *Principles of Corporate Finance,* Boston: Irwin/McGraw Hill, 2006 (p. 151), states, "Moral: If the cost of capital is estimated from historical returns or risk premiums, use arithmetic averages, not compound annual rates of return."

The appropriateness of using arithmetic averages, as opposed to geometric averages, for estimation of the cost of equity is succinctly explained in Ibbotson Associates; *Stocks, Bonds, Bills and Inflation*, *1998 Yearbook,* pp. 157-159:

> The expected equity risk premium should always be calculated using the arithmetic mean. The arithmetic mean is the rate of return which when compounded over multiple periods, gives the mean of the probability distribution of ending wealth values . . . in the investment markets, where returns are described by a probability distribution, the arithmetic mean is the measure that accounts for uncertainty, and is the appropriate one for estimating discount rates and the cost of capital.

Triumph of the Optimists: 101 Years of Global Investment Returns by Elroy Dimson, Paul Marsh and Mike Staunton, Princeton: Princeton University Press, 2002 (p. 182), stated,

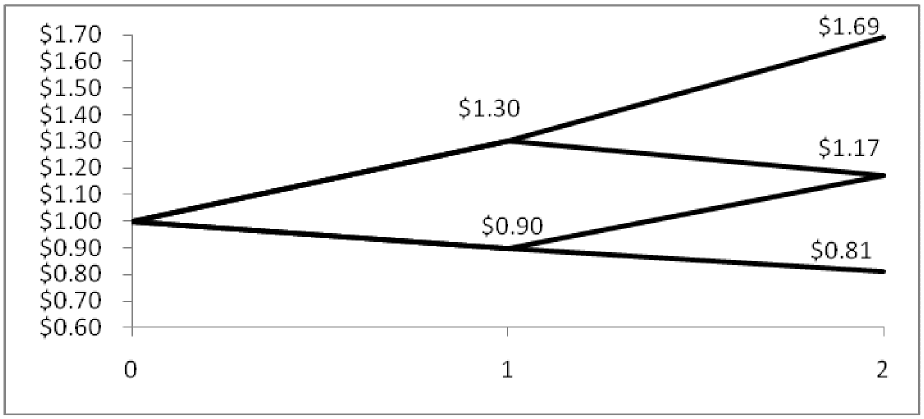
> The arithmetic mean of a sequence of different returns is always larger than the geometric mean. To see this, consider equally likely returns of +25 and –20 percent. Their arithmetic mean is 2½ percent, since (25 – 20)/2 = 2½. Their geometric mean is zero, since (1 + 25/100) x (1 – 20/100) – 1 = 0. But which mean is the right one for discounting risky expected future cash flows? For forward-looking decisions, the arithmetic mean is the appropriate measure.
>
> To verify that the arithmetic mean is the correct choice, we can use the 2½ percent required return to value the investment we just described. A $1 stake would offer equal probabilities of receiving back $1.25 or $0.80. To value this, we discount the cash flows at the arithmetic mean rate of 2½ percent. The present values are respectively $1.25/1.025 = $1.22 and $0.80/1.025 = $0.78, each with equal probability, so the value is $1.22 x ½ + $0.80 x ½ = $1.00. If there were a sequence of equally likely returns of +25 and –20 percent, the geometric mean return will eventually converge on zero. The 2½ percent forward-looking arithmetic mean is required to compensate for the year-to-year volatility of returns.

b. Illustration of Why Arithmetic Average Should be Used

In Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: Valuation Edition, 2010,* the following discussion was included:

> To illustrate how the arithmetic mean is more appropriate than the geometric mean in discounting cash flows, suppose the expected return on a stock is 10 percent per year with a standard deviation of 20 percent. Also assume that only two outcomes are possible each year: +30 percent and -10 percent (i.e., the mean plus or minus one standard deviation). The probability of occurrence for each outcome is equal. The growth of wealth over a two-year period is illustrated in Graph 5-3

Graph 5-3
Growth of Wealth Example



The most common outcome of $1.17 is given by the geometric mean of 8.2 percent. Compounding the possible outcomes as follows derives the geometric mean:

$$[(1+0.30) \times (1-0.10)]^{½} - 1 = 0.082$$

However, the expected value is predicted by compounding the arithmetic, not the geometric, mean. To illustrate this, we need to look at the probability-weighted average of all possible outcomes:

	(0.25 x $1.69)	=	$0.4225
+	(0.50 x $1.17)	=	$0.5850
+	(0.25 x $0.81)	=	<u>$0.2025</u>
	Total		$1.2100

Therefore, $1.21 is the probability-weighted expected value. The rate that must be compounded to achieve the terminal value of $1.21 after 2 years is 10 percent, the arithmetic mean.

$$\$1 \times (1+0.10)^2 = \$1.21$$

The geometric mean, when compounded, results in the median of the distribution:

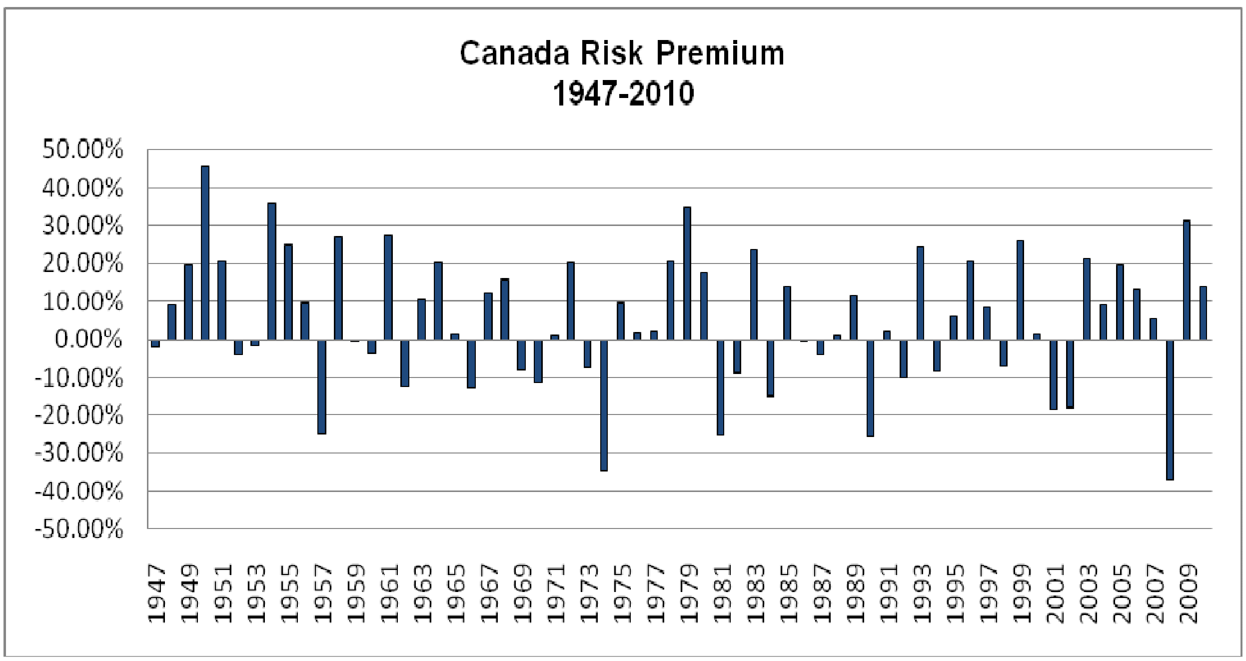
$$\$1 \times (1+0.082)^2 = \$1.17$$

The arithmetic mean equates the expected future value with the present value; it is therefore the appropriate discount rate.

c. Randomness of Annual Equity Market Risk Premiums

The use of arithmetic averages is premised on the unpredictability of future risk premiums. The following figures illustrate the uncertainty in the future risk premiums by reference to the historical post-World War II annual risk premiums (measured as the equity market return less the corresponding year's long-term government bond income return). The figures for both Canada and the U.S. suggest that each year's actual risk premium has been random, that is, not serially correlated with the preceding year's risk premium.[4]

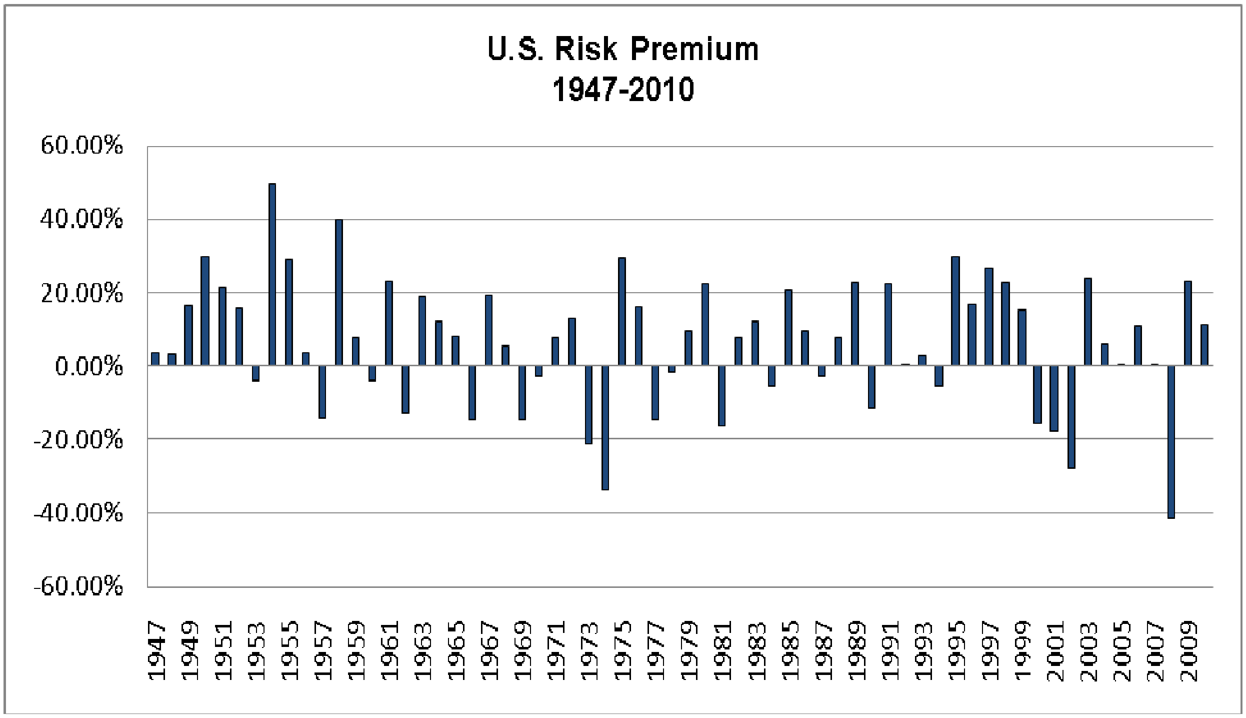
Chart A - 1



Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics, 1924-2009*, and *TSX Review*.

[4] A test for serial correlation between the year-to-year equity risk premiums shows that the serial correlations between the current year's risk premium (equity market return less bond income return) and that of the prior year for the period 1947-2010 are -0.045 for Canada and -0.03 for the U.S. If the current year's risk premium were predictable based on the prior year's risk premium, the serial correlation would be close to positive or negative 1.0.

Chart A - 2



Source: www.federalreserve.gov; Ibbotson Associates, *Stocks, Bonds, Bills & Inflation, 2010 Yearbook*, and www.standardandpoors.com .

4. THE CANADIAN EQUITY MARKET

Several factors inherent in the Canadian equity market make historic Canadian equity risk returns problematic in estimating the forward-looking expected equity market return. First and foremost, the Canadian equity market has been, and continues to be dominated by a relatively small number of sectors; the returns do not reflect those of a fully diversified portfolio.

Historically, the Canadian equity market composite has been dominated by resource-based stocks. At the end of 1980, no less than 46% of the market value of the TSX Composite Index (previously the TSE 300), was resource-based stocks.[5] The next largest sector, financial

[5] As measured by the oil and gas, gold and precious minerals, metals/minerals, and pulp and paper products sectors. Excludes "the conglomerates sector", which also contained stocks with significant commodity exposure.

services, at less than 15% of the total market value of the composite, was a distant second. With the rise of the technology-based sectors and the increasing market presence of financial services, at the end of 2000, resource-based stocks had dropped to less than 20% of the total market value of the TSX Composite Index. By comparison, as indicated in Table A-1 below, the technology-based and financial service sectors accounted for over half of the market value of the index.

Table A - 1

	1980	**2000**
Information Technology	0.9%	24.1%
Telecommunication Services	4.8%	6.5%
Financial Services	13.5%	24.1%
Total	19.2%	54.7%

Source: *TSE Review*, December 1980 and December 2000.

With the technology sector bust in 2000-2001, and the run-up in commodity prices commencing in 2004, the resource-based sectors reclaimed dominance. At the end of 2007, the energy and materials (largely mining) sectors accounted for close to 45% of the total market value of the composite. Including the financial services sector, three sectors accounted for close to 75% of the total market value of the composite. Despite the sharp decline in commodity prices in 2008-2009 and the fall-out of the sub-prime mortgage crisis, the same three sectors represented almost 80% of the value of the S&P/TSX Composite Index at the end of 2010.

By comparison, the U.S. market has been significantly more diversified among industry sectors. A comparison of market weights in Canada and the U.S. of the major sectors at year-end 2010 demonstrates the difference.

Table A - 2

Sector	S&P/TSX Canada	S&P 500 U.S.
Consumer Discretionary	4.5%	10.6%
Consumer Staples	2.5%	10.5%
Energy	26.7%	11.9%
Financials	27.9%	16.3%
Health Care	0.8%	10.9%
Industrials	5.5%	10.9%
Information Technology	2.4%	18.7%
Materials	24.1%	3.7%
Telecommunication Services	4.0%	3.2%
Utilities	1.7%	3.3%

Source: *TSX Review*, December 2010 and www.standardandpoors.com (January 5, 2011).

Even within the remaining areas of the Canadian market (the less than 25% accounted for by the non-resource and non-financial sectors), there are various sectors of the economy that are relatively underrepresented, e.g., pharmaceuticals, health care and retailing.

Further, the performance of the Canadian equity market as the "market portfolio" has been, at different periods of time, unduly influenced by a small number of companies. In mid-2000, before the debacle in Nortel Networks' stock value, Nortel shares alone accounted for almost 35% of the total market value of the TSX Composite Index as compared to the largest stock in the S&P 500 at that time (General Electric) which accounted for only 4% of total market value. In 2007, two stocks, Potash Corporation and Research in Motion, were responsible for approximately half of the gain in the S&P/TSX Composite Index. At the end of December 2010, the largest twenty stocks in the Composite Index accounted for approximately 50% of the total market capitalization of the S&P/TSX Composite Index. Of the twenty, six (19% of Composite Index market capitalization) were financial and eleven (25% of Composite Index market capitalization) were resource (energy and mining) companies.[6] The undue influence of a small

[6] By comparison, the largest 20 stocks in the S&P 500 accounted for less than 30% of the total index market capitalization, with no single industry represented among the top 20 stocks accounting for more than 10% of the total market capitalization of the index.

number of stocks requires caution in drawing conclusions from the history of the Composite Index regarding the forward-looking market risk premium.

Criticism of the former TSE 300 Index cited the lack of liquidity as well as questioned the quality and size of the stocks which comprised the index. In a speech in early 2002, Joseph Oliver, President and CEO of the Investment Dealers Association of Canada stated,

> Over the last 25 years, the TSE 300 has steadily declined as a relevant benchmark index. Part of the problem relates to the illiquidity of the smaller component companies and part to the departure of larger companies that were merged or acquired. Over the last two years, 120 Canadian companies have been deleted from the TSE 300.
>
> When a company disappears from a US index due to a merger or acquisition, that doesn't affect the U.S. market's liquidity. An ample supply of large cap, liquid U.S. companies can take its place. In Canada, when a company merges or is acquired by another company, it leaves the index and is replaced by a smaller, less liquid Canadian company. We have seen this over the last two years, -- notably in the energy sector. Over the next few years, we are likely to see it in financial services, where further consolidation is inevitable. Over time, Canada's senior index has become less diversified, with more smaller component companies. As a result, as many as 75 of the TSE 300 will not qualify for inclusion in the new S&P/TSE Composite Index.

Standard & Poor's and the TSX addressed some of these concerns when they overhauled the TSE 300 in May 2002, creating the S&P/TSX Composite Index. The overhaul of the index, which included more stringent criteria for inclusion, did not require that a specific number of companies be included in the index. As a result, only 275 companies were initially included instead of the previous 300. At December 31, 2010 there were 245 companies in the S&P/TSX Composite Index.

The addition of income trusts at the end of 2005 represented a significant change in the make-up of the Composite Index. From the beginning of the decade to their peak in late 2006, the market value of income trusts grew rapidly, from a market capitalization of approximately $20 billion, to more than $200 billion. At the end of September 2006, prior to the announced change in tax treatment for income trusts, they accounted for over 11.5% of the total market value of the S&P/TSX Composite. From 1998 (the first year for which returns were reported) to 2005, the annual compound total return for the S&P/TSX Capped Income Trust Index was 19%, compared to 8.5% for the S&P/TSX Composite Index.[7] As income trusts significantly outperformed "conventional" equities, their exclusion from the S&P/TSX Composite Index prior to 2005 means that the measured equity returns using the Composite Index understate the actual equity market returns achieved by Canadian investors.[8]

A further complication is created by the existence of restrictions on the foreign content of assets held in pension plans and tax deferred savings plans such as Registered Retirement Savings Plans (RRSPs) for approximately five decades (1957-2005). The restrictions on the ability of Canadians to invest globally negatively impacted their achieved returns. In 1957, when tax deferred savings plans were first established, no more than 10% of the income in pension plans or RRSPs could come from foreign sources. The Foreign Property Rule was instated in 1971 and limited foreign content to 10% of the book value of assets in the funds. The limit was raised to 20% in 2% increments between 1990 and 1994.

In 1999, the Investment Funds Institute of Canada (IFIC) estimated that raising the cap to 20% had increased annual returns by 1% and that a 30% limit would increase returns a further 0.5%.[9] The limit was raised to 30% in 5% increments between 2000 and 2001. In 2002, the Pension Investment Association of Canada (PIAC) and the Association of Canadian Pension Management (ACPM) published a report entitled *The Foreign Property Rule: A Cost-Benefit Analysis*,[10] which supported the removal of the cap.[11] At that time, the *Globe and Mail* reported

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[7] The annual compound total return for the S&P/TSX Capped Income Trust Index over the 1998-2010 period averaged 14.1%, compared to 7.7% for the S&P/TSX Composite Index.

[8] With the change to the income tax treatment of income trusts announced in October 2006 (effective January 1, 2011), most of the income trusts in the S&P/TSX Composite Index have converted back to conventional corporations.

[9] Tom Hockin, President and CEO IFIC, *Paving the Way for Change to RRSP Foreign Content Rules*, January 31, 2000.

[10] David Burgess and Joel Fried, *The Foreign Property Rule: A Cost-Benefit Analysis*, The University of Western Ontario, November 2002.

[11] The IFIC's report *Year 2002 in Review* stated,

> During the period of 1991-1998, the percentage of sales in equity mutual funds that were comprised of non-domestic equities has hovered around the 41-58% range. This has significantly increased in 1999 and onwards. While performance in the markets is the major factor affecting such an increase, these figures can also be attributed to increases in foreign content limits in registered retirement savings plans as well as increased interest and availability of foreign clone funds.

that the removal of the foreign content cap was expected to "have the broadest long-term impact of any personal finance measure in the budget. Global stock markets, accessible to any investor through global equity mutual funds, have historically made higher returns than the Canadian market, which only accounts for just over 2 per cent of the world's stock market value."[12] The Foreign Property Rule was eliminated in 2005.

Effectively, the combination of mediocre returns and small size of the Canadian market relative to the total global market put pressure on the government to increase and finally eliminate the cap on foreign investment that could be held in RRSPs and pension funds. From this perspective, historic Canadian equity returns therefore are likely to understate investor return requirements.

Investor reaction to the increasingly less restrictive FPR supports that conclusion. Equity investment outside of Canada grew rapidly as the barriers to foreign investment (in terms of transactions and information costs as well as the foreign investment cap) declined. Foreign stock purchases by Canadians increased almost ten-fold between 1995 and 2007. Purchases of foreign stocks in 1995 were $83 billion; in 2007, they were $915 billion. Although purchases have declined from their 2007 peaks, in 2010 they exceeded $500 billion of which over 70% were U.S. stocks.[13] In mid-2010, although the total percentage of foreign assets in trusteed pension funds was less than 30%, the percentage of foreign equity to total equity was close to 50%.[14, 15] In addition, the U.S. equity market has historically been the principal alternative for Canadian investors to domestic equity investments. Close to 40% of Canadian portfolio investment in foreign equities at the end of 2009 was in the U.S.[16]

[12] Rob Carrick, *Finance: Your Bottom Line*, www.globeandmail.com, February 23, 2005.
[13] Statistics Canada, *International Transactions in Securities*, *December 2010*, February 2011.
[14] Based on market value. Statistics Canada, Table 280-0003, data through September 2010, available March 2011.
[15] Pension funds have increasingly been investing in infrastructure assets outside of Canada. With specific respect to utility investments, in early 2009 a consortium of investors including the British Columbia Investment Management Corporation, the Alberta Investment Management Corporation and the Canada Pension Plan Investment Board completed the acquisition of Puget Energy, an electric and gas utility serving northern Washington State. The most recent allowed returns for Puget Sound Energy (both electric and gas) were 10.1% on a 46% common equity ratio, adopted in April 2010.
[16] Statistics Canada, *Canada's International Investment Position – Third quarter 2010,* January 2011. The U.S. portion of Canadian direct investment abroad at the end of 2009 was 44%.

5. TRENDS IN PRICE/EARNINGS RATIOS

Several studies of historic and equity risk premiums conclude that the equity returns generated historically are unsustainable, since they were achieved through an increase in price/earnings ratios that cannot be perpetuated.

With respect to the U.S. equity market, the preponderance of the increase in price/earnings ratios occurred during the 1990s. The P/E ratio[17] of the S&P 500 averaged 13.25 times from 1936-1988, with no discernible upward trend.[18] From 11.7 times in 1988, the P/E ratio gradually rose, peaking at over 46 times in late 2001. At the height of the equity market (1998 to mid-2000), frequently described as a "speculative bubble", investors believed the only risk they faced was not being in the equity market. In mid-2000, the bubble burst, as the U.S. economy began to lose steam. The events of September 11, 2001, the threat of war, the loss of credibility on Wall Street, accounting misrepresentations and outright fraud, led to a loss of confidence in the market and a sense of pessimism about the equity market. These events led to a heightened appreciation of the inherent risk of investing in the equity market, all of which translated into a "bearish" outlook for the U.S. equity market and sent retail investors to the sidelines.[19] By mid-2006, the P/E ratio had fallen to 17 times based on reported earnings and 15.5 times based on operating earnings.

As the market advanced from 2006 to late 2007, the P/E ratio expanded; when the S&P 500 was at its pre-crisis peak, the P/E ratio reached 19 times based on reported earnings (17 times based on operating earnings). As both the market and reported earnings collapsed during the financial crisis, the P/E ratio based on reported earnings soared to above 100 times during the second quarter of 2009. Based on operating earnings, the increase was much less extreme; the P/E ratio based on operating earnings reached 27 times during third quarter 2009. With recovery in both

[17] Price to trailing earnings.
[18] The average P/E ratio from 1947-1988 was 13 times.
[19] Weakness in the equity markets was partly responsible (along with low interest rates) for the burgeoning income trust market in Canada.

earnings and the equity market, the P/E ratio fell. At the end of December 2010, the P/E ratio of the S&P 500 was 15.0 times (based on estimated 2010 operating earnings), compared to the long-term (1936-2010) average of approximately 16 times.

To assess the impact of rising P/E ratios on achieved returns, I analyzed the equity returns of the S&P 500 achieved between 1936 (the first year for which P/E ratios are readily available) and 1988, that is, prior to the observed upward trend in P/E ratios. The analysis indicates that the achieved arithmetic average equity return for the S&P 500 was 12.3% from 1936-1988. The corresponding average return from 1936-2010 was 12.0%. Hence, despite the increase in P/E ratios experienced during the 1990s, the average equity market returns were actually lower over the entire 1936-2010 period than over the 1936-1988 period. The results are similar for the post-World War II period. The average returns from 1947-1988, at 13.1%, are higher than the average of 12.5% over the entire 1947-2010 period. In other words, the increase in P/E ratios during the 1990s did not result in a higher and unsustainable level of equity market returns. Consequently, based on history, an expected value for the U.S. equity market return equal to the historic level of approximately 12.0% is not unreasonable.

A review of equity returns in Canada indicates similar results. The 1936-1988 arithmetic average return for the Canadian equity market was 11.8%, higher than the average 1936-2010 return of 11.4%. Similarly, the 1947-1988 equity market return of 12.9% was higher than the 1947-2010 return of 12.1%. There is no indication that rising P/E ratios during the bull market of the 1990s resulted in average equity market returns that are unsustainable going forward.

6. RELATIVE RISK ADJUSTMENT

a. Beta

The body of evidence on CAPM leads to the conclusion that, while betas[20] do measure relative volatility, the proportionate relationship between beta and return posited by the CAPM has not been established. A summary of various studies, published in a guide for practitioners, concluded,

> Empirical tests of the CAPM have, in retrospect, produced results that are often at odds with the theory itself. Much of the failure to find empirical support for the CAPM is due to our lack of ex ante, expectational data. This, combined with our inability to observe or properly measure the return on the true, complete, market portfolio, has contributed to the body of conflicting evidence about the validity of the CAPM. It is also possible that the CAPM does not describe investors' behavior in the marketplace.
>
> Theoretically and empirically, one of the most troubling problems for academics and money managers has been that the CAPM's single source of risk is the market. They believe that the market is not the only factor that is important in determining the return an asset is expected to earn. (Diana R. Harrington, *Modern Portfolio Theory*, *The Capital Asset Pricing Model & Arbitrage Pricing Theory: A User's Guide*, Second Edition, Prentice-Hall, Inc., 1987, page 188.)

Fama and French stated in "The CAPM: Theory and Evidence", *Journal of Economic Perspectives*, Volume 18, Number 3 (Summer 2004), pp. 25-26:

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[20] The beta is equal to:

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

Where: R_E = Return on the individual stock or portfolio of stocks and R_M is the return on the equity market.

Alternatively, the beta can be expressed as:

Standard Deviation of R_E / Standard Deviation of R_M X Correlation Coefficient (ρ)

Betas are typically calculated by reference to historical relative volatility using simple regression analysis of the change in the market portfolio return and the corresponding change in an individual stock or portfolio of stock returns.

> The attraction of the CAPM is that it offers powerful and intuitively pleasing predictions about how to measure risk and the relation between expected return and risk. Unfortunately, the empirical record of the model is poor – poor enough to invalidate the way it is used in applications. The CAPM's empirical problems may reflect theoretical failings, the result of many simplifying assumptions. But they may also be caused by difficulties in implementing valid tests of the model. For example, the CAPM says that the risk of a stock should be measured relative to a comprehensive 'market portfolio' that in principle can include not just traded financial assets, but also consumer durables, real estate and human capital. Even if we take a narrow view of the model and limit its purview to traded financial assets, is it legitimate to limit further the market portfolio to U.S. common stocks (a typical choice), or should the market be expanded to include bonds, and other financial assets, perhaps around the world? In the end, we argue that whether the model's problems reflect weaknesses in the theory or in its empirical implementation, the failure of the CAPM in empirical tests implies that most applications of the model are invalid.

The Fama French study found that the relationship between beta and average return is much flatter than the CAPM would predict. Specifically, based on analysis covering 1928 to 2003 for the U.S. market, they showed that the predicted return on the lowest beta stock portfolio was 2.8 percentage points lower than the actual return.[21]

To quote Burton Malkiel in *A Random Walk Down Wall Street*, New York: W. W. Norton & Co., 2003:

> Beta, the risk measure from the capital-asset pricing model, looks nice on the surface. It is a simple, easy-to-understand measure of market sensitivity. Alas, beta also has its warts. The actual relationship between beta and rate of return has not corresponded to the relationship predicted in theory during long periods of the twentieth century. Moreover, betas for individual stocks are not stable from period to period, and they are very sensitive to the particular market proxy against which they are measured.
>
> I have argued here that no single measure is likely to capture adequately the variety of systematic risk influences on individual stocks and portfolios. Returns are probably sensitive to general market swings, to changes in interest and inflation rates, to changes in national income, and, undoubtedly, to other economic factors such as exchange rates. And if the best single risk estimate

[21] Fama and French developed an alternative model which incorporates two additional explanatory factors in an attempt to overcome the problems inherent in the single variable CAPM. The additional factors are size and book to market.

> were to be chosen, the traditional beta measure is unlikely to be everyone's first choice. The mystical perfect risk measure is still beyond our grasp. (page 240)

One of the key developers of the Arbitrage Pricing Model, Dr. Stephen Ross, has stated,

> Beta is not very useful for determining the expected return on a stock, and it actually has nothing to say about the CAPM. For many years, we have been under the illusion that the CAPM is the same as finding that beta and expected returns are related to each other. That is true as a theoretical and philosophical tautology, but pragmatically, they are miles apart.[22]

b. Relationship between Beta and Return in the Canadian Equity Market

To test the actual relationship between beta and return in a Canadian context, the betas (using monthly total return data) were calculated for various periods for each of the 15 major sub-indices of the "old" TSE 300 as were the corresponding actual geometric average total returns. Simple regressions of the betas on the achieved market returns were then conducted to determine if there was indeed the expected positive relationship. The regressions covered (a) 1956-2003, the longest period for which data for the TSE 300 and its sub-index components are available; (b) 1956-1997, which eliminates the major effects of the "technology bubble", and (c) all potential non-overlapping 10-year periods from 2003 backwards.

The analysis showed the following:

Table A - 3

Returns Measured Over:	Coefficient on Beta	R^2
1956-2003	-.088	47%
1956-1997	-.082	44%
1964-1973	-.020	1%
1974-1983	-.008	1%
1984-1993	-.056	11%
1994-2003	-.053	9%

Source: Schedule 10, page 1 of 2.

[22] Dr. Stephen A. Ross, "Is Beta Useful?" *The CAPM Controversy: Policy and Strategy Implications for Investment Management*, AIMR, 1993.

The analysis suggests that, over the longer term, the relationship between beta and return has been negative, rather than the positive relationship posited by the CAPM. For example, as indicated in Table A-3 above, for the period 1956-2003, the R^2 of 47% means that the betas explained 47% of the variation in returns among the key sectors of the TSE 300 index. However, since the coefficient on the beta was negative, this means that the higher beta companies actually earned lower returns than the low beta companies.

A series of regressions was also performed on the 10 major sectors of the S&P/TSX Composite. These regressions covered (a) 1988-2010, the longest period for which data for the new Composite and its sector components were available; (b) 1988-1997,[23] and (c) the 10-year period ending 2010.

That analysis showed the following:

Table A - 4

Returns Measured Over:	Coefficient on Beta	R^2
1988-2010	-.004	26%
1988-1997	-.017	1%
2001-2010	-.125	31%

Source: Schedule 10, page 2 of 2.

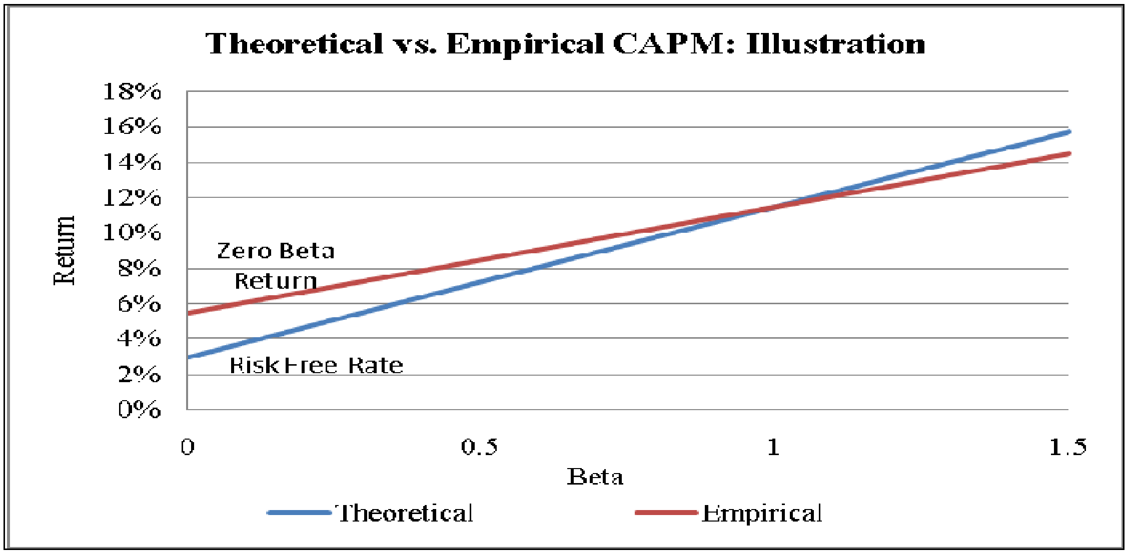
These analyses indicate that, historically, the relationship between beta and return in the Canadian equity market has been the reverse (higher beta = lower return) than the posited relationship.

The theoretical CAPM posits a market security line with an intercept equal to a “risk-free rate” and returns for risky securities proportional to their beta. Empirical studies point to a higher intercept and a flatter market security line than the theoretical model posits. In other words, a “zero beta” stock has a higher return than the risk-free rate and low (high)

[23] The use of this sub-period was intended to eliminate of the impacts of any anomalous market behavior during the technology “bubble and bust”, which occurred mainly from 1999 through mid-2002.

beta stocks have achieved higher returns than their "raw" betas imply, as illustrated in Chart A-3, below.

Chart A - 3



The empirical studies that have tested the CAPM typically rely on a short-term government bond return. To some extent, the application of the CAPM using a long-term government bond yield rather than a short-term instrument adjusts for the tendency of the CAPM to understate (overstate) returns for low (high) beta stocks. The use of a long-term risk-free rate rather than a short-term rate shifts the intercept of the market security line upward and decreases the slope of the line. The implication of this shift for a stock with a "raw" beta of 1.0 can be illustrated as follows:

In Canada, the spread between the three-month Treasury bill and the long-term government bond yield historically has been approximately 1.3%. If the three-month Treasury bill rate is 4.0%, the market return is 11.5% and the "raw" beta of a utility portfolio is 0.50, using the short-term rate as the risk-free rate produces a CAPM return of 7.75% (4.0% + 0.50 (11.5%-4.0%)). When a long-term Government of Canada bond yield 5.25% is used as the risk-free rate, the CAPM return is equal to 8.375% (5.25% + 0.50 (11.5%-5.25%)). Replacing the short-term Treasury bill rate with the long-term government bond yield adjusts the cost of equity of a stock with a 0.50 “raw” beta upward by 0.625 percentage points. Similarly, using the long-term government bond yield as the risk-free rate adjusts the cost of equity of a stock with a “raw” beta of 1.50 downward by 0.625 percentage points.

The indicated increase in returns for low beta stocks that is indicated by the replacement of the short-term rate with the long-term rate is well below the 2.8 percentage point difference between the actual and predicted return for the lowest beta portfolio that was identified in the Fama and French study referenced above.

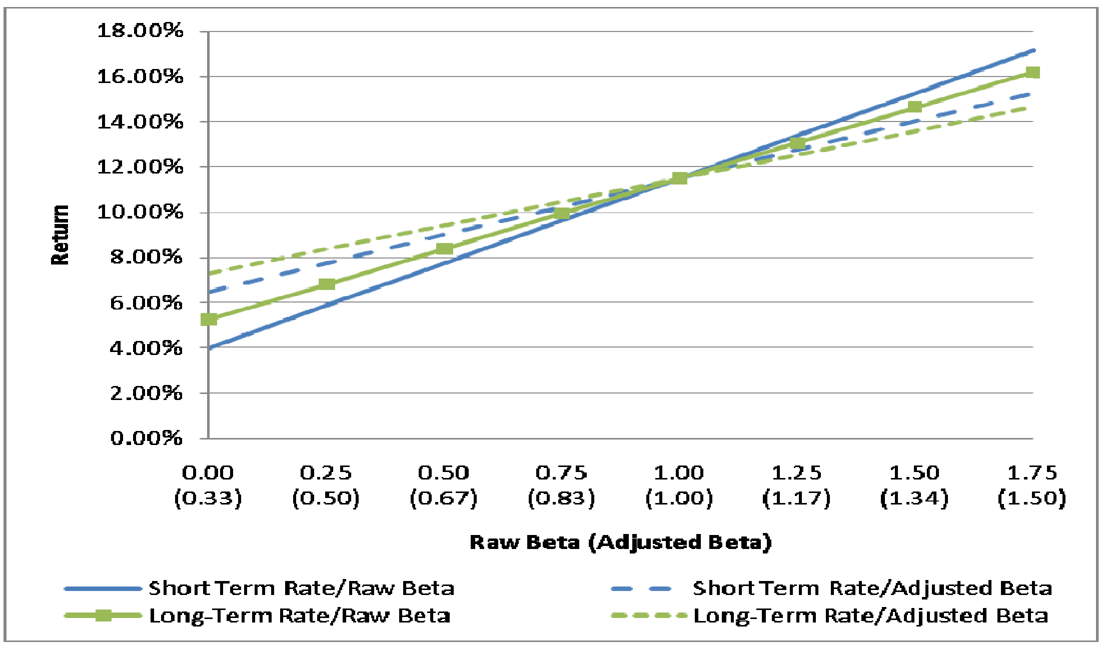
The use of adjusted betas in place of “raw” betas provides a further means of correcting for betas’ under (over) prediction of returns for low (high) beta stocks. Reliance on adjusted betas initially arose in response to the empirically documented failure of betas calculated from one period to be good predictors of betas calculated in a subsequent period. The standard adjustment formula for beta adjusts the “raw” beta toward the market mean beta of 1.0 as follows:

Adjusted beta = “Raw Beta” X (2/3) + Market Mean Beta of 1.0 X (1/3)

While the standard beta adjustment formula was initially adopted to account for the observed tendency of betas generally to trend toward the market mean beta of 1.0, effectively its application acts to further adjust for the under and over prediction of returns of low and high beta stocks by the “classic” single variable CAPM. Reliance on betas adjusted using the formula set out above in conjunction with a long-term Government of Canada bond yield as the risk-free rate results in (1) a market security line intercept that lies above the long-term government bond yield and (2) a further flattening of the slope of the line. The implications are higher predicted returns for stocks with betas below the market mean beta of 1.0 and lower predicted returns for stocks with betas above the market mean beta of 1.0.

Chart A-4 below illustrates the differences in predicted returns arising from using (1) a short-term risk-free rate and a "raw" beta; (2) a long-term risk-free rate and a "raw" beta; and (3) a long-term risk-free rate and an adjusted beta. The key implications of using a long-term risk-free rate and an adjusted beta are: (1) a "zero beta" stock, i.e., one whose stock price movements are uncorrelated with those of the market portfolio would be expected to achieve a higher return than achievable by investing in government bonds; and (2) the trade-off between risk and return across the beta risk spectrum is less pronounced than suggested by either the short-term risk-free rate/"raw" beta or the long-term risk-free rate/ "raw" beta approach.

Chart A- 4



Using the standard beta adjustment formula set out above moves a "raw" utility beta of 0.50 to 0.67. With the same inputs for market return (11.5%) and long-term government bond yield (5.25%) as in the previous example, the use of an adjusted beta rather than a "raw" beta increases the indicated utility equity return by slightly more than 1.0%. The total adjustment to the utility equity return of approximately 1.65% (0.625% for the difference between the long-term and short-term risk-free rates and 1.03% for the difference between the adjusted and "raw" betas) is materially lower than the total 2.8

percentage point under-prediction for the lowest beta portfolio identified in the Fama and French study.

APPENDIX B

SELECTION OF U.S. ELECTRIC UTILITY SAMPLE

For the estimation of an ROE applicable to NSPI using the Discounted Cash Flow-Based Equity Risk Premium Test and the Discounted Cash Flow Test (see Appendix C), a sample of U.S. electric utilities was selected.

The sample is comprised of all publicly-traded U.S. electric utilities satisfying the following criteria:

1. Classified by *Edison Electric Institute 2009 Financial Review* as a regulated or mostly regulated electric utility;

2. Preponderance of electric utility operations in states that have not restructured their electric utility industry or have suspended restructuring;

3. Analysts' long-term earnings forecasts available from three of the four following sources: I/B/E/S (First Call), Reuters, *Value Line* and Zacks;

4. Standard & Poor's and Moody's debt ratings of BBB/Baa2 or higher;

5. Not being acquired or involved in a merger;

6. Paid dividends quarterly from 1995 to 2010, or since the initiation of trading of common shares.

The fifteen utilities that met these criteria are:

ALLETE Inc.
Alliant Energy Corp.
Dominion Resources Inc.
Duke Energy Corp.
IDACORP Inc.
NextEra Energy Inc.
OGE Energy Corp.
Portland General Electric Co.
Progress Energy
SCANA Corp.
Sempra Energy
Southern Co.
Vectren Corp.
Wisconsin Energy Corp.
Xcel Energy Inc.

Utility-specific information is found on pages B-3 to B-36 of this Appendix and on Schedule 12.

Attachment 1 to Appendix B

ALLETE Inc.

Operating Characteristics:	
Operations:	Principal subsidiaries are regulated utilities: *Minnesota Power(MP)*: electric distribution in northeastern Minnesota *Superior Water Light & Power(SWL&P)*: electric, natural gas and water service in northwestern Wisconsin Have an investment in ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in Wisconsin, Michigan, Minnesota and Illinois Unregulated subsidiaries represent 9% of assets; include coal mining operations (consumed primarily by two electric cooperatives, Minnkota & Square Butte, from whom MP purchases capacity and energy under contracts to 2026), real estate, emerging technology investments, and a small amount of non-rate base generation.
Total Assets:	$2,393 million
Percentage of Assets in Gas and Electric Operations:	Approximately 91% of assets in regulated
State(s) of Utility Operations:	Northeastern Minnesota and northwestern Wisconsin
Number of Customers:	MP – 146,000 electric customers and 16 municipalities in Minnesota SWL&P – 15,000 electric, 12,000 gas, and 10,000 water customers in Wisconsin

Customers by Type:

Regulated Utility Sales by Customer Type	2009 % of Kwh Sold	2010 % of Kwh Sold
Residential	10%	9%
Commercial	12%	11%
Industrial	37%	52%
Municipals	8%	7%
Other Power Suppliers	33%	21%

(ALE cont'd)

Regulatory Environment:	
Test Year:	Partial forecast for Minnesota Forecast for Wisconsin
Return on Equity (Latest Allowed):	**Electric:** MP: 10.38% (Nov 2010) SWL&P: 10.9% (Dec 2010) **Gas:** SWL&P: 10.9% (Dec 2010)
Equity Ratio (Latest Allowed):	MP: 54.3% (Dec 2010) SWL&P: 54.9% (Dec 2010)
Earnings Sharing:	n/a
Deferral Mechanisms:[i]	Deferral of certain expenses; pension and OPEB, Lost and unaccounted for gas mechanism. Rate riders provided for annual recovery of specific costs (transmission expenditures, emission reduction, conservation, environmental and renewable) as of 2010 rate case, moved to PP&E in rate base to be recovered in base rates.
Fuel/Gas Cost Recovery:	MN: fuel adjustment clause that is adjusted monthly with a two-month lag. Allowed to recover through the FAC non-administrative Midwest Independent System Operator Day 2 costs. WI: purchased power costs are forecast and compared on a monthly basis to annual range, if likely outside that range (currently +/- 2%) the PSC may conduct a hearing to establish new rates. Gas tariffs contain an automatic adjustment clause.
Sales and Weather Normalization:	Jan 2009, Wisconsin PSC implemented 4-year, pilot revenue decoupling mechanisms for residential and small commercial electric and gas customers.
RRA Regulatory Climate:[ii]	Average 2 (MI) Above Average 2 (WI)
Moody's Rating Methodology:[iii] Weight accorded to category in parentheses	Regulatory Framework (25%): A Ability to Recover Costs/Earn Return (25%): Baa Diversification (10%): Ba Financial Strength (40%): A
S&P's Regulatory Comment	"Regulatory support for various environmental upgrades should help bolster financial measures during construction."

Alliant Energy Corp.

Operating Characteristics:	
Operations:	Principal subsidiaries are regulated utilities: *Interstate Power and Light(IPL)*: electric generation and distribution, and gas distribution in Iowa and Minnesota; 77% 2009 revenues electric, 18% 2009 revenues gas *Wisconsin Power and Light(WPL)*: electric generation and distribution, and gas distribution in Wisconsin; 84% 2009 revenues electric, 16% 2009 revenues gas IPL completed sale of electric transmission assets in IA, MN and IL to ITC in 2007; WPL transferred transmission assets to ATC in 2001 in exchange for ownership interest in ATC. IPL & WPL members in MISO a FERC-approved RTO. Unregulated subsidiaries represent 5% of assets; include RMT (environmental, consulting, engineering and renewable energy services), rail and barge transportation services, and non-regulated generation.
Total Assets:	$9,036 million.
Percentage of Assets in Gas and Electric Operations:	Approximately 95% of assets in utility operations.
State(s) of Utility Operations:	Iowa, southern Minnesota, and southern and central Wisconsin
Number of Customers:	IPL – 525,000 electric customers and 234,000 gas customers in Iowa and southern Minnesota WPL– 454,000 electric and 178,000 gas customers in Wisconsin
Customers by Type:	see table below

Customer Type	2009 % of Revenues	2009% Sales MWh
Residential	35%	25%
Commercial	22%	20%
Industrial	29%	36%
Wholesale	8%	11%
Bulk Power & Other	6%	9%

(LNT cont'd)

Regulatory Environment:	
Test Year:	Historical in Iowa Partial forecast for Minnesota Forecast for Wisconsin
Return on Equity (Latest Allowed):	**Electric:** IPL (Iowa): 10.44% (Dec 2010) reduced to 10.0% due to automatic rider for transmission cost recovery approved January 2011 as part of same case. IPL (Minnesota): 10.39% (Mar 2006) WPL (Wisconsin): 10.40% (Dec 2009) **Gas:** IPL (Iowa): 10.40% (Oct 2005) WPL (Wisconsin): 10.40% (Dec 2009)
Equity Ratio (Latest Allowed):	**Electric:** IPL (Iowa): 44.24% (Dec 2010) IPL (Minnesota): 49.10% (Mar 2006) WPL(Wisconsin): 50.38% (Dec 2009) **Gas:** IPL (Iowa): 49.35% (Oct 2005) WPL (Wisconsin): 50.38% (Dec 2009)
Earnings Sharing:	n/a
Deferral Mechanisms:	Pension and OPEB, Lost and unaccounted for gas mechanism, Energy Efficiency Cost Recovery (EECR), In December 2010, IPL was authorized to implement a pilot transmission cost recovery mechanism (automatic rider) for a three-year term. The rider was implemented in conjunction with a 3-year base rate freeze and reduction in allowed ROE of 0.40%. A similar transmission cost rider was proposed in Minnesota (Jan 2010)
Fuel/Gas Cost Recovery:	IA: retail electric and gas tariffs contain automatic adjustment clause modified monthly. WI: purchased power costs are forecast and compared on a monthly basis to annual range, if likely outside that range (currently +/- 2%) the PSC may conduct a hearing to establish new rates. Gas tariffs contain an automatic adjustment clause.
Sales and Weather Normalization:	Jan 2009, Wisconsin PSC implemented 4-year, pilot revenue decoupling mechanisms for residential and small commercial electric and gas customers.
RRA Regulatory Climate:	Above Average 3 (IA) Average 2 (MN) Above Average 2 (WI)

(LNT cont'd)

Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): A Ability to Recover Costs/Earn Return (25%): A Diversification (10%): A/Baa Financial Strength (40%): A
S&P's Regulatory Comment	"More credit supportive regulatory jurisdictions"

Dominion Resources Inc.

Operating Characteristics:	
Operations:	*Dominion Virginia Power (DVP)* – regulated electric distribution and transmission; non-regulated retail energy marketing (17% Earnings 2009) *Dominion Generation* Regulated generation at both Dominion and Virginia Power and Merchant Fleet generation (Dominion only) (59% Earnings 2009) *Dominion Energy* – regulated gas transmission, distribution, and storage, LNG import and storage, gas exploration and production (sold 2010). (24% Earnings 2009)
Total Assets:	$42,554 million
Percentage of Assets in Gas and Electric Operations:	Approximately 47% of assets in electric and gas operations, and 44% in generation.
State(s) of Utility Operations:	Virginia, northeastern North Carolina, Ohio, Pennsylvania, and West Virginia.
Number of Customers:	Approximately 4 million customers in 2009 of which 2.4 million in Virginia and North Carolina, 1.2 million in Ohio, 358,000 in Pennsylvania (sold 2010)
Customers by Type:	see table below

DVP 2009	**Retail Electric Sales**	**Customers By Type**
Residential	47%	89%
Commercial	34%	10%
Industrial	8%	<1%
Governmental	11%	1%

Regulatory Environment:	
Test Year:	NC, VA, WV: Historic with adjustments for known and measurable changes OH: Partial forecast PA: Forecast
Return on Equity (Latest Allowed):	**Electric:** 11.9% (2010 VA) 10.7% (2010 NC) **Gas:** 9.45% (2009 WV)
Equity Ratio (Latest Allowed):	**Electric:** 47.71% (2010 VA) 51.00% (2010 NC) **Gas:** 42.34% (2009 WV)
Earnings Sharing:	n/a

(D cont'd)

Deferral Mechanisms:	Rate adjustment for construction related financing costs related to two hybrid energy centers, rate rider for transmission related expenditures, Lost and unaccounted for gas mechanism,
Fuel/Gas Cost Recovery:	NC: prudent electric fuel and fuel-related costs are recoverable through a fuel adjustment clause. The annual increase in rates related to the recovery of purchased power costs is limited to 2% of total retail revenues. VA: electric rates reset annually on the basis of projected usage and costs; any over- or under-accruals, reconciled through the following year's fuel factor. Purchased power energy and capacity charges for "economy" purchases are included in the fuel factor calculation. Energy charges associated with reliability purchases may flow through the fuel factor; capacity charges recovered through base rates. OH, PA & WV: gas cost recovery fully recovered. Purchased gas cost recovery filings generally cover prospective one, three, or twelve-month periods.
Sales and Weather Normalization:	In December 2008, Dominion East Ohio implemented a transition to a Straight Fixed Variable rate design.
RRA Regulatory Climate:	Above Average 3 (VA) Above Average 2 (NC) Average 1 (OH) Average 3 (WV and PA)
Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): Baa Diversification (10%): A Financial Strength (40%): Baa/Ba
S&P's Regulatory Comment	"benefits from low regulatory risk"

Duke Energy Corp.

Operating Characteristics:	
Operations:	*Utility* – generates, transmits, distributes and sells electricity in North Carolina, South Carolina, Ohio, Indiana, and Kentucky. Transports and sells natural gas in Ohio and Kentucky. *Commercial Power* – owns, operates, and manages power plants and engages in the wholesale marketing of electric power, fuel, and emission allowances. *International Energy* – owns, operates, and manages power generation facilities outside the U.S. *Other* – insurance and interest in communications.
Total Assets:	$57,040 million
Percentage of Assets in Gas and Electric Operations:	Approximately 75% of assets in regulated electric and gas operations.
State(s) of Utility Operations:	Electric utility operations in central and western North Carolina, western South Carolina, southwestern Ohio, central, north central, and southern Indiana, and northern Kentucky. Gas utility operations in southwestern Ohio and northern Kentucky.
Number of Customers:	4.0 million electric customers; 2.4 million in North and South Carolina, 685,000 in Ohio, 780,000 in Indiana, and 135,000 in Kentucky. 500,000 gas customers; 400,000 in Ohio and 100,000 in Kentucky.
Customers by Type:	**Customer Type** / **2009% Electric Revenue** Residential 42% Commercial 33% Industrial 18% Other 7%
Regulatory Environment:	
Test Year:	NC: Partial or fully forecast IN, KY, SC: Historic with adjustments for known and measurable changes OH: Partial forecast

(DUK cont'd)

Return on Equity (Latest Allowed):	**Electric:** 10.5% (2004 IN) 11.5% (1992 KY) 10.7% (2009 NC) 10.63% (2009 OH) 10.7% (2010 SC) **Gas:** 10.38% (2009 KY) 10.50% (2008 OH)
Equity Ratio (Latest Allowed):	**Electric:** 44.44% (2004 IN) 45.95% (1992 KY) 52.50% (2009 NC) 51.59% (2009 OH) 53.00% (2010 SC) **Gas:** 49.90% (2009 KY) 55.76% (2008 OH)
Earnings Sharing:	n/a
Deferral Mechanisms:	Storm costs (OH, KY), Catawba Nuclear Station and related environmental compliance costs (NC, SC), carbon storage costs (Indiana), Bad Debt Expense (OH), Lost and unaccounted for gas mechanism
Fuel/Gas Cost Recovery:	NC: prudent electric fuel and fuel-related costs are recoverable through a fuel adjustment clause SC: non-automatic electric fuel and purchased gas adjustment clauses OH: Electric: rate stabilization plan that allows for rate recognition of a portion of the increases in fuel prices, purchased power costs, and emission expenditures. Gas: gas cost recovery charge providing quarterly adjustments with an annual review/hearing. Charges may be revised in a subsequent three-month period for any under- or over-recoveries related to the collection of an earlier period. IN: Electric: adjustments for changes in fuel and purchased power (energy component only) costs every three months, following hearings. Recovers 100% of purchased power capacity/demand charges through a summer reliability tracking mechanism in place until next base rate proceeding. KY: Recover fuel and purchased power (energy only) costs through automatic fuel adjustment clauses. Adjusted monthly, based on actual costs for the second preceding month with an under/over-recovery mechanism

(DUK cont'd)

Sales and Weather Normalization:	n/a
RRA Regulatory Climate:	Above Average 2 (NC) Above Average 3 (IN) Average 1 (SC, OH, KY)
Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): A Diversification (10%): Baa Financial Strength (40%): A
S&P's Regulatory Comment	"Regulatory risk is managed relatively well, aided in part by jurisdictions with credit-supportive regulatory environments"

IDACORP Inc.

Operating Characteristics:	
Operations:	*Utility Operations:* subsidiary Idaho Power is engaged in the generation, transmission, distribution, sale, and purchase of electric energy. *Non-Utility*: investments in affordable housing and operation of small hydroelectric generation projects.
Total Assets:	$4,238 million
Percentage of Assets in Gas and Electric Operations:	Approximately 96% of assets in electric operations.
State(s) of Utility Operations:	Idaho (95% of revenue) and eastern Oregon
Number of Customers:	490,000
Customers by Type:	**Customer Type** / **2009 % of Revenues** Residential 45.8% Commercial 26.1% Industrial 15.8% Irrigation 12.3%
Regulatory Environment:	
Test Year:	ID: Historic with adjustments for known and measurable OR: Partial or fully forecast
Return on Equity (Latest Allowed):	10.5% (2009 ID) 10.18% (2010 OR)
Equity Ratio (Latest Allowed):	49.27% (2009 ID) 49.80% (2010 OR)
Earnings Sharing:	Idaho Power is operating under an earnings sharing mechanism under which incremental earnings in excess of a 10.5% ROE in any calendar year 2009-2011 are to be shared equally.
Deferral Mechanisms:	Energy Efficiency Rider
Fuel/Gas Cost Recovery:	Electric power supply cost mechanism which trues-up costs on an annual basis subject to a deadband within which 90/10 sharing of costs and benefits between customers and shareholders. Collection/refund of revenues limited to 100bp impact on last allowed ROE
Sales and Weather Normalization:	Operating on a pilot program through 2011 applicable to residential and small general service customers only designed to adjust the company's electric rates to recover fixed costs independent of the volume of energy costs (decoupling)

(IDA cont'd)

RRA Regulatory Climate:	Average 2 (ID) Average 3 (OR)
Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): Baa Diversification (10%): A/Baa Financial Strength (40%): Baa/Ba
S&P's Regulatory Comment	"Generally supportive state regulatory regime"

NextEra Energy Inc.

Operating Characteristics:	
Operations:	*Florida Power & Light (FPL)* – regulated utility engaged in the generation, transmission, distribution and sale of electric energy in Florida. *NextEra Energy Resources* – owns, develops, constructs, manages, and operates electric-generating facilities. Provides full energy and capacity requirements services. Engages in power and gas marketing and trading activities.
Total Assets:	$46,950 million
Percentage of Assets in Gas and Electric Operations:	FPL accounts for approximately 57% of assets; NextEra Energy approximately 43% assets
State(s) of Utility Operations:	Florida
Number of Customers:	4.5 million
Customers by Type:	**Customer Type** / **2009 % of Sales (kwh)** Residential 51% Commercial 43% Industrial 3% Wholesale 1% Other 2%
Regulatory Environment:	
Test Year:	Full or partial forecast
Return on Equity (Latest Allowed):	10.0% (2010 FL)
Equity Ratio (Latest Allowed):	47.0% (2010 FL)
Earnings Sharing:	n/a
Deferral Mechanisms:	Pre-construction costs and carrying charges on construction costs for new nuclear capacity and new solar generating facilities recovered through cost recovery clauses, Storm-recovery bonds including interest and bond issuance costs recovered through surcharge to retail customers, Deferral for pension expense
Fuel/Gas Cost Recovery:	Fuel and purchased power cost recovery clause provides recovery of prudently incurred fuel and purchased power costs. Annual fuel factors are established based upon 12-month projections of fuel cost and energy purchases and sales. Hearings are held each November during which the PSC sets fuel factors for the next calendar year.

(NEE cont'd)

Sales and Weather Normalization:	n/a
RRA Regulatory Climate:	Average 1 (FL)
Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): A Diversification (10%): Baa Financial Strength (40%): A
S&P's Regulatory Comment	Although "Low regulatory risk in Florida" has been "shaken in recent years" as decisions have reflected "more intense political influence over the regulatory environment" the "Utility's actions to rebuild its regulatory risk profile have been effective;" referred to as "credit supportive regulatory environment:

OGE Energy Corp.

Operating Characteristics:	
Operations:	*Oklahoma Gas and Electric* (OG&E) – regulated utility that generates, transmits, distributes and sells electric energy in Oklahoma and Arkansas. *Enogex LLC* – gathering, processing, transporting, and storing natural gas.
Total Assets:	$8,067 million
Percentage of Assets in Gas and Electric Operations:	**2009 % Assets** Electric Utility 67.9% Transportation & Storage 19.8% Gathering & Processing 10.7% Marketing 1.6%
State(s) of Utility Operations:	Oklahoma (90% of revenues) and western Arkansas
Number of Customers:	776,550 customers
Customers by Type:	**Customer Type — 2009 % of Revenues** Residential 44.0% Commercial 27.0% Industrial 10.6% Oilfield 8.1% Public authorities 10.3%
Regulatory Environment:	
Test Year:	OK: Historic with adjustments for known and measurable changes. AK: Partial forecast.
Return on Equity (Latest Allowed):	10.75% (2005 OK) 10.25% (2009 AR)
Equity Ratio (Latest Allowed):	55.69% (2005 OK) 36.04% (2009 AR)
Earnings Sharing:	n/a
Deferral Mechanisms:	Storm costs, pension expense
Fuel/Gas Cost Recovery:	AR: fuel and purchased power costs are recovered through an annual energy cost recovery rider. OK: semi-automatic fuel adjustment clause adjusted annually subject to a cap on under- or over-recoveries.

(OGE cont'd)

Sales and Weather Normalization:	n/a
RRA Regulatory Climate:	Average 3 (OK and AR)
Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): Baa Diversification (10%): Baa Financial Strength (40%): A
S&P's Regulatory Comment	"We view Oklahoma's and Arkansas' regulatory climates as credit supportive."

Portland General Electric Co.

Operating Characteristics:	
Operations:	*Electric Operations*-generation, purchase, transmission, distribution, and retail sale of electricity in Oregon.
Total Assets:	$5,172 million.
Percentage of Assets in Gas and Electric Operations:	Approximately 100% of assets in electric operations.
State(s) of Utility Operations:	Oregon
Number of Customers:	815,739 customers
Customers by Type:	**Customer Type** / **2009 % of Revenues** Residential 47.9% Commercial 37.4% Industrial 10.1% Other 4.6%
Regulatory Environment:	
Test Year:	Partial or fully forecast
Return on Equity (Latest Allowed):	10.0% (2010 OR)
Equity Ratio (Latest Allowed):	50.00% (2010 OR)
Earnings Sharing:	n/a
Deferral Mechanisms:	Pension expense, deferred broker settlements , forced outage costs
Fuel/Gas Cost Recovery:	Are permitted to annually adjust rates to reflect forecasted power costs (PCAM). Also have a power cost adjustment mechanism that is subject to a deadband of $15 million below to $30 million above the ultimately established net variable power costs. Portland absorbs 100% of the costs/benefits within the deadband, and amounts above or below the deadband are shared 90% with customers and 10% with Portland. A refund would occur only to the extent that the refund would result in Portland's actual ROE for that year being no less than 100 basis points above the last authorized ROE. A surcharge would occur only to the extent that surcharge would result in Portland's actual ROE for that year being no greater than 100 basis points below the last authorized ROE.

(POR cont'd)

Sales and Weather Normalization:	Commercial and industrial customers of Portland are eligible for direct access.
RRA Regulatory Climate:	Average 3 (OR)
Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): Baa Diversification (10%): Baa Financial Strength (40%): Baa
S&P's Regulatory Comment	Decisions have been supportive of ratings stability

Progress Energy

Operating Characteristics:	
Operations:	*Carolina Power & Light* – generation, transmission, distribution, and sale of electricity in North Carolina and South Carolina. *Progress Energy Florida* – generation, transmission, distribution, and sale of electricity in Florida. *Other* – miscellaneous nonregulated businesses that do not separately meet the quantitative thresholds for disclosure as separate reportable business segments.
Total Assets:	$31,236 million
Percentage of Assets in Gas and Electric Operations:	Approximately 85% of assets in electric operations.
State(s) of Utility Operations:	Central and eastern North Carolina, northeastern South Carolina, and north and central Florida.
Number of Customers:	3.1 million customers (1.5 million in North and South Carolina, 1.6 million in Florida)
Customers by Type:	**Customer Type** — **2009 % of kWh** Residential — 37.2% Commercial — 26.0% Wholesale — 18.1% Industrial — 13.9% Other Retail — 4.8%
Regulatory Environment:	
Test Year:	FL: Partial or full forecast NC, SC: Historic with adjustments for known and measurable changes
Return on Equity (Latest Allowed):	10.5% (2010 FL) 11.0% (2003 NC)
Equity Ratio (Latest Allowed):	46.74% (2010 FL) 51.14% (2003 NC)
Earnings Sharing:	n/a
Deferral Mechanisms:	Storm costs, costs associated with nuclear expansion in Florida, Energy Efficiency/DSM, pension expense

(PGN cont’d)

Fuel/Gas Cost Recovery:	FL: fuel and purchased power cost recovery clause provides for recovery of prudently incurred fuel and purchased power costs. Annual fuel factors are established based upon 12-month projections of fuel costs and energy purchases and sales. Hearings are held each November, during which the PSC sets fuel factors for the next calendar year. NC: prudent electric fuel and fuel-related costs are recoverable through a fuel adjustment clause. SC: non-automatic electric fuel and purchased gas adjustment clauses are in place.
Sales and Weather Normalization:	n/a
RRA Regulatory Climate:	Above Average 2 (NC) Average 1 (SC and FL)
Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): A Diversification (10%): A/Baa Financial Strength (40%): Baa
S&P's Regulatory Comment	"Operations under generally supportive regulatory environments"

SCANA Corp.

Operating Characteristics:	
Operations:	*Regulated Utilities*: SCE&G: engaged in the generation, transmission, distribution, and sale of electricity and the purchase, sale, and transportation of natural gas to customers in South Carolina. GENCO: sells electricity to SCE&G. Fuel Company: acquires, owns, and provides financing for SCE&G's nuclear fuel, fossil fuel, and emission allowances. PSNC Energy: purchases, sells, and transports natural gas to customers in North Carolina. CGT operates an interstate pipeline company in Georgia and South Carolina. *Unregulated* – markets natural gas, provides energy-related risk management services, and owns a fiber optic telecommunications network.
Total Assets:	$12,094 million
Percentage of Assets in Gas and Electric Operations:	Approximately 94% of assets in regulated utility operations.
State(s) of Utility Operations:	Central, southern, and southwestern South Carolina and North Carolina.
Number of Customers:	1.438 million customers (655,000 electric, 310,000 natural gas in South Carolina, 473,000 natural gas in North Carolina)
Customers by Type:	**Electric (SCE&G)** — **2009 % of Electric Revenues** Residential 43% Commercial 32% Industrial 16% Sales for Resale & Other 8% **Gas (SCE&G)** — **2009 % Gas % Transportation Revenues** Residential 46% Commercial 30% Industrial 19% Transportation Gas 4%

(SCG cont'd)

Regulatory Environment:	
Test Year:	NC, SC: Historic with adjustments for known and measurable changes
Return on Equity (Latest Allowed):	10.6% (2008 NC) 10.7% (2010 SC)
Equity Ratio (Latest Allowed):	54.00% (2008 NC) 52.96% (2010 SC)
Earnings Sharing:	n/a
Deferral Mechanisms:	Pension and OPEB costs, environmental remediation costs associated with manufactured gas plants
Fuel/Gas Cost Recovery:	NC: prudent electric fuel and fuel-related costs are recoverable through a fuel adjustment clause. SC: non-automatic electric fuel and purchased gas adjustment clauses are in place. Allows for monthly adjustment to its gas costs that are calculated based on a rolling 12-month forecast of purchased gas costs.
Sales and Weather Normalization:	NC: rates decoupled , rates periodically adjusted based on average per customer consumption SC: Weather normalization adjustment in effect increases tariff rates if weather is warmer than normal and decreases rates if weather is colder than normal.
RRA Regulatory Climate:	Above Average 2 (NC) Average 1 (SC)
Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): A Ability to Recover Costs/Earn Return (25%): A Diversification (10%): Baa/Ba Financial Strength (40%): Baa
S&P's Regulatory Comment	"Supportive regulatory environments in South Carolina and North Carolina"

Sempra Energy

Operating Characteristics:	
Operations:	**Utility Operations***:* *San Diego Gas & Electric(SDG&E)*-electric and gas utility covering 4,100 square miles in the San Diego, CA area *Southern California Gas (SoCalGas)*-gas utility in central and southern California. **Non-Utility**: *Sempra Commodities*-commodities marketing and holds firm service capacity on the Rockies Express Pipeline. *Sempra Generation*-owns and operates natural gas-fired power plants and a wind-power generation project. *Sempra Pipelines & Storage*-operates and/or owns 2,000 miles of transmission pipelines and underground storage facilities. Also operates a small natural gas distribution utility serving Southwest Alabama. *Sempra LNG*-constructs and operates LNG receiving terminals.
Total Assets:	$28,512 million
Percentage of Assets in Gas and Electric Operations:	Approximately 63% of assets in electric and gas operations.
State(s) of Utility Operations:	Primarily central and southern California. Non-regulated operations or development projects by Sempra Generation, Sempra Pipelines & Storage and Sempra LNG in Alabama, Arizona, California, Indiana, Louisiana, Mississippi, Nevada, Texas and Hawaii.
Number of Customers:	Natural Gas Operations: 6.6 million Electric Operations: 1.4 million
Customers by Type:	**Electric** — **2009 % Revenues** Residential — 46% Commercial — 39% Industrial — 10% Direct Access — 5% **Gas** Residential — 69% Commercial & Industrial — 29% Electric Generation — 2% Wholesale — <1%

(SRE cont'd)

Regulatory Environment:	
Test Year:	AL: Historic with adjustments for known and measurable changes. CA: Forecast
Return on Equity (Latest Allowed):	**Electric:** 10.7% (2008 CA) **Gas:** 10.70% (2008 CA, SDG&E) 10.82% (2008 CA, SoCalGas) 13.60% (1995 AL)
Equity Ratio (Latest Allowed):	**Electric:** 49.00% (2008 CA) **Gas:** 49.00% (2008 CA, SDG&E) 48.00% (2008 CA, SoCalGas) 46.99% (1995 AL)
Earnings Sharing:	AL: regulator conducts quarterly reviews to determine if, based on projections, ROE will fall within range of 13.35% to 13.85%. Reductions in rates can be made quarterly to bring ROE within range. Increases allowed once a year. Equity on which ROE can be earned limited to 55%. If O&M expense exceed cap based on CPI, 75% of excess returned to customers. If below cap, company retains 50% of savings.
Deferral Mechanisms:	Environmental costs, pensions and OPEB; Additional incentive mechanisms in CA for operational activities e.g., safety, energy efficiency, and unbundled natural gas storage and system operator hub services.
Fuel/Gas Cost Recovery:	CA: Incentive for natural gas procurement (Gas Cost Incentive Mechanism) permits full recovery of costs incurred in range around the benchmark and sharing of costs/saving outside the range with core customers (primarily residential, small commercial and industrial customers)
Sales and Weather Normalization:	CA: decoupling mechanisms for both gas and electric utilities)
RRA Regulatory Climate:	Average 1 (CA) Above Average 2 (AL)
Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): Baa Diversification (10%): A Financial Strength (40%): Baa
S&P's Regulatory Comment	"exceptionally supportive of credit quality"

Southern Co.

Operating Characteristics:	
Operations:	*Traditional Operating Companies:* Each own generation, transmission and distribution facilities: *Alabama Power* (Alabama) *Georgia Power* (Georgia) *Gulf Power* (Florida) *Mississippi Power* (Mississippi). *Regulated Generation :* *Southern Power*-constructs, acquires, owns, and manages generation assets and sells electricity at market-based rates. Subject to FERC regulation Non-Utility Operations: Digital wireless communications, operates and provides services to utilities nuclear plants, acquires, owns, and constructs renewable generation assets.
Total Assets:	$52,046 million
Percentage of Assets in Gas and Electric Operations:	Approximately 94% of assets in traditional electric operating companies.
State(s) of Utility Operations:	Most of the states of Alabama and Georgia, along with the northwestern portion of Florida and southeastern Mississippi.
Number of Customers:	4.4 million customers (traditional operating companies)
Customers by Type:	**Customer Type** — **2009 % of Revenues** Residential — 36% Commercial — 32% Industrial — 19% Other - Retail — 1% Wholesale — 12%
Regulatory Environment:	
Test Year:	AL: Historic with adjustments for known and measurable FL: Partial or full forecast GA: Partial forecast MS: Full forecast

(SO cont'd)

Return on Equity (Latest Allowed):	14.00% (1980 AL) 12.00% (2002 FL) 11.15% (2010 GA) 12.88% (2001 MS)
Equity Ratio (Latest Allowed):	25.95% (1980 AL) 41.02% (2002 FL) 51.67% (2001 GA) 53.68% (2001 MS)
Earnings Sharing:	AL: Alabama Power operates under a Rate Stabilization and Equalization framework. Annual rate increases limited to 5% and rate increases for any two-year period, when averaged, cannot exceed 4% per year. If projected ROE is outside the allowed ROE range of 13%-14.5% rates are adjusted, subject to the limits above, to establish a 13.75% ROE. If actual earned ROE is above 14.5%, customers are refunded revenues that caused the earned ROE to exceed 14.5%. No provision for recovering shortfalls if the earned ROE is below 13%. GA: Georgia Power operating under an alternative rate plan since 1996; current version applies to years 2011-2013. Not permitted to file a general rate case unless earnings are projected to fall below a 10.25% ROE. Two-thirds of earnings above a 12.25% ROE are refunded to customers. No automatic recovery of any earnings shortfall below a 10.25% ROE, but may petition to utilize an Interim Cost Recovery Tariff to adjust earnings to a 10.25% ROE in lieu of filing a rate case. Permitted to retain 15% of the net present value of the net benefits generated by certain demand-side management programs.
Deferral Mechanisms:	Pension and employee benefit expense, Plant outage costs, Environmental remediation costs, Storm damage cost recovery, AL: Rate Certificated New Plant (CNP) mechanism adjusts rates annually to recognize the cost of placing new generating facilities in retail service and recovery of retail costs associated with certificated PPAs. CNP includes environmental costs and return on invested capital. GA: CWIP in rate base

(SO cont'd)

Fuel/Gas Cost Recovery:	AL: an Energy Cost Recovery (ECR) rate in place established on the basis of estimates of electric sales, fuel, and net purchased energy costs, and reflects accumulated over- or under-recovered amounts. GA: non-automatic fuel adjustment mechanism is in place. FL: the fuel and purchased power cost recovery clause provides for recovery of prudently incurred fuel and purchased power costs. Annual fuel factors are established base upon 12-month projections of fuel costs and energy purchases and sales. Hearings are held each November, during with the PSC sets fuel factors for the next calendar year. MS: an automatic electric fuel adjustment clause is in effect, with the energy component of purchased power recovered through the fuel clause and the capacity component recovered in base rates.
Sales and Weather Normalization:	n/a
RRA Regulatory Climate:	Above Average 2 (AL and MS) Average 1 (FL and GA)
Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): A Ability to Recover Costs/Earn Return (25%): A Diversification (10%): Baa Financial Strength (40%): A/Baa
S&P's Regulatory Comment	"Operations under generally constructive regulatory environments"

Vectren Corp

Operating Characteristics:	
Operations:	*Vectren Utility Holdings* – comprised of Indiana Gas, Southern Indiana Gas & Electric Company and Ohio operations. *Vectren Enterprises* – support services to utility operations.
Total Assets:	$3820 million
Percentage of Assets in Gas and Electric Operations:	Approximately 100% of assets in gas and electric operations of which 24% in generation.
State(s) of Utility Operations:	Nearly 2/3rds of the state of Indiana (gas and electric) and part of Ohio (gas).
Number of Customers:	679,000 gas and 141,000 electric customers in central and southern Indiana. 317,000 gas customers in west central Ohio.
Customers by Type:	**Customer Type** / **2009 % of Revenues** Residential 58.2% Commercial 26.6% Industrial 15.2%
Regulatory Environment:	
Test Year:	Historic with adjustments for known and measurable changes for Indiana Partial forecast for Ohio
Return on Equity (Latest Allowed):	**Electric:** SIGECO: 10.4% (2007) Vectren Elec. Delivery Ohio: not specified (2009) previously 10.6% (2005) **Gas:** Indiana Gas: 10.20% (2008) SIGECO: 10.15% (2007)
Equity Ratio (Latest Allowed):	SIGECO: 47.05% (2007) Indiana Gas: 48.99% (2008 IN) Vectren Energy Delivery: 48.10% (2005 OH); 2009 not specified
Earnings Sharing:	n/a

(VVC cont'd)

Deferral Mechanisms:	Employee benefit deferral Demand side management expense Pipeline integrity expense Bad debt recovery mechanism (IN, OH) Environmental CWIP tracker Infrastructure cost recovery (IN, OH)
Fuel/Gas Cost Recovery:	Electric utilities may adjust rates for changes in fuel and purchased power (energy component only) costs every three months, following hearings, through the fuel adjustment clause (FAC)
Sales and Weather Normalization:	SIGECO pursuing electric decoupling via sales reconciliation tracker in current rate case – decision expected 2011Q1 Decoupling (gas) in IN through weather normalization and conservation tariffs Straight fixed variable rate design (OH)
RRA Regulatory Climate:	Above Average 3 (IN) Average 1 (OH)
Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): A Diversification (10%): Baa Financial Strength (40%):Baa/A
S&P's Regulatory Comment	"a supportive regulatory environment"

Wisconsin Energy Corp.

Operating Characteristics:	
Operations:	*Utility Energy* – electric and gas utilities operating together under the trade name of We Energies and Edison Sault serving customers in Wisconsin and Michigan. In October 2009 they reached an agreement to sell Edison Sault *Non-Utility Energy* –We Power designs, constructs, owns, and leases generating capacity.
Total Assets:	$12,698 million
Percentage of Assets in Gas and Electric Operations:	Approximately 85% are in gas and electric operations.
State(s) of Utility Operations:	Wisconsin and the Upper Peninsula of Michigan
Number of Customers:	1.1 million electric customers in Wisconsin & Michigan's Upper Peninsula 1.0 million gas customers in Wisconsin 0.5 million steam customers in Milwaukee
Customers by Type:	**Customer Type** — **2009% of Revenues** Residential — 40% Small Commercial/Industrial — 35% Large Commercial/Industrial — 25% Other — <1%
Regulatory Environment:	
Test Year:	MI: Partial forecast WI: Forecast
Return on Equity (Latest Allowed):	**Electric:** 10.40% (2009 WI) 10.25% (2010 MI) **Gas:** 10.40% (2009 WI)
Equity Ratio (Latest Allowed):	**Electric:** 53.02% (2009 WI) 47.61% (2010 MI) **Gas:** 53.02% (2009 WI)
Earnings Sharing:	n/a
Deferral Mechanisms:	Bad debt expense, recovery of unrecovered transmission costs

(WEC cont'd)

Fuel/Gas Cost Recovery:	Gas: Full recovery. Prior to 2010 incentive mechanism permitting increased revenues if gas purchased at prices lower than approved benchmarks, currently one-for-one recovery measured against a monthly benchmark with 2% tolerance. Costs above the benchmark subject to further review. (now in line with other Wisconsin utilities) Fuel and Purchased Power: no adjustments made to rates as long as fuel and purchased power costs are within a band of costs included in rates for a 12 month period. If costs are expected to fall outside the band, may file for a change in fuel recoveries on a prospective basis.
Sales and Weather Normalization:	TBD
RRA Regulatory Climate:	Above Average 2 (WI) Average 1 (MI)
Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): A Ability to Recover Costs/Earn Return (25%): A Diversification (10%): Baa Financial Strength (40%): Baa
S&P's Regulatory Comment	"More credit supportive" Wisconsin regulatory environment"

Xcel Energy Inc.

Operating Characteristics:	
Operations:	Regulated Utilities: *Northern States Power Minnesota*: electric distribution in Minnesota, North Dakota, and South Dakota. Gas distribution in Minnesota and North Dakota *Northern States Power Wisconsin*: electric and gas distribution in Wisconsin and Michigan *Public Service Co. of Colorado*: electric and gas distribution in Colorado *Southwestern Public Service*: electric distribution in Texas and New Mexico WestGas InterState-a small interstate natural gas pipeline. WYCO Development-50% ownership, develops and leases natural gas pipeline, storage, and compression facilities. Unregulated subsidiaries-rental housing projects
Total Assets:	$25,488 million
Percentage of Assets in Gas and Electric Operations:	Essentially 100% regulated operations (<1% revenues unregulated)
State(s) of Utility Operations:	Colorado, Michigan (western Upper Peninsula), Minnesota, New Mexico, North Dakota, South Dakota, Texas, northwestern Wisconsin and Texas
Number of Customers:	3.4 million electric customers and 1.9 million gas customers.
Customers by Type:	**Electric** / **2009 % of Revenues** Residential: 31% Commercial and Industrial: 53% Public Authorities & Other: 2% Wholesale: 12% Other: 4% **Gas Customer Type** Residential: 62% Commercial and Industrial: 34% Transportation & Other: 4%

(XEL cont'd)

Regulatory Environment:	
Test Year:	CO, NM, SD, TX: Historic with adjustments for known and measurable changes MN, MI: Partial forecast ND: Partial or full forecast WI: Full forecast
Return on Equity (Latest Allowed):	**Electric:** 10.50% (2009 CO) 10.88% (2009 MN) 10.75% (2008 ND) 10.18% (2008 NM) 12.00% (1990 SD) No ROE decision in last two rate cases. 10.40% (2009 WI) **Gas:** 10.25% (2007 CO) 10.09% (2010 MN) 10.75% (2007 ND) 10.75% (2008 WI)
Equity Ratio (Latest Allowed):	**Electric:** 58.56% (2009 CO) 52.47% (2009 MN) 51.77% (2008 ND) 51.23% (2008 NM) 42.50% (1990 SD) No Equity Ratio decision in last two rate cases. 52.30% (2009 WI) **Gas:** 60.17% (2007 CO) 52.46% (2010 MN) 51.59% (2007 ND) 52.51% (2008 WI)
Earnings Sharing:	ND: earnings in excess of 10.75% ROE are shared with customers. If earnings are between 10.75%-11.25% ROE, they are shared equally. Earnings above 11.25% ROE are shared 75% to ratepayers and 25% to shareholders. CO: customers receive bill credits if company did not achieve certain performance targets relating to electric reliability, customer service, and natural gas leak repair time.

(XEL cont'd)

Deferral Mechanisms:	CO, MN: Enhanced cost recovery for emissions reduction provides a return on CWIP and an incentive based ROE (energy savings goals) CO: specific retail rate rider for certain costs associated with renewable energy resources; Transmission Cost Adjustment recovers costs associated with investments in transmission facilities TX: recovery of certain transmission investments and other transmission costs through TCRF rider
Fuel/Gas Cost Recovery:	Cost-of-Energy Adjustment mechanisms for purchases of coal, nuclear fuel and natural gas in all states except Wisconsin which does not permit recovery of purchased electric energy or electric fuel
Sales and Weather Normalization:	n/a
RRA Regulatory Climate:	Above Average 2 (WI) Average 1 (MI and ND) Average 2 (CO, MN, and SD) Below Average 1 (NM and TX)
Moody's Rating Methodology: Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): A Diversification (10%): A Financial Strength (40%):Baa
S&P's Regulatory Comment	"credit supportive regulation"

[i] Lost and Unaccounted for Trackers (LUAF) are in 47 of 50 states (excluding Michigan, Montana and South Dakota as of June 2010 (AGA, *Innovative Rates, Non-Volumetric Rates, and Tracking Mechanisms: Current List as of June 2010)*

[ii] RRA maintains three principal rating categories for regulatory climates: Above Average, Average, and Below Average. Within the principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger rating; 2, a mid-range rating; and, 3, a weaker rating. The evaluations are assigned from an investor perspective and indicate the relative regulatory risk associated with the ownership of securities issued by the jurisdiction's utilities. The evaluation reflects our assessment of the probable level and quality of the earnings to be realized by the state's utilities as a result of regulatory, legislative, and court actions.

[iii] Financial strength is comprised 10% liquidity and four metrics each weighted 7.5% for a total of 40%. The four metrics measured are: 1) (Cash from operations (CFO) pre-working capital (WC) plus interest) over interest expense; 2) CFO Pre-WC/Debt; 3) (CFO Pre-WC less dividends)/Debt; and 4) Debt/Book Capitalization.

APPENDIX C

DISCOUNTED CASH FLOW TEST

1. CONCEPTUAL UNDERPINNINGS

The discounted cash flow (DCF) approach proceeds from the proposition that the price of a common stock is the present value of the future expected cash flows to the investor, discounted at a rate that reflects the risk of those cash flows. If the price of the security is known (can be observed), and if the expected stream of cash flows can be estimated, it is possible to approximate the investor's required return, which is the rate that equates the price of the stock to the discounted value of future cash flows.

2. DCF MODELS

There are multiple versions of the discounted cash flow model available to estimate the investor's required return. An analyst can employ a constant growth model or a multiple period model to estimate the cost of equity. To estimate the DCF cost of equity, both constant growth and a three-stage growth models were utilized. These two models are discussed below.

a. Constant Growth 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[24]
$\mathbf{P_o}$	=	current price
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 earnings. Hence, focusing on investor expectations of earnings growth will encompass all of the sources of investor returns (e.g., dividends and retained earnings).

b. Three-Stage Model

The three-stage model is based on the premise that investors expect the growth rate for the utilities to be equal to the company-specific growth rates for the near-term (Stage 1), to migrate to the expected long-run rate of growth in the economy (GDP Growth) (Stage 2) and to equal expected long-term GDP growth in the long term (Stage 3).

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

Using the three-stage DCF model, the DCF cost of equity is estimated as the internal rate of return that causes the price of the stock to equal the present value of all future cash flows to the investor where the cash flows are defined as follows:

The cash flow per share in Year 1 is equal to:

Last Paid Annualized Dividend x (1 + Stage 1 Growth)

For Years 2 through 5, cash flow is defined as:

Cash Flow $_{t-1}$ x (1 + Stage 1 Growth)

For Years 6 through 10, cash flow is defined as:

Cash Flow $_{t-1}$ x (1 + Stage 2 Growth)

Cash flows from Year 11 onward are estimated as:

Cash Flow $_{t-1}$ x (1 + GDP Growth)

3. GROWTH COMPONENT OF THE DCF MODELS

The growth component of the DCF models is an estimate of what investors expect over the longer-term. For a regulated utility, whose growth prospects are tied to allowed returns, the estimate of growth expectations is subject to circularity because the analyst is, in some measure, attempting to project what returns the regulator will allow, and the extent to which the utilities will exceed or fall short of those returns. To mitigate that circularity, it is important to rely on a sample of proxies, rather than the subject company. (When the subject company does not have traded shares, a sample of proxies is required.) Further, to the extent feasible, one should rely on estimates of longer-term growth readily available to investors, rather than superimpose on the analysis one's own view of what growth should be.

a. Constant Growth Model Growth Rates

In the application of the constant growth model, two estimates of investors' expectations of long-term earnings growth were relied upon: a consensus of investment analysts' earnings forecasts and an estimate of the sustainable growth rate. The earnings growth rate forecasts were obtained from four different sources, I/B/E/S (First Call), Reuters, *Value Line*, and Zacks. I/B/E/S (First Call) is a leading provider of earnings expectations data. I/B/E/S compiles data from forecasts made by investment analysts for thousands of publicly traded companies.[25] The I/B/E/S consensus earnings growth rate forecasts for each company are intended to represent the expected annual increase in operating earnings over the next business cycle. Reuters[26] is a global provider of real time financial news and data. *Value Line* provides investment research and forecasts for approximately 1,700 large capitalization stocks as well as investment research on 1,800 mid and small capitalization stocks. Its publications are broadly accessible to both individual and institutional investors. Zacks provides consensus estimates and ratings for approximately 4,500 US and Canadian companies that have at least one sell-side analyst covering them. In general, all of these long-term earnings forecasts refer to a period of between three and five years and are intended to represent the normalized ("smoothed") rate of earnings growth over a business cycle. The consensus earnings forecasts are reflective of the analyst community's views and, therefore, are a reasonable proxy of (unobservable) investor growth expectations

As an alternative to the consensus of investment analysts' earnings forecasts, constant growth DCF costs of equity for the sample were estimated based on sustainable growth rates derived from *Value Line* forecasts of returns on equity, earnings retention rates and earnings growth from external financing.

[25] I/B/E/S collects data from over 4,000 analysts at over 800 institutions worldwide covering over 12,000 companies in more than 45 countries.
[26] Reuters provides real time forecasts for over 20,000 active companies from over 600 contributing brokerage firms in more than 70 countries.

Sustainable growth, or earnings retention growth, is premised on the notion that future dividend growth depends on both internal and external financing. Internal growth is achieved by the firm retaining a portion of its earnings in order to produce earnings and dividends in the future. External growth measures the long-run expected stock financing undertaken by the utility and the percentage of funds from that investment that are expected to accrue to existing investors. The internal growth rate is estimated as the fraction of earnings (B) expected to be retained multiplied by expected return on equity (R). The external financing portion of the sustainable growth rate is estimated as the forecast growth in the number of shares of common stock outstanding (S) multiplied by the equity accretion rate (V) which is the fraction of sales of new equity investment expected to accrue to existing stockholders. The V term is calculated as 1-Book Value/Market Price per share. The sustainable growth rate is then calculated as the sum of BR and SV. The external growth component recognizes that investors may expect future growth to be achieved not only through the retention of earnings but also through the issuance of additional equity capital which is invested in projects that are accretive to earnings.

b. Expected Long-Term Growth in the Economy (Stage 3 Growth)

The use of forecast GDP growth in a multi-stage model as the proxy for the rate of growth to which companies will migrate over the longer term is a widely utilized approach. For example, the Merrill Lynch discounted cash flow model for valuation utilizes nominal GDP growth as a proxy for long-term growth expectations. The Federal Energy Regulatory Commission relies on GDP growth to estimate expected long-term nominal GDP growth for conventional corporations in its standard DCF models for gas and oil pipelines.

The use of forecast long-term growth in the economy as the proxy for long-term growth in the DCF model recognizes that, while all industries go through various stages in their life cycle, mature industries are those whose growth parallels that of the overall economy. Utilities are considered to be the quintessential mature industry.

c. Reliability of Analysts' Earnings Forecasts

The reliability of the analysts' earnings growth forecasts as a measure of investor expectations has been questioned by some Canadian regulators. The issue of reliability arises because of the documented optimism of analysts' forecasts historically. However, as long as investors have believed the forecasts, and have priced the securities accordingly, the resulting DCF costs of equity are an unbiased estimate of investors' expected returns. That proposition can be tested indirectly. .

The potential bias of the analysts' growth rates for the U.S. utilities was assessed in three separate ways. First, because utilities are quintessentially mature companies, it is reasonable to expect that investors would anticipate that, over the long-term, growth would parallel the long-term nominal rate of growth in the economy. In this context, the I/B/E/S forecasts were compared to the consensus forecasts of long-term growth. For the sample of U.S. electric utilities, the average expected long-term growth rate, as estimated using the I/B/E/S consensus earnings growth forecasts, for the entire 1995-2010 period of analysis used in the DCF-based risk premium test was 5.3%. The average expected long-term nominal rate of growth in the U.S. economy, based on consensus forecasts (Blue Chip *Economic Indicators*, March and October editions, 1995-2010), was 5.1% from 1995-2010. The similar expected nominal growth in the economy compared to the I/B/E/S forecasts for the utility sample suggests that the I/B/E/S forecasts are not an upwardly biased measure of investor expectations.

Second, the I/B/E/S forecasts were compared to the long-term earnings forecasts for the same companies made by *Value Line*. As an independent research firm, *Value Line* as no incentive to "inflate" its estimates of earnings growth in an attempt to make stocks more attractive to investors, which is the criticism frequently aimed at equity analysts. Over the entire period of analysis of the DCF-based risk premium test (1995-2010), the average *Value Line* long-term earnings growth rate forecast for the sample of companies was 5.5%, compared to the average I/B/E/S long-term earnings growth rate forecast for the same companies of 5.3%. Again, the higher *Value Line* than I/B/E/S forecasts suggest that the I/B/E/S forecasts are not upwardly biased.

Third, allowed returns for U.S. utilities are derived in large part by reference to the results of the DCF model. Regulators in all jurisdictions, however, do not use the same form of the DCF model. For example, some regulators may rely on the constant growth model, while others prefer to use a multi-stage growth model. In addition, even if different jurisdictions use the same form (e.g., constant growth) of the model, the inputs to the model are not necessarily derived in equivalent ways. For example, two jurisdictions may use the constant growth model but one may favour the use of forecast growth, while another may favour the use of historic growth rates. In the aggregate, however, across all jurisdictions, the differences in approach likely balance out, resulting in the allowed returns reflecting neither an upwardly or downwardly biased measure of the utility cost of equity as a result of the underlying growth assumptions. When the allowed returns for all U.S. utilities published by Regulatory Research Associates (RRA) are compared to the estimated constant growth DCF costs of equity for the benchmark sample of U.S. utilities estimated using the I/B/E/S analysts' growth forecasts over the same period (1995-2010), the comparison shows that the allowed returns for all U.S. utilities as reported by RRA exceeded the returns estimated using the various DCF models as follows:

Table C-1

Average Allowed ROEs (1995-2010)	**10.9%**	**Average Difference From Allowed ROEs**
Constant Growth DCF Cost of Equity (1995-2010)	10.3%	-0.6%

Sources: Schedule 13, page 1 of 4 and Schedule 14, page 1 of 2.

The comparison of the DCF costs of equity to the ROEs allowed by regulators provides a further indication that the earnings forecasts are not an upwardly biased measure of investor expectations.

4. APPLICATION OF THE DCF MODELS

a. Constant Growth Model

The constant growth DCF model was applied to the sample of U.S. electric utilities using the following inputs to calculate the dividend yield:

(1) the most recent annualized dividend paid as of December 2010 as D_o; and,

(2) the average of the daily close prices for the period October 1, 2010 to December 31, 2010 as P_o.

The constant growth model was applied using two estimates of long-term growth, the average of four investment analysts' long-term earnings growth forecasts compiled by I/B/E/S (First Call), Reuters, *Value Line*, and Zacks, and estimates of sustainable growth. For the model based on investment analysts' earnings forecasts, the average of the four earnings growth forecasts as of December 2010 were used to estimate "g" in the growth component for each utility and to adjust the current dividend yield to the expected dividend yield. The sustainable growth rate was derived from the fourth quarter 2010 *Value Line* forecasts as described on page C-5 above.

b. Three-Stage Model

The three-stage DCF model applied to the sample of U.S. electric utilities relied on the average of the four sources of analysts' earnings forecasts for the first five years (Stage 1), the average of the Stage 1 forecast and the forecast long-term growth in the economy for the next five years (Stage 2) and the long-term growth in the economy thereafter (Stage 3). In the three-stage DCF test, the long-run expected nominal rate of growth in GDP of 4.9% was based on the consensus of economists' forecasts for the period 2013-2020 found in Blue Chip *Financial Forecasts*, December 1, 2010.[27]

A three-stage model was also used in the application of the DCF-based equity risk premium test. In the application of this test, estimates of the DCF cost of equity for the sample as a whole were made for each month from January 1995 to December 2010. For each month, the dividend yield to which the growth rates were applied was the sample average dividend yield in that month.

For each month in the analysis, the sample average I/B/E/S forecast growth rate in that month was applied for the first stage of the model (Years 1 to 5). For the third stage (Years 11 and beyond), the expected growth rate was represented by the most recent long-term nominal GDP growth rate forecast available in that month from Blue Chip *Financial Forecasts*. As noted above, Blue Chip *Financial Forecasts* publishes long-term GDP growth forecasts in June and December of each year.[28] Therefore, as examples, the Stage 3 expected growth rate for the months June through November 2009 was represented by the nominal GDP growth forecast published in June 2009. The Stage 3 expected growth rate for the months December 2009 through May 2010 was represented by the December 2009 long-term nominal GDP forecast. Similar to the three-stage DCF test, Stage 2 growth (Years 6 to 10) is equal to the average of Stage 1 and Stage 3 growth rates.

[27] Published twice annually in June and December.
[28] Prior to December 1996, the long-term GDP forecasts were published in the March and October editions of Blue Chip *Financial Forecasts*.

APPENDIX D
FINANCING FLEXIBILITY ADJUSTMENT

An adjustment to the equity risk premium and discounted cash flow test results for financing flexibility is required because the measurement of the return requirement based on market data results in a "bare-bones" cost. It is “bare-bones” in the sense that, theoretically, if this return is applied to (and earned on) the book equity of the rate base (assuming the expected return corresponds to the approved return), the market value of the utility would be kept close to book value.

The financing flexibility allowance is an integral part of the cost of capital as well as a required element of the concept of a fair return. The allowance is intended to cover three distinct aspects: (1) flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) a recognition of the "fairness" principle. Fairness dictates that regulation should not seek to keep the market value of a utility stock close to book value when unregulated companies of comparable investment risk have been able to consistently maintain the real value of their assets considerably above book value.

The financing flexibility allowance recognizes that return regulation remains, fundamentally, a surrogate for competition. Competitive unregulated companies of reasonably similar risk to utilities have consistently been able to maintain the real value of their assets significantly in excess of book value, consistent with the proposition that, under competition, market value will tend to equal the replacement cost, not the book value, of assets.

Utility return regulation should not seek to target the market/book ratios achieved by such unregulated companies, but, at the same time, it should not preclude utilities from achieving a level of financial integrity that gives some recognition to the longer run tendency for the market value of unregulated companies to equate to the replacement cost of their productive capacity.

This is warranted not only on grounds of fairness, but also on economic grounds, to avoid misallocation of capital resources. To ignore these principles in determining an appropriate financing flexibility allowance is to ignore the basic premise of regulation. The adjustment for financing flexibility recognizes that the market return derived from the equity risk premium test needs to be translated into a return that is fair and reasonable when applied to book value. The concept of a financing flexibility or flotation cost allowance has been accepted by most Canadian regulators.

This premise was recognized by the Independent Assessment Team (IAT), retained by the Alberta Department of Resource Development to determine the cost parameters for the Power Purchase Arrangement (PPAs) for existing regulated generating plants, concluded in its 1999 report, regarding flotation costs,

> This is sometimes associated with flotation costs but is more properly regarded as providing a financial cushion which is particularly applicable given the use of historic cost book values in traditional rate of return regulation in Canada. No such adjustment has ever been made in UK utility regulation cases which tend to use market values or current cost values.[29]

The Report of the IAT was accepted by the Alberta Energy and Utilities Board in Decision U99113 (December 1999).

[29]*Independent Assessment Team Power Purchase Arrangement Report*, July 1999, page XLV, footnote 99.

At a minimum, the financing flexibility allowance should be adequate to allow a utility to maintain its market value, notionally, at a slight premium to book value, i.e., in the range of 1.05-1.10. At this level, a utility will be able to recover actual financing costs, as well as be in a position to raise new equity (under most market conditions) without impairing its financial integrity. A financing flexibility allowance adequate to maintain a market/book in the range of 1.05-1.10 is approximately 50 basis points.[30]

Further, the financing flexibility allowance should also recognize that both the equity risk premium and DCF cost of equity estimates are derived from market values of equity capital. The cost of capital reflects the market value of the firms' capital, both debt and equity. The market value capital structures may be quite different from the book value capital structures. When the market value common equity ratio is higher (lower) than the book value common equity ratio, the market is attributing less (more) financial risk to the firm than is "on the books" as measured by the book value capital structure. Higher financial risk leads to a higher cost of common equity, all other things equal.

To put this concept in common sense terms, assume that I purchased my home 10 years ago for $100,000 and took out a mortgage for the full amount. My home is currently worth $250,000 and my mortgage is now $85,000. If I were applying for a loan, the bank would consider my net worth (equity) to be $165,000 (market value of $250,000 less the $85,000 unpaid mortgage), not

[30] The minimum financing flexibility allowance can be estimated using the following formula developed from the discounted cash flow formula:

$$\text{Return on Book Equity} = \frac{\text{Market/Book Ratio x “bare-bones” Cost of Equity}}{1 + [\text{retention rate (M/B} - 1.0)]}$$

For a market/book ratio of 1.075 (mid-point of 1.05 and 1.10), assuming a retention rate of 25% and a "bare-bones" cost of equity of 9.75%, the indicated ROE is:

$$\text{ROE} = \frac{1.075 \text{ x } 9.75\%}{1+[.25(1.075-1.0)]}$$

$$\text{ROE} = 10.3\%$$

The difference of approximately 50 basis points between the ROE and the "bare-bones" cost of equity is the financing flexibility allowance.

the "book value" of the equity in my home of $15,000, which reflects the original purchase price less the unpaid mortgage loan amount. It is the market value of my home that determines my financial risk to the bank, not the original purchase price. The same principle applies when the cost of common equity is estimated. The book value of the common equity shares is not the relevant measure of financial risk to equity investors; it is their market value, that is, the value at which the shares could be sold.

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 corporate 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.[31]

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, in a competitive environment, 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 and the greater the risk that equity shareholders will not recover their invested capital and a compensatory return thereon. 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

[31] 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).

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.[32]

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, taxable 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.[33]

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.

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[32] Franco Modigliani and Merton H. Miller, "Corporate Income Taxes and the Cost of Capital: A Correction," *American Economic Review*, 53: 433-443 (June 1963).

[33] 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). At the 2012 marginal corporate and personal income tax rates (on interest, dividends and capital gains) in Canada, the gain from corporate leverage is relatively small.

The cost of equity has been estimated using samples of comparable proxy companies with a lower level of financial risk, as reflected in their market value capital structures, than the financial risk reflected in the book value capital structure. Regulatory convention applies the allowed ROE to a book value capital structure. When the market value equity ratios of the proxy utilities are well in excess of their book value common equity ratios, the failure to recognize the higher level of financial risk in the book value capital structure relative to the financial risk of the proxy samples of utilities, as recognized by equity investors, results in an underestimation of the cost of equity.

Three approaches can be used to quantify the range of the impact of a change in financial risk on the cost of equity when interest expense is deductible for income tax purposes.

Approach 1 is based on the theory that the overall after-tax cost of capital and the pre-tax cost of capital do not change materially over a relatively broad range of capital structures. This approach effectively assumes that the benefit of the deductibility of interest expense for corporate income tax purposes (which would tend to lower the overall cost of capital) is offset by personal income taxes on interest.

Approach 2 is based on the theoretical model which assumes that the overall cost of capital declines as the debt ratio rises due to the income tax shield on interest expense. The second approach does not account for any of the factors that offset the corporate income tax advantage of debt, including the costs of bankruptcy/loss of financing flexibility, the impact of personal income taxes on the attractiveness of issuing debt, or the flow-through of the benefits of interest expense deductibility to ratepayers. Thus, the results of applying the second approach will over-estimate the impact of leverage on the overall cost of capital and understate the impact of increasing financial leverage on the cost of equity.

Approach 3 assumes for utility cost of capital purposes that the corporate income tax rate is zero. The underlying premise is that the benefits of the corporate tax deductibility of interest accrue to rate payers, not shareholders, as is the case with unregulated companies. As with the first approach, the overall cost of capital remains unchanged as the capital structure changes. However, since the cost of capital contains no income tax component, the impact on the cost of equity due to changing leverage is less than in the presence of corporate income tax and interest deductibility.

Table D-1 below shows the adjustments to the cost of equity that are required to recognize the difference in financial risk between the market value capital structures of the Canadian and U.S. utility samples and the book value capital structures under the three approaches. Schedule 22 provides the formulas for estimating the change in the cost of equity due to capital structure differences under each of the three approaches. Approach 3 and Approach 1 are identical when the corporate income tax rate is zero.

Table D-1

		Market Value	Book Value	Adjustment to ROE for Book Value Capital Structure		
	Cost of Equity	**Equity Ratio**	**Equity Ratio**	**Approach 1 (28% tax rate)**	**Approach 2 (28% tax rate)**	**Approach 3 (0% tax rate)**
Canadian Utilities	9.3%	55%	40%	2.1%	1.3%	1.6%
U.S. Utilities	9.6%	56%	45%	1.4%	0.9%	1.1%

Source: Schedules 4, 5, 21 and 22.

Notes: Based on incremental utility cost of long-term debt at the time the DCF costs were estimated of 5.0% for the A-rated Canadian utility sample and 5.15% for the BBB rated U.S. utilities sample. Corporate income tax rate of 28% is estimated combined federal/provincial rate for Canada.

Full recognition of the difference in financial risk between the market value equity ratios of the two utility samples results in an increase in the range of approximately 0.9% to 2.1% (mid-point of approximately 140 basis points based on all estimates in Table D-1).

APPENDIX E

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

Alberta Natural Gas
1994

Alberta Utilities Generic Cost of Capital
2011

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, 1992, 1993, 1994, 1995,
1996, 1997, 2001, 2002

Enbridge Gas New Brunswick
2000, 2010

Enbridge Pipelines (Line 9)
2007, 2009

Enbridge Pipelines (Southern Lights)
2007

FortisBC
1995, 1999, 2001, 2004

Gas Company of Hawaii
2000, 2008

Gaz Métro
1988

Gazifère
1993, 1994, 1995, 1996, 1997, 1998, 2010

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

Maritime Electric
2010

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, 2010

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, 2010

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
Maritimes & Northeast Pipeline	Return on Escrow Account	2010
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 Métro/ Province of Québec	Cost Allocation/ Incremental vs. Rolled-In Tolling	1984

TREND IN INTEREST RATES AND OUTSTANDING BOND YIELDS
(Percent Per Annum)

	Government Securities													
	T-Bills		10 Year		Long-Term		Canada Bonds Over 10	Canadian Inflation	Canadian A-Rated	Canadian A-Rated Spread	Moody's U.S. Utility Long-Term	Moody's U.S. Utility Long-Term	Exchange Rates (Canadian dollars
Year	Canadian	U.S. 1/	Canadian	U.S.	Canadian	U.S. 2/	Years 3/	Indexed Bonds	Utility Bonds 4/	Over Long Canadas	A-Rated Bonds	Baa-Rated Bonds	in U.S. funds)
Annual													
1990	12.81	7.49	10.76	8.55	10.69	8.61	10.85		12.13	1.44	9.86	10.06	0.86
1991	8.73	5.38	9.42	7.86	9.72	8.14	9.76		11.00	1.28	9.36	9.55	0.84
1992	6.59	3.43	8.05	7.01	8.68	7.67	8.77	4.62	10.01	1.33	8.69	8.86	0.82
1993	4.84	3.02	7.22	5.87	7.86	6.59	7.85	4.28	9.08	1.22	7.59	7.91	0.77
1994	5.54	4.34	8.43	7.08	8.69	7.39	8.63	4.41	9.81	1.12	8.30	8.63	0.73
1995	6.89	5.44	8.08	6.58	8.41	6.85	8.28	4.68	9.29	0.88	7.89	8.29	0.73
1996	4.21	5.04	7.20	6.44	7.75	6.73	7.50	4.61	8.38	0.63	7.75	8.16	0.73
1997	3.26	5.11	6.11	6.32	6.66	6.58	6.42	4.14	7.19	0.53	7.60	7.96	0.72
1998	4.73	4.79	5.30	5.26	5.59	5.54	5.47	4.02	6.38	0.79	7.04	7.27	0.68
1999	4.69	4.71	5.55	5.68	5.72	5.91	5.69	4.07	6.92	1.20	7.62	7.88	0.67
2000	5.45	5.85	5.89	5.98	5.71	5.88	5.89	3.69	7.05	1.34	8.24	8.36	0.67
2001	3.78	3.34	5.49	4.99	5.77	5.50	5.76	3.59	7.10	1.33	7.74	8.00	0.65
2002	2.55	1.63	5.27	4.56	5.67	5.41	5.65	3.49	7.08	1.41	7.34	7.99	0.64
2003	2.86	1.03	4.78	4.02	5.31	5.03	5.26	3.04	6.65	1.33	6.54	6.80	0.72
2004	2.21	1.44	4.55	4.27	5.11	5.08	5.05	2.34	6.14	1.03	6.14	6.39	0.77
2005	2.73	3.29	4.04	4.27	4.38	4.52	4.36	1.81	5.43	1.05	5.62	5.90	0.83
2006	4.05	4.86	4.21	4.79	4.26	4.87	4.28	1.67	5.36	1.09	6.06	6.31	0.89
2007	4.13	4.42	4.25	4.58	4.30	4.80	4.31	1.95	5.52	1.22	6.06	6.33	0.94
2008	2.26	1.28	3.56	3.61	4.04	4.22	4.03	1.90	6.29	2.26	6.54	7.31	0.94
2009	0.31	0.15	3.27	3.29	3.85	4.10	3.85	1.86	6.10	2.24	5.99	6.95	0.88
2010	0.59	0.14	3.17	3.14	3.70	4.17	3.63	1.36	5.20	1.51	5.38	5.89	0.97

1/ Rates on new issues.

2/ 30-year maturities through January 2002. Theoretical 30-year yield, February 2002 to January 2006, when no 30-year Treasury bonds were issued. The theoretical 30-year Treasury bond yield represents the yield on all outstanding Treasury bonds with a term to maturity greater than 25 years plus an extrapolation factor published by the U.S. Department of the Treasury to allow the estimation of a 30-year rate; 30-year maturities February 2006 forward.

3/ Terms to maturity of l0 years or more.

4/ Series is comprised of the CBRS Utilities Index through 1995; CBRS 30-year Utilities Index from 1996- August 2000; a series of liquid long-term utility bonds maintained by Foster Associates from September 2000 forward.

Source: www.bankofcanada.ca; www.federalreserve.gov, www.globeandmail.com; www.moodys.com
www.ustreas.gov

TREND IN INTEREST RATES AND OUTSTANDING BOND YIELDS
(Percent Per Annum)

Year		Government Securities: T-BILLS Canadian	T-BILLS U.S. [1/]	10 Year Canadian	10 Year U.S.	Long-Term Canadian	Long-Term U.S. [2/]	Canada Bonds Over 10 Years [3/]	Canadian Inflation Indexed Bonds	Canadian A-Rated Utility Bonds [4/]	Canadian A-Rated Spread Over Long Canadas	Moody's U.S. Utility Long-Term A-Rated Bonds	Moody's U.S. Utility Long-Term Baa-Rated Bonds	Exchange Rates (Canadian dollars in U.S. funds)
2004	q1	2.12	0.94	4.41	4.00	5.09	4.96	4.99	2.50	6.02	0.93	6.06	6.26	0.76
	q2	1.98	1.13	4.74	4.60	5.29	5.35	5.22	2.38	6.34	1.04	6.45	6.69	0.74
	q3	2.23	1.58	4.66	4.26	5.14	5.08	5.13	2.29	6.23	1.10	6.11	6.42	0.77
	q4	2.53	2.11	4.40	4.22	4.92	4.93	4.87	2.18	5.98	1.06	5.95	6.18	0.83
2005	q1	2.47	2.67	4.27	4.33	4.72	4.70	4.69	2.05	5.78	1.06	5.72	5.92	0.82
	q2	2.46	3.01	3.93	4.05	4.39	4.36	4.35	1.86	5.47	1.09	5.43	5.75	0.81
	q3	2.73	3.50	3.88	4.21	4.20	4.39	4.19	1.75	5.20	0.99	5.49	5.79	0.84
	q4	3.25	4.00	4.07	4.49	4.19	4.63	4.21	1.59	5.25	1.06	5.82	6.14	0.85
2006	q1	3.70	4.57	4.18	4.65	4.23	4.70	4.25	1.53	5.32	1.09	5.92	6.20	0.87
	q2	4.17	4.84	4.51	5.11	4.54	5.19	4.57	1.81	5.65	1.10	6.41	6.63	0.90
	q3	4.14	5.00	4.14	4.79	4.21	4.91	4.23	1.67	5.34	1.12	6.09	6.34	0.89
	q4	4.16	5.04	4.00	4.59	4.07	4.70	4.08	1.68	5.13	1.06	5.82	6.07	0.87
2007	q1	4.17	5.11	4.10	4.68	4.17	4.82	4.18	1.77	5.23	1.06	5.92	6.16	0.86
	q2	4.29	4.82	4.39	4.85	4.35	4.98	4.38	1.94	5.49	1.14	6.08	6.32	0.92
	q3	4.17	4.26	4.43	4.64	4.45	4.86	4.46	2.09	5.75	1.30	6.19	6.45	0.97
	q4	3.90	3.48	4.09	4.16	4.21	4.53	4.21	2.01	5.61	1.39	6.05	6.38	1.02
2008	q1	2.76	1.73	3.65	3.55	4.07	4.35	4.03	1.80	5.65	1.58	6.16	6.59	0.99
	q2	2.60	1.74	3.68	3.94	4.10	4.58	4.07	1.60	5.84	1.74	6.30	6.85	0.99
	q3	2.23	1.44	3.66	3.89	4.11	4.44	4.13	1.78	6.21	2.10	6.58	7.22	0.95
	q4	1.45	0.19	3.26	3.06	3.88	3.50	3.91	2.42	7.47	3.60	7.13	8.59	0.82
2009	q1	0.61	0.24	2.99	2.87	3.68	3.62	3.65	2.13	7.06	3.38	6.44	7.95	0.80
	q2	0.21	0.16	3.28	3.39	3.90	4.24	3.86	1.97	6.27	2.37	6.35	7.48	0.87
	q3	0.22	0.16	3.38	3.41	3.89	4.17	3.94	1.76	5.49	1.60	5.54	6.21	0.92
	q4	0.21	0.06	3.42	3.49	3.95	4.35	3.96	1.57	5.56	1.62	5.65	6.16	0.94
2010	q1	0.20	0.12	3.43	3.69	4.01	4.59	3.94	1.54	5.45	1.44	5.80	6.17	0.96
	q2	0.46	0.17	3.36	3.32	3.80	4.22	3.73	1.45	5.37	1.57	5.46	6.05	0.96
	q3	0.74	0.15	2.88	2.65	3.49	3.73	3.42	1.35	5.00	1.51	4.96	5.54	0.96
	q4	0.97	0.14	2.99	2.91	3.48	4.15	3.42	1.11	4.98	1.50	5.31	5.79	0.99
2007	Jan	4.17	5.12	4.17	4.83	4.22	4.93	4.23	1.79	5.27	1.05	6.01	6.22	0.85
	Feb	4.19	5.16	4.03	4.56	4.09	4.68	4.10	1.75	5.15	1.06	5.78	6.01	0.85
	Mar	4.16	5.04	4.11	4.65	4.20	4.84	4.21	1.77	5.28	1.08	5.97	6.25	0.87
	Apr	4.16	4.91	4.14	4.63	4.19	4.81	4.20	1.76	5.32	1.13	5.90	6.16	0.90
	May	4.29	4.73	4.49	4.90	4.38	5.01	4.42	1.99	5.50	1.12	6.10	6.35	0.93
	Jun	4.43	4.82	4.55	5.03	4.49	5.12	4.51	2.08	5.66	1.17	6.24	6.46	0.94
	Jul	4.56	4.96	4.52	4.78	4.45	4.92	4.48	2.07	5.72	1.27	6.18	6.46	0.94
	Aug	3.99	4.01	4.42	4.54	4.46	4.83	4.47	2.14	5.74	1.28	6.17	6.45	0.95
	Sep	3.96	3.82	4.34	4.59	4.44	4.83	4.44	2.07	5.79	1.35	6.22	6.45	1.01
	Oct	3.96	3.94	4.31	4.48	4.38	4.74	4.39	2.05	5.67	1.29	6.07	6.36	1.06
	Nov	3.91	3.15	3.98	3.97	4.16	4.40	4.15	2.07	5.67	1.51	6.00	6.34	1.00
	Dec	3.82	3.36	3.99	4.04	4.10	4.45	4.10	1.91	5.47	1.37	6.07	6.43	1.01
2008	Jan	3.38	1.96	3.88	3.67	4.18	4.35	4.16	1.96	5.67	1.49	6.07	6.40	1.00
	Feb	3.04	1.85	3.64	3.53	4.09	4.41	4.04	1.85	5.66	1.57	6.22	6.63	1.02
	Mar	1.87	1.38	3.43	3.45	3.94	4.30	3.88	1.60	5.63	1.69	6.20	6.74	0.97
	Apr	2.68	1.43	3.58	3.77	4.08	4.49	4.02	1.72	5.78	1.70	6.22	6.74	0.99
	May	2.64	1.89	3.71	4.06	4.13	4.72	4.09	1.61	5.83	1.70	6.36	6.93	0.99
	Jun	2.48	1.90	3.74	3.99	4.08	4.53	4.10	1.47	5.89	1.81	6.32	6.87	0.98
	Jul	2.39	1.68	3.70	3.99	4.10	4.59	4.11	1.54	5.92	1.82	6.44	7.03	0.98
	Aug	2.40	1.72	3.53	3.83	4.01	4.43	4.02	1.57	6.09	2.08	6.32	6.94	0.94
	Sep	1.89	0.92	3.75	3.85	4.23	4.31	4.25	2.23	6.64	2.41	6.98	7.69	0.94
	Oct	1.85	0.46	3.76	4.01	4.28	4.35	4.33	2.51	7.61	3.33	8.01	9.28	0.82
	Nov	1.67	0.01	3.32	2.93	3.90	3.45	3.96	2.65	7.48	3.58	7.18	8.72	0.81
	Dec	0.83	0.11	2.69	2.25	3.45	2.69	3.45	2.10	7.33	3.88	6.20	7.76	0.82
2009	Jan	0.86	0.24	3.06	2.87	3.77	3.58	3.80	2.27	7.33	3.56	6.52	7.97	0.81
	Feb	0.59	0.26	3.12	3.02	3.70	3.71	3.70	2.32	7.07	3.37	6.38	7.85	0.79
	Mar	0.39	0.21	2.79	2.71	3.57	3.56	3.46	1.81	6.78	3.21	6.41	8.04	0.79
	Apr	0.20	0.14	3.09	3.16	3.84	4.05	3.74	2.05	6.71	2.87	6.55	7.91	0.84
	May	0.20	0.14	3.39	3.47	3.99	4.34	3.93	2.00	6.14	2.15	6.53	7.56	0.91
	Jun	0.24	0.19	3.36	3.53	3.86	4.32	3.91	1.86	5.94	2.08	5.96	6.96	0.86
	Jul	0.24	0.18	3.46	3.52	3.95	4.31	4.01	1.73	5.54	1.59	5.68	6.45	0.93
	Aug	0.20	0.15	3.37	3.40	3.89	4.18	3.94	1.81	5.45	1.56	5.54	6.17	0.91
	Sep	0.22	0.14	3.31	3.31	3.84	4.03	3.87	1.74	5.49	1.65	5.41	6.00	0.93
	Oct	0.22	0.05	3.42	3.41	3.92	4.23	3.95	1.60	5.49	1.57	5.55	6.12	0.93
	Nov	0.21	0.06	3.22	3.21	3.84	4.20	3.83	1.58	5.50	1.66	5.54	6.04	0.95
	Dec	0.19	0.06	3.61	3.85	4.08	4.63	4.09	1.53	5.69	1.61	5.86	6.31	0.96
2010	Jan	0.16	0.08	3.34	3.63	3.94	4.51	3.90	1.49	5.42	1.48	5.73	6.09	0.94
	Feb	0.16	0.13	3.39	3.61	4.02	4.55	3.94	1.58	5.49	1.47	5.77	6.17	0.95
	Mar	0.28	0.16	3.56	3.84	4.07	4.72	3.99	1.56	5.44	1.37	5.89	6.25	0.98
	Apr	0.39	0.16	3.65	3.69	4.01	4.53	3.94	1.49	5.40	1.39	5.60	5.98	0.99
	May	0.50	0.16	3.36	3.31	3.73	4.22	3.65	1.45	5.46	1.73	5.57	6.16	0.96
	Jun	0.50	0.18	3.08	2.97	3.65	3.91	3.59	1.42	5.24	1.59	5.21	6.00	0.94
	Jul	0.66	0.15	3.11	2.94	3.69	3.98	3.62	1.51	5.17	1.48	5.17	5.80	0.97
	Aug	0.70	0.14	2.78	2.47	3.44	3.52	3.36	1.34	5.01	1.57	4.78	5.36	0.94
	Sep	0.87	0.16	2.75	2.53	3.35	3.69	3.27	1.20	4.82	1.47	4.93	5.45	0.97
	Oct	0.92	0.12	2.80	2.63	3.44	3.99	3.32	1.09	4.89	1.45	5.21	5.70	0.98
	Nov	1.01	0.17	3.07	2.81	3.48	4.12	3.45	1.12	5.04	1.56	5.28	5.75	0.97
	Dec	0.97	0.12	3.11	3.30	3.52	4.34	3.48	1.11	5.00	1.48	5.45	5.93	1.01
2011	Jan	0.96	0.15	3.27	3.42	3.73	4.58	3.68	1.38	5.18	1.45	5.61	6.05	1.00
	Feb	0.96	0.15	3.30	3.42	3.70	4.49	3.65	1.22	5.14	1.44	5.51	5.92	1.03

[1/] Rates on new issues.
[2/] Theoretical 30-year yield, 2004 to January 2006. 30-year maturities February 2006 forward.
[3/] Terms to maturity of l0 years or more.
[4/] Series of liquid long-term utility bonds maintained by Foster Associates.
Note: Monthly data reflect rate in effect at end of month.

Source: www.bankofcanada.ca; www.federalreserve.gov, www.globeandmail.com; www.moodys.com
RBC Capital Markets, www.ustreas.gov

EQUITY RETURN AWARDS AND CAPITAL STRUCTURES ADOPTED BY

REGULATORY BOARDS FOR CANADIAN UTILITIES

(Percentages)

	Decision Date	Regulator	Order/ File Number	Debt	Preferred Stock	Common Stock Equity	Equity Return	Forecast 30-Year Bond Yield	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
Electric Utilities									
AltaLink	11/09	AUC	2009-216	64.00	0.00	36.00	9.00	n/a	
ATCO Electric									
Transmission	11/09	AUC	2009-216	58.00	6.00	36.00	9.00	n/a	
Distribution	11/09	AUC	2009-216	54.10	6.90	39.00	9.00	n/a	
ENMAX									
Transmission	11/09	AUC	2009-216	63.00	0.00	37.00	9.00	n/a	
Distribution	11/09	AUC	2009-216	59.00	0.00	41.00	9.00	n/a	
EPCOR									
Transmission	11/09	AUC	2009-216	63.00	0.00	37.00	9.00	n/a	
Distribution	11/09	AUC	2009-216	59.00	0.00	41.00	9.00	n/a	
FortisAlberta Inc.	11/09	AUC	2009-216	59.00	0.00	41.00	9.00	n/a	
FortisBC Inc.	5/05; 12/09	BCUC	G-52-05; G-158-09	60.00	0.00	40.00	9.90	n/a	
Hydro One Transmission	8/07; 12/10	OEB	EB-2006-0501; EB-2010-0002	60.00	0.00	40.00	9.66	3.94	
Maritime Electric	7/10	IRAC	UE-10-03	59.50	0.00	40.50	9.75	n/a	
Newfoundland Power	12/09; 12/10	NLPub	P.U. 46 (2009); P.U. 32 (2010)	54.27	1.04	44.69	8.38	3.72	
Nova Scotia Power	3/06;11/08	NSUARB	2006 NSUARB 23; 2008 NSUARB 140	53.30	9.20	37.50	9.35	n/a	
Ontario Electricity Distributors	12/09; 11/10	OEB	EB-2009-0084; Letter Cost of Capital Parameters	60.00	0.00	40.00	9.66	3.94	
Ontario Power Generation	3/11	OEB	EB-2010-0008	53.00	0.00	47.00	9.43 (2011) 9.55 (2012)	3.61 (2011) 3.85 (2012)	[1]
Gas Distributors									
AltaGas Utilities	11/09	AUC	2009-216	57.00	0.00	43.00	9.00	n/a	
ATCO Gas	11/09	AUC	2009-216	54.10	6.90	39.00	9.00	n/a	
Enbridge Gas Distribution Inc	1/04; 7/07; 2/08	OEB	RP-2002-0158; EB-2006-0034; EB-2007-0615	61.33	2.67	36.00	8.39	4.23	
Gaz Métro	12/09, 11/10	Régie	D-2009-156 (formula), 2010-149 (ROE)	54.00	7.50	38.50	9.09	4.15	
Pacific Northern Gas-West	5/10	BCUC	G-84-10	51.15	3.85	45.00	10.15	n/a	
Terasen Gas	12/09	BCUC	G-158-09	60.00	0.00	40.00	9.50	n/a	
Terasen Gas (Vancouver Island)	12/09	BCUC	G-14-06; G-158-09	60.00	0.00	40.00	10.00	n/a	
Union Gas	1/04; 5/06; 1/08	OEB	RP-2002-0158; EB-2006-0520; EB-2007-0606	60.60	3.40	36.00	8.54	4.23	
Gas Pipelines									
ATCO Pipelines	11/09; 5/10	AUC	2009-216; 2010-228	49.30	5.70	45.00	9.00	n/a	
Foothills Pipe Lines Ltd.	6/10	NEB	TG-03-2010	60.00	0.00	40.00	9.70	n/a	
Nova Gas Transmission Ltd.	9/10	NEB	TG-05-2010	60.00	0.00	40.00	9.70	n/a	
TransCanada PipeLines	5/07; 12/09	NEB	RH-2-94;TG-06-2007; NEB Letter 12-09	60.00	0.00	40.00	8.08	3.72	
Trans Québec & Maritimes Pipeline	3/09; 11/10	NEB	RH-1-2008; TG-07-2010	60.00	0.00	40.00	9.70	n/a	[2]
Westcoast Energy	1/11	NEB	TG-01-2011	60.00	0.00	40.00	9.70	n/a	

[1] The forecast long Canada yield of 3.85% (2012) was estimated.

[2] Settlement for 2010-2012 does not specify return on rate base; AFUDC rate, income taxes and capital variances based on a 9.7% ROE, 60%/40% debt/equity capital structure and TQM's embedded cost of debt.

Source: Regulatory Decisions.

**RATES OF RETURN ON COMMON EQUITY ADOPTED BY
REGULATORY BOARDS FOR CANADIAN UTILITIES**

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Electric Utilities																					
AltaLink	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.40	9.60	9.50	8.93	8.51	8.75	9.00	9.00
ATCO Electric	13.50	13.50	13.25	11.88	NA	NA	11.25	[1/]	[1/]	[1/]	[1/]	[1/]	[1/]	9.40	9.60	9.50	8.93	8.51	8.75	9.00	9.00
FortisAlberta Inc.	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.50	9.50	9.60	9.50	8.93	8.51	8.75	9.00	9.00
FortisBC Inc. [3/]	13.50	NA	11.75	11.50	11.00	12.25	11.25	10.50	10.25	9.50	10.00	9.75	9.53	9.82	9.55	9.43	9.20	8.77	9.02	8.87	9.90
Newfoundland Power	13.95	13.25	NA	NA	NA	NA	11.00	NA	9.25	9.25	9.59	9.59	9.05	9.75	9.75	9.24	9.24	8.60	8.95	8.95	9.00
Nova Scotia Power	NA	NA	NA	11.75	NA	NA	10.75	NA	NA	NA	NA	NA	10.15	NA	NA	9.55	9.55	9.55	NA	9.35	NA
Ontario Electricity Distributors	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.35	9.88	9.88	9.88	9.88	9.88	9.88	9.00	9.00	8.57	8.01	9.85
TransAlta Utilities	13.50	13.50	13.25	11.88	NA	12.25	11.25	[1/]	[2/]	9.25	9.25	NA	9.40	NA	NA	NA	NA	NA	NA	NA	NA
Mean of Electric Utilities	**13.61**	**13.42**	**12.75**	**11.75**	**11.00**	**12.25**	**11.10**	**10.50**	**9.75**	**9.34**	**9.68**	**9.74**	**9.59**	**9.63**	**9.66**	**9.51**	**9.11**	**8.78**	**8.80**	**8.88**	**9.29**
Gas Distributors																					
ATCO Gas	13.25	13.25	12.25	12.25	NA	NA	NA	10.50	9.38	NA	NA	9.75	9.75	9.50	9.50	9.50	8.93	8.51	8.75	9.00	9.00
Enbridge Gas Distribution	13.25	13.13	13.13	12.30	11.60	11.65	11.88	11.50	10.30	9.51	9.73	9.54	9.66	9.69	NA	9.57	8.74	8.39	8.39	8.39	8.39
Gaz Métro	14.25	14.25	14.00	12.50	12.00	12.00	12.00	11.50	10.75	9.64	9.72	9.60	9.67	9.89	9.45	9.69	8.95	8.73	9.05	8.76	9.20
Pacific Northern Gas [3/]	15.00	14.00	13.25	NA	11.50	12.75	11.75	11.00	10.75	10.00	10.25	10.00	9.88	10.17	9.80	9.68	9.45	9.02	9.27	9.12	10.15
Terasen Gas [3/]	NA	NA	12.25	NA	10.65	12.00	11.00	10.25	10.00	9.25	9.50	9.25	9.13	9.42	9.15	9.03	8.80	8.37	8.62	8.47	9.50
Union Gas	13.75	13.50	13.50	13.00	12.50	11.75	11.75	11.00	10.44	9.61	9.95	9.95	9.95	9.95	9.62	9.62	8.89	8.54	8.54	8.54	8.54
Mean of Gas Distributors	**13.90**	**13.63**	**13.06**	**12.51**	**11.65**	**12.03**	**11.68**	**10.96**	**10.27**	**9.60**	**9.83**	**9.68**	**9.67**	**9.77**	**9.50**	**9.52**	**8.96**	**8.59**	**8.77**	**8.71**	**9.13**
Gas Pipelines (NEB)																					
TransCanada PipeLines	13.25	13.50	13.25	12.25	11.25	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79	9.56	9.46	8.88	8.46	8.72	8.57	8.52
Westcoast Energy	13.25	13.75	12.50	12.25	11.50	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79	9.56	9.46	8.88	8.46	8.72	8.57	8.52
Mean of Gas Pipelines	**13.25**	**13.63**	**12.88**	**12.25**	**11.38**	**12.25**	**11.25**	**10.67**	**10.21**	**9.58**	**9.90**	**9.61**	**9.53**	**9.79**	**9.56**	**9.46**	**8.88**	**8.46**	**8.72**	**8.57**	**8.52**
Mean of All Companies	**13.68**	**13.56**	**12.94**	**12.16**	**11.50**	**12.13**	**11.36**	**10.84**	**10.15**	**9.50**	**9.79**	**9.68**	**9.62**	**9.71**	**9.59**	**9.51**	**9.02**	**8.66**	**8.78**	**8.77**	**9.11**

[1/] Negotiated settlement, details not available.
[2/] Negotiated settlement, implicit ROE made public is 10.5%.
[3/] Allowed ROE for 2009 for first six months

Source: Regulatory Decisions

**COMPARISON BETWEEN ALLOWED RETURNS
FOR CANADIAN AND U.S. UTILITIES**

	Canadian Utilities			U.S. Utilities			U.S. Gas Utilities			U.S. Electric Utilities		
Year	Allowed ROE	Average Long Canada Yield	Equity Risk Premium	Allowed ROE	Average Long Treasury Yield	Equity Risk Premium	Allowed ROE	Average Long Treasury Yield	Equity Risk Premium	Allowed ROE	Average Long Treasury Yield	Equity Risk Premium
1990	13.68	10.69	2.99	12.69	8.62	4.07	12.67	8.62	4.05	12.70	8.62	4.08
1991	13.56	9.72	3.85	12.51	8.09	4.43	12.46	8.09	4.38	12.55	8.09	4.47
1992	12.94	8.68	4.26	12.06	7.68	4.39	12.01	7.68	4.34	12.09	7.68	4.42
1993	12.16	7.86	4.30	11.37	6.58	4.79	11.35	6.58	4.77	11.41	6.58	4.83
1994	11.50	8.69	2.81	11.34	7.41	3.93	11.35	7.41	3.94	11.34	7.41	3.93
1995	12.13	8.41	3.72	11.51	6.81	4.70	11.43	6.81	4.62	11.55	6.81	4.74
1996	11.36	7.75	3.62	11.29	6.72	4.57	11.19	6.72	4.47	11.39	6.72	4.67
1997	10.84	6.66	4.18	11.34	6.57	4.77	11.29	6.57	4.72	11.40	6.57	4.83
1998	10.15	5.59	4.56	11.59	5.53	6.06	11.51	5.53	5.98	11.66	5.53	6.13
1999	9.50	5.72	3.78	10.74	5.91	4.83	10.66	5.91	4.75	10.77	5.91	4.86
2000	9.79	5.71	4.08	11.41	5.88	5.53	11.39	5.88	5.51	11.43	5.88	5.55
2001	9.68	5.77	3.92	11.05	5.47	5.58	10.95	5.47	5.48	11.09	5.47	5.62
2002	9.62	5.67	3.95	11.10	5.41	5.69	11.03	5.41	5.62	11.16	5.41	5.75
2003	9.71	5.31	4.40	10.98	5.03	5.95	10.99	5.03	5.96	10.97	5.03	5.94
2004	9.59	5.11	4.48	10.66	5.09	5.56	10.59	5.09	5.50	10.73	5.09	5.64
2005	9.51	4.38	5.13	10.50	4.52	5.98	10.46	4.52	5.94	10.54	4.52	6.02
2006	9.02	4.26	4.76	10.39	4.87	5.52	10.44	4.87	5.57	10.36	4.87	5.49
2007	8.66	4.30	4.37	10.30	4.80	5.51	10.24	4.80	5.44	10.36	4.80	5.56
2008	8.78	4.04	4.74	10.42	4.22	6.20	10.37	4.22	6.15	10.46	4.22	6.24
2009	8.77	3.85	4.92	10.36	4.10	6.27	10.19	4.10	6.10	10.48	4.10	6.39
2010	9.11	3.70	5.42	10.24	4.17	6.07	10.08	4.17	5.91	10.34	4.17	6.17
Means:												
1990-1993	**13.08**	**9.24**	**3.85**	**12.16**	**7.74**	**4.42**	**12.12**	**7.74**	**4.38**	**12.19**	**7.74**	**4.45**
1994-1997	**11.46**	**7.88**	**3.58**	**11.37**	**6.88**	**4.49**	**11.32**	**6.88**	**4.44**	**11.42**	**6.88**	**4.54**
1998-2010	**9.38**	**4.88**	**4.50**	**10.75**	**5.00**	**5.75**	**10.68**	**5.00**	**5.68**	**10.80**	**5.00**	**5.80**
1996-2010	**9.61**	**5.19**	**4.42**	**10.82**	**5.22**	**5.61**	**10.76**	**5.22**	**5.54**	**10.88**	**5.22**	**5.66**

Sources: www.bankofcanada.ca; Canadian Regulatory decisions; www.federalreserve.gov; Regulatory Research Associates at www.snl.com; www.ustreas.gov.

Schedule 3

DEBT RATINGS OF CANADIAN UTILITIES

	Ratings							
	DBRS		Moody's		S&P			
Company	Issuer Rating	Debt Rating	Issuer Rating	Debt Rating	Corporate Credit Rating	Debt Rating	S&P Business Risk Profile
Electric Utilities							
AltaLink L.P.		A (Senior Secured)			A-	A- (Senior Secured)	Excellent
Chatham-Kent Energy Inc.					A		Excellent
CU Inc.		A(high) (Unsecured)			A	A (Senior Unsecured)	Excellent
Enersource	A						
ENMAX Corp.		A(low) (Senior Unsecured)			BBB+	BBB+ (Senior Unsecured)	Strong
EPCOR Utilities Inc.		A(low) (Senior Unsecured)			BBB+	BBB+ (Senior Unsecured)	Strong
FortisAlberta Inc.		A(low) (Senior Unsecured)		Baa1 (Senior Unsecured)	A-	A- (Senior Unsecured)	Excellent
FortisBC Inc.		A(low) (Senior Unsecured)		Baa1 (Senior Unsecured)			
Hamilton Utilities					A	A (Senior Unsecured)	Excellent
Hydro One Inc.		A(high) (Senior Unsecured)		Aa3 (Senior Unsecured) 1/	A+ 1/	A+ (Senior Unsecured) 1/	Excellent
Hydro Ottawa Holding Inc.		A (Senior Unsecured)			A	A (Senior Unsecured)	Excellent
London Hydro					A		Excellent
Maritime Electric					BBB+	A- (Senior Secured)	Strong
Newfoundland Power		A (Senior Secured)	Baa1 2/	A2 (First Mortgage) 2/			
Nova Scotia Power		A(low) (Unsecured)			BBB+	BBB+ (Senior Unsecured)	Strong
Toronto Hydro		A(high) (Senior Unsecured)			A	A (Senior Unsecured)	Excellent
Veridian Corp.	A						
Gas Distributors							
Enbridge Gas Distribution		A (Unsecured)			A-	A- (Senior Unsecured)	Excellent
Gaz Métro L.P.		A (Senior Secured)			A-	A (Senior Secured)	Excellent
Pacific Northern Gas		BBB(low) (Senior Secured)					
Terasen Gas 3/		A (Senior Unsecured)		A3 (Senior Unsecured)	A	A (Senior Unsecured)	Excellent
				A1 (Senior Secured)		AA- (Senior Secured)	
Terasen Gas (Vancouver Island)		BBB(high) (Debentures)		A3 (Senior Unsecured)			
Union Gas Limited		A (Unsecured)			BBB+	BBB+ (Senior Unsecured)	Strong
Pipelines							
Enbridge Pipelines Inc.		A (Unsecured)			A-	A- (Senior Unsecured)	Excellent
NOVA Gas Transmission Ltd.		A (Unsecured)		A3 (Senior Unsecured)	A-	A- (Senior Unsecured)	Strong
Trans Québec & Maritimes Pipeline		A(low) (Senior Unsecured)			BBB+	BBB+ (Senior Unsecured)	Satisfactory
TransCanada PipeLines Ltd.		A (Senior Unsecured)	A3	A3 (Senior Unsecured)	A-	A- (Senior Unsecured)	Strong
Westcoast Energy Inc.		A(low) (Senior Unsecured)			BBB+	BBB+ (Senior Unsecured)	Strong
Medians							
Electric Utilities		**A**		**A3**	**A**	**A-**	**Excellent**
Gas Distributors		**A**		**A3**	**A-**	**A**	**Excellent**
Pipelines		**A**		**A3**	**A-**	**A-**	**Strong**
All Companies		**A**		**A3**	**A-**	**A-**	**Excellent**
All Investor Owned Companies		**A**		**A3**	**A-**	**A-**	**Excellent/Strong**

1/ Moody's rating reflects application of methodology for government-related issuers. Implied senior unsecured rating of Baa1. S&P stand-alone rating is A.
2/ Ratings withdrawn at request on company March 2010; previously rated Baa1.
3/ S&P ratings affirmed then withdrawn September 23, 2010.

Source: www.dbrs.com, www.moodys.com, Standard & Poor's.

Schedule 4

**CAPITAL STRUCTURE RATIOS
OF CANADIAN UTILITIES WITH RATED DEBT
(2009)[1/]**

Company	Total Debt [2/]	Preferred Stock [3/]	Common Stock Equity [4/]
Electric Utilities			
AltaLink L.P.	54.1%	0.0%	45.9%
CU Inc.	53.7%	7.7%	38.6%
Enersource	55.7%	0.0%	44.3%
ENMAX Corp.	43.4%	0.0%	56.6%
EPCOR Utilities Inc.	43.7%	0.0%	56.3%
FortisAlberta Inc.	57.3%	0.0%	42.7%
FortisBC Inc.	59.2%	0.0%	40.8%
Hamilton Utilities	31.8%	0.0%	68.2%
Hydro One Inc.	56.2%	2.6%	41.2%
Hydro Ottawa Holding Inc.	43.2%	0.0%	56.8%
London Hydro	40.8%	0.0%	59.2%
Maritime Electric	58.5%	0.0%	41.5%
Newfoundland Power	55.1%	1.0%	43.8%
Nova Scotia Power	58.2%	4.6%	37.2%
Toronto Hydro	54.8%	0.0%	45.2%
Veridian Corp.	38.5%	0.0%	61.5%
Gas Distributors [1/]			
Enbridge Gas Distribution	56.2%	2.2%	41.6%
Gaz Métro L.P.	63.9%	0.0%	36.1%
Pacific Northern Gas	47.8%	2.8%	49.4%
Terasen Gas	60.9%	0.0%	39.1%
Union Gas Limited	59.3%	2.6%	38.1%
Pipelines			
Enbridge Pipelines Inc.	57.1%	0.0%	42.9%
Nova Gas Transmission Ltd.	64.3%	0.0%	35.7%
Trans Québec & Maritimes Pipeline	62.9%	0.0%	37.1%
TransCanada PipeLines Ltd.	56.5%	1.1%	42.4%
Westcoast Energy Inc.	58.7%	5.4%	35.9%
Medians			
Electric Utilities	**54.5%**	**0.0%**	**44.7%**
Gas Distributors	**59.3%**	**2.2%**	**39.1%**
Pipelines	**58.7%**	**0.0%**	**37.1%**
All Companies	**56.2%**	**0.0%**	**42.6%**
All Investor Owned Companies	**58.2%**	**0.0%**	**40.8%**

[1/] The average of the four quarters ending September 2010 for gas distributors was used to better measure the actual sources of funds over the year due to the seasonal pattern of use of short-term debt.
[2/] Includes preferred securities classified as debt.
[3/] Includes non-controlling interests in preferred shares of subsidiary companies and preferred securities.
[4/] Includes non-controlling interests in common shares of subsidiary companies.

Note: Financial statements for Terasen Gas (Vancouver Island) are not publicly available.

Source: Reports to Shareholders

Schedule 5

CAPITAL STRUCTURE RATIOS
OF U.S. ELECTRIC UTILITIES
(Four Quarters Ending September 2010)

Company	Total Debt [1/]	Preferred Stock [2/]	Common Stock Equity [3/]
ALLETE, Inc.	43.1	0.0	56.9
Alliant Energy Corporation	47.1	4.2	48.7
Dominion Resources, Inc.	58.9	0.9	40.3
Duke Energy Corporation	44.3	0.0	55.7
IDACORP, Inc.	50.9	0.0	49.1
NextEra Energy, Inc.	59.7	0.0	40.3
OGE Energy Corp.	54.6	0.0	45.4
Portland General Electric Company	53.5	0.0	46.5
Progress Energy	56.2	0.4	43.4
SCANA Corporation	58.1	0.0	41.9
Sempra Energy	48.3	1.0	50.7
Southern Company	55.3	3.0	41.7
Vectren Corporation	56.1	0.0	43.9
Wisconsin Energy Corporation	57.3	0.4	42.3
Xcel Energy, Inc.	54.6	0.6	44.8
Mean	**53.2**	**0.7**	**46.1**
Median	**54.6**	**0.0**	**44.8**

[1/] Includes preferred securities classified as debt.
[2/] Includes non-controlling interests in preferred shares of subsidiary companies and preferred securities.
[3/] Includes non-controlling interests in common shares of subsidiary companies.

Source: Reports to Shareholders.

CREDIT METRICS OF CANADIAN UTILITIES WITH RATED DEBT

Company	EBIT Coverage (X)				FFO Interest Coverage (X)				FFO To Debt (%)			
	2009	2008	2007	3 Year Average	2009	2008	2007	3 Year Average	2009	2008	2007	3 Year Average
Electric Utilities												
AltaLink L.P.	1.8	1.8	1.7	1.8	3.0	3.2	3.0	3.1	12.7	12.7	11.6	12.3
Chatham-Kent Energy Inc.	3.7	3.5	3.7	3.6	5.4	5.5	5.2	5.4	29.5	34.9	32.9	32.4
CU Inc.	2.5	2.2	2.1	2.3	3.4	3.6	3.5	3.5	17.7	17.6	17.4	17.6
Enersource				2.3 1/				3.3 1/				16.1 1/
ENMAX Corp.	2.8	2.7	2.6	2.7	3.3	3.8	3.8	3.6	13.6	13.7	17.1	14.8
EPCOR Utilities Inc.	2.1	1.5	2.6	2.1	2.6	2.9	3.3	2.9	16.4	15.1	20.8	17.4
FortisAlberta Inc.	2.1	2.0	2.0	2.0	3.8	4.0	3.9	3.9	13.2	13.4	13.6	13.4
FortisBC Inc.	2.0	2.1	2.0	2.0 2/	2.9	2.7	2.8	2.8 5/	11.9	11.2	10.9	11.3 5/
Hamilton Utilities	3.3	3.3	3.7	3.4	4.6	5.1	5.0	4.9	29.6	35.3	34.5	33.1
Hydro One Inc.	2.1	2.8	3.0	2.6	2.8	4.0	3.7	3.5	11.4	14.5	13.9	13.3
Hydro Ottawa Holding Inc.	4.3	4.1	3.8	4.1	6.2	6.2	5.6	6.0	27.3	25.5	21.6	24.8
London Hydro	3.3	2.9	3.4	3.2 3/		4.8	4.4	4.6	27.5	26.2	23.7	25.8 3/
Maritime Electric	2.0	2.0	2.1	2.0	2.7	2.8	2.8	2.8	13.3	14.1	13.3	13.6
Newfoundland Power	2.4	2.5	2.2	2.4 2/	3.1	3.0	2.7	2.9 5/	15.0	15.8	12.6	14.5 5/
Nova Scotia Power	2.2	2.4	2.6	2.4	3.1	3.1	3.3	3.2	14.5	15.9	16.9	15.8
Toronto Hydro	1.6	1.8	2.2	1.9	3.3	3.4	3.4	3.4	16.3	17.5	17.1	17.0
Veridian Corp.	3.6	3.2	3.5	3.4 2/					33.5	24.2	30.9	29.5 2/
Gas Distributors												
Enbridge Gas Distribution	2.4	2.3	2.1	2.3	3.5	3.3	2.9	3.2	18.1	16.3	15.2	16.5
Gaz Métro L.P.	2.2	2.2	2.3	2.2	4.7	4.9	4.7	4.8	21.2	20.7	19.6	20.5
Pacific Northern Gas	2.6	2.1	2.2	2.3 2/	2.6	2.3	2.0	2.3 6/	11.7	11.2	9.5	10.8 2/
Terasen Gas	1.9	1.9	1.9	1.9 2/	2.6	2.5	2.4	2.5 5/	10.3	9.8	8.8	9.6 5/
Union Gas Limited	2.4	2.4	2.3	2.4	2.9	3.4	3.2	3.2	14.8	15.1	15.5	15.1
Pipelines												
Enbridge Pipelines Inc.	2.7	2.9	3.4	3.0	2.8	2.6	3.0	2.8	8.1	6.6	12.0	8.9
NOVA Gas Transmission Ltd.	2.0	2.2	2.4	2.2 4/			3.2	3.2	14.2	14.2	20.1	16.2 4/
Trans Québec & Maritimes Pipeline	3.5	2.1	2.0	2.5	4.4	3.6	2.4	3.5	20.2	15.8	8.3	14.8
TransCanada PipeLines Ltd.	1.9	2.3	2.3	2.2	2.8	3.0	2.9	2.9	12.4	13.0	14.4	13.3
Westcoast Energy Inc.	2.4	2.7	2.5	2.5	2.9	3.5	3.6	3.3	13.3	17.9	20.0	17.1
Medians												
Electric Utilities	**2.3**	**2.5**	**2.6**	**2.4**	**3.2**	**3.6**	**3.5**	**3.4**	**15.7**	**15.9**	**17.1**	**16.1**
Gas Distributors	**2.4**	**2.2**	**2.2**	**2.3**	**2.9**	**3.3**	**2.9**	**3.2**	**14.8**	**15.1**	**15.2**	**15.1**
Pipelines	**2.4**	**2.3**	**2.4**	**2.5**	**2.9**	**3.3**	**3.0**	**3.2**	**13.3**	**14.2**	**14.4**	**14.8**
All Companies	**2.4**	**2.3**	**2.3**	**2.3**	**3.1**	**3.4**	**3.3**	**3.3**	**14.7**	**15.5**	**16.2**	**15.8**
All Investor Owned Companies	**2.2**	**2.2**	**2.2**	**2.3**	**3.0**	**3.2**	**3.0**	**3.2**	**13.3**	**14.2**	**13.6**	**14.5**

1/ From S&P full analysis report for Hamilton Utilities.
2/ Data from DBRS.
3/ 2009 data from S&P Credit Stats.
4/ Data from S&P Credit Stats.
5/ Data from Moody's.
6/ Calculated from Annual Reports.

Source: Standard & Poor's Debt Rating Reports except where noted.

CREDIT METRICS OF U.S. ELECTRIC UTILITIES

	EBIT Coverage (X)				FFO Interest Coverage (X)				FFO To Debt (%)			
Company	2009	2008	2007	3 Year Average	2009	2008	2007	3 Year Average	2009	2008	2007	3 Year Average
ALLETE, Inc.	3.30	4.10	4.30	3.90	5.50	5.20	4.70	5.13	20.00	17.60	21.30	19.63
Alliant Energy Corporation	2.60	3.20	3.50	3.10	4.50	4.60	4.50	4.53	22.70	20.00	23.30	22.00
Dominion Resources, Inc.	3.20	3.40	1.90	2.83 [1/]		3.90	0.50	2.20	22.20	16.70	-2.70	12.07 [1/]
Duke Energy Corporation	3.30	3.00	3.70	3.33	5.20	5.30	6.50	5.67	21.00	23.50	32.50	25.67
IDACORP, Inc.	2.60	2.20	2.10	2.30	4.00	2.90	2.40	3.10	16.70	10.30	7.70	11.57
NextEra Energy, Inc.	3.50	3.50	3.20	3.40	6.30	5.80	6.30	6.13	24.00	23.10	33.00	26.70
OGE Energy Corp.	3.70	3.70	5.10	4.17	6.70	6.60	3.50	5.60	31.40	25.40	13.70	23.50
Portland General Electric Company	1.80	1.90	2.90	2.20 [1/]		4.10	3.50	3.80	14.50	20.00	18.20	17.57 [1/]
Progress Energy	2.40	2.40	2.50	2.43	3.60	2.90	3.80	3.43	16.10	12.10	16.40	14.87
SCANA Corporation	2.80	2.90	2.80	2.83	3.10	3.40	4.00	3.50	12.60	13.80	19.70	15.37
Sempra Energy	3.80	4.70	4.10	4.20 [1/]					18.60	15.10	24.50	19.40 [1/]
Southern Company	3.20	3.30	3.40	3.30	4.40	4.20	4.30	4.30	17.70	17.20	19.20	18.03
Vectren Corporation	2.90	3.10	3.00	3.00	5.00	5.10	4.00	4.70	21.40	21.20	17.90	20.17
Wisconsin Energy Corporation	2.20	1.10	2.90	2.07	4.70	4.90	4.30	4.63	16.70	18.40	16.70	17.27
Xcel Energy, Inc.	2.70	2.50	2.30	2.50	4.10	3.80	3.70	3.87	18.80	17.10	19.60	18.50
Medians												
All Companies	**2.90**	**3.10**	**3.00**	**3.00**	**4.60**	**4.40**	**4.00**	**4.42**	**18.80**	**17.60**	**19.20**	**18.50**

[1/] 2009 data from S&P Credit Stats.

Source: Standard & Poor's Debt Rating Reports except where noted.

HISTORIC EQUITY MARKET RISK PREMIUMS
(Arithmetic Averages)

Canada
(1947-2010)

Stock Return	Bond Total Return	Risk Premium
12.1	6.9	5.2

Stock Return	Bond Income Return	Risk Premium
12.1	6.8	5.3

United States
(1947-2010)

Stock Return	Bond Total Return	Risk Premium
12.5	6.3	6.2

Stock Return	Bond Income Return	Risk Premium
12.5	5.9	6.6

Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2009*; www.federalreserve.gov; Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2010 Yearbook*; www.standardandpoors.com; *TSX Review.*

HISTORIC EQUITY MARKET RISK PREMIUMS
(Arithmetic Averages)

Canada
(1924-2010)

Stock Return	Bond Total Return	Risk Premium
11.7	6.5	5.2
Stock Return	Bond Income Return	Risk Premium
11.7	6.0	5.6

United States
(1926-2010)

Stock Return	Bond Total Return	Risk Premium
11.9	5.9	6.0
Stock Return	Bond Income Return	Risk Premium
11.9	5.2	6.7

Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2009*; www.federalreserve.gov; Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2010 Yearbook*; www.standardandpoors.com; *TSX Review.*

Schedule 8

FIVE-YEAR STANDARD DEVIATIONS OF MARKET RETURNS FOR 10 SECTOR INDICES OF S&P/TSX COMPOSITE
(Percentages)

Five Year Periods Ending:	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average
S&P / TSX Composite	**3.57**	**4.68**	**4.84**	**5.40**	**5.87**	**5.83**	**4.97**	**4.59**	**4.04**	**3.24**	**2.86**	**4.35**	**4.88**	**4.88**	**4.57**
10 Sector Indices															
Consumer Discretionary	3.69	4.36	4.62	4.99	5.38	5.73	5.35	5.00	4.35	3.69	3.08	3.84	4.07	4.04	4.44
Consumer Staples	3.57	4.01	3.70	4.04	4.17	4.76	4.45	4.37	4.05	3.88	2.97	3.24	3.36	3.68	3.88
Energy	5.60	6.16	7.31	7.97	8.30	8.10	6.98	5.72	5.56	5.46	5.40	7.04	7.37	6.71	6.69
Financials	4.27	5.89	5.92	6.22	6.17	6.06	4.58	4.23	3.77	3.36	2.97	3.99	5.38	5.59	4.89
Health Care	6.62	7.73	8.19	9.38	9.00	9.39	8.93	8.68	6.98	6.57	5.45	4.92	5.38	5.89	7.36
Industrials	4.13	4.93	4.69	5.12	6.50	7.18	6.92	6.87	6.48	5.16	4.08	4.87	5.48	5.51	5.57
Information Technology	7.99	9.17	10.35	12.27	15.16	17.12	16.64	17.09	15.81	13.36	10.20	11.82	11.68	12.14	12.92
Materials	5.87	6.98	7.22	7.29	7.40	7.25	5.89	5.65	5.67	5.88	5.59	7.96	8.48	8.60	6.84
Telecommunication Services	3.66	5.82	7.37	7.87	8.46	8.71	7.54	5.74	4.97	4.64	4.18	5.08	5.07	4.93	6.00
Utilities	3.12	3.80	4.00	4.80	5.06	4.88	4.49	4.09	3.36	3.13	3.49	4.04	4.32	4.30	4.06
Mean	**4.85**	**5.89**	**6.34**	**7.00**	**7.56**	**7.92**	**7.18**	**6.75**	**6.10**	**5.51**	**4.74**	**5.68**	**6.06**	**6.14**	**6.26**
Median	**4.20**	**5.85**	**6.57**	**6.76**	**6.95**	**7.21**	**6.41**	**5.68**	**5.27**	**4.90**	**4.13**	**4.90**	**5.38**	**5.55**	**5.70**
Ratios of Standard Deviations															
S&P/TSX Utilities Index as a Percent of:															
10 Sector Indices (Mean)	**0.64**	**0.65**	**0.63**	**0.69**	**0.67**	**0.62**	**0.63**	**0.61**	**0.55**	**0.57**	**0.74**	**0.71**	**0.71**	**0.70**	**0.65**
10 Sector Indices (Median)	**0.74**	**0.65**	**0.61**	**0.71**	**0.73**	**0.68**	**0.70**	**0.72**	**0.64**	**0.64**	**0.85**	**0.82**	**0.80**	**0.77**	**0.72**

Source: *TSX Review*

Schedule 9

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

	Consumer Discretionary	Consumer Staples	Energy	Financials	Health Care	Industrials	Information Technology	Materials	Telecommunication Services	Utilities
1997	0.82	0.62	0.97	0.94	0.60	0.97	1.57	1.32	0.64	0.53
1998	0.80	0.60	0.85	1.12	1.01	0.93	1.41	1.12	0.92	0.55
1999	0.73	0.44	0.90	1.00	1.00	0.78	1.55	1.04	1.11	0.30
2000	0.69	0.23	0.66	0.78	1.09	0.72	1.78	0.74	0.92	0.14
2001	0.68	0.10	0.49	0.66	0.98	0.82	2.13	0.60	0.94	-0.03
2002	0.73	0.08	0.43	0.66	0.99	0.86	2.28	0.57	0.93	-0.06
2003	0.74	-0.08	0.26	0.38	0.85	0.91	2.74	0.43	0.83	-0.25
2004	0.80	-0.07	0.17	0.39	0.82	1.05	2.87	0.41	0.58	-0.13
2005	0.83	0.07	0.48	0.56	0.72	1.13	2.68	0.77	0.74	0.00
2006	0.86	0.37	1.03	0.68	0.85	1.06	2.07	1.32	0.52	0.25
2007	0.73	0.54	1.44	0.51	0.54	0.96	1.12	1.45	0.62	0.46
2008	0.59	0.32	1.43	0.61	0.48	0.81	1.43	1.30	0.55	0.49
2009	0.56	0.28	1.35	0.80	0.41	0.83	1.22	1.24	0.47	0.41
2010	0.55	0.33	1.24	0.85	0.39	0.87	1.37	1.22	0.46	0.42

Source: *TSX Review*

TSE 300 SUB-INDEX COMPOUND RETURNS AND BETAS
(1956-2003)

	Sub-Index Compound Returns [1/]						Sub-Index Betas					
	56-03	56-97	64-73	74-83	84-93	94-03	56-03	56-97	64-73	74-83	84-93	94-03
Metals/Minerals	7.8	7.6	7.5	11.2	6.8	7.2	1.15	1.23	1.14	1.22	1.37	0.87
Gold/Precious Metals	9.5	10.4	16.2	16.0	11.0	-2.7	0.85	0.96	0.36	1.31	1.24	0.64
Oil and Gas	9.5	8.4	14.6	11.9	4.5	15.3	1.06	1.20	1.25	1.40	0.98	0.52
Paper/Forest Products	7.1	7.4	4.8	11.8	10.3	2.6	1.02	1.07	1.15	1.00	1.27	0.85
Consumer Products	11.3	11.9	10.2	13.8	11.2	9.6	0.83	0.86	0.84	0.90	0.89	0.73
Industrial Products	7.2	9.6	8.3	10.9	6.0	1.1	1.17	1.02	1.11	0.87	1.08	1.69
Real Estate [2/]	5.3	5.5	0.7	16.7	-2.3	1.3	1.00	1.18	1.21	1.28	1.06	0.46
Transportation/Environmental	10.1	11.4	12.7	18.4	3.0	8.8	0.94	1.04	0.94	1.08	1.22	0.62
Pipelines	11.7	12.1	5.2	13.8	13.7	13.1	0.68	0.85	0.80	0.92	0.76	0.02
Utilities	11.0	10.7	3.3	17.8	11.0	16.3	0.54	0.48	0.50	0.47	0.40	0.79
Communications/Media	13.5	15.0	19.1	15.3	12.9	7.5	0.77	0.77	0.96	0.69	0.95	0.80
Merchandising	10.1	10.7	10.6	12.2	8.7	7.2	0.78	0.86	0.93	0.84	0.83	0.46
Finance	12.4	12.8	12.0	11.7	11.6	17.9	0.83	0.85	0.95	0.71	0.93	0.77
Conglomerates	10.8	10.8	12.8	15.2	9.5	13.9	0.94	1.03	1.26	0.97	1.20	0.68
Adjusted R Square [3/]							**47%**	**44%**	**1%**	**1%**	**11%**	**9%**
Beta [4/]							**-0.088**	**-0.082**	**-0.020**	**-0.008**	**-0.056**	**-0.053**

[1/] Annualized rate of return at which capital has compounded over time.
[2/] Data only available starting July 1961
[3/] Represents percentage of variation in sub-index returns explained by the sub-index betas.
[4/] Represents relationship between sub-index returns and sub-index betas.

Source: *TSX Review*

S&P/TSX COMPOSITE SECTOR COMPOUND RETURNS AND BETAS
(1988-2010)

	Sector Compound Returns [1/]			Sector Betas		
	88-10	88-97	01-10	88-10	88-97	01-10
Consumer Discretionary	6.9	10.2	4.1	0.73	0.90	0.67
Consumer Staples	11.3	12.7	10.5	0.35	0.73	0.23
Energy	11.2	8.4	19.1	0.80	0.76	0.93
Financials	13.1	18.3	13.2	0.81	1.04	0.72
Health Care	4.9	15.5	-4.6	0.75	0.81	0.54
Industrials	6.4	8.3	7.0	0.94	1.13	0.97
Information Technology	5.7	21.8	-16.7	1.70	1.21	1.91
Materials	8.0	3.4	15.5	0.98	1.26	1.04
Telecommunication Services	12.6	15.4	4.5	0.68	0.58	0.57
Utilities	10.5	11.5	16.2	0.30	0.62	0.24
Adjusted R Square [2/]				**26%**	**1%**	**31%**
Beta [3/]				**-0.040**	**-0.017**	**-0.125**

[1/] Data only available starting December 1987. Annualized rate of return at which capital has compounded over time.
[2/] Represents percentage of variation in sector returns explained by the sector betas.
[3/] Represents relationship between sector returns and sector betas.

Source: *TSX Review*

BETAS FOR REGULATED CANADIAN UTILITIES

"Raw" Monthly Price Betas
Five Year Period Ending:

COMPANY	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Canadian Utilities Limited	0.46	0.54	0.48	0.55	0.63	0.62	0.54	0.38	0.27	0.19	0.05	0.03	0.20	0.32	0.58	0.19	0.06	0.06
Emera Inc.	na	na	na	0.52	0.40	0.55	0.41	0.27	0.20	0.15	-0.05	0.01	0.07	0.12	0.24	0.17	0.16	0.21
Enbridge Inc.	0.35	0.53	0.46	0.44	0.43	0.48	0.26	0.07	-0.10	-0.18	-0.37	-0.32	-0.19	0.22	0.54	0.30	0.30	0.32
Fortis Inc.	0.35	0.44	0.51	0.37	0.30	0.49	0.33	0.23	0.14	0.13	-0.06	0.01	0.21	0.48	0.65	0.21	0.20	0.16
Pacific Northern Gas	0.51	0.56	0.42	0.30	0.39	0.55	0.47	0.44	0.42	0.44	0.37	0.49	0.54	0.54	0.35	0.26	0.44	0.39
Terasen Inc. 1/	0.40	0.53	0.59	0.53	0.46	0.48	0.36	0.25	0.18	0.12	0.02	-0.02	0.06	na	na	na	na	na
TransCanada Corporation	0.40	0.57	0.56	0.52	0.36	0.55	0.21	0.15	-0.08	-0.09	-0.38	-0.16	-0.15	0.34	0.52	0.38	0.39	0.39
Mean	**0.41**	**0.53**	**0.50**	**0.46**	**0.42**	**0.53**	**0.37**	**0.26**	**0.14**	**0.11**	**-0.06**	**0.01**	**0.11**	**0.34**	**0.48**	**0.25**	**0.26**	**0.26**
Median	**0.40**	**0.54**	**0.50**	**0.52**	**0.40**	**0.55**	**0.36**	**0.25**	**0.18**	**0.13**	**-0.05**	**0.01**	**0.07**	**0.33**	**0.53**	**0.24**	**0.25**	**0.27**
TSE Gas/Electric Index	0.42	0.48	0.52	0.52	0.46	0.55	0.38	0.21	0.17	0.14	NA	NA	NA	NA	NA	NA	NA	NA
S&P/TSX Utilities	0.55	0.63	0.67	0.65	0.53	0.55	0.30	0.14	-0.03	-0.06	-0.25	-0.13	0.00	0.25	0.46	0.49	0.41	0.42

Adjusted Betas 2/
Five Year Period Ending:

COMPANY	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Canadian Utilities Limited	0.64	0.69	0.65	0.70	0.75	0.75	0.69	0.58	0.51	0.46	0.37	0.35	0.47	0.54	0.72	0.45	0.37	0.37
Emera Inc.	NA	NA	NA	0.68	0.60	0.70	0.60	0.51	0.46	0.43	0.29	0.33	0.38	0.41	0.49	0.44	0.44	0.47
Enbridge Inc.	0.56	0.69	0.64	0.62	0.62	0.65	0.50	0.38	0.26	0.21	0.08	0.12	0.21	0.48	0.69	0.53	0.53	0.54
Fortis Inc.	0.57	0.62	0.67	0.58	0.53	0.66	0.55	0.48	0.42	0.41	0.29	0.34	0.47	0.65	0.77	0.47	0.46	0.44
Pacific Northern Gas	0.67	0.71	0.61	0.53	0.59	0.70	0.65	0.63	0.61	0.63	0.58	0.66	0.69	0.69	0.56	0.50	0.62	0.59
Terasen Inc. 1/	0.60	0.69	0.72	0.69	0.64	0.65	0.57	0.50	0.45	0.41	0.35	0.32	0.37	na	na	na	na	na
TransCanada Corporation	0.60	0.71	0.71	0.68	0.57	0.70	0.47	0.43	0.28	0.27	0.08	0.22	0.23	0.56	0.68	0.58	0.59	0.59
Mean	**0.61**	**0.68**	**0.67**	**0.64**	**0.61**	**0.69**	**0.58**	**0.50**	**0.43**	**0.40**	**0.29**	**0.33**	**0.40**	**0.56**	**0.65**	**0.50**	**0.50**	**0.50**
Median	**0.60**	**0.69**	**0.66**	**0.68**	**0.60**	**0.70**	**0.57**	**0.50**	**0.45**	**0.41**	**0.29**	**0.33**	**0.38**	**0.55**	**0.68**	**0.49**	**0.50**	**0.51**
TSE Gas/Electric Index	0.61	0.65	0.68	0.68	0.64	0.70	0.59	0.47	0.44	0.42	NA	NA	NA	NA	NA	NA	NA	NA
S&P/TSX Utilities	0.70	0.76	0.78	0.77	0.69	0.70	0.53	0.42	0.31	0.29	0.16	0.24	0.33	0.50	0.64	0.66	0.60	0.61

1/ Due to its purchase by Kinder Morgan, Terasen betas are calculated through November 2005.
2/ Adjusted beta = "raw" beta * 67% + market beta of 1.0 * 33%.

Source: Standard and Poor's *Research Insight* and *TSX Review*.

Monthly Betas and R^2s
Canadian Utilities

Beta	Canadian Utilities Limited		Emera Inc.		Enbridge Inc.		Fortis Inc.		Pacific Northern Gas		TransCanada Corp.		S&P/TSX Utilities	
Ending	Beta	R^2	Beta	R^2	Beta	R^2	Beta	R^2	Beta	R^2	Beta	R^2	Beta	R^2
2004	0.03	0.1%	0.01	0.0%	-0.32	7.0%	0.01	0.0%	0.49	3.7%	-0.16	1.6%	-0.13	2.3%
2005	0.20	4.2%	0.07	0.5%	-0.19	2.8%	0.21	3.0%	0.54	4.9%	-0.15	2.5%	0.00	0.0%
2006	0.32	4.9%	0.12	1.1%	0.22	4.2%	0.48	9.0%	0.54	6.1%	0.34	10.0%	0.25	6.8%
2007	0.58	10.1%	0.24	3.2%	0.54	12.5%	0.65	11.8%	0.35	3.8%	0.52	14.8%	0.46	14.3%
2008	0.19	1.9%	0.17	3.5%	0.30	7.8%	0.21	2.8%	0.26	5.9%	0.38	16.4%	0.49	28.1%
2009	0.06	0.2%	0.16	3.3%	0.30	10.0%	0.20	2.9%	0.44	16.6%	0.39	19.7%	0.41	21.5%
2010	0.06	0.2%	0.21	4.9%	0.32	11.2%	0.16	2.3%	0.39	15.7%	0.39	19.1%	0.42	22.3%

Source: Standard and Poor's *Research Insight*

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INDIVIDUAL COMPANY RISK DATA FOR SAMPLE OF U.S. ELECTRIC UTILITIES

	Value Line									S & P		Moody's
	Safety	Forecast Common Equity Ratio 2013-2015	Forecast Return On Average Common Equity 2013-2015	Dividend Payout Forecast 2013-2015	2010 Q4 Beta	"Raw" Weekly Betas[1/]	Adjusted Weekly Betas	Common Equity Ratio (Four Quarters ending 2010Q3)	2007-2009 Average Earned Returns	Business Risk Profile	Debt Rating	Debt Rating[2/]
ALLETE, Inc.	2	54.5%	9.5%	67.3%	0.70	0.60	0.73	56.9%	10.0%	Strong	BBB+	Baa1
Alliant Energy Corporation	2	51.5%	12.1%	53.3%	0.70	0.71	0.81	48.7%	10.1%	Excellent	BBB+	Baa1
Dominion Resources, Inc.	2	45.0%	14.2%	64.0%	0.70	0.59	0.73	40.3%	18.4%	Excellent	A-	Baa2
Duke Energy Corporation	2	50.0%	8.3%	70.0%	0.65	0.53	0.69	55.7%	5.8%	Excellent	A-	Baa2
IDACORP, Inc.	3	50.5%	8.7%	45.2%	0.70	0.59	0.73	49.1%	8.0%	Excellent	BBB	Baa2
NextEra Energy, Inc.	2	48.0%	12.0%	45.7%	0.75	0.67	0.78	40.3%	13.5%	Strong	A-	Baa1
OGE Energy Corp.	2	49.0%	13.0%	44.0%	0.75	0.77	0.85	45.4%	13.6%	Strong	BBB+	Baa1
Portland General Electric Co.	3	50.0%	8.6%	60.0%	0.75	0.59	0.72	46.5%	8.2%	Strong	BBB	Baa2
Progress Energy	2	47.0%	9.0%	72.7%	0.60	0.47	0.65	43.4%	8.0%	Excellent	BBB+	Baa2
SCANA Corporation	2	47.5%	10.1%	57.1%	0.70	0.57	0.71	41.9%	11.1%	Excellent	BBB+	Baa2
Sempra Energy	2	51.5%	9.6%	45.6%	0.85	0.74	0.82	50.7%	13.6%	Strong	BBB+	Baa1
Southern Company	1	44.5%	13.0%	70.0%	0.55	0.35	0.57	42.0%	13.3%	Excellent	A	Baa1
Vectren Corporation	2	50.5%	10.5%	66.7%	0.70	0.61	0.74	43.9%	10.5%	Excellent	A-	A3
Wisconsin Energy Corp.	2	49.5%	13.6%	51.4%	0.65	0.48	0.65	42.3%	11.1%	Excellent	BBB+	A3
Xcel Energy, Inc.	2	49.0%	10.2%	57.5%	0.65	0.48	0.66	44.8%	9.5%	Excellent	A-	Baa1
Mean	**2**	**49.2%**	**10.8%**	**58.0%**	**0.69**	**0.58**	**0.72**	**46.1%**	**11.0%**	**Excellent**	**BBB+**	**Baa1**
Median	**2**	**49.5%**	**10.2%**	**57.5%**	**0.70**	**0.59**	**0.73**	**44.8%**	**10.5%**	**Excellent**	**BBB+**	**Baa1**

[1/] "Raw" betas calculated using weekly price changes against the NYSE Composite (260 weeks ending December 27, 2010). Duke prices begin in January 2007, Portland prices begin in May 2006.
[2/] Rating for Vectren Corp. is for Vectren Utility Holdings.

Source: www.Moodys.com; Standard and Poor's, *Issuer Ranking: U.S. Invester-Owned Electric Utilities, Strongest To Weakes* t (October 6, 2010);
Standard and Poor's, *Issuer Ranking: U.S. Natural Gas Distributors And Integrated Gas Companies, Strongest To Weakest* (December 22, 2010);
Standard and Poor's Research Insight; *Value Line* (November and December 2010); *Value Line Index*, December 24, 2010; and

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DCF-BASED EQUITY RISK PREMIUM STUDY FOR
SAMPLE OF U.S. ELECTRIC UTILITIES
CONSTANT GROWTH DCF MODEL

(Annual Averages of Monthly Data)

Year	Expected Dividend Yield [1/]	I/B/E/S EPS Growth Forecast	DCF Cost of Equity	Long-Term Treasury Yield	Equity Risk Premium	Moody's Spread [2/]
1995	6.2	3.4	9.6	6.8	2.8	1.5
1996	5.8	3.6	9.4	6.7	2.7	1.4
1997	5.8	3.6	9.5	6.6	2.9	1.4
1998	5.2	3.9	9.1	5.5	3.5	1.7
1999	6.1	4.4	10.5	5.9	4.6	2.0
2000	5.8	5.5	11.3	5.9	5.4	2.5
2001	5.0	6.6	11.6	5.5	6.2	2.5
2002	5.7	7.0	12.7	5.4	7.3	2.6
2003	4.9	5.9	10.8	5.0	5.8	1.8
2004	4.2	5.1	9.3	5.1	4.2	1.3
2005	3.9	4.9	8.9	4.5	4.3	1.4
2006	3.9	6.1	10.0	4.9	5.1	1.4
2007	3.8	5.9	9.7	4.8	4.9	1.5
2008	4.5	6.6	11.0	4.2	6.8	3.1
2009	5.4	6.2	11.6	4.1	7.5	2.9
2010	4.8	5.7	10.5	4.2	6.3	1.7
Means for Long Treasury Yields:						
Below 4.0%	**5.0**	**6.0**	**11.0**	**3.6**	**7.4**	**3.3**
4.0-4.99%	**4.5**	**5.8**	**10.3**	**4.6**	**5.7**	**1.9**
Below 5.0%	**4.5**	**5.9**	**10.4**	**4.5**	**5.9**	**2.0**
5.0-5.99%	**5.1**	**5.5**	**10.6**	**5.5**	**5.1**	**2.0**
6.0-6.99%	**6.0**	**3.9**	**9.9**	**6.5**	**3.4**	**1.6**
7.0% and above	**6.2**	**3.4**	**9.7**	**7.3**	**2.4**	**1.3**
Means:						
1995 - 2010	**5.1**	**5.3**	**10.3**	**5.3**	**5.0**	**1.9**

[1/] Dividend Yield adjusted for I/B/E/S growth (DY (1+g)).
[2/] Moody's Spread is the yield on Moody's long-term Baa-rated Utility Index minus the long-term Treasury yield.

Source: www.federalreserve.gov; I/B/E/S; www.Moodys.com; Standard & Poor's *Research Insight*; and www.ustreas.gov.

DCF-BASED EQUITY RISK PREMIUM STUDY FOR
SAMPLE OF U.S. ELECTRIC UTILITIES
CONSTANT GROWTH DCF MODEL

Regression Analysis Results 1995-2010

EQUATION 1:

Equity Risk Premium = 11.66 - 1.25 (30-Year Treasury Yield)

t-statistics:
30-Year Treasury Yield = -14.03
R^2 = 51%

Equity Risk Premium at Long-Term Bond Yield of 4.5% = 6.0%

ROE at Long-Term Bond Yield of 4.5% = 10.5%

EQUATION 2:

Equity Risk Premium = 7.65 - 0.92 (30-Year Treasury Yield) + 1.16 (Spread)

Where Spread = Spread between Baa-rated Utility Bond Yields and 30-year Treasury Yields

t-statistics:
30-Year Treasury Yield = -13.08
Spread = 12.98

R^2 = 74%

Equity Risk Premium at Long-term Bond Yield of 4.5% and Spread of 1.65% = 5.4%

ROE at Long-Term Bond Yield of 4.5% and Spread of 1.65% = 9.9%

EQUATION 3:

Equity Risk Premium = 7.30 - 0.58 (Baa-rated Utility Bond Yields)

t-statistics:
Baa-rated Utility Bond Yield = -6.90
R^2 = 20%

Equity Risk Premium at Baa-rated Utility Bond Yield of 6.15% = 3.7%

ROE at A-rated Utility Bond Yield of 6.15% = 9.9%

Note: t-statistics measure the statistical significance of an independent variable in explaining the dependent variable. The higher the t-value, the greater the confidence in the coefficient as a predictor. R^2 is the proportion of the variability in the dependent variable that is explained by the independent variable(s).

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DCF-BASED EQUITY RISK PREMIUM STUDY FOR
SAMPLE OF U.S. ELECTRIC UTILITIES
THREE STAGE MODEL

(Annual Averages of Monthly Data)

Year	Expected Dividend Yield [1/]	I/B/E/S EPS Growth Forecast	DCF Cost of Equity	Long-Term Treasury Yield	Equity Risk Premium	Moody's Spread [2/]
1995	6.2	3.4	11.0	6.8	4.2	1.5
1996	5.8	3.6	10.1	6.7	3.4	1.4
1997	5.8	3.6	10.3	6.6	3.8	1.4
1998	5.2	3.9	9.7	5.5	4.1	1.7
1999	6.1	4.4	10.7	5.9	4.8	2.0
2000	5.8	5.5	11.0	5.9	5.1	2.5
2001	5.0	6.6	10.8	5.5	5.3	2.5
2002	5.7	7.0	11.6	5.4	6.2	2.6
2003	4.9	5.9	10.5	5.0	5.5	1.8
2004	4.2	5.1	9.6	5.1	4.5	1.3
2005	3.9	4.9	9.3	4.5	4.7	1.4
2006	3.9	6.1	9.5	4.9	4.6	1.4
2007	3.8	5.9	9.1	4.8	4.3	1.5
2008	4.5	6.6	9.8	4.2	5.6	3.1
2009	5.4	6.2	10.8	4.1	6.7	2.9
2010	4.8	5.7	9.9	4.2	5.8	1.7
Means for Long Treasury Yields:						
Below 4.0%	**5.0**	**6.0**	**10.3**	**3.6**	**6.7**	**3.3**
4.0-4.99%	**4.5**	**5.8**	**9.8**	**4.6**	**5.2**	**1.9**
Below 5.0%	**4.5**	**5.9**	**9.9**	**4.5**	**5.4**	**2.0**
5.0-5.99%	**5.1**	**5.5**	**10.4**	**5.5**	**4.9**	**2.0**
6.0-6.99%	**6.0**	**3.9**	**10.6**	**6.5**	**4.1**	**1.6**
7.0% and above	**6.2**	**3.4**	**10.9**	**7.3**	**3.6**	**1.3**
Means:						
1995 - 2010	**5.1**	**5.3**	**10.2**	**5.3**	**4.9**	**1.9**

[1/] Dividend Yield adjusted for I/B/E/S growth (DY (1+g)).
[2/] Moody's Spread is the yield on Moody's long-term Baa-rated Utility Index minus the long-term Treasury yield.

Source: www.federalreserve.gov; I/B/E/S; www.Moodys.com; Standard & Poor's *Research Insight*; and www.ustreas.gov.

DCF-BASED EQUITY RISK PREMIUM STUDY FOR SAMPLE OF U.S. ELECTRIC UTILITIES THREE STAGE MODEL

Regression Analysis Results 1995-2010

EQUATION 1:

Equity Risk Premium = 8.67 - 0.71 (30-Year Treasury Yield)

t-statistics:

30-Year Treasury Yield = -11.99

R^2 = 43%

Equity Risk Premium at Long-Term Bond Yield of 4.50% **= 5.5%**

ROE at Long-Term Bond Yield of 4.50% **= 10.0%**

EQUATION 2:

Equity Risk Premium = 6.17 - 0.50 (30-Year Treasury Yield) + 0.72 (Spread)

Where Spread = Spread between Baa-rated Utility Bond Yields and 30-year Treasury Yields

t-statistics:

30-Year Treasury Yield = -10.25

Spread = 11.62

R^2 = 67%

Equity Risk Premium at Long-term Bond Yield of 4.5% and Spread of 1.65% **= 5.1%**

ROE at Long-Term Bond Yield of 4.5% and Spread of 1.65% **= 9.6%**

EQUATION 3:

Equity Risk Premium = 6.10 - 0.43 (Baa-rated Utility Bond Yields)

t-statistics:

A-rated Utility Bond Yield = -9.39

R^2 = 32%

Equity Risk Premium at Baa-rated Utility Bond Yield of 6.15% **= 3.5%**

ROE at Baa-rated Utility Bond Yield of 6.15% **= 9.6%**

Note: t-statistics measure the statistical significance of an independent variable in explaining the dependent variable. The higher the t-value, the greater the confidence in the coefficient as a predictor. R^2 is the proportion of the variability in the dependent variable that is explained by the independent variable(s).

APPROVED U.S. ELECTRIC AND GAS UTILITY ROES, RISK PREMIUMS, BOND YIELDS AND SPREADS

	Approved Electric and Gas ROEs	Moody's Baa Utility Bond	30-Year Treasury Yield	Baa Utility/ Treasury Yield Spread	Allowed ROE Risk Premium Over Baa Utility Bond		Approved Electric and Gas ROEs	Moody's Baa Utility Bond	30-Year Treasury Yield	Baa Utility/ Treasury Yield Spread	Allowed ROE Risk Premium Over Baa Utility Bond
1994 Q3		8.84	7.56	1.28		2002 Q4	10.94	7.71	5.11	2.59	3.24
1994 Q4		9.25	7.95	1.30		2003 Q1	11.43	7.11	4.93	2.18	4.32
1995 Q1	11.96	8.95	7.54	1.42	3.01	2003 Q2	11.26	6.49	4.71	1.79	4.77
1995 Q2	11.32	8.33	6.88	1.45	3.00	2003 Q3	10.28	6.92	5.28	1.64	3.36
1995 Q3	11.24	8.11	6.67	1.44	3.13	2003 Q4	10.93	6.69	5.22	1.47	4.24
1995 Q4	11.55	7.75	6.15	1.61	3.79	2004 Q1	11.06	6.26	4.96	1.29	4.80
1996 Q1	11.37	7.86	6.39	1.46	3.51	2004 Q2	10.47	6.69	5.39	1.29	3.78
1996 Q2	11.23	8.43	6.93	1.50	2.80	2004 Q3	10.36	6.42	5.08	1.34	3.94
1996 Q3	10.96	8.37	7.01	1.35	2.59	2004 Q4	10.80	6.18	4.93	1.25	4.62
1996 Q4	11.44	8.00	6.56	1.44	3.44	2005 Q1	10.54	5.92	4.70	1.22	4.62
1997 Q1	11.31	8.15	6.90	1.25	3.15	2005 Q2	10.25	5.75	4.36	1.39	4.50
1997 Q2	11.64	8.27	6.89	1.38	3.37	2005 Q3	10.63	5.79	4.39	1.40	4.84
1997 Q3	12.00	7.88	6.44	1.44	4.12	2005 Q4	10.55	6.14	4.63	1.50	4.42
1997 Q4	11.04	7.52	6.04	1.48	3.52	2006 Q1	10.55	6.20	4.70	1.50	4.35
1998 Q1	11.31	7.34	5.89	1.44	3.97	2006 Q2	10.64	6.63	5.19	1.44	4.00
1998 Q2	11.58	7.31	5.79	1.51	4.27	2006 Q3	10.18	6.34	4.91	1.43	3.84
1998 Q3	11.57	7.19	5.33	1.86	4.38	2006 Q4	10.31	6.07	4.70	1.37	4.24
1998 Q4	11.75	7.23	5.11	2.12	4.52	2007 Q1	10.36	6.16	4.82	1.34	4.20
1999 Q1	10.68	7.42	5.43	1.99	3.26	2007 Q2	10.23	6.32	4.98	1.34	3.91
1999 Q2	10.89	7.76	5.83	1.93	3.13	2007 Q3	10.03	6.45	4.86	1.59	3.57
1999 Q3	10.63	8.11	6.08	2.03	2.52	2007 Q4	10.42	6.38	4.53	1.85	4.04
1999 Q4	10.76	8.24	6.31	1.93	2.52	2008 Q1	10.42	6.59	4.35	2.24	3.83
2000 Q1	11.00	8.38	6.16	2.22	2.63	2008 Q2	10.46	6.85	4.58	2.27	3.61
2000 Q2	11.09	8.58	5.96	2.61	2.51	2008 Q3	10.48	7.22	4.44	2.78	3.26
2000 Q3	11.43	8.30	5.78	2.52	3.13	2008 Q4	10.34	8.59	3.50	5.09	1.75
2000 Q4	12.25	8.18	5.62	2.57	4.06	2009 Q1	10.27	7.95	3.62	4.34	2.32
2001 Q1	11.23	7.93	5.45	2.48	3.31	2009 Q2	10.35	7.48	4.24	3.24	2.88
2001 Q2	10.84	8.12	5.77	2.35	2.72	2009 Q3	10.23	6.21	4.17	2.03	4.02
2001 Q3	10.78	7.98	5.44	2.54	2.80	2009 Q4	10.41	6.16	4.35	1.80	4.26
2001 Q4	11.29	7.96	5.21	2.75	3.32	2010 Q1	10.51	6.17	4.59	1.58	4.34
2002 Q1	10.80	8.27	5.66	2.61	2.53	2010 Q2	10.04	6.05	4.22	1.83	3.99
2002 Q2	11.50	8.24	5.72	2.52	3.26	2010 Q3	10.17	5.54	3.73	1.81	4.64
2002 Q3	11.25	7.73	5.13	2.60	3.52	2010 Q4	10.21	5.79	4.15	1.64	4.42

Sources: www.federalreserve.gov; www.moodys.com; Regulatory Research Associates at www.snl.com; www.ustreas.gov

APPROVED ROEs FOR U.S. ELECTRIC AND GAS UTILITIES

Regression Analysis Results 1995-2010

EQUATION 1:

Equity Risk Premium = 8.59 - 0.58 (6 Months Lagged 30-Year Treasury Yield)

t-statistics:
6 Months Lagged 30-Year Treasury Yield = 12.66
R^2 = 72%

Equity Risk Premium at Long-Term Bond Yield of 4.50% = 6.0%

ROE at Long-Term Bond Yield of 4.50% = 10.5%

EQUATION 2:

Equity Risk Premium = 7.90 - 0.52 (6 Months Lagged 30-Year Treasury Yield) + 0.19 (Spread)

Where Spread = 6 Months Lagged Spread between Baa-rated Utility Bond Yields and 30-year Treasury Yields

t-statistics:
6 Months Lagged 30-Year Treasury Yield = -10.97
Spread = 3.00

R^2 = 76%

Equity Risk Premium at Long-term Bond Yield of 4.5% and Spread of 1.65% = 5.9%

ROE at Long-Term Bond Yield of 4.5% and Spread of 1.65% = 10.4%

EQUATION 3:

Equity Risk Premium = 7.89 - 0.59 (6 Months Lagged Moody's Baa-Rated)

t-statistics:
6 Months Lagged Baa-Rated Utility Bond Yield = -11.51

R^2 = 68%

Equity Risk Premium at Baa-Rated Utility Bond Yield of 6.15% = 4.2%

ROE at Baa-Rated Utility Bond Yield of 6.15% = 10.4%

HISTORIC UTILITY EQUITY RISK PREMIUMS
(Arithmetic Averages)

Canada
(1956-2010)

Utilities Index Return	Bond Total Return	Risk Premium
12.2	7.7	4.5

Utilities Index Return	Bond Income Return	Risk Premium
12.2	7.4	4.8

United States
(1947-2010)

S&P/Moody's Electric Index Return	Bond Total Return	Risk Premium
10.8	6.3	4.5

S&P/Moody's Electric Index Return	Bond Income Return	Risk Premium
10.8	5.9	4.9

S&P / Moody's Gas Distribution Index Return	Bond Total Return	Risk Premium
11.8	6.3	5.6

S&P / Moody's Gas Distribution Index Return	Bond Income Return	Risk Premium
11.8	5.9	5.9

Notes:
The Canadian Utilities Index is based on the Gas/Electric Index of the TSE 300 (from 1956 to 1987) and on the S&P/TSX Utilities Index from 1988-2010.

The S&P/Moody's Electric Index reflects S&P's Electric Index from 1947 to 1998 and Moody's Electric Index from 1999 to 2001. The 2002 to 2010 data were estimated using simple average of the prices and dividends for the utilities included in Moody's Electric Index as of the end of 2001. These utilities include American Electric Power, Centerpoint Energy, CH Energy, Cinergy, Consolidated Edison, Constellation, Dominion Resources, DPL, DTE Energy, Duke Energy, Energy East, Exelon, FirstEnergy, IDACORP, Nisource, OGE Energy, Pepco Holdings, PPL, Progress Energy, Public Service Enterprise Grp., Southern Co., Teco and Xcel Energy.

The S&P/Moody's Gas Distribution Index reflects S&P's Natural Gas Distributors Index from 1947 to 1984, when S&P eliminated its gas distribution index. The 1985-2001 data are for Moody's Gas index. The index was terminated in July 2002. The 2002-2010 returns were estimated using simple averages of the prices and dividends for the utilities that were included in Moody's Gas Index of the end of 2001. These LDCs include AGL Resources, Keyspan Corp., Laclede Group, Northwest Natural, Peoples Energy and WGL Holdings.

Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2009*; www.federalreserve.gov; Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2010 Yearbook*; www.standardandpoors.com; *TSX Review.*

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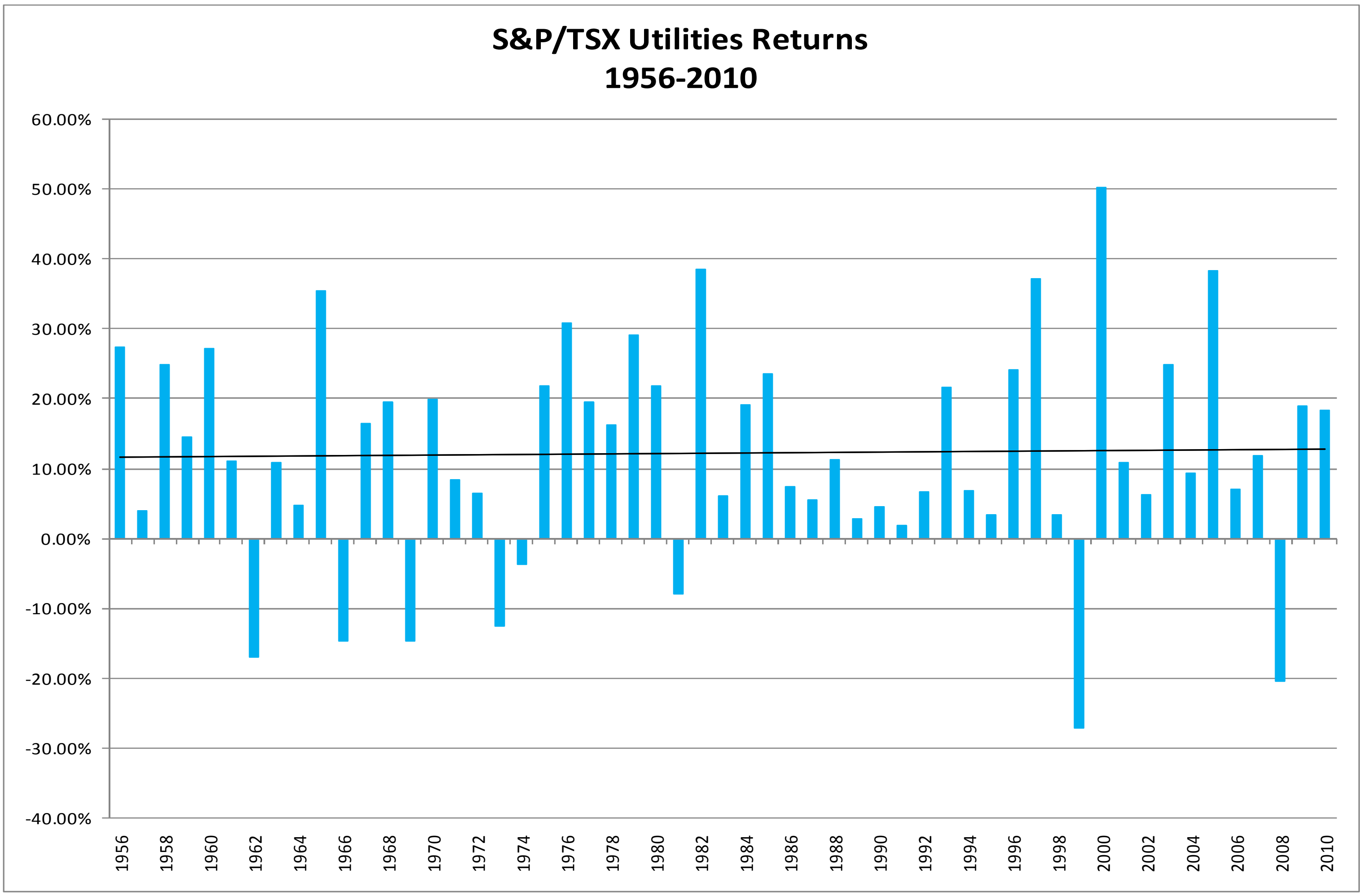

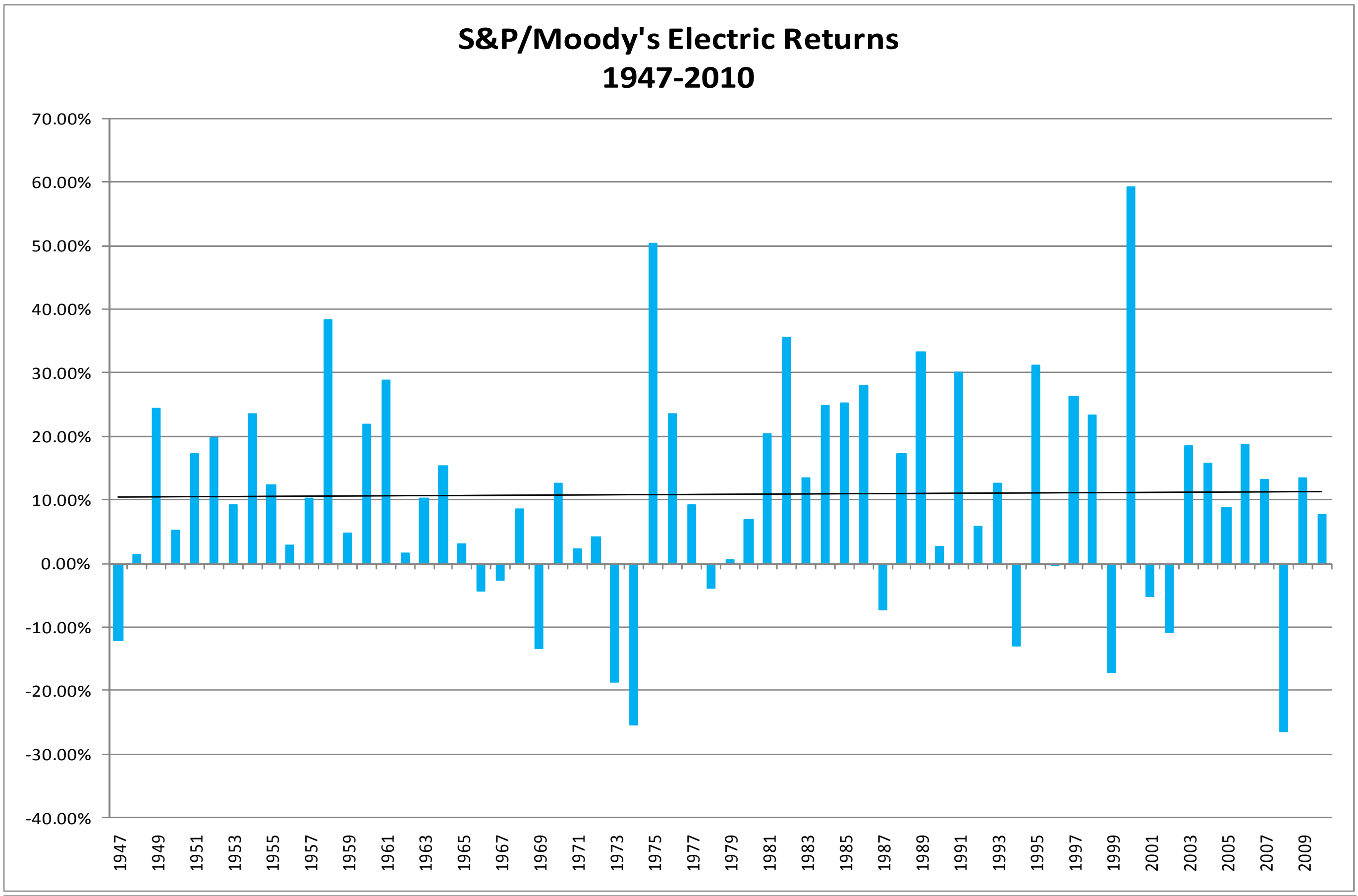
S&P/Moody's Electric Returns
1947-2010
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
-10.00%
-20.00%
-30.00%
-40.00%
1947
1949
1951
1953
1955
1957
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1963
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1967
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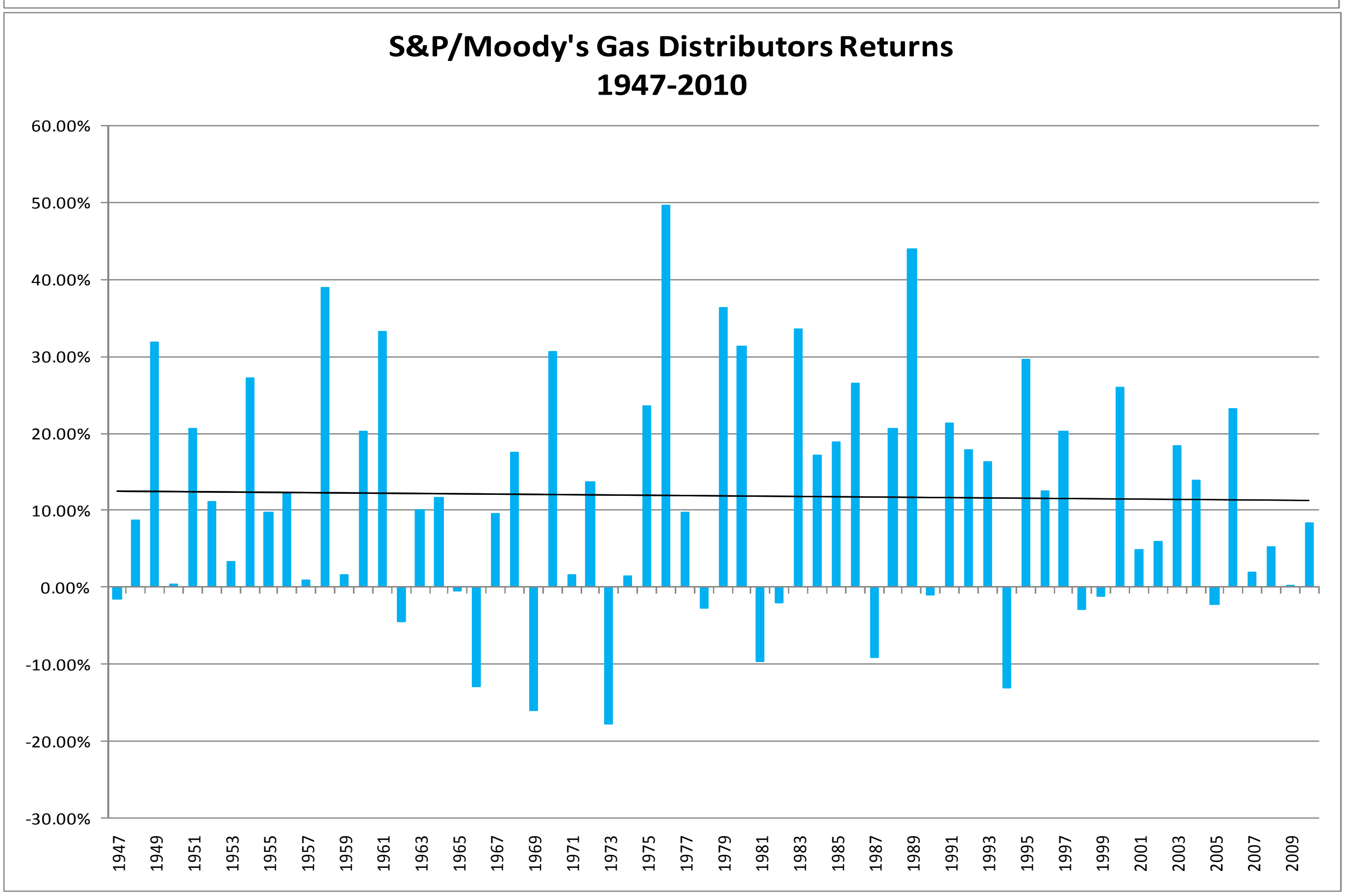
S&P/Moody's Gas Distributors Returns
1947-2010
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
-10.00%
-20.00%
-30.00%
1947
1949
1951
1953
1955
1957
1959
1961
1963
1965
1967
1969
1971
1973
1975
1977
1979
1981
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009

Schedule 16

DCF COST OF EQUITY FOR SAMPLE OF U.S. ELECTRIC UTILITIES
(BASED ON ANALYSTS' EARNINGS GROWTH FORECASTS)

Company	Annualized Last Paid Dividend (1)	Average Daily Close Prices 10/1/2010-12/31/2010 (2)	Expected Dividend Yield [1/] (3)	Analysts' Long-Term Earnings Growth Forecasts: I/B/E/S (4)	Value Line (5)	Reuters (6)	Zacks (7)	Average of All EPS Estimates (8)	DCF Cost of Equity [2/] (5)
ALLETE, Inc.	1.76	36.43	5.0	5.3	1.0	5.3	4.0	3.9	8.9
Alliant Energy Corporation	1.58	36.63	4.6	9.6	7.0	7.1	3.5	6.8	11.4
Dominion Resources, Inc.	1.83	43.14	4.5	3.5	6.5	6.5	3.4	5.0	9.4
Duke Energy Corporation	0.98	17.77	5.7	4.4	5.0	5.6	1.3	4.1	9.8
IDACORP, Inc.	1.20	36.76	3.4	4.7	5.5	4.7	4.7	4.9	8.3
NextEra Energy, Inc.	2.00	53.18	4.0	6.6	5.5	6.5	6.4	6.3	10.3
OGE Energy Corp.	1.45	44.40	3.5	7.0	6.5	5.8	5.5	6.2	9.7
Portland General Electric Company	1.04	21.28	5.1	5.4	3.0	5.3	5.6	4.8	9.9
Progress Energy	2.48	44.22	5.8	3.7	3.5	3.7	4.0	3.7	9.5
SCANA Corporation	1.90	40.91	4.8	4.8	3.5	4.7	3.8	4.2	9.0
Sempra Energy	1.56	52.25	3.1	6.6	0.0	6.5	8.5	5.4	8.5
Southern Company	1.82	37.98	5.0	5.3	4.5	5.3	4.8	5.0	10.0
Vectren Corporation	1.38	26.26	5.5	4.8	4.5	4.8	5.0	4.8	10.3
Wisconsin Energy Corporation	1.60	59.22	3.0	10.1	9.5	8.8	8.5	9.2	12.2
Xcel Energy, Inc.	1.01	23.65	4.5	6.7	5.5	6.1	5.5	5.9	10.4
Mean	**1.57**	**38.27**	**4.5**	**5.9**	**4.7**	**5.8**	**5.0**	**5.3**	**9.9**
Median	**1.58**	**37.98**	**4.6**	**5.3**	**5.0**	**5.6**	**4.8**	**5.0**	**9.8**

[1/] Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (8))
[2/] Expected Dividend Yield (Col (3)) + Average of All EPS Estimates (Col (8))

Source: www.reuters.com, Standard and Poor's *Research Insight* , *Value Line* (November and December 2010), www.yahoo.com, and www.zacks.com.

Schedule 17

DCF COSTS OF EQUITY FOR SAMPLE OF U.S. ELECTRIC UTILITIES (SUSTAINABLE GROWTH)

Company	Annualized Last Dividend Paid (1)	Average Daily Close Prices 10/1/2010-12/31/2010 (2)	Expected Dividend Yield [1] (3)	Forecast Return on Common Equity (4)	Forecast Earnings Retention Rate (5)	BR Growth [2] (4th Qtr.2010) (6)	SV Growth [3] (4th Qtr. 2010) (7)	Sustainable Growth [4] (4th Qtr. 2010) (8)	DCF Cost of Equity [5] (9)
ALLETE, Inc.	1.76	36.43	5.0	9.5	32.7	3.1	0.33	3.4	8.4
Alliant Energy Corporation	1.58	36.63	4.6	12.1	46.7	5.6	0.34	6.0	10.6
Dominion Resources, Inc.	1.83	43.14	4.5	14.2	36.0	5.1	-0.07	5.1	9.5
Duke Energy Corporation	0.98	17.77	5.7	8.3	30.0	2.5	0.05	2.5	8.2
IDACORP, Inc.	1.20	36.76	3.4	8.7	54.8	4.8	0.14	4.9	8.3
NextEra Energy, Inc.	2.00	53.18	4.0	12.0	54.3	6.5	0.54	7.0	11.1
OGE Energy Corp.	1.45	44.40	3.5	13.0	56.0	7.3	0.19	7.4	11.0
Portland General Electric Company	1.04	21.28	5.1	8.6	40.0	3.4	0.18	3.6	8.7
Progress Energy	2.48	44.22	5.8	9.0	27.3	2.5	0.08	2.5	8.3
SCANA Corporation	1.90	40.91	4.9	10.1	42.9	4.3	0.79	5.1	10.0
Sempra Energy	1.56	52.25	3.1	9.6	54.4	5.2	-0.12	5.1	8.3
Southern Company	1.82	37.98	5.0	13.0	30.0	3.9	0.79	4.7	9.7
Vectren Corporation	1.38	26.26	5.5	10.5	33.3	3.5	0.36	3.9	9.3
Wisconsin Energy Corporation	1.60	59.22	2.9	13.6	48.6	6.6	0.00	6.6	9.5
Xcel Energy, Inc.	1.01	23.65	4.5	10.2	42.5	4.3	0.32	4.7	9.1
Mean	**1.57**	**38.27**	**4.49**	**10.83**	**41.97**	**4.58**	**0.26**	**4.8**	**9.3**
Median	**1.58**	**37.98**	**4.57**	**10.22**	**42.50**	**4.35**	**0.19**	**4.9**	**9.3**

[1] Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (8))
[2] BR Growth = Col (4) * (Col (5) / 100)
[3] SV Growth = Percent expected growth in number of shares of stock * Percent of funds from new equity financing that accrues to existing shareholders [1- B/M]
[4] Col (6) + Col (7)
[5] Expected Dividend Yield Col (3) + Sustainable Growth Col (8)

Source: Standard and Poors *Research Insight*, *Value Line* (November and December 2010) , www.yahoo.com.

Schedule 18

DCF COSTS OF EQUITY FOR SAMPLE OF U.S. ELECTRIC UTILITIES
(THREE-STAGE MODEL)

Company	Annualized Last Paid Dividend	Average Daily Close Prices 10/1/2010-12/31/2010	Growth Rates: Stage 1: Average of All EPS Forecasts	Growth Rates: Stage 2: Average of Stage 1 & 3	Growth Rates: Stage 3: GDP Growth [1/]	DCF Cost of Equity [2/]
	(1)	(2)	(3)	(4)		(5)
ALLETE, Inc.	1.76	36.43	3.9	4.4	4.9	9.6
Alliant Energy Corporation	1.58	36.63	6.8	5.9	4.9	9.9
Dominion Resources, Inc.	1.83	43.14	5.0	4.9	4.9	9.3
Duke Energy Corporation	0.98	17.77	4.1	4.5	4.9	10.4
IDACORP, Inc.	1.20	36.76	4.9	4.9	4.9	8.2
NextEra Energy, Inc.	2.00	53.18	6.3	5.6	4.9	9.1
OGE Energy Corp.	1.45	44.40	6.2	5.5	4.9	8.5
Portland General Electric Company	1.04	21.28	4.8	4.9	4.9	10.0
Progress Energy	2.48	44.22	3.7	4.3	4.9	10.3
SCANA Corporation	1.90	40.91	4.2	4.5	4.9	9.5
Sempra Energy	1.56	52.25	5.4	5.2	4.9	8.0
Southern Company	1.82	37.98	5.0	4.9	4.9	9.9
Vectren Corporation	1.38	26.26	4.8	4.8	4.9	10.3
Wisconsin Energy Corporation	1.60	59.22	9.2	7.1	4.9	8.5
Xcel Energy, Inc.	1.01	23.65	5.9	5.4	4.9	9.6
Mean	**1.57**	**38.27**	**5.3**	**5.1**	**4.9**	**9.4**
Median	**1.58**	**37.98**	**5.0**	**4.9**	**4.9**	**9.6**

[1/] Forecast nominal rate of GDP growth, 2012-21

[2/] Internal Rate of Return: Stage 1 growth rate applies for first 5 years; Stage 2 growth rate applies for years 6-10; Stage 3 growth thereafter.

Source: Blue Chip *Financial Forecasts* (December 2010), www.reuters.com, Standard and Poor's *Research Insight*, *Value Line* (November and December 2010), www.yahoo.com, and www.zacks.com.

Schedule 19

DCF COST OF EQUITY FOR SAMPLE OF CANADIAN UTILITIES
(BASED ON ANALYSTS' EARNINGS GROWTH FORECASTS)

Company	Annualized Last Paid Dividend (1)	Average Daily Close Prices 10/1/2010-12/31/2010 (2)	Expected Dividend Yield [1/] (3)	I/B/E/S/ Long-Term EPS Forecasts (4)	Bloomberg Long-Term EPS Forecasts (5)	Average of EPS Estimates (6)	DCF Cost of Equity [2/] (7)
Canadian Utilities Limited	1.51	50.83	3.0	-2.6	3.0	0.2	3.2
Emera Inc.	1.30	30.96	4.5	5.0	7.0	6.0	10.5
Enbridge Inc.	1.70	55.87	3.3	8.2	9.2	8.7	12.0
Fortis Inc.	1.12	32.62	3.7	7.2	8.0	7.6	11.3
TransCanada Corp.	1.60	37.60	4.5	6.0	6.0	6.0	10.5
Mean	**1.45**	**41.58**	**3.8**	**4.8**	**6.6**	**5.7**	**9.5**
Median	**1.51**	**37.60**	**3.7**	**6.0**	**7.0**	**6.0**	**10.5**

[1/] Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (6))
[2/] Expected Dividend Yield (Col (3)) + Average of EPS Estimates (Col (6))

Source: Bloomberg; Standard and Poor's *Research Insight* ; and www.yahoo.com.

Schedule 20

DCF COSTS OF EQUITY FOR SAMPLE OF CANADIAN UTILITIES
(THREE-STAGE MODEL)

Company	Annualized Last Paid Dividend	Average Daily Close Prices 10/1/2010-12/31/2010	Growth Rates Stage 1: Average of EPS Forecasts	Growth Rates Stage 2: Average of Stage 1 & 3	Growth Rates Stage 3: GDP Growth [1/]	DCF Cost of Equity [2/]
	(1)	(2)	(3)	(4)		(5)
Canadian Utilities Limited	1.51	50.83	0.2	2.4	4.6	6.6
Emera Inc.	1.30	30.96	6.0	5.3	4.6	9.3
Enbridge Inc.	1.70	55.87	8.7	6.6	4.6	8.6
Fortis Inc.	1.12	32.62	7.6	6.1	4.6	8.8
TransCanada Corp.	1.60	37.60	6.0	5.3	4.6	9.4
Mean	**1.45**	**41.58**	**5.7**	**5.1**	**4.6**	**8.5**
Median	**1.51**	**37.60**	**6.0**	**5.3**	**4.6**	**8.8**

[1/] Forecast nominal rate of GDP growth, 2011-20
[2/] Internal Rate of Return: Stage 1 growth rate applies for first 5 years; Stage 2 growth rate applies for years 6-10; Stage 3 growth thereafter.

Source: Bloomberg; Consensus Economics *Consensus Forecasts* (October 2010); Standard and Poor's *Research Insight*; and www.yahoo.com.

Schedule 21

MARKET VALUE CAPITAL STRUCTURES FOR CANADIAN UTILITIES SAMPLE

	Debt and Preferred Shares at Par in Millions $ (September 2010)	Common Share Price Average Daily Close 10/1/2010-12/31/2010	Common Shares Outstanding in Millions (September 2010)	Total Market Capitalization (Millions $)	Market Value Common Equity Ratio
Canadian Utilities Limited	3,722	50.83	126	6,396	63.2%
Emera Inc.	3,186	30.96	114	3,523	52.5%
Enbridge Inc.	13,613	55.87	384	21,452	61.2%
Fortis Inc.	6,787	32.62	174	5,663	45.5%
TransCanada Corp.	22,294	37.60	692	26,018	53.9%
Mean				**$12,610**	**55.2%**
Median				**$6,396**	**53.9%**

MARKET VALUE CAPITAL STRUCTURES FOR U.S. ELECTRIC UTILITIES SAMPLE

	Debt and Preferred Shares at Par in Millions $ (September 2010)	Common Share Price Average Daily Close 10/1/2010-12/31/2010	Common Shares Outstanding in Millions (September 2010)	Total Market Capitalization (Millions $)	Market Value Common Equity Ratio
ALLETE, Inc.	787	36.43	34	1,242	61.2%
Alliant Energy Corporation	2,949	36.63	110	4,046	57.8%
Dominion Resources, Inc.	17,156	43.14	585	25,237	59.5%
Duke Energy Corporation	18,004	17.77	1320	23,454	56.6%
IDACORP, Inc.	1,619	36.76	48	1,768	52.2%
NextEra Energy, Inc.	20,468	53.18	411	21,851	51.6%
OGE Energy Corp.	2,597	44.40	97	4,325	62.5%
Portland General Electric Company	1,828	21.28	75	1,602	46.7%
Progress Energy	12,734	44.22	294	13,000	50.5%
SCANA Corporation	4,831	40.91	127	5,180	51.7%
Sempra Energy	9,110	52.25	247	12,887	58.6%
Southern Company	21,193	37.98	836	31,750	60.0%
Vectren Corporation	1,796	26.26	81	2,132	54.3%
Wisconsin Energy Corporation	4,957	59.22	117	6,923	58.3%
Xcel Energy, Inc.	9,424	23.65	460	10,889	53.6%
Mean				**$11,086**	**55.7%**
Median				**$6,923**	**56.6%**

Source: Reports to Shareholders, www.yahoo.com

QUANTIFICATION OF IMPACT ON EQUITY RETURN REQUIREMENT FOR DIFFERENCE BETWEEN MARKET VALUE AND BOOK VALUE CAPITAL STRUCTURES:

Formula for After-Tax Weighted Average Cost of Capital:

$WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)

APPROACH 1:

The after-tax weighted average cost of capital ($WACC_{AT}$) is invariant to changes in the capital structure. The cost of equity increases as leverage (debt ratio) increases, but

$WACC_{AT(LL)}$ = $WACC_{AT(ML)}$

Where LL = less levered (lower debt ratio)
ML = more levered (higher debt ratio)

ASSUMPTIONS:

Debt Cost	=	Market Cost of Long Term Debt for Baa rated utility
	=	5.00%
Equity Cost	=	9.30%
Tax Rate	=	28.0%
CEQ Ratio	Step (1)	55.0%
Debt Ratio	Step (1)	45.0%
CEQ Ratio	Step (2)	40.0%
Debt Ratio	Step (2)	60.0%

STEPS:

1. Estimate $WACC_{AT}$ for the less levered sample (common equity ratio of 55.0%)

$WACC_{AT}$ = (5.00%)(1-.280)(45.0%) + (9.30%)(55.0%)
= 6.74%

2. Estimate Cost of Equity for sample at 40.0% common equity ratio with $WACC_{AT}$ unchanged at 6.74%

$WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)
6.74% = (5.00%)(1-.280)(60.0%) + (X)(40.0%)
Cost of Equity at 40.0% Equity Ratio = 11.44%

3. Difference between Equity Return at 55.0% and 40.0% common equity ratios:

11.44% - 9.30% = 2.14% (214 basis points)

APPROACH 2:

After-Tax Cost of Capital Falls as Debt Ratio Increases; Cost of Equity Increases

$$WACC_{AT(LL)} = WACC_{AT(ML)} \times \frac{(1\text{-}tD_{LL})}{(1\text{-}tD_{ML})}$$

Where LL,ML as before
t = tax rate
D = debt ratio

ASSUMPTIONS:

Debt Cost	=	Market Cost of Long Term Debt for Baa rated utility
	=	5.00%
Equity Cost	=	9.30%
Tax Rate	=	28.0%
CEQ Ratio	Step (1)	55.0%
Debt Ratio	Step (1)	45.0%
CEQ Ratio	Step (2)	40.0%
Debt Ratio	Step (2)	60.0%

STEPS:

1. Estimate $WACC_{AT}$ for less levered sample (common equity ratio of 55.0%)

$WACC_{AT}$ = (5.00%)(1-.280)(45.0%) + (9.30%)(55.0%)
= 6.74%

2. Estimate $WACC_{AT}$ for more levered firm (common equity ratio of 40.0%)

$WACC_{AT(ML)} = WACC_{AT(LL)}$ x (1-t x Debt $Ratio_{ML}$)/(1-t x Debt $Ratio_{LL}$)

$$WACC_{AT(ML)} = 6.74\% \times \frac{(1\text{-}.280 \times 60.0\%)}{(1\text{-}.280 \times 45.0\%)}$$

$WACC_{AT(ML)}$ = 6.41%

3. Estimate Cost of Equity at new $WACC_{AT}$ for more levered firm:

$WACC_{AT(ML)}$ = (Debt Cost)(1-tax rate)(Debt $Ratio_{ML}$) + (Equity Cost)(Equity $Ratio_{ML}$)
6.41% = (5.00%)(1-.280)(60.0%) + (X)(40.0%)
Cost of Equity at 40.0% Equity Ratio = 10.63%

4. Difference between Equity Return at 55.0% and 40.0% common equity ratios:

10.63% - 9.30% = 1.33% (133 basis points)

Capital Structure

Testimony provided by:

Kathleen C. McShane
Foster Associates Inc.

June 2005

9.0 TESTIMONY OF KATHLEEN C. MCSHANE - CAPITAL STRUCTURE

9.1 Introduction

My name is Kathleen C. McShane and my business address is 4550 Montgomery Avenue, Suite 350N, Bethesda, Maryland 20814. I am a Senior Vice President of Foster Associates, Inc., an economic consulting firm. I hold a Masters in Business Administration with a concentration in Finance from the University of Florida (1980) and the Chartered Financial Analyst designation (1989).

I have testified on issues related to cost of capital and various ratemaking issues on behalf of local gas distribution utilities, pipelines, electric utilities and telephone companies, in more than 130 proceedings in Canada and the U.S. My professional experience is provided in Appendix D.

9.1.1 Purpose of Testimony

Nova Scotia Power Inc. ("NSPI") is requesting, as part of its application for 2006 rates, to maintain the 9.55% return on equity and 37.5% common equity ratio allowed by the Nova Scotia Utility and Review Board (UARB) in NSUARB-NSPI-P-881 dated March 31, 2005. NSPI has requested that I provide an expert opinion on its proposal.

9.1.2. Approach

The UARB issued its decision setting NSPI's allowed return on equity at 9.55% (with a range of 9.3-9.8%) less than three months ago. That decision reflects its consideration of evidence from a number of cost of capital witnesses. The witnesses applied the various cost of equity tests that are typically employed to estimate a fair return on equity. Their tests and conclusions were thoroughly tested through the information request and cross-examination process.

In light of the recent review of the issues, my opinion in this case is not based on a *de novo* application of the traditional tests. Instead, my opinion is based primarily on whether NSPI's proposal to maintain the 9.55% allowed return on common equity is reasonable in light of:

1. Current capital market conditions and their implications for the reasonableness of the level of allowed returns of Canadian utilities generally;

2. The level of allowed returns for U.S. utilities, in conjunction with their allowed capital structures;

3. The returns on equity allowed elsewhere in Canada for NSPI's peers; and,

4. NSPI's relative risk compared to other Canadian utilities and the indicated required differential in allowed return.

9.1.3 Conclusions

My principal conclusions are as follows:

1. A fair return on equity for a utility explicitly recognizes the alternative investment opportunities available to equity holders.

2. The opportunities for equity investors, which are both domestic and global, indicate the allowed returns for Canadian utilities generally are relatively low.

3. Market participants, such as debt rating agencies and equity analysts, confirm this conclusion.

4. NSPI's allowed return on equity of 9.55% is effectively lower than those of its Canadian peers, since NSPI faces higher business risk than the typical Canadian investor-owned utility; the higher business risk has not been offset by lowering the financial risks through a thicker common equity ratio.

5. A common equity ratio of approximately 45% is warranted for NSPI, based on its relative business risks. The proposed 37.5% common equity ratio is materially lower than 45%.

6. At a 37.5% common equity ratio, an increment to the return on equity of 50-110 basis points relative to the average allowed return of other Canadian utilities is required to compensate for NSPI's higher risks. The incremental return, if added to an estimated allowed ROE of about 9.3% for other Canadian utilities would place NSPI's risk-adjusted return at 9.8-10.4%, in excess of the 9.55% return on equity currently allowed.

7. Based on the above considerations, NSPI's 9.55% allowed ROE is relatively low under prevailing and forecast capital market conditions, given its risk profile. Under these circumstances, the Company's proposal to maintain the current allowed return at the relatively low level of 9.55% is reasonable.

9.2. The Fair Return on Equity

9.2.1 Standards for a Fair Return

The estimation of what constitutes a fair return on equity starts with the three criteria that have been adopted by both judicial and regulatory precedent.[54]

A fair return is one that provides a utility with the opportunity to:

1. Earn a return on investment commensurate with that of comparable risk enterprises;
2. Maintain its financial integrity; and,
3. Attract capital on reasonable terms.

These criteria give rise to two separate standards, the capital attraction standard and the comparable returns, or comparable earnings, standard.

The ability to attract capital is not synonymous with being allowed a return that meets the comparable earnings or comparable returns criterion. Virtually any utility can attract capital (debt or equity) at a cost. Moreover, in determining the allowed return on equity, the focus needs to be on the return requirements of the equity investor. The objective is not to set a return on equity that allows the utility to raise new debt at reasonable cost, but rather to set a return on equity that is equal to that achievable on investments of similar risk, i.e., that is fair and reasonable to the equity investor.

A fair return on equity does not depend on whether the utility has an immediate need to raise additional funds externally. First, failure to award a return on equity that meets the comparable returns standard risks incenting

[54] Northwestern Utilities Ltd., v. Edmonton (1929 S.C.R. 186); Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923); and Federal Power Commission v. Hope Natural Gas Company (320 U.S. 301, 1944).

existing investors to withdraw capital and reinvest it in a venture that provides an appropriate return for the risk assumed, thus impairing the utility's financial integrity. Awarding a return that meets the comparable returns standard only when there is an immediate need to raise new equity is a strategy that is doomed to failure. Allowing a return that meets the comparable returns standard only when new equity is required is a form of investor entrapment, which investors can avoid by committing capital elsewhere from the outset.

Second, a utility always may have the option to either pay out earnings in dividends or retain earnings for reinvestment. Investors are not likely to sanction the retention of earnings for reinvestment if they themselves can reinvest the dividends in investments that have the opportunity for higher returns at similar levels of risk.

If a utility's investors demand 100% payout of earnings in the form of dividends a utility will be forced to access the equity market each time it requires funds in excess of depreciation. That recognition leads to the logical conclusion that the fair return is not tied to a utility's ability to generate adequate funds internally to meet it capital expenditures. It is tied to the cost of raising those funds.

9.2.2 Alternative Investment Opportunities

The opportunities for equity investors in Canada are expanding domestically as well as globally. Focusing on domestic opportunities, over the past three years, the income trust market in Canada has grown exponentially. In the past five years, the market value of income trusts has grown from $20 billion to over $130 billion, accounting for over 10% of the total market value of the publicly traded equity in Canada. In 2004, income trusts accounted for approximately 50% of all initial and secondary equity offerings. The appeal of income trusts lies in their income tax efficiency[55], and in their distribution to investors of virtually 100% of their free cash flow.

The income trust market provides an attractive alternative to the conventional equity market for investors. While income trusts span the spectrum of industries, approximately 15% of the outstanding market capitalization of income trusts is attributable to pipeline and power income trusts. These income trusts, which are generally of lower or similar risk to conventional utility equities, compete directly with the conventional utility equities for capital.

In addition to the burgeoning domestic market for income trusts, the globalization of capital markets makes available to Canadian investors a broader array of investment opportunities. Historically, investment abroad was limited by various factors. Transaction costs and costs of information barriers to global investment proved to be substantial. Those barriers, however, are being removed. Such factors as standardization of financial reporting, and the increasing coverage of global equities make possible an "apples to apples" comparison of a Canadian utility investment to a foreign utility investment.

The barriers have also been lowered by virtue of the removal of the foreign investment cap to which Canadian pension funds and other investment plans (RRSPs, RESPs) have been subject. The foreign investment cap, which had been raised from 20% to 25% in 2000 and to 30% in 2001, will be removed in its entirety as a result of the 2005 Federal budget (second reading May 19, 2005).[56] Investment outside of Canada has continued to grow rapidly as the

[55] The term tax efficiency means that the trust is structured to minimize corporate income taxes owed with the tax burden shifted to the investor, eliminating double taxation of investment income. Investment income takes the form of interest, dividends and return of capital. Return of capital results in a deferral of income tax.

[56] *The Globe and Mail* reported that the removal of the foreign content cap is expected to "have the broadest long-term impact of any personal finance measure in the budget. Global stock markets, accessible to any investor through global equity mutual funds, have historically made higher returns than the Canadian market, which only accounts for just over 2 per cent of the world's stock market value." Rob Carrick, "Finance: Your Bottom Line", Globe and Mail.com, February 23, 2005.

barriers to foreign investment have declined. Foreign stock purchases by Canadians have more than quadrupled since the mid 1990s. Purchases in 1995 were $83 billion; in 2004, they were $513 billion.[57] In 2004, although the total percentage of foreign assets in the top 100 Canadian pension funds was only approximately 29%, the percentage of foreign equity to total equity was over 50%.[58] In other words, pension funds have concentrated their foreign investment allocations to the equity markets, with the preponderance of their fixed income allocations in domestic bonds.

The removal of the 30% foreign investment cap may not impact, in the near-term, the proportion of capital committed by the large pension funds outside of Canada. It has been possible to effectively circumvent the 30% cap through investments in clone funds that qualified as Canadian content, but whose returns tracked foreign indices.[59] The removal will likely, however, impact the form in which pension funds allocate their investments, e.g., direct investment in specific equities rather than indirect investments through clone funds. Further, it is likely to impact directly the proportion of foreign investment made by the smaller pension funds and individual investors. In addition, it provides a platform for the larger pension funds to increasingly build their portfolios in regulated firms abroad, such as the investment by Ontario Municipal Employees Retirement System and Ontario Teachers Pension Plan in the Express Pipeline in the U.S., and Scottish and Southern Energy in the U.K.[60]

With the increasing focus on global opportunities, the ability of Canadian utilities as a sector to retain capital investment is dependent on the

[57] The IFIC's report "Year 2002 in Review" stated,

> "During the period of 1991-1998, the percentage of sales in equity mutual funds that were comprised of non-domestic equities has hovered around the 41-58% range. This has significantly increased in 1999 and onwards. While performance in the markets is the major factor affecting such an increase, these figures can also be attributed to increases in foreign content limits in registered retirement savings plans as well as increased interest and availability of foreign clone funds."

[58] Benefits Canada, "Pensions Without Borders", May 2005.

[59] Clone funds were declared "obsolete" immediately following the announcement that the cap would be removed.

[60] In August 2004, OMERS announced an asset mix strategy which will see a shift from 4% of its assets invested in infrastructure to 15% in the next few years.

competitiveness of their returns. Recent allowed returns in Canada are relatively unattractive, particularly in comparison to those of U.S. utilities, to which Canadian utilities are most comparable.

The following table compares the allowed returns for Canadian utilities to those allowed for U.S. utilities (electric and gas) over the past decade.

Table 1

Year	Average Allowed ROE: Canadian Utilities	Average 30-Year Canada Yield	Risk Premium	Average Allowed ROE: U.S. Utilities	Average 30-Year/ Long-Term Treasury Yield	Risk Premium
1995	12.1	8.4	3.7	11.5	6.8	4.7
1996	11.4	7.8	3.6	11.3	6.7	4.6
1997	10.9	6.7	4.2	11.3	6.6	4.8
1998	10.2	5.6	4.6	11.6	5.5	6.0
1999	9.5	5.7	3.8	10.7	5.9	4.8
2000	9.8	5.7	4.1	11.4	5.9	5.5
2001	9.7	5.8	3.9	11.0	5.5	5.5
2002	9.6	5.7	3.9	11.1	5.4	5.7
2003	9.7	5.3	4.4	11.0	5.0	6.0
2004	9.6	5.1	4.5	10.7	5.1	5.6
2005 Q1	9.5	4.7	4.8	10.5	4.7	5.8

Source: Appendix D, Schedule 1.

Table 1 shows that Canadian allowed utility returns were at similar levels to U.S. utility returns between 1995-1997. However, while allowed Canadian returns have declined by approximately 250 basis points between 1995 and 2005 from about 12% to 9.5%, the decline in U.S. allowed returns has been more modulated (from about 11.5% to 10.5%).

Given the similarity in the cost of capital environment between Canada and the U.S., it should be expected that the allowed returns in the two countries should, given a similar utility risk environment, have converged. However, as the majority of Canadian regulators began to gravitate toward the equity risk premium test starting in the mid-1990s, Canadian allowed returns on equity have tracked the downward trend in government bond yields to a much closer degree than allowed returns in the U.S. Currently the differential between allowed returns in Canada generally and the U.S. is about 100 basis points.

The possibility that electric and gas utilities in the U.S. face higher business/regulatory risks than the typical Canadian utility is offset by significantly higher allowed common equity ratios in the U.S. The average allowed common equity ratio for the major investor-owned Canadian electric and gas utilities is approximately 37%. In contrast, the average allowed common equity ratio for U.S. electric and gas utilities (2000-2005 Q1) has been approximately 47%, as shown below in Table 2.

Table 2

Allowed Common Equity Ratios for U.S. Gas and Electric Utilities	
2000	48.7%
2001	46.3%
2002	47.2%
2003	49.7%
2004	46.3%
2005 (Q1)	45.3%
Average [1/]	47.2%

1/ Weighted by number of decisions in each year.

Source: Regulatory Research Associates, *Major Rate Case Decisions, January 1990-December 2004*, January 2005 and *Major Rate Case Decisions - January to March 2005*, April 2005.

The difference in equity ratios between Canadian and U.S. utilities can be quantified, that is, translated into a further differential in equity returns. The ten percentage point differential between the average common equity ratios for the U.S. and Canadian utilities translates into approximately 100 basis points in additional equity return compensation in favor of U.S. utilities if the Canadian and U.S. utilities are placed on an equivalent common equity ratio basis.

9.2.3 Capital Market Participant Commentary

There have been, over the past several years, concerns expressed by market participants as a result of the disparity between allowed returns in Canada and the U.S. The Dominion Bond Rating Service (DBRS) has pointed to the low level of returns. In a May 2003 commentary entitled, "The Rating Process and the Cost of Capital for Utilities: Five Reasons Why Canadian Utilities Have Lower Ratios, and Five Changes to Regulation Which Should Be Introduced in Canada" (May 2003), DBRS called for increasing the allowed returns in Canada in order to make them more consistent with U.S. returns.

The most recent commentary by DBRS on the low level of returns was issued subsequent to the Alberta Energy and Utilities Board's (AEUB) Generic Cost of Capital Decision in July 2004. In its decision, the AEUB set allowed capital structures and returns on equity for eleven electric transmission and distribution utilities, and natural gas distribution and pipeline companies under its jurisdiction. The decision (2004-052, dated July 2, 2004) set the allowed common equity ratios at 33% for electric transmission utilities, 37% for electric distribution utilities, and 38% for the major gas distribution utility in the province. The allowed return on equity for all eleven utilities was set at 9.6% for 2004. A mechanism to automatically adjust allowed returns on equity, based on changes in the forecast long-term Canada bond yield, was also implemented. The resulting allowed ROE for 2005 is 9.5%, virtually identical to NSPI's allowed 9.55%.

In December 2004, DBRS referred to the low approved returns on equity as a "Challenge" for the ATCO Utilities. The ATCO Ltd. report stated:

> While ATCO's diversified operations, coupled with the Company's prudent management approach, provide a level of earnings stability, additional challenges over the medium term include the relatively low approved returns on equity (ROE) and deemed equity for the regulated businesses, continuing regulatory risk and lag and ATCO's merchant power exposure in Alberta.[61]

Additional recent DBRS reports citing the challenge of low approved returns on equity have been published for other Alberta utilities, i.e., AltaLink,[62] and FortisAlberta.[63]

Standard & Poor's has also cited the Alberta utilities' low equity returns and common equity ratios subsequent to the Generic Cost of Capital decision. In its recent report for AltaLink, S&P stated,

> Like many Canadian regulated utilities, AltaLink's modest financial position is constrained by a comparatively low approved ROE and thin equity base.[64]

A CIBC World Markets Report entitled "Pipelines and Utilities: Time to Lighten Up", published December 2001, stated, in reference to the-then recent formulaic reduction in Newfoundland Power's allowed return:

> The magnitude of the reduction in the case of Newfoundland Power illustrates the flaw in using a brief snapshot of existing rates rather than a forecast of rates that are expected to persist during the upcoming year. More importantly, however, it shows the shortcoming of the formula approach itself. Mechanically tying allowed returns on equity to long bond yields is an approach that is simple for regulators to apply; however, in recent years, with a steady decline in bond yields, it has produced-allowed

[61] DBRS, "Credit Rating Report: ATCO Ltd.", December 29, 2004, page 1.
[62] DBRS, "Credit Rating Report: AltaLink, L.P.", November 24, 2004.
[63] DBRS, "Credit Rating Report: FortisAlberta", September 22, 2004.
[64] Standard & Poor's, "Research: AltaLink, L.P.", April 19, 2005.

> returns that are out of sync with the cost of capital, and returns that are being achieved with comparable nonregulated companies or regulated returns that are achievable in the U.S.[65]

In her August 15, 2003 "Research Industry Comment: Utilities", entitled "It's the Grid, Silly" (following the power outage in Canada and the U.S.), RBC Capital Markets' analyst Maureen Howe pointed to the relatively low level of Canadian utility returns. In her "Investment Opinion", she stated,

> Allowed returns on equity (ROEs) in Canada for regulated transmission and distribution utilities are relatively low compared to the U.S. For example, the Alberta Energy and Utilities Board recently approved an allowed ROE of 9.4% based on a 34% deemed common equity component for AltaLink. In comparison, the U.S. Federal Energy Regulatory Commission (FERC) approved an allowed ROE of 13.88% for International Transmission Co., which took over DTE Energy's transmission assets in April 2003. To encourage new transmission investment, FERC has proposed additional incentives that would boost allowed ROEs for transmission investments. With renewed emphasis on new investment in the power grid, Canadian regulators could follow suit.

A further perspective on the relatively low allowed rates of earnings arises from a comparison with the earnings levels of unregulated, but relatively low risk firms. A comparable earnings analysis I have recently conducted shows that low risk competitive firms in Canada have been earning, on average, returns on equity in the 12.0-12.5% range over the past full business cycle (1993-2004). The low interest rate environment has been positive for competitive firms; their rate of earnings has increased from an average of approximately 12.0% in the first half of the cycle (1993-1998) to an average of 13.0% in the second half of the cycle (1999-2004). By comparison, the low interest rate environment has reduced the allowed returns for Canadian utilities to approximately 9.5%. Thus, representing a gap between the two of over 275 basis points based on the cycle average earnings of low risk industrials

[65] Although Newfoundland Power's allowed equity risk premium was subsequently increased in a June 2003 decision, its 2005 allowed return of 9.24% is subject to the same criticisms expressed in 2001.

and about 350 basis points based on the industrials' earnings during the latter half of the cycle.

In sum, the preceding observations and analysis support the conclusion that the allowed returns on equity of Canadian utilities generally have been regarded as low. Since NSPI's allowed return is well within the range of returns allowed elsewhere in Canada, it would be similarly viewed as low.

9.3. NSPI Compared to its Canadian Utility Peers

9.3.1. Basic Principles

The preceding section focused on the low level of allowed returns for Canadian utilities generally. In that context, NSPI's allowed return of 9.55%, applied to an allowed common equity ratio of 37.5%, is virtually identical to the average of other investor-owned Canadian utilities (9.5% on an average allowed common equity ratio of 37%; see Schedule 1).

This section limits the comparison of NSPI's proposal, i.e., to maintain the recent allowed return of 9.55% and a common equity ratio of 37.5%, to the corresponding returns and capital structures of NSPI's Canadian peers.

This comparison needs to recognize from the outset that the fair return is a function of a utility's business and financial risk, the latter encapsulated in its allowed common equity ratio. With respect to the common equity ratio, the UARB has, in its two prior decisions, authorized NSPI to increase its actual common equity ratio to 40%. NSPI has not yet attained that level; consequently, the comparison with other Canadian utilities should reflect the common equity ratio on which NSPI's rates will actually be set, 37.5%.

As regards the relationship between business risk, financial risk, and allowed return on equity, the following principles are relevant:

All other things being equal (e.g., capital structure ratios), the higher the business risk, the higher the cost of equity, and, consequently, the higher should be the allowed return.

The higher the business risk a specific utility faces relative to its peers, the higher the allowed common equity ratio needs to be to offset the higher level of business risk. In other words, two utilities that face different levels of business risk can have the same level of total risk if the utility facing higher business risk also has a higher allowed equity ratio. If, however, the higher business risk utility's common equity ratio does not fully offset its higher business risk relative to its peers', its allowed common equity return needs to be higher than its peers' to fully compensate equity investors for the total (business plus financial) risk to which they are exposed.

9.3.2. NSPI's Relative Business Risks

In light of these considerations, the assessment of the reasonableness of NSPI's 9.55% allowed return relative to the allowed returns of its Canadian peers should start with an assessment of NSPI's relative business risks. Tables 3 and 4 below summarize my conclusions regarding NSPI's business risk position relative to each of the major investor-owned electric and gas distribution utilities. Table 3 compares NSPI to the other electric utilities; Table 4 compares NSPI to the major gas distribution utilities.

Table 3

Electric Comparators	Type [1/]	Relative Business Risk vs. NSPI [2/]
AltaLink	T	L
ATCO Electric	T&D	L
FortisAlberta	D	L
FortisBC	Integrated	L
Maritime Electric	T&D	L
Newfoundland Power	T&D	L

1/ T = Transmission; D = Distribution.

2/ L = Lower business risk than NSPI; H = Higher business risk than NSPI.

Table 4

Gas Comparators	Relative Business Risk vs. NSPI
ATCO Gas	L
Enbridge Gas	L
Gaz Metro	H
Pacific Northern Gas	H
Terasen Gas	L
Union Gas	L

In my opinion, as indicated on Tables 3 and 4 above, of the major investor-owned electric and gas utilities, only Gaz Metro and Pacific Northern Gas face higher business risk than NSPI.

The factors that lead to the conclusion that NSPI faces higher business risks than all but two of the electric and gas utilities listed above include the following.

1. Only two of the utilities (NSPI and FortisBC) are truly integrated

utilities, that is, they own and operate the generating plants that supply a significant portion of their load.

Generation carries higher operating risks than a "wires-only" or "pipes-only" business. This is because of the high capital investment and risk associated with the costs and availability of fuel, and issues such as replacement power costs if the plant fails to operate. Moreover, generation is the major utility function that is not necessarily a natural monopoly; the electric wires and gas distribution pipes are unlikely to ever be duplicated.

A comparison of NSPI to FortisBC reveals that NSPI has largely coal and oil fired plants (54.2% and 15.3% of generating plant respectively), while FortisBC's generating plant is comprised entirely of lower risk and lower cost hydro facilities. The lower cost hydro facilities of FortisBC translate into a lower probability that FortisBC's generating capacity will be replaced by alternative generating sources. This means a lower level of long-term competitive and stranded cost risk for FortisBC versus NSPI.

2. Integrated utilities, like NSPI, also have the obligation to build new capacity, and are therefore subject to the risk of significant cost disallowances if the generating plants have to be shut down. Also an integrated utility has the obligation to acquire replacement power, if its own plants are unavailable, potentially at higher costs that may not be recoverable. None of the Alberta electric utilities retain the obligation to build; their obligation to supply customers is very limited in the restructured electric utility environment.

3. Other risks largely related to generation that are not faced by other Canadian utilities to the same degree as NSPI include:

Foreign exchange risk: NSPI has significant exposure to foreign exchange risk due primarily to its fuel requirements, purchased in world markets in U.S. dollars. None of the other utilities listed in Tables 3 and 4 has a similar level of exposure.

Exposure to future costs of environmental compliance: NSPI faces the risk of incurring significant costs to comply with environmental laws, such as the Kyoto Accord and Provincial emissions requirements. This risk is relatively high for NSPI due to the nature of its generation facilities. None of the other utilities in Tables 3 and 4 has a similar level of exposure.

4. The Alberta utilities also have a lower level of risk arising from the provision of transmission service than NSPI. Many of the transmission responsibilities that were formerly the role of the electric utilities have been transferred to the Alberta Electric Systems Operator (AESO).[66] In addition, the Alberta transmission utilities have little risk of underrecovery of their allowed revenue requirement. The transmission revenue requirement recovered by the facility owners from the AESO in monthly amounts; its recovery is neither dependent on the weather nor the economy. The same is not true of NSPI, for whom recovery of its entire revenue requirement is subject to load variations arising from both weather and economic conditions.

[66] For example, the AESO is responsible for the planning of the transmission network and dispatching of generating plants.

5. A key difference between NSPI and other Canadian utilities is the absence of a mechanism to recover its fuel costs. Virtually all of the other electric utilities in Table 3 either operate with such a mechanism (Maritime Electric and Newfoundland Power) or have no need of one. The Alberta utilities have no requirement for such a mechanism as they no longer directly supply end use customers.[67] FortisBC is the only investor-owned utility other than NSPI which provides a bundled supply that has some exposure. While FortisBC has some exposure to underrecovery of power costs, (1) it has more limited exposure to market prices than NSPI, since FortisBC's own generation is hydro,[68] and (2) it has operated with a mechanism which shares with customers deviations from forecast purchased power costs.

Each gas distributor in Table 4 has a mechanism that allows the timely recovery of actual purchased gas costs.

6. A further risk mitigating mechanism from which a number of the Canadian utilities benefit is a weather-normalization mechanism. A weather-normalization mechanism provides for timely recovery from customers of underearnings due to warmer than normal weather (or refunding to customers of overearnings due to colder than normal weather). The utilities in Tables 3 and 4 that benefit from such a mechanism include Newfoundland Power, Gaz Metro, Terasen Gas, and Pacific Northern Gas. Although the Alberta electric distribution utilities have no such mechanism, their loads tend to be less impacted by weather variability than NSPI's, since the Alberta electric utilities have no heating load. By

[67] Both ATCO Electric and Fortis Alberta have authorized other companies to serve those customers that still qualify for a regulated rate service.
[68] Its exposure is limited to a relatively small component of its purchased power.

comparison, electricity has an approximately 25% market share for home heating in Nova Scotia.

7. Finally, the business risk profile of a utility is a function of the economic environment of its service area. In comparison to Alberta, British Columbia, and Ontario, the provinces served by the majority of the utilities in the Tables 3 and 4, Nova Scotia has a smaller, less economically diverse economy. As such, the lesser economic diversity of NSPI's customer base is a further contributor to a higher business risk profile relative to the other major investor-owned Canadian utilities.

9.3.3. Market Participants' Commentary on NSPI's Business Risk

My conclusion that NSPI is among the highest business risk Canadian utilities is shared by Standard & Poor's. S&P has assigned to NSPI a business risk profile score of "4".[69] No other Canadian utility has been assigned a score of "4". Table 5 below indicates that virtually every other Canadian utility assigned such a score was assigned a "3".

[69] On a scale of "1" to "10", with "10" indicating the highest business risk.

Table 5

Company	S&P Business Risk Profile
AltaLink L.P.	2.5
CU Inc.	3
Enbridge [1/]	2
Hydro One Inc.	3
Newfoundland Power	3
Nova Gas Transmission	3
Terasen Inc./Terasen Gas	3
TransCanada PipeLines	3
Median	**3**

1/ Enbridge Inc. and Enbridge Gas Distribution.

S&P has specifically referenced NSPI's lack of a fuel clause in its assessment that NSPI is of higher business risk than its Canadian peers. In a recent report,[70] S&P noted:

> A recent regulatory decision in Nova Scotia, however, has left a number of issues unresolved for that province's incumbent utility, Nova Scotia Power Inc. (BBB+/Stable/__) and its parent, Emera Inc. (BBB+/Stable/__). The high level of regulatory oversight and lack of fuel-protection mechanisms expose Nova Scotia Power to higher business risk relative to other Canadian gas and electric utilities that typically benefit from fuel adjustment or fuel cost flow through mechanisms.

DBRS has also cited a number of NSPI's business risk challenges.[71] These include a number of the relative risk factors I discussed above. The challenges are:

a. NSPI is one of the highest cost generators in Canada, which makes Nova Scotia an attractive market for potential competitors;

[70] Standard & Poor's, "Industry Report Card: Top 48 Global Utilities", May 17, 2005.
[71] DBRS, "Credit Rating Report: Nova Scotia Power Inc.", January 20, 2005.

b. Low population density in service area;

c. Competition from natural gas in longer-term;

d. Earnings sensitivity to weather and fuel costs; and

e. Future environmental risks.

9.3.4. Implications of NSPI's Higher Business Risk

While NSPI faces higher business risk relative to its peers, that higher business risk is not offset by a higher allowed common equity ratio. For 2006, NSPI's applied for common equity ratio is 37.5%. An allowed common equity ratio of 37.5% is lower than the average of all the major investor-owned electric utilities (see Table 6 below), all of which face lower business risk than NSPI. More significantly, it is materially lower than the average of those electric utilities which NSPI is closer to (but still higher than) in business risk. NSPI's 37.5% proposed common equity ratio for 2006 compares to an average of 41.5% for FortisBC, Maritime Electric and Newfoundland Power.

Table 6

Electric Comparators	Type	Allowed Equity Ratios	2004 Actual Equity Ratios (Based on Total Capital)
AltaLink	T	35%	39.1%
ATCO Electric	T&D	33-37%	35.0%
Fortis Alberta	D	37.0%	42.9%
FortisBC	Integrated	40.0%	40.6%
Maritime Electric	T&D	40.0% [1/]	46.8%
Newfoundland Power	T&D	44.5% [2/]	44.4%

1/ Minimum, as set by legislation.

2/ Allowed up to 45%.

Based on my assessment of the relative business risks faced by NSPI, the capital structures of its Canadian peers, and the debt ratings of its Canadian peers, NSPI would likely require a common equity ratio in the range of 42.5-47.5% (mid-point of 45%) to be equivalent in total risk to the typical investor-owned Canadian utility. The average debt ratings by the major Canadian debt rating agencies (Standard & Poor's and DBRS) are in the A category. NSPI, in comparison, has a DBRS rating of A-, an S&P rating of BBB+ and a Moody's rating of Baa1 (See Schedule 2).

As a test of the conclusion that a 45% common equity ratio would be adequate to offset NSPI's higher business risk, I looked at S&P's debt rating guidelines. S&P has issued financial ratio guidelines for various debt rating categories at various business risk profile scores. For the "4" business risk profile score that was assigned to NSPI, and a debt rating of A, S&P's guideline debt ratio range is 45-52%. If NSPI's preferred shares are treated as debt, as they are by both S&P and Moody's, a 45% common equity ratio equates to a 55% debt ratio. A 55% debt ratio lies somewhat above the upper end of S&P's guideline range for NSPI's business risk profile. If, instead, NSPI's preferred shares are viewed as having a 30% debt weighting[72], a 45% allowed common equity ratio implies an effective debt ratio of approximately 48.5% (including 30% of the 9.2% preferred share component). A 48.5% debt ratio is the mid-point of S&P's guideline debt ratio range for an A rating and a "4" business risk profile score.

Thus, on balance, a 45% allowed common equity ratio for NSPI would be compatible with ratings in the A category which, in turn, would approximately equate it to an average risk, or typical, Canadian utility, in terms of total risk. However, there is a material gap between the 45.0% common equity ratio that would equate NSPI's total risk to that of the typical Canadian utility and its proposed common equity ratio of 37.5%. The required equity return differential to compensate for that gap is developed below.

[72] DBRS assigns NSPI's preferred shares a 30% debt weighting.

Table 7 below sets out for each of the major investor-owned utilities, or groups of utilities, subject to automatic adjustment formulas (1) the actual allowed return for 2005; and (2) an estimate of the allowed equity returns for 2006, based on the most recent consensus forecast available of Government of Canada bond yields.

The allowed equity return estimates for 2006 were based on Consensus Economics, *Consensus Forecasts* (May 2005), 12-month forward forecast of 10-year Canadas of 4.9% to which the April spread of 44 basis points between 10- and 30-year Canadas was added. This results in a forecast of the 30-year Canada bond yield of 5.34% using the typical methodology relied on by the automatic adjustment mechanisms. The 12-month forward consensus forecast was used as a proxy for the November 2005 forecast on which virtually all the formula-based ROEs will be set. The indicated forecast of 30-year Canadas is 5.23%.

Table 7

Company	2005 Allowed ROE	Estimated 2006 Allowed ROE
Alberta Utilities	9.50%	9.34%
Enbridge Gas	9.57%	9.22%
FortisBC	9.43%	9.24%
Gaz Metro	9.69%	9.34%
NEB Pipelines	9.56%	9.30%
Newfoundland Power	9.24%	9.54%
Terasen Gas	9.03%	8.84%
Union Gas	9.62%	9.37%
Average	**9.46%**	**9.27%**

At a forecast 30-year Canada yield of 5.34%, the typical allowed ROE for investor-owned utilities in 2006, as shown in Table 7, will be 9.3%. At 9.55%, NSPI's allowed ROE would be only 25 basis points higher than the average. This differential, however, needs to be assessed in light of the incremental risk premium that would be sufficient to compensate for NSPI's higher business risks relative to its Canadian peers. The equity return differential that would be sufficient to compensate for NSPI's proposed 37.5% common equity ratio when its level of business risks supports a 45% common equity ratio is approximately 50 to 110 basis points.[73] Thus, NSPI's allowed common equity return would need to be in the 9.80% to 10.40% range (mid-point of approximately 10.10%) compared to the 9.3% estimate for its Canadian peers. This required return differential is independent of the generally low level of Canadian allowed returns.

9.3.5. Effect Of Low Interest Rate Environment

The allowed ROEs that were estimated in Table 7 reflect the recent low levels of long Canada bond yields that most Canadian utilities' allowed ROEs now track[74] through the operation of automatic adjustment mechanisms. However, the consensus forecast relied on by Canadian regulators in their implementation of the adjustment mechanisms anticipates that interest rates will rise. Based on the consensus forecast, the 30-year Canada yield will average approximately 6.0%[75] in 2006, and remain, on average, around 6.0% from 2007-2015. A 6.0% long Canada yield would push the average allowed return of investor-owned Canadian utilities subject to the automatic changes from 9.3% to about 9.75%, well above NSPI's current allowed return.

The allowed returns set forth in Table 7 and the likely future changes that will be generated by changes in long Canada yields demonstrate the sensitivity of these returns to changes in interest rates. The sensitivity to interest rates of

[73] See Schedule 3.

[74] The automatic adjustment mechanisms range from a change in allowed ROE of 75% of the change in long Canada yields (in Alberta, Ontario and Québec) to 100% of the change (in British Columbia, when long Canada yields are below 6.0%).

[75] Based on Consensus Economics, *Consensus Forecasts*, April 2005, forecast of 10-year Canada's of 5.6% plus the recent 10/30-year Canada bond yield spread of 40 basis points.

allowed returns subject to automatic adjustment formulas has been characterized by DBRS as a "challenge" for the affected utilities. Implicitly subjecting NSPI to such a formula, by lowering its allowed return to reflect temporary declines in interest rates, would effectively add a further "challenge" for NSPI to those challenges DBRS has already cited in its most recent report for NSPI referred to above.

9.3.6. Conclusions

My principal conclusions are as follows:

1. A fair return on equity for a utility explicitly recognizes the alternative investment opportunities available to equity holders.

2. The opportunities for equity investors, which are both domestic and global, indicate the allowed returns for Canadian utilities generally are relatively low.

3. Market participants, such as debt rating agencies and equity analysts, confirm this conclusion.

4. NSPI's proposed common equity ratio of 37.5% is lower than its peers' and materially lower than is warranted by its level of business risk.

5. NSPI's allowed return on equity of 9.55% is effectively lower than the allowed returns of its Canadian peers, since NSPI faces higher total (business plus financial) risk than the typical Canadian investor-owned utility.

6. In the absence of a thicker common equity ratio, an increment to the return on equity of 50-110 basis points relative to the average allowed return of other Canadian utilities is required to compensate for NSPI's higher risks. The incremental return, if added to an estimated allowed ROE of about 9.3% for other Canadian utilities, would place NSPI's risk-adjusted return at 9.8-10.4%, in excess of the 9.55% return on equity currently allowed.

7. Based on the above considerations, NSPI's 9.55% allowed ROE is relatively low under prevailing and forecast capital market conditions, given its risk profile. Under these circumstances, the Company's proposal to maintain the current allowed return at the relatively low level of 9.55% is reasonable.

Appendix D

Kathleen C. McShane Resume & Schedules

QUALIFICATIONS OF KATHLEEN C. McSHANE

Kathleen McShane is a Senior Vice 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 125 proceedings on rate of return and capital structure before federal, state, provincial and territorial regulatory boards, on behalf of U.S. and Canadian telephone companies, gas pipelines and distributors, and electric utilities. 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 for regulated 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 & Capital Structure

Alberta Natural Gas	1994
AltaGas Utilities	2000
Ameren (Central Illinois Public Service)	2000, 2002
Ameren (Illinois Power)	2004
Ameren (Union Electric)	2000 (2 cases), 2002 (2 cases), 2003
ATCO Electric	1989, 1991, 1993, 1995, 1998, 1999, 2000, 2003
ATCO Gas	2000, 2003
ATCO Pipelines	2000, 2003
Bell Canada	1987, 1993
Benchmark Utility Cost of Equity (British Columbia)	1999
Canadian Western Natural Gas	1989, 1998, 1999
Centra Gas B.C.	1992, 1995, 1996, 2002
Centra Gas Ontario	1990, 1991, 1993, 1994, 1996
Direct Energy Regulated Services	2005
Dow Pool A Joint Venture	1992
Edmonton Water/EPCOR Water Services	1994, 2000
Enbridge Gas Distribution	1988, 1989, 1991-1997, 2001, 2002
Enbridge Gas New Brunswick	2000
FortisBC	1995, 1999, 2001, 2004
Gas Company of Hawaii	2000
Gaz Metropolitain	1988
Gazifère	1993, 1994, 1995, 1996, 1997, 1998
Generic Cost of Capital, Alberta (ATCO and AltaGas Utilities)	2003
Heritage Gas	2002
HydroOne	1999, 2000

Insurance Bureau of Canada (Newfoundland)	2004
Laclede Gas Company	1998, 1999, 2001, 2002, 2005
Mackenzie Valley Pipeline	2005
Maritimes NRG (Nova Scotia) and (New Brunswick)	1999
Multi-Pipeline Cost of Capital Hearing (National Energy Board)	1994
Natural Resource Gas	1994, 1997
Newfoundland & Labrador Hydro	2001, 2003
Newfoundland Power	1998, 2002
Newfoundland Telephone	1992
Northwestel, Inc.	2000
Northwestern Utilities	1987, 1990
Northwest Territories Power Corp.	1990, 1992, 1993, 1995, 2001
Nova Scotia Power Inc.	2001, 2002
Ozark Gas Transmission	2000
Pacific Northern Gas	1990, 1991, 1994, 1997, 1999, 2001, 2005
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
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
Yukon Electric Co. Ltd./Yukon Energy	1991, 1993

Expert Testimony/Opinions
on
Other Issues

Client	Issue	Date
Ontario Electricity Distributors	Stand-Alone Income Taxes	2005
Caisse Centrale de Réassurance	Collateral Damages	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

SCHEDULE 1
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EQUITY RETURN AWARDS AND CAPITAL STRUCTURES ADOPTED BY REGULATORY BOARDS FOR INVESTOR-OWNED CANADIAN UTILITIES
(Percentages)

	Decision Date	Order/ File Number	Debt	Preferred Stock	Common Stock Equity		Equity Return	Forecast 30-Year Bond Yield	
	(1)	(2)	(3)	(4)	(5)		(6)	(7)	
Electric Utilities									
AltaLink	11/04	EUB 2004-423	65.00	0.00	35.00	a/	9.50	5.55	
ATCO Electric									
Transmission	11/04	EUB 2004-423	61.00	6.00	33.00		9.50	5.55	
Distribution	11/04	EUB 2004-423	56.10	6.90	37.00		9.50	5.55	
FortisAlberta Inc.	11/04	EUB 2004-423	63.00	0.00	37.00		9.50	5.55	
FortisBC Inc.	11/04; 5/05	L-55-04; G-52-5	60.00	0.00	40.00		9.43	5.53	
Newfoundland Power	12/04	PU 50 (2004)	54.06	1.39	44.55		9.24	4.96	
Nova Scotia Power	3/05	NSUARB-NSPI-P-881	53.30	9.20	37.50		9.55	na	b/
Gas Distributors									
ATCO Gas	11/04	EUB 2004-423	55.10	6.90	38.00		9.50	5.55	
Enbridge Gas Distribution Inc	1/04;12/04	RP-2002-0158; RP-2003-0203	61.91	3.09	35.00		9.57	5.81	
Gaz Metropolitain	9/04	D-2004-196	54.00	7.50	38.50		9.69	5.80	c/
Pacific Northern Gas	11/03; 7/04	L-57-03; G-69-04	60.32	3.69	36.00		9.80	5.65	d/
Terasen Gas	11/04	L-55-04	67.00	0.00	33.00		9.03	5.53	
Union Gas	1/04;3/04	RP-2002-0158; RP-2003-0063	61.50	3.50	35.00		9.62	5.68	
Gas Pipelines									
Alberta Natural Gas	11/04	RH-2-94	70.00	0.00	30.00		9.46	5.55	
Foothills Pipe Lines (Yukon) Ltd.	11/04	RH-2-94	70.00	0.00	30.00		9.46	5.55	
TransCanada PipeLines	11/04; 4/05	RH-3-94/RH-2-2004	64.00	0.00	36.00		9.46	5.55	
Trans Quebec & Maritimes Pipeline	11/04	RH-2-94	70.00	0.00	30.00		9.46	5.55	
Westcoast Energy	8/04; 11/04	RH-2-94; RH-1-2004	69.00	0.00	31.00		9.46	5.55	

a/ EUB 2004-052 set the equity ratio at 35% (33% for transmission plus 2% in recognition of AltaLink's tax status).
b/ The Board approved an ROE of 9.55% for ratemaking purposes and set the earnings range at 9.30-9.80%.
c/ Gaz Metro is allowed to earn an additional 1.95% based on expected productivity gains for the 2005 fiscal year.
d/ 2005 rate application currently pending.

Source: Board Decisions.

SCHEDULE 1
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RATES OF RETURN ON COMMON EQUITY ADOPTED BY REGULATORY BOARDS FOR INVESTOR-OWNED CANADIAN UTILITIES

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Electric Utilities																
AltaLink	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.40	9.60	9.50
ATCO Electric	13.50	13.50	13.25	11.88	NA	NA	11.25	a/	a/	a/	a/	a/	a/	9.40	9.60	9.50
FortisAlberta Inc.	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.50	9.50	9.60	9.50
FortisBC Inc.	13.50	NA	11.75	11.50	11.00	12.25	11.25	10.50	10.25	9.50	10.00	9.75	9.53	9.82	9.55	9.43
Newfoundland Power	13.95	13.25	NA	NA	NA	NA	11.00	NA	9.25	9.25	9.59	9.59	9.05	9.75	9.75	9.24
Nova Scotia Power	NA	NA	NA	11.75	NA	NA	10.75	NA	NA	NA	NA	NA	10.15	NA	NA	9.55
TransAlta Utilities	13.50	13.50	13.25	11.88	NA	12.25	11.25	a/	b/	9.25	9.25	NA	9.40	NA	NA	NA
Average of Electric Utilities	**13.61**	**13.42**	**12.75**	**11.75**	**11.00**	**12.25**	**11.10**	**10.50**	**9.75**	**9.33**	**9.61**	**9.67**	**9.53**	**9.57**	**9.62**	**9.45**
Gas Distributors																
Atco Gas	13.25	13.25	12.25	12.25	NA	NA	NA	10.50	9.38	NA	NA	9.75	9.75	9.50	9.50	9.50
Centra Gas Ontario	13.50	13.75	13.50	12.50	11.85	12.13	NA	11.25	10.69	c/	c/	c/	c/	c/	c/	c/
Enbridge Gas Distribution Inc	13.25	13.13	13.13	12.30	11.60	11.65	11.88	11.50	10.30	9.51	9.73	9.54	9.66	9.69	NA	9.57
Gaz Metro	14.25	14.25	14.00	12.50	12.00	12.00	12.00	11.50	10.75	9.64	9.72	9.60	9.67	9.89	9.45	9.69
Pacific Northern Gas	15.00	14.00	13.25	NA	11.50	12.75	11.75	11.00	10.75	10.00	10.25	10.00	9.88	10.17	9.80	d/
Terasen Gas	NA	NA	12.25	NA	10.65	12.00	11.00	10.25	10.00	9.25	9.50	9.25	9.13	9.42	9.15	9.03
Union Gas	13.75	13.50	13.50	13.00	12.50	11.75	11.75	11.00	10.44	9.61	9.95	9.95	NA	NA	9.62	9.62
Average of Gas Distributors	**13.83**	**13.65**	**13.13**	**12.51**	**11.68**	**12.05**	**11.68**	**11.00**	**10.33**	**9.60**	**9.83**	**9.68**	**9.62**	**9.73**	**9.50**	**9.48**
Gas Pipelines (NEB)																
TransCanada PipeLines	13.25	13.50	13.25	12.25	11.25	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79	9.56	9.46
Westcoast Energy	13.25	13.75	12.50	12.25	11.50	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79	9.56	9.46
Average of Gas Pipelines	**13.25**	**13.63**	**12.88**	**12.25**	**11.38**	**12.25**	**11.25**	**10.67**	**10.21**	**9.58**	**9.90**	**9.61**	**9.53**	**9.79**	**9.56**	**9.46**
Average of All Companies	**13.66**	**13.58**	**12.99**	**12.19**	**11.54**	**12.13**	**11.36**	**10.88**	**10.20**	**9.52**	**9.78**	**9.67**	**9.57**	**9.68**	**9.56**	**9.47**

Note: A rate freeze was in effect for BC Gas (now Terasen Gas) in 1990 and 1991, BCUC regulation resumed in late 1991.
Nova Scotia Power was privatized in 1992.

a/ Negotiated settlement, details not available.
b/ Negotiated settlement, implicit ROE made public is 10.5%.
c/ Merged with Union Gas.
d/ 2005 rate application currently pending.

Source: Regulatory Decisions

COMPARISON BETWEEN ALLOWED EQUITY RISK PREMIUMS FOR CANADIAN AND U.S. UTILITIES

	Canadian Utilities			U.S. Utilities		
Year	Allowed ROE	Average Long Canada Yield	Equity Risk Premium	Allowed ROE	Average Long Treasury Yield	Equity Risk Premium
1990	13.66	10.69	2.97	12.69	8.61	4.08
1991	13.58	9.72	3.87	12.51	8.14	4.37
1992	12.99	8.68	4.37	12.06	7.67	4.39
1993	12.19	7.86	4.30	11.37	6.59	4.78
1994	11.54	8.69	2.88	11.34	7.39	3.95
1995	12.13	8.41	3.72	11.51	6.85	4.66
1996	11.36	7.75	3.61	11.29	6.73	4.56
1997	10.88	6.66	4.22	11.34	6.58	4.76
1998	10.20	5.59	4.61	11.59	5.54	6.05
1999	9.52	5.72	3.80	10.74	5.91	4.83
2000	9.78	5.71	4.07	11.41	5.88	5.53
2001	9.67	5.77	3.90	11.04	5.50	5.54
2002	9.57	5.67	3.92	11.10	5.41	5.69
2003	9.68	5.31	4.37	10.98	5.03	5.95
2004	9.56	5.11	4.45	10.73	5.08	5.65
2005 [a/]	9.47	4.72	4.75	10.48	4.70	5.78
Averages:						
1990-1993	**13.10**	**9.24**	**3.88**	**12.16**	**7.75**	**4.41**
1994-1998	**11.22**	**7.42**	**3.81**	**11.41**	**6.62**	**4.80**
1999-2005Q1	**9.60**	**5.43**	**4.18**	**10.93**	**5.36**	**5.57**

Note: For U.S. Treasury yields, 30-year maturities used through January 2002; theoretical 30-year yield from February 2002 forward.

a/ Includes all U.S. returns determined in the first quarter of 2005.

Sources: Regulatory Focus, Regulatory Research Associates; Various Canadian Regulatory Decisions; Bank of Canada; Federal Reserve, U.S. Treasury.

Schedule 2

DEBT AND COMMON STOCK QUALITY RATINGS OF MAJOR CANADIAN GAS AND ELECTRIC UTILITIES

Company	Debt Rated	DBRS Bond Rating	Moody's Bond Rating	S&P Bond Rating	CBS Stock Ranking
AltaLink L.P.	Senior Secured	A(high)		A-	NR
CU Inc.	Senior Unsecured	A(high)		A	Very conservative
Enbridge Gas Distribution Inc.	Senior Unsecured	A		A-	Very conservative
Enbridge Pipelines	Senior Unsecured	A(high)		A-	Very conservative
Epcor Utilities Inc	Senior Unsecured	A(low)	Baa2	BBB+	NR
FortisAlberta Inc.	Senior Unsecured	A(low)	Baa1	NR	Very conservative
FortisBC Inc	Secured Debentures	BBB(high)	Baa3	NR	Very conservative
Gaz Metropolitain	Senior Secured	A		A	NR
Hydro One	Senior Unsecured	A	A2	A	NR
Maritime Electric	Senior Secured	NR		BBB+	Very conservative
Newfoundland Power	Senior Secured	A	Baa1	A-	Very conservative
NOVA Gas Transmission	Senior Unsecured	A	A2	A-	Very conservative
Nova Scotia Power	Senior Unsecured	A(low)	Baa1	BBB+	Very conservative
Pacific Northern Gas	Senior Secured	BBB(low)		NR 1/	Average
Terasen Gas	Senior Secured	A	A1	A-	Very conservative
	Senior Unsecured	A	A2	BBB	
TransCanada PipeLines	Senior Unsecured	A	A2	A-	Very conservative
Union Gas Limited	Senior Unsecured	A		BBB	Very conservative
Westcoast Energy	Senior Unsecured	A(low)		BBB	Very conservative
Median		**A**	**A3**	**A-**	**Very conservative**

1/ Withdrawn by company; BB- prior to withdrawal.

Note: Debt ratings are for utility; Stock rankings are for parent.

Source: DBRS Bond Ratings, Moodys.com, Standard & Poor's, The Blue Book of CBS Stock Reports.

IMPACT OF CHANGE IN CAPITAL STRUCTURE ON COST OF EQUITY

THEORY 1:

The overall cost of capital is invariant to changes in the capital structure. The cost of equity rises as the debt ratio rises, but the after-tax weighted average cost of capital stays the same.

Formula for After-Tax Weighted Average Cost of Capital:

$WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)

ASSUMPTIONS:

Debt Cost = Current Cost of Long Term Debt for A rated utility
= 6.2%

Equity Cost = Estimated Average 2006 Allowed Return on Equity for Canadian Utilities
= 9.3%

Tax Rate = 38.12%

STEPS:

1. Estimate $WACC_{AT}$ @ 45% common equity ratio

   $WACC_{AT}$ = (6.2%)(1-.3812)(55%) + (9.3%)(45%)
   = 6.3%

2. Estimate Cost of Equity at NSPI's actual 38.3% common equity ratio with $WACC_{AT}$ unchanged at 6.3%

   $WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)
   6.3% = (6.2%)(1-.3812)(62.5%) + (X)(37.5%)

   Cost of Equity at 37.5% Common Equity Ratio = 10.4%

3. Difference between Equity Return at 37.5% and 45% common equity ratios:
   10.4% - 9.3% = 1.1% (110 basis points)

THEORY 2:

After-Tax Cost of Capital Declines as Debt Ratio Rises; Cost of Equity Rises

ASSUMPTIONS:

Debt Cost	=	Current Cost of Long Term Debt for A rated utility
	=	6.2%
Equity Cost	=	Estimated Average 2006 Allowed Return on Equity for Canadian Utilities
	=	9.3%
Tax Rate	=	38.12%

STEPS:

1. Estimate $WACC_{AT}$ @ 45% common equity ratio

$$WACC_{AT} = (6.2\%)(1-.3812)(55\%) + (9.3\%)(45\%)$$
$$= 6.3\%$$

2. Estimate $WACC_{AT}$ @ NSPI's 37.5% common equity ratio (62.5% debt ratio)

$$WACC_{AT(\text{new debt ratio})} = WACC_{AT(\text{old debt ratio})} \text{ x } (1\text{-t x Debt Ratio}_{new})/(1\text{-t x Debt Ratio}_{old})$$

$$WACC_{AT(\text{new debt ratio})} = 6.3\% \; \frac{(1-.3812 \text{ x } 62.5\%)}{(1-.3812 \text{ x } 55.0\%)}$$

$$WACC_{AT(\text{new debt ratio})} = 6.1\%$$

3. Estimate Cost of Equity at new $WACC_{AT}$ at higher debt ratio:

$WACC_{AT(new\ debt\ ratio)}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)

6.1% = (6.2%)(1-.3812)(62.5%) + (X)(37.5%)

Cost of Equity at 37.5% equity ratio = 9.8%

4. Difference between Equity Return at 38.3% and 45% common equity ratios:
9.8% - 9.3% = 0.5% (50 basis points)

ESTIMATE OF IMPACT OF CHANGE IN CAPITAL STRUCTURE ON COST OF EQUITY

50-110 BASIS POINTS

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Request IR-5:

Reference: Pension expense $26 million DE-03, page 14 and pages 53 on:

a) **For 2013 NSPI indicates it will use a 1.0% lower discount rate at 4.5% rather than 5.5%. Please confirm that this is a nominal rate and that NSPI is proposing to use a real rate of 2.25% if we subtract the forecast NSPI inflation rate of 2.25%.**

b) **On page 84 NSPI indicates that it intends to use a long run rate of return on plan assets of 6.75% instead of 7.0% for 2013. Please confirm that the difference between the long run return on plan asset and the discount rate is the actuary's provision for adverse deviations (PfADs).**

c) **Please indicate why the long run return has dropped by 0.25% but the discount rate has dropped by 1.0%, or alternatively why the PfAD has increased by 0.75%.**

d) **NSPI indicates that its pension plan is a 65:35 equity:bond plan with an overall long run return of 6.75%. Please indicate the actual expected equity and bond returns that were used to derive the 6.75% long run plan return.**

Response IR-5:

(a) The discount rate of 4.5 percent is a nominal rate. Based on the assumed inflation rate of 2.25 percent, the real rate is 2.25 percent. As required by accounting standards, the discount rate is determined based on high quality bonds that have the same duration as the obligations. The 4.5 percent is based on the methodology set out in the Educational Note published by the Canadian Institute of Actuaries in September 2011,[1] and bond yields as at December 31, 2011 and January 31, 2012.

[1] Educational Note published September 20, 2011 by the Canadian Institute of Actuaries' Task Force on Pension and Post Retirement Benefit Accounting Discount Rates entitled, "Accounting Discount Rate Assumption for Pension and Post-employment Benefit Plans".

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(b) The assumed rate of return on plan assets of 6.75 percent is based on management's best estimate of the net long-term expected return on plan assets. This return assumption was determined based on the Plan investment portfolio which includes equity and bonds. The discount rate is determined based solely on high quality bonds. There is no provision for adverse deviation (PfaD) in either the asset return assumption or discount rate assumption.

(c) The discount rate is based on high quality bond yields as of the reporting date whereas the long term rate of return assumption is based on management expectation of the long-term rate of return on Plan assets. As the method to determine each assumption is different, the two assumptions are not directly linked. As such, a change to one assumption will not necessarily result in a change to the other assumption in either the same direction or magnitude.

The assumed discount rate has fallen by 1.0 percent from the 2012 GRA[2] to the 2013 GRA for two main reasons:

(i) The yield on high quality bonds fell over this period; and

(ii) The methodology used to determine the discount rate for the 2013 GRA is different than what was used for the 2012 GRA. For the 2013 GRA, the discount rate was determined based on the methodology set out in the Educational Note published by the Canadian Institute of Actuaries in September 2011 (the "CIA Guidance Note"). The 2012 GRA used the "Morneau Shepell PC Bonds" method to determine the discount rate of 5.5 percent (The CIA Guidance Note was not yet published at the time of the 2012 GRA). It is expected that the majority of plan

[2] NSPI 2012 General Rate Application, NSUARB-NSPI-P-892, May 13, 2011.

sponsors will adopt the CIA Guidance Note methodology for setting discount rates to determine benefit cost for fiscal 2013 and later.

In setting the rate of return assumption, NS Power with the help of its actuaries, reviewed the forecast for financial markets taking into account the Plan's asset mix, and considered the return assumptions used by other Canadian organizations for pension plan accounting purposes.

(d) NS Power's management determines its best estimate long-term rate of return assumptions by working with its actuaries, Morneau Shepell, and reviewing other third party material.

Management reviews both Morneau Shepell and market information to determine the best estimate long-term real return for each asset class. Please refer to Confidential Attachment 1 which shows the development of the 6.75 percent asset return assumption. Please refer to Confidential Attachment 2 which shows the development of the asset return assumption using the new asset mix as contained in the Statement of Investment Policies and Procedures approved in September 2011. Both attachments show the same 6.75 percent asset return assumption, note the highlighted information in yellow.

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Request IR-6:

Reference: NSPI Credit ratings: DE-04, page 119 on:

a) **NSPI indicates that when markets are tight it is possible that buyers with low credit ratings may not have financial access to commodities in question. Would NSPI confirm that between October 2008 and March 2009 market conditions were tighter than they have been since the 1930's? If NSPI cannot so agree please indicate a time period when market conditions were tighter.**

b) **Can NSPI (or Ms. McShane) agree that when market conditions are tight competitive firms usually issue shorter term debt, since they find that there are few buyers for longer term issues? If not please explain how financing strategy develops during a "tight market" period.**

c) **Please indicate how DBRS describes an A (low) credit such as NSPI.**

d) **Please indicate any A (low) Canadian utilities that were unable to raise capital on fair and reasonable terms during the worst of the financial crisis from 2008-09 to 2009-03.**

e) **Please indicate whether in the judgment of either NSPI or Ms. McShane the value of being a regulated utility shows up as larger or smaller spreads over similarly rated non-utility bonds during a tight money period.**

f) **In BMO's rating reports on NSPI (November 7, 2011 for example) they show a graph of the spread of NSPI's 5, 10 and 30 year debt, presumably over equivalent maturity Canada bonds. Please provide the monthly yields on these issues back to November 2002, as well as that for the Bloomberg Utility series and the (Ontario) Hydro One bonds discussed in various filed BMO reports.**

g) **Please provide the yields on Emera's preferred shares back to November 2002 consistent with the yields in g) above.**

Response IR-6:

(a) Confirmed.

(b) Both regulated and unregulated firms will maintain credit facilities so that they can finance short-term when debt markets are not receptive to long-term debt issues.

(c) To NS Power's knowledge, DBRS does not provide a specific characterization for an "A" (low) rating. It describes the "A" rating category as "Good" credit quality. The capacity for the payment of financial obligations is substantial, but of lesser credit quality than "AA" maybe vulnerable to future events, but qualifying negative factors is considered manageable." A (low) credit like NS Power would be of somewhat lesser credit quality than an issuer rated "A", that is, one without the "low" sub-category attached.

(d) Utilities maintain regular contact with their debt capital market advisors. It is Ms. McShane's understanding, based on her conversations with Canadian utilities, that during the financial crisis, these advisors indicated that investors were avoiding all but the safest of credits, and that for those transactions that did get completed, credit spreads and new issue concessions had increased dramatically compared to earlier periods. Based on Ms. McShane's review of new utility issues over the period between the end of August 2008 and early February 2009, no regulated company issued debt with a term greater than 10 years. At the time of the five year debt issue in December 2008, issued at a 400 basis point spread over the five-year benchmark Canada bond, NS Power could not have raised debt with a term of 10 years or more. Around the same time, AltaLink had planned to issue long-term debt pursuant to AUC Order No. U2008-317, but in December 2008 informed the Alberta Utilities Commission that it had been advised by its lead dealer that it was highly likely that the proposed long-term debt offering could not be successfully marketed until early 2009. Also of note is that during the period June 11, 2008 to January 29, 2009 inclusive there was not a single issuer without at least one "A" credit

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rating who was able to issue long-term debt on any terms in the public Canadian debt market.

(e) During tighter market conditions, the spreads for regulated utility debt tend to be somewhat lower than for similarly rated unregulated debt.

(f) Please refer to Confidential Attachment 1 based on information provided by BMO. NS Power could not locate Bloomberg Canadian Utility index but has provided the Canadian DEX Infrastructure index (of which Canadian utilities account for 46 percent). The information is available beginning in August 2003.

(g) Please refer to Confidential Attachment 1.

Request IR-7:

Reference: ROE: DE-03, page 122-123

a) NSPI references the thorough review of the ROE in the 2012 GRA. Please provide copies of all ROE testimony filed in the 2012 GRA except for that provided by Ms. McShane that was requested in 4 above.

b) In its research note (September 19, 2011), BMO reports EPS, DPS, Payout, BV, P/B and ROE for Emera since 1993. Please provide the same data for NSPI (except for that which uses market data). Please confirm that Emera's market to book (P/B or price to book) ratio in 2010 was 2.2, and provide the latest value.

c) Please confirm that Emera's market (price) to book ratio has increased since the introduction of FAM in 2009 to exceed 2.0X.

d) Does NSPI believe that a market (price) to book ratio of over 2.0X indicates that investors are happy or unhappy with Emera and indirectly NSPI's profitability (ROE)?

Response IR-7:

(a) Please refer to the 2012 GRA, posted on the Board's website, for copies of all return on equity (ROE) testimony filed in the 2012 GRA.[1]

(b) Please refer to Attachment 1 for NS Power financial data. NS Power has calculated Emera price to book (P/B) ratios as follows:

	US GAAP 3/31/2012	**US GAAP 12/31/2011**	**US GAAP 12/31/2010**	**CAN GAAP 12/31/2010**	**CAN GAAP 12/31/2009**
P/B Ratio	2.8x	2.8x	2.9x	2.2x	1.9x

[1] NSPI 2012 General Rate Application, NSUARB-NSPI-P-892, May 13, 2011 at www.nsuarb.ca.

(c) The calculations indicate the P/B ratio has increased since 2009. Caution should be used in comparing P/B ratios between US GAAP and CAD GAAP, as Emera converted to US GAAP in 2011, which resulted in accounting adjustments that may have affected the P/B ratio.

(d) NS Power is not in a position to comment on investor motivations for purchasing Emera shares but does not accept the implication of the question that the FAM within NS Power would be a primary driver of the Emera stock price.

Nova Scotia Power Inc.
Historical Financial Data
Years Ended December 31st
Millions of Dollars

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Average common equity	$761.4	$789.7	$820.9	$849.6	$877.5	$901.6	$926.9	$947.8	$966.7	$1,029.1	$1,101.8	$1,104.9	$1,085.6	$1,121.2	$1,123.6	$1,128.2	$1,220.0	$1,263.5	$1,362.3
Outstanding Shares	85.2	85.4	85.6	86.1	86.5	86.8	86.8	86.8	91.8	96.6	96.8	96.8	96.8	96.8	96.8	106.8	107.2	112.2	117.2
Regulated Earnings	$91.5	$94.0	$94.8	$90.0	$92.7	$85.4	$103.2	$103.7	$105.1	$106.0	$115.3	$110.8	$94.7	$107.3	$103.0	$109.6	$111.8	$121.3	$131.3
Return on equity	12.0%	11.9%	11.5%	10.6%	10.6%	9.5%	10.8%	10.9%	10.9%	10.3%	10.5%	10.0%	8.7%	9.6%	9.2%	9.7%	9.2%	9.6%	9.6%
Earnings per Share in dollars	1.1	1.1	1.1	1.0	1.1	1.0	1.2	1.2	1.1	1.1	1.2	1.1	1.0	1.1	1.1	1.0	1.0	1.1	1.1
Dividends	$63.9	$64.8	$66.7	$68.7	$69.9	$71.1	$72.2	$93.2	$161.2	$84.4	$70.0	$153.1	$91.0	$50.0	$193.0	$75.0	$126.0	$100.0	$25.0
Payout	69.8%	68.9%	70.4%	76.3%	75.4%	83.3%	70.0%	89.9%	153.4%	79.6%	60.7%	138.2%	96.1%	46.6%	187.3%	68.4%	112.7%	82.4%	19.0%
Dividends per Share in dolla	0.8	0.8	0.8	0.8	0.8	0.8	0.8	1.1	1.8	0.9	0.7	1.6	0.9	0.5	2.0	0.7	1.2	0.9	0.2
Book Value	$773.7	$805.6	$836.2	$862.9	$892.0	$911.2	$942.5	$953.0	$980.5	$1,077.6	$1,126.0	$1,083.7	$1,087.4	$1,150.3	$1,060.3	$1,191.6	$1,181.5	$1,258.3	$1,404.4

Notes:

1) In 1999, there was a $3.1M gain on the sale of Enercom shares to NS Power Holdings Inc. This one time gain is not included in the return on common equity calculation.

NON-CONFIDENTIAL

Request IR-8:

Reference Capital Structure: Ms. McShane's testimony Appendix H, page 6

a) **Ms. McShane discusses the stand alone principle. Is Ms. McShane aware that currently in a hearing before the NEB the TransCanada Mainline is attempting to get part of its costs allocated to a sister corporation, NGTL, through a transportation by others (TBO) agreement. If so would she agree that a TBO agreement that was not requested by any party, but proposed by one utility to help out another utility owned by the same parent violates the stand alone principle?**

b) **Would Ms. McShane accept that the use of debt magnifies returns to the common shareholder, but if there is very little business risk to start out with due to the use of deferral accounts, then there is very little magnification? If not please explain in full.**

c) **In her discussion of business risk and the use of debt by NSPI, would Ms. McShane accept that the adoption of FAM ensures that all the fuel costs, not just increases in fuel prices, are paid by ratepayers, and that as a result the 2009 agreement reduces earnings volatility as discussed by DBRS?**

d) **Would Ms. McShane accept that the reallocation of the cost of stranded assets to remaining customers, as requested by NSPI, also reduces stranded asset risk as discussed by the analysts at TD Securities and RBC? If not please explain why not.**

e) **Can Ms. McShane point to any factors that increase NSPI's business risk to offset the items mentioned in c) and d) above?**

f) **Would Ms. McShane accept the decisions of the OEB, AUC, NEB and others that the primary factor in setting financial structure is the utility's business risk?**

Response IR-8:

(a) Ms. McShane is not familiar enough with the TCPL restructuring proposal to comment on the proposal or the implications as it regards the stand-alone principle. In any event, whether the TCPL proposal does or does not violate the stand-alone principle has no bearing on whether that principle should be respected for the purposes of setting the allowed return for NS Power.

(b) The use of debt creates financial risk. Financial risk does magnify business risk, for example, a given unanticipated increase in expenses or reduction in revenues will have a larger impact on the return on equity (ROE) of a company with debt than on a company with no debt. However, the question appears to contain an erroneous premise, i.e., that the use of deferral accounts means that there is little business risk. Business risk, which relates to the probability of earning a fair return on the capital invested and recovery of that capital, has both short-term and long-term elements; it is not defined solely by year-to-year volatility in returns.

(c) Ms. McShane understands that the FAM provides for recovery of differences between forecast and actual incurred fuel costs subject to a determination of prudency, and potentially over an extended period of time, as was the case with the 2010 FAM balance.[1] She also notes that, as part of the FAM agreement, NS Power's allowed ROE for 2009 was reduced by 0.20 percent in recognition of the risk mitigation. Please refer to Appendix H, page 12 of 48 of the Application, for Ms. McShane's testimony where she specifically refers to DBRS' most recent comments regarding the FAM. In a January 2011 press release, with reference to the Board's decision to defer recovery of 2011 FAM amounts, DBRS commented that the decision was not favourable for NS Power and that a deferral that was significant enough to have a material effect on NS Power's liquidity could affect the ratings, particularly in a period of high capital requirements.[2]

[1] NSPI 2010 Fuel Adjustment Mechanism, NSUARB-P-887(2).
[2] DBRS, Press Release, "DBRS Comments on Nova Scotia Power Inc's Fuel Cost Decision, January 26, 2011.

(d) Ms. McShane does not accept the premise of the question and consequently does not agree that there has been a reduction in stranded asset risk. NS Power is not seeking to recover stranded assets. The Company is requesting recovery of fixed costs that were prudently incurred to provide service to all customers, consistent with the regulatory framework under which it (as well as other North American utilities) operates and upon which allowed returns have been based.

(e) It is unclear what time frame is being referenced in the question. Ms. McShane recognizes that the implementation of the FAM in 2009 provided some risk mitigation, which has been reflected in her selection of proxy utilities (i.e., utilities which also have mechanisms for recovery of fuel costs). She disagrees, however, that there has been a reduction in stranded asset risk, as stated in response (d). As indicated in response to Booth IR-4 (c), Ms. McShane considers that the minor reduction in NS Power's risks due to the adoption of the FAM has been more than offset by the challenges that have arisen as a result of Nova Scotia energy policy and related legislation and regulations and the weak economy.

(f) Ms. McShane agrees that business risk has been identified as an important factor by the regulators. However, business risk is essentially qualitative in nature and its assessment in isolation does not provide a point of reference or guidance regarding what is a reasonable capital structure. Objective factors such as capital structures adopted by peer companies, debt rating agency guidelines, actual credit metrics, and debt ratings must be used in conjunction with the qualitative business risk assessment in order to judge the reasonableness of capital structure and, ultimately, how the overall risk of a utility compares to its peers.

NON-CONFIDENTIAL

Request IR-9:

Reference: Business Risk: Ms. McShane's testimony Appendix H, pages 7-13

a) Can Ms. McShane confirm that the data in Table 1 is the % of revenues by customer class?

b) Please provide the customer class breakdown by revenues for each year since 2000.

c) Can Ms. McShane confirm that she normally judges distributor risk in part by its customer breakdown, with a high industrial load as indicative of higher risk?

d) In this instance does Ms. McShane judge NSPI to be lower risk, since it has probably lost significant industrial load? If not why not?

Response IR-9:

(a) Not confirmed. The percentage breakdown is GWh, as indicated in the table heading.

(b) Please refer to Attachment 1. Also, please refer to FOR-05 of the Application.

(c) Ms. McShane confirms that one factor in assessing relative utility risk is its customer breakdown, with, all other things equal, high dependence on industrial load pointing to higher risk than a utility with a more balanced customer base.

(d) No. Not only does there remain considerable uncertainty surrounding NS Power's pulp and paper related load and the impact on the utility, Ms. McShane considers that lost load and revenue from pulp and paper customers would be a crystallization of a risk, rather than a reduction in risk that would translate into a lower investor return requirement.

NSPI Electric Revenues in Millions of Canadian Dollars

	2011 Revenues	2010 Revenues	2009 Revenues	2008 Revenues	2007 Revenues	2006 Revenues	2005 Revenues	2004 Revenues	2003 Revenues	2002 Revenues	2001 Revenues	2000 Revenues
Residential	564.9	531	547.3	496.3	485.6	439.9	411.4	402.9	375.8	370.7	362	352
Commercial	341.8	325.4	333.9	305.2	307.6	285.2	263.6	258.3	253.4	241.9	233	227
Industrial	260.1	269.3	263.8	268.1	266.6	184.8	235.1	222.5	218.5	203.3	197	197
Other	42.9	41.6	43.1	41.5	42.2	58	44.9	43.2	47.9	53.2	41	37
Total	1209.7	1167.3	1188.1	1111.1	1102	967.9	955	926.9	895.6	869.1	833	813
% of Revenues												
Residential	46.7%	45.5%	46.1%	44.7%	44.1%	45.4%	43.1%	43.5%	42.0%	42.7%	43.5%	43.3%
Commercial	28.3%	27.9%	28.1%	27.5%	27.9%	29.5%	27.6%	27.9%	28.3%	27.8%	28.0%	27.9%
Industrial	21.5%	23.1%	22.2%	24.1%	24.2%	19.1%	24.6%	24.0%	24.4%	23.4%	23.6%	24.2%
Other	3.5%	3.6%	3.6%	3.7%	3.8%	6.0%	4.7%	4.7%	5.3%	6.1%	4.9%	4.6%

Source: Annual MD&A Reports

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Request IR-10:

Reference: Fair ROE: Ms. McShane's testimony Appendix H, pages 16-24

a) **Please justify the assertion that NSPI needs 45% common equity (page 19) given that it has an A(low) DBRS bond rating.**

b) **Please indicate the current allowed ROE for Gaz Metro (page 23)**

c) **Please indicate the current allowed ROE for both Union Gas and EGDI as agreed to under their five year settlement.**

d) **Please confirm that the 2011 ROE for Newfoundland Power was 8.38%**

e) **Please confirm that the New Brunswick PUB determined the benchmark fair ROE, before a premium for EGNB, for 2011 was 8.13% (Decision November 30, 2010).**

Response IR-10:

(a) Ms. McShane did not state that NS Power needed a common equity ratio of 45 percent. She stated that the common equity ratio that would fully compensate for NS Power's higher business risks relative to those adopted for Alberta utilities would be no less than 45 percent. The Alberta Utilities Commission allows the same return on equity (ROE) for all the utilities it regulates and adjusts for differences in business risk using common equity ratios. For a taxable electric distribution utility in Alberta, which is of materially lower business risk than NS Power, the allowed common equity ratio is 39 percent. The allowed common equity ratio for AltaGas Utilities, a small gas distribution utility, is 43 percent. Ms. McShane judges NS Power to be of fundamentally higher business risk than AltaGas Utilities, indicating that NS Power's common equity ratio would need to be higher than AltaGas Utilities' in order for the single AUC ROE (currently 8.75 percent) to be applicable to NS Power. Since NS Power's allowed common equity ratio is lower than what would be warranted based on its business risk relative to the Alberta utilities, its allowed ROE should be higher than the ROE adopted for the Alberta utilities.

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(b) The current allowed ROE for Gaz Metro is 8.9 percent, as stated at page 25 of 48, line 616 of Ms. McShane's Evidence. Please refer to Appendix H of the Application.

(c) The allowed ROEs that were included in the base rates of Union Gas and Enbridge Gas Distribution at the outset of five-year incentive regulation plans in 2007 were 8.54 percent and 8.39 percent respectively. Those ROEs were produced by an automatic adjustment formula that the Ontario Energy Board subsequently amended in 2009. The incentive plans are set to expire at the end of 2012. Both utilities have applied to have their 2013 ROE set on the basis of the amended formula, described and discussed in Ms. McShane's Evidence at pages 22-23 of 48 (Appendix H of the Application).

(d) Confirmed, and fully discussed at pages 24-25 of 48 of Ms. McShane's Evidence, Appendix H of the Application.

(e) Confirmed.

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Request IR-11:

Reference: US Allowed ROEs: Ms. McShane's testimony Appendix H, pages 24-30

a) **Please indicate all Canadian jurisdictions that have accepted the use of US estimates of allowed ROEs as being identical to Canadian, that is, without making any adjustments.**

b) **Please confirm that regulators such as the BCUC, NEB, the Regie and the Board of Commissioners of Newfoundland and Labrador have either rejected such comparisons or suggested that adjustments have to be made.**

c) **Please confirm that the Regie regards Gaz Metro as above average risk and allows it a premium over what the Regie judges to be a benchmark ROE.**

d) **Please confirm that the Macquarie report was written right in the middle of the financial crisis (Feb 23, 2009) which reached its low-point March 9, 2009.**

e) **Please confirm that Matt Akman of Macquarie before Camput in 2008 stated clearly that the ROE adjustment formula used by Canadian boards "appears to be working."**

f) **Please provide an updated graph similar to the following one provided by Ms. McShane in answer to IOL information request #197d in an Enbridge Line 9 hearing before the NEB in 2010. This shows the distribution of S&P business risk rankings for US utilities by their respective bond rating.**

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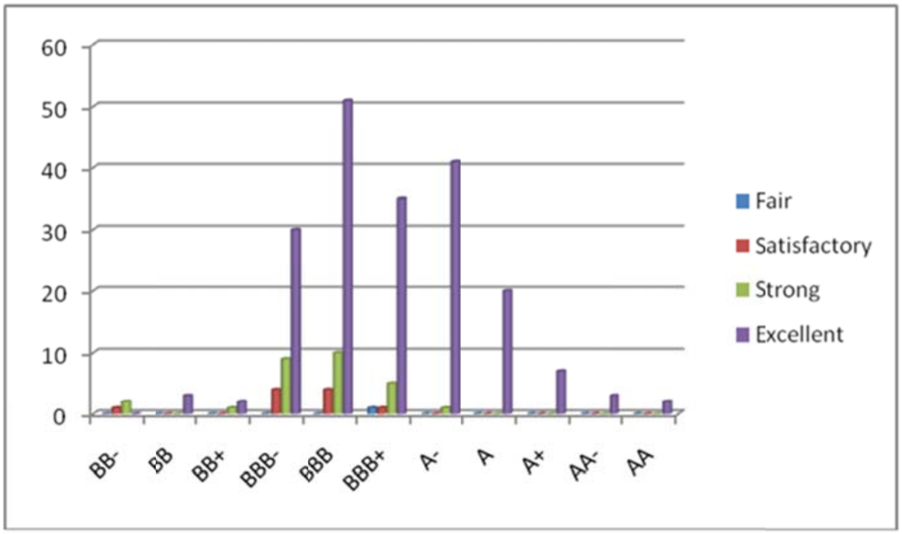

g) **Please confirm that the OEB ceased accepting DCF estimates for Consumers Gas (EGDI) after it beame a wholly owned subsidiary, since it felt the most relevent base for a DCF estimate was the utility (Consumers Gas) in question. If not please explain why not.**

h) **Ms. McShane indicates that the regulatory model in the US is similar to that in Canada. Does she mean the same or simply that it is a rate of return model? Does she know of any opinion by Moodys that indicates that the application of that model is different in the US, as compared to Canada?**

i) **Please indicate whether the sample selection criteria (page 27) used for her US electric utilities and the resulting sample are the same as used in her current Newfoundland Power testimony.**

j) **Please confirm that Ms. McShane is aware of the following quote from the BCUC evaluation of Ms. McShane's US returns evidence:**

> The Commission Panel agrees with Dr Booth that "significant risk adjustments" to US utility data are required in this instance to recognize the fact that TGI possesses a full array of deferral mechanisms which give it more certainty that it will, in the short-term, earn its allowed return than the *Value Line* US natural gas LDCs enjoy. The Commission Panel notes Dr. Booth's suggestion that the risk premium required by US utilities is between 90 and 100 basis points more than utilities in Canada require may set an upper limit on the necessary adjustment. Accordingly, the Commission Panel will reduce its DCF estimate by between 50 and 100 basis points to a range of 9.0 percent to 10.0 percent, before any allowance for financing flexibility.

k) Please confirm that a similar adjustment of 0.50-1.0% from Ms. McShane's current US DCF estimates results in a range of 8.30-8.80% (subtracting 0.50-1.0 from the mid points in her Table 4, page 30).

Response IR-11:

(a) Ms. McShane is not aware of any Canadian regulator which has explicitly stated that it accepts U.S. estimates of the allowed return as being identical to Canadian, although the 2009 Ontario Energy Board Report of the Board on the Cost of Capital for Ontario's Regulated Utilities[1] made no adjustments to U.S. estimates in arriving at its revised benchmark utility ROE.

(b) Ms. McShane confirms that the BCUC, in its 2009 Cost of Capital Decision for Fortis BC Energy Inc., or FEI (formerly Terasen Gas Inc., or TGI), considered that adjustments

[1] Ontario Energy Board, *EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009*, December 11, 2009, pages 22 to 23: http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec&sm_udf10=eb-2009-0084&sortd1=rs_dateregistered&rows=200

were required due to FEI's full array of deferral mechanisms.[2] Please refer to response (k) below.

The NEB in its March 2009 Reasons for Decision for TransQuébec and Maritimes Pipeline (RH-1-2008) was of the view that the risks faced by TQM and those faced by U.S. pipelines were not so different as to make them inappropriate comparators, that there are many similarities faced by pipelines in the two countries due to the two regulatory models sharing, to a large extent, the same fundamental principles. The NEB stated that risk differences between Canada and the U.S. can be understood and accounted for, but did not specify, what, if any, adjustment should be applied for differences in risk between TQM and the samples of U.S. companies used as proxies to estimate TQM's cost of capital.[3]

In its 2009 Decision for Newfoundland Power, the Newfoundland and Labrador Board of Commissioners of Public Utilities concluded that the U.S. proxy utilities were riskier than Newfoundland Power specifically and that estimates using U.S. companies could not be used without appropriate adjustments.[4]

With respect to the Régie, the regulator has concluded that the evidence does not make it possible to conclude that the regulatory, institutional, economic and financial contexts of the two countries and their impacts on the resulting opportunities for investors are comparable.[5] Despite that conclusion, in estimating the utility cost of equity using the

[2] British Columbia Utilities Commission, *In the Matter of Terasen Gas Inc. Terasen Gas (Vancouver Island) Inc. Terasen Gas (Whistler) Inc. and Return on Equity and Capital Structure Decision, Order G-158-09,* December 16, 2009: http://www.bcuc.com/DecisionIndex.aspx

[3] National Energy Board, *Reasons for Decision, Trans Québec & Maritimes Pipelines Inc. RH-2-2008*, March 2009: https://www.neb-one.gc.ca/ll-eng/livelink.exe?func=ll&objId=551491&objAction=browse&sort=name

[4] Newfoundland & Labrador Board of Commissioners of Public Utilities, *Reasons for Decision: Order NO. P.U. 43(2009*), December 24, 2009: http://www.pub.nf.ca/applications/NP2010GRA/index.htm

[5] Régie de l'énergie, *Décision D-2009-0156 R-3690-2009 Société en commandite Gaz Métro*, December 7, 2009: http://www.regie-energie.qc.ca/audiences/2009.htm

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Capital Asset Pricing Model, the Régie gives 50 percent weight to U.S. market risk premium data.

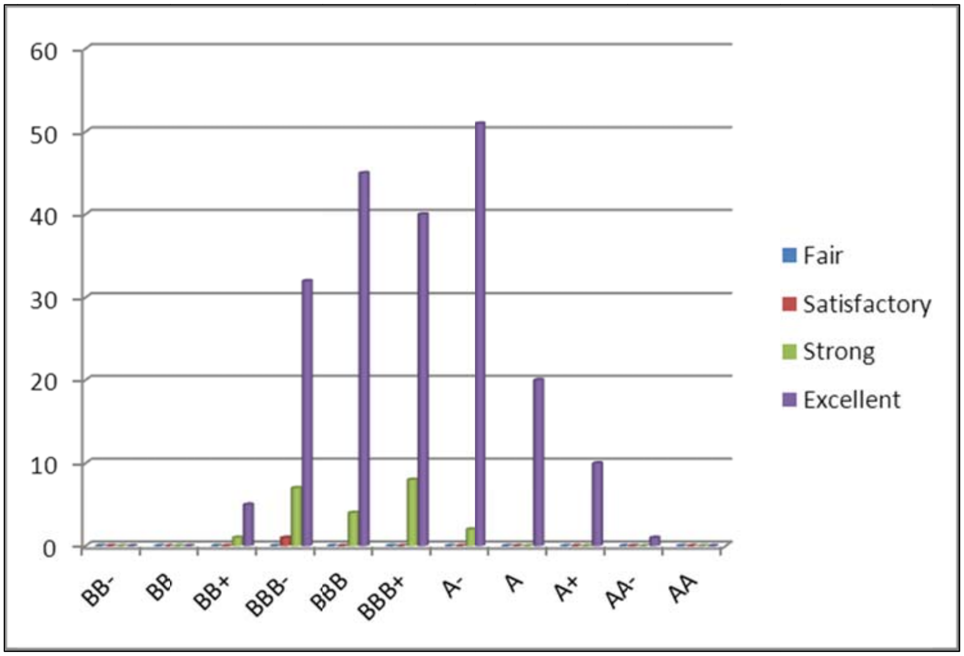
(c) Confirmed that the Régie views Gaz Métro as being of higher risk than a benchmark gas distribution utility.

(d) Confirmed.

(e) Confirmed, but incomplete. Mr. Akman's statement in his presentation that the ROE formula appears to be working was followed by caveats. The evidence maybe masked by fund flows away from other yield products, modest increase in allowed equity and loosening of regulatory framework. His presentation further stated that a reduction in allowed returns could be detrimental. In a later report, Canadian Energy Infrastructure: Stakes Raised in ROE Reviews, September 2009, Mr. Akman confirmed his March 2009 conclusion that the "old" formula was no longer valid and stated that "clearly the US data shows that today's allowed returns violate the comparable investment principle.[6]

(f) The updated graph is provided below.

[6] Macquarie Equities Research, Matthew Akman, *Canadian energy infrastructure: Stakes raised in ROE review*, September 21, 2009, pages 10-11.



(g) Ms. McShane cannot confirm the language utilized in the question. She is aware that the Ontario Energy Board historically had considered the DCF test to be problematic because the shares of the regulated utilities in Ontario including Enbridge Gas and Union Gas were not publicly traded. In Ms. McShane's view, the fact that the shares of the utilities are not publicly-traded should not detract from the usefulness of the DCF test, as the test should be applied to proxy companies of similar risk, rather than to specific utility whose allowed ROE is being estimated to avoid circularity.

Ms. McShane would further note that, in its 2009 Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, the OEB's revised benchmark ROE was based on the results of multiple tests performed by various experts, including DCF tests applied to samples of U.S. utilities.[7]

[7] Ontario Energy Board, *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, pages 22 and 23 and page 36.

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(h) Ms. McShane means that public utility regulation in both Canada and the U.S. is based on the same fundamental principles, including the fair return standard, and implements that standard, with some exceptions in both countries, using the same regulatory paradigm, that is, a cost of service model, which includes an allowed return on a historical cost rate base. Ms. McShane is aware that Moody's considers the regulatory environment in Canada generally to be more supportive than the regulatory environment generally in the U.S., as per its August 2009 Ratings Methodology: Regulated Electric and Gas Utilities.[8]

(i) No, they are not the same.

(j) Ms. McShane is aware of the statement, but disagrees with the conclusion as it applied to TGI (now FEI). At the very least, the conclusion overlooked the offsetting factor of TGI's (FEI's) lower common equity ratio compared to the U.S. proxy utilities.

(k) The arithmetic is correct. However, please refer to response (j). Further, the conclusion is even less applicable to NS Power, which does not have the full array of deferral accounts to which the BCUC referred in making the adjustment.

[8] Moody's, *Rating Methodology: Regulated Electric and Gas Utilities*, August 2009, page 6.

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Request IR-12:

Reference: Conclusions: Ms. McShane's testimony Appendix H, page 34

a) **Please indicate the current yield on US Treasury and Government of Canada 30 year bonds.**
b) **Would Ms. McShane accept that these 30 year yields are commonly used in CAPM-risk premium type estimates of the fair ROE?**
c) **Would Ms. McShane accept that at the current point in time long term Canada bond yields (30 year) are signficantly lower than in the US and further that they are forecast to remain so? If not please provide evidence that forecast long term (30 year) bond yields in the US are either the same or lower than in Canada.**
d) **Further to c) above would Ms. McShane accept that the Government of Canada has no problem raising money on lower yields than the US government and that this does not contradict the "returns on comparable risk securities" criteria, but simply reflects that one yield is in US $ and the other C$?**
e) **Please indicate what Ms. McShane understands by the interest rate parity condition in finance.**

Response IR-12:

(a) As of June 5, 2012, the yields on the 30 year Government of Canada and the 30 year U.S. Treasury bonds were 2.28 percent and 2.63 percent respectively.

(b) Ms. McShane accepts that 30-year Government bond yields are frequently used in CAPM estimates.

(c) The 30-year Government bond yield is currently 0.35 percent lower in Canada than in the U.S. Economists' recent projections anticipate that the 30-year Canada bond yield will remain below the corresponding term U.S. Treasury bond yield.

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(d) The Government of Canada is able to raise 30-year funds in Canada at yields lower than the U.S. in the U.S. For 10-year funds, the rate is slightly higher in Canada, at 1.74 percent as of June 5, 2012 versus 1.57 percent in the U.S. The difference reflects, in principle, a combination of differences in expected rates of inflation, the expected path of exchange rates, credit risk and supply of and demand for the specific securities. The difference is not a contradiction of the comparable investment returns criterion. As further context regarding relative yields on debt securities in the two countries, on average from January 2011 to May 2012, the difference in yields on long-term AAA/AA, A and BBB rated corporate bonds has been less than 10 basis points.

(e) The interest parity condition holds that the difference in interest rates between two countries operating in two different currencies should be equal to the difference between the spot and forward exchange rates, as per the following formula:

$$F/S = (1 + I_{US}) / (1 + I_C)$$

Where

F = Forward Exchange Rate (USD/CAD)

S = Spot Exchange Rate (USD/CAD)

I_{US} = Nominal Interest Rate, US

I_C = Nominal Interest Rate, Canada