NEWFOUNDLAND POWER
A FORTIS COMPANY

Newfoundland Power Inc.

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DELIVERED BY HAND

March 30, 2012

Board of Commissioners of Public Utilities
P.O. Box 21040
120 Torbay Road
St. John's, NL A1A 5B2

Attention: G. Cheryl Blundon
Director of Corporate Services
and Board Secretary

Ladies and Gentlemen:

Re: Newfoundland Power's 2012 Cost of Capital Application

A. Enclosures

Please find enclosed the original and eight copies of:

1. Newfoundland Power's Application for an order of the Board establishing a just and reasonable return on rate base for 2012 and discontinuing the use of the automatic adjustment formula (the "Application");
2. Evidence of Newfoundland Power in support of the Application;
3. *Opinion on Capital Structure and Return on Equity for Newfoundland Power Inc.* by Kathleen C. McShane of Foster Associates Inc.; and
4. *Written Evidence of James H. Vander Wiede, Ph.D. for Newfoundland Power Inc.* by Dr. James H. Vander Wiede of Financial Strategy Associates.

B. Background

In Order No. P.U. 43 (2009), Board ordered, in effect, that Newfoundland Power's 2010 customer electricity rates be based upon an allowed return on rate base which reflected a regulated return on equity of 9.0%, and that the Company's rate of return on rate base for 2011 and 2012 be set using the automatic adjustment formula (the "Formula").

For 2011, operation of the Formula resulted in an allowed return on rate base for the Company which reflected a regulated return on equity of 8.38%. For 2012, the Formula indicated an estimated cost of equity for Newfoundland Power of 7.85%.

In Order No. P.U. 25 (2011), the Board ordered, in effect, that (i) the operation of the Formula be suspended for 2012 and (ii) Newfoundland Power's allowed return on rate base continue, on an interim basis, to be that established by Order No. P.U. 32 (2010).

Section 80 of the *Public Utilities Act* entitles Newfoundland Power to a reasonable opportunity to earn a just and reasonable return each year. Neither the estimated cost of equity of 8.38% reflected in existing rates nor the estimated cost of equity of 7.85% indicated by the Formula constitutes a just and reasonable return for Newfoundland Power in 2012.

C. The Application

In this Application, Newfoundland Power seeks an order of the Board establishing the Company's cost of capital for 2012. The Application also seeks an order of the Board discontinuing the use of the Formula as it does not accurately estimate the appropriate return on equity under current financial market conditions.

When the Formula was introduced in 1998, the principal benefits were expected to be reduced costs resulting from less frequent reviews of cost of capital and reduced regulatory uncertainty. Since 2008, the Formula has failed to provide either.

The Application proposes that the adjustments to revenue requirement and rates resulting from the Board's determination of a ratemaking return on equity for 2012 be flowed through the Company's 2010 test year. This will permit timely recovery of the allowed return on equity and avoid the delay and cost associated with a GRA. Had the operation of the Formula not been suspended, the change in the Company's 2012 forecast cost of equity would have been reflected in rates based upon the 2010 test year.

D. Process

To provide Newfoundland Power with a reasonable opportunity in 2012 to earn a just and reasonable return as determined by the Board in this proceeding, it is desirable that the hearing of the Application proceed without delay. Newfoundland Power is prepared to meet any reasonable timetable for the proceeding that will accommodate the Board's agenda.

From discussions with the Board's legal counsel, it would appear that it would be convenient for the Board if the matter could proceed to hearing prior to the end of May. Newfoundland Power observes that its 1998 cost of capital proceeding, convened on the Board's initiative, progressed from pre-hearing conference to hearing commencement in just over 2 months.

E. Concluding

We trust the foregoing and enclosed are found to be in order. If you have any questions whatsoever, please feel free to contact us.

Copies of the Application have been forwarded directly to Mr. Geoffrey Young, Counsel to Newfoundland and Labrador Hydro and Mr. Thomas Johnson, the Consumer Advocate.

Yours very truly,

Gerard M. Hayes
Senior Counsel

Enclosures

c. Geoffrey Young
Newfoundland and Labrador Hydro

Thomas Johnson
O'Dea Earle Law Offices

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IN THE MATTER OF the *Public Utilities Act,*
(the "Act"); and

IN THE MATTER OF the establishment of a just and reasonable return on rate base pursuant to Section 80 of the Act for Newfoundland Power Inc. ("Newfoundland Power").

TO: The Board of Commissioners of Public Utilities ("the Board")

THE APPLICATION of Newfoundland Power **SAYS THAT**:

A. Background

1. Newfoundland Power is a corporation duly organized and existing under the laws of the Province of Newfoundland and Labrador, is a public utility within the meaning of the Act, and is subject to the provisions of the *Electrical Power Control Act, 1994.*

2. By Order No. P.U. 43 (2009), the Board ordered, in effect, that Newfoundland Power's 2010 customer electricity rates be based upon an allowed return on rate base which reflected a regulated return on equity of 9.0%.

3. By Order Nos. P.U. 16 (1998-99), P.U. 36 (1998-99), P.U. 19 (2003), P.U. 32 (2007), P.U. 43 (2009), and P.U. 12 (2010), the Board ordered, in effect, that an automatic adjustment formula be established to set the electrical rates and allowed rates of return for Newfoundland Power based upon changes in forecast long-term Government of Canada bond yields (the "Formula").

4. By Order No. P.U. 43 (2009), the Board also ordered, in effect, that Newfoundland Power:

   (a) apply no later than November 30th in each of 2010 and 2011 for application of the Formula to the rate of return on rate base; and

   (b) file its next general rate application with the Board no later than May 31, 2012 with a 2013 test year;

   unless otherwise ordered by the Board.

5. By Order No. P.U. 32 (2010), the Board ordered, in effect, that Newfoundland Power's 2011 customer electricity rates be based upon an allowed return on rate base which reflected a regulated return on equity of 8.38% as established by the Formula.

6. By Order No. P.U. 25 (2011), the Board ordered, in effect, that (i) the operation of the Formula be suspended for 2012; (ii) Newfoundland Power's allowed return on rate base continue, on an interim basis, to be that established by Order No. P.U. 32 (2010); and (iii) the process and timing to determine a just and reasonable rate of return on rate base for Newfoundland Power for 2012 and Newfoundland Power's next general rate application shall be established by a further direction of the Board.

B. Application Proposals

7. This Application proposes that the Board:

   (a) approve a just and reasonable return on rate base for Newfoundland Power for 2012;

   (b) discontinue use of the Formula for setting the allowed return on rate base for Newfoundland Power; and

   (c) approve a schedule of customer rates, tolls and charges based upon the rate of return on average rate base for 2012 as approved by the Board in this proceeding;

   all as described in the evidence filed in support of this Application.

C. Order Requested

8. Newfoundland Power requests that, pursuant to Section 80 of the Act, the Board make an Order:

   (a) approving a just and reasonable rate of return on average rate base for 2012;

   (b) approving rates, tolls and charges which provide Newfoundland Power a reasonable opportunity to earn a just and reasonable return on rate base for 2012;

   (c) discontinuing the use of the Formula; and

   (d) approving such further, other or alternate relief which may, upon hearing of this Application, appear just and reasonable in the circumstances.

D. Communications

9. Communications with respect to this Application should be forwarded to the attention of Ian F. Kelly, Q.C. and Gerard M. Hayes, Counsel to Newfoundland Power.

DATED at St. John's, Newfoundland and Labrador this 30th day of March, 2012.

NEWFOUNDLAND POWER INC.

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IN THE MATTER OF the *Public Utilities Act,*
(the "Act"); and

IN THE MATTER OF the establishment of a just and reasonable return on rate base pursuant to Section 80 of the Act for Newfoundland Power Inc. ("Newfoundland Power").

AFFIDAVIT

I, Peter Alteen, of the City of St. John's in the Province of Newfoundland and Labrador, make oath and say as follows:

1. That I am Vice-President, Regulation and Planning of Newfoundland Power Inc.

2. To the best of my knowledge, information and belief, all matters, facts and things set out in this Application are true.

SWORN to before me at St. John's in the Province of Newfoundland and Labrador this 29th day of March, 2012.

Barrister

Peter Alteen

IN THE MATTER OF the *Public Utilities Act,* (the "Act"); and

IN THE MATTER OF the establishment of a just and reasonable return on rate base pursuant to Section 80 of the Act for Newfoundland Power Inc. ("Newfoundland Power") for 2012.

EVIDENCE OF NEWFOUNDLAND POWER

March 30, 2012

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1.0 OVERVIEW

The central issue in this Application is the establishment of a just and reasonable return on rate base for Newfoundland Power (the "Company"). In particular, the Application's focus is the ratemaking return on equity to be included in establishing a just and reasonable return on rate base. Neither the ratemaking return on equity of 7.85% for 2012 indicated by the automatic adjustment mechanism used to establish a return on rate base for the Company (the "Formula") nor the ratemaking return on equity of 8.38% currently included in the Company's return on rate base on an interim basis are appropriate. Neither meets the fair return standard because they are too low.

The other key issue in this Application is the future of the Formula. The Formula was adopted by the Board of Commissioners of Public Utilities (the "Board") in 1998 amidst a growing national regulatory consensus on the appropriateness of the use of such automatic adjustment mechanisms.[1] Nothing resembling such a consensus exists in current Canadian regulatory practice.[2] This lack of consensus is primarily the result of shortcomings of the capital asset pricing model in estimating a fair utility return on equity in current financial market conditions.

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1 At the time of the adoption of the Formula in 1998, similar formulas were approved by the British Columbia Utilities Commission (the "BCUC"), the Public Utilities Board of Manitoba (the "Manitoba PUB"), the National Energy Board (the "NEB"), and the Ontario Energy Board (the "OEB"). See Order No. P.U. 16 (1998-99), page 4.

2 The Alberta Utilities Commission (the "AUC"), the BCUC, the Manitoba PUB and the NEB do not currently use formulas to establish returns for utilities under their regulatory jurisdiction, although the BCUC may consider the matter in cost of capital proceedings in 2012. The OEB uses a formula to establish returns for electricity distributors under its jurisdiction. The OEB formula was modified in 2009 along with rebasing of the benchmark ROE to a higher level than in its previous formula. In late 2011, the AUC decided not to reinstate a formula but has left the matter open for reconsideration for 2013 (see Decision 2011-474, December 8, 2011). The Régie d'énergie du Quebec (the "Régie") continues to use a modified formula to establish returns for Gáz Metro. Neither the Nova Scotia Utility and Review Board nor the Island Regulatory and Appeals Commission (Prince Edward Island) ever adopted a formula to establish returns for investor-owned utilities under their respective jurisdictions.

These shortcomings have caused a number of Canadian regulators to abandon the use of formulas and reduce reliance on the capital asset pricing model in establishing utility returns.[3]

Establishing a just and reasonable return on rate base for Newfoundland Power for 2012 will require the Board to consider (i) the elements of risk faced by Newfoundland Power as a business and (ii) expert opinion concerning a fair return on equity. Considering the future of the Formula will require an examination of its performance since 2009. Finally, providing Newfoundland Power with a reasonable opportunity to recover a fair return on equity for 2012 will require the Board to consider certain implementation issues.

This evidence addresses (i) specific risks faced by Newfoundland Power as a business, (ii) the operation of the Formula since 2009, and (iii) matters related to the recovery of a revised cost of equity for 2012.

The expert evidence of Ms. Kathleen McShane and Dr. James Vander Weide is also provided in support of this Application.

[3] In March 2009, the NEB first determined that a single variable, the long Canada bond yield, could potentially not capture market changes that affect a utility's cost of capital (see RH-1-2008, page 17). By October 2009, the NEB had abandoned the single variable formula to establish utilities' cost of equity (see RH-R-2-94). The AUC has twice determined that the relationship between long-term Canada bond yields and the required rate of return for utilities did not necessarily hold in current financial market conditions. For that reason, the AUC declined to continue, or reintroduce, the use of a capital asset pricing model-based formula. The AUC has indicated a return to such a formula in the future is possible when relationships in the capital markets are again considered reasonably predictable. (see Decision 2009-216, November 2009, pages 107-110 and Decision 2011-474, December 2011, pages 28-31). In December 2009, the BCUC determined that a single variable such as the long Canada bond yield was unlikely to capture the many causes of changes in returns on equity, including the flight to quality which drove down the yields on those bonds. Accordingly, the BCUC placed only limited weight on the capital asset pricing model in determining ratemaking returns on equity (see Decision G-158-09, pages 72-73).

2.0 BACKGROUND

In its 2010 General Rate Application ("GRA"), Newfoundland Power proposed, amongst other things, (i) not using the Formula to establish the Company's 2010 return on equity and (ii) discontinuing future use of the Formula due to material changes in financial market conditions which affected the fairness of the returns on equity yielded by the Formula.

In Order No. P.U. 43 (2009), the Board determined that a return on equity of 9% was reasonable for Newfoundland Power for 2010. The Board decided not to accept the return on equity of 8.48% indicated by the Formula for 2010, but ordered continued use of the Formula to establish returns on equity for 2011 and 2012.

Operation of the Formula for 2011 resulted in an estimated return on equity for Newfoundland Power of 8.38%.[4] This was the lowest ratemaking return on equity for a Canadian investor-owned electric utility for 2011.[5]

Operation of the Formula for 2012 would have resulted in an estimated return on equity for Newfoundland Power of 7.85%.[6] In November 2011, the Company filed an application seeking, amongst other things, to suspend the operation of the Formula for 2012 and to establish a process to determine a just and reasonable return for 2012.

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4 See Order No. P.U. 32 (2010).

5 For 2011, ratemaking returns on equity for Canadian investor-owned electric utilities, other than Newfoundland Power, ranged from a low of 9% in Alberta to a high of 9.9% for British Columbia-based FortisBC.

6 If approved by the Board, this would have been the lowest ratemaking return on equity for a Canadian investor-owned electric utility for 2012. For 2012, ratemaking returns on equity for Canadian investor-owned electric utilities, other than Newfoundland Power, range from a low of 8.75% in Alberta to a high of 9.9% in British Columbia. BCUC Order No. G-20-12, establishes a proceeding to determine the appropriate cost of capital for a benchmark low risk utility effective January 1, 2013.

By Order No. P.U. 25 (2011), the Board in effect (i) suspended the operation of the Formula for 2012 and (ii) approved on an interim basis the continued use of the ratemaking return on equity of 8.38% currently included in the Company's return on rate base.

3.0 RISK ASSESSMENT

3.1 General

Cost of capital is the rate of return that investors could expect to earn if they invested in equally risky securities.[7] Therefore, cost of capital is essentially a relative concept. The accepted relative measure for determining a business' cost of capital is risk.

Risk is an assessment of the capability of an enterprise to recover its investment as well as earn a return on that investment. For regulated utilities such as Newfoundland Power, risk is generally considered to have business, regulatory and financial elements. The business elements relate to the Company's operations and assets. Newfoundland Power principally invests in long-lived assets, which implies that risk assessment should be undertaken over long-term horizons.[8] The regulatory elements relate to the regulatory framework under which the Company operates and the Board's determinations of how Newfoundland Power's costs are to be recovered and how its risks are to be shared between investors and ratepayers. The financial elements of risk principally relate to the degree that debt is used to finance the Company.

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[7] Brealey, Myers et. al., *Fundamentals of Corporate Finance* (2nd Canadian Edition), page 271.

[8] For example, in Order No. P.U. 32 (2007), the Board approved depreciation rates based upon a study which indicated that Company distribution assets had service lives between 36 and 50 years. (see 2006 Depreciation Study, Volume 3, Expert Evidence, Tab 3, Schedule 1, Newfoundland Power's 2008 GRA). This implies that the Company can expect to recover new investment in distribution assets over a 36 to 50 year time horizon.

Cost of capital depends on all three elements of risk and how they compare to those of other enterprises, including other enterprises in the same industry. Regulated utilities are typically considered to be relatively low risk enterprises.

Relative to its Canadian utility peers, the Board has historically assessed Newfoundland Power to be an average risk Canadian utility.[9] Financial market conditions have changed dramatically in recent years. Newfoundland Power's principal business, regulatory and financial risks, however, have not changed materially over this time.

This portion of the Company's evidence assesses some of the more prominent elements of risks faced by Newfoundland Power.

3.2 Business Elements

Business Profile

Newfoundland Power is a relatively small electrical distribution utility which principally serves mature residential, commercial and institutional markets on the island of Newfoundland.[10] The Company currently serves approximately 247,000 customers. Large industrial customers on the island of Newfoundland are served by Newfoundland and Labrador Hydro ("Hydro").

Over the past ten years, annual average energy sales growth for Newfoundland Power has been 1.8% and annual average growth in the number of customers served has been 1.3%. Growth in

[9] See, for example, Order No. P.U. 19 (2003), page 33, where the Board indicated that the business risk profile of Newfoundland Power had not changed appreciably since 1998, and Order No. P.U. 43 (2009), page 13, where the Board found that Newfoundland Power continued to be an average risk Canadian utility.

[10] The relatively small size of Newfoundland Power has been recognized by the Board as an element of its risk profile insofar as it reduces the Company's financial flexibility and supports a stronger capital structure. See, for example, Order No. P.U. 16 (1998-99), page 37 and Order No. P.U. 19 (2003), page 45.

service sector Gross Domestic Product for Newfoundland and Labrador ("GDP") has been approximately 2.6% per year over the past ten years.[11]

For the five years ending in 2016, annual average sales growth for Newfoundland Power is forecast to be approximately 1.6%.[12] This reflects annual forecast service sector GDP growth of 1.5% over this period. For the next ten and twenty years, growth in provincial service sector GDP is forecast by the Conference Board of Canada to be 1.3% per year and 1.0% per year, respectively.

Service Territory Demographics

Newfoundland and Labrador's population is in decline, increasingly urbanized and rapidly aging.

Population

Newfoundland and Labrador's population declined by 9.3% in the 20 years to 2011, and is expected to further decline by 6.2% through 2030.[13] The Conference Board of Canada is forecasting that Newfoundland and Labrador will be the only province with an absolute decline in population through 2030.[14]

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[11] Conference Board of Canada, *Provincial Outlook Long-Term Economic Forecast 2011*, May 2011. By contrast, the average annual growth in overall GDP for Newfoundland and Labrador for the 10 years ending in 2010 as reported by the Conference Board of Canada was 3.1%. This overall GDP growth is largely reflective of increased oil and mineral development in the province over the period. Newfoundland Power serves residential, commercial and institutional electricity markets. Growth in these markets has tended more to reflect growth in service sector GDP than overall GDP.

[12] Newfoundland Power does not forecast energy sales and the number of customers beyond five years.

[13] The population of Newfoundland and Labrador was approximately 568,000 in 1991 and approximately 515,000 in 2011 representing a decline of 9.3% (515,000/568,000-1= -0.093), although in the decade from 2001 to 2011 the population increased marginally from approximately 513,000 to 515,000 (see Statistics Canada 2011 Census). Conference Board of Canada, *Provincial Outlook Long-Term Economic Forecast 2011*, May 2011, forecasts the population of the Province to be 483,000 in 2030, which represents a further decline of 6.2% (483,000/515,000-1= -0.062).

[14] Conference Board of Canada, *Provincial Outlook Long-Term Economic Forecast 2011*, May 2011.

Urbanization

Population losses in rural areas of the Province have been partly driven by increased migration to urban areas. This trend is expected to continue.[15]

Approximately 70% of the municipalities served by Newfoundland Power have a population of less than 1,000 people.[16] While 14% of Newfoundland Power's customers reside in these relatively small municipalities, approximately 40% of the Company's total distribution investment is dedicated to serving these customers.[17]

Over the 10 years to 2011, approximately 89% of these small municipalities experienced a decline in population.[18] In approximately 29% of these municipalities, the number of Newfoundland Power customers also declined during this period.[19] Similarly, in approximately 32% of these municipalities, Newfoundland Power's energy sales declined during this period.[20]

In seven municipalities served by Newfoundland Power, the population exceeds 10,000 people.[21] Approximately 43% of Newfoundland Power's customers reside in these seven municipalities.[22]

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15 *Demographic Change: Issues & Implications*, Province of Newfoundland and Labrador, October 2006, page 7.

16 Newfoundland Power currently serves 188 municipalities, of which 133 have a population of less than 1,000 people (133/188= 0.71, or 71%). In aggregate, these 133 municipalities have a population of 54,607 and contain 34,575, or 14%, of Newfoundland Power's customers.

17 The total value of Newfoundland Power's distribution line assets at December 31, 2011 was approximately $452 million. The value of distribution line assets serving municipalities of less than 1,000 residents was $181 million, or 40% of total distribution line investment (181/452= 0.40, or 40%).

18 According to Statistics Canada 2011 Census, 118 of the 133 municipalities' populations declined over the 10- year period ending in 2011 (118/133= 0.89, or 89%).

19 Over the 10-year period ending in 2011, 38 of the 133 municipalities saw a decline in the number of Newfoundland Power customers (38/133= 0.29, or 29%).

20 Over the period 2001 through 2011, 43 of the 133 municipalities saw a decline in Newfoundland Power energy sales (43/133= 0.32, or 32%). The aggregate decline in energy sales was approximately 13 GWh.

21 These are the cities of St. John's, Mount Pearl and Corner Brook, and the towns of Conception Bay South, Paradise, Grand Falls-Windsor and Gander.

22 As at December 31st, 2011, 107,093 of the 247,163 customers of Newfoundland Power resided in these 7 municipalities (107,093/247,163= 0.43, or 43%).

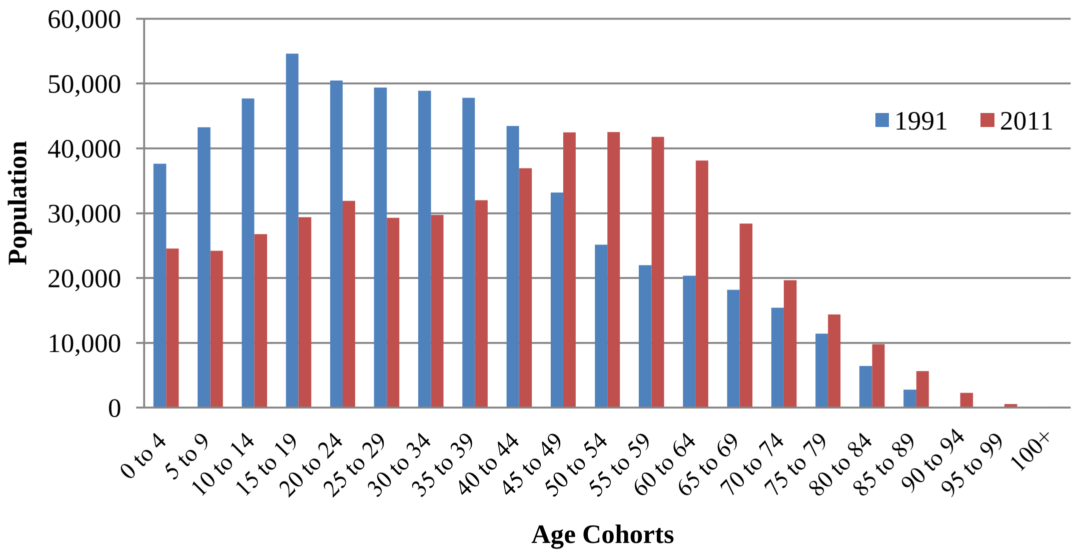
Over the 10 years to 2011, these larger municipalities experienced an aggregate increase in population of 11%.[23] The number of Newfoundland Power customers in these municipalities increased by approximately 19% during this period.[24] Similarly, Newfoundland Power's energy sales to customers in these municipalities increased by approximately 26% for the same period.[25]

Aging Trends

Newfoundland and Labrador has one of the most rapidly aging populations in Canada.[26]

Graph 1 shows the population of Newfoundland and Labrador by age cohorts for 1991 and 2011.[27]

Graph 1
Newfoundland & Labrador
Population by Age Cohorts
1991 and 2011



[23] The aggregate population in these municipalities was 196,610 in 2001 and 217,664 in 2011 according to Statistics Canada 2011 Census (217,664/196,610-1= 0.11, or 11%). This growth was not evenly spread amongst these 7 municipalities during this period. Over the 10 years to 2011, the cities of Mount Pearl and Corner Brook both experienced modest declines in population.

[24] In 2001, 89,619 Newfoundland Power customers resided in these municipalities, by 2011, the number of customers increased to 107,093 (107,093/89,619-1= 0.19, or 19%).

[25] In 2001, Newfoundland Power energy sales to customers resident in these municipalities totalled 2,362 GWh; by 2011, energy sales increased to 2,981 GWh (2,981/2,362-1= 0.26, or 26%).

[26] Conference Board of Canada, *Provincial Outlook Long-Term Economic Forecast 2011*, May 2011 has indicated that current trends will result in both a declining population and a faster aging of the population in Newfoundland and Labrador (see Executive Summary, page ii).

[27] See Statistics Canada, CANSIM table 051-0001, compiled by the Economics and Statistics Branch, Newfoundland & Labrador Statistics Agency.

The provincial population in 2011 is, on average, significantly older than it was in 1991. For example, the population of residents 19 years of age and under has significantly declined over the 20 year period, while the population of residents 50 years of age and over has significantly increased.[28]

Demographic Impacts

In the 20 years to 2011, the population over 19 years of age within the Company's service territory grew by approximately 9.2%, while overall population declined by approximately 6.5%.[29] The increasing proportion of the population over the age of 19 resulted in increased household formation in the Company's service territory which, in turn, increased the number of customers served by the Company. In the 20 years to 2011, the overall number of customers served by Newfoundland Power grew by approximately 26%, or 1.3% per year.[30]

In the 20 years to 2011, the Company's overall energy sales grew by approximately 32%, or 1.6% per year.[31] The increasing number of customers was a primary reason for the increase in energy sales. The other principal contributor to energy sales growth was an increase in the market share of electric space heating over the period.[32]

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[28] In 1991, there were approximately 183,000 residents in the province 19 years of age and under compared to approximately 105,000 residents in 2011, a decrease of 42% (105,000/183,000-1= 0.42). In 1991, there were approximately 122,000 residents 50 years of age and over compared to approximately 203,000 in 2011, an increase of 66% (203,000/122,000-1= 0.66).

[29] In 1991, Newfoundland Power's service territory had an overall population of approximately 478,000, of which approximately 328,000 were 19 years of age or older. In 2011, overall population was approximately 447,000, of which 358,000 were 19 years of age or older. The decline in overall population in the Company's service territory was approximately 6.5% (447,000/478,000-1= -0.065). The increase in population over 19 years of age in the Company's service territory was approximately 9.2% (358,000/328,000-1= 0.092).

[30] In 1991, Newfoundland Power had approximately 196,000 customers and in 2011 approximately 247,000 customers, representing an increase of 26% (247,000/196,000-1= 0.260).

[31] In 1991, Newfoundland Power had approximately 4,196 GWh in energy sales and in 2011 approximately 5,553 GWh in energy sales, representing an increase of 32% (5,553/4,196 -1= 0.323).

[32] For example, in 2001, approximately 54% of Newfoundland Power customers used electricity as a primary heating source; by 2011, this had increased to approximately 63%.

Newfoundland and Labrador's population is aging at a relatively rapid rate. It is also forecast to decline further. Demographic trends already indicate a decline in the number of customers and energy sales in a material portion of Newfoundland Power's service territory. This is accompanied by concentrated growth in the larger urban centers.

These trends have implications for investment and long-term cost recovery. The Company will be required to make increased investment to fulfill its obligation to serve growing populations in urban centers.[33] In addition, ongoing investment will be required to fulfill the obligation to serve rural areas which have fewer customers and declining sales. The need to recover this increased investment from a declining customer base can be expected to exert increasing pressure on the Company's required investment return over the longer term.

Operating Conditions

Newfoundland Power is predominantly a distribution utility with a substantial heating load. Response to service interruptions, particularly in winter, is critical given the number of the Company's customers that rely on electricity for heating.

Approximately 80% of interruptions in electricity supply to customers result from electrical distribution system failures.[34] Weather conditions are the leading cause of electrical distribution system failure in Canada, including the island of Newfoundland.[35] The climate across the

[33] For example, in 2010 and 2011, the Company installed 4 new power transformers to provide additional service capacity. This compares to a total of 6 new power transformers installed over the 19-year period from 1991 through 2009. The Company expects to install another 8 power transformers in the 5-year period from 2012 through 2016 at an average cost of over $3 million each.

[34] Based upon the 5-year average system average interruption frequency index, or SAIFI, data for Newfoundland Power from 2007 to 2011.

[35] Canadian Electricity Association, *Annual Service Continuity Report on Distribution System Performance in Electric Utilities*, 2010.

Company's service territory includes the most severe wind and ice conditions in populated regions of Canada.[36] These conditions are particularly hazardous for aerial transmission and distribution systems.[37]

Severe weather conditions increase volatility in the Company's operating and capital costs.[38]

Cost Flexibility

Table 1 shows revenue and costs for Newfoundland Power on a kWh basis for 1991, 2001 and 2011.[39]

Table 1
Revenue and Costs
¢ per kWh

	1991	**2001**	**2011**
Revenue	7.61	7.70	10.32
Energy Supply Costs	4.31	4.34	5.67
Fixed Costs[40]	1.57	1.71	3.01
Operating Costs	1.06	1.02	1.02
Operating Costs as % of Revenue	14%	13%	10%

36 Data for historic weather is available from Environment Canada, National Climate Data and Information Archive website, http://climate.weatheroffice.gc.ca/winners/intro_e.html. For example, St. John's typically experiences 127 days each year where the average wind speed exceeds 40 km/hr, the most of any city in Canada. Similarly, both Gander and St. John's lead the country in the number of days each year where freezing rain is experienced.

37 High winds and freezing rain contribute to unscheduled outages on the Company's overhead distribution and transmission infrastructure. By way of example, major weather events in 2010 resulted in unplanned expenditures of approximately $10 million. In March 2010, an ice storm caused $4.2 million in damage to the Company's transmission and distribution systems. In September 2010, the Company incurred approximately $1.8 million in additional operating expenditures and approximately $3.7 million in additional capital expenditures resulting from Hurricane Igor.

38 For some utilities, such as those in Alberta, specific regulatory accounts exist to provide for the deferred recovery of uninsured damage over $100,000 that results from severe weather events.

39 Revenue and cost on a kWh basis are defined as the annual revenue and cost divided by the kWh sales in the same year.

40 Fixed costs include demand supply costs, depreciation, employee future benefit costs, finance costs and income taxes.

Over the last 20 years, Newfoundland Power's electricity rates and revenues have increased primarily as a result of increased supply costs and fixed costs. The increase in fixed costs reflects increases in finance and depreciation costs associated with growing investment in the business. It also reflects the introduction of a demand charge into the wholesale rate structure in 2005 and increased recovery of employee future benefit costs since 2008. Energy supply costs and fixed costs, which increased materially in the last 10 years, currently comprise approximately 84% of revenues on a kWh basis. These costs are substantially beyond management control in any year.

Newfoundland Power's nominal operating costs on a kWh basis have been stable over the 20 years to 2011.[41] However, operating costs as a proportion of revenue have declined since 1991. The Company's operating costs, over which a *degree* of management control can be expected, currently comprise approximately 10% of revenue.[42]

While reducing operating costs on a real basis is reflective of sound management, the decreasing *proportion* of operating costs reduces the Company's flexibility to respond to extraordinary operating events such as those related to weather.[43]

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[41] This *nominal* stability masks considerable improvement in the Company's operating productivity over the 20 year period. Inflation in the 20-years ending in 2011 was 43.8%.

[42] While operating costs are subject to a *degree* of management control, the extent of that control varies by the nature of the cost. For example, the reduction of labour costs associated with full time employees may not be controllable in the short term due to severance obligations. On the other hand, 3rd party maintenance arrangements may be controllable in the short term, depending on agreements.

[43] See footnote 37.

Power Supply

Newfoundland Power is dependent upon Hydro for the power supply required by the Company to meet its obligation to serve its customers.[44] Power purchases from Hydro are Newfoundland Power's largest cost, accounting for approximately 66% of revenue from rates in 2011.[45]

Newfoundland Power's single supply dependence is relatively rare for investor-owned electric utilities in Canada.[46] Currently, the Company effectively recovers its power supply costs through a combination of customer rates and regulatory mechanisms.[47]

Newfoundland Power's single supply dependence limits management's ability to influence the Company's largest cost.[48] While this circumstance does not materially affect current recovery of the Company's cost of service, it could possibly do so in the future. Further, the impact of power supply costs on customer rates could serve to influence consumer behaviour and restrict sales growth or promote sales decline. Finally, abrupt increases in power supply costs could have the effect of delaying recovery of Newfoundland Power's other costs.[49]

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44 Currently, Newfoundland Power purchases approximately 93% of its power supply requirements from Hydro. Newfoundland Power has no practical alternative to Hydro for the additional power supply required to meet increasing customer load.

45 Newfoundland Power's 2011 purchased power costs were approximately $369 million; 2011 revenue from rates was approximately $559 million (369/559= 0.66, or 66%).

46 In Ontario and Alberta, energy supply for distribution to consumers is coordinated at a wholesale level by independent market operators which effectively ensure least cost supply on a real-time basis through competitive bidding. In Nova Scotia, Prince Edward Island and British Columbia, electric utilities are practically able to seek competitive sources of energy supply in regional wholesale markets. Saskatchewan, Manitoba and New Brunswick do not have investor-owned electric utilities.

47 See pages 14 to 16 for a description of the regulatory mechanisms that permit Newfoundland Power to recover its power supply costs.

48 Newfoundland Power management does have some limited ability to influence power supply costs included in customer electricity rates through the regulatory process.

49 This point has been made by the Dominion Bond Rating Service in the context of credit risk assessment (see Exhibit 1 for DBRS rating report, January 24, 2012, page 2).

3.3 Regulatory Elements

Regulatory Framework

Newfoundland Power is regulated on a cost of service basis consistent with other investor-owned utilities across Canada. Section 80 of the *Public Utilities Acts* (the "Act") provides that in addition to recovery of its prudently incurred costs, a public utility is also entitled to earn annually a just and reasonable return on its rate base.

Section 3 (a) (iii) of the *Electrical Power Control Act, 1994* (the "EPCA") provides that the rates approved by the Board should provide sufficient revenue to a utility "…to enable it to earn a just and reasonable return as construed under the *Public Utilities Act* so that it is able to achieve and maintain a sound credit rating in the financial markets of the world…".

Section 80 of the Act, together with Section 3 (a) (iii) of the EPCA are the cornerstones of the regulatory framework governing the recovery of costs and establishment of returns for public utilities in Newfoundland & Labrador.

Cost Recovery

The Board has approved regulatory mechanisms to ensure reasonable recovery of (i) supply costs from Hydro, (ii) costs due to variations in weather and (iii) employee future benefit costs.

Newfoundland Power's Rate Stabilization Account (the "RSA") is the primary means by which changes in supply costs from Hydro are recovered. This account principally recovers variations in the cost of fuel burned at Hydro's Holyrood Thermal Generating Station.[50]

The RSA also recovers, or rebates, as appropriate, variations in Newfoundland Power's supply costs due to changes from test year energy and demand costs.[51] The RSA effectively limits Newfoundland Power's risk of recovery of supply costs to approximately ± $550,000, which represents approximately 25% of the range of return on rate base typically approved by the Board. Supply cost recovery or flow through mechanisms are common Canadian regulatory practice for distribution utilities.[52]

Newfoundland Power's Weather Normalization Reserve stabilizes customer electricity rates by adjusting revenue and power supply costs to account for variations in weather.[53] Such adjustments ensure that Newfoundland Power experiences neither an earnings windfall nor an earnings shortfall as a result of weather conditions. Normalization of revenue and supply costs for weather is common for regulated utilities that supply a substantial heating load.[54]

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50 The RSA was originally approved by Order No. P.U. 34 (1985) to enable Newfoundland Power to flow through changes in Hydro's fuel costs.

51 In Order No. P.U. 32 (2007), the Board originally approved a change in the RSA to permit Newfoundland Power to recover the difference between the marginal energy supply cost from Hydro and the average energy supply cost from Hydro. Given supply cost dynamics on the Island grid, without such a recovery, annual GRAs would be necessary for Newfoundland Power. In Order No. P.U. 32 (2007), the Board also approved the potential recovery or rebate of demand costs through the RSA where demand costs vary by more than 1% from test year demand costs. Recovery or rebate is subject to Board approval which includes consideration of Newfoundland Power's demand management activities. Demand management incentives achieved by Newfoundland Power have resulted in credits to customers of approximately $6 million since 2005.

52 Currently, cost recovery or flow through mechanisms have been approved for supply cost or margin variations for utilities in all provinces except Manitoba and Saskatchewan where the utilities are not investor owned.

53 Normalization associated with hydraulic production originated in Order No. P.U. 32 (1968). Normalization associated with sales and purchase variations related to space heating originated in Order No. P.U. 1 (1974).

54 These are typically natural gas distribution utilities.

Newfoundland Power has variation accounts to ensure recovery of only those employee future benefit costs which are actually incurred by the Company.[55] Recovery accounts for utility employee future benefit costs have become more common as a result of a combination of changes in accounting practice and financial market conditions.[56]

Return Limits

Historically, the Board has approved a range of return on rate base for Newfoundland Power. This has partially been justified on the basis that setting a reasonable rate of return is not an exact science, no matter what methodology is adopted by the regulator to establish the return. It has also been justified partially by the Board's desire to limit the return that Newfoundland Power may actually earn in any given year.[57] Use of a range has also been justified for its incentive effect.[58]

Newfoundland Power has an Excess Earnings Account which captures all earnings in excess of the upper limit of the range of return on rate base approved by the Board.[59] The typical range approved by the Board for Newfoundland Power is ± 0.18% return on rate base which broadly equates to ± 0.375% return on equity on a *pro forma* basis. The Excess Earnings Account effectively limits the return on equity that Newfoundland Power is capable of earning to

[55] The variation accounts ensure recovery of annual defined benefit pension costs and other post employment benefit costs. Each account operates to true up estimated costs to actual costs. The defined benefit pension variation account was approved in Order No. P.U. 43 (2009). The other post employment benefit variation account was approved in Order No. P.U. 31 (2010).

[56] Changes in accounting practice have included the adoption of the annual marking to market of future benefit obligations and fund assets. This has increased the annual volatility of employee future benefit costs. Currently, recovery mechanisms have also been approved for employee future benefit costs for utilities in Alberta and British Columbia.

[57] See paragraphs 25 *et. seq.*of the June 15, 1998 Court of Appeal decision in the Stated Case.

[58] See, for example, Order No. P.U. 19 (2003), page 76, where the Board indicated its view that "…the range of return on rate base can act as an incentive device to encourage NP to seek efficiencies between rate hearings, which can then be passed on to customers."

[59] See, for example, Order Nos. P.U. 32 (2010) and P.U. 46 (2009).

approximately $1.5 million more than the allowed return on equity used for rate making purposes in a test year. The Excess Earnings Account does not provide for the recovery of shortfalls in earned returns below the range approved by the Board.[60]

The Excess Earnings Account creates an element of asymmetry in Newfoundland Power's earnings risk. Sharing of earnings variances between utilities and customers has been a feature of certain performance based ratemaking regimes in Canada.[61] However, a cap such as that created by the Company's Excess Earnings Account is relatively rare among Canadian investor-owned utilities.

3.4 Financial Elements

Capital Structure

Table 2 shows the targeted capital structure of Newfoundland Power.

Table 2
Targeted Capital Structure

Debt	54%
Preferred Equity	1%
Common Equity	45%

[60] See paragraph 70 of the June 15, 1998 Court of Appeal decision in the Stated Case where the Court found, "While the utility, if it earned as much as the maximum would be entitled to keep that amount of earnings, it is not, for reasons already given, guaranteed that level of return if it is not in fact successful in earning them. *The Board is under no obligation to adjust future rates or to take other steps to make up any such shortfall*." (Italics added).

[61] In British Columbia, sharing of positive and negative variances between approved and actual regulated earnings between customers and utilities has been part of performance based regulatory schemes for gas and electric utilities.

The Company's target of 45% common equity in its capital structure is consistent with Board orders since 1990.[62] Newfoundland Power's capital structure is a relative strength that mitigates risks associated with the Company's small size and low long-term forecast growth estimates.[63]

Credit Ratings

The most recent credit rating reports from DBRS Limited ("DBRS") and Moody's Investors Services ("Moody's") are found in Exhibit 1. Both DBRS and Moody's assess the Company's creditworthiness on a stand-alone basis.

Table 3 shows DBRS and Moody's current credit ratings for Newfoundland Power.

Table 3
Credit Ratings

Rating Agency	Issuer Rating	Bond Rating
DBRS	-[64]	A, Stable
Moody's	Baa1	A2, Stable

Newfoundland Power's first mortgage bonds are its primary source of long term debt financing. These bonds have held an investment grade rating from two credit rating agencies throughout the past two decades.

Newfoundland Power's current credit ratings are investment grade and are consistent with both (i) least cost service delivery to customers over the long term and (ii) maintaining a sound credit rating in the financial markets of the world as required under the Act.

62 See Order Nos. P.U. 1(1990), P.U. 6 (1991), P.U. 7 (1996-97), P.U. 16 (1998-99), P.U. 19 (2003), P.U. 32 (2007), and P.U. 43 (2009).
63 See footnote 10.
64 DBRS does not rate the issuer of securities; it only rates the securities issued.

4.0 AUTOMATIC ADJUSTMENT FORMULA

4.1 Regulatory Objectives

The Board first ordered adoption of the Formula in 1998. At that time, the principal benefits were expected to be reduced costs resulting from less frequent reviews of cost of capital and reduced regulatory uncertainty.[65]

Following adoption of the Formula in 1998, Newfoundland Power's cost of capital was re-examined in the Company's 2003 and 2008 GRAs. For the most part, during the decade ending in 2007 (the year the Company's 2008 GRA was determined), the Formula appeared to broadly achieve the regulatory objectives of less frequent reviews of cost of capital and reduced regulatory uncertainty.[66]

Since 2008, the Formula has failed to produce either fewer reviews of Newfoundland Power's cost of capital or reduced regulatory uncertainty. Instead, the Formula has yielded estimates of Newfoundland Power's cost of equity which have triggered successive re-examinations of the Company's cost of capital and the operation of the Formula.[67]

[65] See, for example, Order No. P.U. 16 (1998-99), page 103 and Order No. P.U. 43 (2009), pages 28-29.

[66] Modifications to the Formula occurred in this period. For example, in Order No. P.U. 19 (2003), the Board ordered changes in the series of Long Canada Bond Yields used to estimate the risk-free rate (see page 66-67 of the Order).

[67] Applications to the Board related to the Company's ratemaking returns on equity have increased markedly since 2008. In the applications resulting in Order Nos. P.U. 32 (2007) and P.U. 43 (2009) and in this Application, the sufficiency of the ratemaking returns on equity of Newfoundland Power were, or are, at issue. In the applications resulting in Order Nos. P.U. 35 (2008), P.U. 12 (2010), P.U. 32 (2010) and P.U. 25 (2011), the mechanics, operation or suspension of the Formula were at issue. Given this level of regulatory attention, it is difficult to maintain that, since 2008, the Formula has contributed to either reduced regulatory costs or reduced regulatory uncertainty.

4.2 Brief History of the Formula

Cost of capital formulas to determine return on equity for ratemaking purposes originated with the BCUC decision to adopt a formula in 1994.[68] Following this, the NEB and the Manitoba PUB each adopted formulas to estimate the cost of equity for 1995.[69] The AUC, the OEB and the Régie also adopted formulas for this purpose over the period 1997 through 2004. In Order No. P.U. 16 (1998-99) the Board ordered the implementation of the Formula.[70]

In 2009, a number of Canadian utility regulators, including the Board, NEB, OEB, BCUC, the Régie and AUC, reconsidered formula based approaches to annually update cost of equity based on forecast changes in long Canada bond yields. The NEB, BCUC and AUC chose to discontinue or suspend the operation of their formulas.[71] The OEB, the Régie and the Board continued the use of formulas.[72]

In Order No. P.U. 43 (2009), the Board determined that Newfoundland Power's rate of return on rate base for 2011 and 2012 would be set using the Formula.

[68] The BCUC adopted a formula to determine return on equity in Decision No. G-35-94.

[69] The NEB established a formula for return on equity for 6 nationally regulated gas pipelines in Decision RH-2-94. The Manitoba PUB determined in Order 103/05 that a formula would be used as an upper bound reasonableness check on return for Centra Gas.

[70] The details of implementation, including the accounting methodology used to annually calculate a return on rate base for Newfoundland Power, were addressed by the Board in Order No. P.U. 36 (1998-99).

[71] In 2009, both the NEB and BCUC eliminated their formulas. The NEB continues to publish the results of the discontinued formula for the purposes of parties that are still bound by settlements based on the previous adjustment formula. In 2009, the AUC suspended the use of its formula for 2010 pending a further review. The AUC did not reinstate its formula in its 2011 decision (see Decision 2011-474, December 8, 2011). These changes were primarily due to the perceived inability of formulas based upon long term Government of Canada bond yields to predict a fair forecast cost of equity in then-current market conditions.

[72] In 2009, the OEB modified its formula to include a second independent variable based on observed credit spreads. In addition, it reduced the coefficient on long Canada bond yields from 75% to 50% and rebased the benchmark return on equity to 9.75%. Based upon the previous OEB formula, the benchmark return on equity would have been 8.4%. In 2009, the Régie continued use of a formula based approach to establish the cost of equity for Gaz Metro for 2011, but reset the 2010 base return on equity to a higher level to take account of financial market conditions. Gaz Metro's return on equity was effectively set at a level 0.5% higher than it would have been under the previous formula.

The Formula, as effectively approved by the Board in 2009, was:

Forecast cost of equity = 9.00 + (0.80 (RFR – 4.50))

where:

(i) 9.00 is the cost of equity approved for ratemaking purposes in 2010;
(ii) 0.80 is the adjustment coefficient for the change in the forecast risk-free rate;
(iii) RFR is the risk-free rate; and,
(iv) 4.50 is the risk-free rate approved by the Board for the 2010 Test Year.

The Board continued use of the Formula without materially increasing the benchmark return on equity. The allowed return on equity of 9% for 2010 establish by Order No. P.U. 43 (2009) was only 0.13% higher than the 8.87% indicated by the Formula using a long Canada bond yield of 4.5%.[73] Other regulators that retained the use of formulas in 2009 made materially larger increases to their risk premium component.[74] In its 2009 order, the Board indicated it believed continued use of a formula to adjust Newfoundland Power's return on rate base was appropriate, as financial market conditions appeared to be settling.[75]

Modifications to the calculation of the risk-free rate were approved by the Board in Order No. P.U. 12 (2010).[76]

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[73] This 9.0% allowed return on equity was based on a 4.5% risk-free rate and a 4.5% equity risk premium (see Order No. P.U. 43 (2009), page 25). If a 4.5% risk-free rate had been used in the Formula for 2010, the risk premium would have been 4.37%, for an allowed return on equity of 8.87%. The 2010 return on equity of 8.48% referred to at page 3, line 7 of this evidence is based upon a risk-free rate of 4.01% calculated as required by the Formula at that time (see U-10 (1st Revision) from Newfoundland Power 2010 GRA).

[74] The OEB's 9.75% allowed return on equity was based on a 4.25% risk-free rate and an equity risk premium of 5.5%. See Decision EB-2009-0084, December 11, 2009, page 37. The Regie's 9.20% allowed return on equity was based upon a risk-free rate of 4.30% and an equity risk premium of 4.90%. See Decision D-2009-156, December 7, 2009, page 28.

[75] See Order No. P.U. 43 (2009) at page 29, lines 18-19 and page 29, lines 32-36.

[76] As a result of the modifications approved in Order No. P.U. 12 (2010), the risk-free rate is determined by adding (i) the average of the 3-month and 12-month forecast of 10-year Government of Canada Bonds as published by *Consensus Forecasts* in the preceding November and (ii) the average observed spread between 10-year and 30-year Government of Canada Bonds for all trading days in the preceding October.

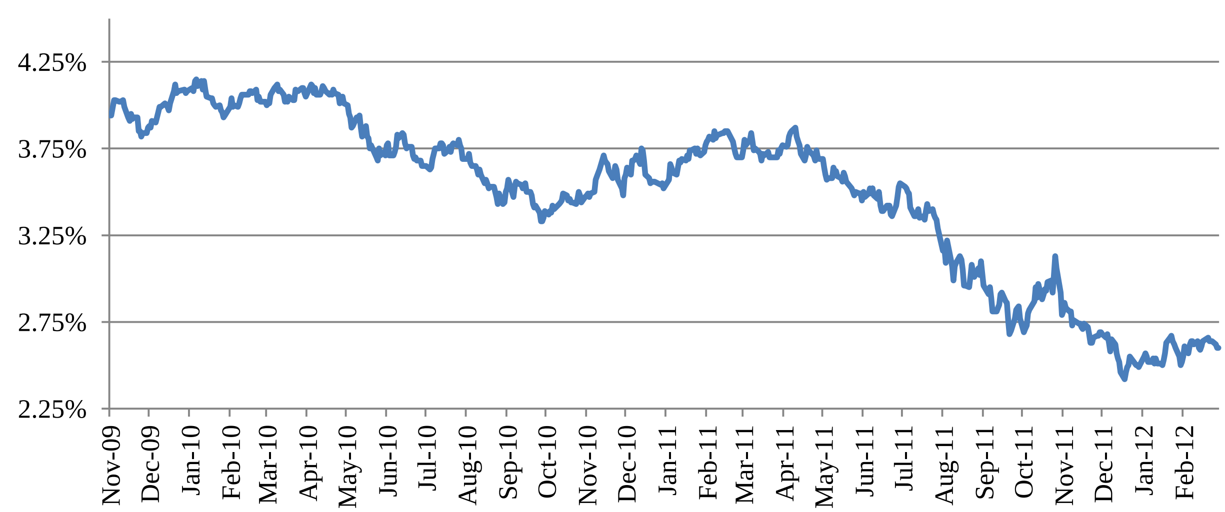
For 2012, the Formula indicates an estimated cost of equity for Newfoundland Power of 7.85%.[77] This is materially lower than the ratemaking return on equity of 9% allowed by the Board for 2010.

Financial market conditions became increasingly unstable in the last half of 2011. These conditions included unusually low and volatile Government of Canada bond yields. Forecast yields of Government of Canada 30-year benchmark bonds ("Long Canada Bond Yields") are currently used in the Formula as a risk-free rate. Because of this, the *decline* in the forecast cost of equity indicated by the Formula simply reflects the decline in Long Canada Bond Yields.

4.3 Bond Yields and Forecasts

Graph 2 shows the daily Long Canada Bond Yields from November 2nd, 2009 through February 29th, 2012.

Graph 2
Government of Canada Benchmark
Daily Long Canada Bond Yields

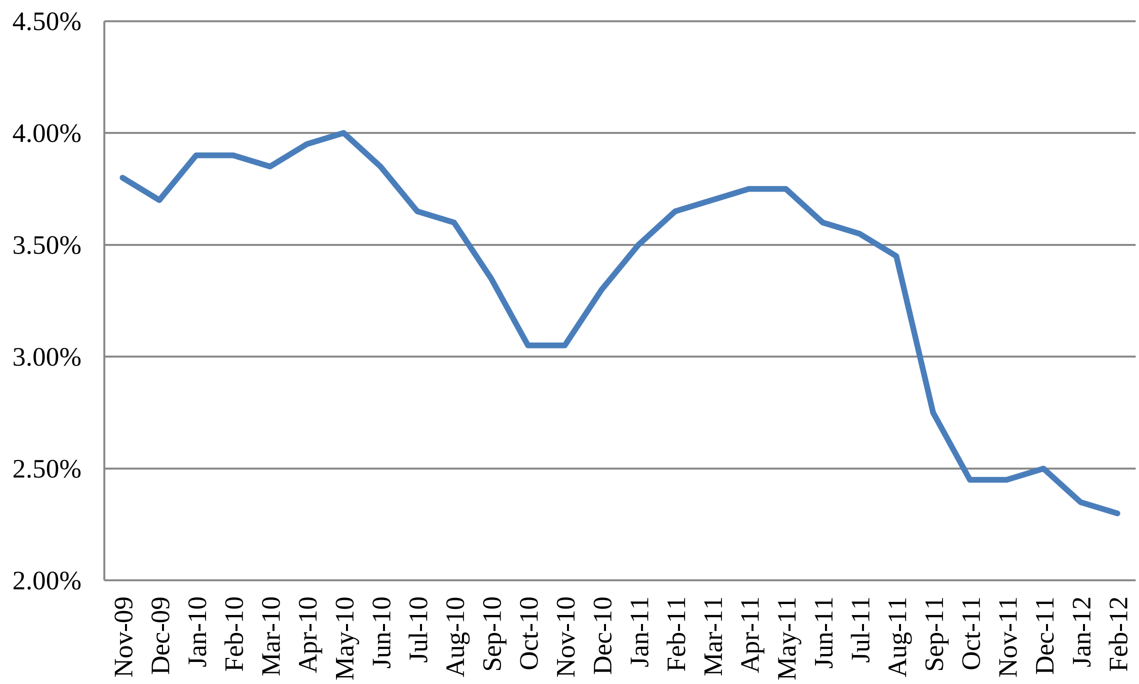


[77] For 2012, the forecast cost of equity as determined by the Formula is calculated as follows: 9.00 + (0.80 (3.06-4.50)) =7.85%.

Since November 2009, Long Canada Bond Yields have declined appreciably.[78] At February 29th, 2012, the benchmark bond yield was 2.6%. Current Long Canada Bond Yields are well below those used to establish Newfoundland Power's 2010 ratemaking return on equity.

Graph 3 shows the average of the 3-month and 12-month forecasts of 10-year Government of Canada bond yields as published by *Consensus Forecasts* monthly from November 2009 through February 2012.

Graph 3
Consensus Forecasts - Forecast of 10 Year Bond Yields



Since November 2009, forecast 10-year Government of Canada bond yields have declined appreciably.[79] At February 2012, the monthly average of the 3-month and 12-month forecasts as published by *Consensus Forecasts* was 2.3%. Low Long Canada Bond Yields and low 10-year

[78] In November 2009, Long Canada Bond Yields averaged 3.94%. In February 2012, Long Canada Bond Yields averaged 2.61%.

[79] In November 2009, the forecast 10-year Government of Canada bond yields averaged 3.8%. In February 2012, the forecast 10-year Government of Canada bond yields averaged 2.3%.

bond yield forecasts are influenced by federal monetary policy encouraging low interest rates in current economic conditions.[80]

The broad economic outlook continues to appear unsettled and subject to possible further political or governmental intervention. The Department of Finance Canada communiqué, February 26th, 2012 states that,

> "The international economic environment has continued to be characterized by an uneven performance, with weak growth in advanced economies and a stronger, albeit slowing, expansion in emerging markets. Structural problems, insufficient global rebalancing, a persistent development gap and high levels of public and private indebtedness and uncertainty continue weighing on medium-term global growth prospects. *While volatility in international financial markets has declined, it generally remains high and we are committed to further reduce downside risks*."[81]

4.4 Concluding

Section 80 of the Act entitles Newfoundland Power to a reasonable opportunity to earn a just and reasonable return *each year*.

In Order No. P.U. 43 (2009), the Board ordered continued use of the Formula as it believed financial market conditions appeared to be settling. The 8.38% estimated cost of equity indicated by the Formula for 2011 was the result of declining forecast Long Canada Bond

[80] The Bank of Canada policy encouraging low interest rates was confirmed in its *Monetary Policy Summary Report*, January 2012. Canadian monetary policy is not, however, the only contributor to low long-term bond yields. For a discussion of other factors, see McShane Evidence, page 34, lines 827 to 834.

[81] *Communiqué of Finance Ministers and Central Bank Governors of the G-20*, Mexico City, February 26, 2012; Department of Finance Canada, 2012-022. (Italics added).

Yields. It was also the lowest ratemaking return on equity awarded for a Canadian investor-owned electric utility in 2011.[82]

The estimated cost of equity of 7.85% indicated by the Formula for 2012 does not constitute a fair return for Newfoundland Power. It is well below ratemaking returns on equity for Canadian investor-owned electric utilities for 2012.[83]

The current increased uncertainty associated with forecasting Long Canada Bond Yields largely reflects monetary policy. The Formula should be discontinued as it does not accurately estimate the appropriate return on equity under current financial market conditions.

5.0 IMPLEMENTATION

5.1 General

In Order No. P.U. 25 (2011) the Board ordered, in effect, that future direction would be given regarding (i) the process and timing to be followed to determine a just and reasonable rate of return on rate base for Newfoundland Power for 2012 and (ii) the timing of the filing of Newfoundland Power's next general rate application.

A reasonable opportunity to recover the rate of return requires consideration of the timing of Newfoundland Power's next general rate application.

[82] See footnote 5.
[83] See footnote 6.

5.2 2012 Cost of Equity

The evidence filed in support of this Application indicates that the cost of equity for Newfoundland Power is materially higher than either the ratemaking return on equity of 7.85% indicated by the Formula or the 8.38% currently embedded in the Company's rates on an interim basis. Ms. McShane and Dr. Vander Weide have respectively indicated that an appropriate return on equity for Newfoundland Power for 2012 would be 10.5% and 10.4%.

Once a just and reasonable rate of return on rate base for Newfoundland Power for 2012 is determined by the Board, the Company should be given a reasonable opportunity to recover that rate of return *in 2012.* This is consistent with Section 80 of the Act.

Recovery of the Board's determined ratemaking return on equity for 2012, using a 2012 test year, would require a complete examination of the Company's revenue and costs through a GRA. Alternatively, without a 2012 GRA, it is practically necessary for the adjustments to revenue requirement and rates resulting from the Board's determination of a ratemaking return on equity for 2012 to be flowed through the Company's 2010 test year. This would permit timely recovery of that return on equity and avoid the delay of a GRA.[84]

[84] In the absence of the suspension of the Formula by Order No. P.U. 25 (2011), changes in the Company's 2012 forecast cost of equity would have been reflected in rates based upon the 2010 test year.

Table 4 shows the respective impacts of 2012 allowed returns on equity of 10.5% and 10.4% on Newfoundland Power's return on rate base, revenue requirement and customer rates.

Table 4
Impacts of 2012 Rate of Return on Equity
Based on 2010 Test Year

	10.5%	**10.4%**
Return on Rate Base (%)	8.90	8.86
Revenue Requirement Change ($000s)	11,817	11,325
Customer Rate Change (%)[85]	2.0	1.9

A 2012 allowed rate of return on equity of 10.5% translates into a 2012 rate of return on rate base of 8.90% for Newfoundland Power based on the 2010 test year. This rate of return would result in an increase in the Company's revenue requirement of approximately $11.8 million and an average increase in customer rates of approximately 2%.

A 2012 allowed rate of return on equity of 10.4% translates into a 2012 rate of return on rate base of 8.86% for Newfoundland Power based on the 2010 test year. This rate of return would result in an increase in the Company's revenue requirement of approximately $11.3 million and an average increase in customer rates of 1.9%.

To ensure that Newfoundland Power be given a reasonable opportunity to recover the appropriate rate of return *for 2012* as determined by the Board, the use of a deferral account may be appropriate to accommodate regulatory lag. Such an approach would be consistent with both Section 80 of the Act and Canadian public utility practice.[86]

85 Generally, a 1% change in the allowed rate of return on equity results in approximately a 1% change in customer rates.

86 Such an approach was adopted by the BCUC in Order No. G-158-09 of December 16th, 2009 which ordered an increased return on equity for Terasen Gas Inc. *effective July 1, 2009*.

Exhibit 2 shows the calculation of the 2012 rates of return on rate base, based on the 2010 test year, incorporating 2012 returns on equity of 10.5% and 10.4%, respectively.

Exhibit 3 shows the calculation of the 2012 returns on rate base, based on the 2010 test year, incorporating 2012 returns on equity of 10.5% and 10.4%, respectively.

Exhibit 4 shows the calculation of the revised 2010 test year revenue requirement adjusted for revised 2012 returns on equity of 10.5% and 10.4%, respectively.

5.3 Beyond 2012

In this Application, Newfoundland Power seeks a Board order (i) establishing a just and reasonable return on rate base for 2012 and (ii) discontinuing use of the Formula due to current financial market conditions.

Continued use of the 2012 ratemaking return on equity for 2013 would be reasonable and consistent with current Canadian public utility practice.[87] In current unsettled financial market conditions, such an approach would reduce regulatory costs and uncertainty to the extent reasonably permitted by the circumstances. This is consistent with the regulatory objectives which originally justified adoption of formulas in the 1990s.

[87] Ms. McShane's evidence specifically addresses an appropriate ratemaking return on equity for 2012 and 2013 (see: McShane, opinion, page 2). This 2-year approach is consistent with the Board's Order No. P.U. 19 (2003) where a ratemaking return on equity was established for 2 years (2003 and 2004). After discontinuing use of a formula in Alberta, the AUC adopted a similar approach by setting a ratemaking return on equity for 2-year periods (see: Decisions 2009-216 and 2011-474).

Credit Rating Reports
DBRS and Moody's

Report Date:
January 24, 2012
Previous Report:
January 31, 2011

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The Company

Newfoundland Power Inc. generates, transmits and distributes electricity. The Company has approximately 247,000 customers throughout the island portion of the Province of Newfoundland and Labrador. It purchases approximately 93% of its electricity needs from government-owned Newfoundland and Labrador Hydro and generates the balance from its own generation facilities (140 megawatts). Newfoundland Power Inc. is a wholly owned subsidiary of Fortis Inc., a Canadian public holding company focused primarily on electric and gas utility operations in Canada, the Caribbean and the United States.

Ratings

Debt	Rating	Rating Action	Trend
First Mortgage Bonds	A	Confirmed	Stable
Preferred Shares – cumulative, redeemable	Pfd-2	Confirmed	Stable

Rating Update

DBRS has confirmed the ratings of the First Mortgage Bonds and Preferred Shares of Newfoundland Power Inc. (Newfoundland Power or the Company) at "A" and Pfd-2, respectively; the trends remain Stable. The rating confirmations reflect Newfoundland Power's low business risk stemming from the regulated nature of its operations, strong balance sheet, and consistent operating results.

The Company's rate of return on rate base for ratemaking purposes was reduced to 7.96% in 2011 (8.23% in 2010), with a range of 7.78% to 8.14%. This reflects a regulated return on common equity (ROE) of 8.38% for 2011, down from 9.00% in 2010; the 8.38% was set explicitly by the automatic adjustment formula used as a mechanism to establish customer rates between general rate hearings. The Board of Commissioners of Public Utilities (PUB) has approved Newfoundland Power's request to suspend the use of the automatic adjustment formula in 2012 (approved ROE and return on rate base in 2012 are on an interim basis, awaiting the full cost of capital review in 2012). The 8.38% ROE for 2011 is among the lowest regulatory ROEs in the country. Despite a low regulated return on rate base, the Company continues to benefit from the following characteristics: (1) a favourable deemed equity ratio of 45%; (2) a weather normalization reserve (WNR) account that stabilizes earnings during extreme weather conditions; (3) a rate stabilization account (RSA) that absorbs fluctuations in purchased power costs; and (4) a pension expense variance deferral account (PEVDA) and other post-employment benefits (OPEBs) cost deferral account. Newfoundland Power operates in a stable and supportive regulatory environment, allowing for the material pass-through of all power-generation and procurement-related costs, and the full recovery of all prudently incurred operating expenses and capital expenditures, within a reasonable time frame, which significantly reduces operating risk.

Although Newfoundland Power has a strong parent organization, through Fortis Inc. (Fortis, rated A (low) with a Stable trend; see the September 7, 2011, DBRS rating report), the Company is largely rated on a stand-alone basis. Fortis is a large, integrated electric and gas utility holding company that has the financial capability to provide equity support if required by Newfoundland Power.

Rating Considerations

Strengths

(1) Stable and supportive regulatory environment
(2) Strong balance sheet and favourable financial profile
(3) Stable customer base
(4) Limited competition from alternative fuels

Challenges

(1) Reliance on Newfoundland and Labrador Hydro for majority of power supply
(2) Managing forecast risk
(3) Limited growth potential
(4) Allowed returns are sensitive to interest rates

Financial Information

	9 mos.ending Sept. 30		12 mos.	For the year ended December 31				
(CAD thousands where applicable)	2011	2010	Sept. 30	2010	2009	2008	2007	2006
Net income before extras.	26,088	26,212	35,450	35,574	33,201	32,895	30,452	30,666
Cash flow (before working cap. changes)	62,789	62,536	84,891	84,638	72,075	70,860	57,138	53,122
Return on equity	8.4%	8.8%	8.6%	8.9%	8.6%	8.8%	8.6%	9.0%
Total debt in capital structure	53.6%	54.0%	53.6%	53.7%	55.1%	53.4%	54.8%	54.6%
Cash flow/total debt	17.2%	17.6%	17.5%	17.8%	15.0%	16.2%	12.9%	12.8%
EBIT interest coverage (times)	2.37	2.41	2.38	2.41	2.40	2.53	2.20	2.26
(Cash flow - dividends)/capex	0.88	0.91	0.87	0.90	0.65	0.85	0.66	0.57

Rating Considerations Details

Strengths

(1) Stable and supportive regulatory environment. Newfoundland Power operates in a stable and supportive regulatory environment that is based on cost-of-service regulation. The PUB allows for the pass-through of purchased power costs and, in addition, an RSA is in place to absorb fluctuations in purchased power costs relating primarily to the cost of fuel oil used by Newfoundland and Labrador Hydro ((NLH), rated "A", with a Stable trend; see the August 25, 2011, DBRS rating report) to generate electricity.

(2) Strong balance sheet and favourable financial profile. The Company has a strong balance sheet, with a capital structure based on a 45% allowable equity component established by the PUB for rate-setting purposes. The high allowance for equity in the capital structure allows Newfoundland Power to generate greater earnings and incur lower interest payments relative to utilities with lower equity allowances within their capital structure.

(3) Stable customer base. Newfoundland Power has a stable customer base, with power sales comprised solely of residential and commercial customers. Serving industrial customers exposes organizations to a greater level of counterparty risk and increased earnings volatility. Industrial customers in Newfoundland are served primarily by NLH.

(4) Limited competition from alternative fuels. The lack of availability of natural gas, due to geographic isolation and insufficient infrastructure, limits competitive pressures. As a result, over 50% of the Company's current customers utilize electric space heating, resulting in much higher electricity sales during the winter months relative to the summer.

Challenges

(1) Reliance on NLH for majority of power supply. Newfoundland Power relies heavily on NLH for its power supply, sourcing approximately 93% of its power requirements from this provider. The cost of power purchased from NLH is largely influenced by the market price of bunker C fuel used for thermal generation, which is passed through to Newfoundland Power's customers through the RSA. However, higher rates, driven by the high cost of oil in recent years, could make it more difficult for the Company to get approval for its own rate increases. NLH is looking to reduce its exposure to highly expensive and volatile oil. The Muskrat Falls project is planned to come online in 2017 and could potentially replace the oil-fired power generated at the Holyrood Thermal Generating Station with cleaner hydro-generated power.

(2) Managing forecast risk. The key challenge with respect to the Demand Management Incentive Account (DMIA) will be the Company's ability to accurately and consistently forecast electricity demand going forward. However, through this account, variations in the unit cost of purchased power related to demand are limited, at the discretion of the PUB, to 1% of demand costs ($545,208 for 2011). In the deliberation of the final value to be placed in the DMIA account, the PUB considers the merits of the Company's conservation and demand management activities.

(3) Limited growth potential. Overall growth is largely driven by growth in the customer base and in average customer consumption levels. Achieving strong growth through increases in the Company's customer base is limited given the geographic isolation of Newfoundland. Furthermore, although average consumption is expected to increase over time, anticipated increases are likely to be incremental. Customer volumes will be tied to provincial population growth, while consumption growth will be tied more closely to economic prosperity within the province, including the health of the volatile natural resources sector.

(4) Allowed returns are sensitive to interest rates. Under the current regulatory regime, the rate-setting ROE, and hence earnings, are sensitive to interest rates. A Consensus Forecast is used in determining the risk-free rate for calculating the forecast cost of equity to be used in the adjustment formula. The prevailing low interest rate environment continues to affect the regulated ROE. Lower ROE has a negative impact on earnings and cash flow. However, the PUB has shown its willingness to deviate from the rate of return generated by the automatic adjustment formula, most recently seen in its December 2011 decision to suspend the use of the formula for 2012 rate-setting purposes.

Newfoundland Power Inc.

Report Date:
January 24, 2012

Earnings and Outlook

(CAD thousands)	9 mos.ending Sept. 30 2011	9 mos.ending Sept. 30 2010	12 mos. Sept. 30	For the year ended December 31 2010	2009	2008	2007	2006
Revenues	416,671	403,473	568,148	554,950	527,179	516,889	491,709	421,264
EBITDA	111,614	100,491	145,421	134,298	129,535	130,059	111,729	110,111
EBIT	64,609	65,382	86,305	87,078	83,848	85,548	77,567	76,982
Gross interest expense	27,264	27,180	36,268	36,184	34,958	33,828	35,193	34,016
Net income before extras.	26,088	26,212	35,450	35,574	33,201	32,895	30,452	30,666
Return on equity	8.4%	8.8%	8.6%	8.9%	8.6%	8.8%	8.6%	9.0%
Rate base ($ millions)	n/a	n/a	n/a	875	848	821	794	753
Growth in rate base	n/a	n/a	n/a	3.2%	3.3%	3.4%	5.4%	1.0%
Rate setting common equity	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%
Allowed ROE - midpoint	8.38%	9.00%	n/a	9.00%	8.95%	8.95%	8.60%	9.24%

Summary

- Newfoundland Power continues to generate stable earnings, reflective of moderate annual customer growth, slightly higher average consumption and an expanding rate base, offset by a declining regulatory-approved ROE.
  - The declining ROE was largely a result of the low interest rate environment affecting the output of the automatic adjustment formula.
  - The trend toward incremental increases in average consumption is mainly driven by the greater proportion of electric heating relative to oil heating in new homes, as well as by economic growth.
- Newfoundland Power benefits from the highly regulated environment in which it operates, as this provides predictability and stability to earnings, both of which are essential factors in determining the level of risk associated with an organization’s ability to meet its obligations.
- The Company is subject to seasonality in electricity sales and purchased power costs. Electricity sales are greatest in the first quarter (winter) and lowest in the third quarter (summer). However, earnings are lowest in the winter months, given the increased cost of power purchases, while earnings are comparatively higher in the summer, when power can be purchased at more favourable rates.
- The Company benefits from a stable customer base consisting solely of residential and commercial customers, with NLH supplying the more volatile industrial segment.
- Overall average customer electricity rates increased by 0.8% as of January 1, 2011, mainly reflective of higher OPEB costs; partially offset by the decline in ROE.
- Effective July 1, 2011, customer electricity rates were raised by an overall average of 7.7%. The increase in rates was mainly a result of the price of oil exceeding the forecasted price on which NLH’s electricity rates were based. The increase in customer rates has no material impact on Newfoundland Power’s earnings; all costs are flowed through to customers using the RSA.

Outlook

- Newfoundland Power’s revenue will likely continue to increase modestly while EBITDA and net earnings remain flat; this performance is in line with the historical trend.
- In September 2011, the PUB approved Newfoundland Power’s sale of 40% of its joint-use poles back to Bell Aliant, representing 5% of Newfoundland Power’s rate base. This sale will account for a decline in revenue; however, it is not expected to materially affect the Company’s ability to generate a reasonable return.
  - The sale to Bell Aliant closed in January of 2012.
- Factors that are expected to offset a potential prolonged low ROE environment are: growth in rate base related to ongoing capital projects, economic expansion in the Company’s service area, modest housing starts and increased average customer electricity consumption.
- In the near term, DBRS expects credit metrics to remain relatively flat and within the Company’s current rating category.

Financial Profile

(CAD thousands)	9 mos.ending Sept. 30 2011	9 mos.ending Sept. 30 2010	12 mos. Sept. 30	For the year ended December 31 2010	2009	2008	2007	2006
Net income before extraordinary items	26,088	26,212	35,450	35,574	33,201	32,895	30,452	30,666
Depreciation, depletion & amortization	31,807	32,402	43,033	43,628	42,097	40,947	39,955	38,922
Deferred income taxes and other	4,894	3,922	6,408	5,436	(3,223)	(2,982)	(13,269)	(16,466)
Cash flow (before working cap. changes)	62,789	62,536	84,891	84,638	72,075	70,860	57,138	53,122
Dividends paid	(15,595)	(12,193)	(19,658)	(16,256)	(25,754)	(15,828)	(9,668)	(18,751)
Capital and exploration expenditures	(53,482)	(55,126)	(74,703)	(76,347)	(71,267)	(64,959)	(72,167)	(60,235)
Free Cash Flow (bef. work. cap. changes)	(6,288)	(4,783)	(9,470)	(7,965)	(24,946)	(9,927)	(24,697)	(25,864)
Changes in non-cash work. cap. items	(4,033)	7,023	(1,128)	9,928	(12,695)	14,191	(7,887)	3,929
Net Free Cash Flow	(10,321)	2,240	(10,598)	1,963	(37,641)	4,264	(32,584)	(21,935)
Acquisitions & Long-term Investments	(1,618)	(1,264)	(2,388)	(2,034)	(2,808)	(2,374)	0	0
Net equity change	(30)	0	(30)	0	(241)	0	(1)	(57)
Net debt change	10,000	(5,500)	11,800	(3,700)	41,300	(5,550)	31,829	19,461
Other	1,925	1,647	2,923	2,645	4,079	3,212	2,223	2,903
Change in cash	(44)	(2,877)	1,707	(1,126)	4,689	(448)	1,467	372
Total debt	485,580	473,893	485,580	475,482	479,250	438,154	443,527	415,209
Cash and equivalents	4,138	2,431	4,138	4,182	5,308	619	1,067	0
Total debt in capital structure	53.6%	54.0%	53.6%	53.7%	55.1%	53.4%	54.8%	54.6%
Cash flow/total debt	17.2%	17.6%	17.5%	17.8%	15.0%	16.2%	12.9%	12.8%
EBIT interest coverage (times)	2.37	2.41	2.38	2.41	2.40	2.53	2.20	2.26
Adjusted EBIT interest coverage (times)*	2.37	2.41	2.38	2.41	2.40	2.53	2.20	2.26

*Including operating leases.

Summary

- Newfoundland Power has a good financial profile, supported by its attractive capital structure and stable operating cash flows.
- Cash flow from operations has historically displayed the same underlying stability and predictability as EBITDA, reflecting the regulated nature of the Company's operations.
- Newfoundland Power's capital expenditure program is focused primarily on plant replacement to support its current customer base, and secondly toward customer and sales growth.
  - Over the past five years, the Company has dedicated approximately half of its capital expenditures toward plant replacement and one-third toward customer and sales growth.
- Although the Company continues to maintain strong and stable cash flow from operations, capital expenditures continue to cause modest free cash flow deficits.
- The Company has historically utilized its credit facilities to finance free cash flow shortfalls as a bridge to the issuance of First Mortgage Bonds.
- Newfoundland Power utilizes its annual dividend to maintain a long-term capital structure of 55% debt and 45% equity, as approved by the PUB for rate-setting purposes.
- Leverage has remained relatively unchanged at approximately 55% over the past five years, while coverage ratios have gradually shown improvement.

Outlook

- On October 5, 2011, Newfoundland Power received proceeds in the amount of $45.7 million in exchange for 40% of the Company's joint-use poles and related infrastructure from Bell Aliant. As of September 30, 2011, these assets were recorded as assets held for sale on the balance sheet. The sale to Bell Aliant closed in January 2012. The Company used the proceeds to pay down short-term debt and pay a special dividend of $29.9 million to Fortis to maintain its capital structure of 45% common equity.
- The Company's 2012 capital budget of $77 million has been approved by the regulator. Newfoundland Power forecasted capital expenditures to increase to just below $90 million in 2014. As a result, modest free cash flow deficits are expected to persist and be funded by credit facilities and long-term debt issuances.
- Over the next five years, the Company has forecasted that approximately 49% of capital expenditures will be allocated to plant replacements, to support the existing customer base, and 34% to customer and sales growth to drive revenue gains.
- The Company's credit profile is largely dependent on its future rate applications to the PUB.

Long-Term Debt Maturities and Liquidity

$ million	2011	2012	2013	2014	2015	Thereafter	Total
Long-term bonds	5.2	5.2	5.2	33.8	4.8	409.5	463.7
Credit Facilities	0	0	0	0	25	0	25
as at September 30, 2011	5.2	5.2	5.2	33.8	29.8	409.5	488.7

*Gross debt, debt issue costs not subtracted from total debt

Securities Outstanding			Sept. 30
First mortgage sinking fund bonds:			2011
	2014	10.55%	30.2
	2016	10.95%	32.4
	2022	10.13%	32.8
	2020	9.00%	33.6
	2026	8.90%	34.4
	2028	6.80%	44.0
	2032	7.52%	69.0
	2035	5.44%	56.4
	2037	5.90%	67.2
	2039	6.61%	63.7
			463.7
	Credit facilities		25.0
			488.7
	Less: current portion		5.2
			483.5

*Gross debt, debt issue costs not subtracted from total debt

Summary

- Newfoundland Power's debt consists of $463.7 million in First Mortgage Bonds and $25 million in committed unsecured credit facilities as at September 30, 2011.
- The First Mortgage Bonds are secured by a first fixed and specific charge on property, plant and equipment owned or to be acquired by the Company, and by a floating charge on all other assets.
- Newfoundland Power has the following credit facilities available:
  - A four-year $100 million syndicated, committed revolving unsecured credit facility expiring in August 2015.
  - A $20 million uncommitted demand facility.
- As at September 30, 2011, $25 million was outstanding on the Company's $100 million credit facility.
- The credit facilities contain a covenant that states that the Company shall not declare or pay any dividends or make any other restricted payments if immediately thereafter the debt-to-capitalization ratio exceeds 65%.
- The Company is also restricted under its Trust Deed to meet specific tests when it intends to issue additional long-term bonds.
- The Company must meet an Earnings Test where the net earnings, in a period of any 12 consecutive months terminating within 24 months preceding the delivery of such additional bonds, are at least two times the annual interest charges on all bonds outstanding after any proposed additional bond issue.
- Secondly, the Company must meet the Additional Property Test, whereby the additional bonds must not exceed 60% of the fair value of the additional property.

Outlook

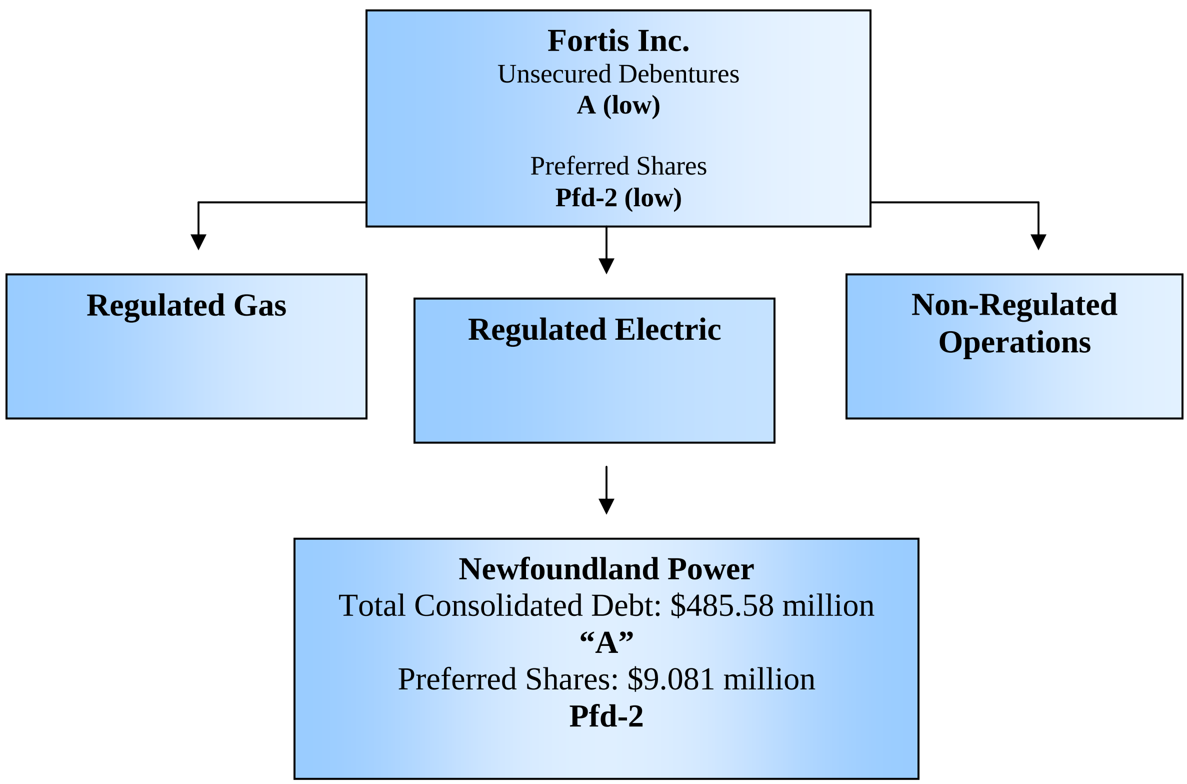
- The debt repayment schedule is very modest in the near term. The most notable maturity is in 2014, when approximately $29 million of First Mortgage Bonds mature. Given the availability of funds under the credit facilities and stable cash flow from operations, the Company's liquidity remains more than adequate to fund both working capital requirements and cash flow deficits.

Description of Operations

Newfoundland Power generates, transmits and distributes electricity. The Company serves just over 247,000 customers throughout the island portion of the province of Newfoundland and Labrador. Approximately 60% of electricity sales are to residential customers, with the remainder sold to commercial customers and for street lighting. As a result, total sales have shown strong stability, with modest growth year over year.

The Company's generating capacity consists of 23 hydroelectric stations, six thermal plants and 130 substations, with a total installed capacity of 140.4 megawatts (MW). Approximately 93% of power requirements are sourced from NLH. The principal terms of the supply agreement are regulated by the PUB on a similar basis to that of the Company's customers.

Simplified Ownership/Debt Chart



Regulation

Regulatory Overview

- Newfoundland Power is regulated by the PUB, which is responsible for setting electricity rates, approving capital expenditures and deciding on the appropriate capital structure and ROE for rate-setting purposes.
- Rates are based on a cost-of-service/rate-of-return methodology.
- Newfoundland Power's allowable equity portion within the capital structure is favourable, at 45%.
- The Company's rate of return on rate base for rate-setting purposes was reduced to 7.96% in 2011 (8.23% in 2010), with a range of 7.78% to 8.14%.
  - This reflects a regulated return on common equity (ROE) of 8.38% for 2011, down from 9.00% in 2010; the 8.38% was set explicitly by the automatic adjustment formula used as a mechanism to establish customer rates in between general rate hearings.

- Newfoundland Power's 2012 capital budget of $77 million and 2010 rate base of $875 million have been approved by the PUB.
- Historically (since 1998), the PUB used the automatic adjustment formula to set Newfoundland Power's rate of return on rate base.
  - However, the regulator has decided to suspend the operation of the automatic adjustment formula in 2012.
  - The Company's regulated ROE will remain at 8.38% and current customer electricity rates will be in effect throughout 2012; both on an interim basis.
- The suspension of the automatic adjustment formula for 2012 halts the decline in ROE that Newfoundland Power has recently experienced.
- The regulated ROEs of other Canadian provinces are well above Newfoundland's current level of 8.38%. The spread between ROEs would have likely been further exacerbated had it not been for the decision to deviate from the rate generated by the adjustment formula.
- A full cost of capital review is expected to be held in 2012.

Regulator-Approved Accounts

Given that Company rates are based on several estimates, including electricity sales volumes and the cost of purchasing electricity, a number of deferral accounts are in place to smooth the impact of realized expenses and events differing from forecasts. The core deferral accounts approved by the regulator for the use of Newfoundland Power are:

- **Weather Normalization Reserve (WNR):** The WNR reduces earnings volatility by adjusting electricity purchases and sales to eliminate the variance between normal weather conditions, based on long-term averages, and actual realized weather conditions.
- **Rate Stabilization Account (RSA):** The RSA allows Newfoundland Power to pass through costs related to changes in the price and quantity of fuel charged by NLH along to the end consumer. On July 1 of each year customer rates are re-calculated in order to amortize, over the subsequent 12 months, the balance in the RSA as of March 31 of the current year. In the absence of rate regulation, these transactions would be accounted for in a similar manner; however, the amount and timing of the recovery would not be subject to PUB approval. To the extent actual electricity sales in any period exceed forecast electricity sales used to set customer rates, marginal purchased power expense will exceed related revenue. The PUB ordered, effective January 1, 2008, that variations in purchased power expense caused by differences between the actual unit cost of energy and the cost reflected in customer rates be recovered from (refunded to) customers through the rate stabilization account.
- **Demand Management Incentive Account (DMIA):** Through the demand management incentive account, variations in the unit cost of purchased power related to demand are limited, at the discretion of the PUB, to 1% of demand costs reflected in customer rates. Balances in this account are recorded as a regulatory asset or regulatory liability on Newfoundland Power's balance sheet. The final balance of regulatory assets and liabilities is determined by the PUB, which takes into consideration the merits of the Company's conservation efforts and demand management activities.
- **Pension Expense Variance Deferral Account (PEVDA):** The PEVDA is utilized when differences exist between the defined benefit pension expense calculated in accordance with designated accounting standards and the pension expense approved by the PUB for rate-setting purposes.
- **Other Post-Employment Benefits (OPEB):** The OPEB cost deferral account is utilized when differences exist between the OPEB expense calculated in accordance with designated accounting standards and the OPEB expense approved by the PUB for rate setting purposes. The PUB approved in December 2010 the adoption of the accrual method of accounting for OPEB costs and income tax related to OPEBs effective January 1, 2011.

Newfoundland Power Inc.

Report Date:
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Newfoundland Power

Balance Sheet (CAD thousands)	Sept. 30	Dec. 31	Dec. 31		Sept. 30	Dec. 31	Dec. 31
Assets	2011	2010	2009	**Liabilities & Equity**	2011	2010	2009
Cash & equivalents	4,138	4,182	5,308	S.T. borrowings	0	0	0
Accounts receivable	50,247	61,654	64,553	Accounts payable	51,593	64,269	65,727
Inventories	1,211	992	934	Current portion L.T.D.	5,200	5,200	5,200
Prepaid expenses & other	61,711	12,863	14,306	Deferred tax	3,044	3,211	2,431
Total Current Assets	**117,307**	**79,691**	**85,101**	Other current liab.	3,293	4,302	5,724
				Total Current Liab.	**63,130**	**76,982**	**79,082**
Net fixed assets	799,619	776,382	787,218	Long-term debt	480,380	470,282	474,050
Future income tax assets	125,052	117,964	118,447	Deferred income taxes	124,113	120,016	122,426
Goodwill & intangibles	14,959	15,310	16,113	Other L.T. liab.	123,024	114,183	99,333
Investments & others	153,786	201,729	158,308	Shareholders equity	420,076	409,613	390,296
Total Assets	**1,210,723**	**1,191,076**	**1,165,187**	**Total Liab. & SE**	**1,210,723**	**1,191,076**	**1,165,187**

Balance Sheet &	9 mos.ending Sept. 30		12 mos.	For the year ended December 31				
Liquidity & Capital Ratios (1)	2011	2010	Sept. 30	2010	2009	2008	2007	2006
Current ratio	1.86	0.98	1.86	1.04	1.08	0.90	1.01	0.70
Net debt in capital structure	53.4%	53.8%	53.4%	53.5%	54.8%	53.3%	54.7%	54.6%
Total debt in capital structure	53.6%	54.0%	53.6%	53.7%	55.1%	53.4%	54.8%	54.6%
Cash flow/total debt	17.2%	17.6%	17.5%	17.8%	15.0%	16.2%	12.9%	12.8%
(Cash flow - dividends)/capex (2)	0.88	0.91	0.87	0.90	0.65	0.85	0.66	0.57
Dividend payout ratio	59.8%	46.5%	55.5%	45.7%	77.6%	48.1%	31.7%	61.1%
Max. equity for rate setting purposes	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%
Coverage Ratios (times) (3)								
EBIT interest coverage	2.37	2.41	2.38	2.41	2.40	2.53	2.20	2.26
EBITDA interest coverage	4.09	3.70	4.01	3.71	3.71	3.84	3.17	3.24
Fixed-charge coverage	2.32	2.35	2.33	2.35	2.34	2.47	2.15	2.24
Adjusted EBIT interest coverage*	2.37	2.41	2.38	2.41	2.40	2.53	2.20	2.26
Profitability Ratios								
Power purchases/revenues	63.9%	63.5%	64.9%	64.6%	65.6%	65.1%	66.5%	61.0%
EBIT margin	15.5%	16.2%	15.2%	15.7%	15.9%	16.6%	15.8%	18.3%
Net margin (before extras)	6.3%	6.5%	6.2%	6.4%	6.3%	6.4%	6.2%	7.3%
Return on equity	8.4%	8.8%	8.6%	8.9%	8.6%	8.8%	8.6%	9.0%
Allowed rate of return common equity	8.38%	9.00%	n/a	9.00%	8.95%	8.95%	8.60%	9.24%
Growth of customer base	n/a	n/a	n/a	1.7%	1.5%	1.5%	1.2%	1.0%
Rate base ($ millions)	n/a	n/a	n/a	875	848	821	794	753
Growth in rate base	n/a	n/a	n/a	3.2%	3.3%	3.4%	5.4%	1.0%

(1) Minority interests treated as equity equivalents. (2) Capital expenditures excluding acquisitions and equity investments.

(3) Before capitalized interest is deducted. *Including operating leases.

Newfoundland Power Inc.

Report Date:
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Operating Statistics	9 mos.ending Sept. 30		12 mos.	For the year ended December 31				
	2011	2010	Sept. 30	2010	2009	2008	2007	2006
Electricity Sales - Breakdown (GWh)								
Residential	2,439	2,374	3,376	3,311	3,203	3,130	3,044	2,981
General service	1,587	1,557	2,138	2,108	2,096	2,078	2,049	2,014
Total sales	4,026	3,931	5,514	5,419	5,299	5,208	5,093	4,995
Growth in volume throughputs	2.4%			2.3%	1.7%	2.3%	2.0%	-0.2%
Customers								
Residential	213,366	209,793	213,366	211,091	207,335	204,204	201,045	198,568
Commercial	32,482	32,228	32,482	32,335	31,972	31,574	31,217	30,932
Total	245,848	242,021	245,848	243,426	239,307	235,778	232,262	229,500

Energy Generated and Purchased (GWh)	9 mos.ending Sept. 30		12 mos.	For the year ended December 31				
	2011	2010	Sept. 30	2010	2009	2008	2007	2006
Energy generated	311	312	424	425	426	426	381	417
Energy purchased	3,953	3,852	5,410	5,308	5,188	5,088	5,013	4,876
Energy generated + purchased	4,265	4,163	5,834	5,733	5,614	5,514	5,394	5,293
Less: transmission losses + internal use	238	233	320	314	315	300	301	298
Total Sales	4,026	3,931	5,514	5,419	5,299	5,214	5,093	4,995
System losses and internal use	5.9%	5.9%	5.8%	5.8%	5.9%	5.8%	5.9%	6.0%
Installed Generation Capacity (MW)								
Hydroelectric	97	97	97	97	97	97	96	92
Gas turbine	37	37	37	37	36	36	37	37
Diesel	7	7	7	7	7	7	7	7
Total	140	140	140	140	140	140	139	136
Peak demand (MW)	n/a	n/a	n/a	1,206	1,219	1,165	1,166	1,124

Newfoundland Power Inc.

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Ratings

Debt	Rating	Rating Action	Trend
First Mortgage Bonds	A	Confirmed	Stable
Preferred Shares – cumulative, redeemable	Pfd-2	Confirmed	Stable

Rating History

	Current	2011	2010	2009	2008	2007
First Mortgage Bonds	A	A	A	A	A	A
Preferred Shares – cumulative, redeemable	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2

Related Research

- Fortis Inc., September 7, 2011.
- Newfoundland and Labrador Hydro, August 25, 2011.

Notes:
All figures are in Canadian dollars unless otherwise noted.

MOODY'S
INVESTORS SERVICE

Credit Opinion: Newfoundland Power Inc.

Global Credit Research - 19 Jul 2011

St. John's, Newfoundland, Canada

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating -Dom Curr	Baa1
First Mortgage Bonds -Dom Curr	A2

Contacts

Analyst	Phone
Allan McLean/Toronto	416.214.3852
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Key Indicators

[1]**Newfoundland Power Inc.**

	[2]LTM	2010	2009	2008	2007
(CFO Pre-W/C + Interest) / Interest Expense	**3.4x**	**3.4x**	**3.1x**	**3.0x**	**2.7x**
(CFO Pre-W/C) / Debt	**17.2%**	**17.6%**	**15.0%**	**15.8%**	**13.7%**
(CFO Pre-W/C - Dividends) / Debt	**13.9%**	**14.3%**	**9.8%**	**12.3%**	**11.7%**
Debt / Book Capitalization	**48.8%**	**48.2%**	**49.2%**	**54.5%**	**56.0%**

[1] All ratios calculated in accordance with Moody's Regulated Electric and Gas Utilities Rating Methodology using Moody's standard adjustments. Source: Moody's Financial Metrics. [2] Last twelve months ended March 31, 2011

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Low-risk regulated electric utility

Supportive regulatory and business environment

Modestly weaker metrics going forward

Strong liquidity

Corporate Profile

Headquartered in St. John's, Newfoundland, Newfoundland Power Inc. (NPI) is a vertically integrated electric utility which operates under cost of service regulation as administered by the Newfoundland and Labrador Board of Commissioners of Public Utilities (PUB) under the Public Utilities Act (the Act). NPI is a wholly-owned subsidiary of Fortis Inc. (FTS, not rated), a diversified electric and gas utility holding company also based in St. John's, Newfoundland and Labrador.

SUMMARY RATING RATIONALE

NPI's Baa1 issuer rating reflects the company's low business risk as a cost-of-service regulated, predominately transmission and distribution (T&D) utility with no unregulated business activities. Approximately 93% of NPI's power requirements are purchased from provincially-owned Newfoundland & Labrador Hydro (Hydro), the cost of which is passed through to ratepayers. Despite the fact that NPI currently has one of the lowest allowed ROEs in Canada (8.38% for 2011), we continue to view the PUB as one of the more supportive regulators in Canada. Regulatory decisions tend to be timely and balanced and NPI's 45% deemed equity is one of the highest in Canada. In addition, NPI benefits from a number of deferral accounts that are intended to protect it from factors beyond management's control. NPI's assigned rating of Baa1 is one notch lower than the rating implied by a grid reflecting key factors outlined in Moody's Regulated Electric and Gas Utilities Methodology which, in part, reflects our belief that NPI's future financial metrics will be modestly weaker than those of 2010 due primarily to the reduction in NPI's allowed ROE to 8.38% in 2011 from 9.0% in 2010.

DETAILED RATING CONSIDERATIONS

LOW-RISK BUSINESS MODEL

NPI's rating reflects the company's low business risk as a cost of service-regulated utility. NPI owns and operates a vertically integrated electric utility located on the island portion of the province of Newfoundland and Labrador and dominates that market, which is geographically isolated and effectively protected from potential competition. NPI serves roughly 86% of the province's electricity customers. The market is mature and has tended to grow at a relatively low and predictable rate of about 1 to 2% annually. Historically, growth has therefore not taxed NPI either operationally or financially. Although NPI is notionally vertically integrated, it is predominantly a T&D utility since its generation assets provide only about 7% of the electricity that NPI delivers. NPI's own generation assets are regulated and represent roughly 15% of NPI's property, plant and equipment. Accordingly, Moody's considers NPI's business risk profile to be more like that of a T&D utility than a vertically integrated utility. The T&D segment is regarded as a relatively lower risk segment of the electric utility industry since it is typically not exposed to commodity price and volume risks or the operational, financial and environmental risks associated with electricity generation.

SUPPORTIVE REGULATORY AND BUSINESS ENVIRONMENT

All of NPI's operations are located in Canada whose regulatory and business environments we consider to be supportive relative to those in other jurisdictions. Furthermore, we consider the PUB to be one of the more supportive regulators in Canada. Notwithstanding that NPI's 2011 allowed ROE of 8.38% is currently one of the lowest in Canada, its 45% deemed equity is one of the highest in Canada and the PUB's decisions tend to be timely and balanced. We believe that the PUB's review and approval of NPI's capital spending plans and long-term debt issuances significantly reduces the risk of cost disallowances or the inability to fully recover costs on a timely basis. NPI submits a proposed capital plan for PUB approval annually. Furthermore, NPI is required to obtain PUB pre-approval for the issuance of any First Mortgage Bonds (FMB) or the incurrence of credit facilities with maturities exceeding one year.

Several cost recovery mechanisms reduce NPI's exposure to unexpected costs due to variations in purchased power cost, weather and pension and other post-employment benefit (OPEB) costs. While NPI foregoes some upside potential, the stability and predictability of its cash flows is increased. For example, the Rate Stabilization Account (RSA) facilitates timely recovery of purchased power costs in excess of those forecasted for rate-making purposes. We consider this particularly important since the marginal cost of power that NPI obtains from Hydro exceeds the average supply costs embedded in customer rates. The RSA provides for the amortization of the under or over collection over a 12 month period. Other mechanisms include the Weather Normalization Account and the Demand Management Incentive Account (which limits NPI's exposure to variation in the demand component of supply costs to approximately $0.5 million). As part of the 2010 General Rate Application, the PUB approved a Pension Expense Variance Deferral Account which will be charged or credited with the amount by which actual annual pension expense differs from the level assumed in the test year. The balance in the PEVDA will be transferred to the Rate Stabilization Account and recovered or refunded in future rates. Also, effective January 1, 2011, NPI is authorized to recover OPEB costs in rates on an accrual basis, recover previously deferred OPEB costs of nearly $53 million over 15 years and establish a deferral account to track any difference between actual accrual OPEB costs and those assumed for rate-making purposes. Since NPI's accrual OPEB costs exceed its cash OPEB costs, the transition to recovering accrual OPEB costs and the recovery of previously deferred OPEB costs is positive for NPI's cash flow.

MODESTLY WEAKER FINANCIAL METRICS EXPECTED IN FUTURE

NPI's ratios continue to be somewhat weaker than those of other Baa1-rated peers predominantly engaged in T&D such as FortisAlberta Inc (FAB, a sister company), Connecticut Light and Power Company (CLP), Orange and Rockland Utilities, Inc.(O&R), and Public Service Electric and Gas Company (PSE&G). We expect FAB to generate CFO pre-WC plus interest / interest (cash flow interest coverage) in the 4x range and CFO pre-WC to debt of about 18% going forward. CLP, O&R and PSE&G have reported cash flow interest coverage in the 4x to 5x range and CFO pre-WC to debt in the 20% range. In contrast we expect NPI to generate cash flow interest coverage in the low 3x range and CFO pre-WC to debt in the 15% to 17% range. These figures are modestly weaker than NPI's 2010 results and reflect, in part, NPI's 2011 allowed ROE of 8.38% (down from 9% in 2010).

NPI IS OPERATIONALLY AND FINANCIALLY INDEPENDENT OF FTS AND ITS SUBSIDIARIES

While NPI is one of a number of utility operating companies owned by Fortis, we consider NPI, like sister companies FAB, FortisBC Inc., FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc., to be operationally and financially independent from Fortis. Fortis has consistently demonstrated good management and support of its subsidiaries and we view NPI's access to the executive and strategic support of Fortis to be a credit positive.

Liquidity Profile

NPI's liquidity arrangements are considered strong in the context of its modest funding requirements.

In the twelve months ending June 30, 2012, we estimate that NPI will generate approximately $60 million of retained cash flow. After capital expenditures and working capital changes of approximately $75 million, we expect NPI to be free cash flow negative by about $15 million. Since there are no significant debt repayments during this period, we estimate that NPI's funding requirement will be roughly $15 million which is less than our estimate of the availability under NPI's credit facilities.

The company's core liquidity facility is a $100 million syndicated committed revolving credit facility that is scheduled to mature in August 2015. While the credit agreement contains a covenant that NPI maintain its debt to capitalization ratio at or below 65%, the credit agreement does not include funding inhibiting language such as a material adverse change (MAC) default or representation and warranty prior to drawdowns. Unutilized capacity under this facility was approximately $75 million at March 31, 2011.

We expect that NPI will periodically issue additional FMBs to reduce outstandings under its bank credit facility and to refinance scheduled debt maturities. While NPI has annual sinking fund requirements of roughly $5.2 million, the next scheduled FMB maturity is not until 2014.

Structural Considerations

The A2 rating of NPI's senior secured FMB reflects the first mortgage security over NPI's property, plant and equipment and floating charge on all other assets. This is consistent with the two notch differential between most senior secured debt ratings and senior unsecured debt ratings of investment-grade regulated utilities operating in North America. The differential is based on our analysis of the history of regulated utility defaults, which indicates that regulated utilities have experienced lower loss given default rates (higher recovery rates) than non-financial, non-utility corporate issuers.

Rating Outlook

The rating outlook is stable based on the expectation that NPI will continue to generate CFO pre-WC to debt in the range of 15% to 17% and cash flow interest coverage in the low 3x range.

What Could Change the Rating - Up

NPI's rating would likely be upgraded if there was a sustainable improvement in financial metrics, such as cash flow interest coverage above 3.4x, CFO pre-WC to debt above 17% and RCF to debt above 12%.

What Could Change the Rating - Down

We consider a downward revision in NPI's rating to be unlikely in the near term. However, NPI's rating would likely be downgraded if we perceived a meaningful reduction in the level of regulatory support combined with weaker liquidity and a sustained deterioration in NPI's financial metrics such as cash flow interest coverage of less than 2.6x, CFO pre-WC to debt in the low teens and RCF to debt below 9%.

Rating Factors

Newfoundland Power Inc.

Regulated Electric and Gas Utilities Industry [1]	[2]**Current**		[3]**Moody's 12-18 month Forward View As of 06/30/2011**	
Factor 1: Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Regulatory Framework		A		A
Factor 2: Ability To Recover Costs And Earn Returns (25%)				
a) Ability To Recover Costs And Earn Returns		A		A
Factor 3: Diversification (10%)				
a) Market Position (5%)		Baa		Baa
b) Generation and Fuel Diversity (5%)		A		A
Factor 4: Fin. Strength, Liquidity And Key Fin. Metrics (40%)				
a) Liquidity (10%)		A		A
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	3.2x	Baa3	3.0x-3.3x	Baa3
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	16.1%	Baa3	15%-17%	Baa3/Baa2
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	12.2%	Baa2	7%-13%	Ba1/Baa2
e) Debt/Capitalization (3 Year Avg) (7.5%)	50.4%	Baa2	48%-50%	Baa2
Rating:				
a) Indicated Rating from Methodology Grid		A3		A3
b) Actual Baseline Credit Assessment Assigned		Baa1		Baa1

Source: Moody's Financial Metrics.

[1] All ratios calculated in accordance with Moody's Regulated Electric and Gas Utilities Rating Methodology using Moody's standard adjustments. [2] Financial ratios reflect three year averages for 2008, 2009 and 2010. [3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.

Moody's
INVESTORS SERVICE

Newfoundland Power Inc.

Calculation of 2012 Rate of Return on Rate Base[1]
Based on Revised Forecast Cost of Equity For 2012 of 10.5%

	%	Cost	Weighted Cost
Debt	54.27% [2]	7.64% [2]	4.15%
Preference Shares	1.04% [2]	6.23% [2]	0.06%
Equity	44.69% [2]	10.50% [3]	4.69%
2012 Rate of Return on Rate Base			8.90%

[1] Under the Asset Rate Base Method approved in Order No. P.U. 32 (2007), the rate of return on rate base equals the weighted average cost of capital.
[2] Based on 2010 Test Year, approved in Order No. P.U. 46 (2009).
[3] 2012 Forecast Cost of Equity as recommended by Ms. McShane.

Newfoundland Power Inc.

Calculation of 2012 Rate of Return on Rate Base[1]
Based on Revised Forecast Cost of Equity For 2012 of 10.4%

	%	Cost	Weighted Cost
Debt	54.27% [2]	7.64% [2]	4.15%
Preference Shares	1.04% [2]	6.23% [2]	0.06%
Equity	44.69% [2]	10.40% [3]	4.65%
2012 Rate of Return on Rate Base			8.86%

[1] Under the Asset Rate Base Method approved in Order No. P.U. 32 (2007), the rate of return on rate base equals the weighted average cost of capital.
[2] Based on 2010 Test Year, approved in Order No. P.U. 46 (2009).
[3] 2012 Forecast Cost of Equity as recommended by Dr. Vander Weide.

Newfoundland Power Inc.

Calculation of 2012 Return on Rate Base
Based on Revised Forecast Cost of Equity For 2012 of 10.5%
(000's)

Return on Rate Base Formula Approved by Order No. P.U. 32 (2007):

Return on Rate Base	=	Rate Base	X	Rate of Return on Rate Base

2011 Return on Rate Base (approved by Order No. P.U. 36 (2010)):

$ 69,378 [1]	=	$871,585 [2]	X	7.96% [1]
$ 69,181	=	$ 69,378	-	$ 197 [3]

2012 Return on Rate Base:

$ 77,571	=	$871,585 [2]	X	8.90% [4]

Change in 2010 Test Year Return on Rate Base:

$ 8,390	=	$ 77,571	-	$ 69,181

[1] Results of the Operation of the Formula for 2011 approved in Order No. P.U. 32 (2010).
[2] Approved in Order No. P.U. 46 (2009).
[3] Adjustment for Other Post Employment Benefits approved in Order No. P.U. 31 (2010).
[4] As calculated in Exhibit 2.

Newfoundland Power Inc.

Calculation of 2012 Return on Rate Base
Based on Revised Forecast Cost of Equity For 2012 of 10.4%
(000's)

Return on Rate Base Formula Approved by Order No. P.U. 32 (2007):

Return on Rate Base	=	Rate Base	X	Rate of Return on Rate Base

2011 Return on Rate Base (approved by Order No. P.U. 36 (2010)):

$ 69,378 [1]	=	$871,585 [2]	X	7.96% [1]
$ 69,181	=	$ 69,378	-	$ 197 [3]

2012 Return on Rate Base:

$ 77,222	=	$871,585 [2]	X	8.86% [4]

Change in 2010 Test Year Return on Rate Base:

$ 8,041	=	$ 77,222	-	$ 69,181

[1] Results of the Operation of the Formula for 2011 approved in Order No. P.U. 32 (2010).

[2] Approved in Order No. P.U. 46 (2009).

[3] Adjustment for Other Post Employment Benefits approved in Order No. P.U. 31 (2010).

[4] As calculated in Exhibit 2.

Newfoundland Power Inc.

Revised 2010 Test Year Revenue Requirement

Adjusted for the revised cost of equity for 2012 of 10.5%

($000s)

	2010 Test Year[1]	Operation of the Formula for 2011[2]	OPEBs[2]	2011 Revised	Revised Cost of Equity for 2012	2012 Revised
Return on Rate Base	71,750	(2,372)	(197)	69,181	8,390[3]	77,571
Other Costs						
Power Supply Cost	351,034	-	-	351,034	-	351,034
Operating Costs	51,689	-	-	51,689	-	51,689
Pension	8,196	-	-	8,196	-	8,196
OPEBs Expense	-	-	7,635	7,635	-	7,635
Amortization of Depreciation Cost Recovery Deferral	3,861	-	-	3,861	-	3,861
Depreciation	43,378	-	-	43,378	-	43,378
Income Taxes	17,098	(1,041)	108	16,165	3,427[4]	19,592
	475,256	(1,041)	7,743	481,958		485,385
2010 Revenue Requirement	547,006	(3,413)	7,546	551,139	11,817[5]	562,956
Deductions						
Other Revenue	(13,692)	-	-	(13,692)	-	(13,692)
2005 Unbilled Revenue	(4,618)	-	-	(4,618)	-	(4,618)
Other Adjustments	87	-	-	87	-	87
	(18,223)	-	-	(18,223)	-	(18,223)
2010 Revenue Requirement from Base Rates	528,783	(3,413)	7,546	532,916	11,817	544,733

[1] Approved in Order No. P.U. 46 (2009).

[2] In Order No. P.U. 36 (2010), the Board approved changes to Newfoundland Power's 2010 Test Year revenue requirement resulting from the operation of the Formula for 2011 (Order No. P.U. 32 (2010)) and the adoption of accrual accounting for Other Post Employment Benefits (Order No. P.U. 31 (2010)).

[3] See Exhibit 3 for the calculation of the change in the 2010 Test Year return on rate base resulting from incorporating the revised cost of equity for 2012.

[4] The change in income taxes for the 2010 Test Year is calculated as:

	($000s)
Change in Return on Rate Base	8,390
Gross up for Income Tax Purposes	11,817
Income Tax Rate	29.0%
Change in Income Taxes	3,427

[5] This is the change in the revised 2010 Test Year revenue requirement resulting from incorporating the revised cost of equity for 2012.

Newfoundland Power Inc.

Revised 2010 Test Year Revenue Requirement
Adjusted for the revised cost of equity for 2012 of 10.4%
($000s)

	2010 Test Year[1]	Operation of the Formula for 2011[2]	OPEBs[2]	2011 Revised	Revised Cost of Equity for 2012	2012 Revised
Return on Rate Base	71,750	(2,372)	(197)	69,181	8,041[3]	77,222
Other Costs						
Power Supply Cost	351,034	-	-	351,034	-	351,034
Operating Costs	51,689	-	-	51,689	-	51,689
Pension	8,196	-	-	8,196	-	8,196
OPEBs Expense	-	-	7,635	7,635	-	7,635
Amortization of Depreciation Cost Recovery Deferral	3,861	-	-	3,861	-	3,861
Depreciation	43,378	-	-	43,378	-	43,378
Income Taxes	17,098	(1,041)	108	16,165	3,284[4]	19,449
	475,256	(1,041)	7,743	481,958		485,242
2010 Revenue Requirement	547,006	(3,413)	7,546	551,139	11,325[5]	562,464
Deductions						
Other Revenue	(13,692)	-	-	(13,692)	-	(13,692)
2005 Unbilled Revenue	(4,618)	-	-	(4,618)	-	(4,618)
Other Adjustments	87	-	-	87	-	87
	(18,223)	-	-	(18,223)	-	(18,223)
2010 Revenue Requirement from Base Rates	528,783	(3,413)	7,546	532,916	11,325	544,241

[1] Approved in Order No. P.U. 46 (2009).

[2] In Order No. P.U. 36 (2010), the Board approved changes to Newfoundland Power's 2010 Test Year revenue requirement resulting from the operation of the Formula for 2011 (Order No. P.U. 32 (2010)) and the adoption of accrual accounting for Other Post Employment Benefits (Order No. P.U. 31 (2010)).

[3] See Exhibit 3 for the calculation of the change in the 2010 Test Year return on rate base resulting from incorporating the revised cost of equity for 2012.

[4] The change in income taxes for the 2010 Test Year is calculated as:

	($000s)
Change in Return on Rate Base	8,041
Gross up for Income Tax Purposes	11,325
Income Tax Rate	29.0%
Change in Income Taxes	3,284

[5] This is the change in the revised 2010 Test Year revenue requirement resulting from incorporating the revised cost of equity for 2012.

OPINION

ON

CAPITAL STRUCTURE

AND

RETURN ON EQUITY

FOR

Newfoundland Power Inc.

Prepared by

KATHLEEN C. MCSHANE

FOSTER ASSOCIATES, INC.

March 2012

TABLE OF CONTENTS

I. INTRODUCTION AND SUMMARY OF CONCLUSIONS

A. INTRODUCTION

My name is Kathleen C. McShane and my business address is One Church Street, Suite 101, Rockville, Maryland 20850. 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 Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB" or "Board"). My professional experience is provided in Appendix G.

I have been requested by Newfoundland Power Inc. ("Newfoundland Power" or "the Company") to provide an expert opinion on the reasonableness of its capital structure and to recommend a fair ROE for the Company.

B. SUMMARY OF CONCLUSIONS

My principal conclusions are as follows:

1. The allowed return for Newfoundland Power must meet all three criteria of the fair return standard, including the comparable return standard. The fair return extends to both the capital structure and return on equity, that is, the overall return allowed must satisfy the fair return standard.

2. Satisfying the comparable return standard requires consideration of returns available to comparable utilities in the U.S., given the similarity of operating and regulatory environments, the integration of the two capital markets, and the small number of Canadian utilities with equity market data.

3. Newfoundland Power's forecast capital structure includes a common equity ratio of 45%. The Company's capital structure is reasonable in light of its business risks, the importance of maintaining the existing credit ratings, the upward trend in the common equity ratios of Newfoundland Power's Canadian peers, the necessity of ensuring financial strength in uncertain capital markets and the need to be positioned to compete for capital on reasonable terms and conditions.

4. Global financial markets remain unsettled. As a result, I recommend that the Board not reinstate the automatic adjustment formula at this time and have developed the fair return on equity for Newfoundland Power on the premise that it will remain unchanged through at least 2013.

5. The fair return on equity for Newfoundland Power was estimated at 10.5%, and reflects the following:

   a. The recommended return on equity is based on the results of equity risk premium and discounted cash flow tests.

   b. A forecast 30-year Government of Canada bond yield for 2012 and 2013 of 3.25% to 3.50%.

   c. Three separate equity risk premium tests with the following costs of equity before adjustment for financing flexibility:

Risk Premium Test	**Cost of Equity**
Risk-Adjusted Equity Market	8.8%
Discounted Cash Flow-Based	9.5%
Historic Utility	10.0% - 10.25%
Average	**9.5%**

d. The discounted cash flow test, applied to a sample of U.S electric and gas utilities selected to serve as a proxy for Newfoundland Power, as well as to a sample of Canadian utilities, supports a cost of equity of 9.5%.

e. The addition of an allowance for financing flexibility equal to the midpoint of the indicated range of 50 to 150 basis points (100 basis points) to the "bare-bones" return on equity estimate of 9.5%, derived from the equity risk premium and DCF tests, is required to fully recognize the disparity between the levels of financial risk in the market value capital structures and utility book value capital structures. The resulting estimate of the fair return on equity for Newfoundland Power is approximately 10.5%.

f. An alternative approach is to give weight to the comparable earnings test and to limit the financing flexibility to the market-based tests to the minimum level of 50 basis points. The comparable earnings test, which measures returns in relation to book value, was applied to a sample of 21 Canadian low risk unregulated companies of reasonably comparable risk to an average risk Canadian utility, e.g., Newfoundland Power. Based on the comparable earnings test, a fair return on equity for an average risk Canadian utility is in the range of 11.25% to 12.0%.

g. This alternative approach, with preponderant weight given to the results of the equity risk premium and discounted cash flow tests, provides additional support for a fair return on equity for Newfoundland Power of 10.5%.

II. BACKGROUND FOR REVIEW OF NEWFOUNDLAND POWER'S COST OF CAPITAL

In Reasons for Decision: Order No. P.U. 43(2009), issued on December 24, 2009, the Board determined the allowed return on rate base for Newfoundland Power for 2010, incorporating a regulated return on common equity of 9.0%. The 9.0% regulated return on common equity was based predominantly on the application of the Capital Asset Pricing Model, premised on a forecast long-term Government of Canada bond yield of 4.5%. In the Decision, the Board also concluded that discontinuing the use of the automatic adjustment formula would be an excessive response to financial market conditions, which, while severe in the fall of 2008 and the spring of 2009, appeared to be settling. In Order No. P.U. 12(2010), the Board approved the continuation of the automatic adjustment formula that it had initially approved in 1998, with a modification: the substitution of actual long-term Government of Canada bond yields with forecast yields. The application of the formula for 2011 produced a regulated return on equity for Newfoundland Power of 8.38%; if applied for 2012, the formula would have produced a regulated return on equity of only 7.85%, based on a forecast long-term Canada bond yield of 3.06%.

In November 2011, Newfoundland Power applied to the Board for a suspension of the formula to establish a return on rate base for 2012, approval of the continued use, on an interim basis, of the existing 2011 range of rate of return on rate base and the establishment of a process to determine a fair and reasonable return on rate base for 2012. The Board approved the suspension of the automatic adjustment formula in Order No. P.U. 25(2011), dated December 13, 2011, and provided for the subsequent adoption of a process to set the fair return on rate base for Newfoundland Power for 2012.

This Opinion represents my analysis of and recommendations for the capital structure and fair return on equity for the purpose of the determination of a fair return on rate base for Newfoundland Power.

III. FAIR RETURN STANDARD

The standards for a fair return arise from legal precedents[1] which are echoed in numerous regulatory decisions across North America, including the Board's Order No. P.U. 43(2009). 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. 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.

Further, as the Federal Court of Appeal held in *TransCanada PipeLines Ltd. v. National Energy Board et al.*, [2004] F.C.A. 149, the required rate of return must be based on the cost of equity. The impact on customers of any rate increases cannot be a factor in the determination of the cost of equity capital.[2]

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. Fair compensation on the capital committed to the utility provides the financial means to pursue technological innovations and build the infrastructure

[1] The principal seminal 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] In its *Reasons for Decision, Trans Québec and Maritimes Pipelines Inc., RH-1-2008, March 2009* (page 6), the NEB stated: "In the Board's view, the Federal Court of Appeal was clear that the overall return on equity must be determined solely on the basis of a company's cost of equity capital, and that the impact of any resulting toll increase is an irrelevant consideration in that determination."

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 necessary expansion and innovation, 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 a utility is not provided the opportunity to earn a fair return, it may be prevented from making the requisite level of investments in the existing infrastructure in order to reliably provide utility services to its customers.

IV. CAPITAL STRUCTURE

A. NEWFOUNDLAND POWER'S PROPOSED CAPITAL STRUCTURE

Newfoundland Power is requesting that the Board approve its forecast actual 2012 capital structure which includes a common equity ratio of 45%.

B. ANALYTICAL FRAMEWORK

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

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

There are effectively two approaches that can be used to determine the fair return. The first approach entails acceptance of the utility's actual capital structure for regulatory purposes or deeming a capital structure that adequately protects bondholders but does not necessarily equate the total (fundamental business, regulatory and financial) risk of the regulated company to those of the proxy companies used to estimate the cost of equity. If the total risk of the proxy companies is higher or lower than that of the specific utility, the proxies' estimated cost of equity needs to be adjusted upward or downward to arrive at the cost of equity of the specific utility.

The second approach assesses the utility's fundamental business and regulatory risks, and then establishes a capital structure that is both compatible with those risks and that permits the application of a cost of equity determined by reference to proxy companies, with no adjustment to that cost. This approach can be applied to a spectrum of regulated companies within a range of combined fundamental business and regulatory risks.

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. Both approaches are used by Canadian regulators and 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.

For Newfoundland Power, I have relied on the second approach. Specifically, I analyzed Newfoundland Power's requested forecast capital structure, based on the principles set out in Section IV.C below. I then determined whether, with the proposed capital structure, Newfoundland Power would face a similar level of investment risk to an average risk Canadian utility.

C. PRINCIPLES FOR CAPITAL STRUCTURE DETERMINATION

The following principles should be respected when establishing both the cost of capital generally and a reasonable capital structure for Newfoundland Power:

1. Stand-Alone Principle
2. Compatibility of Capital Structure with Business Risks
3. Maintenance of Creditworthiness/Financial Integrity
4. Ability to Attract Capital on Reasonable Terms and Conditions
5. Comparability of Returns

Each of these five principles is defined below. The five principles which apply to the determination of a reasonable capital structure include the three standards (Principles 3 to 5) which govern a fair return identified in Section III above, reflecting the interdependence between capital structure and ROE.

1. Stand-Alone Principle

The stand-alone principle encompasses the notion that the cost of capital incurred by a utility should be equivalent to that which would be faced if it was raising capital in the public markets on the strength of its own business and financial parameters; in other words, as if it were operating as an independent entity. The cost of capital for the company should reflect neither subsidies given to, nor taken from, other activities of the firm. Respect for the stand-alone principle is intended to promote efficient allocation of capital resources among the various activities of the firm. As Newfoundland Power is a stand-alone regulated entity which raises its own debt on the strength of its own business and financial risk profile, the application of the stand-alone principle is not an issue.

2. Compatibility of Capital Structure with Business Risks

The capital structure of a utility should be consistent with the business and regulatory risks of the specific entity for which the capital structure is being set. 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 fundamental business risks of a utility include demand, competitive, supply, operating, technology-related and political risks. Regulatory risk relates to the framework that determines how the fundamental business risks are allocated between the utility's customers and its investors.

3. Maintenance of Creditworthiness/Financial Integrity

A reasonable capital structure for Newfoundland Power, in conjunction with the returns allowed on the various sources of capital, should provide the basis for stand-alone investment grade debt ratings in the A category. Debt ratings in the A category ensure that the utility would be able to access the capital markets on reasonable terms and conditions during both robust and difficult, or weak, capital market conditions. In contrast to unregulated companies, utilities do not have the same flexibility to defer financing new assets. Utilities are required to provide service on demand, and must access the capital markets when service requirements demand it.

The importance of credit ratings in the A category arises from two factors: market access and cost. Even a utility with split-ratings (that is, one debt rating in the A category and one rating in the BBB/Baa[3] category) faces a higher cost of debt and lesser market access relative to a utility with all debt ratings in the A category. Regulated issuers with BBB/Baa ratings can be closed out of the market at times, particularly at the longer end (20-30 year term) of the debt market.[4]

[3] BBB is the DBRS and Standard Poor's medium grade ratings designation; Baa is the corresponding Moody's designation.

[4] During the period June 11, 2008 to January 29, 2009 inclusive there was not a single issuer without at least one "A" credit rating who was able to issue long-term debt <u>on any terms</u> in the public Canadian debt market.

Newfoundland Power is principally financing long-term assets. Thus, the Company needs to maintain the financing flexibility required to be able to access debt with long-term maturities in both strong and weak capital market conditions.

If a utility experiences a downgrade, the downgrade would not only result in an increase in the cost of the additional debt that the company needs to raise, but it will affect all of the outstanding debt. An increase in the cost of debt to a utility increases the required yield on the outstanding debt and reduces the value of that debt. Since existing debt holders are the most likely purchasers of future issues, a debt rating downgrade, with the resulting negative impact on the value of their existing holdings, would likely make them less willing to purchase future issues.

4. Ability to Attract Capital on Reasonable Terms and Conditions

A higher cost of debt to the utility translates into a higher cost of debt to ratepayers. The relative cost of A rated debt versus BBB rated debt varies with market conditions, but ratings in the BBB category can be materially more costly to ratepayers than ratings in the A category.[5] As the global financial market crisis demonstrated, capital markets can deteriorate rapidly, and spreads can widen dramatically.

Although the market for lower rated credits in Canada has been growing, it is still relatively small. Institutional investors continue to face limits on the proportion of BBB rated debt they are allowed to hold in their portfolios or are precluded from investing in BBB rated debt. The relatively small size of the Canadian market for BBB rated debt and the limitations on the ability of BBB issuers to raise debt in the long-term end of the debt market underscore the importance of A credit ratings.

Newfoundland Power is competing for capital in a global market in which there may be unprecedented requirements for energy infrastructure capital, particularly in the power sector. In its 2011 *World Energy Outlook*, the International Energy Agency estimated that between 2011

[5] Over the past 15 years, the average spread between yields on long-term BBB-rated and A-rated corporate debt in Canada has been 75 basis points. During the same period, the spread has been as high as 200 basis points.

and 2035 close to $17 trillion in investment would be required by the global electricity industry of which over $7 trillion would be comprised of investments in transmission and distribution assets.[6] The Conference Board of Canada estimates that investment in electricity infrastructure in Canada over the period 2011 to 2030 will be close to $348 billion.[7] To compete successfully for the required capital, that is, to continue to be able to attract capital on flexible terms and conditions, Newfoundland Power requires financial metrics (which reflect the combination of capital structure and ROE) that are competitive with those of its peers.

5. Comparability of Returns

The combination of the adopted capital structure and return on capital should be comparable to the returns of comparable risk companies.

In order to be competitive in the capital markets, a regulated utility's financial parameters – which encompass both capital structure and ROE – need to be comparable to those of its peers. In this regard, it is important to recognize that Newfoundland Power competes for capital not only with other Canadian regulated companies, but with regulated companies globally, as well as with unregulated companies, both within Canada and globally. The achievement of comparability requires recognition of the financial parameters of the companies of comparable risk to Newfoundland Power, including regulated companies throughout North America.

[6] Approximately $38 trillion world-wide in global cumulative energy infrastructure investment. (2011 *World Energy Outlook*, Figure 2.0)
[7] Conference Board of Canada, *Shedding Light on the Economic Impact of Investing in Electricity Infrastructure*, February 2012.

D. BUSINESS RISK PROFILE OF NEWFOUNDLAND POWER

As noted above, business risk comprises the fundamental characteristics of the business (e.g., demand, supply and operating factors) that together determine the probability that future returns to investors will fall short of their expected and required returns. While different business risk categories can be identified, they are inter-related. The regulatory framework, for example, is frequently designed around the inherent demand/competitive risks.

Business risks have both short-term and longer-term aspects. 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 business 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 business risks that are of primary concern to the investor.

Regulatory risk relates to the framework that determines how the fundamental business risks are allocated between ratepayers and shareholders. 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.

Because regulated firms are generally regulated on the basis of annual revenue requirements, there has been 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 factors and ratepayer resistance may forestall higher return awards when the risk materializes. Second, no regulator can bind his or her successors and thus guarantee that investors will be compensated for longer-term risks when they are incurred in the future.

Demographics and Economic Outlook

Newfoundland Power is a relatively small integrated electric utility serving most of the larger communities on the island portion of Newfoundland and Labrador. The utility serves approximately 247,000 mostly residential and commercial customers, delivers 5,500 GWh of power annually and has an approximately $875 million rate base. Newfoundland Power's long-term business risk profile largely relates to the demographics and economic outlook of its service area.

During the past 15 years, the province of Newfoundland and Labrador has benefited greatly from the development and expansion of the oil and gas industry. The oil and gas industry has accounted for approximately 50% of provincial growth since 1997, and was approximately 30% of GDP in 2010. During the 10-year period ending 2010, real GDP growth in Newfoundland and Labrador outpaced Canada as a whole (3.1% versus 1.9%) as well as any of the individual provinces. While the Province's real economic growth was the most rapid of all the provinces, the annual rates of real growth were also by far the most volatile, primarily due to volatility in exports generally and oil and gas production specifically.[8]

Table 1 below compares historic economic indicators that are more closely related to Newfoundland Power's growth to the corresponding data for Canada as a whole.

Table 1

10 Year Compound Growth Rate 2000-2010		
	Newfoundland and Labrador	**Canada**
Personal Disposable Income	4.8%	4.7%
Retail Sales	4.6%	4.3%
Housing Starts	9.5%	2.3%
Population	-0.3%	1.1%
Employment	1.0%	1.4%
Service Industries (GDP, real)	2.5%	2.7%

Source: Statistics Canada

[8] In 2009, for example, real GDP in Newfoundland and Labrador declined by 9%. The decline in real GDP was significantly less dramatic when adjusted for income earned by non-resident owners of provincial resource-related mega-projects.

As the table shows, the rates of growth in personal disposable income and real GDP of the service producing industries in Newfoundland and Labrador were in line with those for Canada as a whole, employment growth lagged the rest of the country, and, as a result of outmigration, the Province's population declined. Growth in housing starts significantly surpassed the rest of the country, albeit from a relatively small base, predominantly reflecting migration from rural to urban areas. Over this same period (2000-2010), Newfoundland Power experienced annual customer growth of approximately 1.2% and electricity sales growth of approximately 1.7%. Newfoundland Power's growth over this period reflects in part new household formation and in part a high capture rate in new housing.

Over the longer-term, the Conference Board of Canada anticipates that real growth in Newfoundland and Labrador will be relatively modest, at less than 1% per year from 2010 to 2030, compared to 2% for Canada as a whole.[9] The Conference Board forecasts that only Nova Scotia will grow at a slower pace. The relatively low growth forecasts for Newfoundland and Labrador are primarily attributable to a declining labour force resulting from persistent outmigration[10] and a low and falling natural rate of population growth (i.e., an aging population). The Conference Board notes that its forecast rate of real GDP growth is significantly impacted by the expected decline in offshore production, absent which GDP growth would average 1.7% per year from 2010 to 2030. Nevertheless, forecasts for the remaining economic indicators highlighted in Table 1 above also point to limited longer-term growth prospects for the province and for Newfoundland Power. As shown in Table 2 below, Newfoundland and Labrador is expected to lag Canada as a whole in each of the economic indicators.[11]

[9] Conference Board of Canada, *Provincial Outlook Long-Term Economic Forecast 2011*, May 2011.
[10] Since 1982, there have been only two years (2009 and 2010) in which Newfoundland and Labrador experienced positive net migration.
[11] Newfoundland and Labrador is the only province forecast to experience an absolute decline in population between 2010 and 2030.

Table 2

	Newfoundland and Labrador		
	2010-2020	**2020-2030**	**2010-2030**
Personal Disposable Income	2.5%	1.8%	2.2%
Retail Sales	2.3%	1.2%	1.7%
Housing Starts	-7.5%	-10.5%	-9.0%
Population	-0.1%	-0.5%	-0.3%
Employment	0.1%	-1.1%	-0.5%
Service Industries (GDP, real)	1.3%	0.6%	1.0%

	Canada		
	2010-2020	**2020-2030**	**2010-2030**
Personal Disposable Income	3.8%	3.5%	3.7%
Retail Sales	3.7%	2.7%	3.2%
Housing Starts	1.0%	-1.0%	0.0%
Population	1.2%	1.0%	1.1%
Employment	1.2%	0.6%	0.9%
Service Industries (GDP, real)	2.3%	1.8%	2.1%

Source: Conference Board of Canada, *Provincial Outlook Long-Term Economic Forecast 2011*, May 2011

As detailed in the Company's evidence, Newfoundland Power's service territory has been, in recent years, characterized by migration from rural areas to urban areas. This trend is expected to continue. As a result, the percentage of Newfoundland Power's net distribution investment attributable to small, rural communities is disproportionately high, as summarized in the table below.

Table 3

	Population		
	Under 1,000	**Between 1,000 and 10,000**	**Over 10,000**
Number of Municipalities	133	48	7
Percent of Municipalities	71%	25%	4%
Percent of Customers	14%	43%	43%
Percent of Sales	11%	29%	60%
Percent of Distribution Investment	40%	37%	23%

Source: Company data.

New investment must be made to serve customers who have moved to urban areas, as well as to maintain service in communities with declining populations. As a consequence, the total investment that must be recovered is increasing, but, over the longer term, it must be recovered from an ageing and declining total customer base, potentially putting pressure on the ability to recover the invested capital.

There has been no material change in the long-term outlook for Newfoundland Power's service area since its last two general rate applications in 2007 and 2009.[12]

Operating Environment

As regards operating risks, the principal risk relates to weather-related service disruption. As indicated in the Company's testimony, Newfoundland Power's service area is characterized by the most severe wind and ice conditions in populated regions of Canada. The need to address supply disruptions due to severe weather conditions entails unanticipated and potentially volatile capital and operating costs. Operating risks have not changed materially since Newfoundland Power's last two general rate applications in 2009 and 2007.

Supply

With respect to supply risks, Newfoundland Power relies on Newfoundland and Labrador Hydro (NLH) for over 90% of its power supply. DBRS views Newfoundland Power's reliance on NLH for most of its supply as a challenge (*Rating Report, Newfoundland Power Inc.*, January 24, 2012), as it has consistently since 1994. Power costs, over which the Company has little control, but which can influence customers' consumption behaviour (e.g., conservation), make up almost two-thirds of Newfoundland Power's costs. As Newfoundland Power has no plans to build additional generating facilities, its dependence on NLH will gradually increase.

[12] The business risk analysis that I conducted in my *Opinion on Capital Structure and Fair Return on Equity* for Newfoundland Power filed in May 2009 similarly concluded that the long-term outlook for the service area had not changed materially since its previous general rate application in 2007.

Regulatory Framework

Newfoundland Power's regulatory framework remains constructive. Newfoundland Power has a weather normalization mechanism[13] and a rate stabilization mechanism. The latter allows for pass-through of variations between forecast and actual fuel costs and contains components to account for both energy and demand variances, limiting Newfoundland Power's exposure to both fluctuations in costs of fuel oil and customer demand. The Company also has a variation account for employee future benefits costs.

Newfoundland Power's allowed rate of return on rate base is set within a range of +/- 18 basis points. The corresponding range of return on equity is approximately +/- 40 basis points. Earnings above the upper end of the allowed rate of return on rate base range are credited to an excess earnings account for the benefit of ratepayers. If Newfoundland Power earns below the lower end of the allowed return on rate base range, the under-earnings are to the account of the shareholder. As constructed, the allowed return on rate base range creates an element of asymmetric risk.

As discussed in further detail below, in August 2009, Moody's adopted a new ratings framework for electric and gas utilities.[14] The new ratings framework gives 50% weight to two factors that reflect regulatory risk, regulatory framework (25% weight) and ability to recover costs and earn returns (25% weight). Moody's assigns letter grades to these factors, using the same rating scale that it uses to assign debt ratings. Moody's first applied its new framework to Newfoundland Power in its March 2010 *Credit Opinion*. On both regulatory framework and ability to recover costs and earn returns, Moody's assigned Newfoundland Power a letter grade of "A". These grades were confirmed in its July 2011 *Credit Opinion*. The grades assigned Newfoundland Power on these two categories are the same as the average grade assigned to all other Canadian utilities that have been rated by Moody's.[15] Based on Moody's assessment, Newfoundland

[13] Weather normalization clauses or deferral accounts are common for utilities, particularly gas distribution utilities, which have significant heating load. In the absence of the weather normalization mechanism, Newfoundland Power's annual revenues would vary widely from year to year, due to its relatively high heating load.
[14] Moody's Global Infrastructure Finance, *Rating Methodology: Regulated Electric and Gas Utilities*, August 2009.
[15] Includes utilities in Alberta, British Columbia, Nova Scotia and Ontario.

Power would be considered of approximately average regulatory risk relative to its Canadian peers.

Overall Assessment

In summary, the business risk profile of Newfoundland Power has not changed materially since its last two GRAs in 2007 and 2009.

E. BOND RATINGS AND CREDIT METRICS

Newfoundland Power is rated by two major debt rating agencies, Moody's and DBRS.

In August 2009, during Newfoundland Power's 2010 General Rate Application, Moody's upgraded Newfoundland Power's first mortgage bonds from Baa1 to A2 with a Stable outlook.[16] The upgrade was made in the context of an industry-wide change, under which the debt rating agency widened the notching between the secured and unsecured debt ratings of investment-grade utilities to two notches.[17] The upgrade to Newfoundland Power's First Mortgage Bonds reflected two factors. First, it represented Moody's conclusion that there should be a wider differential between the secured and unsecured ratings of regulated utilities, given the lower default rates of utilities compared to other non-financial corporate issuers. Second, it reflected a

[16] The Moody's ratings scale is as follows:

Rating	Rating Definition
Aaa	Highest quality with minimal credit risk
Aa	High quality with very low credit risk
A	Upper medium credit with low credit risk
Baa	Medium grade with moderate credit risk; may possess certain speculative elements
Ba	Have speculative elements and are subject to substantial credit risk
B	Speculative and subject to high credit risk
Caa	Of poor standing and subject to very high credit risk

To ratings within each major category, a modifier of 1 to 3 is appended, with 1 meaning that the obligation ranks in the upper end of its generic rating category and 3 means that the obligation ranks at the lower end of its generic rating category. Ratings of Baa3 or higher are considered investment grade.

[17] Over $90 billion of securities in North America were upgraded. For most utilities with senior secured securities the upgrades were a single notch. Since there was previously no notching differential between Newfoundland Power's senior secured securities' (First Mortgage Bonds) rating and its issuer rating, the upgrade for its First Mortgage Bonds represented a two-notch change.

one-notch upgrade for Newfoundland Power largely in recognition of its improved and likely sustainable credit metrics in 2008.[18] At the same time, Moody's assigned an issuer rating to Newfoundland Power of Baa1.[19]

In August 2009, as noted above, Moody's also adopted a new ratings framework for electric and gas utilities.[20] In addition to the two business/regulatory risk factors, to which it gives 50% weight, Moody's methodology for rating gas distribution and electric utilities worldwide also considers diversification (10% weight)[21] and financial strength and liquidity (40% weight). The financial strength and liquidity factors are divided into sub-categories with individual weights assigned to the sub-categories. The sub-categories and weights are: Liquidity (10%),[22] Cash from Operations (CFO) plus Interest/Interest, or CFO Interest Coverage (7.5%), CFO to Debt (7.5%), CFO less Dividends to Debt (7.5%) and Debt to Total Capital (7.5%). Each utility is assigned a rating in each of the eight categories based on the criteria applicable to the factor. The actual rating assigned to the utility is based on the weighted average of the ratings assigned to each of the factors.

For the four credit metrics discussed above, Moody's indicative ranges for A and Baa ratings based on those factors are set out in the table below:

[18] In its *Rating Action* (May 2009), Moody's did note that Newfoundland Power's credit metrics remained "somewhat weaker than those of other Baa1-rated low risk regulated utilities."

[19] An issuer rating represents Moody's opinion of the ability of entities to honor senior unsecured financial obligations and contracts. At present, all of Newfoundland Power's long-term debt is secured, in contrast to the majority of Canadian utilities, whose long-term debt is mostly unsecured.

[20] As noted in Section IV.D, Moody's first applied its new framework to Newfoundland Power in its March 2010 *Credit Opinion* In assigning the upgrade to Newfoundland Power in August 2009, Moody's principally followed its March 2005 Global Regulated Electric Utilities ratings methodology.

[21] Diversification for electric utilities is comprised of market position (5%), which reflects the make-up of the customer base (e.g., dependence on industrial load) and growth potential, and generation and fuel diversity (5%).

[22] Liquidity encompasses a company's ability to generate cash from internal sources, as well as the availability of external sources of financings to supplement these internal sources.

Table 4

	A	Baa
CFO Interest Coverage	4.5-6.0X	2.7-4.5X
CFO/Debt	22-30%	13-22%
CFO less Dividends to Debt	17-25%	9-17%
Debt/Total Capital	35-45%	45-55%

Source: Moody's, *Rating Methodology: Regulated Gas and Electric Utilities*, August 2009.

Newfoundland Power's Moody's ratings and outlook have not changed since the upgrade in August 2009. In its most recent *Credit Opinion* for Newfoundland Power (July 2011), Moody's assigned the following ratings to each of the eight key factors:

Table 5

Factor	Weighting	Rating
Regulatory Framework	25%	A
Ability to Recover Costs and Earn Returns	25%	A
Market Position	5%	Baa
Generation and Fuel Diversity	5%	A
Liquidity	10%	A
CFO Interest Coverage	7.5%	Baa3
CFO to Debt	7.5%	Baa3
CFO-Dividends to Debt	7.5%	Baa2
Debt/Capital	7.5%	Baa2
Indicated Rating from Methodology Grid		A3
Actual Rating		**Baa1**

Source: Moody's, *Credit Opinion: Newfoundland Power Inc*., July 19, 2011.

Moody's noted that, while the assigned rating of Baa1 is one notch lower than the rating implied by the grid, the difference in part reflects its belief that Newfoundland Power's future financial metrics will be modestly weaker than those in 2010 due primarily to the reduction in the allowed ROE to 8.38% in 2011 from 9.0% in 2010. Moody's considers, as it had previously, e.g. in the May 2009 *Rating Action* noted above and in previous *Credit Opinions*, that Newfoundland Power's financial metrics are somewhat weaker than those of its Baa1 rated peers in North America, including its sister company, FortisAlberta Inc. The Baa1 rating is one notch lower than the average rating accorded by Moody's to the regulated Canadian utility companies it rates (Schedule 4).

With respect to its assessment of Newfoundland Power's business and regulatory risk, Moody's continues to conclude that Newfoundland Power operates in a supportive business and regulatory environment. A review of the *Credit Opinions* for Newfoundland Power since March 2009 (most recent available at the time of the Company's last General Rate Application) does not indicate Moody's has materially changed its assessment of Newfoundland Power's business and regulatory environment over the past three years.

According to Moody's, it is unlikely that there will be a downward revision to Newfoundland Power's rating in the near-term. However, Newfoundland Power's rating would likely be downgraded if there were a perceived meaningful reduction in the level of regulatory support combined with weaker liquidity and a sustained deterioration in Newfoundland Power's financial metrics such as CFO interest coverage of less than 2.6 times (compared to Moody's 12-18 months forward view of 3.0 to 3.3 times), CFO to debt in the low teens (versus 15-17% anticipated) and CFO less dividends to debt below 9% (compared to a forward range of 7-13%).

With respect to DBRS, it recently confirmed the rating of Newfoundland Power's senior secured debt of A with a Stable trend.[23] Newfoundland Power's DBRS rating has remained unchanged since the beginning of 1996. Newfoundland Power's A debt rating by DBRS is equal to the Canadian utility industry average (Schedule 4). As was the case in its May 2008 Rating Report,[24] DBRS views Newfoundland Power's principal business strengths to be its supportive regulatory framework, stable customer base and minimal competitive pressures. The key challenges are related to its reliance on Newfoundland and Labrador Hydro for the preponderance of its power supply, the sensitivity of its earnings to interest rates (as a result of the automatic adjustment mechanism for return), managing forecast risk and limited growth potential.

[23] DBRS, *Rating Report: Newfoundland Power Inc*., January 24, 2012.
[24] DBRS, *Rating Report: Newfoundland Power Inc*., May 5, 2008. At the time of Newfoundland Power's last GRA, this was the most recent report available from DBRS.

With respect to the financial profile, DBRS considers Newfoundland Power to have a strong balance sheet and favourable financial profile. In its January 2012 Rating Report, DBRS noted that the coverage ratios had shown gradual improvement (which is consistent with their expectations in the May 2008 Rating Report), with an expectation that credit metrics would remain flat, and within the Company's current credit rating, but recognized that the Company's credit profile was dependent on its future rate applications to the PUB.

F. REASONABLENESS OF PROPOSED CAPITAL STRUCTURE

Within a reasonable range, the capital structure for a particular utility 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. Newfoundland Power's actual and approved (for rate setting purposes) common equity ratios have been close to 45% for at least 15 years. In my opinion, Newfoundland Power's proposed capital structure, which contains approximately 45% common equity, remains reasonable, for the reasons summarized below.

1. There has been no material change in the level of business risk to which Newfoundland Power is exposed since which would warrant a change in the common equity ratio from the level agreed to by parties to the negotiated settlement in Newfoundland Power's 2010 GRA and accepted by the Board.

2. Maintenance of debt ratings in the A category is a reasonable objective. With a common equity ratio of approximately 45%, Newfoundland Power's credit metrics have been sufficient to achieve and maintain debt ratings in the A category by both Moody's and DBRS for its senior secured debentures, but only a Baa1 issuer rating (i.e., the rating that would be applicable to unsecured debt) by Moody's. If the approved common equity ratio were to be lowered, not only would the credit metrics weaken, but also a decision to lower the equity ratio would likely be viewed by the credit rating agencies as a reduction in the level of regulatory support afforded the Company.

3. Over the past several years, while Newfoundland Power's common equity ratio has remained relatively constant, the allowed common equity ratios of a number of its Canadian peers have been raised, particularly in Alberta and British Columbia, as well as at the National Energy Board. The Alberta Utilities Commission (AUC) approved an across-the-board increase in allowed common equity ratios for the Alberta utilities in its Generic Cost of Capital Decision 2009-216, in part to recognize that:

> "events that drove the original [financial] crisis will be factored into investors' perceptions. Companies will therefore protect their balance sheets and investors will adjust risk perceptions whether unexpected events present themselves again or not. In order to protect investors' and ratepayers' interests, the Commission must award equity ratios that recognize the need for the ongoing viability of the utility even in adverse conditions." (page 90)

With minor exceptions for company-specific circumstances, the AUC confirmed the across-the-board increase in its 2011 Generic Cost of Capital Decision 2011-474 (December 2011). As discussed in Section V below, capital market conditions remain unsettled. Persistent risks to the global financial system support, at a minimum, maintenance of Newfoundland Power's equity ratio at previously approved levels.

4. Future investment requirements for power sector infrastructure globally are potentially massive, and may entail significant competition for capital. Newfoundland Power should be positioned so that it can continue to compete successfully for capital, that is, continue to obtain capital as required on reasonable terms and conditions. As noted above, Newfoundland Power's credit metrics have been considered weaker than those of its similarly rated peers.

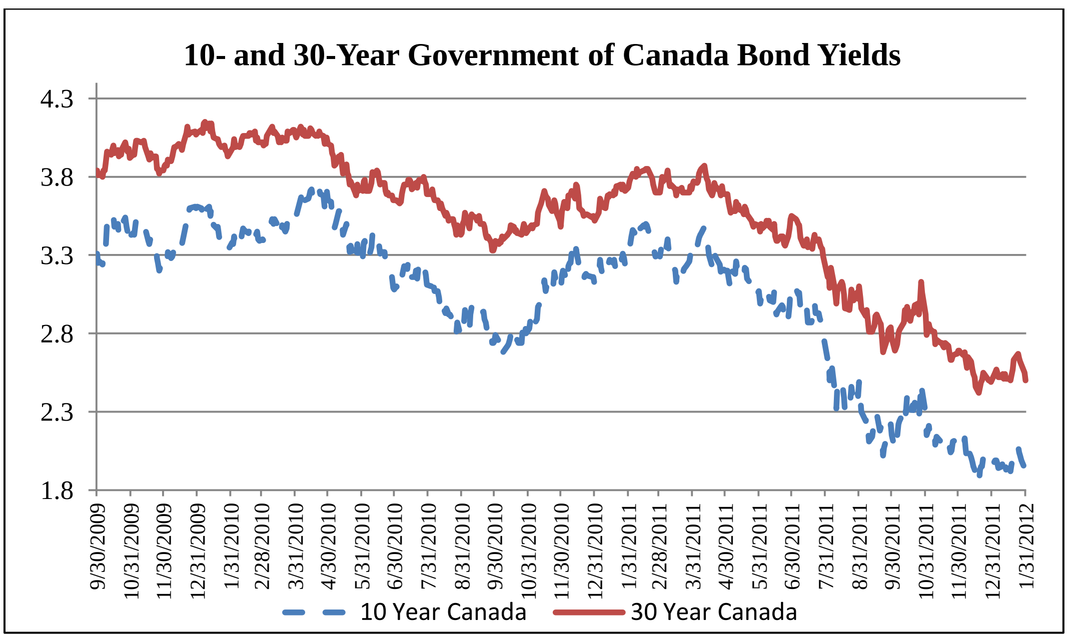
At the forecast capital structure and its current debt ratings, in my opinion, Newfoundland Power would be viewed by investors as an approximately average risk Canadian utility. The ROE developed below is intended to apply to an average risk Canadian utility, e.g., to Newfoundland Power.

V. TRENDS IN ECONOMIC AND CAPITAL MARKET CONDITIONS

Order No. P.U. 43(2009), which established an ROE of 9.0% for Newfoundland Power for 2010 at a forecast 30-year Government of Canada bond yield of 4.5%, was premised upon a relatively optimistic outlook for economic recovery following the recession of 2008-2009 and rapid stabilization of capital market conditions from the financial crisis.

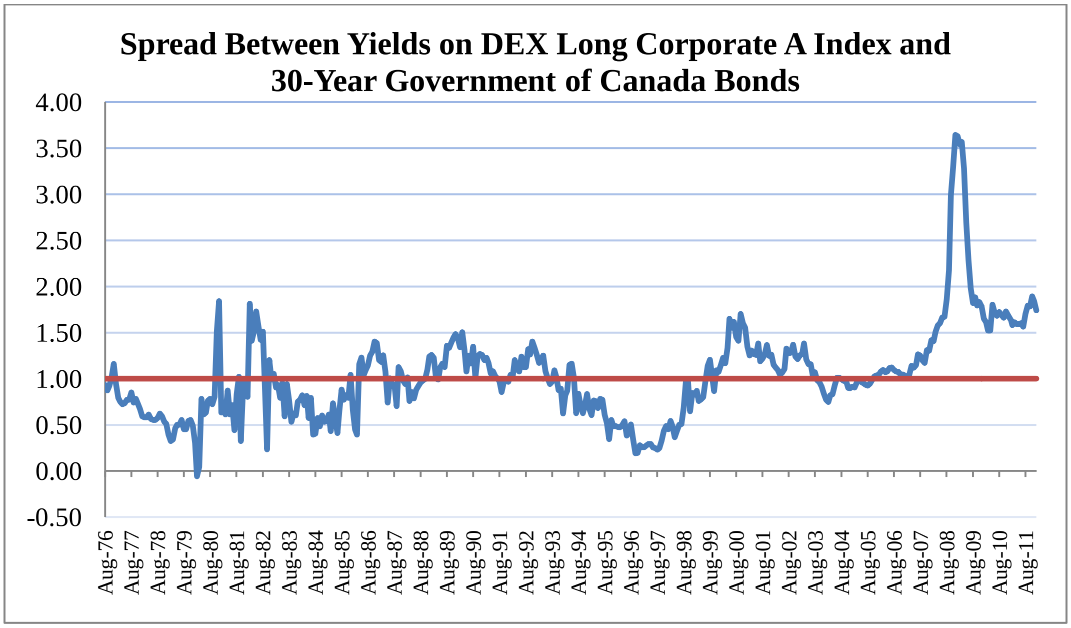
During the first months subsequent to Order No. P.U. 43(2009), economic and financial market conditions in Canada did continue to improve. Real GDP growth rates in Canada in 4Q 2009 and 1Q 2010 were 4.9% and 5.5% respectively. Between December 2009 and April 2010, long-term Canada bond yields hovered within a fairly narrow range of 3.9% to 4.2%. Chart 1 below shows the trends in 10-year and 30-year Canada bond yields from the end of 3Q 2009 to the end of January 2012.

Chart 1



The spread between A-rated corporate and long-term Canada bond yields, having narrowed from the March 2009 peak of 3.6% to 1.8% at the end of November 2009, contracted further. The spread reached 1.5% at the end of April 2010, still well above the pre-crisis long-term average of less than 1.0%. Chart 2 below sets out the spreads since 1976, the first year that 30-year Government of Canada bond yields were reported.

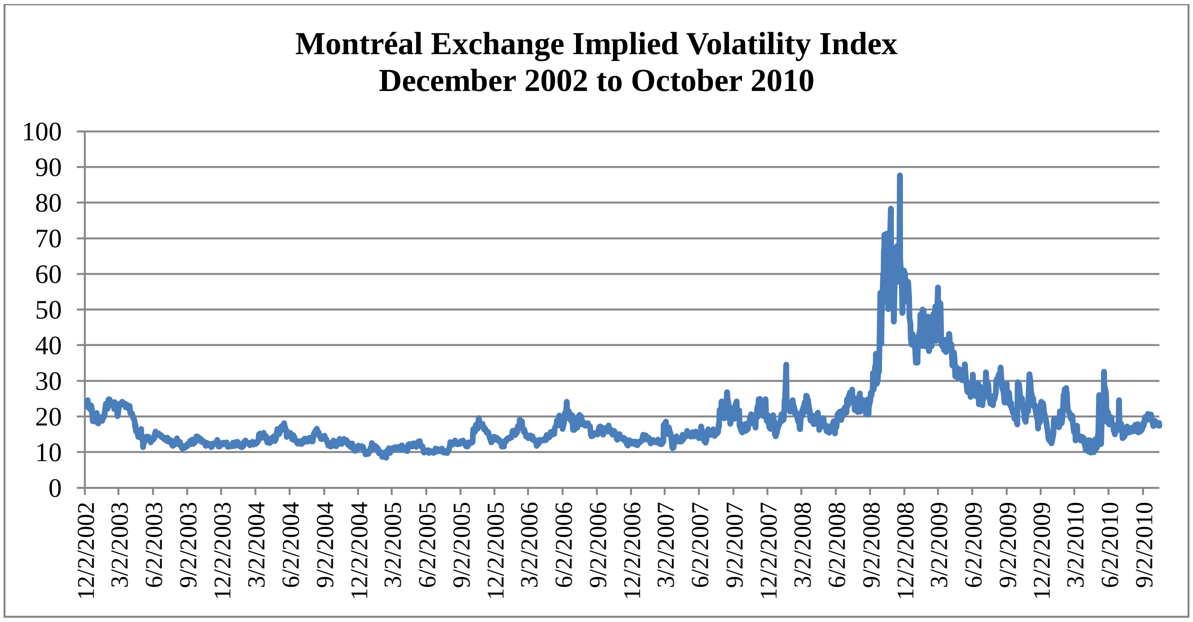
Chart 2



The equity market's recovery from its March 2009 trough had continued; the S&P/TSX Composite Index, which had dropped 50% between June 2008 and March 2009, ended April 2010 approximately 20% below its 2008 peak. During April 2010, expected equity market volatility, as measured by the Implied Volatility Index ("MVX"), was below pre-crisis average levels. Chart 3 below tracks the MVX from its inception in December 2002 until mid-October 2010.[25]

[25] The MVX, introduced by the Montréal Stock Exchange in 2002, measured the market expectation of stock market volatility over the next month. It has been 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 S&P/TSX 60 VIX Index (VIXC), in October 2010, with historical data available from October 1, 2009. Similar to the MVX, the VIXC measures the market's expectation of stock market volatility over the next month.

Chart 3



In May 2010, as the Bank of Canada noted in its June 2010 *Financial System Review*, "mounting concerns over fiscal sustainability in some euro-area member states and the exposure of global banks to sovereign risk erupted into a period of severe stress in international financial markets.…". With Government of Canada bonds increasingly viewed as a safe haven alternative to U.S. Treasuries, a flight to quality exerted downward pressure on Canada bond yields. Foreign investors acquired over $11 billion of Government of Canada bonds in May 2010,[26] helping to push long-term Canada bond yields to their lowest level since April 2009. At the end of May 2010, the yield on long-term Government of Canada bonds had fallen to 3.73%.

The Bank considered that, despite the momentum gained in the domestic and global economic recovery, the strengthening of the Canadian financial system and the fact that "bold policy actions taken by European governments and central banks, with international support, succeeded in heading off a full-blown crisis of confidence" the risks to Canadian financial stability had increased during the prior six months.[27]

[26] Statistics Canada, *Canada's International Transactions in Securities*, May 2010.
[27] Bank of Canada, *Financial System Review*, June 2010.

The strength in the Canadian economy during the first part of 2010 led the Bank of Canada to raise its target overnight rate three times between June and September (from 0.25% to 1.0%). However, in October 2010, the Bank of Canada announced that the economic outlook for Canada had changed and it expected growth to be more muted and the global recovery more gradual than previously forecasted. The changed economic outlook led the Bank of Canada to leave its target overnight rate unchanged, leaving significant monetary stimulus in place, and to conclude that "any further reduction in monetary policy stimulus would need to be carefully considered."[28] The Bank's statements led economists to conclude that there would likely be no further reduction in monetary policy stimulus before mid-2011.[29]

The relatively modest expected pace of growth reflected 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 related austerity programs in those countries, as well as constraints on export growth arising from a combination of tempered growth abroad, the high Canadian dollar and relatively weak productivity).

In its December 2010 *Financial System Review*, the Bank of Canada again assessed the risks to the Canadian financial system, summing 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; [30]
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.

[28] Bank of Canada, *Monetary Policy Report*, October 2010.
[29] Consensus Forecasts, *Consensus Economics*, November 2010.
[30] 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 all but one (potential for excessive risk-taking behaviour) of these categories, the Bank of Canada concluded that the risks to the Canadian financial system had risen over the previous six months. 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.

With the Bank of Canada and other central banks maintaining their policy rates at historically low levels to stimulate economic growth, expectations that the global recovery would be protracted, along with rising risks from global sovereign debt, particularly in Europe and the U.S., and continued strong inflows into Canadian bonds,[31] resulted in Government of Canada bond yields drifting downward during the latter half of 2010, as did forecast yields.[32]

As 2011 unfolded, despite headwinds from the ongoing sovereign debt vulnerabilities in Europe and the complications of a two-speed global economic recovery (i.e., modest growth in advanced economies versus emerging economies at risk of overheating), the Canadian economy appeared poised to advance at a steady, but modest pace. GDP growth in Canada in both the fourth quarter of 2010 and the first quarter of 2011 had been stronger than anticipated. From their third quarter 2010 low of 3.33%, long-term Canada bond yields gradually shifted upward, peaking in early second quarter 2011 at 3.87%. Similarly, the downward trend in forecast Canada bond yields reversed; the consensus forecast of the twelve-month forward 10-year Canada increased each month between November 2010 and April 2011.

[31] On average during 2009-2011 non residents acquired government of Canada bonds at a rate of approximately $6.8 billion a month compared to approximately $1.0 billion per month in 2004-2006. At the end of 2012, foreign holdings were 24% compared to 13% in 2006.

[32] In November 2009, Consensus Economics, *Consensus Forecasts*, had anticipated that the 10-year Government of Canada bond would yield 3.6% and 4.0% three and twelve months forward; in November 2010, the corresponding forecasts had dropped to 2.8% and 3.3%. Because Newfoundland Power's automatic adjustment mechanism changed the regulated ROE by 80% of the change in forecast long-term Canada bond yields, the regulated ROE declined from 9.0% for 2010 to 8.38% for 2011, i.e., to a level well below the ROEs authorized for other Canadian utilities for the same period.

In its June 2011 *Financial System Review*, the Bank of Canada noted decreased risk aversion in financial markets, evidenced by low yields on and record bond issuance in high yield (non-investment grade) debt, as well as low volatility in the equity markets. Nevertheless, in the Bank's view, risks to the financial system were still higher than in their six month earlier assessment, as the risk associated with global sovereign debt had edged higher and the risk associated with the low interest rate environment in advanced economies had increased with the growing popularity of riskier securities and strategies in both Canadian and global markets.

By July 2011, market sentiment had started to shift. In the July 2011 *Monetary Policy Report*, the Bank of Canada pointed to several developments weighing on sentiment, including:

1. declines in equity market prices in both advanced and emerging economies during the prior three months in reaction to increasing uncertainty over the strength of the global recovery,
2. some deterioration in corporate credit markets,
3. a sharp reduction in bond issuance, and
4. shifting of capital into perceived safe haven assets and currencies, putting downward pressure on government bond yields in major advanced economies.

By the end of July 2011, long-term Canada bond yields had fallen to 3.3%.

Over the next few months, a number of the risks with which the Bank of Canada had expressed concern in earlier reports were experienced. In its October 2011 *Monetary Policy Report*, the Bank of Canada referenced the acute fiscal and financial strains in Europe and concerns about the strength of global economic activity that had led to increased and significant financial market volatility, reduced business and consumer confidence, and an escalation of risk aversion. The increased volatility was triggered by a reassessment of the prospects for global economic growth, as well as heightened worries over debt sustainability in the euro area and uncertainty over the direction of fiscal policy in the United States. According to the Bank, the already negative tone in financial markets was exacerbated by numerous credit rating downgrades of sovereigns and global financial institutions. As the Bank noted, as a result, investment flows shifted toward safer and more liquid assets. Government bond yields in a number of advanced economies, where markets are most liquid and which are perceived to be better credit risks, had fallen sharply. At the same time, prices of riskier assets had declined significantly.

In its January 2012 *Monetary Policy Report*, the Bank anticipated that growth in the Canadian economy throughout 2012 would be weaker than previously forecast, despite the better than anticipated momentum experienced during the second half of 2011. The weaker growth forecast was largely due to the continued deterioration in the global economy, resulting in further tightening of international financial markets and continued risk aversion. Economic indicators suggested that the Euro area had entered into a recession in the fourth quarter of 2011 and the "deteriorating financial conditions, bank deleveraging, fiscal consolidation and large negative confidence effects" of this recession were expected to last well into 2012. The Bank found that, since the October *Monetary Policy Report*, investors had continued to shift toward safer and more-liquid assets, resulting in yields on government bonds in Canada, Germany, the United Kingdom and the United States continuing to decline at the same time that spreads in some of the Euro-region's largest economies had risen, in some cases to post-euro record highs. Investor anxiety had also continued at high levels, resulting in continued market volatility in global markets.

With respect to volatility, as Chart 4 below demonstrates, expected equity market volatility, as measured by the VIXC,[33] increased markedly in August 2011. Although expected volatility has dropped from its 2011 highs, on average during the past three months (November 2011-January 2012), the VIXC has been 20% higher than during the corresponding period in 2009-2010.

[33] Chart 4 tracks expected volatility as measured by the S&P/TSX 60 VIX Index (VIXC) from October 1, 2009, the first day for which historical data are available.

Chart 4

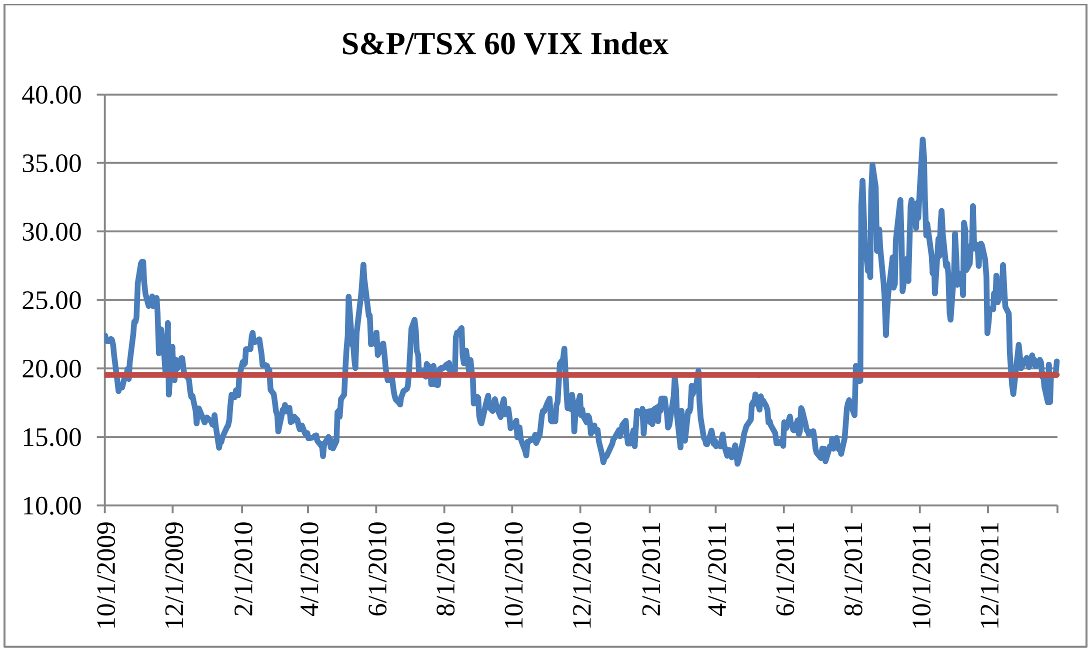
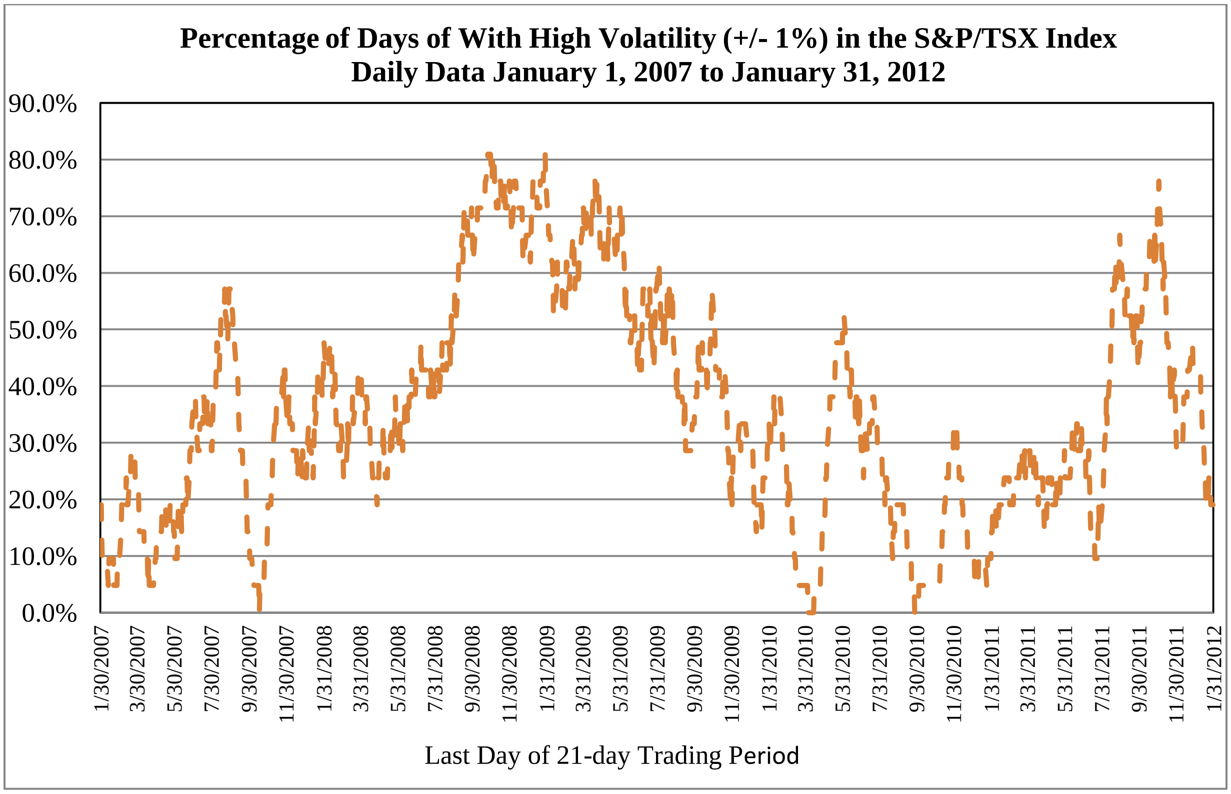


Chart 5 below tracks the actual volatility in the Canadian equity market from before the onset of the financial crisis to the end of January 2012 as the percentage of days over rolling 21-day periods (approximately one month) that the S&P/TSX Composite changed by more than plus or minus 1%. The chart demonstrates the material increase in the percentage of trading days on which the S&P/TSX Composite changed by more than one percentage point that transpired during the latter half of 2011.

Chart 5



While equity markets have been calmer recently (late 2011 and early 2012), as of January 31, 2012, the S&P/TSX Composite was still 20% below its pre-crisis (mid-June 2008) peak.

Another indicator of the recent trends in investor sentiment is the trend in yields on Canadian high yield (non-investment grade) bond indices. High yield bonds are considered to have characteristics of both debt and equity, the latter due in large part to their higher default risk, higher sensitivity to the business cycle and closer connection to the underlying fundamental risks of the issuers than high grade corporate bonds. The yield on the DEX Overall High Yield Bond Index[34] jumped from a two-year low of 6.5% in April 2011 to 9.5% at the end of September 2011. While the yield on the index has since retreated from its 2011 peak, at a yield of 8.76% at January 31, 2012, it was still well above the yield prevailing by the end of 2009 (7.8%). Additionally, despite government bond yields already at historically low levels at the beginning of 2011, the increased economic uncertainty, investor risk aversion and global shifting of funds

[34] The DEX Overall High Yield Bond Index is designed to be a broad measure of the Canadian non-investment grade fixed income market.

into the safe haven of a smaller pool of highly rated government bonds,[35] have pushed yields on long-term Canada bonds down more than a full percentage point over the past 12 months. As of January 31, 2012, the yield on long-term[36] Canada bonds stood at 2.4%, a level not seen for sixty years.

The forecasts of Canada bond yields also declined precipitously during 2011. Between May and October 2011, the twelve-month forward forecast 10-year Canada bond yield plummeted by 1.4 percentage points, of which 1.1 percentage points of the decline occurred between August and October alone. The 1.1 percentage point change in the twelve month forward 10-year Canada bond yield consensus forecast between August and October 2011 was the largest two month change (positive or negative) observed since the inception of the *Consensus Forecasts* in 1990. The January 2012 twelve-month forward consensus forecast of the 10-year Government of Canada bond yield remains at the same level as forecast in October 2011. The January 2012 consensus forecast anticipates that the 10-year Government of Canada bond yield will reach 2.6% (2.8% on a median forecast basis) by January 2013, compared to its January 31, 2012 level of 1.9%.

While there have been some signs of improvement in the global economy in the past two months, e.g., an improving labor market in the U.S., considerable headwinds to a sustained recovery remain, as the Bank of Canada's January 2012 *Monetary Policy Report* discussed above underscored. The International Monetary Fund's *World Economic Outlook Update* released January 24, 2012 concluded that the global economic recovery is threatened by intensifying strains in the euro area and fragilities elsewhere and that financial conditions have deteriorated, growth prospects have dimmed and downside risks have escalated. The downside risks relate to the potential reduction in credit availability and output in the euro zone arising from sovereign and bank funding pressures, which is transmitted to the rest of the world, excessive fiscal tightening in the U.S. in the near term but failure to arrive at a credible fiscal consolidation

[35] After the United States and the United Kingdom, Canada is the largest non-Euro zone economy with AAA sovereign debt ratings. The U.S. was downgraded to AA+ by Standard & Poor's in August 2011, but still has AAA ratings by Moody's, Fitch and DBRS. Despite the S&P downgrade, U.S. Treasury bonds continue to be regarded as a safe haven investment.

[36] As represented by the yield on the Government of Canada marketable bonds over 10 years Series V39062.

strategy in the medium term, a hard landing in emerging economies, and intensified concerns about an Iran-related oil supply shock.

As the turmoil in the capital markets during the latter half of 2011 demonstrates, conditions in the financial markets have remained unsettled. The systemic risks to the global economy and financial system are high, and, based on the Bank of Canada's *Financial System Reviews*, have continued to rise since December 2009.

The current level of Canada bond yields reflects a confluence of factors, including deterioration in the global economic outlook, the Bank of Canada's decisions to maintain its overnight rate at historically low levels, and investor flight to quality, i.e., away from riskier assets including equities. With respect to the last factor, with the numerous ratings downgrades of sovereign bonds that have taken place in the euro zone over the past two years, the supply of safe haven assets has shrunk, and a scarcity value attributed to high grade sovereign bonds (including those of Canada, the U.S., the U.K. and Germany) that are viewed as least affected by the euro zone debt crisis.

Over the longer-term, 10-year Government of Canada bond yields are forecast to rise to more normal levels, as indicated in Table 6 below.[37]

Table 6

Year	2014	2015	2016	2017-2021
Forecast 10-year Canada	4.3%	4.5%	4.6%	4.6%

Source: Consensus Economics, *Consensus Forecasts*, October 2011.

With an average historical spread between 30-year and 10-year Government of Canada bonds of 0.35%, the corresponding longer term yield on 30-year Canada bonds is approximately 5.0%.

The recent downward trend in long-term Government of Canada bond yields has little to do with the trend in the cost of equity for a public utility. This conclusion is supported by the trend in the

[37] Consensus Economics issues long-term forecasts of key economic indicators, including the 10-year Canada bond yield, twice a year, in April and October.

relationship between public utility dividend yields, a major component of the utility cost of equity, and long-term Government of Canada bond yields. From 1998 to 2007, before the onset of the financial crisis, utility dividend yields generally tracked the long-term Government of Canada bond yield. Over this period, the ratio of the dividend yield of the major publicly-traded Canadian utility holding companies[38] to the yield on the 30-year Government of Canada bond was approximately 75%. Since the beginning of 2008, the ratio of utility dividend yields to long-term Canada bond yields has risen markedly; at the end of January 2012, the ratio was just under 1.4. In other words, prior to the onset of the crisis, the utility dividend yield was 25% lower than the corresponding 30-year Government of Canada bond yield. At the end of January 2012, the utility dividend yield was 40% higher than the 30-year Canada bond yield. Since the beginning of 2010, the utility dividend yield has only changed, on average, by just over 25% of the change in 30-year Government of Canada bond yields.

Based on the pre-crisis relationship between utility dividend yields and the yield on the 30-year Canada bond, at a current 30-year Canada bond yield (January 2012) of 2.5%, the current utility dividend yield should be approximately 1.8% (75% of 2.5%), rather than the observed 3.5%. Alternatively, based on the pre-crisis relationship, all other things equal, the observed 3.5% utility dividend yield would correspond to a 30-year Canada bond yield of approximately 4.5% (3.5%/0.75), rather than the much lower prevailing level.

The observed change in the relationship between the utility dividend yield and the long-term Government of Canada bond yield strongly suggests the following:

1. The estimation of a fair ROE for Newfoundland Power should be based on multiple tests, including tests which are not benchmarked from the long-term Government of Canada bond yield; and

2. In the application of equity risk premium tests that are benchmarked to the long-term Government of Canada bond yield, the abnormally low level of recent and

[38] Canadian Utilities Limited, Emera Inc., Enbridge Inc., Fortis Inc., and TransCanada Corporation.

forecast yields needs to be taken into account in the assessment of what constitutes an appropriate equity risk premium.

In addition, given that capital markets continue to be unsettled, I recommend that the Board not reinstate the automatic adjustment formula at this time. As a result, I have developed the fair ROE for Newfoundland Power on the premise that it will remain unchanged through at least 2013. In that context, the equity risk premium tests which I have applied below are based on a single (average) forecast of the 30-year Government of Canada bond yield for 2012-2013.

VI. FAIR ROE FOR NEWFOUNDLAND POWER

A. CONCEPTUAL CONSIDERATIONS

The cost of equity, as estimated using tests applied to proxy companies, reflects the composite of those proxy companies' business, regulatory and financial risks. The cost of equity estimated by reference to a sample of companies is applicable to a specific utility without adjustment if the magnitude of the total risks (business plus financial) of the sample and the specific utility is comparable. In principle, given a sufficiently large universe of utilities, different samples of proxy companies can be selected, each designed to be a proxy for a specific utility. If, however, the total risk of the sample and the specific utility is not comparable, the solutions include: (1) changing the specific utility's capital structure; (2) making an adjustment to the proxy companies' cost of equity to reflect the relative total risk of the specific utility; or (3) some combination of (1) and (2). To minimize the extent to which such adjustments are required, the point of departure should be the selection of companies that are of relatively similar total risk to an average risk Canadian utility, e.g., Newfoundland Power.

In Canada, there are only six publicly-traded Canadian companies whose operations are largely regulated.[39] These companies are relatively heterogeneous in terms of both operations[40] and

[39] Canadian Utilities Limited, Emera Inc., Enbridge Inc., Fortis Inc., TransCanada Corporation and Valener Inc. (formerly Gaz Métro LP).

[40] 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.

size.[41] The relatively small and heterogeneous universe of publicly-traded Canadian utilities means that it is impossible to select a sample of companies that would be considered directly comparable in total risk to any specific Canadian utility.

While market data for the Canadian utilities provide some perspective on the fair return for an average risk Canadian utility, a more accurate assessment can be made by reliance on a sample of U.S. utilities drawn from a much broader universe and selected using criteria that are designed to (1) identify companies that are of relatively similar risk to an average risk Canadian utility and (2) produce a large enough sample of companies to ensure reliable cost of equity test results.

B. IMPORTANCE OF MULTIPLE TESTS

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:

1. Equity Risk Premium (including, but not limited to, the Capital Asset Pricing Model),
2. Discounted Cash Flow, and
3. Comparable Earnings.

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.[42] Moreover, different tests may be more or

[41] Ranging from an equity market capitalization of approximately $610 million (Valener) to $26.5 billion (Enbridge).

[42] 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,

less reliable depending on prevailing economic and capital market conditions.[43] These considerations emphasize the importance of reliance on multiple tests.

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 generally with clear recognition of its shortcomings and the various adjustments to the "classic" model that may be required. 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.

Albert L. Danielsen, David R. Kamerschen, *Principles of Public Utility Rates*, 2nd Ed., page 317, Arlington, VA.: Public Utility Reports, Inc., March 1988).

[43] 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.

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 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.[44] 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. This obstacle is particularly problematic with current and forecast long-term Canada bond yields at historically low levels.

4. The achieved equity market risk premium in Canada is significantly influenced by historic behaviour of the long-term Government of Canada bond. The improvement in Canada's fiscal performance over the past fourteen years has contributed to a steady decline in long-term government bond yields and a

[44] 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.

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.

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.

The British Columbia Utilities Commission ("BCUC") and 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)

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.

C. 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 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[45] of 1.7X (U.S. sample) to 2.2X (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 should 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 inadequate level of earnings which will discourage utilities from making investments in critical infrastructure.

D. SELECTION OF COMPARABLE UTILITIES

As noted above, in Canada, there are only six investor-owned publicly-traded companies whose operations are largely regulated, which makes it impossible to select a sample of companies that would be considered directly comparable in total risk to any specific Canadian utility. While market data for the Canadian utilities were relied on to provide a perspective on the fair return for an average risk Canadian utility, a sample of low risk U.S. distribution utilities was also used.

[45] January 2012 price and most recent *Value Line* 2011 forecast (U.S.) or calculated (Cdn) book value per share.

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 an average risk Canadian utility. 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.

Equity markets are global; investors are increasingly committing equity funds beyond domestic borders.[46] Canadian investors looking to commit funds to utility equity shares will compare returns available from Canadian utilities to returns available from utility shares globally, including returns from U.S. utilities (both market and allowed). A review of the major Canadian public sector defined benefit pension funds which list all their equity holdings individually shows that the funds have invested in a significant number of U.S. utilities.

Nevertheless, not all utilities in the U.S. would be considered of similar risk to an average risk Canadian utility, just as not all utilities in the U.S. would be similar to each other. Consequently, the sample of U.S. utilities which serve as a proxy for an average risk Canadian utility was selected according to criteria specifically designed to identify utilities that are comparable to an average risk Canadian utility like Newfoundland Power.

To ensure comparability with an average risk Canadian utility, only relatively pure-play U.S. utilities were selected. The selected utilities are rated no lower than BBB+/Baa1 by both Standard & Poor's and Moody's. The median S&P debt rating of the U.S. utility sample is A-, identical to the A- rating accorded on average to the universe of Canadian utilities rated by S&P. The sample average S&P business risk category (Excellent) is the same as the assigned to the majority of Canadian utilities.[47] The median Moody's rating for the U.S. utility sample is Baa1 (Schedule 13, page 1 of 2), the same as Newfoundland Power's issuer rating. The median *Value Line* Safety rank of the U.S. utility sample is 2 (Schedule 13, page 1 of 2); the Safety ranks of both of the two Canadian regulated companies covered by *Value Line* (TransCanada Corp. and

[46] See Appendix A, pages A-13 to A-15 for discussion of global investment by Canadian investors.

[47] 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 but one of the utilities in the proxy sample of U.S. utilities has an "Excellent" business profile.

Enbridge Inc.) are also 2.[48] The average difference in the adjusted monthly betas of the Canadian utilities and low risk U.S. utility sample for five-year periods ending 1993-2011 has been minor (Schedule 12, page 1 of 2 and Schedule 13, page 2 of 2). Even if equity investors viewed the U.S. utility sample as facing higher business (combined operating and regulatory) risk than an average risk Canadian utility, the U.S. utility sample has higher common equity ratios (lower financial risk). The average common equity ratio of the sample of low risk U.S. utilities (based on the average of the last four quarters ending September 2011) was approximately 50% (Schedule 6), compared to Newfoundland Power's actual common equity ratio of 45%.[49]

E. EQUITY RISK PREMIUM TESTS

1. Conceptual Underpinnings

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 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

[48] 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.

[49] Appendix B provides both details of the selection criteria and information on the selected U.S. utilities' operations and regulation, including for each a list of the regulatory mechanisms that have been adopted. Schedule 13, page 1 of 2 provides additional quantitative and qualitative data for the selected U.S. utilities.

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. An equity risk premium can be estimated relative to a risk-free rate, for which a government bond yield is typically the proxy, as well as relative to utility bond yields, depending on the type of equity risk premium test being conducted.

Three equity risk premium tests were used to estimate the utility cost of equity:

1. Risk-Adjusted Equity Market Risk Premium Test;
2. DCF-Based Equity Risk Premium Test; and
3. Historic Utility Equity Risk Premium Test.

In the application of the equity risk premium test, each of the methods was accorded equal weight in the estimation of the cost of equity for Newfoundland Power.

2. Risk-Free Rate

The application of equity risk premium tests in relation to a risk-free rate requires a forecast of the risk-free rate to which the equity risk premium is applied. A forecast long-term (30-year) Government of Canada bond yield is most widely used as the risk-free rate, although long-term Government of Canada bond yields are not risk-free. They are considered to be free of default risk, but are subject to interest rate risk.[50] Use of the long-term government bond yield recognizes (1) the administered nature (determined by monetary policy) of short-term rates; and (2) the long-term nature of the assets to which the utility equity return is applicable.

In the application of the equity risk premium tests, the forecast 30-year Government of Canada bond yield for the near term (2012-2013) was estimated and utilized as the risk-free rate. The

[50] If interest rates rise, the value of the bond will decline.

30-year Government of Canada bond yield for 2012-2013 was estimated at 3.25%-3.50% based on the January 2012 forecasts issued by the major Canadian investment banking firms.[51]

Over the longer-term (2014-2021), the 10-year Canada bond yield is expected to average close to 4.6%.[52] The corresponding 30-year Canada bond yield, assuming the historical long-term average spread between 30-year and 10-year Canada bonds of 0.35% prevails, is estimated at close to 5.0%.

3. Risk-Adjusted Equity Market Risk Premium Test

3.a. Conceptual and Empirical Considerations

The risk-adjusted equity market risk premium approach to estimating the required equity market risk premium for a 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 utility equity market risk premium. 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

[51] BMO Capital Markets, CIBC World Markets, Desjardins Economic Studies, National Bank Economy and Strategy Group, RBC Economics, ScotiaBank Group and TD Securities. The median forecasts of the 30-year Government of Canada bond yield were 3.0% and 3.7% for 2012 and 2013 respectively.

[52] Consensus Economics, *Consensus Forecasts* (October 2011). There are no longer-term consensus forecasts for the 30-year Government of Canada bond yield.

beta is a calculation of the historical correlation between the overall equity market returns, as proxied in Canada by the returns on the S&P/TSX Composite, and the returns on individual stocks or portfolios of stocks.

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 both the post-World War II period (1947-2011)[53] and 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, pages A-13 to A-15) and the similarity between historical Canadian and U.S. equity market returns and equity return volatility.

[53] 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.

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.[54]

Table 7

Period	Stock Return	Bond Total Returns	Bond Income Returns	Risk Premium Over Bond Total Returns	Risk Premium Over Bond Income Returns
Canada					
1924-2011	11.4%	6.6%	6.0%	4.8%	5.4%
1947-2011	11.8%	7.1%	6.7%	4.7%	5.0%
U.S.					
1926-2011	11.8%	6.1%	5.2%	5.6%	6.6%
1947-2011	12.3%	6.6%	5.9%	5.7%	6.4%

Source: Schedule 8.

The raw data in Table 7 show that, on average, equity returns in Canada have averaged approximately 11.4% to 11.8%, compared to average bond income[55] returns of approximately 6.0% to 7.0%, resulting in average achieved risk premiums relative to bond income returns in the range of approximately 5.0% to 5.5%.[56] 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 11.75% to 12.25%, corresponding to average bond income returns of approximately 5.25% to

[54] The equity and bond market returns in Table 4 represent arithmetic averages of historical returns. Appendix A explains the rationale for using arithmetic, rather than compound (geometric) averages for the purpose of estimating the expected return from historic returns.

[55] 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. The bond total return includes annual capital gains or losses and reinvestment of the bond coupons. 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.

[56] The median risk premiums over the periods 1924-2011 and 1947-2011 were somewhat higher, 6.2% and 5.5%, respectively, relative to bond income returns.

6.0%, resulting in an average achieved equity risk premium of approximately 6.5% relative to bond income returns.

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 1932 to 2011 were examined and are presented in Table 8 below.

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**
1932-1941	9.1%	6.6%	2.5%	3.6%	5.5%
1942-1951	18.9%	2.4%	16.6%	2.9%	16.0%
1952-1961	13.2%	2.4%	10.7%	4.1%	9.1%
1962-1971	7.8%	4.5%	3.2%	6.1%	1.7%
1972-1981	13.6%	2.7%	11.0%	9.7%	3.9%
1982-1991	10.8%	16.5%	-5.7%	11.1%	-0.2%
1992-2001	11.4%	10.8%	0.6%	7.1%	4.3%
2002-2011	9.1%	8.7%	0.4%	4.4%	4.7%

Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2010; TSX Review.*

Table 8 indicates a clear pattern in bond returns, reflecting:

1. rising bond yields in the 1950s through the early 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.[57]

In contrast to the pattern in bond returns, Table 8 does not indicate a discernible pattern in equity market returns.[58]

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: 1924-2011			**Averages for the Period: 1947-2011**		
Bond Income Returns:	**Equity Returns**	**Bond Income Returns**	**Risk Premium**	**Equity Returns**	**Bond Income Returns**	**Risk Premium**
Below 4%	13.9%	3.2%	10.7%	17.9%	3.3%	14.7%
Below 5%	12.6%	3.7%	8.9%	13.8%	3.6%	10.2%
Below 6%	11.1%	4.2%	7.0%	11.6%	4.4%	7.2%
Below 7%	11.3%	4.3%	7.0%	11.9%	4.6%	7.3%
Below 8%	11.8%	4.6%	7.3%	12.6%	4.9%	7.6%
Below 9%	10.9%	4.9%	5.9%	11.0%	5.4%	5.6%
All Observations	11.4%	6.0%	5.4%	11.8%	6.7%	5.0%

Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2010; TSX Review*.

Table 9 above indicates that, except at the lowest levels of long-term Government of Canada bond income returns, average equity returns have been broadly in the range of approximately 11.0% to 12.5% during the two periods. At bond income returns below 8% (average of 4.5% to 5.0%), the corresponding equity risk premium averaged approximately 7.25% to 7.5%. Only when the highest levels of bond income returns are included do the average achieved equity risk premiums drop to approximately 5.5% to 6.0% and then to approximately 5.0% to 5.5%. In

[57] The long-term Government of Canada bond yield is equivalent to an estimate of the expected return on the bond.
[58] Slope coefficients of trend lines fitted to the annual equity return data for the periods 1924-2011 and 1947-2011 are estimated at 0.00 for both periods.

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 3.25% to 3.5% 30-year Canada bond yield for 2012-2013 is approximately 2.5 to 2.75 percentage points lower than the long-term average bond income return (6.0%) and approximately 3.25 to 3.5 percentage points lower than the post-World War II average bond income return (6.7%). The 2012-2013 forecast long-term Government of Canada bond yield of 3.25% to 3.5% suggests an equity risk premium, based on historical risk premiums at similar levels of interest rates, of no less than 8.0%.

3.b.(iv) Impact of Inflation on Equity Market Returns[59]

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 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 Canada was higher than the rate of inflation currently forecast to prevail over the longer term. The arithmetic average CPI rate of inflation from 1926-2011 in Canada was 3.0%; the most recent consensus long-term (2014-2021) forecast of CPI inflation is 2.0%.[60] 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 10 below summarizes the nominal and real rates of equity market returns historically at different levels of CPI inflation.

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[59] 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.

[60] Consensus Economics, *Consensus Forecasts*, October 2011.

Table 10

Inflation Range	Nominal Equity Return	Average Rate of Inflation	Real Equity Return
Less than 1%	15.7%	-1.4%	17.0%
1-3%	12.4%	1.9%	10.4%
3-5%	4.8%	4.1%	0.7%
Over 5%	12.5%	9.2%	3.3%
Avg. 1924-2011	11.4%	3.0%	8.4%

Source: Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2010;* 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 11.4% over the longer-term and 11.8% since the end of World War II, or approximately 11.5% to 11.75%.

It also bears noting that, while the average real equity return in Canada over the longer period was 8.4%, the average is materially affected by the inclusion of high inflation years. When years in which inflation exceeded 10% are excluded (seven of 88 observations), the average real equity return is a full percentage point higher, i.e., 9.4%. The corresponding average rate of CPI inflation was 2.3%, similar to the forecast rate of inflation. The average real equity return is similar, at approximately 9.5%, when the years in which inflation exceeded 10% and the same number of abnormally low inflation years (average of -4.1%) are removed. At a real equity return of 9.5% and an inflation rate of 2.0%, the indicated nominal equity return is approximately 11.5%. At a nominal equity return of 11.5%, the market equity risk premium at the near-term forecast long-term Canada bond yield of 3.25% to 3.50% is 8.0% to 8.25%.

3.b(v) 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 11.5% to 12.25% (see Table 7 above).

Despite relatively similar equity market returns, the achieved risk premium (equity market returns less bond income returns) in Canada has been approximately 1.2% to 1.4% lower than in the U.S. The difference in the equity market returns accounts for 0.4% to 0.5% of the difference in the observed risk premiums. Approximately two-thirds of the difference is attributable to higher bond yields 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 2011, 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 -16 basis points.[61]

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 1926-2011 and post-World War II (1947-2011) for the two countries.

[61] The October 2011 *Consensus Forecasts* anticipate that the 10-year Canada bond yield will be, on average, approximately 0.30% lower than the yield on 10-year U.S. Treasury bond from 2014-2021.

Table 11

	Canada			United States		
	Arithmetic Average	Standard Deviation	Compound Average	Arithmetic Average	Standard Deviation	Compound Average
1926-2011	11.2%	18.9%	9.6%	11.8%	20.3%	9.8%
1947-2011	11.8%	17.1%	10.4%	12.3%	17.4%	10.9%

Source: Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2010*, Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2011 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, 1926-2011, 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 both Canada and the U.S. was approximately 1.4%. 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 the same in the U.S. and in Canada. In sum, the differences are *de minimus*.[62]

With similar government bond yields in the two countries for more than a decade, U.S. historical equity market risk premiums are a relevant benchmark for the estimation of the forward-looking

[62] Since the onset of the financial crisis (August 2007) to the end of January 2012, the two markets have exhibited similar volatility; the standard deviations of weekly price changes in the S&P/TSX Composite (Canada) and the S&P 500 (United States) have been virtually identical.

equity market risk premium for Canadian investors. As shown in Table 7 above, the average achieved equity risk premium relative to bond income returns in the U.S. has been approximately 6.5%. Similar to Canada, however, as demonstrated in Table 12 below, higher risk premiums have been associated with lower bond income returns.

Table 12

Bond Income Returns:	Averages for the Period: 1926-2011			Averages for the Period: 1947-2011		
	Equity Returns	Bond Income Returns	Risk Premium	Equity Returns	Bond Income Returns	Risk Premium
Below 4%	13.9%	2.9%	11.0%	19.0%	2.9%	16.1%
Below 5%	11.9%	3.3%	8.6%	13.2%	3.6%	9.6%
Below 6%	11.1%	3.6%	7.5%	11.7%	4.0%	7.6%
Below 7%	10.7%	3.9%	6.8%	11.0%	4.4%	6.6%
Below 8%	10.7%	4.4%	6.3%	10.9%	5.0%	6.0%
Below 9%	11.3%	4.7%	6.6%	11.7%	5.3%	6.4%
All Observations	11.8%	5.2%	6.6%	12.3%	5.9%	6.4%

As Table 12 shows, the 6.6% average historical equity risk premium corresponds to an average bond income return of 5.2%, approximately 2.0 percentage points higher than the 2012-2013 forecast 3.25% to 3.50% 30-year Canada bond yield. The experienced equity risk premium at levels of bond income returns similar to the 2012-2013 forecast 30-year Canada bond yield was in the range of approximately 7.5% to 9.5%.

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,[63] and the observed negative relationship between real equity returns and inflation, a reasonable estimate of the expected value of the nominal equity market return is approximately 11.5%, based on Canadian equity market returns and supported by U.S. equity market returns. Over the longer-term, the expected return on 30-year Canada bonds is approximately 5.0%, corresponding to an equity risk premium of approximately 6.5%. However, in the near-term, 30-year Canada bond yields are forecast at

[63] The P/E ratio analysis is included in Appendix A.

approximately 3.25% to 3.50%, approximately 1.5% to 1.75% below “normal”. The analysis of both Canadian and U.S. equity risk premiums in conjunction with bond income returns supports a market equity risk premium of no less than 8.0% at a forecast 30-year Canada bond yield of 3.25% to 3.50%, corresponding to an expected equity market return of 11.25% to 11.50%.

3.c. Relative Risk Adjustment

3.c.(i) Overview

The market risk premium result needs to be adjusted to recognize the relative risk of an average risk Canadian utility, e.g., Newfoundland Power. 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.

Impediments to reliance on the equity beta as the sole relative risk measure 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;

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; and,

5. Utilities are not investing in a portfolio of securities. They are committing capital to long-term assets. Once the capital is committed, it cannot be withdrawn and redeployed elsewhere.

Thus, a risk measurement that reflects those considerations is relevant for estimating the equity risk premium applicable to an average risk Canadian utility.

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 utility. The absence of an observable relationship between "raw" betas and the achieved market returns on equity in the Canadian market[64] 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 an average risk Canadian 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 2011 (Schedule 9).

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 <u>relative</u> 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 9 shows the ratios of the standard deviations of the Utilities Index to those of the 10 S&P/TSX

[64] See Appendix A.

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 an average risk Canadian utility in the range of 0.55-0.85, with a central tendency of approximately 0.65-0.70.

3.c.(iii) Historical "Raw" Betas of Canadian Utilities

Schedule 12, pages 1 to 3 summarizes "raw"[65] betas calculated using monthly and weekly price changes[66] for the five major[67] publicly-traded Canadian regulated utility holding companies, the TSE Gas/Electric Index, and the S&P/TSX Utilities Sector.[68]

As Schedule 12, page 1 indicates, there was a significant decline in the calculated "raw" monthly five-year betas of the individual regulated Canadian companies between 1994-1998 and 1999-2005 (from approximately 0.50 to 0.0 and slightly negative). Following an increase in 2007 to slightly above 0.50, the "raw" monthly betas for the individual regulated Canadian companies again declined in 2008 to approximately 0.20 and have remained at a similar level through the end of 2011.

The observed levels and pattern of the calculated "raw" utility betas in 1999-2011 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

[65] The term "raw" means that the beta is simply the result of a single variable ordinary least squares regression.
[66] 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) betas for Canadian utilities showed that there was no material difference between the two.
[67] Canadian Utilities Limited, Emera Inc., Enbridge Inc., Fortis Inc., and TransCanada Corporation.
[68] 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.

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.[69]

There can be significant differences in measured "raw" 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.[70] Table 13 below shows that, for the five large publicly-traded Canadian utilities whose shares are regularly traded, the mean and median five-year betas ending December 2008 to December 2011 calculated using weekly price changes were twice as high as the corresponding mean and median betas calculated using monthly price changes.

Table 13

	Weekly Data	
	Mean	**Median**
2008	0.46	0.45
2009	0.43	0.44
2010	0.44	0.44
2011	0.45	0.44
	Monthly Data	
	Mean	**Median**
2008	0.25	0.21
2009	0.22	0.20
2010	0.23	0.21
2011	0.21	0.21

[69] Schedule 10 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 five-year monthly 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.

[70] There is no theoretically correct time interval for calculations of betas. Betas are frequently, but not exclusively, measured over five years using monthly price change intervals (60 observations). For example, Bloomberg calculates betas over three-year periods using weekly price change intervals (156 observations) whereas *Value Line*, which also utilizes weekly prices, estimates the beta over a period of 2.5 to 5 years (over 250 observations). The measurement of betas over a five-year period is simply a convention. In *Modern Portfolio Theory, The Capital Asset Pricing Model & Arbitrage Pricing Theory: A User's Guide* (Second Edition, Prentice-Hall, 1987), the author, Dr. Diana Harrington, noted that the CAPM itself provides no guidance with respect to the choice of a measurement horizon; the five-year estimation period (i.e., 60 monthly observations) became widely used because of the availability of monthly data in computer-readable form, and the need for a reasonably sized sample.

3.c.(iv) Canadian Regulated Company Returns and "Raw" Betas

The equity betas of traded Canadian utility company shares and of the S&P/TSX Utilities Index explain a relatively small percentage of the actual achieved market returns over time. The following analysis 1) estimates how much of the historical utility market returns can be explained by the equity market, long-term Government of Canada bonds and other factors and 2) uses these relationships to assist in the determination of an appropriate estimate of the required relative risk adjustment.

A regression of the monthly returns on the TSX Utilities Index against the returns on the TSX Composite, for example, over the period 1970-2011[71] shows the following:

Table 14

Monthly TSX Utilities Index Return	=	0.0060 +	0.47	$\left\{ \text{Monthly TSE Composite Return} \right\}$
t-statistic	=		13.8	
R^2	=	28%		

The relationship quantified in the above equation suggests a long-term utility beta of 0.47, or approximately 0.50. 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.[72]

[71] The Monthly TSX Utilities Index Returns are comprised of the monthly returns on the TSE Gas & Electric Index for the period January 1970 to April 2003 and the monthly returns on the S&P/TSX Utilities Index for the period May 2003 to December 2011.

[72] As shown in Schedule 12, page 2 of 2, the R^2s of the monthly betas for individual Canadian utilities calculated over five-year periods ending 2004 to 2011 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 five-year "raw" monthly and weekly betas ending December 2011 of Canadian Utilities Limited, at 0.03 and 0.38 respectively, are 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.

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:

Table 15

$$\begin{array}{c} \text{Monthly TSX} \\ \text{Utilities Index} \\ \text{Return} \end{array} = 0.0026 + .41 \left\{ \begin{array}{c} \text{Monthly TSE} \\ \text{Composite} \\ \text{Return} \end{array} \right\} + .47 \left\{ \begin{array}{c} \text{Monthly} \\ \text{Long Canada} \\ \text{Bond Return} \end{array} \right\}$$

$$\begin{array}{lll} \text{t-statistics} & = & \qquad\quad 12.6 \qquad\qquad\qquad\qquad 8.7 \\ R^2 & = & 37\% \end{array}$$

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 market return for the utilities index from 1970-2011 was 12.7%. 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.[73]

To assess whether this unexplained component of the utility returns arises from a downward trend in utility risk over the period 1970-2011, I analyzed the trend in the relative total volatility of the S&P/TSX Utilities Index, measured by the ratio of five-year monthly standard deviations of the total market returns of the Utilities Index to those of Composite. The results of the analysis indicated that, although the relative volatility was not constant throughout the period, there has not been a statistically significant trend up or down in the relative total risk of the Utilities Index compared to the Composite over the period 1970-2011.

[73] 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%.

The objective of the relative risk adjustment is to predict the investors' required or expected return. To do so, the persistent large unexplained component of the achieved utility return, as reflected in the equation's intercept, should be explicitly accounted for. The use of the calculated "raw" Canadian betas alone as an estimate of the relative risk adjustment, without consideration of the value of the intercept, will result in the underestimation of expected utility returns. [74]

Using the regression equation in Table 15 (including the intercept), and current estimates of the market return and the long-term Canada bond return, the expected utility return can be estimated two ways. First, at an expected annual equity market return of 11.5% (as developed in Section VI.E.3.b above), a 30-year Canada bond return of 5.0% (equal to the 5.0% yield forecast for the longer term), and the 3.2 percentage point annual historical average "unexplained" utility return represented by the equation intercept, the indicated expected utility return is 10.2%.[75]

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%[76]). In this case, the expected utility return is 9.4%.[77] The average of the two utility return estimates is 9.8%; the corresponding utility risk premium above the longer term forecast 30-year Canada bond yield of 5.0% is 4.8%. The indicated longer-term market equity risk premium using the expected equity market return estimate of 11.5% and longer-term 30-year Canada bond return of 5.0% is 6.5%. The resulting utility relative risk adjustment is 0.73.[78]

[74] The explicit recognition of the unexplained component of the return is consistent with the empirical observation that low beta stocks, including, but not limited to, utilities have historically earned returns higher than the CAPM predicts, with the converse observed for high beta stocks.

[75] 10.2% = 3.2% + (0.41 x 11.5%) + (0.47 x 5.0%).

[76] 3.2%/12.7% ≈ 25%, where the 12.7% represents the average actual annual return on the TSX Utilities Index from 1970 to 2011.

[77] 9.4% = ((0.41x 11.5%) + (0.47 x 5.0%))/ (1-25%).

[78] $\frac{9.8\% - 5.0\%}{11.5\% - 5.0\%} = 0.73$

Alternatively, the utility return can be estimated using the Treasury bill, rather than the 30-year Canada bond, as the risk-free rate. This approach results in the following equation:

Table 16

$$\text{Monthly TSX Utilities Index Return} = 0.0075 + .40\left\{\begin{array}{c}\text{Monthly TSE}\\\text{Composite}\\\text{Excess Return}\\\text{over T-bills}\end{array}\right\} + .46\left\{\begin{array}{c}\text{Monthly Excess}\\\text{Long Canada}\\\text{Bond Return}\\\text{over T-bills}\end{array}\right\}$$

t-statistics	=	12.4	8.6
R^2	= 37%		

In this equation, the market equity risk premium is equal to the return on the equity market composite less the Treasury bill return and the long-term Canada bond risk premium is equal to the return on the long-term Canada bond less the Treasury bill return, or maturity premium. The intercept in the equation in Table 16 is the sum of the historical monthly return on 90-day Treasury bills plus the portion of the monthly utility return that is unexplained by either the equity or the long-term government bond market. As in Table 15, the equation intercept is a monthly number. When annualized, the intercept equals approximately 9.4%. Since the average annualized Treasury bill return over the period of analysis (1970-2011) was 7.0%, there remains an annualized return of 2.5% which is unexplained by either the equity or government bond market.

Solving the equation with expected values of the equity market return (11.5%), the long-term Canada bond return equal to the expected yield on the long Canada bond over the longer-term (5.0%) and a corresponding Treasury bill return of 3.75% (equal to the long-term Canada bond return less the approximate average historical spread, or maturity premium, between long and short term government rates of 1.25%), plus the unexplained return, the indicated utility return is equal to 9.9%.

Utility Return = Unexplained Return + Treasury bill yield +
(Equity Beta X Equity Market Risk Premium relative to T-bill) +
(Bond Market Beta X Maturity Premium)

Utility Return = 2.5% + 3.75% +.40 (11.5%-3.75%) + .46 (5.0%-3.75%) = 9.9%

As with the earlier approach, the prospective unexplained component of the utility return can be also estimated to be in the same proportion to the total utility return as was the case historically (approximately 20%[79]). In this case, the expected utility return is 9.25%.[80] The average of the two utility return estimates is 9.6%; the corresponding utility risk premium above the Treasury bill yield of 3.75% is 5.8%. The indicated market risk premium using the same equity market return estimate of 11.5% and Treasury bill yield of 3.75% is 7.75%. The resulting utility relative risk adjustment is 0.75, virtually identical to the 0.73 estimate obtained using the equation in Table 15.[81]

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.[82]

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.

[79] 2.5%/12.7% ≈ 20%.

[80] 9.25% = (3.75% + (0.40*7.75%) + (0.46*1.25%))/ (1-20%).

[81] $\frac{9.6\% - 5.0\%}{11.5\% - 5.0\%} = 0.75$

[82] See Appendix A, page A-18.

Their methodologies give approximately 2/3 weight to the calculated "raw" beta and 1/3 weight to the equity market beta of 1.0. While the rationale for the specific adjustment formula reflects the tendency for betas in general to drift toward the market mean beta of 1.0, the adjustment is also justified on the grounds that the adjusted betas are better predictors of returns than "raw" betas.

The following table compares recent reported Bloomberg betas (calculated using three years of weekly prices)[83] for the five major Canadian utilities to calculated "raw" weekly betas for a 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 0.62 to 0.67. The application of the same adjustment formula used by Bloomberg to the long-term calculated "raw" beta of 0.47 for the TSX Utilities Index shown in Table 14 above results in a relative risk adjustment of 0.65.[84]

Table 17

Company	**"Raw" Weekly Beta**	**Bloomberg Beta**
Canadian Utilities Ltd.	0.30	0.58
Emera Inc.	0.49	0.72
Enbridge Inc.	0.33	0.62
Fortis Inc.	0.50	0.82
TransCanada Corp.	0.37	0.62
Average	**0.40**	**0.67**
Median	**0.37**	**0.62**

Source: www.yahoo.com and www.bloomberg.com

A comparison of the betas reported by the widely disseminated *Value Line*[85] to the "raw" calculated betas for the sample of low risk U.S. utilities relied upon in the application of the DCF and DCF-based risk premium tests shows a similar relationship. While the "raw" calculated weekly betas for the five-year period ending December 31, 2011 averaged approximately 0.55[86],

[83] The Canadian utilities' betas were retrieved from www.bloomberg.com on February 2, 2012.
[84] Adjusted beta = 0.67 x "Raw" Beta + 0.33 x Market Beta of 1.0.
[85] *Value Line* uses a five-year horizon and a weekly price change interval.
[86] 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 (e.g., weekly versus monthly, as noted above) and the market index selected

the 4th Quarter 2011 betas reported by *Value Line* averaged approximately 0.70 for the sample (Schedule 13, page 1 of 2).

3.c.(vi) Relative Risk Adjustment

A summary of the results of the preceding analysis is set out in the table below:

Table 18

Relative Risk Indicator	**Relative Risk Factor**
Total Market Risk (Standard Deviations)	0.65-0.70
Relative Historic Returns and Betas: Canadian Utilities	0.73-0.75
Recent Adjusted Beta: Canadian Utilities	0.62-0.67
Long-term Adjusted Beta: Canadian Utilities Index	0.65
Value Line Beta: Low Risk U.S. Utility Sample	0.70

These results support a relative risk adjustment for an average risk Canadian utility in the approximate range of 0.65-0.70.

3.d. Risk-Adjusted Equity Market Risk Premium Test Results

The equity market risk premium was previously estimated to be 8.0% at the 2012-2013 forecast 30-year Government of Canada bond yield of 3.25% to 3.5%. At an equity market risk premium of 8.0% and a relative risk adjustment of 0.65-0.70, the indicated equity risk premium for an average risk Canadian utility, e.g. Newfoundland Power, is in the range of approximately 5.2% to 5.6%. Based on the risk-adjusted equity market risk premium test, the corresponding cost of equity is in the range of approximately 8.5% to 9.1% (mid-point of 8.8%).

(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 low risk U.S. utility sample.

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 equity risk premium test was applied to a sample of U.S. low risk utilities.[87] The DCF-based equity risk premium test was applied only to the sample of U.S. low risk utilities, because its application requires a history of consensus long-term earnings growth rate forecasts, which is not available for Canadian utilities.[88]

A key advantage of the DCF-based equity 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).[89] In the application of this test, relationships between utility risk premiums, long-term government bond yields, the spread between the yields on long-term utility and government bond yields and utility bond yields were examined.

[87] The selection criteria for the sample of U.S. utilities to which the DCF-Based Equity Risk Premium Test was applied are found in Appendix B.

[88] Analysts' forecasts of long-term earnings growth for Canadian utilities are currently accessible, which permits the application of the DCF test to Canadian utilities. However, there is no readily accessible history of those forecasts which would permit the application of the DCF-based equity risk premium test to a sample of Canadian utilities.

[89] Of the three equity risk premium tests conducted, 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.

4.b. 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 U.S. low risk utilities in the sample from 1998-2011.[90] The construction of the monthly constant growth DCF costs of equity and the corresponding equity risk premiums is described in Appendix D.

For the sample of U.S. low risk utilities, the constant growth DCF-based equity risk premium test indicates that the average 1998-2011 utility risk premium was 5.1%, corresponding to an average long-term government bond yield of 4.9%. The data also show that the risk premium averaged 4.8% when long-term government bond yields were 6.0% or higher and 6.8% when long-term government bond yields were below 4.0%.

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 1998-2011 constant growth analysis.

Table 19

Government Bond Yield	**Below 4.0%**	**4.0%-5.0%**	**5.0%-6.0%**	**Above 6.0%**
Utility Equity Risk Premium	6.8%	5.2%	4.7%	4.8%

Source: Schedule 14, 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.

[90] The period 1998-2011 coincides with the years during which long-term Canada and U. S. Treasury bond yields have been broadly similar.

4.c. Three-Stage DCF-Based Equity Risk Premium Test

The DCF-based risk premium test was also applied using a three-stage DCF model. The construction of the monthly three-stage DCF cost of equity estimates is described in Appendix D. 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 constant growth analysis.[91] Based on the three stage growth model, the average utility equity risk premium was 5.2% at an average 30-year government bond yield of 4.9%. 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 1998-2011 three-stage growth analysis.

Table 20

Government Bond Yield	Below 4.0%	4.0%-5.0%	5.0%-6.0%	Above 6.0%
Utility Equity Risk Premium	6.6%	5.3%	4.8%	4.6%

Source: Schedule 14, page 3 of 4.

4.d. Relationships between Equity Risk Premiums and Interest Rates

Using both the constant growth and three-stage growth DCF models, the relationship between 30-year government bond yields (independent variable) and the corresponding utility equity risk premiums (dependent variable) was tested. The analysis indicated that, based on the constant growth model, over the 1998-2011 period, on average, 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 75 basis points.[92] The results using the three-stage model were similar, i.e., a 67 basis point increase (decrease) in the utility equity risk premium for every 100 basis point decrease (increase) in the long-term government bond yield. In effect, this specific

[91] The standard deviation of the monthly sample I/B/E/S growth rates is approximately 0.5; the standard deviation of the monthly implied growth rates utilized in the three-stage DCF-based risk premium analysis is approximately 0.3.

[92] Expressed in terms of cost of equity, the cost of equity, as measured by the DCF-based equity risk premium test, increases (decreases) by 25 basis points for every one percentage point increase (decrease) in the long-term government bond yield.

analysis indicates that utility equity risk premiums are much more sensitive to, and the corresponding utility cost of equity much less sensitive to, long-term government bond yields than has been assumed by the automatic ROE adjustment formula first adopted by the PUB in 1998. That formula, which is similar to those that have been suspended, rescinded or significantly revised by other Canadian regulators, assumes that the utility equity risk premium increases/decreases by 20 basis points for every one percentage decrease/increase in the long-term Government of Canada bond yield.[93]

The table below sets out the utility equity risk premium at various levels of long-term government bond yields based on the regressions which used long-term government bond yields as the single independent variable.

Table 21

Government Bond Yield	3.0%	4.0%	5.0%	6.0%	7.0%
Utility ERP:					
Constant Growth	6.6%	5.8%	5.1%	4.3%	3.6%
Three-stage Growth	6.5%	5.8%	5.1%	4.5%	3.8%

The analysis demonstrates 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.

Based on this relationship, over the 1998-2011 period, at the 2012-2013 forecast 30-year government bond yield of 3.25% to 3.5%, the indicated utility equity risk premium is approximately 6.25%. The corresponding utility cost of equity is 9.6%.

[93] The National Energy Board rescinded its automatic adjustment formula in October 2009. The Alberta Utilities Commission suspended its formula in November 2009 and opted not to reinstate a formula in its December 2011 Generic Cost of Capital Decision. The British Columbia Utilities Commission terminated its automatic adjustment formula in December 2009. The Ontario Energy Board significantly revised its automatic adjustment formula in December 2009, lowering the sensitivity of the allowed ROE to changes in long-term Canada bonds from 75% to 50% and adding a second explanatory variable, the spread between 30-year A-rated utility and Government of Canada bond yields, with a sensitivity factor of 50%. The OEB also reset the benchmark ROE. The Régie de l'énergie du Québec continues to apply a 75% sensitivity factor to changes in long-term Government of Canada bond yields, but has added the same spread variable as in the OEB's revised formula with the same 50% sensitivity factor.

The single independent variable analysis reflects only the relationship between the equity risk premium and government bond yields to the exclusion of other factors which impact on 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.[94] In the two independent variable regression analysis, government bond yields and the spread between long-term A-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, over the 1998-2011 period, the constant growth analysis showed that the utility equity risk premium increased or decreased by approximately 85 basis points when the government bond yield decreased or increased by 100 basis points and increased or decreased by approximately eleven basis points for every ten basis point increase or decrease in the utility/government bond yield spread (Schedule 14, page 2 of 4). The three-stage growth DCF model indicates that the utility equity risk premium increased or decreased by just under 75 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.[95]

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[94] Examples include: N.F. Chen, R. Roll, and S. A. Ross, "Economic Forces and the Stock Market", *Journal of Business*, Vol. 59, No. 3, July 1986, pages 383-403 and R.S. Harris and F.C. Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts, *Financial Management*, Summer 1992, pages 63-70.

[95] The two independent variables can be collapsed into a single independent variable, the long-term A-rated utility bond yield. That analysis shows the utility equity risk premium rising and falling by approximately 50% (60%) of the change in the A-rated utility bond yield using the constant growth (three-stage growth) model.

As an alternative test of the relationships, quarterly ROEs allowed for U.S. utilities[96] 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 1998 to 2011 were regressed against long-term Treasury bond yields lagged by six months.[97] The result indicated that the utility equity risk premium increased or decreased by approximately 45 basis points for every one percentage point decrease or increase in long-term government bond yields.

When long-term A-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 27 basis points for every one percentage point increase or decrease in the long-term A-rated utility/government bond yield spread.

Collapsing the two independent variables into a single variable, long-term A-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 just over 55 basis points for every one percentage point increase (decrease) in the A-rated utility bond yield.[98]

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[96] The analysis was not performed for Canadian utilities due to the widespread use of formulas that specified the relationship between government bond yields and allowed ROEs. Thus, the analysis would provide no independent estimate of the relationship.

[97] 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.

[98] Details of all the regressions are found in Schedules 14 and 15.

4.e. DCF-Based Equity Risk Premium Test Results

The regressions were solved using the 3.25% to 3.5% forecast 30-year Canada bond yield. For the 30-year A-rated utility/Government of Canada bond yield spread, the end of January 2012 spread of 1.45% was used.[99]

The table below summarizes the estimated relationships among equity risk premiums, long-term government bond yields and utility/government bond yield spreads applying the various models to the U.S. utility sample over the 1998-2011 period and the resulting equity risk premiums and costs of equity at a forecast long-term Canada bond yield of 3.25% to 3.5% (mid-point of 3.375%) and a long-term A rated utility/government bond yield spread of 1.45%.

Table 22

	Coefficients		**Equity Risk Premium**	**Cost of Equity**
	Government Bond	**Bond Yield Spread**		
Constant Growth				
Single Variable	-0.75	n/a	6.3%	9.6%
Two Variable	-0.84	1.13	6.2%	9.6%
Three-Stage Growth				
Single Variable	-0.67	n/a	6.2%	9.6%
Two Variable	-0.73	0.70	6.2%	9.6%
Allowed ROEs				
Single Variable	-0.45	n/a	6.4%	9.8%
Two Variable	-0.46	0.27	6.4%	9.8%

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.
Sources: Schedules 14 and 15.

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.

[99] Represents the spread between the yields on the Bloomberg A-rated Canadian Utility 30 Year Index and the benchmark long-term Government of Canada bond.

Table 23 below summarizes the regression results using an A-rated bond yield of 4.8% (equal to the forecast 30-year Canada bond yield of 3.25% to 3.5% plus a spread of 1.45%):

Table 23

Model	Coefficient	Risk Premium over A-Rated Bond Yield	Cost of Equity
Constant Growth DCF	-0.47	4.3%	9.1%
Three-Stage DCF	-0.57	4.6%	9.4%
Allowed ROEs	-0.57	5.1%	9.9%

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, as the allowed ROEs do not represent my estimates of the cost of equity. Nevertheless, that analysis provides support for the conclusion that the utility cost of equity does not track government bond yields nearly to the extent that has been embedded in most of the automatic adjustment formulas that have been used in Canada.

Based on the DCF-based regression analyses, at the forecast 30-year Canada and A-rated utility bond yields, the indicated utility cost of equity is in the range of approximately 9.1% to 9.6%, and approximately 9.5% based on all the DCF-based risk premium models.

5. Historic Utility Equity Risk Premium Test

5.a. Overview

The historic experienced returns for utilities provide an additional perspective on a reasonable expectation for the forward-looking utility equity risk premium. Similar to the DCF-based equity 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. Historic Returns and Risk Premiums

As shown in Table 24 below, over the longest term available (1956-2011),[100] the average achieved utility (gas and electric combined) equity risk premiums in Canada were 4.2% and 4.8% in relation to total and income returns for long-term Government of Canada bonds respectively.[101] For U.S. electric utilities, the average historic equity risk premiums in relation to total and income returns on bonds over the entire post-World War II period (1947-2011) were 4.4% and 5.1%. For U.S. gas utilities, the corresponding average historic equity risk premiums in relation to total and income returns on bonds were 5.3% and 6.0% respectively.

Table 24

	Utility Equity Returns	Bond Total Returns	Bond Income Returns	Risk Premium Over: Bond Total Returns	Risk Premium Over: Bond Income Returns
Canadian Utilities	12.1%	7.9%	7.3%	4.2%	4.8%
U.S. Electric Utilities	11.0%	6.6%	5.9%	4.4%	5.1%
U.S. Gas Utilities	11.9%	6.6%	5.9%	5.3%	6.0%

Source: Schedule 16.

5.c. Trends in Equity Returns and Bond Returns

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 16, 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 7.3% to

[100] The longest period for which Canadian utility index data are available from the Toronto Stock Exchange.
[101] Based on the Gas/Electric Index of the TSE 300 from 1956 to 1987 and on the S&P/TSX Utilities Index from 1988-2011.

7.9%, were materially higher than the yields on 30-year Canada bonds forecast for both the near-term (3.25% to 3.5%) and over the longer-term (5.0%).

A reasonable approach to interpreting the historical utility equity market return data is the recognition of the inverse relationship between utility equity risk premiums and government bond yields. Table 25 derives estimates of the utility equity risk premium for the longer term from the historical average risk premiums by applying a 50% sensitivity factor to the difference between the historical average bond income returns and the forecast Government of Canada bond yield forecast. A 50% sensitivity factor comports with the lower end of the range of the sensitivities of utility risk premiums to government bond yield changes estimated in Section VI.E.3.c above.

Table 25

		Canadian Utilities	**U.S. Electric Utilities**	**U.S Gas Utilities**
Equity Returns	(1)	12.1%	11.0%	11.9%
Bond Income Returns	(2)	7.3%	5.9%	5.9%
Risk Premium (RP)	(3) = (1) – (2)	4.8%	5.1%	6.0%
Forecast 30-Year Canada Bond Yield (LCBY)	(4)	3.25-3.5%	3.25-3.5%	3.25-3.5%
Change in Bond Yield/Return	(5) = (4) – (2)	-3.9%	-2.5%	-2.5%
Change in Equity RP	(6) = – (5) X 50%	+2.0%	+1.25%	+1.25%
Equity Risk Premium at 5.0% LCBY	(7) = (3) + (6)	6.75%	6.35%	7.25%

Source: Schedule 16, page 1 of 3.

At the forecast 30-year Canada bond yield of 3.25% to 3.5% and a 50% sensitivity factor between utility equity risk premiums and long-term government bond yields, the indicated longer-term utility equity risk premium derived from historical averages is in the approximate range of 6.25% to 7.25% (mid-point of estimates of approximately 6.75%).

5.d. Historic Utility Equity Risk Premium Test Results

Recognizing the inverse relationship between utility equity risk premiums and long-term government bond yields, the historic utility equity risk premium approach indicates a utility equity risk premium of approximately 6.75% at the forecast 30-year Canada bond yield of 3.25% to 3.5%. The corresponding utility cost of equity is approximately 10.0% to 10.25%.

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 summarized below:

Table 26

Risk Premium Test	Cost of Equity
Risk-Adjusted Equity Market	8.8%
DCF-Based	9.5%
Historic Utility	10.0% - 10.25%

Giving equal weight to all three equity risk premium tests, the indicated utility cost of equity is approximately 9.5%.

F. DISCOUNTED CASH FLOW TEST[102]

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

[102] See Appendix C for a more detailed discussion.

estimates the cost of equity indirectly. The DCF model is widely used to estimate the utility cost of equity for the purpose of establishing the allowed ROE.

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[103]

$\mathbf{P_o}$ = 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. Application of the DCF Test

2.a. DCF Models

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 the sample of U.S. electric and gas utilities selected to serve as a proxy for Newfoundland Power (the same sample used in the DCF-based equity risk premium test), as well as to a sample of Canadian utilities.

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

2.b. Growth Estimates

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 sample of proxies, rather than the subject company. When the subject company does not have traded shares, a sample of proxies is required.[104]

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: Bloomberg, 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, as some studies have concluded that analysts' earnings growth forecasts are optimistic. 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.

[104] 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. Utilities

The constant growth model applied to the U.S. utility sample using the consensus of analysts' long-term earnings growth forecasts indicates a cost of equity of approximately 9.4% (Schedule 17). The utility cost of equity based on the sustainable growth model is approximately 8.6% (Schedules 17 and 18).

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. utilities indicates a cost of equity of approximately 9.1% (Schedule 19).

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.[105] The application of the constant growth model to a sample of five Canadian utilities indicated a cost of equity of approximately 11.7%; see Schedule 20. The cost of equity developed using the three-stage model indicates a cost of equity of approximately 8.8%; see Schedule 21.

[105] For the Canadian utilities (Canadian Utilities Limited, Emera Inc., Enbridge Inc., Fortis Inc., and TransCanada Corporation), the consensus long-term earnings growth forecasts were obtained from Reuters, as it provided the highest number of analysts' forecasts for each company. 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.

3.c. DCF Cost of Equity

The table below summarizes the results of the DCF models applied to both the U.S. and Canadian utility samples.

Table 27

	Constant Growth		
	Analysts' EPS Forecasts	**Sustainable Growth**	**Three-Stage Model**
U.S. Utilities	9.4%	8.6%	9.1%
Canadian Utilities	11.7%	N/A	8.8%

Source: Schedules 17-21.

The constant growth and three-stage DCF models applied to the U.S. sample indicate a utility cost of equity of approximately 9.0%. For the Canadian utilities, the higher long-term earnings growth forecasts in conjunction with lower dividend yields lead to a wider range of DCF test results than for the U.S. utilities. Based on the mid-point of the range of the constant growth and three-stage models, the cost of equity for the Canadian utility sample is approximately 10.25%. The application of both constant growth and three-stage models to the two samples supports a DCF cost of equity of approximately 9.5%.

G. ALLOWANCE FOR FINANCING FLEXIBILITY[106]

The equity risk premium tests (Section VI.E) and discounted cash flow tests (Section VI.F) both indicate a "bare-bones" cost of equity for Newfoundland Power of approximately 9.5%. 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.

[106] See Appendix E for a more complete discussion.

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.[107]

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.[108] 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

[107] The market to book ratio of the S&P 500 includes Utilities. The market to book ratio of the S&P Industrials alone has been higher.
[108] Based on the DCF model as shown in Appendix E, footnote 2.

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 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 150 basis points (See Appendix E).

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 150 basis points. The addition of an allowance for financing flexibility of 50 to 150 basis points to the "bare-bones" return on equity estimate of 9.5%, derived from the equity risk premium and DCF tests, results in an estimate of the fair return on equity for Newfoundland Power of approximately 10.5%.

H. COMPARABLE EARNINGS TEST

The comparable earnings test provides a measure of the fair return based on the concept of opportunity cost. Specifically, the test arises from the notion that capital should not be committed to a venture unless it can earn a return commensurate with that available prospectively in alternative ventures of comparable risk. Since regulation is a surrogate for competition, the opportunity cost principle entails permitting utilities the opportunity to earn a return commensurate with the levels achievable by competitive firms facing similar risk. The comparable earnings test, which measures returns in relation to book value, is the only test that can be directly applied to the equity component of an original cost rate base without an adjustment to correct for the discrepancy between book values and current market values. Neither the equity risk premium results nor the DCF results, if left without adjustment, recognizes the discrepancy. The 50 basis point financing flexibility adjustment that has typically been adopted by Canadian regulators only minimally addresses the discrepancy.

The comparable earnings test is an implementation of the comparable returns standard, as distinguished from the cost of attracting capital standard. The comparable earnings test recognizes that utility costs are measured in vintaged dollars and rates are based on accounting costs, not economic costs. In contrast, the tests for estimating the cost of attracting capital rely on costs expressed in dollars of current purchasing power, i.e., a market-related cost of capital. In the absence of experienced inflation, the two concepts would be quite similar, but the impact of inflation has rendered them dissimilar and distinct.

The concept that regulation is a surrogate for competition may be interpreted to mean that the combination of an original cost rate base and a fair return should result in a value to investors commensurate with that of competitive ventures of similar risk. The fact that an original cost rate base provides a starting point for the application of a fair return does not mean that the original cost of the assets is a measure of their fair value. The concept that regulation is a surrogate for competition implies that the regulatory application of a fair return to an original cost rate base should result in a value to investors commensurate with that of similar risk competitive ventures. The comparable returns standard, as well as the principle of fairness, suggests that, if competitive firms facing a level of total risk similar to utilities are able to maintain the value of their assets considerably above book value, the return allowed to utilities should not seek to maintain the value of utility assets at book value. It is critical that the regulator recognize the comparable returns standard when setting a just and reasonable return.

The comparable earnings test remains the only test that explicitly recognizes that, in the North American regulatory framework, the return is applied to an original cost (book value) rate base. The persistence of moderate inflation continues to create systematic deviations between book and market values. Application of a market-derived cost of capital to book value ignores that distinction. The application of the results of the cost of attracting capital tests, i.e., equity risk premium and discounted cash flow to the book value of equity, unless adjusted, do not make any allowance for the discrepancy between the return on market value and the corresponding fair return on book value. The comparable earnings test, however, does. It applies “apples to apples”, i.e., a book value-measured return is applied to a book value-measured equity investment.

The principal issues in the application of the comparable earnings test are:[109]

1. The selection of a sample of unregulated companies of reasonably comparable total risk to a Canadian utility.

2. The selection of an appropriate time period over which returns are to be measured in order to estimate prospective returns.

3. The need for any adjustment to the "raw" comparable earnings results if the selected unregulated companies are not of precisely equivalent risk to a utility.

4. The need for a downward adjustment for the unregulated companies' market/book ratios.

The application of the comparable earnings test first requires the selection of a sample of unregulated companies of reasonably comparable risk to a Canadian utility. The selection should conform to investor perceptions of the risk characteristics of utilities, which are generally characterized by relative stability of earnings, dividends and market prices. These were the principal criteria for the selection of a sample of unregulated companies (from consumer-oriented industries). The criteria for selecting comparable unregulated low risk companies include industry, size, dividend history, capital structures, bond ratings and betas (See Appendix F).

Since the universe of Canadian unregulated companies is sufficiently large to produce a representative sample of sufficient size, the focus of the comparable earnings analysis was on Canadian firms. The application of the selection criteria to the Canadian universe produced a sample of 21 companies.

Next, since unregulated companies' returns on equity tend to be cyclical, the selection of an appropriate period for measuring their returns must be determined. The period selected should, in principle, encompass an entire business cycle, covering years of both expansion and decline.

[109] Full discussion in Appendix F.

That cycle should be representative of a future normal cycle, e.g., the historic and forecast cycles should be similar in terms of inflation and real economic growth. The last full business cycle, encompassing 1994-2010, may overestimate the returns on equity achievable going forward as nominal economic growth was higher, on average, than is projected for the longer term. As a result, the focus of the test was on the period 2003-2010, which commences subsequent to the 2001 downturn and includes the 2008-2009 recession. The period 2003-2010 represents an appropriate proxy for the next business cycle, as the average experienced rates of inflation and economic growth were reasonably similar to the average rates projected by economists over the next decade. The experienced returns on equity of the sample of 21 Canadian low risk unregulated companies over this period were in the range of 12.75%-13.5% (see Appendix F and Schedule 25).

The next step is to assess whether or not there is a need to adjust the "raw" comparable earnings results to reflect the differential risk of a Canadian utility relative to the selected unregulated companies. The comparative risk data (including betas and stock and bond ratings) indicate that the unregulated Canadian companies are of higher risk than the typical Canadian utility, e.g., Newfoundland Power. To recognize the unregulated companies' higher risk, a downward adjustment of 150 basis points[110] to their returns on equity was made, resulting in a comparable earnings result in the range of 11.25% to 12.0%.

The final step is to assess the need for a market/book adjustment to the comparable earnings results. The sample results would warrant such an adjustment if their market/book ratios relative to the overall market indicated an ability to exert market power. In other words, a high market/book ratio (relative to that of the overall market) could suggest returns on equity that were higher than the levels achievable if market power were not present. The average market/book ratio of the sample of Canadian comparable unregulated companies over the both the full business cycle 1994-2010 and the shorter period 2003-2010 period was 2.3 times, similar to the market/book ratio of the S&P/TSX composite over the same periods and lower than the market/book ratio of the S&P 500 (see Appendix F). The similar to lower average market/book

[110] Based on the typical spread between Moody's BBB-rated long-term industrial bond yields and long-term A-rated utility bond yields and the relative betas of the unregulated companies and Canadian utilities.

ratio of the Canadian sample of unregulated companies relative to both the Canadian and U.S. equity market composites indicates no evidence of market power. Thus there is no rationale for making an additional downward adjustment to the unregulated Canadian companies' returns on equity due to their market/book ratios. As a result, a fair return on equity based on the comparable earnings test is approximately 11.25% to12.0%.

I. FAIR RETURN ON EQUITY FOR NEWFOUNDLAND POWER

Based solely on the market-based cost of equity tests, a fair return on equity for Newfoundland Power is approximately 10.5%, reflecting the following:

The results of the equity risk premium and discounted cash flow tests support a "bare-bones" cost of equity of approximately 9.5%, as summarized in the table below:

Table 28

Cost of Equity Test	Cost of Equity
Risk Premium Tests:	
Risk-Adjusted Equity Market	8.8%
Discounted Cash Flow-Based	9.5%
Historic Utility	10.0% - 10.25%
Discounted Cash Flow Test	9.5%

Adding an allowance for financing flexibility of 1.0%, reflecting the mid-point of a range of 0.50% to 1.50%, results in a recommended ROE for Newfoundland Power of 10.5%. The lower end of the financing flexibility 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.

Alternatively, the fair ROE for Newfoundland Power can be viewed as falling within a range bounded by the market-based cost of equity inclusive of the minimal allowance for financing flexibility (10.0%) at the bottom end of the range and the comparable earnings test results

(11.25% to 12.0%) at the upper end of the range. The specific weight to be given the comparable earnings test versus the market-based tests is largely a matter of judgment. The comparable earnings test is, in my opinion, entitled to significant weight. When preponderant weight is given to the market-based tests, this alternative approach provides further support for a fair ROE of approximately 10.5%.

Appendices

to

OPINION

ON

CAPITAL STRUCTURE

AND

RETURN ON EQUITY

FOR

Newfoundland Power Inc.

Prepared by

KATHLEEN C. McSHANE

FOSTER ASSOCIATES, INC.

March 2012

APPENDICES

APPENDIX A

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:

$$\mathbf{R_F \quad + \quad \beta(R_M - R_F),}$$

Where:

$\mathbf{R_F}$	=	risk-free rate
$\boldsymbol{\beta}$	=	covariability of the security with the market (M)
$\mathbf{R_M}$	=	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.

The "father" of modern portfolio theory (and winner of the Nobel Prize for Economics) Harry Markowitz has stated that "The CAPM is a thing of beauty. Thanks to one or another counterfactual assumption, it achieves clean and simple conclusions."[1] A key counter-factual assumption is the investor's ability to borrow unlimited amounts at the risk-free rate. He

[1] Markowitz, Harry M., "Market Efficiency: A Theoretical Distinction and So What?", *Financial Analysts Journal*, September/October 2005, page 29.

concludes that because key assumptions of the model do not hold, then it no longer holds that expected returns are linearly related to beta. He does state that CAPM should be taught, despite its drawbacks. According to Dr. Markowitz:

> It is like studying the motion of objects on Earth under the assumption that the Earth has no air. The calculations and results are much simpler if this assumption is made. But at some point, the obvious fact that, on Earth, cannonballs and feathers do not fall at the same rate should be noted and explained to some extent.[2]

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.[3] In 2008/2009, despite a budget

[2] *Ibid.*, pages 28-29.

[3] Following budget deficits of $55.6 billion and $33.4 billion in fiscal years 2009/2010 and 2010/2011 respectively, the Department of Finance's *Update of Economic and Fiscal Projections, November 8, 2011* (page 41) anticipated declining budget deficits through 2015/2016, with a small surplus ($0.5 billion) in 2016/2017. Recent data releases suggest that the deficit for the fiscal year 2011/2012 may be "much better" than had been projected in the November *Update*, at $27-$28 billion compared to the Department's earlier $31 billion projected deficit (TD Economics, *Fiscal Monitor November 2011*, January 27, 2012). The Department of Finance's projections show the federal debt to

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 2011, Government of Canada bonds accounted for a little over one-quarter of total Canadian dollar bonds outstanding,[4] compared to almost half in 1996.[5] 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 long-term government bonds to incorporate a scarcity premium reflecting an imbalance between demand and supply.

Further, with the credit downgrades of a number of advanced economy sovereign issuers in the last several years, the pool of high grade sovereign debt globally has shrunk over the past several years. The Government of Canada is one of relatively few advanced economy debt issuers with AAA ratings, and the third largest economy with AAA ratings by all three ratings agencies, in a global capital market with a high demand for safe haven assets. However, Canada is a relatively small economy, and accounts for only about 2% of the world capital market, and the supply of its debt is limited.[6] As a result, the recent yields on long-term Government of Canada debt are likely to reflect a scarcity premium.

(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

GDP peaking at approximately 35% in 2012/13, then declining to 30.3% in 2016/2017, close to its pre-recession level of 29% in 2008/2009.

[4] Includes provincial, municipal, corporate, foreign issuer, and term securitization bonds.

[5] Statistics Canada, www.statcan.gc.ca

[6] The demand for the February 2012 issue of $3 billion in U.S. dollar-denominated five-year bonds by the Government of Canada was outstripped by supply by a factor of 3-to-1.

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.[7]

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

[7] As stated in Ibbotson *SBBI 2011 Valuation Yearbook* (page 55), "Another point to keep in mind when calculating the equity risk premium is that the income return on the appropriate horizon Treasury security, rather than the total return, is used in the calculation. The total return is comprised of three return components: the income return, the capital appreciation return, and the reinvestment return. The income return is defined as the portion of the total return that results from a periodic cash flow or, in this case, the bond coupon payment. The capital appreciation return results from the price change of a bond over a specific period. Bond prices generally change in reaction to unexpected fluctuations in yields. Reinvestment return is the return on a given month's investment income when reinvested into the same asset class in the subsequent months of the year. The income return is thus used in the estimation of the equity risk premium because it represents the truly riskless portion of the return."

> 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,

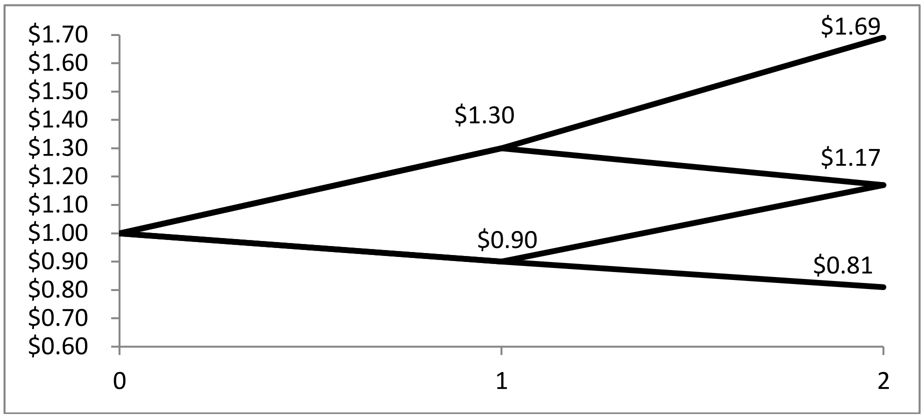
> The arithmetic mean of a sequence of different returns is always larger than the geometric mean. To see this, consider equally likely returns of +25 and –20 percent. Their arithmetic mean is 2½ percent, since (25 – 20)/2 = 2½. Their geometric mean is zero, since (1 + 25/100) x (1 – 20/100) – 1 = 0. 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)	=	$0.2025
	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:

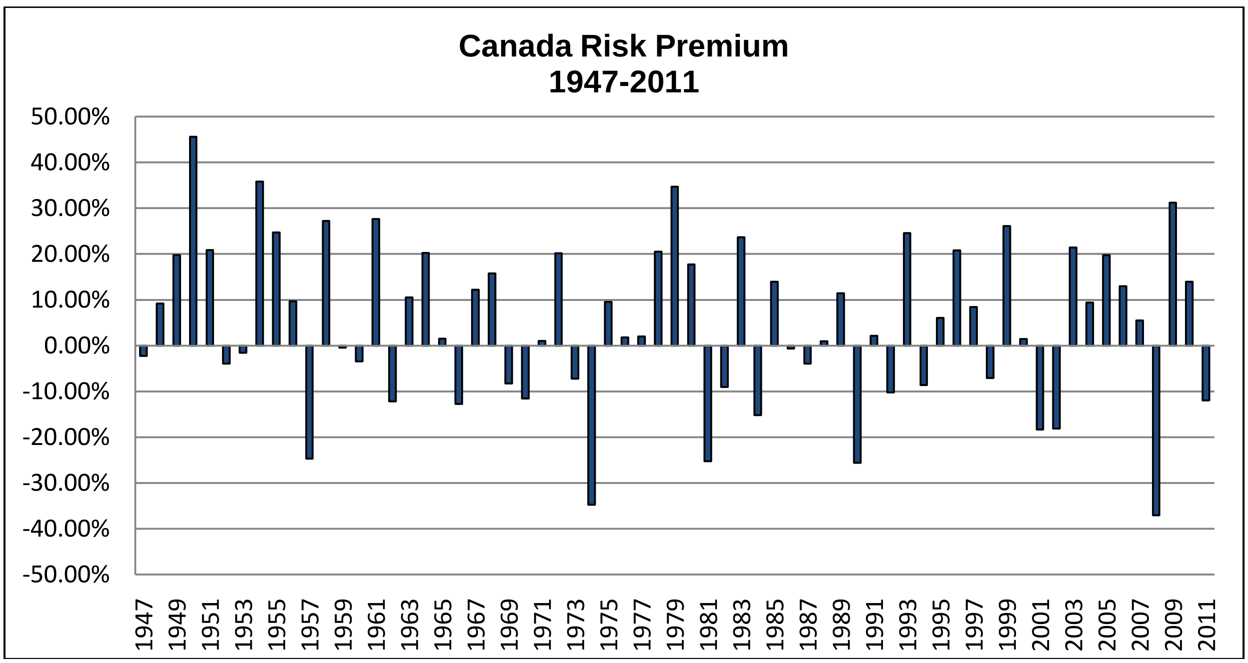
$$\$1 \times (1+0.082)^2 = \$1.17$$

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.[8]

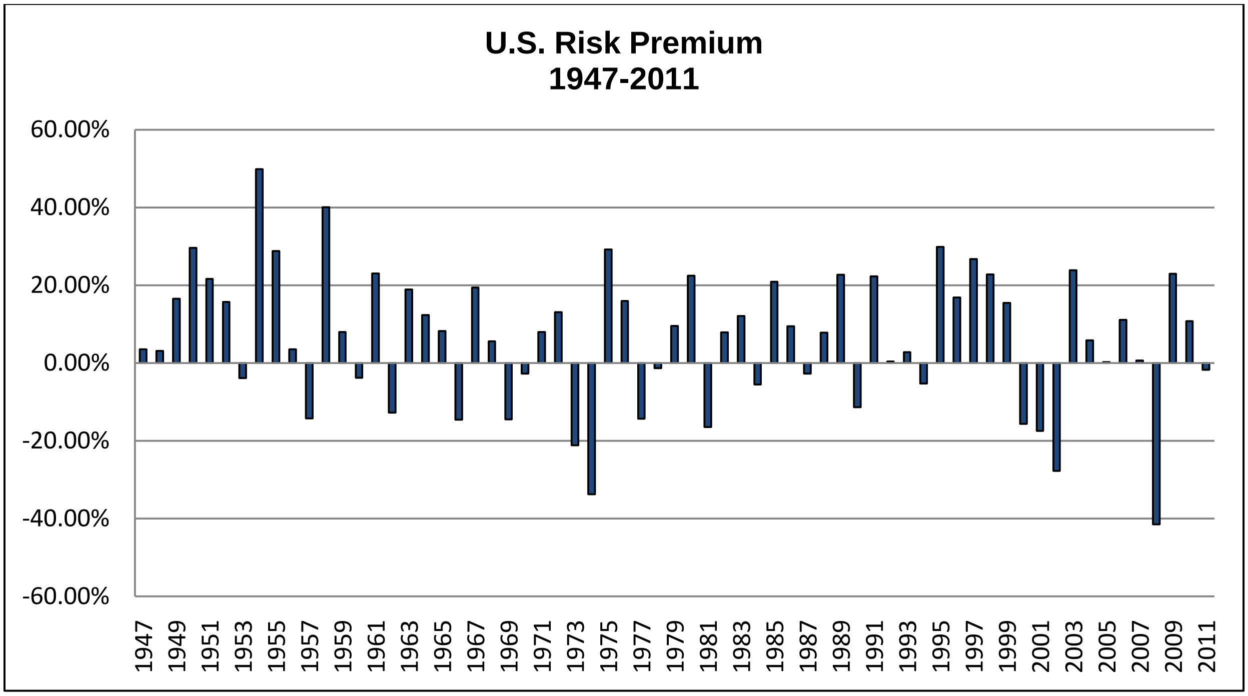
Chart A - 1



Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics, 1924-2010*, and *TSX Review*.

[8] 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 1947-2011 are -0.052 for Canada and -0.029 for the U.S. For the period 1924-2011 the serial correlation in Canada is 0.119. For the period 1927-2011 the serial correlation in the U.S. is 0.020. 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, 2011 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.[9] The next largest sector, financial 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,

[9] 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.

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 2011, the energy and materials (largely mining) sectors accounted for over 45% of the total market value of the composite. Including the financial services sector, three sectors accounted for close to 80% of the total market value of the S&P/TSX Composite.

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 2011 illustrates the difference.

Table A - 2

Sector	**S&P/TSX Canada**	**S&P 500 U.S.**
Consumer Discretionary	4.0%	10.7%
Consumer Staples	2.8%	11.5%
Energy	27.1%	12.3%
Financials	29.4%	13.6%
Health Care	1.4%	11.9%
Industrials	5.8%	10.7%
Information Technology	1.3%	19.0%
Materials	21.1%	3.5%
Telecommunication Services	5.2%	3.0%
Utilities	2.0%	3.9%

Source: *TSX Review*, December 2011 and www.standardandpoors.com (January 17, 2012).

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, 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 2011, the largest twenty stocks accounted for approximately 50% of the total market capitalization of the S&P/TSX Composite Index. Of the twenty, six (20% of Composite Index market capitalization) were financial and nine (22% of Composite Index market capitalization) were resource (energy and mining) companies.[10] The undue influence of a small 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

[10] By comparison, the largest 20 stocks in the S&P 500 accounted for 33% of the total index market capitalization, with no single sector represented among the top 20 stocks accounting for more than 10% of the total market capitalization of the index.

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, 2011 there were 253 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.[11] 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.[12]

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

[11] 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.
[12] 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.

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%.[13] 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*,[14] which supported the removal of the cap.[15] At that time, the *Globe and Mail* reported 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."[16] 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

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[13] Tom Hockin, President and CEO IFIC, *Paving the Way for Change to RRSP Foreign Content Rules*, January 31, 2000.

[14] David Burgess and Joel Fried, *The Foreign Property Rule: A Cost-Benefit Analysis*, The University of Western Ontario, November 2002.

[15] 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.

[16] Rob Carrick, *Finance: Your Bottom Line*, www.globeandmail.com, February 23, 2005.

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 2011 they are expected to be approximately $500 billion, of which over 70% are U.S. stocks.[17] As of 2011Q1, although the total percentage of foreign assets in trusteed pension funds was approximately 30%, the percentage of foreign equity to total equity was close to 50%.[18] In addition, the U.S. equity market has historically been the principal alternative for Canadian investors to domestic equity investments. Just over 40% of Canadian portfolio investment in foreign equities at the end of 2010 was in the U.S.[19]

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[20] of the S&P 500 averaged 13.25 times from 1936-1988, with no discernible upward trend.[21] 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"

[17] Statistics Canada, *International Transactions in Securities, November 2011*, January 2012, Table 12-2.
[18] Based on market value. Statistics Canada, Table 280-0003, data through June 2011. .
[19] Statistics Canada, *Canada's International Investment Position – Third quarter 2011*, December 2011, Table 6. The U.S. portion of Canadian direct investment abroad at the end of 2010 was approximately 40%.
[20] Price to trailing earnings.
[21] The average P/E ratio from 1947-1988 was 13 times.

outlook for the U.S. equity market and sent retail investors to the sidelines.[22] 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 earnings and the equity market, the P/E ratio fell. At the end of December 2011, the P/E ratio of the S&P 500 was 12.8 times (based on estimated 2011 operating earnings), compared to the long-term (1936-2011) 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 1936-2011 was 11.9%. Hence, despite the increase in P/E ratios experienced during the 1990s, the average equity market returns were actually lower over the entire 1936-2011 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 12.3% over the entire 1947-2011 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 1936-2011

[22] Weakness in the equity markets was partly responsible (along with low interest rates) for the burgeoning income trust market in Canada.

return of 11.2%. Similarly, the 1947-1988 equity market return of 12.9% was higher than the 1947-2011 return of 11.8%. 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[23] 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*

[23] 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.

> *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:

> 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.[24]

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

[24] 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.

> 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 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.[25]

In a May 2009 survey, "Betas Used by Professors: A Survey with 2,500 Answers," Dr. Pablo Fernandez cites nine different problems with betas including: (1) they have little correlation with stock returns; (2) a beta of 1.0 has a higher correlation with stock returns for many companies; (3) frequently we don't know if the beta of one company is higher than another; (4) the correlation coefficients of the regressions used to calculate the betas are very small; (5) and the relative magnitude of betas often makes very little sense.

From these reasons, Dr. Fernandez reaches two findings: the beta calculated with historical data is not a good approximation to the company's beta and the beta of a company (a common figure for all investors) does not exist. The two conclusions, Dr. Fernandez states, imply the CAPM does not work. Ultimately, Dr. Fernandez concludes: "We argue, as many professors mention, that historical betas (calculated from historical data) are useless to calculate the required return to equity (footnote omitted), to rank portfolios with respect to systematic risk, and to estimate the expected return of companies."

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[25] Dr. Stephen A. Ross, "Is Beta Useful?" *The CAPM Controversy: Policy and Strategy Implications for Investment Management*, AIMR, 1993.

In an article released at approximately the same time entitled "β = 1 Does a Better Job than Calculated Betas", May 19, 2009, Dr. Fernandez and co-author, Vicente Bermejo find that adjusted betas (0.67 calculated beta + 0.33 Market Beta of 1.0) does a better job of predicting returns than the calculated beta. They also find that assuming a beta of 1.0 (i.e., the market beta) does a better job than the adjusted beta.

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.[26]

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 11, page 1 of 2.

[26] Non-overlapping periods were used so that each observation represents an independent time period. The length of the period was chosen to minimize the potential for random noise in the return data.

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) 1988-2011, the longest period for which data for the new Composite and its sector components were available; (b) 1988-1997,[27] and (c) the 10-year period ending 2011.

That analysis showed the following:

Table A - 4

Returns Measured Over:	Coefficient on Beta	R^2
1988-2011	-.063	52%
1988-1997	-.017	1%
2002-2011	-.094	18%

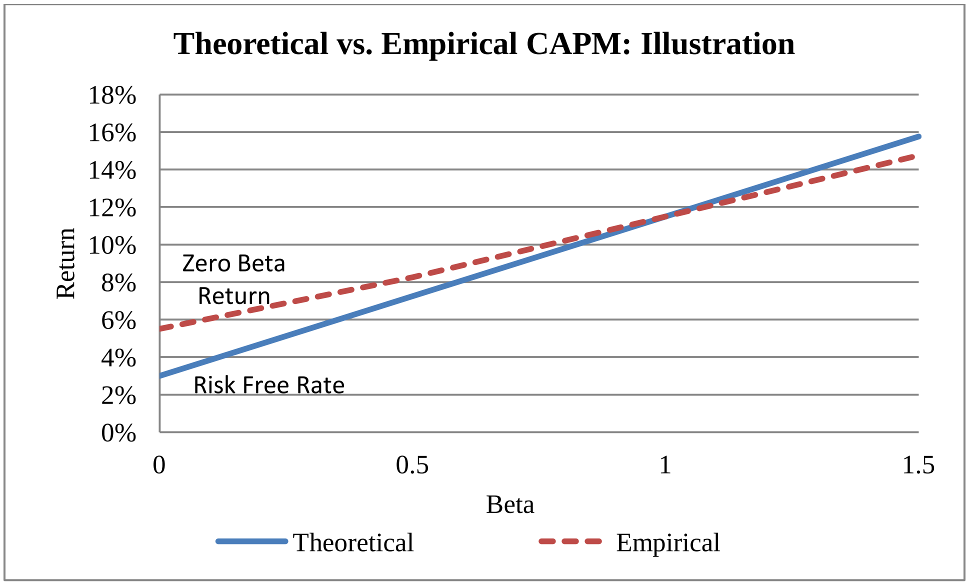
Source: Schedule 11, page 2 of 2.

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 (lower beta = lower return).[28]

[27] The use of this sub-period was intended to eliminate the impacts of any anomalous market behavior during the technology "bubble and bust", which occurred mainly from 1999 through mid-2002.
[28] In a recent article entitled "Benchmarks as Limits to Arbitrage: Understanding the Low-Volatility Anomaly", *Financial Analysts' Journal*, Vol. 67, No. 1, 2011, Drs. Malcolm Baker, Brendan Bradley and Jeffrey Wurgler conclude: "In an efficient market, investors realize above average returns only by taking above-average risks. Risky stocks have high returns, on average, and safe stocks do not. This simple empirical proposition has been hard to support on the basis of the history of U.S. stock returns. The most widely used measures of risk point rather strongly in the wrong direction."

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) 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 3.75%, 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 7.625% (3.75% + 0.50 (11.5%-3.75%)). When a long-term Government of Canada bond yield of 5.0% is used as the risk-free rate, the CAPM return is equal to 8.25% (5.0% + 0.50 (11.5%-5.0%)). 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.

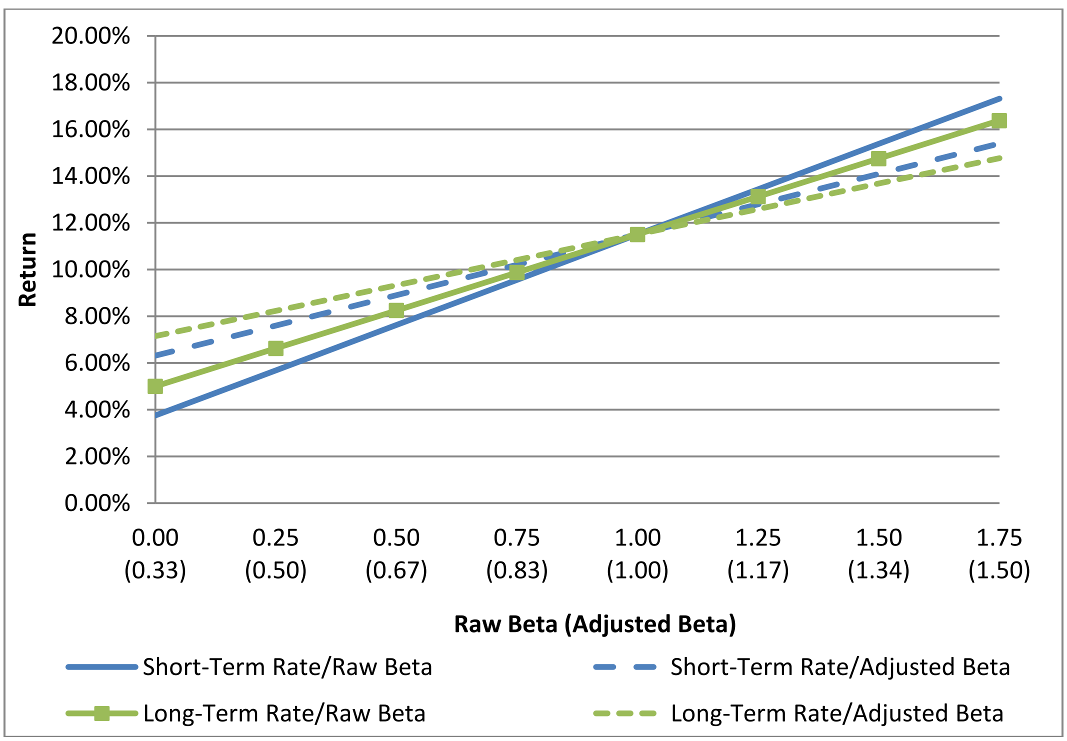
The use of adjusted betas in place of "raw" betas provides a further means of correcting for betas' under (over) prediction of returns for low (high) beta stocks. Reliance on adjusted betas initially arose in response to the empirically documented failure of betas calculated from one period to be good 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 short-term risk-free rate and an adjusted beta; (3) a long-term risk-free rate and a "raw" beta; and (4) 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 (5.0%) as in the previous example, the use of an adjusted beta rather than a “raw” beta increases the indicated utility equity return by close to 1.1%. The total adjustment to the utility equity return of approximately 1.7% (0.625% for the difference between the long-term and short-term risk-free rates and 1.1% 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. LOW RISK UTILITY SAMPLE

For the estimation of a fair ROE for an average risk Canadian utility using the Discounted Cash Flow-Based Equity Risk Premium Test and the Discounted Cash Flow Test, a sample of low risk U.S. utilities was selected.

The sample is comprised of all U.S. electric and natural gas utilities satisfying the following criteria:

1. Classified as either an electric or gas utility in *Value Line;*
2. Debt ratings of BBB+ or better and Baa1 or better by S&P and Moody's, respectively;
3. Consistent dividend history over the period 2002-2011;
4. Not being acquired or part of a merger;
5. Utility assets equal to or greater than 80% of total assets; and
6. Long-term earnings growth forecasts available from three of four sources: Bloomberg, Reuters, *Value Line* and Zacks.

The thirteen utilities that met these criteria are:

Electric	**Natural Gas**
ALLETE	AGL Resources
Alliant Energy	Atmos Energy
Consolidated Edison	Northwest Natural Gas
Integrys Energy	Piedmont Natural Gas
Southern Co.	WGL Holdings Inc.
Vectren Corp.	
Wisconsin Energy	
Xcel Energy Inc.	

Utility-specific information is found on pages B-2 to B-34 of this Appendix and on Schedule 13.

AGL Resources

Operating Characteristics:	
Operations:	Completed merger with NICOR in December 2011. Nation's largest natural gas-only distribution company (4.5 million customers) NICOR Gas - Illinois Southern Operations consisting of: Atlanta Gas Light - Georgia Florida City Gas - Florida Chattanooga Gas - Tennessee Mid-Atlantic Operations consisting of: Virginia Natural Gas - Virginia Elizabethtown Gas - New Jersey Elkton Gas - Maryland Other non-regulated businesses include competitive gas operations including retail services, wholesale operations, and shipping.
Total Assets:	$12,015 million
Percentage of Assets in Utility Operations:	Approximately 81%
State(s) of Operation:	Florida, Georgia, Illinois, Maryland, New Jersey, Tennessee and Virginia
Number of Customers:	Utility Customers: IL 2.2 million GA, FL & TN 1.7 million MD, NJ & VA 0.6 million
Customers by Type:	**2010 Operating Revenues** Residential 57.7% Commercial 20.0% Transportation 13.0% Industrial 5.6% Other 3.7%
Regulatory Environment:	
Test Year:	Partially Forecast - FL Forecast - GA, IL, TN Historic (adj. for known & measurable changes) - MD, NJ, VA

(GAS cont'd)

Return on Equity (Latest Allowed):	Atlanta Gas Light - 10.75% (2010, GA) Chattanooga Gas - 10.05% (2010, TN) Elizabethtown Gas - 10.3% (2009, NJ) Elkton Gas- 8.33% overall return, settlement (2008, MD) Florida City Gas -11.25% (2004, FL) Nicor Gas - 10.17% (2009, IL) Virginia Natural Gas - 10% (2011, VA)
Equity Ratio (Latest Allowed):	Atlanta Gas Light - 51.0% (2010) Chattanooga Gas - 46.06% (2010) Elizabethtown Gas - 47.89% (2009) Florida City Gas -36.77% (2004) Nicor Gas - 51.07% (2009) Virginia Natural Gas - 45.36% (2011)
Earnings Sharing:	NJ - Elizabethtown Gas shares 50/50 up to $1m annually between monthly benchmark and the actual cost of gas TN - Has interruptible margin credit rider where it shares equally with ratepayers margins resulting from transactions with non-regulated customers that utilize Chattanooga assets. VA - shares equally with rate payers any gas costs that deviate from Commission-approved benchmarks.
Deferral Mechanisms:[i]	Bad Debt Cost Recovery Mechanism - IL, TN, VA Infrastructure Cost Recovery Mechanism - GA, NJ
Fuel/Gas Cost Recovery:	PGA - all states
Sales and Weather Normalization:	Revenue Decoupling - NJ (pending), TN, VA Flat Monthly Fee Rate Design (SFV) - GA, IL Weather Normalization Adj - NJ, TN
RRA Regulatory Climate:[ii]	Average 1 - FL, GA, TN Average 2 - NJ Average 3 - VA Below Average 2 - IL, MD

(GAS cont'd)

Moody's Rating Methodology:[iii] Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): Baa Diversification (10%): Baa/A Financial Strength (40%): Baa
S&P's Regulatory Comment	"generally regard Illinois to be a challenging regulatory environment for utilities to manage. However, Nicor has historically enjoyed satisfactory regulatory relations due in large part to its competitive rates to customers and good operating efficiency statistics. The utility has an acceptable 10.2% authorized return on equity, favorable weather-normalization and cost-recovery mechanisms, and a bad debt tracker. We view regulation in Georgia more favorably. In Georgia, the company benefits from a straight-fixed-variable-rate design structure that minimizes revenue risk due to weather and conservation. Georgia is one of a few states where natural gas delivery is deregulated."

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 Has an investment in American Transmission Co. (ATC), a 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 and 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:	$2,609 million (2010)
Percentage of Assets in Utility Operations:	Approximately 91%
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 (FAC) that is adjusted monthly with a two-month lag. Allowed to recover through the FAC non-administrative Midwest Independent System Operator 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%): Baa Ability to Recover Costs/Earn Return (25%): A 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; 2010 revenues 82% electric, 15% gas *Wisconsin Power and Light (WPL)*: electric generation and distribution, and gas distribution in Wisconsin; 2010 revenues 85% electric, 14% gas IPL sold electric transmission assets in IA, MN and IL to ITC Holdings in 2007; WPL transferred transmission assets to American Transmission Company in 2001 in exchange for ownership interest (16%) in ATC. IPL and WPL members in MISO, a FERC-approved regional transmission organization (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:	$9,283 million (2010)
Percentage of Assets in Utility Operations:	Approximately 95%
State(s) of Utility Operations:	Iowa, southern Minnesota, and southern and central Wisconsin
Number of Customers:	IPL – 526,000 electric customers and 234,000 gas customers in Iowa and southern Minnesota WPL – 455,000 electric and 179,000 gas customers in Wisconsin
Customers by Type:	see table below

Customer Type	2010 % of Revenues	2010% Sales (MWh)
Residential	37%	26%
Commercial	23%	21%
Industrial	29%	37%
Wholesale	7%	11%
Bulk Power & Other	4%	5%

(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% blended ROE, including 10% on preponderance of rate base and 11.7% and 12.33% on specific generation investments (January 2011) IPL (Minnesota): 10.35% (Aug 2011) 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): 47.74% (Aug 2011 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:[i]	Pension and OPEB, Lost and unaccounted for gas mechanism, Energy Efficiency Cost Recovery (EECR), IPL was authorized (12/10) 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%.
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.

(LNT cont'd)

RRA Regulatory Climate:[ii]	Above Average 3 (IA) Average 2 (MN) 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%): A Diversification (10%): Baa Financial Strength (40%): A
S&P's Regulatory Comment	"More credit supportive regulatory jurisdictions"

Atmos Energy

<table>
<tr><td colspan="2">Operating Characteristics:</td></tr>
<tr><td>Operations:</td><td>Natural gas distribution – six divisions as follows:
Atmos Energy Colorado-Kansas
Atmos Energy Kentucky/Mid-States
Atmos Energy Louisiana
Atmos Energy Mid-Tex (includes Dallas and environs)
Atmos Energy Mississippi
Atmos Energy West Texas

Non-regulated businesses comprised of natural gas management and marketing services to municipalities, other LDCs and industrial customers, and natural gas transportation along with storage service to the own distribution divisions and third parties.</td></tr>
<tr><td>Total Assets:</td><td>$8,717 million</td></tr>
<tr><td>Percentage of Assets in Gas and Electric Operations:</td><td>Approximately 81% of assets in natural gas distribution; 11% regulated transmission and storage</td></tr>
<tr><td>State(s) of Operation:</td><td>Primary service areas are in Colorado, Kansas, Kentucky, Louisiana, Mississippi, Tennessee and Texas. More limited service in Georgia, Illinois, Iowa, Missouri and Virginia. Sale of Illinois, Iowa and Missouri assets announced in May 2011 (84,000 customers).</td></tr>
<tr><td>Number of Customers:</td><td>3 million customers in 12 states</td></tr>
<tr><td>Customers by Type:</td><td>2011 % Operating Revenues
Residential 62.0% | Public Authority 2.7%
Commercial 27.6% | Transportation Revenues 2.4%
Industrial 4.2% | Other Revenue 1.1%</td></tr>
<tr><td colspan="2">Regulatory Environment:</td></tr>
<tr><td>Test Year:</td><td>Historic - CO, LA
Historic (adj. for known and measurable changes) - IA, KS, KY, MO, TX and VA
Partial Forecast - GA
Forecast - IL, MS, TN</td></tr>
</table>

ATO (cont'd)

Return on Equity (Latest Allowed):		**Jurisdiction & Effective Date**	**ROE**
	Colorado-Kansas	Colorado 01/04/2010	10.25%
		Kansas 08/01/2010	n/a
	Kentucky/Mid-States	Georgia 03/31/2010	10.70%
		Illinois 11/01/2000	11.56%
		Iowa 03/01/2001	11.00%
		Kentucky 06/01/2010	n/a
		Missouri 09/01/2010	n/a
		Tennessee 04/01/2009	10.30%
		Virginia 11/23/2009	9.50% -10.50%
	Louisiana	Trans LA 04/01/2011	10.00% -10.80%
		LGS 07/01/2011	10.40%
	Mid-Tex Settled Cities	Texas 09/01/2011	9.70%
	Mid-Tex Dallas	Texas 06/22/2011	10.10%
	Mid-Tex Environs GRIP	Texas 06/27/2011	10.40%
	Mississippi	Mississippi 04/05/2011	9.86%
	West Texas	Amarillo 08/01/2011	9.60%
		Lubbock 09/09/2011	9.60%
		West Texas 08/01/2011	9.60%
	[1/] GRIP - Gas Reliability Infrastructure Program		
Equity Ratio (Latest Allowed):	**Colorado-Kansas**	Colorado	50%
		Kansas	na
	Kentucky/Mid-States	Georgia	48%
		Illinois	33%
		Iowa	43%
		Kentucky	na
		Missouri	51%
		Tennessee	48%
		Virginia	49%
	Louisiana	Trans LA	48%
		LGS	48%
	Mid-Tex Settled Cities	Texas	50%
	Mid-Tex Dallas & Environs	Texas	49%
	Mississippi	Mississippi	50%
	West Texas	Amarillo	48%
		Lubbock	48%
		West Texas	48%

(ATO cont'd)

Earnings Sharing:	Performance based rate programs in Georgia (if earnings outside range of 10.5%-10.9% then rates adjusted to change revenue to achieve the upper/lower earnings band; no rate change if earnings within the band), Kentucky and Tennessee whereby purchased gas costs savings are shared.
Deferral Mechanisms:[i]	Bad debt rider in CO, KS, KY, TN, TX and VA Infrastructure Cost Recovery in GA, KS, KY, MO and TX OPEB Cost Recovery in LA and MS
Fuel/Gas Cost Recovery:	All states
Sales and Weather Normalization:	Weather Normalization Adjustments approved for "94% of residential and commercial margins" in company's service areas (GA, KS, KY, LA, MS and TX) Innovative rate structures approved: MO: flat fee rate plus small variable charge: 75% costs recovered in monthly fee LA, MS & TX: Rate stabilization tariffs GA: Georgia Rate Adjustment Mechanism (GRAM) providing a non-gas cost revenue true-up implemented 12/2011.
RRA Regulatory Climate:[ii]	Above Average 2 (MS) Above Average 3 (IA, VA) Average 1 (CO, GA, KY, LA, TN) Average 2 (KS, MO) Below Average 1 (TX) Below Average 2 (IL)
Moody's Rating Methodology:[iii] 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	"geographic and regulatory diversity provided by regulated operations in 12 states"; "supportive regulatory environment"

Consolidated Edison Inc

Operating Characteristics:	
Operations:	Principal subsidiaries are regulated transmission and distribution utilities comprising largest utility system in New York State area: *Con Edison of New York*: electric, gas and steam distribution and transmission infrastructure *Orange & Rockland*: gas and electric distribution infrastructure. ORU in turn has two wholly owned electric subsidiaries - Rockland Electric (NJ) and Pike County Light & Power (PA) Unregulated subsidiaries represent less than 5% of assets; include retail and wholesale energy supply.
Total Assets:	$35,600 million
Percentage of Assets in Utility Operations:	Approximately 98% of assets in utility operations; less than 5% assets in generation
State(s) of Operation:	New York including most of New York City; northern New Jersey and parts of eastern Pennsylvania
Number of Customers:	ConEd NY - 3.3 million electric customers, 1.1 million gas customers (New York City and Westchester County) and 23,000 steam customers Orange & Rockland – 0.3 million electric customers in NY, NJ and PA and over 0.1 million gas customers in southeastern NY and northeastern PA.
Customers by Type:	**2010 % Revenues** **Customer Type / Electric / Gas** Residential: 37% / 47% Com./Industrial: 31% Retail Access: 25% General: 21% (Gas) Trans. & Other: 32% (Gas)
Regulatory Environment:	
Test Year:	Forecast
Return on Equity (Latest Allowed):	**Electric:** ConEd NY: 3/10 - 10.15% 3 yr settlement (previously 10%, 2009) Orange & Rockland: 6/11 - 9.2% (fully litigated) Rockland Electric (NJ): 6/10 - settlement 10.3% (previously 9.75%, 2007) **Gas:** ConEd NY: 9/10 - 9.6%; (prev. 9.7% 3 yr plan) Orange & Rockland: 10/09 adopted 10.4%- 3 yr plan expiring Oct. 2012

(ED cont'd)

Equity Ratio (Latest Allowed):	ConEd NY: 48.0% (2010) Orange & Rockland: 48.0% (2011) Rockland Electric: 49.85% (2010)
Earnings Sharing:	*ConEd* Electric: 100bp over allowed ROE shared 50/50 Gas: 75bp over allowed ROE shared 60/40 (ratepayers/shareholders) *Orange & Rockland* Electric: Earnings between 10.2% & 11.2% ROE shared 50/50; above 11.2% shared 75/25 (ratepayers/shareholders) Gas: Earnings between 11.4% and 12.4% shared 50/50; 12.4% to 14% shared 65/35 (ratepayers/shareholders); over 14% allocated 90% to ratepayers. ROE threshold reduced 20 basis points in any rate year company fails to meet objectives of its retail choice program
Deferral Mechanisms: [i]	Deferral of certain expenses: property taxes (partial), interest on debt (partial), pension and OPEB, environmental remediation expenses, deferred derivative losses (long-term) gas rate plan deferral, World Trade restoration costs collected through rates/riders; bad debt recovery mechanism (NY) and relocation of facilities to accommodate government projects. Lost and unaccounted for gas mechanism
Fuel/Gas Cost Recovery:	With electric industry restructuring, transitioned from the fuel adjustment clause (FAC) to a market power adjustment clause (MAC) or a commodity adjustment clause (CAC). The MAC/CAC allows the distribution utilities to flow through the costs of power procured to serve customers who have not selected an alternative supplier. Changes in the clause are recognized in each customer bill (i.e., monthly, bi-monthly, etc.). Although the incumbent distributors retain the provider-of-last-resort (POLR) obligation, the operation of these clauses leaves the distributor insulated from any financial effects associated with changes in market prices. Recovery of gas commodity costs is through semi-automatic fuel adjustment clauses.

(ED cont'd)

Sales and Weather Normalization:	Revenue decoupling for both gas and electric; weather normalization adjustment clauses for gas companies
RRA Regulatory Climate:[ii]	Average 3 (NY) Average 2 (NJ) Average 3 (PA)
Moody's Rating Methodology:[iii] 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	"Ability to achieve constructive regulatory outcomes"

Integrys

Operating Characteristics:	
Operations:	**Regulated Subsidiaries**: *Wisconsin Public Service Corp (WPS)* *Peoples Gas Light & Coke Co. (PG)* *North Shore Gas Co. (NSG)* *Upper Peninsula Power Co.(UPP)* *Minnesota Energy Resources Corp.(MERC)* *Michigan Gas Utilities Corp (MGU)* **Regulated Investments:** 34% interest in *American Transmission Co.(ATC)* **Non-rate-regulated:** *Integrys Energy Services*
Total Assets:	$9,400 million.
Percentage of Assets in Utility Operations:	Approximately 87%
State(s) of Operation:	Illinois (ATC, PG, NSG), Michigan (ATC, MGU, MERC, UPP), Minnesota (ATC) and Wisconsin (WPS, ATC),
Number of Customers:	Integrys Energy - 1.7 million natural gas and 0.5 million electric customers

Customers	'000s	%	Gas	Electric
Wisconsin Public Service	757	35%	19%	89%
Peoples Gas	819	23%	49%	-
Minnesota Energy Res.	212	6%	13%	-
Michigan Gas Utilities	166	2%	10%	-
North Shore Gas	158	8%	9%	-
Upper Peninsula Power	52	7%	-	11%

Customers by Type:

Gas Throughput (therms)		Electric Sales (kWh)	
Residential	40.1%	Residential	19%
Comm. & Industrial	12.2%	Comm. & Indus.	51%
Interruptible	1.1%	Wholesale	30%
Transport	46.3%	Other	<1%

Regulatory Environment:	
Test Year:	Forecast- Illinois, Wisconsin Partial forecast - Michigan, Minnesota;

(TEG cont'd)

Return on Equity (Latest Allowed):	**Gas Decisions:** WPS: 10.3% (Jan 2011) PG, NSG: 10.45% (Jan 2012); MERC: 10.21% (June 2009) MGU: 10.75% (Dec 2009) **Electric Decisions:** WPS: 10.3% (Jan 2011) UPP: 10.2% (Dec 2011)
Equity Ratio (Latest Allowed):	**Gas Decisions:** WPS: 51.65% (Jan 2011) PG, NSG: 49% and 50.0%, respectively (Jan 2012) MERC: 48.77% (June 2009) MGU: 46.49% (Dec 2009) **Electric Decisions:** WPS: 51.65% (Jan 2011) UPP: 45.74% (Dec 2011)
Earnings Sharing:	n/a
Deferral Mechanisms:[i]	**MI:** uncollectible expense true-up mechanism for MGU. **MN:** n/a **IL:** *Gas* - bad debt riders; infrastructure cost recovery **WI:** pension and other post retirement benefit costs related to 2008 losses (approved 2009)
Fuel/Gas Cost Recovery:	**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. **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 costs. **MI**: The Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) clauses require utilities to annually file projected costs, and a forward-looking PSCR or GCR supply factor is established at the beginning of the 12 month collection period. Annual reconciliation proceedings are required. **IL:** *Electric* - The power to meet the utilities' standard offer service (SOS) obligations is procured competitively; SOS costs and revenues are subject to an annual true-up mechanism. *Gas* - PGA clause

(TEG cont'd)

Sales and Weather Normalization:	**Decoupling:** **WI -** WPS' decoupling mechanism includes an annual cap for the deferral of any excess or shortfall from the rate case authorized margin ($8m gas; $14m electric) **MI -** UPP's decoupling mechanism terminated effective 1/2012 by settlement- new mechanism to commence 1/2013 **IL -** 1/2012 decision made permanent for both NSG & PG a decoupling mechanism (Volume Balancing Rider (VBA)) first approved in 2008; also established rate design permitting 67% (NSG) and 55% (PG) of fixed costs to be recovered in customer charges **MN -** n/a
RRA Regulatory Climate:[ii]	Below Average 2 (IL) Average 1 (MI) Average 2 (MN) and Above Average 2 (WI)
Moody's Rating Methodology:[iii] 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/A
S&P's Regulatory Comment	" Wisconsin regulation to be in the 'more credit supportive' category" "possible increased regulatory risk for the Illinois gas companies"

Northwest Natural Gas Co.

Operating Characteristics:	
Operations:	*Utility* – local regulated gas distribution business *Gas Storage* – storage services to intrastate and interstate customers and asset optimization services *Other* – investments in gas pipelines (1% of assets)
Total Assets:	$2600 million
Percentage of Assets in Gas and Electric Operations:	Approximately 92% of assets in gas operations.
State(s) of Operation:	90 communities in Oregon and southwest Washington, including Portland and Eugene OR, and Vancouver WA.
Number of Customers:	674,000 customers (90% customer base in Oregon)
Customers by Type:	**Customer Type** / **2010 % of Revenues** Residential 61% Commercial 30% Industrial 9%
Regulatory Environment:	
Test Year:	Partial or full forecast for Oregon Historic with adjustments for known and measurable changes for Washington
Return on Equity (Latest Allowed):	10.2% (2003 OR) 10.1% (2008 WA)
Equity Ratio (Latest Allowed):	49.50% (2003 OR) 50.74% (2008 WA)
Earnings Sharing:	Tied to PGA option; see Fuel/Gas Cost Recovery
Deferral Mechanisms:[i]	Pipeline integrity management program Pension expense deferral Environmental cost deferral Lost and unaccounted for gas mechanism Infrastructure cost recovery mechanism
Fuel/Gas Cost Recovery:	PGA in Oregon – contains an incentive mechanism whereby a percentage of various between companies' cost of gas in rates and actual cost is absorbed or retained by the LDC - subject to annual earnings review PGA in Washington requires 100% pass through of prudently incurred gas cost deferrals
Sales and Weather Normalization:	Revenue decoupling in Oregon; Weather normalization adjustment in Oregon (through 2012).

(NWN cont'd)

RRA Regulatory Climate:[ii]	Average 3 (OR and WA)
Moody's Rating Methodology:[iii] 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	"..supportive rate design and incentive programs that allow exceptionally stable cash flows that are largely insulated from gas price, weather, and usage rate fluctuations."

Piedmont Natural Gas

Operating Characteristics:	
Operations:	*Regulated* – distribution of natural gas *Unregulated* – retail natural gas marketing, storage and transportation
Total Assets:	$3,140 million
Percentage of Assets in Utility Operations:	Approximately 95%
State(s) of Operation:	North Carolina (72% net utility plant), South Carolina, Tennessee
Number of Customers:	968,188 customers
Customers by Type:	**Customer Type** — **2011 % of Revenues** Residential — 56% Commercial — 32% Industrial — 9%
Regulatory Environment:	
Test Year:	Historic test period in NC and SC (adjusted for known and measurable changes) Forward test year in TN
Return on Equity (Latest Allowed):	10.6% (2008 NC) 11.3% (2011 SC) 10.2% (2011 TN, stipulation)
Equity Ratio (Latest Allowed):	51% (2008 NC) 61% (2011 SC) 52.71% (2011 TN, stipulation)
Earnings Sharing:	Rate stabilization tariffs in SC: revenues adjusted annually such that earned ROE remains within a range of +/- 50 basis points of the allowed ROE of 11.3%.
Deferral Mechanisms:[i]	Pension and retirement benefits expense Environmental remediation Demand side management Pipeline integrity expense Lost and unaccounted for gas Bad debt cost recovery mechanism (NC, SC & TN)
Fuel/Gas Cost Recovery:	PGA recovers 100% of costs

(PNY cont'd)

Sales and Weather Normalization:	Decoupling tariffs in NC only. In NC the Customer Utilization Tracker (CUT) is in effect, accounting for the impact of both weather and utilization. Weather normalization in all other areas.
RRA Regulatory Climate:[ii]	Above Average 2 (NC); Average 1 (SC and TN)
Moody's Rating Methodology:[iii] Weight accorded to category in parentheses	Regulatory Framework (25%): A Ability to Recover Costs/Earn Return (25%): A Diversification (10%): A Financial Strength (40%): Baa/A
S&P's Regulatory Comment	"Supportive regulatory environment"

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:	$55,700 million
Percentage of Assets in Utility Operations:	Approximately 92%
State(s) of Utility Operations:	Majority of operations in 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** / **2010 % of Operating Revenues** Residential 38% Commercial 31% Industrial 19% Other - Retail 1% Wholesale 12%
Regulatory Environment:	
Test Year:	AL: Historic with adjustments for known and measurable changes FL: Partial or full forecast GA: Partial forecast MS: Full forecast

(SO cont'd)

Return on Equity (Latest Allowed):	13.75% (2005 AL) 10.25% (2012 FL) 11.15% (2010 GA) 10.701% (2011 MS) ROE is performance adjusted and reflects Alternative Rate Plan (ARP) filing
Equity Ratio (Latest Allowed):	45.00% (2005 AL) 38.5% (2012 FL) 51.67% (2001 GA) 47.51% (2011 MS) based on ARP filing
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:[i]	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:[ii]	Above Average 2 (AL and MS) Average 1 (FL and GA)
Moody's Rating Methodology:[iii] 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:	$4,795 million
Percentage of Assets in Utility Operations:	Approximately 82% in utility operations; approximately 20% in generation.
State(s) of Operation:	Nearly 2/3rds of the state of Indiana (gas and electric) and part of Ohio (gas).
Number of Customers:	681,000 gas and 142,000 electric customers in central and southern Indiana. 314,000 gas customers in west central Ohio.
Customers by Type:	**Customer Type** — **2010 % of Margin** Residential & Comm. — 86% Industrial — 12% Other — 3%
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% (2011) Vectren Energy Delivery Ohio: 8.89% overall return (2009) settlement **Gas:** Indiana Gas: 10.20% (2008) SIGECO: 10.15% (2007)
Equity Ratio (Latest Allowed):	SIGECO: 43.46% (2011) 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:[i]	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:	Decoupling (gas) in IN through weather normalization and conservation tariffs Straight fixed variable rate design (OH)
RRA Regulatory Climate:[ii]	Above Average 3 (IN) Average 1 (OH)
Moody's Rating Methodology:[iii] Weight accorded to category in parentheses Note: Info for Vectren Utility Hldgs.	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): A Diversification (10%): Baa Financial Strength (40%):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 (Wisconsin Electric, Wisconsin Gas). Completed sale of Edison Sault in 2010. *Non-Utility Energy* –We Power designs, constructs, owns, and leases generating capacity.
Total Assets:	$13,059 million
Percentage of Assets in Utility Operations:	Approximately 80% in utility operations; approximately 53% in generation
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:	**2010% Revenues** **Customer Type** / **Electric** / **Gas** Residential / 38% / 63% Comm./Industrial / 55% / 31% Other / 7% / 6%
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:[i]	Bad debt expense, recovery of unrecovered transmission costs

(WEC cont'd)

Fuel/Gas Cost Recovery:	Gas: Full recovery. One-for-one recovery measured against a monthly benchmark with 2% tolerance. Costs above the benchmark subject to further review. Fuel and Purchased Power: no automatic adjustments; 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:	n/a
RRA Regulatory Climate:[ii]	Above Average 2 (WI) Average 1 (MI)
Moody's Rating Methodology:[iii] 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"

WGL Holdings Inc.

Operating Characteristics:	
Operations:	*Regulated Utility* – Washington Gas (DC,MD & VA) and Hampshire (FERC) *Retail Energy-Marketing* –sales of natural gas and electric commodity *Design-Build energy systems*-energy efficiency solutions to government and commercial customers
Total Assets:	$1730 million
Percentage of Assets in Utility Operations:	Approximately 86%
State(s) of Operation:	District of Columbia, Maryland and Virginia
Number of Customers:	1.1 Million – 14% DC, 41% MD, 45% VA
Customers by Type:	**Customer Type** — **2009 % of Therms Delivered** Residential — 77.3% Commercial and Industrial — 22.7%
Regulatory Environment:	
Test Year:	Partial forecast for Maryland and Washington D.C. Historic with adjustments for known and measurable changes for Virginia
Return on Equity (Latest Allowed):	District of Columbia: 10.0% (2006) Maryland: 9.6% (2011) Virginia: 10.0% (2011)
Equity Ratio (Latest Allowed):	50.30% (2003 DC); unspecified in 2006 57.88% (2011 MD) 55.70% (2011 VA)
Earnings Sharing:	n/a
Deferral Mechanisms:[i]	Trackers for pension and OPEB expenses and Lost and unaccounted for gas; accelerated recovery mechanisms for costs of eligible infrastructure replacement programs in VA
Fuel/Gas Cost Recovery:	PGAs recover 100% of costs. A Gas Administrative Charge (GAC) permits company to recover bad debts relating to gas costs through the purchased gas charge clause rather than base rates.

(WGL cont'd)

Sales and Weather Normalization:	Weather normalization (VA) Decoupling (MD) Declining block rates (MD, VA)
RRA Regulatory Climate:[ii]	Below Average 2 (MD) Average 2 (DC) Above Average 3 (VA)
Moody's Rating Methodology:[iii] Weight accorded to category in parentheses Note: Info for Washington Gas Light	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): A Diversification (10%): A Financial Strength (40%): A/Aa
S&P's Regulatory Comment	"Supportive regulatory environment with favorable cost recovery mechanisms that enhance cash flow predictability"

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 Utility Operations:	Approximately 95%
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) 10.40% (2012 ND) 10.18% (2008 NM) 8.32% (2010 SD) overall ROE, settlement 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) 52.30% (2009 WI) **Gas:** 60.17% (2007 CO) 52.46% (2010 MN) 51.77% (2008 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:[i]	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: no automatic adjustments; 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:	n/a
RRA Regulatory Climate:[ii]	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:[iii] Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): A Diversification (10%): A Financial Strength (40%): A/Baa
S&P's Regulatory Comment	"credit supportive regulation"

[i] Lost and Unaccounted for Gas Trackers (LUAF) are in 47 of 50 states (excluding Michigan, Montana and South Dakota) (AGA, *Innovative Rates, Non-Volumetric Rates, and Tracking Mechanisms: As of December 2011)*

[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 RRA's 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: i) (Cash from operations (CFO) pre-working capital (WC) plus interest) over interest expense; ii) CFO Pre-WC/Debt; iii) (CFO Pre-WC less dividends)/Debt; and iv) 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:

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

where,

$\mathbf{D_1}$	=	next expected dividend[1]
$\mathbf{P_o}$	=	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).

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:

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

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 consensus earnings growth forecasts were obtained from four different sources, Bloomberg: Reuters, *Value Line* and Zacks. Bloomberg[2] and Reuters[3] are both global providers 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.

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

[2] Bloomberg data are available for a fee on the internet and through "Bloomberg terminals". Bloomberg has offices in more than 200 places around the world.

[3] Reuters provides real time forecasts for over 20,000 active companies from over 600 contributing brokerage firms in more than 70 countries. Reuters is part of Thomson Reuters, which also publishes I/B/E/S and First Call consensus earnings growth estimates.

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 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 Thomson Reuters I/B/E/S earnings growth forecasts, for which Foster Associates maintains a data base which contains monthly consensus forecasts for utilities back to 1976, were compared to the consensus forecasts of long-term growth. From 1998-2011, the period of analysis used in the DCF-based risk premium test, the average I/B/E/S forecast long-term earnings growth rate for the sample of low risk U.S. utilities was 5.1%. That growth rate is the same as the average consensus forecast of long-term nominal growth in the economy over the same period. 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, 1998-2011), was 5.1% from 1998-2011. The similar expected nominal growth in the economy compared to the I/B/E/S forecasts suggests that the consensus long-term earnings growth 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* has 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. Since 1998, 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 5.1%. Again, the higher *Value Line* than I/B/E/S forecasts suggest that the consensus long-term earnings 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 consensus long-term earnings forecasts over the same period (1998-2011), the comparison shows that the allowed returns for all U.S. utilities as reported by RRA exceeded the returns estimated using the constant growth DCF models as follows:

Table C-1

Average Allowed ROEs (1998-2011)	10.7%	**Average Difference From Allowed ROEs**
Constant Growth DCF Cost of Equity (1998-2011)	10.0%	-0.7%

Sources: Schedule 14, page 1 of 4 and Schedule 15, 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. low risk utilities using the following inputs to calculate the dividend yield:

(1) the most recent annualized dividend paid as of January 31, 2012 as D_o; and,

(2) the average of the daily close prices for the period November 1, 2011 to January 31, 2012 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 Bloomberg, 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 January 2012 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 2011 *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. low risk 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 2013-2022 found in Blue Chip *Financial Forecasts*, December 1, 2011.[4]

The three-stage DCF test determines the utility cost of equity as the internal rate of return derived from the forecast stream of annual cash flows.

[4] Published twice annually in June and December.

APPENDIX D

DCF-BASED EQUITY RISK PREMIUM TEST

1. INTRODUCTION

The DCF-based equity risk premium is a forward-looking test which uses the discounted cash flow model and long-term government bond yields to estimate expected utility returns and risk premiums over time. The utility equity risk premium is measured as the difference between the DCF cost of equity and the yield on long-term government bond yields. The advantage of the DCF-based equity risk premium test is that it allows for testing of the relationship between the utility cost of equity (or the utility equity risk premium) and interest rates.

2. SAMPLE OF LOW RISK U.S. UTILITIES

The same sample of U.S. utilities was used to perform the DCF-based equity risk premium tests as for the DCF test. The selection criteria for the sample of U.S. utilities are described in Appendix B.

3. CONSTRUCTION OF THE CONSTANT GROWTH DCF-BASED EQUITY RISK PREMIUM TEST

To estimate each monthly sample DCF cost of equity, the monthly published long-term earnings growth rate forecast (**g**) for each of the sample utilities was retrieved from the I/B/E/S data base, from which the monthly sample median was calculated. For each month of the analysis, the current dividend yield (**DY**) for each utility was calculated as the most recent quarterly dividend paid, annualized, divided by the monthly closing price. The expected dividend yield (**DY_e**) for the sample was then calculated by adjusting the monthly median dividend yield for the monthly median forecast earnings growth rate **(DY_e=DY x (1+g))**. The sample DCF cost of equity (DCF) in each month was calculated by combining the forecast growth rate and the expected dividend yield. The monthly utility sample equity risk premium **(ERP)** was calculated by subtracting the corresponding 30-year Treasury yield **(TY)** from the DCF cost of equity **(ERP=DCF–TY)**. The annual averages of the monthly utility sample constant growth DCF costs of equity, Treasury bond yields and utility equity risk premiums are found on Schedule 14, page 1 of 4.

4. CONSTRUCTION OF THE THREE-STAGE GROWTH DCF-BASED EQUITY RISK PREMIUM TEST

A three-stage growth model was also used in the application of the DCF-based equity risk premium test. As with the constant growth model, monthly estimates of the DCF cost of equity were made for the sample, using the sample median dividend yield as the point of departure.

For the forecast growth rates, the first stage (Years 1 to 5) of the model used the sample median I/B/E/S forecast growth rate published in that month. 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*. Blue Chip *Financial Forecasts* publishes long-term GDP growth forecasts in June and December of each year. 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.

For each month of the analysis, the DCF cost of equity was then determined for the utility sample using the forecast stream of annual cash flows to derive the internal rate of return.

As with the constant growth DCF-based risk premium test, the utility sample monthly equity risk premium **(ERP)** was calculated by subtracting the corresponding 30-year Treasury yield **(TY)** from the monthly DCF cost of equity **(ERP=DCF–TY).** The annual averages of the three-stage DCF model costs of equity, Treasury bond yields and utility equity risk premiums are found on Schedule 14, page 3 of 4.

APPENDIX E

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.[1]

The Report of the IAT was accepted by the Alberta Energy and Utilities Board in Decision U99113 (December 1999).

[1] *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.[2]

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 the "book value" of the equity in my home of $15,000, which reflects the original purchase price

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[2] 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 9.5%, the indicated ROE is:

$$\text{ROE} = \frac{1.075 \times 9.5\%}{1 + [.25\ (1.075 - 1.0)]}$$

$$\text{ROE} = 10.0\%$$

The difference of 50 basis points between the ROE and the "bare-bones" cost of equity is the financing flexibility allowance.

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.[3]

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

[3] 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.[4]

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.[5]

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.

[4] Franco Modigliani and Merton H. Miller, "Corporate Income Taxes and the Cost of Capital: A Correction," *American Economic Review*, 53: 433-443 (June 1963).

[5] 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 2011 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 E-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 23 provides the formulas for estimating the change in the cost of equity due to capital structure differences under Approaches 1 and 2. When the corporate income tax rate is zero, Approach 1 and 2 result in the same adjustment to the ROE as Approach 3.

Table E-1

	Cost of Equity	Market Value Equity Ratio	Book Value Equity Ratio	Adjustment to ROE for Book Value Capital Structure		
				Approach 1 (26% tax rate)	Approach 2 (26% tax rate)	Approach 3 (0% tax rate)
Canadian Utilities	9.5%	58%	40%	2.7%	1.75%	2.1%
U.S. Utilities	9.5%	61%	50%	1.3%	0.9%	1.0%

Source: Schedules 22 and 23

Notes: Based on incremental utility cost of long-term debt of 4.8%.
Corporate income tax rate of 26% is estimated combined federal/provincial 2012 rate for Canada.

Full recognition of the difference in financial risk between the market value equity ratios of the publicly-traded Canadian utilities (58%) and the U.S. utilities (61%) and the average book value common equity ratio of investor-owned Canadian regulated utilities (40%) and the U.S. utilities (50%) equity (Schedules 5, 6, 21 and 22) results in an adjustment to the "bare bones" cost of equity in the range of approximately 1.0% to 2.0% (mid-point of approximately 1.5% or 150 basis points).

APPENDIX F

COMPARABLE EARNINGS TEST

1. SELECTION OF CANADIAN UNREGULATED COMPANIES

The selection process starts with the recognition that unregulated companies generally are exposed to higher business risk, but lower financial risk, than the typical utility. The selection of unregulated companies focuses on total investment risk, i.e., the combined business and financial risks. The unregulated companies' higher business risks are offset by a more conservative capital structure, i.e., higher equity ratios, thus permitting the selection of samples of reasonably comparable investment risk to utilities.

As a point of departure, the selection was limited to industries that are characterized by relatively stable demand characteristics, as well as consistent dividend payments and relatively low earnings and share price volatility. The initial universe consisted of all firms on the TSX in Global Industry Classification Standard (GICS) sectors 20-30. The sectors represented by the GICS codes in this range are: Industrials, Consumer Discretionary and Consumer Staples.[1] The resulting universe contained 516 firms. Companies were removed which:

- Had missing or negative common equity during 2000-2010,
- Were income trusts or incorporated outside Canada
- Paid no dividends in any year 2007 to 2011,
- Had less than five years of market data,
- Had total assets less than $500 million,
- Had a 2010 equity ratio (including short term debt) less than 50%,

[1] Included in these sectors are major industries such as: Food Retail, Food Distributors, Tobacco, Packaged Foods, Soft Drinks, Distillers, Household Appliances, Aerospace and Defense, Electrical Components & Equipment, Industrial Machinery, Publishing & Printing, Department Stores, and General Merchandise.

- Had an average 2010-2011 adjusted beta over 1.0, and
- Had debt rated non-investment grade, i.e., BB+ or below by either DBRS or Standard & Poor's.

The final sample of low risk Canadian unregulated companies is comprised of 21 companies (Schedule 24).

2. TIME PERIOD FOR MEASURING RETURNS

Since unregulated companies' returns on equity tend to be cyclical, the appropriate period for measuring unregulated company returns should encompass an entire business cycle, covering years of both expansion and decline. The cycle should be representative of a future normal cycle, e.g., relatively similar in terms of inflation and real economic growth. The period 1993-2010 constitutes a full business cycle, commencing with 1994 (the second full year of expansion following the 1991-1992 recession), including the 2008-2009 recession and the first full year of recovery (2010). Over the period 1994-2010, the experienced returns on equity of the sample of 21 low risk unregulated Canadian companies were as follows.

Table F-1

ROEs for Low Risk Canadian Unregulated Companies (1994-2010)

Average	13.6%
Median	13.3%
Average of Annual Medians	13.2%

Source: Schedule 25.

Based on these data, the ROEs for the low risk Canadian unregulated companies are in the approximate range of 13.0-13.5%.

The average nominal economic growth for Canada during the 1994-2010 business cycle was 4.9%. The historic average nominal growth rate over the full business cycle is somewhat higher than the forecast nominal GDP growth rate of approximately 4.3% from 2012 to 2021.[2]

In light of the lower forecast economic growth compared to the historical level, the achieved equity returns for the sample were also calculated over a shorter and more recent period of time (2003 to 2010) with a rate of economic growth that more closely matches the forecast rate. This period commences with the second full year following the 2001 economic downturn, and, similar to the longer period, includes the 2008-2009 recession and the first full year of recovery. Over the years 2003-2010, the nominal economic growth in Canada averaged 4.3%, identical to the average rate of growth forecast for the period 2012-2021.

The experienced returns on equity of the sample of 21 low risk unregulated Canadian companies during 2003-2010 were as follows.

Table F-2

ROEs for Low Risk Canadian Unregulated Companies (2003-2010)	
Average	13.3%
Median	12.8%
Average of Annual Medians	13.5%

Source: Schedule 25

Since nominal growth is forecast to be virtually identical to the experienced rate during 2003-2010, the experienced returns on book equity for this period of approximately 12.75% to 13.5%, absent extraordinary events, provide a reasonable proxy for the future.

[2] Based on Consensus Economics, *Consensus Forecasts*, October 2011, which anticipate real GDP growth of 2.3% and CPI inflation of 2.0% from 2012 to 2021.

3. RELATIVE RISK COMPARISON

With respect to the investment risk of the Canadian unregulated companies relative to Canadian utilities, comparisons of debt ratings and betas indicate that the unregulated companies are of somewhat higher risk than the utilities. For the unregulated companies with debt ratings, the median S&P and DBRS ratings are BBB and BBB/BBB(high) respectively, compared to Canadian utilities' median ratings of A- and A (See Schedules 4 and 24). Based on medians, the average adjusted monthly beta for the unregulated companies for the two five-year periods ending December 2010 and 2011 was 0.64 (see Schedule 24), compared to a 0.47 adjusted monthly beta for the major publicly-traded Canadian utilities over the same time period (Schedule 12).

There is no universally accepted methodology for making a downward adjustment to the unregulated low risk company returns on common equity for the lower risk of utilities. The difference in yields on A-rated utility bonds and BBB-rated corporate bonds provides one measure of a reasonable downward adjustment. Historically the average difference has been approximately 75 basis points. The relative adjusted betas of the unregulated companies and Canadian utilities can also be used as an alternative of indicator of the downward adjustment required. When applied to the difference between the achieved ROEs and the longer-term forecast 30-year Canada bond yield, the betas suggest a downward adjustment of approximately 2.25%. Together the bond yield spreads and betas indicate that a downward adjustment to the unregulated companies' ROEs in the range of 0.75% to 2.25% (mid-point of 1.5%) is reasonable. The resulting fair ROE for an average risk Canadian utility based on the comparable earnings test is approximately 11.25% to 12.0%.

4. MARKET/BOOK RATIOS

The argument that a downward adjustment to the comparable earnings test results for the market/book ratios of the unregulated companies has been made on the following bases:

a. The market/book ratio of utility common shares should be approximately 1.0 times, i.e., that the fair market value of utility shares is equal to their book value.

b. Market/book ratios of unregulated firms well in excess of 1.0 times is evidence that the companies are earning returns in excess of their cost of capital, and thus are exerting market power.

Both of these arguments are without merit. With respect to the notion that the market/book ratio of utility shares should be approximately 1.0 times, that conclusion is incompatible with the standard of comparable returns. The comparable returns standard requires that a utility have the opportunity to earn a return commensurate with returns on investments in other enterprises having corresponding risks.

Regulation is intended to be a surrogate for competition. If unregulated competitive enterprises of corresponding risks to utilities are able to maintain market/book ratios in excess of 1.0, it would be patently contrary to the to the objective of regulation and to the comparable earnings standard to reduce the returns of unregulated comparable firms in order to target a particular market/book ratio for a utility.

With respect to the second rationale, the question that needs to be addressed is whether the market/book ratios of the sample of comparable unregulated companies are evidence of market power.

To address this question, the first issue is whether the market/book ratios of competitive companies should, in principle, trend toward 1.0. Regulation is intended to be a surrogate for competition. The competitive model indicates that equity market values tend to gravitate toward the replacement cost of the underlying assets. This is due to the economic proposition that, if the discounted present value of expected returns (market value) exceeds the cost of adding capacity, firms will expand until an equilibrium is reached, i.e., when the market value equals the replacement cost of the productive capacity of the assets.

The ratio of market value to replacement cost is called the "Q Ratio", a term coined by the Nobel Prize winning economist James Tobin in the late 1960s.[3] Essentially, the economic theory is that the market value of assets in the aggregate should equate to their replacement cost, that is, the "Q Ratio" (market value/replacement cost) should trend toward 1.0.

The "Q Ratio" has since gained stature as an investment tool,[4] whose importance was underscored in a March 2002 *New York Times* article which stated, referring to Tobin's obituaries:

> Great emphasis was placed on how revolutionary his insights were three, four or five decades ago. Yet most were relatively silent on how those insights can lead us to be more successful investors today. It is a shame. Investors greatly handicap themselves if they ignore Dr. Tobin's work.
>
> Consider Tobin's Q, the ratio for which Dr. Tobin, at least at one time, was most famous among investors. This is the ratio of a company's total market capitalization to the replacement value of that company's total assets. <u>While the Q ratio – as Tobin's Q is often called – is conceptually similar to the price-to-book ratio, it avoids the myriad accounting difficulties associated with book value. For example, while book value carries assets at depreciated original cost, replacement value focuses on how much it would cost to buy those assets today</u>. [emphasis added]

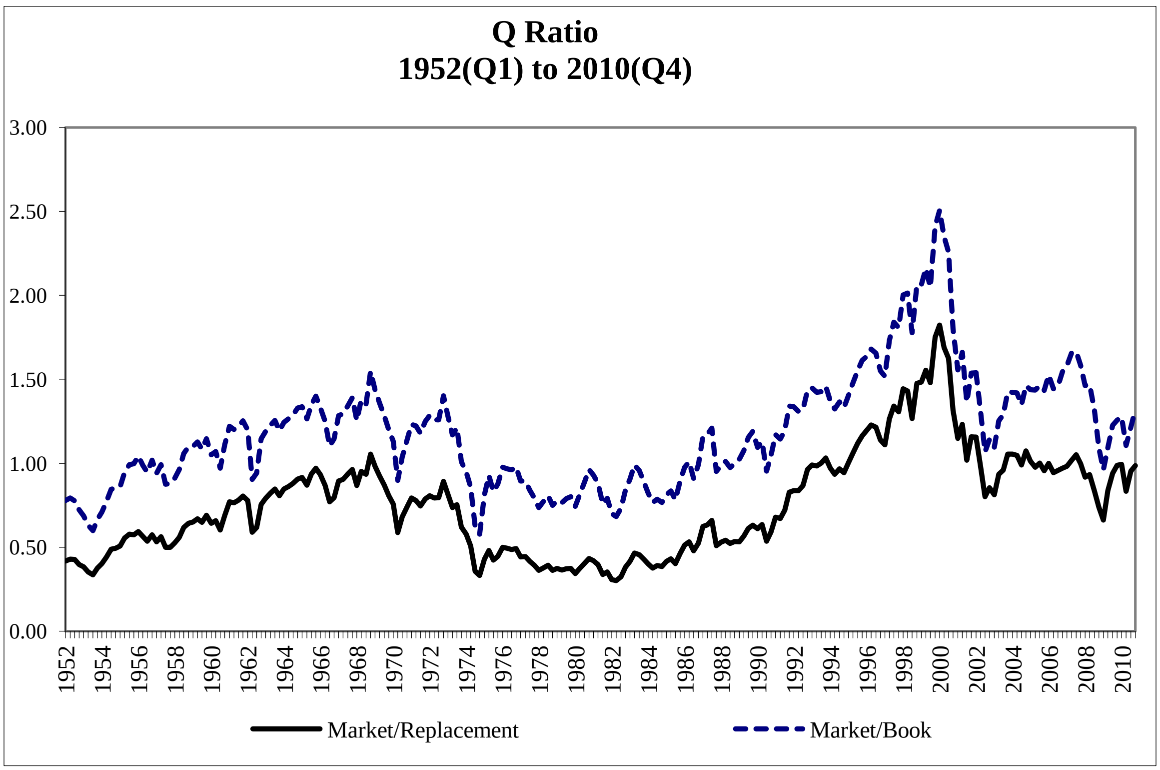
Absent inflation and technological change, the market value and replacement cost of firms operating in a competitive environment would tend to equal their book value or cost. However, the fact that inflation has occurred, and continues to occur, renders that relationship invalid. With inflation, under competition, the market value of a firm trends toward the current cost of its assets. The book value of the assets, in contrast, reflects the historic depreciated cost of the

[3] The general idea had been expressed decades earlier by the economist John Keynes.
[4] The Federal Reserve Board tracks the "Q Ratio" of the U.S. equity market. It was the level of the "Q Ratio", along with the price/dividend ratio, that led Fed Chairman Alan Greenspan to warn of a speculative bubble in the equity market as early as 1996.

assets. Since there have been moderate to relatively high levels of inflation over the past twenty-five years, it is reasonable to expect market values to exceed the book value of those assets.

As indicated in Figure F-1 below, market/replacement cost ratios for U.S. firms, as derived from the flow of funds accounts, have been systematically lower than the market to original cost ratios. For the U.S., the market/replacement cost ratio for corporations[5] has averaged approximately 30% lower than the market/book ratio over the business cycle 1994-2010.

Figure F-1

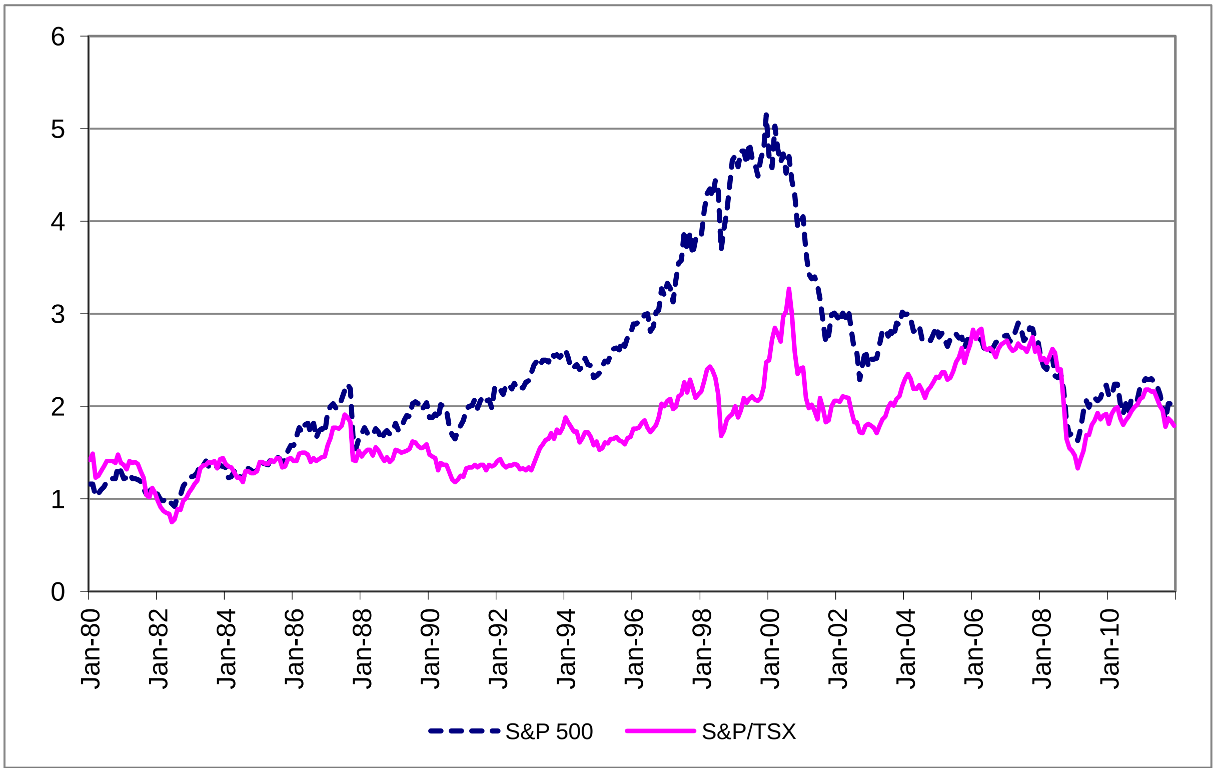


Source: US Federal Reserve Flow of Funds (B102).

To test the potential for market power in the achieved returns of the sample of low risk unregulated Canadian firms used in the comparable earnings test, their market/book ratios were compared to those of Canadian and U.S. equity market composites. The figure below tracks the market/book values for the S&P/TSX Composite and the S&P 500 from 1980-2011.

[5] Based on non-farm, non-financial corporate businesses.

Figure F-2



Source: RBC Capital Markets Quantitative Research

The data from which the table was created indicate that the market/book ratio for the overall Canadian equity market has averaged approximately 1.8 times from 1980-2011, and 2.1 times from 1994-2010, the last full business cycle and 2.3 times from 2003-2010, the period over which the comparable earnings test was conducted. Based on over three decades of data, the market/book ratio for the Canadian equity market has varied around an average of close to 1.8 times, not 1.0 times. For the S&P 500, the market/book ratios were approximately 2.4 times, 3.0 times, and 2.6 times respectively, over the same three periods. Over both periods 1994-2010 and 2003-2010, the market/book ratios for the sample of comparable Canadian unregulated companies averaged 2.3 times, approximately equal to the average for the S&P/TSX Composite and lower than the market/book ratio of the S&P 500. The similar to lower average market/book ratio of the low risk unregulated Canadian companies relative to the Canadian and U.S. equity market composites permit the inference that the sample average returns are not characterized by market power. Thus, no adjustment to the comparable earnings results is warranted for the market/book ratios of the low risk unregulated companies.

APPENDIX G

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.
- "The Fair Return", (co-authored with Michael Cleland), *Energy Law and Policy*, Gordon Kaiser and Bob Heggie, eds., Toronto: Carswell Legal Publications, 2011.

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, 2010

ATCO Gas
2000, 2003, 2007

ATCO Pipelines
2000, 2003, 2007, 2011

ATCO Utilities
(Generic Cost of Capital) 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

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

EPCOR Water Services Inc.
1994, 2000, 2006, 2008, 2011

FortisBC
1995, 1999, 2001, 2004

FortisBC Energy Inc.
1992, 1994, 2005, 2009, 2011

FortisBC Energy (Whistler) Inc.
2008

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, 2011

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, 2011

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

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
Heritage Gas	Criteria for a Mature Utility	2011
Alberta Utilities	Management Fee on CIAC	2011
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

SELECTED INDICATORS OF ECONOMIC ACTIVITY
(1989 = 100)

		Canada							United States				
		Gross Domestic Product					After-Tax Profits		Gross Domestic Product				
Year		Constant Dollars	Current Dollars	Industrial Production	GDP Deflator Index	Consumer Price Index	Billions of Dollars	As Percent of GDP	Constant Dollars	Current Dollars	Industrial Production	Implicit Price Index	Consumer Price Index
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1989		100.0	100.0	100.0	100.0	100.0	41	6.3%	100.0	100.0	100.0	100.0	100.0
1990		100.2	103.4	97.2	103.2	104.8	28	4.1%	101.9	105.8	101.0	103.9	105.4
1991		98.1	104.2	93.5	106.2	110.7	18	2.6%	101.6	109.3	99.4	107.5	109.8
1992		99.0	106.5	94.5	107.6	112.3	18	2.6%	105.1	115.7	102.2	110.1	113.2
1993		101.3	110.6	98.8	109.2	114.4	25	3.4%	108.1	121.6	105.5	112.5	116.5
1994		106.1	117.2	105.1	110.4	114.6	46	6.0%	112.5	129.2	111.1	114.9	119.5
1995		109.1	122.7	109.9	112.9	117.1	54	6.7%	115.3	135.3	116.4	117.3	122.9
1996		110.9	126.8	111.8	114.7	118.9	54	6.5%	119.6	143.0	121.6	119.5	126.5
1997		115.6	133.5	118.0	116.1	120.8	56	6.3%	125.0	152.0	130.3	121.6	129.5
1998		120.3	139.2	122.2	115.6	122.0	55	6.0%	130.4	160.4	137.9	123.0	131.5
1999		127.0	149.4	129.8	117.6	124.2	71	7.3%	136.7	170.6	143.8	124.8	134.4
2000		133.6	163.5	139.6	122.5	127.5	88	8.1%	142.4	181.5	149.6	127.5	138.9
2001		136.0	168.5	134.6	123.9	130.8	91	8.2%	143.9	187.6	144.5	130.4	142.8
2002		140.0	175.3	137.5	125.2	133.7	99	8.6%	146.5	194.1	144.8	132.5	145.1
2003		142.6	184.4	137.7	129.4	137.4	105	8.6%	150.2	203.2	146.6	135.3	148.4
2004		147.0	196.3	139.8	133.5	139.9	122	9.4%	155.4	216.2	150.0	139.1	152.3
2005		151.5	208.9	142.1	137.9	143.0	138	10.0%	160.2	230.3	154.9	143.7	157.5
2006		155.8	220.5	142.1	141.6	145.9	140	9.7%	164.5	244.0	158.3	148.4	162.6
2007		159.2	232.6	141.4	146.1	149.0	146	9.5%	167.6	255.9	162.5	152.7	167.2
2008		160.3	243.8	137.1	152.1	152.6	168	10.5%	167.0	260.7	156.5	156.1	173.6
2009		155.8	232.5	124.1	149.2	153.0	96	6.3%	161.2	254.3	139.0	157.7	173.0
2010		160.9	247.0	130.2	153.6	155.7	126	7.7%	166.1	265.0	146.3	159.5	175.9
2007	1Q	157.6	227.6	142.4	144.4	147.4	139	9.3%	165.7	251.0	160.9	151.5	164.3
	2Q	158.9	232.5	142.3	146.3	149.6	144	9.4%	167.2	255.0	162.7	152.5	167.5
	3Q	159.7	233.4	141.4	146.2	149.6	148	9.6%	168.4	257.7	163.1	153.0	167.9
	4Q	160.5	236.7	139.7	147.4	149.5	152	9.8%	169.1	260.0	163.2	153.7	169.1
2008	1Q	160.3	240.3	138.2	150.0	150.0	163	10.3%	168.4	260.4	162.7	154.6	171.0
	2Q	160.5	246.5	137.6	153.6	153.1	181	11.2%	168.9	263.0	159.9	155.7	174.8
	3Q	160.9	249.3	138.0	155.0	154.7	186	11.4%	167.4	262.6	154.8	156.9	176.8
	4Q	159.4	239.0	134.4	150.0	152.4	142	9.0%	163.5	256.9	148.4	157.1	171.8
2009	1Q	156.1	230.7	128.0	147.8	151.9	105	6.9%	160.7	253.4	140.8	157.7	171.0
	2Q	154.7	229.3	122.6	148.3	153.2	93	6.2%	160.4	252.7	136.6	157.5	172.8
	3Q	155.3	232.0	121.6	149.5	153.4	91	6.0%	161.1	253.9	138.4	157.6	174.0
	4Q	157.2	237.8	124.1	151.3	153.6	93	6.0%	162.6	257.0	140.3	158.0	174.3
2010	1Q	159.4	243.4	127.3	152.7	154.4	109	6.8%	164.2	260.4	143.0	158.6	175.0
	2Q	160.3	244.8	130.1	152.8	155.3	114	7.1%	165.7	263.9	145.5	159.2	175.8
	3Q	161.3	247.1	131.0	153.3	156.2	133	8.2%	166.8	266.4	147.9	159.8	176.0
	4Q	162.5	252.7	132.3	155.6	157.1	146	8.8%	167.7	269.1	149.0	160.5	176.5
2011	1Q	163.9	257.4	134.6	157.1	158.4	156	9.2%	167.9	271.2	150.8	161.6	178.8
	2Q	163.7	258.7	133.1	158.1	160.6	150	8.8%	168.4	273.9	150.9	162.6	181.9
	3Q	165.1	261.7	135.6	158.6	160.9	159	9.3%	169.2	276.8	153.3	163.6	182.6

Note: Data are based on Chain Weighted Indexes.

Source: www.bea.gov, www.cansim2.statcan.ca, www.federalreserve.gov

TREND IN INTEREST RATES AND OUTSTANDING BOND YIELDS
(Percent Per Annum)

	Canada											Moody's U.S. Utility Long-Term	Exchange Rate
	Government Securities												
	T-Bills		10 Year		Long-Term		Bonds Over	Inflation	A-Rated	A-Rated Utility/ Long Canada Bond			
Year	Canadian	U.S. [1/]	Canadian	U.S.	Canadian	U.S. [2/]	10 Years [3/]	Indexed Bonds	Utility Bonds [4/]	Yield Spread		A-Rated Bonds	(Cdn$/US$)
Annual													
1990	12.81	7.49	10.76	8.55	10.69	8.61	10.85		12.13	1.44		9.86	0.86
1991	8.73	5.38	9.42	7.86	9.72	8.14	9.76		11.00	1.28		9.36	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	0.97
2011	0.91	0.06	2.76	2.75	3.26	3.86	3.19	0.92	4.82	1.56		5.00	1.02

[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 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)

		Canada											
		Government Securities									A-Rated Utility/ Long Canada	Moody's U.S. Utility	
		T-Bills		10 Year		Long-Term		Bonds Over	Inflation	A-Rated	Bond	Long-Term	Exchange Rate
Year		Canadian	U.S. 1/	Canadian	U.S.	Canadian	U.S. 2/	10 Years 3/	Indexed Bonds	Utility Bonds 4/	Yield Spread	A-Rated Bonds	(Cdn$/US$)
2005	q1	2.47	2.67	4.27	4.33	4.72	4.70	4.69	2.05	5.78	1.06	5.72	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	0.99
2011	q1	0.95	0.13	3.31	3.44	3.73	4.53	3.68	1.25	5.18	1.46	5.56	1.02
	q2	0.96	0.04	3.13	3.18	3.58	4.33	3.50	1.00	5.07	1.49	5.37	1.04
	q3	0.88	0.05	2.48	2.32	3.05	3.54	2.96	0.83	4.65	1.60	4.74	1.01
	q4	0.86	0.01	2.13	2.05	2.70	3.04	2.61	0.58	4.37	1.67	4.35	0.99
2008	Jan	3.38	1.96	3.88	3.67	4.18	4.35	4.16	1.96	5.67	1.49	6.07	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	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	1.03
	Mar	0.93	0.09	3.35	3.47	3.75	4.51	3.70	1.15	5.23	1.48	5.57	1.03
	Apr	0.98	0.04	3.20	3.32	3.69	4.40	3.62	1.00	5.19	1.50	5.46	1.05
	May	0.96	0.06	3.07	3.05	3.49	4.22	3.38	0.98	4.97	1.48	5.23	1.03
	Jun	0.93	0.03	3.11	3.18	3.55	4.38	3.49	1.03	5.04	1.49	5.41	1.04
	Jul	0.91	0.10	2.79	2.82	3.29	4.12	3.21	0.79	4.73	1.44	5.09	1.05
	Aug	0.93	0.02	2.49	2.23	3.10	3.60	3.00	0.88	4.74	1.64	4.74	1.02
	Sep	0.80	0.02	2.15	1.92	2.77	2.90	2.68	0.82	4.49	1.72	4.38	0.96
	Oct	0.89	0.01	2.29	2.17	2.92	3.16	2.81	0.67	4.54	1.62	4.42	1.01
	Nov	0.86	0.01	2.15	2.08	2.69	3.06	2.61	0.61	4.41	1.72	4.38	0.98
	Dec	0.82	0.02	1.94	1.89	2.49	2.89	2.41	0.45	4.17	1.68	4.24	0.98
2012	Jan	0.88	0.06	1.89	1.83	2.50	2.94	2.40	0.38	4.05	1.55	4.22	0.99

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 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	12/11	AUC	2011-474	63.00	0.00	37.00	8.75	3.60	
ATCO Electric									
Transmission	12/11	AUC	2011-474	52.81	10.19	37.00	8.75	3.60	
Distribution	12/11	AUC	2011-474	50.95	10.05	39.00	8.75	3.60	
ENMAX									
Transmission	12/11	AUC	2011-474	63.00	0.00	37.00	8.75	3.60	
Distribution	12/11	AUC	2011-474	59.00	0.00	41.00	8.75	3.60	
EPCOR									
Transmission	12/11	AUC	2011-474	63.00	0.00	37.00	8.75	3.60	
Distribution	12/11	AUC	2011-474	59.00	0.00	41.00	8.75	3.60	
FortisAlberta Inc.	12/11	AUC	2011-474	59.00	0.00	41.00	8.75	3.60	
FortisBC Inc.	5/05; 12/09	BCUC	G-52-05; G-158-09	60.00	0.00	40.00	9.90	4.30	
Hydro One Transmission	12/10; 11/11	OEB	EB-2010-0002; Letter Cost of Capital Parameters	60.00	0.00	40.00	9.42	3.40	
Maritime Electric	7/10	IRAC	UE-10-03	59.50	0.00	40.50	9.75	n/a	1/
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	11/11	NSUARB	2011 NSUARB 184	53.30	9.20	37.50	9.20	n/a	
Ontario Electricity Distributors	12/09; 11/11	OEB	EB-2009-0084; Letter Cost of Capital Parameters	60.00	0.00	40.00	9.42	3.40	
Ontario Power Generation	3/11	OEB	EB-2010-0008	53.00	0.00	47.00	9.55	3.85	
Gas Distributors									
ATCO Gas	12/11	AUC	2011-474	53.09	7.91	39.00	8.75	3.60	
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	
FortisBC Energy Inc.	12/09	BCUC	G-158-09	60.00	0.00	40.00	9.50	4.30	
FortisBC Energy (Vancouver Island)	12/09	BCUC	G-14-06; G-158-09	60.00	0.00	40.00	10.00	4.30	
Gaz Métro	11/11	Régie	D-2011-182	54.00	7.50	38.50	8.90	4.00	
Pacific Northern Gas-West	12/09; 5/10	BCUC	G-158-09; G-84-10	51.15	3.85	45.00	10.15	4.30	
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									
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; 11/10	NEB	RH-2-94;TG-06-2007; NEB Letter 11-10	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/ In 2010, the Electric Power Amendment Act reduced electricity rates and froze them until March 2013.
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																					
AltaGas Utilities	NA	13.50	13.25	NA	NA	12.00	11.75	11.75	11.75	11.75	9.90	9.70	9.70	9.50	9.60	9.50	8.93	8.51	8.75	9.00	9.00
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
FortisBC Energy 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
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
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**	**13.60**	**13.09**	**12.51**	**11.65**	**12.03**	**11.69**	**11.07**	**10.48**	**9.96**	**9.84**	**9.68**	**9.68**	**9.73**	**9.52**	**9.51**	**8.96**	**8.58**	**8.77**	**8.75**	**9.11**
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**	**12.97**	**12.16**	**11.50**	**12.12**	**11.39**	**10.93**	**10.30**	**9.69**	**9.80**	**9.69**	**9.62**	**9.70**	**9.59**	**9.51**	**9.01**	**8.65**	**8.77**	**8.79**	**9.10**

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

Note: The allowed ROEs for ENMAX Distribution, EPCOR Distribution and EPCOR Transmission have been identical to those of the other Alberta utilities since 2004 (ENMAX Transmission since 2006).

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	3.84	12.51	8.09	4.43	12.46	8.09	4.38	12.55	8.09	4.47
1992	12.97	8.68	4.29	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	12.12	8.41	3.71	11.51	6.81	4.70	11.43	6.81	4.62	11.55	6.81	4.74
1996	11.39	7.75	3.65	11.29	6.72	4.57	11.19	6.72	4.47	11.39	6.72	4.67
1997	10.93	6.66	4.27	11.34	6.57	4.77	11.29	6.57	4.72	11.40	6.57	4.83
1998	10.30	5.59	4.71	11.59	5.53	6.06	11.51	5.53	5.98	11.66	5.53	6.13
1999	9.69	5.72	3.97	10.74	5.91	4.83	10.66	5.91	4.75	10.77	5.91	4.86
2000	9.80	5.71	4.09	11.41	5.88	5.53	11.39	5.88	5.51	11.43	5.88	5.55
2001	9.69	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	3.96	11.10	5.41	5.69	11.03	5.41	5.62	11.16	5.41	5.75
2003	9.70	5.31	4.39	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	9.01	4.26	4.75	10.39	4.87	5.52	10.44	4.87	5.57	10.36	4.87	5.49
2007	8.65	4.30	4.36	10.30	4.80	5.51	10.24	4.80	5.44	10.36	4.80	5.56
2008	8.77	4.04	4.73	10.42	4.22	6.20	10.37	4.22	6.15	10.46	4.22	6.24
2009	8.79	3.85	4.94	10.36	4.10	6.27	10.19	4.10	6.10	10.48	4.10	6.39
2010	9.10	3.70	5.41	10.24	4.17	6.07	10.08	4.17	5.91	10.34	4.17	6.17
2011	9.00	3.26	5.74	10.14	3.86	6.28	9.92	3.86	6.06	10.22	3.86	6.36
Means:												
1990-1993	**13.09**	**9.24**	**3.85**	**12.16**	**7.74**	**4.42**	**12.12**	**7.74**	**4.38**	**12.19**	**7.74**	**4.45**
1994-1997	**11.49**	**7.88**	**3.61**	**11.37**	**6.88**	**4.49**	**11.32**	**6.88**	**4.44**	**11.42**	**6.88**	**4.54**
1998-2011	**9.37**	**4.76**	**4.61**	**10.71**	**4.92**	**5.79**	**10.63**	**4.92**	**5.71**	**10.76**	**4.92**	**5.84**
1996-2011	**9.60**	**5.07**	**4.53**	**10.78**	**5.13**	**5.65**	**10.71**	**5.13**	**5.57**	**10.84**	**5.13**	**5.70**

Sources: www.bankofcanada.ca; Canadian Regulatory decisions; www.federalreserve.gov; Regulatory Research Associates at www.snl.com; www.ustreas.gov.

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	A (Senior Unsecured)					
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 (First Mortgage)	Baa1	A2 (First Mortgage)			
Nova Scotia Power		A(low) (Unsecured)	[2]	[2]	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
FortisBC Energy Inc. [3]		A (Senior Unsecured)		A3 (Senior Unsecured)	A	A (Senior Unsecured)	
		A (Senior Secured)		A1 (Senior Secured)		AA- (Senior Secured)	
FortisBC Energy Inc. (Vancouver Island)		BBB(high) (Debentures)		A3 (Senior Unsecured)			
Gaz Métro Inc.		A (Senior Secured)			A-	A (Senior Secured)	Excellent
Pacific Northern Gas		BBB(low) (Senior Secured)					
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)	
Trans Québec & Maritimes Pipeline		A(low) (Senior Unsecured)			BBB+	BBB+ (Senior Unsecured)	Strong
TransCanada PipeLines Ltd.		A (Senior Unsecured)	A3	A3 (Senior Unsecured)	A-	A- (Senior Unsecured)	Excellent
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-**	**Excellent/Strong**
All Companies		**A**		**A3**	**A-**	**A-**	**Excellent**
All Investor Owned Companies		**A**		**A3**	**A-**	**A-**	**Excellent**

[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 of company March 2010; unsecured debt previously rated Baa1.
[3] S&P ratings affirmed at AA- for Senior Secured Debt and A for Unsecured Debt, then withdrawn September 23, 2010.

Source: www.dbrs.com, www.moodys.com, Standard & Poor's, *Issuer Ranking: Canadian Utilities and Pipelines, Strongest to Weakest (September 14, 2011)* .

CAPITAL STRUCTURE RATIOS
OF CANADIAN UTILITIES WITH RATED DEBT
(2010)

Company	Total Debt [2/]	Preferred Stock [3/]	Common Stock Equity [4/]
Electric Utilities			
AltaLink L.P.	56.0%	0.0%	44.0%
CU Inc.	53.4%	8.3%	38.3%
Enersource	55.0%	0.0%	45.0%
ENMAX Corp.	43.6%	0.0%	56.4%
EPCOR Utilities Inc.	40.5%	0.0%	59.5%
FortisAlberta Inc.	57.3%	0.0%	42.7%
FortisBC Inc.	59.5%	0.0%	40.5%
Hamilton Utilities	38.7%	0.0%	61.3%
Hydro One Inc.	56.5%	2.3%	41.1%
Hydro Ottawa Holding Inc.	42.3%	0.0%	57.7%
London Hydro	45.7%	0.0%	54.3%
Maritime Electric	56.7%	0.0%	43.3%
Newfoundland Power	53.7%	1.0%	45.2%
Nova Scotia Power	59.5%	4.1%	36.4%
Toronto Hydro	57.6%	0.0%	42.4%
Veridian Corp.	44.1%	0.0%	55.9%
Gas Distributors [1/]			
Enbridge Gas Distribution	57.4%	2.2%	40.5%
FortisBC Energy Inc.	59.9%	0.0%	40.1%
Gaz Métro L.P.	61.3%	0.0%	38.7%
Pacific Northern Gas	47.7%	2.6%	49.7%
Union Gas Limited	61.6%	2.5%	35.9%
Pipelines			
Enbridge Pipelines Inc.	54.4%	0.0%	45.6%
Nova Gas Transmission Ltd.	62.9%	0.0%	37.1%
Trans Québec & Maritimes Pipeline	60.0%	0.0%	40.0%
TransCanada PipeLines Ltd.	57.0%	1.0%	42.0%
Westcoast Energy Inc.	57.9%	5.2%	36.9%
Medians			
Electric Utilities	**54.4%**	**0.0%**	**44.5%**
Gas Distributors	**59.9%**	**2.2%**	**40.1%**
Pipelines	**57.9%**	**0.0%**	**40.0%**
All Companies	**56.6%**	**0.0%**	**42.6%**
All Investor Owned Companies	**57.4%**	**0.0%**	**40.5%**

[1/] The average of the four quarters ending September 2011 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 preferred securities classified as equity and non-controlling interests in subsidiary company preferred shares.
[4/] Includes non-controlling interests in common shares of subsidiary companies.

Notes:

Financial statements for FortisBC Energy (Vancouver Island) are not publicly available.

Source: Reports to Shareholders

CAPITAL STRUCTURE RATIOS
OF SAMPLE OF U.S. UTILITIES
(Four Quarters Ending September 2011)

Company	Total Debt [1/]	Preferred Stock [2/]	Common Stock Equity [3/]
AGL Resources Inc.	56.7	0.0	43.3
ALLETE Inc.	44.1	0.0	55.9
Alliant Energy Corp.	47.4	2.8	49.9
Atmos Energy Corp.	49.8	0.0	50.2
Consolidated Edison	48.5	1.0	50.6
Integrys Energy Group Inc.	44.5	0.9	54.5
Northwest Natural Gas	53.4	0.0	46.6
Piedmont Natural Gas [4/]	48.7	0.0	51.3
Southern Company	54.2	1.8	43.9
Vectren Corp.	56.3	0.0	43.7
WGL Holdings Inc.	36.2	1.4	62.4
Wisconsin Energy Corp.	50.8	0.6	48.6
Xcel Energy Inc.	54.3	0.6	45.2
Mean	**49.6**	**0.7**	**49.7**
Median	**49.8**	**0.6**	**49.9**

[1/] Includes preferred securities classified as debt.

[2/] Includes preferred securities classified as equity and non-controlling interests in subsidiary company preferred shares.

[3/] Includes non-controlling interests in common shares of subsidiary companies.

[4/] Trailing four quarters ending October 31, 2011.

Source: Reports to Shareholders.

CREDIT METRICS OF CANADIAN UTILITIES WITH RATED DEBT

Company	EBIT Coverage				FFO Interest Coverage				FFO To Debt			
	2010	2009	2008	3 Year Average	2010	2009	2008	3 Year Average	2010	2009	2008	3 Year Average
Electric Utilities												
AltaLink L.P.	1.80	1.80	1.80	1.80	2.70	3.00	3.20	2.97	11.00	12.70	12.70	12.13
Chatham-Kent Energy Inc.	4.00	3.70	3.50	3.73	5.50	5.40	5.50	5.47	29.70	29.50	34.90	31.37
CU Inc.	2.40	2.40	2.10	2.30	3.10	3.40	3.50	3.33	14.90	17.90	16.90	16.57
Enersource	2.20	2.20	2.50	2.30	3.80	3.60	3.50	3.63	19.40	18.40	18.10	18.63
ENMAX Corp.	1.90	2.30	2.70	2.30	3.10	3.30	3.80	3.40	13.70	13.60	13.70	13.67
EPCOR Utilities Inc.	2.20	2.10	1.50	1.93	2.70	2.60	2.90	2.73	13.20	16.40	15.10	14.90
FortisAlberta Inc.	2.00	2.10	2.00	2.03	3.90	3.80	3.80	3.83	13.90	13.20	12.50	13.20
FortisBC Inc.	2.10	2.04	2.05	2.06 [1/]	3.00	2.90	2.80	2.90 [2/]	11.60	11.90	11.20	11.57 [2/]
Hamilton Utilities	3.10	3.30	3.30	3.23	5.20	4.60	5.10	4.97	27.00	29.60	35.30	30.63
Hydro One Inc.	2.30	2.10	2.80	2.40	3.00	2.80	4.00	3.27	12.20	11.40	14.50	12.70
Hydro Ottawa Holding Inc.	4.30	4.30	4.10	4.23	6.40	6.20	6.20	6.27	27.80	27.30	25.50	26.87
London Hydro	3.10	3.30	2.90	3.10 [3/]	5.50	5.20	4.80	5.17 [4/]	25.60	27.50	26.20	26.43 [3/]
Maritime Electric	2.40	2.30	2.30	2.33	2.80	3.10	3.20	3.03	13.60	16.30	17.40	15.77
Newfoundland Power	2.41	2.40	2.53	2.45 [1/]	3.40	3.10	3.00	3.17 [2/]	17.60	15.00	15.80	16.13 [2/]
Nova Scotia Power	1.80	2.20	2.40	2.13	3.40	3.00	3.10	3.17	14.60	14.50	15.90	15.00
Toronto Hydro	1.80	1.60	1.80	1.73	3.60	3.30	3.40	3.43	16.00	16.30	17.50	16.60
Veridian Corp.	3.49	3.59	3.16	3.41 [1/]	na	na	na	na	29.00	33.50	22.40	28.30 [1/]
Gas Distributors												
Enbridge Gas Distribution	2.30	2.40	2.30	2.33	3.40	3.50	3.30	3.40	16.30	18.10	16.30	16.90
FortisBC Energy Inc.	2.10	1.90	1.90	1.97 [1/]	2.70	2.60	2.50	2.60 [2/]	10.60	10.20	9.80	10.20 [2/]
Gaz Métro L.P.	2.40	2.20	2.20	2.27 [3/]	4.40	4.30	4.50	4.40	20.20	21.90	21.50	21.20
Pacific Northern Gas	2.49	2.59	2.13	2.40 [1/]	3.90	2.60	2.26	2.92 [5/]	19.60	11.70	11.20	14.17 [1/]
Union Gas Limited	2.60	2.40	2.40	2.47	3.50	2.90	3.42	3.27	16.50	14.80	15.10	15.47
Pipelines												
Enbridge Pipelines Inc.	2.30	2.70	2.90	2.63	3.00	2.80	2.60	2.80	13.20	8.10	6.60	9.30
NOVA Gas Transmission Ltd.	2.18	1.94	2.15	2.09 [1/]	na	na	na	na	14.30	14.20	14.20	14.23 [1/]
Trans Québec & Maritimes Pipeline	3.00	3.50	2.10	2.87	4.10	4.40	3.60	4.03	16.50	20.20	15.80	17.50
TransCanada PipeLines Ltd.	1.80	1.90	2.30	2.00	2.90	2.80	3.00	2.90	11.90	12.40	13.00	12.43
Westcoast Energy Inc.	2.60	2.40	2.70	2.57	3.50	2.90	3.50	3.30	15.80	13.30	17.90	15.67
Medians												
Electric Utilities	**2.30**	**2.30**	**2.50**	**2.30**	**3.40**	**3.30**	**3.50**	**3.37**	**14.90**	**16.30**	**16.90**	**16.13**
Gas Distributors	**2.40**	**2.40**	**2.20**	**2.33**	**3.50**	**2.90**	**3.30**	**3.27**	**16.50**	**14.80**	**15.10**	**15.47**
Pipelines	**2.30**	**2.40**	**2.30**	**2.57**	**3.25**	**2.85**	**3.25**	**3.10**	**14.30**	**13.30**	**14.20**	**14.23**
All Companies	**2.30**	**2.30**	**2.30**	**2.33**	**3.40**	**3.10**	**3.42**	**3.30**	**15.80**	**15.00**	**15.80**	**15.67**
All Investor Owned Companies	**2.30**	**2.30**	**2.20**	**2.30**	**3.40**	**3.00**	**3.20**	**3.17**	**14.60**	**14.20**	**15.10**	**15.00**

[1/] Data from DBRS.
[2/] Data from Moody's.
[3/] 2010 data from S&P Credit Stats.
[4/] 2010 data ending September 2010.
[5/] Calculated from Annual Reports.
Source: Standard & Poor's Debt Rating Reports except where noted.

CREDIT METRICS OF U.S. UTILITIES

	EBIT Coverage				FFO Interest Coverage					FFO To Debt			
Company	**2010**	**2009**	**2008**	**3 Year Average**	**2010**	**2009**	**2008**	**3 Year Average**		**2010**	**2009**	**2008**	**3 Year Average**
AGL Resources Inc.	4.40	4.10	3.70	4.07	4.52	4.37	3.50	4.13	[1/]	20.00	20.90	18.80	19.90
ALLETE Inc.	3.60	3.30	4.10	3.67	5.70	5.50	5.20	5.47		21.70	20.00	17.60	19.77
Alliant Energy Corp.	3.30	2.60	3.20	3.03	5.30	4.50	4.50	4.77		24.80	22.70	20.00	22.50
Atmos Energy Corp.	2.93	2.63	2.88	2.81	4.48	3.91	4.24	4.21		25.52	21.36	21.95	22.94
Consolidated Edison	3.50	3.10	3.00	3.20	5.30	4.30	3.20	4.27		21.00	16.40	9.30	15.57
Integrys Energy Group Inc.	3.70	3.10	2.00	2.93	5.70	5.50	5.20	5.47		25.20	25.50	18.20	22.97
Northwest Natural Gas	3.80	3.80	3.80	3.80	5.40	3.70	5.30	4.80		21.90	17.40	21.90	20.40
Piedmont Natural Gas	4.90	4.90	3.70	4.50	5.50	6.40	4.60	5.50		26.20	24.80	21.80	24.27
Southern Company	3.60	3.20	3.30	3.37	4.90	4.40	4.20	4.50		20.10	18.10	17.20	18.47
Vectren Corp.	2.90	2.90	3.10	2.97	5.40	5.00	5.10	5.17		25.50	21.40	21.20	22.70
WGL Holdings Inc.	5.10	5.20	5.20	5.17	6.30	6.70	7.00	6.67		27.60	26.90	30.40	28.30
Wisconsin Energy Corp.	2.80	2.20	1.10	2.03	4.80	4.70	5.00	4.83		18.40	16.70	18.40	17.83
Xcel Energy Inc.	2.90	2.70	2.50	2.70	4.40	4.20	3.90	4.17		19.00	18.80	17.10	18.30
Medians													
All Companies	**3.60**	**3.10**	**3.20**	**3.20**	**5.30**	**4.50**	**4.60**	**4.80**		**21.90**	**20.90**	**18.80**	**20.40**

[1/] Data from S&P Credit Stats.

Source: Standard & Poor's Debt Rating Reports except where noted.

HISTORIC EQUITY MARKET RISK PREMIUMS
(Arithmetic Averages)

Canada
(1947-2011)

Stock Return	Bond Total Return	Risk Premium
11.8	7.1	4.7

Stock Return	Bond Income Return	Risk Premium
11.8	6.7	5.0

United States
(1947-2011)

Stock Return	Bond Total Return	Risk Premium
12.3	6.6	5.7

Stock Return	Bond Income Return	Risk Premium
12.3	5.9	6.4

Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2010* ; www.federalreserve.gov; Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2010 Yearbook* ; PC Bond Analytics; www.standardandpoors.com; *TSX Review.*

HISTORIC EQUITY MARKET RISK PREMIUMS
(Arithmetic Averages)

Canada
(1924-2011)

Stock Return	Bond Total Return	Risk Premium
11.4	6.6	4.8
Stock Return	Bond Income Return	Risk Premium
11.4	6.0	5.4

United States
(1926-2011)

Stock Return	Bond Total Return	Risk Premium
11.8	6.1	5.6
Stock Return	Bond Income Return	Risk Premium
11.8	5.2	6.6

Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2010* ; www.federalreserve.gov; Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2010 Yearbook* ; PC Bond Analytics; www.standardandpoors.com; *TSX Review.*

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	2011	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**	**4.95**	**4.60**
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	4.13	4.42
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	3.54	3.85
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	6.72	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	5.62	4.93
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	7.47	7.37
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	5.66	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	12.60	12.89
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	8.69	6.96
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	4.59	5.91
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	4.09	4.07
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**	**6.31**	**6.27**
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**	**5.64**	**5.69**

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**	**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**	**0.73**	**0.72**

Source: *TSX Review*

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
2011	0.52	0.31	1.25	0.85	0.37	0.89	1.49	1.19	0.45	0.43

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
(1988-2011)

	Sector Compound Returns [1/]			Sector Betas		
	88-11	88-97	02-11	88-11	88-97	02-11
Consumer Discretionary	5.9	10.2	1.3	0.72	0.90	0.63
Consumer Staples	11.2	12.7	7.5	0.34	0.73	0.34
Energy	10.2	8.4	13.3	0.82	0.76	1.19
Financials	12.4	18.3	8.4	0.80	1.04	0.80
Health Care	6.4	15.5	-0.9	0.73	0.81	0.50
Industrials	6.3	8.3	4.7	0.94	1.13	0.92
Information Technology	2.2	21.8	-19.8	1.72	1.21	1.68
Materials	6.6	3.4	13.6	0.99	1.26	1.23
Telecommunication Services	13.0	15.4	4.4	0.66	0.58	0.46
Utilities	10.4	11.5	12.3	0.29	0.62	0.38
Adjusted R Square [2/]				**52%**	**1%**	**18%**
Beta [3/]				**-0.063**	**-0.017**	**-0.094**

[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*

MONTHLY 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	2011
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	0.03
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	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	0.30
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	0.14
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	0.37
Mean	**0.39**	**0.52**	**0.50**	**0.48**	**0.42**	**0.54**	**0.35**	**0.22**	**0.08**	**0.04**	**-0.16**	**-0.08**	**0.03**	**0.30**	**0.51**	**0.25**	**0.22**	**0.23**	**0.21**
Median	**0.38**	**0.54**	**0.50**	**0.52**	**0.40**	**0.55**	**0.33**	**0.23**	**0.14**	**0.13**	**-0.06**	**0.01**	**0.07**	**0.32**	**0.54**	**0.21**	**0.20**	**0.21**	**0.21**
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	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	0.43

Adjusted Betas [1/]
Five Year Period Ending:

COMPANY	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
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	0.35
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	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	0.53
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	0.42
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	0.58
Mean	**0.59**	**0.68**	**0.67**	**0.65**	**0.61**	**0.69**	**0.56**	**0.48**	**0.39**	**0.36**	**0.22**	**0.27**	**0.35**	**0.53**	**0.67**	**0.50**	**0.48**	**0.48**	**0.47**
Median	**0.58**	**0.69**	**0.66**	**0.68**	**0.60**	**0.70**	**0.55**	**0.48**	**0.42**	**0.41**	**0.29**	**0.33**	**0.38**	**0.54**	**0.69**	**0.47**	**0.46**	**0.47**	**0.47**
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	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	0.62

[1/] 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.		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
2004	0.03	0.1%	0.01	0.0%	-0.32	7.0%	0.01	0.0%	-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%	-0.15	2.5%	0.00	0.0%
2006	0.32	4.9%	0.12	1.1%	0.22	4.2%	0.48	9.0%	0.34	10.0%	0.25	6.8%
2007	0.58	10.1%	0.24	3.2%	0.54	12.5%	0.65	11.8%	0.52	14.8%	0.46	14.3%
2008	0.19	1.9%	0.17	3.5%	0.30	7.8%	0.21	2.8%	0.38	16.4%	0.49	28.1%
2009	0.06	0.2%	0.16	3.3%	0.30	10.0%	0.20	2.9%	0.39	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	19.1%	0.42	22.3%
2011	0.03	0.1%	0.21	5.4%	0.30	10.3%	0.14	2.4%	0.37	17.7%	0.43	27.1%

Source: Standard and Poor's *Research Insight*

WEEKLY BETAS FOR REGULATED CANADIAN UTILITIES

"Raw" Weekly Price Betas
Five Year Period Ending:

COMPANY	2004	2005	2006	2007	2008	2009	2010	2011
Canadian Utilities Limited	0.14	0.25	0.32	0.50	0.42	0.40	0.39	0.38
Emera Inc.	0.19	0.03	0.11	0.20	0.32	0.35	0.40	0.43
Enbridge Inc.	0.01	0.21	0.47	0.64	0.58	0.52	0.49	0.49
Fortis Inc.	-0.06	0.21	0.26	0.38	0.50	0.46	0.50	0.53
TransCanada Corporation	-0.02	0.14	0.35	0.48	0.45	0.44	0.44	0.44
Mean	**0.05**	**0.17**	**0.30**	**0.44**	**0.46**	**0.43**	**0.44**	**0.45**
Median	**0.01**	**0.21**	**0.32**	**0.48**	**0.45**	**0.44**	**0.44**	**0.44**
S&P/TSX Utilities	0.04	0.16	0.31	0.42	0.53	0.53	0.55	0.56

Adjusted Betas [1/]
Five Year Period Ending:

COMPANY	2004	2005	2006	2007	2008	2009	2010	2011
Canadian Utilities Limited	0.43	0.49	0.55	0.66	0.61	0.60	0.59	0.59
Emera Inc.	0.46	0.35	0.40	0.47	0.54	0.56	0.59	0.62
Enbridge Inc.	0.34	0.47	0.65	0.76	0.72	0.68	0.66	0.66
Fortis Inc.	0.29	0.47	0.50	0.59	0.67	0.64	0.66	0.68
TransCanada Corporation	0.31	0.42	0.57	0.65	0.63	0.62	0.63	0.62
Mean	**0.37**	**0.44**	**0.53**	**0.63**	**0.64**	**0.62**	**0.63**	**0.63**
Median	**0.34**	**0.47**	**0.55**	**0.65**	**0.63**	**0.62**	**0.63**	**0.62**
S&P/TSX Utilities	0.36	0.44	0.53	0.61	0.69	0.69	0.70	0.70

[1/] Adjusted beta = "raw" beta * 67% + market beta of 1.0 * 33%.

Source: Standard and Poor's *Research Insight* and *TSX Review*.

INDIVIDUAL COMPANY RISK DATA FOR SAMPLE OF U.S. UTILITIES

	Value Line									S & P		Moody's
	Safety	**Forecast Common Equity Ratio 2014-2016**	**Forecast Return On Average Common Equity 2014-2016**	**Dividend Payout Forecast 2014-2016**	**2011 Q4 Beta**	**"Raw" Weekly Betas [1/]**	**Adjusted Weekly Betas**	**Common Equity Ratio 3Q2011 (Trailing Four Quarters)**	**2008-2010 Average Earned Returns**	**Business Risk Profile**	**Debt Rating**	**Debt Rating [2/]**
AGL Resources Inc.	1	58.0%	12.6%	52.3%	0.75	0.64	0.76	43.3%	13.0%	Excellent	BBB+	Baa1
ALLETE Inc.	2	58.5%	10.1%	60.0%	0.70	0.61	0.74	55.9%	8.5%	Strong	BBB+	Baa1
Alliant Energy Corp.	2	52.0%	11.6%	60.0%	0.75	0.68	0.79	49.9%	8.2%	Excellent	BBB+	Baa1
Atmos Energy Corp.	2	51.0%	9.2%	53.7%	0.70	0.61	0.74	50.2%	9.2%	Excellent	BBB+	Baa1
Consolidated Edison	1	50.5%	9.4%	62.8%	0.60	0.42	0.61	50.6%	10.3%	Excellent	A-	Baa1
Integrys Energy Group Inc.	2	55.0%	9.7%	68.0%	0.90	0.72	0.82	54.5%	3.1%	Excellent	A-	Baa1
Northwest Natural Gas	1	64.0%	10.1%	55.9%	0.60	0.48	0.65	46.6%	11.3%	Excellent	A+	A3
Piedmont Natural Gas	2	50.0%	12.4%	72.8%	0.70	0.57	0.72	51.3%	13.7%	Excellent	A	A3
Southern Company	1	45.5%	13.3%	67.7%	0.55	0.33	0.55	43.9%	12.7%	Excellent	A	Baa1
Vectren Corp.	2	50.0%	11.0%	69.6%	0.70	0.59	0.72	43.7%	9.7%	Excellent	A-	A3
WGL Holdings Inc.	1	70.0%	10.1%	62.2%	0.65	0.55	0.70	62.4%	10.8%	Excellent	A+	A2
Wisconsin Energy Corp.	2	46.0%	14.5%	60.0%	0.65	0.45	0.63	48.6%	11.5%	Excellent	A-	A3
Xcel Energy Inc.	2	48.5%	9.7%	57.5%	0.65	0.46	0.64	45.2%	9.7%	Excellent	A-	Baa1
Mean	**2**	**53.8%**	**11.1%**	**61.7%**	**0.68**	**0.55**	**0.70**	**49.7%**	**10.1%**	**Excellent**	**A-**	**Baa1**
Median	**2**	**51.0%**	**10.1%**	**60.0%**	**0.70**	**0.57**	**0.72**	**49.9%**	**10.3%**	**Excellent**	**A-**	**Baa1**

[1/] "Raw" betas calculated using weekly price changes against the NYSE Composite (260 weeks ending January 30, 2012).
[2/] Rating for Vectren Corp. is for Vectren Utility Holdings. Rating for WGL Holdings is Washington Gas Light.

Source: www.Moodys.com; Standard and Poor's, *Issuer Ranking: U.S. Regulated Electric Utilities, Strongest To Weakest* (January 5, 2012); Standard and Poor's, *Issuer Ranking: U.S. Regulated Natural Gas Utilities, Strongest To Weakest* (January 11, 2012); Standard and Poor's *Research Insight*; *Value Line* (November and December 2011); *Value Line Index*, January 27, 2012; and www.yahoo.com.

MONTHLY BETAS FOR U.S. 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	2011
AGL Resources Inc.	0.33	0.40	0.39	0.45	0.62	0.60	0.45	0.29	0.29	0.24	0.21	0.30	0.37	0.36	0.50	0.31	0.40	0.46	0.45
ALLETE Inc.	0.59	0.60	0.58	0.41	0.41	0.15	0.09	0.03	-0.12	0.02	0.26	0.40	0.47	0.94	1.19	0.84	0.66	0.66	0.68
Alliant Energy Corp.	0.46	0.55	0.61	0.46	0.26	0.18	0.08	0.09	-0.02	0.10	0.24	0.34	0.40	0.80	0.72	0.59	0.57	0.53	0.53
Atmos Energy Corp.	0.32	0.32	0.50	0.76	0.08	0.16	0.19	0.00	-0.17	-0.02	-0.03	0.05	0.18	0.41	0.85	0.51	0.50	0.52	0.52
Consolidated Edison	0.57	0.55	0.53	0.59	0.66	0.32	0.18	0.09	-0.04	-0.16	-0.14	-0.05	0.00	0.14	0.39	0.25	0.29	0.31	0.26
Integrys Energy Group Inc.	0.34	0.31	0.38	0.25	0.29	0.16	0.10	0.01	-0.03	-0.01	0.06	0.15	0.17	0.37	0.56	0.48	0.91	0.89	0.87
Northwest Natural Gas	0.21	0.19	0.19	0.14	0.38	0.46	0.18	0.11	0.06	-0.11	-0.19	0.01	0.04	0.14	0.74	0.36	0.25	0.31	0.31
Piedmont Natural Gas	0.35	0.43	0.39	0.27	0.32	0.51	0.28	0.13	0.15	0.09	-0.03	0.13	0.28	0.35	0.58	0.06	0.19	0.23	0.31
Southern Company	0.51	0.47	0.39	0.53	0.42	0.15	0.11	-0.05	-0.36	-0.45	-0.47	-0.47	-0.49	-0.06	0.34	0.37	0.34	0.35	0.30
Vectren Corp.	0.22	0.23	0.23	0.64	0.57	0.34	0.16	0.24	0.20	0.23	0.35	0.46	0.32	0.49	0.56	0.25	0.37	0.42	0.41
WGL Holdings Inc.	0.29	0.36	0.39	0.75	0.62	0.47	0.28	0.25	0.19	0.14	0.11	0.22	0.21	0.27	0.69	0.24	0.17	0.25	0.28
Wisconsin Energy Corp.	0.47	0.53	0.52	0.58	0.43	0.31	0.14	0.11	-0.02	-0.10	-0.09	0.06	0.02	0.18	0.56	0.45	0.39	0.37	0.34
Xcel Energy Inc.	0.63	0.62	0.37	0.60	0.50	0.34	0.27	0.19	-0.01	0.41	0.56	0.70	0.80	1.48	0.60	0.56	0.46	0.44	0.39
Mean	**0.41**	**0.43**	**0.42**	**0.50**	**0.43**	**0.32**	**0.19**	**0.11**	**0.01**	**0.03**	**0.06**	**0.17**	**0.21**	**0.45**	**0.64**	**0.41**	**0.42**	**0.44**	**0.43**
Median	**0.35**	**0.43**	**0.39**	**0.53**	**0.42**	**0.32**	**0.18**	**0.11**	**-0.02**	**0.02**	**0.06**	**0.15**	**0.21**	**0.36**	**0.58**	**0.37**	**0.39**	**0.42**	**0.39**

Adjusted Betas [1/]
Five Year Period Ending:

COMPANY	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
AGL Resources Inc.	0.55	0.60	0.59	0.63	0.74	0.73	0.63	0.52	0.53	0.49	0.47	0.53	0.58	0.57	0.66	0.54	0.60	0.64	0.63
ALLETE Inc.	0.73	0.73	0.72	0.61	0.61	0.43	0.39	0.35	0.25	0.35	0.50	0.60	0.65	0.96	1.13	0.89	0.77	0.77	0.78
Alliant Energy Corp.	0.64	0.70	0.74	0.64	0.50	0.45	0.38	0.39	0.31	0.40	0.49	0.56	0.60	0.87	0.81	0.73	0.71	0.68	0.68
Atmos Energy Corp.	0.55	0.54	0.66	0.84	0.38	0.44	0.46	0.33	0.22	0.32	0.31	0.36	0.45	0.61	0.90	0.67	0.66	0.68	0.68
Consolidated Edison	0.71	0.70	0.68	0.73	0.77	0.54	0.45	0.39	0.30	0.22	0.24	0.30	0.33	0.43	0.59	0.50	0.53	0.54	0.51
Integrys Energy Group Inc.	0.56	0.54	0.59	0.50	0.52	0.44	0.40	0.34	0.31	0.32	0.37	0.43	0.45	0.58	0.71	0.65	0.94	0.93	0.91
Northwest Natural Gas	0.47	0.46	0.46	0.42	0.58	0.64	0.45	0.41	0.37	0.26	0.20	0.33	0.36	0.43	0.83	0.57	0.50	0.54	0.54
Piedmont Natural Gas	0.56	0.62	0.59	0.51	0.54	0.67	0.52	0.42	0.43	0.39	0.31	0.42	0.52	0.57	0.72	0.37	0.46	0.49	0.54
Southern Company	0.67	0.65	0.59	0.69	0.61	0.43	0.40	0.30	0.09	0.03	0.02	0.01	0.00	0.29	0.55	0.58	0.56	0.57	0.53
Vectren Corp.	0.48	0.48	0.48	0.76	0.71	0.56	0.43	0.49	0.46	0.48	0.56	0.64	0.55	0.66	0.71	0.49	0.58	0.61	0.61
WGL Holdings Inc.	0.52	0.57	0.59	0.83	0.75	0.64	0.52	0.50	0.46	0.42	0.41	0.47	0.47	0.51	0.79	0.49	0.44	0.50	0.52
Wisconsin Energy Corp.	0.64	0.68	0.68	0.72	0.62	0.54	0.42	0.40	0.32	0.26	0.27	0.37	0.34	0.45	0.71	0.63	0.59	0.58	0.56
Xcel Energy Inc.	0.75	0.75	0.58	0.73	0.67	0.56	0.51	0.46	0.32	0.60	0.70	0.80	0.87	1.32	0.73	0.70	0.64	0.62	0.59
Mean	**0.60**	**0.62**	**0.61**	**0.66**	**0.62**	**0.54**	**0.46**	**0.41**	**0.34**	**0.35**	**0.37**	**0.45**	**0.47**	**0.63**	**0.76**	**0.60**	**0.61**	**0.63**	**0.62**
Median	**0.56**	**0.62**	**0.59**	**0.69**	**0.61**	**0.54**	**0.45**	**0.40**	**0.32**	**0.35**	**0.37**	**0.43**	**0.47**	**0.57**	**0.72**	**0.58**	**0.59**	**0.61**	**0.59**

[1/] Adjusted beta = "raw" beta * 67% + market beta of 1.0 * 33%.

Source: Standard and Poor's *Research Insight*

DCF-BASED EQUITY RISK PREMIUM STUDY FOR SAMPLE OF U.S. 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/]
1998	5.1	4.3	9.4	5.5	3.9	1.5
1999	5.6	4.7	10.3	5.9	4.4	1.7
2000	6.0	5.4	11.4	5.9	5.6	2.4
2001	5.3	5.4	10.7	5.5	5.2	2.3
2002	5.2	5.9	11.0	5.4	5.6	1.9
2003	5.1	5.1	10.2	5.0	5.1	1.5
2004	4.6	4.5	9.1	5.1	4.1	1.0
2005	4.3	4.5	8.8	4.5	4.3	1.1
2006	4.5	4.8	9.2	4.9	4.3	1.2
2007	4.2	5.0	9.2	4.8	4.4	1.3
2008	4.8	5.3	10.1	4.2	5.9	2.3
2009	5.6	5.5	11.1	4.1	7.0	1.9
2010	4.9	5.1	10.0	4.2	5.9	1.2
2011	4.5	5.3	9.7	3.9	5.9	1.1
Means for Long Treasury Yields:						
Below 4.0%	**5.0**	**5.3**	**10.3**	**3.4**	**6.8**	**1.9**
4.0-4.99%	**4.7**	**5.0**	**9.7**	**4.6**	**5.2**	**1.4**
Below 5.0%	**4.7**	**5.1**	**9.8**	**4.4**	**5.4**	**1.5**
5.0-5.99%	**5.2**	**5.0**	**10.2**	**5.5**	**4.7**	**1.7**
6.0% and above	**6.1**	**4.9**	**11.0**	**6.2**	**4.8**	**1.9**
Means:						
1998 - 2011	**5.0**	**5.1**	**10.0**	**4.9**	**5.1**	**1.6**

[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 A rated Utility Index minus the 30-year 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. UTILITIES
CONSTANT GROWTH DCF MODEL

Regression Analysis Results 1998-2011

EQUATION 1:

Equity Risk Premium = 8.81 - 0.75 (30-Year Treasury Yield)

t-statistics:

30-Year Treasury Yield = -8.01

R^2 = 28%

Equity Risk Premium at Long-Term Bond Yield of 3.25% - 3.50% = 6.3%

ROE at Long-Term Bond Yield of 3.25% - 3.50% = 9.6%

EQUATION 2:

Equity Risk Premium = 7.44 - 0.84 (30-Year Treasury Yield) + 1.13 (Spread)

Where Spread = Spread between A-rated Utility Bond Yields and 30-year Treasury Yields

t-statistics:

30-Year Treasury Yield = -12.68

Spread = 12.99

R^2 = 64%

Equity Risk Premium at Long-term Bond Yield of 3.25% - 3.50% and Spread of 1.45% = 6.2%

ROE at Long-Term Bond Yield of 3.25% - 3.50% and Spread of 1.45% = 9.6%

EQUATION 3:

Equity Risk Premium = 6.59 - 0.47 (A-rated Utility Bond Yield)

t-statistics:

A-rated Utility Bond Yield = -7.90

R^2 = 27%

Equity Risk Premium at A-rated Utility Bond Yield of 4.8% = 4.3%

ROE at A-rated Utility Bond Yield of 4.8% = 9.1%

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).

DCF-BASED EQUITY RISK PREMIUM STUDY FOR SAMPLE OF U.S. UTILITIES
THREE STAGE MODEL

(Annual Averages of Monthly Data)

Year	Dividend Yield	Implied Growth Rate	DCF Cost of Equity [1/]	Long-Term Treasury Yield	Equity Risk Premium	Moody's Spread [2/]
1998	4.9	4.8	9.7	5.5	4.2	1.5
1999	5.3	4.9	10.2	5.9	4.3	1.7
2000	5.7	5.5	11.2	5.9	5.4	2.4
2001	5.0	5.7	10.7	5.5	5.3	2.3
2002	4.9	5.8	10.7	5.4	5.3	1.9
2003	4.8	5.7	10.5	5.0	5.4	1.5
2004	4.4	5.5	9.9	5.1	4.9	1.0
2005	4.1	5.4	9.5	4.5	5.0	1.1
2006	4.3	5.5	9.7	4.9	4.9	1.2
2007	4.0	5.3	9.3	4.8	4.5	1.3
2008	4.5	5.3	9.9	4.2	5.6	2.3
2009	5.3	5.5	10.8	4.1	6.7	1.9
2010	4.7	5.2	9.9	4.2	5.7	1.2
2011	4.2	5.2	9.5	3.9	5.6	1.1
Means for Long Treasury Yields:						
Below 4.0%	**4.7**	**5.3**	**10.0**	**3.4**	**6.6**	**1.9**
4.0-4.99%	**4.5**	**5.4**	**9.9**	**4.6**	**5.3**	**1.4**
Below 5.0%	**4.5**	**5.4**	**9.9**	**4.4**	**5.5**	**1.5**
5.0-5.99%	**4.9**	**5.4**	**10.3**	**5.5**	**4.8**	**1.7**
6.0% and above	**5.8**	**5.0**	**10.8**	**6.2**	**4.6**	**1.9**
Means: 1998 - 2011	**4.7**	**5.4**	**10.1**	**4.9**	**5.2**	**1.6**

[1/] Internal Rate of Return: Stage 1 growth rate, I/B/E/S EPS growth forecast, applies for first 5 years; Stage 2 growth rate, average of Stage 1 and 3 growth rates, applies for years 6-10; Stage 3 growth, equal to the forecast nominal GDP growth rate, applies thereafter.
[2/] Moody's Spread is the yield on Moody's long-term A rated Utility Index minus the 30-year 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. UTILITIES
THREE STAGE MODEL

Regression Analysis Results 1998-2011

EQUATION 1:

Equity Risk Premium = 8.50 - 0.67 (30-Year Treasury Yield)

t-statistics:

30-Year Treasury Yield = -10.54

R^2 = 40%

Equity Risk Premium at Long-Term Bond Yield of 3.25% - 3.50% **= 6.2%**

ROE at Long-Term Bond Yield of 3.25% - 3.50% **= 9.6%**

EQUATION 2:

Equity Risk Premium = 7.66 - 0.73 (30-Year Treasury Yield) + 0.70 (Spread)

Where Spread = Spread between A-rated Utility Bond Yields and 30-year Treasury Yields

t-statistics:

30-Year Treasury Yield = -14.80

Spread = 10.80

R^2 = 65%

Equity Risk Premium at Long-term Bond Yield of 3.25% - 3.50% and Spread of 1.45% **= 6.2%**

ROE at Long-Term Bond Yield of 3.25% -3.50% and Spread of 1.45% **= 9.6%**

EQUATION 3:

Equity Risk Premium = 7.29 - 0.57 (A-rated Utility Bond Yield)

t-statistics:

A-rated Utility Bond Yield = -14.27

R^2 = 55%

Equity Risk Premium at A-rated Utility Bond Yield of 4.8% **= 4.6%**

ROE at A-rated Utility Bond Yield of 4.8% **= 9.4%**

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, BOND YIELDS AND SPREADS

	Approved Electric and Gas ROEs	Moody's A-Rated Utility Bond	30-Year Treasury Yield	A-Rated Utility/ Treasury Yield Spread
1997 Q3		7.49	6.44	1.05
1997 Q4		7.25	6.04	1.21
1998 Q1	11.31	7.11	5.89	1.21
1998 Q2	11.58	7.12	5.79	1.32
1998 Q3	11.57	6.99	5.33	1.65
1998 Q4	11.75	6.97	5.11	1.86
1999 Q1	10.68	7.11	5.43	1.68
1999 Q2	10.89	7.48	5.83	1.64
1999 Q3	10.63	7.85	6.08	1.77
1999 Q4	10.76	8.05	6.31	1.74
2000 Q1	11.00	8.29	6.16	2.13
2000 Q2	11.09	8.45	5.96	2.49
2000 Q3	11.43	8.20	5.78	2.42
2000 Q4	12.25	8.03	5.62	2.41
2001 Q1	11.23	7.74	5.45	2.29
2001 Q2	10.84	7.93	5.77	2.16
2001 Q3	10.78	7.64	5.44	2.20
2001 Q4	11.29	7.61	5.21	2.39
2002 Q1	10.80	7.63	5.66	1.98
2002 Q2	11.50	7.48	5.72	1.76
2002 Q3	11.25	7.14	5.13	2.01
2002 Q4	10.94	7.12	5.11	2.01
2003 Q1	11.43	6.84	4.93	1.91
2003 Q2	11.26	6.37	4.71	1.67
2003 Q3	10.28	6.61	5.28	1.33
2003 Q4	10.93	6.34	5.22	1.13
2004 Q1	11.06	6.06	4.96	1.09
2004 Q2	10.47	6.45	5.39	1.05
2004 Q3	10.36	6.11	5.08	1.03
2004 Q4	10.80	5.95	4.93	1.01
2005 Q1	10.54	5.72	4.70	1.02
2005 Q2	10.25	5.43	4.36	1.07
2005 Q3	10.63	5.49	4.39	1.10
2005 Q4	10.55	5.82	4.63	1.18
2006 Q1	10.55	5.92	4.70	1.22
2006 Q2	10.64	6.41	5.19	1.22
2006 Q3	10.18	6.09	4.91	1.18
2006 Q4	10.31	5.82	4.70	1.13
2007 Q1	10.36	5.92	4.82	1.10
2007 Q2	10.23	6.08	4.98	1.10
2007 Q3	10.03	6.19	4.86	1.33
2007 Q4	10.42	6.05	4.53	1.52
2008 Q1	10.42	6.16	4.35	1.81
2008 Q2	10.46	6.30	4.58	1.72
2008 Q3	10.48	6.58	4.44	2.14
2008 Q4	10.34	7.13	3.50	3.63
2009 Q1	10.27	6.44	3.62	2.82
2009 Q2	10.35	6.35	4.24	2.11
2009 Q3	10.23	5.54	4.17	1.37
2009 Q4	10.41	5.65	4.35	1.30
2010 Q1	10.51	5.80	4.59	1.20
2010 Q2	10.04	5.46	4.22	1.24
2010 Q3	10.17	4.96	3.73	1.23
2010 Q4	10.21	5.31	4.15	1.16
2011 Q1	10.26	5.56	4.53	1.03
2011 Q2	10.04	5.37	4.33	1.04
2011 Q3	9.92	4.74	3.54	1.20
2011 Q4	10.22	4.35	3.04	1.31

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 1998-2011

EQUATION 1:

Equity Risk Premium = 7.96 - 0.45 (6 Months Lagged 30-Year Treasury Yield)

t-statistics:
6 Months Lagged 30-Year Treasury Yield = -6.73
R^2 = 46%

EQUATION 2:

Equity Risk Premium = 7.56 - 0.46 (6 Months Lagged 30-Year Treasury Yield) + 0.27 (Spread)

Where Spread = Spread between A-rated Utility Bond Yields and 30-year Treasury Yields

t-statistics:
6 Months Lagged 30-Year Treasury Yield = -7.52
Spread = 3.56

R^2 = 56%

EQUATION 3:

Equity Risk Premium = 7.84 - 0.57 (6 Months Lagged Moody's A-Rated)

t-statistics:
6 Months Lagged Moody's A-Rated = -11.43

R^2 = 71%

HISTORIC UTILITY EQUITY RISK PREMIUMS
(Arithmetic Averages)

Canada
(1956-2011)

Utilities Index Return	Bond Total Return	Risk Premium
12.1	7.9	4.2

Utilities Index Return	Bond Income Return	Risk Premium
12.1	7.3	4.8

United States
(1947-2011)

S&P/Moody's Electric Index Return	Bond Total Return	Risk Premium
11.0	6.6	4.4

S&P/Moody's Electric Index Return	Bond Income Return	Risk Premium
11.0	5.9	5.1

S&P / Moody's Gas Distribution Index Return	Bond Total Return	Risk Premium
11.9	6.6	5.3

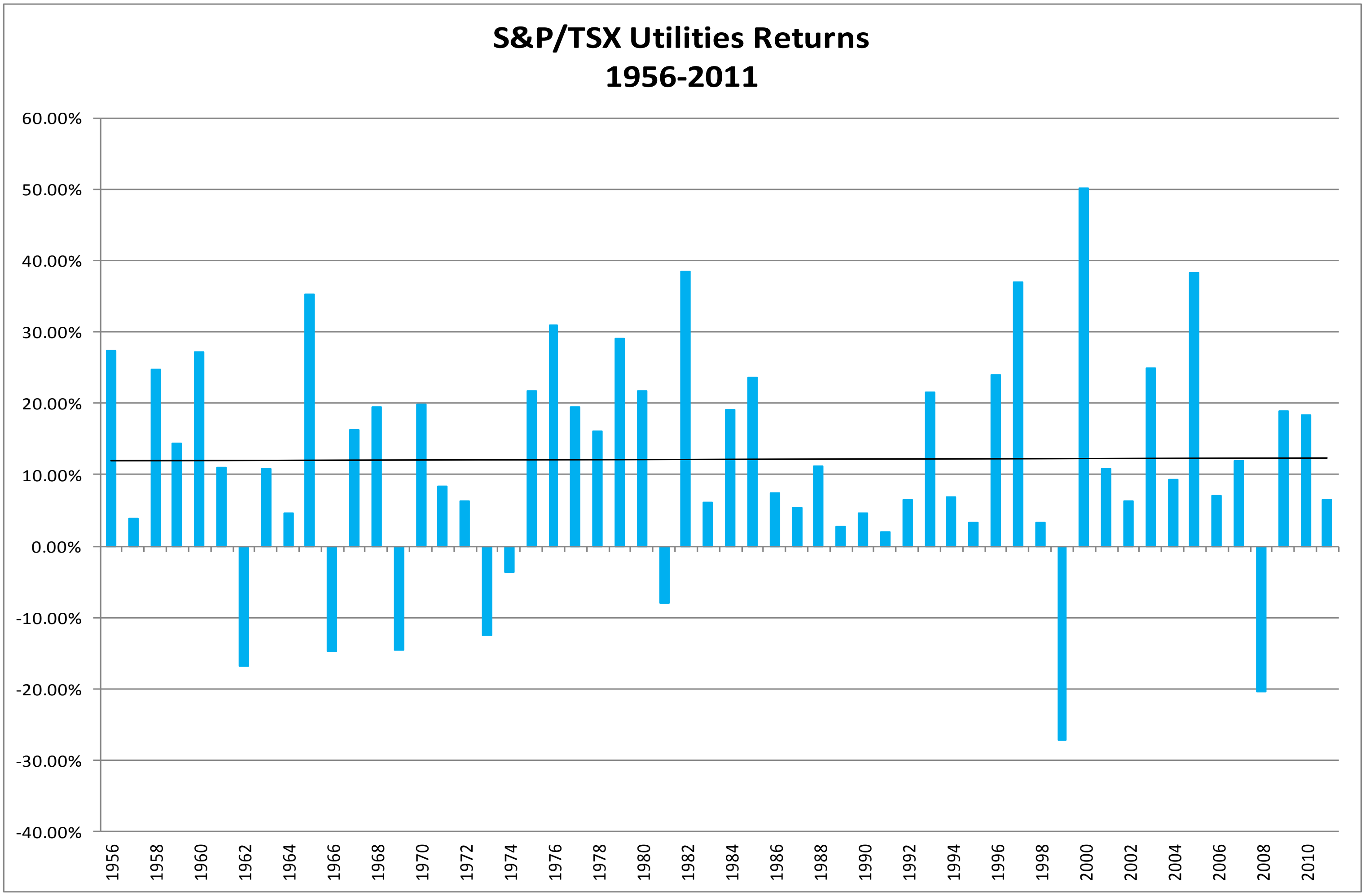
S&P / Moody's Gas Distribution Index Return	Bond Income Return	Risk Premium
11.9	5.9	6.0

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 2011 data were estimated using simple average of the prices and dividends for the utilities, and their successors, included in Moody's Electric Index as of the end of 2001.

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 2002-2011 returns were estimated using simple averages of the prices and dividends for the utilities, and their successors, that were included in Moody's Gas Index as of the end of 2001.

Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2010*; www.federalreserve.gov; Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2010 Yearbook*; www.standardandpoors.com; *TSX Review.*


S&P/TSX Utilities Returns
1956-2011
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
-10.00%
-20.00%
-30.00%
-40.00%
1956
1958
1960
1962
1964
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1968
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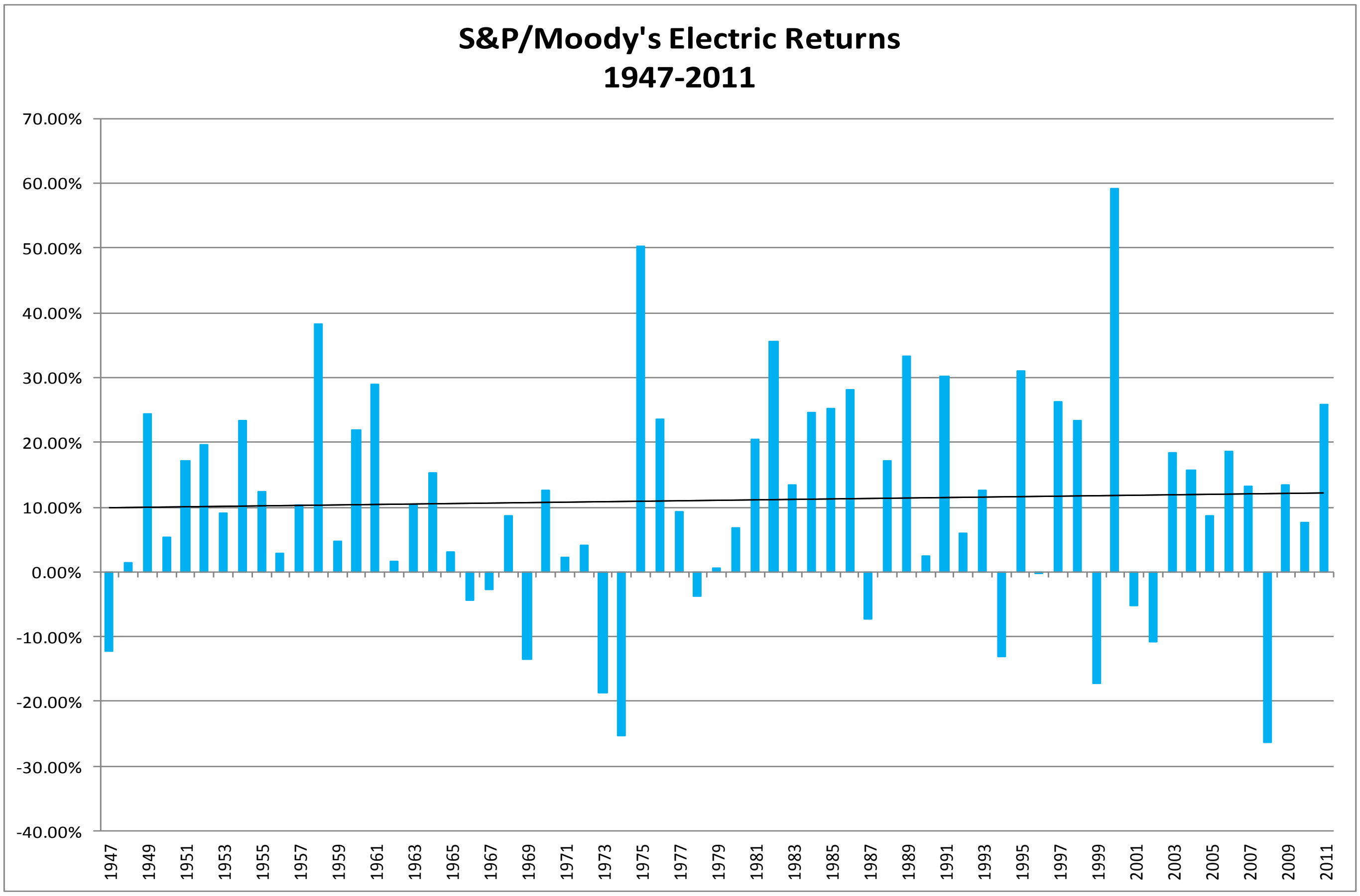
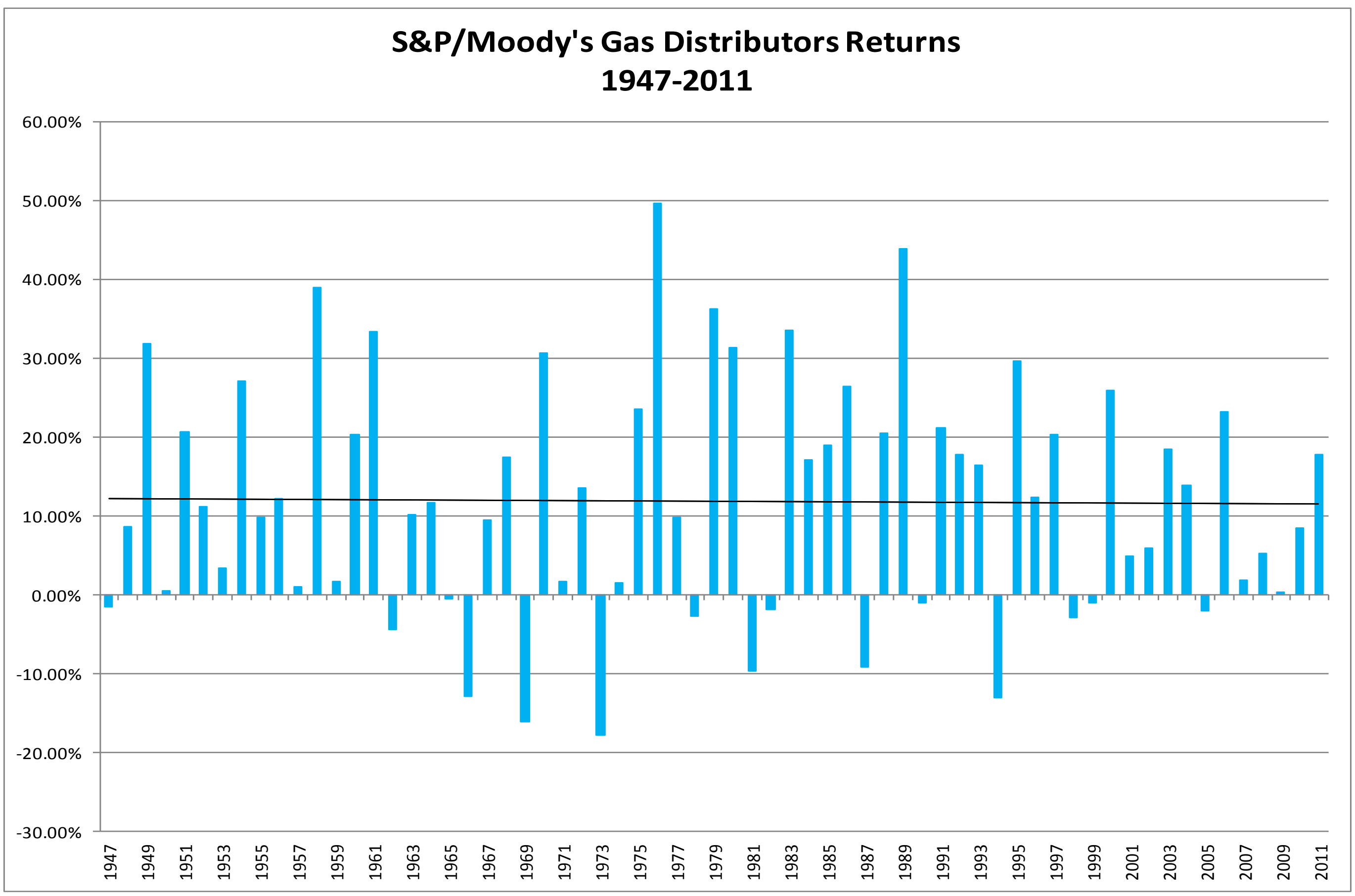

S&P/Moody's Electric Returns
1947-2011
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
-10.00%
-20.00%
-30.00%
-40.00%
1947 1949 1951 1953 1955 1957 1959 1961 1963 1965 1967 1969 1971 1973 1975 1977 1979 1981 1983 1985 1987 1989 1991 1993 1995 1997 1999 2001 2003 2005 2007 2009 2011


S&P/Moody's Gas Distributors Returns
1947-2011
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 2011

DCF COST OF EQUITY FOR SAMPLE OF U.S. UTILITIES
(BASED ON ANALYSTS' EARNINGS GROWTH FORECASTS)

Company	Annualized Last Paid Dividend	Average Daily Close Prices 11/1/2011-1/31/2012	Expected Dividend Yield [1/]	Analyst Forecast Long-Term Growth Rates: Bloomberg	Reuters	Value Line	Zacks	Average of All EPS Estimates	DCF Cost of Equity [2/]
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
AGL Resources Inc.	1.80	41.08	4.6	4.0	4.2	5.0	4.3	4.4	9.0
ALLETE Inc.	1.78	40.03	4.7	5.3	6.5	6.0	5.0	5.7	10.4
Alliant Energy Corp.	1.80	42.28	4.5	6.0	5.4	6.5	6.0	6.0	10.5
Atmos Energy Corp.	1.38	33.23	4.3	5.0	3.8	5.0	4.3	4.5	8.9
Consolidated Edison	2.40	59.18	4.2	3.7	3.7	3.0	3.3	3.4	7.6
Integrys Energy Group Inc.	2.72	51.87	5.6	4.5	7.2	9.0	4.5	6.3	11.9
Northwest Natural Gas	1.78	46.86	4.0	3.9	4.2	4.5	4.3	4.2	8.2
Piedmont Natural Gas	1.16	32.62	3.7	4.5	4.8	2.5	4.7	4.1	7.8
Southern Company	1.89	44.42	4.5	6.0	5.8	6.0	5.1	5.7	10.2
Vectren Corp.	1.40	28.93	5.1	5.5	5.5	5.5	4.3	5.2	10.3
WGL Holdings Inc.	1.55	42.77	3.8	5.5	4.2	2.0	5.2	4.2	8.0
Wisconsin Energy Corp.	1.04	33.47	3.3	6.5	8.1	8.5	6.3	7.3	10.7
Xcel Energy Inc.	1.04	26.42	4.1	5.3	5.3	5.0	5.1	5.2	9.3
Mean	**1.67**	**40.24**	**4.3**	**5.0**	**5.3**	**5.3**	**4.8**	**5.1**	**9.4**
Median	**1.78**	**41.08**	**4.3**	**5.3**	**5.3**	**5.0**	**4.7**	**5.2**	**9.3**

[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: Bloomberg, www.reuters.com, Value Line (November and December 2011), www.yahoo.com, and www.zacks.com.

DCF COSTS OF EQUITY FOR SAMPLE OF U.S. UTILITIES
(SUSTAINABLE GROWTH)

Company	Annualized Last Paid Dividend	Average Daily Close Prices 11/1/2011-1/31/2012	Expected Dividend Yield [1/]	Forecast Return on Common Equity	Forecast Earnings Retention Rate	BR Growth [2/] (4th Qtr.2011)	SV Growth [3/] (4th Qtr. 2011)	Sustainable Growth [4/] (4th Qtr. 2011)	DCF Cost of Equity [5/]
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
AGL Resources Inc.	1.80	41.08	4.7	12.6	47.7	6.0	0.29	6.3	10.9
ALLETE Inc.	1.78	40.03	4.6	10.1	40.0	4.0	0.41	4.5	9.1
Alliant Energy Corp.	1.80	42.28	4.5	11.6	40.0	4.6	0.23	4.9	9.3
Atmos Energy Corp.	1.38	33.23	4.3	9.2	46.3	4.2	0.43	4.7	9.0
Consolidated Edison	2.40	59.18	4.2	9.4	37.2	3.5	0.28	3.8	8.0
Integrys Energy Group Inc.	2.72	51.87	5.4	9.7	32.0	3.1	0.03	3.1	8.5
Northwest Natural Gas	1.78	46.86	4.0	10.1	44.1	4.5	0.08	4.5	8.5
Piedmont Natural Gas	1.16	32.62	3.7	12.4	27.2	3.4	-0.66	2.7	6.4
Southern Company	1.89	44.42	4.5	13.3	32.3	4.3	0.68	5.0	9.4
Vectren Corp.	1.40	28.93	5.0	11.0	30.4	3.4	0.31	3.7	8.7
WGL Holdings Inc.	1.55	42.77	3.8	10.1	37.8	3.8	0.18	4.0	7.8
Wisconsin Energy Corp.	1.04	33.47	3.3	14.5	40.0	5.8	-0.48	5.3	8.6
Xcel Energy Inc.	1.04	26.42	4.1	9.7	42.5	4.1	0.10	4.2	8.3
Mean	**1.67**	**40.24**	**4.31**	**11.06**	**38.28**	**4.21**	**0.14**	**4.4**	**8.7**
Median	**1.78**	**41.08**	**4.35**	**10.14**	**40.00**	**4.13**	**0.23**	**4.5**	**8.6**

[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: *Value Line* (November and December 2011) and www.yahoo.com.

DCF COSTS OF EQUITY FOR SAMPLE OF U.S. UTILITIES
(THREE-STAGE MODEL)

Company	Annualized Last Paid Dividend	Average Daily Close Prices 11/1/2011-1/31/2012	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)	(6)
AGL Resources Inc.	1.80	41.08	4.4	4.6	4.9	9.3
ALLETE Inc.	1.78	40.03	5.7	5.3	4.9	9.7
Alliant Energy Corp.	1.80	42.28	6.0	5.4	4.9	9.6
Atmos Energy Corp.	1.38	33.23	4.5	4.7	4.9	9.1
Consolidated Edison	2.40	59.18	3.4	4.2	4.9	8.7
Integrys Energy Group Inc.	2.72	51.87	6.3	5.6	4.9	10.8
Northwest Natural Gas	1.78	46.86	4.2	4.6	4.9	8.6
Piedmont Natural Gas	1.16	32.62	4.1	4.5	4.9	8.3
Southern Company	1.89	44.42	5.7	5.3	4.9	9.5
Vectren Corp.	1.40	28.93	5.2	5.1	4.9	10.0
WGL Holdings Inc.	1.55	42.77	4.2	4.6	4.9	8.4
Wisconsin Energy Corp.	1.04	33.47	7.3	6.1	4.9	8.6
Xcel Energy Inc.	1.04	26.42	5.2	5.0	4.9	9.0
Mean	**1.67**	**40.24**	**5.1**	**5.0**	**4.9**	**9.2**
Median	**1.78**	**41.08**	**5.2**	**5.0**	**4.9**	**9.1**

[1/] Forecast nominal rate of GDP growth, 2013-22

[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, Blue Chip *Financial Forecasts* (December 2011), www.reuters.com, *Value Line* (November and December 2011), www.yahoo.com, and www.zacks.com.

DCF COST OF EQUITY FOR SAMPLE OF CANADIAN UTILITIES
(BASED ON ANALYSTS' EARNINGS GROWTH FORECASTS)

Company	Annualized Last Paid Dividend	Average Daily Close Prices 11/1/2011-1/31/2012	Expected Dividend Yield [1/]	Reuters Long-Term EPS Forecasts	DCF Cost of Equity [2/]
	(1)	(2)	(3)	(4)	(5)
Canadian Utilities Limited	1.61	60.76	2.9	7.9	10.8
Emera Inc.	1.35	32.57	4.5	7.5	12.0
Enbridge Inc.	0.98	36.26	2.9	8.7	11.6
Fortis Inc.	1.16	32.96	3.8	7.7	11.5
TransCanada Corp.	1.68	42.30	4.3	8.3	12.6
Mean	**1.36**	**40.97**	**3.7**	**8.0**	**11.7**
Median	**1.35**	**36.26**	**3.8**	**7.9**	**11.6**

[1/] Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (4))
[2/] Expected Dividend Yield (Col (3)) + EPS Estimate (Col (4))

Source: www.reuters.com and www.yahoo.com.

DCF COSTS OF EQUITY FOR SAMPLE OF CANADIAN UTILITIES
(THREE-STAGE MODEL)

			Growth Rates			
Company	**Annualized Last Paid Dividend**	**Average Daily Close Prices 11/1/2011-1/31/2012**	**Stage 1: Reuters Long-Term EPS Forecasts**	**Stage 2: Average of Stage 1 & 3**	**Stage 3: GDP Growth** [1/]	**DCF Cost of Equity** [2/]
	(1)	(2)	(3)	(4)	(5)	(6)
Canadian Utilities Limited	1.61	60.76	7.9	6.2	4.4	7.7
Emera Inc.	1.35	32.57	7.5	6.0	4.4	9.6
Enbridge Inc.	0.98	36.26	8.7	6.5	4.4	8.0
Fortis Inc.	1.16	32.96	7.7	6.1	4.4	8.8
TransCanada Corp.	1.68	42.30	8.3	6.4	4.4	9.6
Mean	**1.36**	**40.97**	**8.0**	**6.2**	**4.4**	**8.7**
Median	**1.35**	**36.26**	**7.9**	**6.2**	**4.4**	**8.8**

[1/] Forecast nominal rate of GDP growth, 2013-21
[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: Consensus Economics, *Consensus Forecasts* (October 2011), www.reuters.com, and www.yahoo.com.

MARKET VALUE CAPITAL STRUCTURES FOR CANADIAN UTILITY SAMPLE

	Debt and Preferred Shares at Par (Millions $, September 2011)	Common Share Price Average Daily Close 11/1/2011-1/31/2012	Common Shares Outstanding (Millions, September 2011)	Total Market Capitalization (Millions $)	Market Value Common Equity Ratio
Canadian Utilities Limited	4,798	60.76	126	7,669	61.5%
Emera Inc.	3,495	32.57	123	3,993	53.3%
Enbridge Inc.	14,595	36.26	779	28,251	65.9%
Fortis Inc.	6,429	32.96	187	6,162	48.9%
TransCanada Corp.	21,948	42.30	703	29,739	57.5%
Mean				**$15,163**	**57.5%**
Median				**$7,669**	**57.5%**

MARKET VALUE CAPITAL STRUCTURES FOR U.S. UTILITIES SAMPLE

	Debt and Preferred Shares at Par (Millions $, September 2011)	Common Share Price Average Daily Close 11/1/2011-1/31/2012	Common Shares Outstanding (Millions, September 2011)	Total Market Capitalization (Millions $)	Market Value Common Equity Ratio
AGL Resources Inc.	2,704	41.08	78	3,208	54.3%
ALLETE Inc.	863	40.03	37	1,473	63.1%
Alliant Energy Corp.	2,932	42.28	111	4,679	61.5%
Atmos Energy Corp.	2,415	33.23	91	3,012	55.5%
Consolidated Edison	10,887	59.18	293	17,333	61.4%
Integrys Energy Group Inc.	2,373	51.87	78	4,041	63.0%
Northwest Natural Gas	823	46.86	27	1,250	60.3%
Piedmont Natural Gas	1,005	32.62	72	2,353	70.1%
Southern Company	21,468	44.42	862	38,289	64.1%
Vectren Corp.	1,936	28.93	82	2,364	55.0%
WGL Holdings Inc.	732	42.77	51	2,200	75.0%
Wisconsin Energy Corp.	5,178	33.47	231	7,741	59.9%
Xcel Energy Inc.	10,068	26.42	485	12,824	56.0%
Mean				**$7,751**	**61.5%**
Median				**$3,208**	**61.4%**

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 A rated utility
	=	4.80%
Equity Cost	=	9.50%
Tax Rate	=	26.0%
CEQ Ratio	Step (1)	58.0%
Debt Ratio	Step (1)	42.0%
CEQ Ratio	Step (2)	40.0%
Debt Ratio	Step (2)	60.0%

STEPS:

1. Estimate $WACC_{AT}$ for the less levered samp (common equity ratio of 58.0%)

   $WACC_{AT}$ = (4.80%)(1-.260)(42.0%) + (9.50%)(58.0%)
   = 7.00%

2. Estimate Cost of Equity for sample at 40.0% common equity ratio wit $WACC_{AT}$ unchanged at 7.00%

   $WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)
   7.00% = (4.80%)(1-.260)(60.0%) + (X)(40.0%)
   Cost of Equity at 40.0% Equity Ratio = 12.18%

3. Difference between Equity Return at 58.0% and 40.0% common equity ratios:

   12.18% - 9.50% = 2.68% (268 basis points)

APPROACH 2:

After-Tax Cost of Capital Falls as Debt Ratio Increases; Cost of Equity Increases

$$WACC_{AT(LL)} = WACC_{AT(ML)} \times \frac{(1-tD_{LL})}{(1-tD_{ML})}$$

Where LL,ML as before
t = tax rate
D = debt ratio

ASSUMPTIONS:

Debt Cost	=	Market Cost of Long Term Debt for A rated utility
	=	4.80%
Equity Cost	=	9.50%
Tax Rate	=	26.0%
CEQ Ratio	Step (1)	58.0%
Debt Ratio	Step (1)	42.0%
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 58.0%)

   $WACC_{AT}$ = (4.80%)(1-.260)(42.0%) + (9.50%)(58.0%)
   = 7.00%

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 $Ratio_{LL}$)

   $$WACC_{AT(ML)} = 7.00\% \times \frac{(1-.260 \times 60.0\%)}{(1-.260 \times 42.0\%)}$$

   $WACC_{AT(ML)}$ = 6.63%

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 $Ratio_{ML}$)
   6.63% = (4.80%)(1-.260)(60.0%) + (X)(40.0%)
   Cost of Equity at 40.0% Equity Ratio = 11.26%

4. Difference between Equity Return at 58.0% and 40.0% common equity ratios:

   11.26% - 9.50% = 1.76% (176 basis points)

RISK MEASURES FOR 21 CANADIAN LOW RISK UNREGULATED COMPANIES

Company Name	Debt Ratings S&P	Debt Ratings DBRS	Average 2010-2011 Adjusted Betas	2010 Equity Ratio (Total Capital)	Average Market to Book Ratio 1994-2010	Average Market to Book Ratio 2003-2010
ALGOMA CENTRAL CORP			0.92	79.3%	1.02	1.05
ASTRAL MEDIA INC			0.68	69.5%	1.74	1.85
CANADA BREAD CO LTD			0.64	98.5%	2.01	2.19
CANADIAN NATIONAL RAILWAY CO	A-	A(low)	0.64	65.0%	2.16	2.61
CANADIAN PACIFIC RAILWAY LTD	BBB-	BBB(low)	0.88	52.8%	1.58	1.70
CANADIAN TIRE CORP	BBB+	BBB(high)	0.71	76.9%	1.66	1.77
EMPIRE CO LTD			0.45	74.0%	1.41	1.31
LEON'S FURNITURE LTD			0.80	100.0%	2.46	2.54
LOBLAW COMPANIES LTD	BBB	BBB	0.58	59.8%	3.08	2.47
MAPLE LEAF FOODS INC			0.46	57.4%	2.07	1.62
METRO INC	BBB	BBB	0.45	70.7%	2.40	2.27
REITMANS (CANADA)			0.77	97.9%	1.77	2.58
RITCHIE BROS AUCTIONEERS INC			0.65	80.8%	4.97	4.97
SAPUTO INC			0.51	79.5%	3.63	3.18
SHOPPERS DRUG MART CORP	BBB+	A(low)	0.62	77.1%	3.44	3.48
THOMSON-REUTERS CORP	A-	A(low)	0.56	71.9%	2.43	1.99
TOROMONT INDUSTRIES LTD		BBB(high)	0.84	74.2%	2.87	2.78
TORSTAR CORP		BBB	0.91	63.7%	2.03	1.75
TRANSCONTINENTAL INC	BBB	BBB(high)	0.96	61.2%	1.53	1.56
UNI-SELECT INC			0.64	68.9%	2.11	2.01
WESTON (GEORGE) LTD	BBB	BBB	0.29	55.2%	2.68	2.38
Mean	**BBB+/BBB**	**BBB(high)**	**0.66**	**73.1%**	**2.34**	**2.29**
Median	**BBB**	**BBB(high)/BBB**	**0.64**	**71.9%**	**2.11**	**2.19**

Source: Standard and Poor's Research Insight and DBRS

RETURNS ON AVERAGE COMMON STOCK EQUITY FOR
21 CANADIAN LOW RISK UNREGULATED COMPANIES

Company Name	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average 1994-2010	Average 2003-2010
ALGOMA CENTRAL CORP	19.0	13.3	12.3	52.7	8.5	3.8	1.1	14.8	9.3	4.7	9.2	11.2	13.4	15.1	10.3	8.8	7.3	**12.6**	**10.0**
ASTRAL MEDIA INC	7.0	1.3	-9.5	7.1	7.8	6.4	4.4	8.2	10.0	10.0	10.9	12.1	13.1	13.0	14.7	-12.6	14.8	**7.0**	**9.5**
CANADA BREAD CO LTD	14.5	12.6	12.8	14.2	1.3	2.7	7.4	8.6	13.9	9.6	14.3	14.5	9.5	13.7	9.7	10.6	8.0	**10.5**	**11.2**
CANADIAN NATIONAL RAILWAY CO	9.7	-43.7	6.1	13.9	2.8	12.6	14.4	12.5	8.9	11.2	18.8	18.8	21.9	21.6	18.3	17.0	18.7	**10.8**	**18.3**
CANADIAN PACIFIC RAILWAY LTD	6.1	-13.0	13.5	18.0	10.3	7.3	20.2	6.6	15.2	11.3	10.8	13.0	17.2	18.3	10.8	9.6	11.3	**11.0**	**12.8**
CANADIAN TIRE CORP	0.5	10.2	10.4	11.4	13.0	11.2	10.6	11.5	11.9	12.8	13.6	13.9	13.4	14.2	11.2	9.2	11.7	**11.2**	**12.5**
EMPIRE CO LTD	9.4	3.9	11.9	17.9	21.7	13.3	69.1	16.4	11.4	11.6	11.4	16.2	10.3	14.0	10.5	10.7	11.9	**16.0**	**12.1**
LEON'S FURNITURE LTD	15.3	14.0	13.4	15.1	16.7	21.1	19.3	17.3	17.1	16.5	18.9	19.2	19.6	19.2	18.8	15.6	16.1	**17.3**	**18.0**
LOBLAW COMPANIES LTD	12.4	13.3	14.2	15.3	12.8	13.7	15.7	16.8	18.9	19.1	19.1	13.2	-3.9	6.0	9.6	10.8	10.4	**12.8**	**10.5**
MAPLE LEAF FOODS INC	7.5	-6.7	14.8	14.7	-6.3	17.9	8.0	10.3	12.2	4.8	13.0	9.9	0.5	19.2	-3.2	4.5	2.1	**7.2**	**6.3**
METRO INC	16.2	22.6	22.8	24.7	20.5	20.8	22.8	24.1	23.9	23.8	21.0	16.1	15.6	15.1	14.7	16.4	16.6	**19.9**	**17.4**
REITMANS (CANADA)	9.0	6.2	0.8	8.9	9.4	30.1	10.2	12.6	10.5	15.4	22.0	23.5	20.0	24.7	16.9	13.0	16.8	**14.7**	**19.0**
RITCHIE BROS AUCTIONEERS INC	na	nc	35.6	19.9	38.8	18.2	12.4	13.1	15.5	14.7	12.4	17.2	16.5	17.5	24.8	17.2	11.5	**19.0**	**16.5**
SAPUTO INC	na	nc	37.3	18.9	19.3	18.6	16.0	19.4	18.1	19.5	18.8	14.1	16.2	18.3	15.5	19.1	21.7	**19.4**	**17.9**
SHOPPERS DRUG MART CORP	na	na	na	na	na	nc	2.5	2.0	13.8	15.0	15.8	16.0	16.5	17.0	17.2	16.1	14.7	**13.3**	**16.0**
THOMSON-REUTERS CORP	14.6	22.4	14.2	12.9	34.7	8.0	17.9	10.2	7.3	8.8	10.3	9.3	11.0	31.1	9.1	4.0	4.6	**13.5**	**11.0**
TOROMONT INDUSTRIES LTD	30.6	27.1	24.3	47.5	22.5	16.6	15.4	16.4	12.7	16.9	17.8	17.6	19.0	20.0	19.6	14.8	9.6	**20.5**	**16.9**
TORSTAR CORP	7.9	6.7	11.3	38.4	-0.7	12.8	5.4	-14.6	21.3	17.8	14.6	14.5	9.2	11.3	-22.7	5.3	8.7	**8.7**	**7.4**
TRANSCONTINENTAL INC	8.1	9.3	0.8	10.6	11.2	11.4	13.7	4.0	18.9	17.5	13.9	13.3	12.2	10.3	0.7	-7.7	15.4	**9.6**	**9.4**
UNI-SELECT INC	24.7	21.4	19.9	20.7	20.6	18.7	15.2	16.1	16.7	19.2	15.5	16.3	15.4	13.7	13.6	10.3	12.0	**17.1**	**14.5**
WESTON (GEORGE) LTD	8.7	12.9	15.1	14.5	37.3	14.0	17.4	18.5	18.3	19.4	10.2	16.2	1.6	12.7	17.5	17.6	7.1	**15.2**	**12.8**
Average	**12.3**	**7.4**	**14.1**	**19.9**	**15.1**	**14.0**	**15.2**	**11.7**	**14.6**	**14.3**	**14.9**	**15.1**	**12.8**	**16.5**	**11.3**	**10.0**	**12.0**	**13.6**	**13.3**
Median	**9.5**	**11.4**	**13.5**	**15.2**	**12.9**	**13.5**	**14.4**	**12.6**	**13.9**	**15.0**	**14.3**	**14.5**	**13.4**	**15.1**	**13.6**	**10.7**	**11.7**	**13.3**	**12.8**
Average of Annual Medians																		**13.2**	**13.5**

Source: Standard and Poor's Research Insight.

NEWFOUNDLAND AND LABRADOR BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

WRITTEN EVIDENCE

OF

JAMES H. VANDER WEIDE, PH.D.

FOR

NEWFOUNDLAND POWER INC.

MARCH 2012

WRITTEN EVIDENCE OF
JAMES H. VANDER WEIDE
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Exhibit 20 Appendix 3 The Sensitivity of the Forward-looking Required Equity Risk Premium on Utility Stocks to Changes in Interest Rates

WRITTEN EVIDENCE OF

JAMES H. VANDER WEIDE

I. Introduction

Q 1 What is your name, occupation, and business address?

A 1 My name is James H. Vander Weide. I am Research Professor of Finance and Economics at Duke University, Fuqua School of Business. I am also President of Financial Strategy Associates, a firm that provides strategic and financial consulting services to corporate clients. My business address is 3606 Stoneybrook Drive, Durham, North Carolina 27705.

Q 2 Please summarize your qualifications.

A 2 I graduated from Cornell University with a Bachelor's Degree in Economics and from Northwestern University with a Ph.D. in Finance. After joining the faculty of the School of Business at Duke University, I was named Assistant Professor, Associate Professor, Professor, and then Research Professor. I have published research in the areas of finance and economics and taught courses in these fields at Duke for more than thirty-five years. I am now retired from my teaching duties at Duke.

Q 3 Have you previously testified on financial and economic issues?

A 3 Yes. As an expert on financial and economic theory and practice, I have participated in more than 400 regulatory and legal proceedings before the National Energy Board, the Canadian Radio-Television and Telecommunications Commission, the public service commissions of forty-three states and four Canadian provinces, the U.S. Congress, the Federal Energy Regulatory Commission, the Federal Communications Commission, the National Telecommunications and Information Administration, the insurance commissions of five states, the Iowa State Board of Tax Review, the National Association of Securities Dealers, and the North Carolina Property Tax Commission. In addition, I have prepared expert testimony in proceedings before the U.S. Tax Court, the U.S. District Court for the District of Nebraska; the U.S. District Court for the

District of New Hampshire; the U.S. District Court for the District of Northern Illinois; the U.S. District Court for the Eastern District of North Carolina; the Montana Second Judicial District Court, Silver Bow County; the U.S. District Court for the Northern District of California; the Superior Court, North Carolina; the U.S. Bankruptcy Court for the Southern District of West Virginia; and the U. S. District Court for the Eastern District of Michigan. A summary of my research, teaching, and other professional experience is presented in Appendix 1, Exhibit 18.

Q 4 What is the purpose of your testimony?

A 4 I have been asked by Newfoundland Power Inc. ("Newfoundland Power" or "NP") to prepare an independent: (1) appraisal of the fairness of the returns provided by the Automatic Adjustment Formula ("the ROE Formula") of the Newfoundland and Labrador Board of Commissioners of Public Utilities ("the Board"); and (2) estimate of Newfoundland Power's cost of equity.

II. The Fair Rate of Return Standard

Q 5 Are you familiar with the fair rate of return standard?

A 5 Yes. The fair rate of return standard is a benchmark for determining whether a public utility's allowed rate of return is just and reasonable. According to the fair rate of return standard, a utility's allowed return is considered to be fair if it is: (1) equal to the returns investors expect to earn on other investments of comparable risk; (2) sufficient to allow the regulated firm to attract capital on reasonable terms; and (3) sufficient to allow the regulated firm to maintain its financial integrity.

Q 6 What is the economic definition of the required rate of return, or cost of capital, associated with particular investment decisions, such as the decision to invest in electric utility facilities?

A 6 The economic definition of the cost of capital is similar to the definition of a fair return, namely, the cost of capital is the return investors expect to receive on alternative investments of comparable risk.

Q 7 How does the cost of capital affect a firm's investment decisions?

A 7 From an economic perspective, a firm should only invest in a specific project if the expected return on the investment is greater than or equal to the company's cost of capital. Thus, the cost of capital serves as a hurdle rate for the firm's investment decisions.

Q 8 How does the cost of capital affect investors' willingness to invest in a company?

A 8 The cost of capital measures the return investors can expect on investments of comparable risk. The cost of capital also measures the investor's required rate of return on investment because rational investors will not invest in a particular investment opportunity if the expected return on that opportunity is less than the cost of capital. Thus, the cost of capital is a hurdle rate for both investors and the firm.

Q 9 Do all investors have the same position in the firm?

A 9 No. Bond investors have a fixed claim on a firm's assets and income that must be paid prior to any payment to the firm's equity investors. Since the firm's equity investors have a residual claim on the firm's assets and income, equity investments are riskier than bond investments. Thus, the cost of equity exceeds the cost of debt.

Q 10 What is the overall or average cost of capital?

A 10 The overall or average cost of capital is a weighted average of the cost of debt and cost of equity, where the weights are the percentages of debt and equity in a firm's capital structure.

Q 11 Can you illustrate the calculation of the overall or weighted average cost of capital?

A 11 Yes. Assume that the cost of debt is 6 percent, the cost of equity is 11 percent, and the percentages of debt and equity in the firm's capital structure are 50 percent and 50 percent, respectively. Then the weighted average cost of capital is expressed by .50 times 6 percent plus .50 times 11 percent, or 8.5 percent.[1]

Q 12 How do economists define the cost of equity?

A 12 Economists define the cost of equity as the return investors expect to receive on alternative equity investments of comparable risk. Since the return on an equity investment of comparable risk is not a contractual return, the cost of equity is more difficult to measure than the cost of debt. However, as I have already noted, the cost of equity is greater than the cost of debt. The cost of equity, like the cost of debt, is both forward looking and market based.

Q 13 How do economists measure the percentages of debt and equity in a firm's capital structure?

A 13 Economists measure the percentages of debt and equity in a firm's capital structure by first calculating the market value of the firm's debt and the market value of its equity. The percentage of debt is then calculated by the ratio of the market value of debt to the combined market value of debt and equity, and the percentage of equity by the ratio of the market value of equity to the combined market values of debt and equity. For example, if a firm's debt has a market value of $25 million and its equity has a market value of $75 million, then its total market capitalization is $100 million, and its capital structure contains 25 percent debt and 75 percent equity.

Q 14 Why do economists measure a firm's capital structure in terms of the market values of its debt and equity?

A 14 Economists measure a firm's capital structure in terms of the market values of its debt and equity because: (1) the weighted average cost of capital is defined as the return investors expect to earn on a portfolio of the company's debt and equity securities; (2) investors measure the

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[1] The weighted average cost of capital may be calculated on either an after-tax or a before-tax basis. The difference between these calculations is that the after-tax cost of debt is used to calculate the weighted average cost of capital in an after-tax calculation. For simplicity, I present a before-tax calculation of the weighted average cost of capital in this example.

expected return and risk on their portfolios using market value weights, not book value weights; and (3) market values are the best measures of the amounts of debt and equity investors have invested in the company on a going forward basis.

Q 15 Why do investors measure the expected return and risk on their investment portfolios using market value weights rather than book value weights?

A 15 Investors measure the expected return and risk on their investment portfolios using market value weights because they calculate the expected return by dividing the expected future value of the investment by the current value of the investment, and market value is the best measure of the current value of the investment. From the point of view of investors, the historical cost or book value of their investment is entirely irrelevant to the current risk and return on their portfolios because if they were to sell their investments, they would receive market value, not historical cost. Thus, the expected return and risk can only be measured in terms of market values.

Q 16 Does the required rate of return on an investment vary with the risk of that investment?

A 16 Yes. Since investors are averse to risk, they require a higher rate of return on investments with greater risk.

Q 17 Do investors consider future industry changes when they estimate the risk of a particular investment?

A 17 Yes. Investors consider all the risks that a firm might incur over the future life of the company, including both business and financial risks.

Q 18 Are these economic principles regarding the fair return on capital recognized in any Supreme Court cases?

A 18 Yes. These economic principles regarding the fair rate of return on capital are recognized in at least one Canadian and two United States Supreme Court cases: (1) *Northwestern Utilities Ltd. v. Edmonton*, (1929); (2) *Bluefield Water Works and Improvement Co. v. Public Service Commission*; and (3) *Federal Power Commission v. Hope Natural Gas*

Co. In *Northwestern Utilities Ltd. v. Edmonton*, Mr. Justice Lamont states:

> The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise. [*Northwestern Utilities Ltd. v. Edmonton*, [1929] S.C.R. 186.]

The Court clearly recognizes here that a regulated utility must be allowed to earn a return on the value of its property that is at least equal to its cost of capital.

III. Business and Financial Risks

Q 19 What is the difference between business and financial risk?

A 19 Business risk is the variability in return on investment that equity investors experience from a company's business operations when the company is financed entirely with equity. Financial risk is the additional variability in return on investment that equity investors experience due to the company's use of debt financing, or leverage.

Q 20 What are the primary determinants of an electric utility's business risk?

A 20 The business risk of investing in electric utility companies such as Newfoundland Power is caused by: (1) demand uncertainty; (2) operating expense uncertainty; (3) investment cost uncertainty; (4) high operating leverage; and (5) regulatory uncertainty.

Q 21 How does demand uncertainty affect an electric utility's business risk?

A 21 Demand uncertainty affects an electric utility's business risk through its impact on the variability of the company's revenues and its return on investment. The greater the uncertainty in demand, the greater is the uncertainty in the company's revenues and its return on investment.

Q 22 What causes the demand for electricity to be uncertain?

A 22 Demand uncertainty is caused by: (a) the strong dependence of electric demand on the state of the economy, population growth, and weather patterns; (b) the sensitivity of demand to changes in rates; and (c) the ability of some customers to conserve energy. Demand uncertainty is a problem for electric utilities because utilities need to plan for infrastructure additions in advance of demand.

Q 23 Does Newfoundland Power experience demand uncertainty?

A 23 Yes. As explained in the Company's evidence, Newfoundland Power experiences demand uncertainty associated with the aging of its customer base, the movement of rural customers to urban centers, and the potential long-run decline of the Newfoundland population.

Q 24 Why are an electric utility's operating expenses uncertain?

A 24 Operating expense uncertainty arises as a result of: (a) the prospect of increasing employee health care and pension expenses; (b) uncertainty regarding the cost of purchased power; (c) variability in maintenance costs and the costs of materials; (d) uncertainty over outages of the transmission and distribution systems, as well as storm-related expenses; (e) the prospect of increased expenses for security; and (f) high volatility in fuel prices or interruptions in fuel supply.

Q 25 Does Newfoundland Power experience operating expense uncertainty?

A 25 Yes. Newfoundland Power experiences operating expense uncertainty arising, for example, from storm-related expenses.

Q 26 Why are utility investment costs uncertain?

A 26 The electric utility business requires large investments in the plant and equipment required to deliver electricity to customers. The future amounts of required investments in plant and equipment are uncertain as a result of: (a) demand uncertainty; (b) uncertainty in the costs of construction materials and labor; and (c) uncertainty in the amount of additional investments to ensure the reliability of the company's transmission and distribution networks. Furthermore, the risk of investing in electric utility facilities is increased by the irreversible nature of the company's investments in utility plant and equipment.

Q 27 You note above that high operating leverage contributes to the business risk of electric utilities. What is operating leverage?

A 27 Operating leverage is the increased sensitivity of a company's earnings to sales variability that arises when some of the company's costs are fixed.

Q 28 How do economists measure operating leverage?

A 28 Economists typically measure operating leverage by the ratio of a company's fixed expenses to its operating margin (revenues minus variable expenses).

Q 29 How does operating leverage affect a company's business risk?

A 29 Operating leverage affects a company's business risk through its impact on the variability of the company's profits or income. Generally speaking, the higher a company's operating leverage, the higher is the variability of the company's operating profits.

Q 30 Do electric utilities typically experience high operating leverage?

A 30 Yes. The electric utility business requires a large commitment to fixed costs in relation to the operating margin on sales, a situation known as high operating leverage. The relatively high degree of fixed costs in the electric utility business arises primarily from the average electric utility's large investment in fixed plant and equipment. High operating leverage causes the average electric utility's operating income to be highly sensitive to demand and revenue fluctuations.

Q 31 Does regulation create uncertainty for electric utilities?

A 31 Yes. Investors' perceptions of the business and financial risks of electric utilities are strongly influenced by their views of the quality of regulation. Investors are painfully aware that regulators in some jurisdictions have been unwilling at times to set rates that allow companies an opportunity to recover their cost of service in a timely manner and earn a fair and reasonable return on investment. As a result of the perceived increase in regulatory risk, investors will demand a higher rate of return for electric utilities operating in those jurisdictions. On the other hand, if investors perceive that regulators will provide a reasonable opportunity for the company to maintain its financial integrity and earn a fair rate of return on its investment, investors will view regulatory risk as minimal.

Q 32 Do utilities generally have cost recovery mechanisms that reduce their business and regulatory risks?

A 32 Yes. Utilities typically have cost recovery mechanisms such as fuel cost adjustment clauses and weather normalization clauses that reduce the uncertainty in a company's ability to recover some of their major prudently incurred expenses.

Q 33 What cost recovery mechanisms are available to Newfoundland Power?

A 33 Newfoundland Power has cost recovery mechanisms for the recovery of prudently incurred purchased power costs and future employee benefit costs.

Q 34 How do Newfoundland Power's cost recovery mechanisms compare to the cost recovery mechanisms available to other electric utilities?

A 34 Newfoundland Power's cost recovery mechanisms are typical for electric utilities throughout North America.

Q 35 What is financial leverage?

A 35 Financial leverage is the additional sensitivity of a company's earnings to sales variability that arises when a company uses fixed cost debt financing.

Q 36 How do economists measure financial leverage?

A 36 As discussed above, economists generally measure financial leverage by the percentages of debt and equity in a company's market value capital structure. Companies with a high percentage of debt compared to equity are considered to have high financial leverage.

Q 37 Does financial leverage affect the risk of investing in an electric utility's stock?

A 37 Yes. High debt leverage is a source of additional risk to utility stock investors because it increases the percentage of the firm's costs that are fixed, and the presence of higher fixed costs increases the variability of the equity investors' return on investment.

Q 38 How does Newfoundland Power's allowed equity ratio compare to that of other Canadian and U.S. utilities?

A 38 Newfoundland Power has an allowed equity ratio of 45 percent. Deemed equity ratios for regulated utilities in Canada are generally in the range 37 percent to 45 percent. The average allowed equity ratio for U.S. utilities is approximately 49 percent. These data support the conclusion that Newfoundland Power has slightly less financial risk than the average regulated Canadian utility and slightly more financial risk than the average U.S. regulated utility.

Q 39 What conclusion do you reach from your analysis of business and financial risks?

A 39 I conclude that Newfoundland Power is an average risk utility.

IV. The ROE Formula

Q 40 Are you familiar with the Board's ROE formula for Newfoundland Power?

A 40 Yes. The Board's ROE formula for Newfoundland Power has two parts: (1) an estimate of Newfoundland Power's cost of equity in a specific year, based on the application of the Capital Asset Pricing Model ("CAPM"); and (2) an automatic adjustment formula that "adjusts" the cost of equity in subsequent years for changes in the forecast interest rate on long-term Canadian government bonds.

Q 41 What is the CAPM?

A 41 The CAPM is an equilibrium model of the security markets in which the expected or required return on a given security is equal to the risk-free rate of interest, plus the company equity "beta," times the market risk premium:

Cost of equity = Risk-free rate + Equity beta x Market risk premium

The risk-free rate in this equation is the expected rate of return on a risk-free government security, the equity beta is a measure of the company's risk relative to the market as a whole, and the market risk premium is the premium investors require to invest in the market basket of all securities compared to the risk-free security.

Q 42 When did the Board last apply the CAPM to estimate Newfoundland Power's cost of equity?

A 42 The Board last applied the CAPM to estimate Newfoundland Power's cost of equity for 2010 in Order No. P. U. 43 (2009).

Q 43 What CAPM cost of equity did the Board find for Newfoundland Power in Order No. P. U. 43?

A 43 The Board found a CAPM cost of equity equal to 8.6 percent, based on a forecast long-term Canada government bond yield equal to 4.5 percent, an equity beta equal to 0.60, a market risk premium equal to 6.0 percent, and an allowance for financing flexibility equal to 0.50 percent (8.6 = 4.5 + 0.60 x 6 + 0.50).

Q 44 Did the Board rely entirely on the results of the CAPM to estimate Newfoundland Power's cost of equity for 2010?

A 44 No. The Board adjusted its 8.6 percent CAPM cost of equity result upward to 9.0 percent, based on its review of (1) the results of other cost of equity methodologies; (2) recent decisions of other regulators in Canada; and (3) Newfoundland Power's credit metrics.

Q 45 You mention that the Board's ROE formula also includes an automatic adjustment formula. Does the Board consider the continued use of the automatic adjustment formula in Order No. P. U. 43?

A 45 Yes. In Order No. P. U. 43, the Board concludes that the automatic adjustment formula should be continued in 2011 and 2012. As the Order states:

> Formulaic approaches to the determination of a return on equity do not allow for the exercise of discretion based on a comprehensive review of all the relevant circumstances at the time. The Board believes that the benefit of a cost of capital hearing must be weighed against the significant costs to customers. While it is clear that financial market conditions were unstable in late 2008 and early 2009 Newfoundland Power did not demonstrate that the use of the automatic adjustment formula is inappropriate for future years. Discontinuing the formula at this time would in the Board's view, be an excessive response to financial market conditions which, while severe in the fall of 2008 and spring of 2009, appear to be settling. The Board believes that it is appropriate to continue to use a formula to adjust

> Newfoundland Power's return on rate base for several years following a full review in a general rate application. Therefore the Board will order the continued use of the automatic adjustment formula for 2011 and 2012. [P. U. 43, p. 29]

Q 46 What is the Board's most recent ROE Formula for Newfoundland Power?

A 46 The Board's most recent ROE Formula is given by the equation:

$$ROE = 9.00\% + [0.80 \times (RFR - 4.50)]$$

where:

- 9.00 is the return on equity approved for rate making purposes in 2010;
- 0.80 is the adjustment coefficient for the change in the forecast risk-free rate;
- RFR is the risk-free rate; and
- 4.50 is the risk-free rate approved by the Board for the 2010 Test Year.

Q 47 The ROE Formula uses an adjustment coefficient equal to 0.80. How should this coefficient be interpreted?

A 47 The 0.80 adjustment coefficient reflects the Board's opinion that Newfoundland Power's required ROE changes by eighty percent of the forecasted change in long-term Canada government bond yields. Specifically, the 0.80 adjustment coefficient suggests that Newfoundland Power's required ROE increases by eighty basis points when the forecasted long-term Canada bond yield increases by one hundred basis points and declines by eighty basis points when the forecasted long-term Canada bond yield decreases by one hundred basis points.

Q 48 What does a 0.80 adjustment coefficient suggest about the equity investor's required risk premium on an investment in Newfoundland Power?

A 48 The 0.80 adjustment coefficient suggests that the equity investor's equity risk premium increases by twenty basis points when the interest rate on long-term Canada bonds declines by one hundred basis points.

Q 49 How is the risk-free rate determined in the ROE formula?

A 49 The risk-free rate is determined by adding the average of the three-month and twelve-month forecast of ten-year Government of Canada Bonds as published by Consensus Forecasts in the preceding November to the average observed spread between ten-year and thirty-year Government of Canada Bonds for all trading days in the preceding October.

Q 50 What is the value of the forecast risk-free rate at November 2011?

A 50 At November 2011, the forecast risk-free rate is 3.06 percent.

Q 51 Using a 3.06 percent forecast yield on long-term Canada bonds, what ROE is obtained using the ROE Formula?

A 51 The ROE Formula produces an ROE equal to 7.85 percent. This result is calculated as follows: 7.85 = 9.00 + [0.80 x (3.06 – 4.50)].

Q 52 What equity risk premium is suggested by the ROE Formula?

A 52 The ROE Formula indicates an equity risk premium equal to 4.79 percent (7.85 – 3.06 = 4.79).

V. Tests of the Fairness of the 7.85 Percent Formula ROE

Q 53 Have you performed any tests of the fairness of the 7.85 percent allowed ROE provided by the ROE Formula?

A 53 Yes. I have performed five tests of the fairness of the 7.85 percent ROE provided by the ROE Formula. First, I have examined evidence on the experienced returns achieved by equity investors in two groups of Canadian utilities compared to interest rates on long-term Canada bonds. My studies indicate that the average experienced equity risk premium on an investment in Canadian utility stocks, 6.7 percent (see Table 1), is approximately 190 basis points higher than the 4.79 percent risk premium produced by the ROE Formula. This evidence supports the conclusion that the ROE Formula does not provide a fair ROE for Newfoundland Power.

Second, I have examined evidence on the allowed rates of return on equity and allowed common equity ratios for U.S. electric and natural gas utilities. My studies indicate that average allowed rates of return on equity for U.S. utilities since 2009 are in the range 10.0 percent to 10.4 percent, and the average allowed equity ratio is approximately 49 percent. Since the ROE Formula currently produces a 7.85 percent ROE on an allowed equity ratio of 45 percent, this evidence supports the conclusion that the ROE Formula fails to provide returns that are commensurate with returns on other investments of comparable risk.

Third, I have examined evidence on the sensitivity of the forward-looking, or ex ante, required equity risk premium on utility stocks to changes in interest rates. The ROE Formula suggests that Newfoundland Power's required ROE declines by eighty basis points when the risk-free rate declines by one hundred basis points. Contrary to the eighty-basis-point decline provided by the ROE Formula, my studies indicate that NP's required ROE declines by less than fifty basis points for every one hundred basis point decline in the risk-free rate. From my ex ante risk premium studies, I find that the forward-looking required equity risk premium on utility stocks, 7.7 percent, is almost three hundred basis points higher than the 4.79 percent risk premium suggested by the ROE Formula. This evidence further supports the conclusion that the ROE Formula does not provide a fair ROE for Newfoundland Power.

Fourth, I have examined evidence on the sensitivity of the equity risk premium implied by U.S. utility allowed rates of return on equity to changes in the interest rate on long-term government bonds. My studies indicate that U.S. utility allowed ROEs are significantly less sensitive to changes in interest rates on long-term government bonds than the allowed ROE established by the ROE Formula. Specifically, while the ROE Formula reduces the allowed ROE by eighty basis points when the forecasted yield to maturity on long-term government bonds declines by one hundred basis points, U.S. regulators typically reduce the allowed ROE by approximately fifty basis points when the yield to maturity on long-term government bonds declines by one hundred basis points. This evidence also supports the conclusion that the ROE Formula is not working.

Fifth, I have examined evidence on the volatility of returns on Canadian utility stocks compared to the volatility of returns on the

Canadian market index. My studies indicate that the volatility of returns on Canadian utility stocks exceeds or approximates the volatility of returns on the Canadian market index. Because investors demand a higher return for bearing more risk, this evidence also supports the conclusion that the equity risk premium on Canadian utility stocks is higher than the equity risk premium implied by the ROE Formula.

A. Evidence on Experienced Equity Risk Premiums on Investments in Canadian Utility Stocks

Q 54 How do you measure the experienced equity risk premium on an investment in Canadian utility stocks?

A 54 I measure the experienced equity risk premium on an investment in Canadian utility stocks from data on returns earned by investors in Canadian utility stocks compared to interest rates on long-term Canada bonds.

Q 55 How do you measure the return experienced by investors in Canadian utility stocks?

A 55 I measure the return experienced by investors in Canadian utility stocks from historical data on returns earned by investors in: (1) the S&P/TSX utilities stock index[2]; and (2) a basket of Canadian utility stocks created by BMO Capital Markets ("BMO CM").

Q 56 What companies are currently included in these indices of Canadian utility stock performance?

A 56 The companies currently included in the S&P/TSX utilities stock index are Atco Ltd., Atlantic Power Corporation, Algonquin Power & Utilities Corp., Capital Power Corporation, Canadian Utilities Limited, Emera

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[2] The legacy S&P/TSX utilities index was discontinued by Standard & Poor's in Spring 2002 when Standard & Poor's introduced a new S&P/TSX Composite utilities index that included the GICs 5500 utilities. Standard & Poor's provided total return index value data going back to 1999. The historical data on returns earned by investors in the S&P/TSX utilities index therefore includes total returns on the S&P/TSX legacy utilities index through 1998 and total returns on the new S&P/TSX composite utilities index from 1999 through 2011.

Incorporated, Fortis Inc., Just Energy Group Inc., Northland Power Inc., and TransAlta Corporation.

The BMO CM basket of utility and pipeline companies includes Canadian Utilities Ltd., Emera Inc., Enbridge Inc., Fortis Inc., and TransCanada Corporation. The BMO CM basket also includes return data for Westcoast Energy Inc. until December 2001, Terasen Inc. through July 2005, and Pacific Northern Gas through December 2010.

Q 57 What time periods are covered in your Canadian utility stock return data?

A 57 The S&P/TSX utilities stock return data cover the period 1956 through 2011, and the BMO CM stock return data cover the period 1983 through 2011.

Q 58 Why do you analyze investors' experienced returns over such long time periods?

A 58 I analyze investors' experienced returns over long time periods because experienced returns over short periods can deviate significantly from expectations. However, I also recognize that experienced returns over long periods may deviate from expected returns if the data in some portion of the long time period are unreliable.

Q 59 Would your study provide different risk premium results if you had included different time periods?

A 59 Yes. The risk premium results vary somewhat depending on the historical time period chosen. My policy is to go back as many years as it is possible to obtain reliable data. With regard to the S&P/TSX utilities index, the data begin in 1956, and for the BMO CM utility stock data set, the data begin in 1983.

Q 60 Why do you choose two sets of Canadian utilities stock return performance data rather than simply relying entirely on either the S&P/TSX utilities stock index data or the BMO CM utility stock data set?

A 60 I choose two sets of Canadian utility stock return performance data because each data set provides different information on Canadian utility stock returns. The S&P/TSX utilities index is valuable because it provides information on the returns experienced by investors in a portfolio of

Canadian utility stocks over a relatively long period of time. However, six of the ten companies included in the S&P/TSX utility index operate mainly in non-traditional utility markets. The BMO CM utility stock return database is valuable because it provides information on the experienced returns for a sample of Canadian companies that receive a significantly higher percentage of revenues from traditional utility operations than the companies in the S&P/TSX index. However, the time period covered is not as long as the period covered by the S&P/TSX utility index.

Q 61 How are the experienced returns on an investment in each utility data set calculated?

A 61 The experienced returns on an investment in each utility data set are calculated from the historical record of stock prices and dividends for the companies in the data set. From the historical record of stock prices and dividends, the index sponsors construct an index of investors' wealth at the end of each period, assuming a $100 investment in the index at the time the index was constructed. An annual rate of return is calculated from the wealth index by dividing the wealth index at the end of each period by the wealth index at the beginning of the period and subtracting one [$r_t = (W_t \div W_{t-1}) - 1$].

Q 62 How do you measure the interest rate earned on long-term Canada bonds in your experienced, or ex post, risk premium studies?

A 62 I use the interest rate data on long-term Canada bonds reported by the Bank of Canada.

Q 63 What average risk premium results do you obtain from your analysis of returns experienced by investors in Canadian utility stocks?

A 63 The average experienced risk premium is 6.7 percent, as shown below in Table 1. (The annual data that produce these results are shown in Exhibit 1 and Exhibit 2). This 6.7 percent risk premium is approximately 190 basis points higher than the 4.79 percent risk premium suggested by the ROE Formula.

TABLE 1
EX POST RISK PREMIUM RESULTS

COMPARABLE GROUP	PERIOD OF STUDY	AVERAGE STOCK RETURN	AVERAGE BOND YIELD	RISK PREMIUM
S&P/TSX Utilities	1956 – 2011	11.99	7.33	4.7
BMO CM Utilities Stock Data Set	1983 – 2011	16.01	7.24	8.8
Average				6.7

Q 64 What conclusions do you draw from your experienced, or ex post, risk premium studies about the required risk premium on an investment in Canadian utility stocks?

A 64 My ex post risk premium studies provide evidence that investors require an equity return that is at least 6.7 percentage points above the interest rate on long-term Canada bonds.

Q 65 Do you have any evidence that the required equity risk premium may actually be greater than 6.7 percentage points?

A 65 Yes. I provide evidence below that the required equity risk premium increases when interest rates decline and decreases when interest rates rise. Since the expected 3.06 percent yield on long Canada bonds is significantly less than the 7.3 percent average yield on long Canada bonds over the period of my ex post risk premium studies, the current required equity risk premium should be significantly higher than the average 6.7 percent equity risk premium I obtain from my ex post risk premium studies.

Q 66 How does your evidence on the experienced equity risk premium support your conclusion that the ROE Formula fails to provide a fair return on equity for Newfoundland Power?

A 66 My evidence supports my conclusion that the ROE Formula fails to provide a fair return on equity for Newfoundland Power because it suggests that investors require an equity risk premium on Canadian utility stocks equal to 6.7 percent, a value that is approximately 190 basis points higher than the risk premium suggested by the ROE Formula.

B. Evidence on Recent Allowed Rates of Return on Equity for U.S. Utilities

Q 67 Do you have evidence on recent allowed rates of return on equity for U.S. utilities?

A 67 Yes. I have evidence on recent allowed rates of return on equity for U.S. electric and natural gas utilities from January 2009 through December 2011. Since January 2009, the average allowed ROE for electric utilities is 10.4 percent, and for natural gas utilities, 10.1 percent. In 2011, the average allowed ROE for electric utilities is 10.3 percent, and for natural gas utilities, 10.0 percent (see Exhibit 3 and Exhibit 4).

Q 68 Why do you examine data on allowed rates of return on equity for U.S. utilities rather than Canadian utilities?

A 68 I examine data on allowed rates of return on equity for U.S. utilities rather than Canadian utilities because allowed rates of return on equity for U.S. utilities are based on cost of equity studies for utilities at the time of each case rather than on an ROE formula such as the ROE Formula. Thus, recent allowed rates of return on equity for U.S. utilities are an independent test of whether the ROE Formula provides a fair ROE for Newfoundland Power.

Q 69 Are allowed rates of return on equity the best measure of the cost of equity at each point in time?

A 69 No. Since the cost of equity is determined by investors in the marketplace, not by regulators, the cost of equity is best measured using market models such as the equity risk premium and the discounted cash flow model. However, as noted above, because allowed rates of return in non-formula jurisdictions are based on regulators' judgments regarding the cost of equity and fair rate of return, they provide additional information on the fairness of the ROE provided by the ROE Formula.

Q 70 How do the average allowed ROEs for U.S. electric and natural gas utilities compare to the ROE implied by the ROE Formula?

A 70 The average allowed rates of return on equity for U.S. utilities are in the range 10.0 percent to 10.4 percent. As noted above, the ROE Formula currently provides an ROE equal to 7.85 percent. Thus, the average allowed returns for the U.S. utilities exceed the ROE provided by the ROE Formula by 215 to 255 basis points.

Q 71 Can the difference between allowed ROEs for U.S. utilities and the ROE provided by the ROE Formula be explained by differences in business risk?

A 71 No. The business risk of electric and natural gas utilities is approximately the same in the U.S. as it is in Canada.

Q 72 Why is the business risk of electric and natural gas utilities approximately the same in the U.S. as it is in Canada?

A 72 The business risk of electric and natural gas utilities is similar in the U.S. and Canada because: (1) U.S. electric and natural gas utilities rely on essentially the same electric and natural gas technologies to deliver their services to the public as electric and gas utilities in Canada; (2) the economics of electric and natural gas transmission and distribution is similar in the U.S. and Canada; and (3) U.S. electric and gas utilities are regulated under similar cost-based regulatory structures and fair rate of return principles as Canadian utilities.

Q 73 Some observers have argued that Canadian utilities have lower regulatory risk than U.S. utilities because Canadian regulators generally make greater use of cost adjustment and revenue stabilization mechanisms than U.S. regulators. Do you agree with this argument?

A 73 No. U.S. utilities have many cost adjustment and revenue stabilization mechanisms similar to those of Canadian utilities. For example, many U.S. natural gas distribution companies have cost adjustment mechanisms for the cost of purchased gas, and revenue stabilization mechanisms for weather normalization and declining customer usage. In addition, U.S. natural gas utilities increasingly have rate designs that allow them to recover higher percentages of their fixed costs through fixed monthly rates rather than through variable rates. Many U.S. electric utilities have cost adjustment mechanisms for costs of fuel and purchased power, environmental expenses, demand-side management program costs, renewables expenses, and new generation plant investment; and revenue stabilization mechanisms for conservation and weather normalization. Some electric utilities have cost adjustment mechanisms for storm damage expenses and FERC-approved transmission expenses.

Q 74 Do cost recovery and revenue stabilization mechanisms guarantee that a public utility will earn its cost of equity?

A 74 No. Regulatory risk is associated with the possibility that a utility will be unable to earn its required rate of return as a result of regulation. Although cost recovery and revenue stabilization mechanisms generally reduce the gap between a utility's actual and allowed returns, they do not necessarily reduce the gap between a utility's actual and required returns. To the extent that they are regulated through formula ROEs, Canadian utilities may face greater regulatory risk than U.S. utilities because formula ROEs may be more likely to differ from the market cost of equity than ROEs based on market evidence in each rate proceeding.

Q 75 How does the financial risk of Canadian utilities compare to the financial risk of U.S. utilities?

A 75 Canadian utilities have greater financial risk than U.S. utilities because U.S. utilities generally have average allowed equity ratios in the range 48 percent to 52 percent (see Exhibit 5 and Exhibit 6), whereas Canadian utilities generally have allowed equity ratios in the range 37 percent to 45 percent.

Q 76 What conclusions do you draw from your evidence that allowed ROEs for comparable U.S. utilities are significantly higher than the ROE provided by the ROE Formula?

A 76 My evidence on allowed ROEs for U.S. utilities provides further support for the conclusion that the ROE Formula fails to provide a fair rate of return on equity for Newfoundland Power.

C. Evidence on the Sensitivity of the Forward-looking Required Equity Risk Premium on Utility Stocks to Changes in Interest Rates

Q 77 How do you study the sensitivity of the forward-looking required equity risk premium on utility stocks to changes in interest rates?

A 77 I study the sensitivity of the forward-looking required equity risk premium on utility stocks to changes in interest rates in two steps. First, I estimate the forward-looking required equity risk premium on utility stocks in each month of my study period. Second, I perform a statistical regression analysis of the relationship between changes in the required equity risk premium and changes in interest rates.

Q 78 Please describe how you measure the forward-looking required equity risk premium on an equity investment in utility stocks in each month of your study period.

A 78 My estimate of the required equity risk premium is based on studies of the discounted cash flow ("DCF") expected return on a comparable group of utilities in each month of my study period compared to the interest rate on long-term government bonds. Specifically, for each month in my study period, I calculate the risk premium using the equation,

$$RP_{COMP} = DCF_{COMP} – I_B$$

where:

RP_{COMP}	=	the required risk premium on an equity investment in the comparable companies,
DCF_{COMP}	=	average DCF expected rate of return on a portfolio of comparable companies; and
I_B	=	the yield to maturity on an investment in long-term U.S. Treasury bonds.

Q 79 Please describe the DCF model you use to estimate the forward-looking, or ex ante, required risk premium on an equity investment in utility stocks.

A 79 The DCF model is based on the assumption that investors value an asset on the basis of the future cash flows they expect to receive from owning the asset. Under the assumption that future cash flows grow at a constant rate, g, the resulting cost of equity equation is $k = D_1/P_s + g$, where k is the cost of equity, D_1 is the equivalent future value of the next four quarterly dividends at the end of the year, P_s is the current price of the stock, and g is the constant annual growth rate in earnings, dividends, and book value per share. A complete description of my approach to calculating the DCF-estimated cost of equity for my comparable group of utilities is contained in Exhibit 19, Appendix 2.

Q 80 What comparable companies do you use in your forward-looking equity risk premium studies?

A 80 I use the Moody's group of 24 electric utilities because they are a widely-followed group of utilities and the use of this constant group greatly simplifies the data collection task required to estimate the ex ante risk premium over the months of my study. Simplifying the data collection task is desirable because my forward-looking equity risk premium studies require that the DCF model be estimated for every company in every month of the study period. In addition, all the utilities in my study: (1) pay dividends; (2) have I/B/E/S growth forecasts; (3) are not in the process of being acquired; (4) have a Value Line Safety Rank of 1, 2, or 3; and (5) have investment grade bond ratings.

Q 81 Why do you use U.S. utilities rather than Canadian utilities in your forward-looking, or ex ante, risk premium studies?

A 81 My ex ante risk premium studies rely on the DCF model to determine the expected risk premium on utility stocks. As noted above, the DCF model requires estimates of investors' growth expectations, which are best measured from the average of analysts' growth forecasts for each company. The difficulty with using Canadian utilities is that there are very few, if any, analysts' growth forecasts available for each Canadian utility over the twelve year time period of my study.

Q 82 How do you test whether your forward-looking required equity risk premium estimates are sensitive to changes in interest rates?

A 82 To test whether my estimated monthly equity risk premiums are sensitive to changes in interest rates, I perform a regression analysis of the relationship between the forward-looking equity risk premium and the yield to maturity on 20-year U.S. Treasury bonds using the equation:

$$RP_{COMP} = a + (b \times I_B) + e$$

where:

RP_{COMP} = risk premium on comparable company group;

I_B = yield to maturity on long-term U.S. Treasury bonds;

e = a random residual; and

a, b = coefficients estimated by the regression procedure.

Q 83 What does your regression analysis reveal regarding the sensitivity of the forward-looking required equity risk premium to changes in interest rates?

A 83 My regression analysis reveals that the forward-looking required equity risk premium increases by more than fifty basis points when the yield to maturity on long-term government bonds declines by one hundred basis points. These results suggest that, contrary to the eighty-basis point decline in the cost of equity that is implied by the ROE Formula, the cost of equity for utilities declines by less than fifty basis points when the yield on long-term government bonds declines by one hundred basis points. A more detailed description of my regression analysis is contained in Exhibit 20, Appendix 3. The risk premium data used in the regression analysis are shown in Exhibit 7.

Q 84 What risk premium estimate do you obtain from your forward-looking risk premium studies?

A 84 I obtain a forward-looking risk premium equal to 7.7 percent (see Exhibit 20, Appendix 3).

Q 85 What do your forward-looking equity risk premium studies imply about the return on equity provided by the ROE Formula?

A 85 Like my studies of experienced risk premiums on Canadian utility stocks, my forward-looking equity risk premium studies indicate that the ROE Formula fails to provide a fair return on equity for Newfoundland Power.

D. Evidence on the Sensitivity of the Allowed Equity Risk Premium for U.S. Utilities to Changes in Interest Rates

Q 86 How do you define the allowed equity risk premium for U.S. utilities?

A 86 I define the allowed equity risk premium as the difference between the average allowed return on equity for U.S. utilities and the yield to maturity on long-term U.S. Treasury bonds.

Q 87 How do you test whether the allowed equity risk premium is sensitive to changes in interest rates?

A 87 I test whether the allowed equity risk premium, and, hence, the allowed ROE, is sensitive to changes in interest rates by performing a regression analysis of the relationship between the allowed equity risk premium and the yield to maturity on 20-year U.S. Treasury bonds over the period 1988 through 2011. Recall that the sensitivity of the allowed equity risk premium to changes in interest rates is equal to the sensitivity of the allowed ROE to interest rate changes minus one hundred basis points. For example, if the equity risk premium increases by fifty basis points when interest rates decline by one hundred basis points, then the allowed equity return would decline by fifty basis points when interest rates decline by one hundred basis points.

Q 88 What are the results of your regression analysis?

A 88 I find that when the yield to maturity on long-term government bonds decreases by one hundred basis points, the allowed equity risk premium increases by approximately fifty basis points. This result indicates that the allowed ROE for U.S. utilities decreases by approximately fifty basis points when the yield to maturity on long-term government bonds declines by one hundred basis points. In contrast, the ROE Formula causes the allowed ROE to decline by eighty basis points when the yield on long Canada bonds declines by one hundred basis points. The allowed ROE and equity risk premium data in my study and my regression results are shown in Exhibit 8.

Q 89 You note that your regression results indicate that the equity risk premium varies inversely with interest rates. What forecast allowed equity risk premium result do you obtain from your regression studies when the interest rate on long-term government bonds is 3.06 percent?

A 89 I obtain a forecast allowed equity risk premium equal to 6.8 percent. This forecast allowed equity risk premium for U.S. utilities is two hundred basis points higher than the 4.79 percent basis point equity risk premium determined from the ROE Formula at November 2011.

Q 90 What conclusions do you reach from your analysis of the sensitivity of allowed U.S. equity risk premiums to changes in interest rates?

A 90 I conclude that the ROE Formula underestimates the cost of equity for Newfoundland Power.

E. Evidence on the Relative Risk of Returns on Canadian Utility Stocks Compared to the Canadian Market Index

Q 91 What data do you examine on the relative risk of Canadian utility stocks compared to the risk of the Canadian stock market as a whole?

A 91 I examine the standard deviation, or volatility, of utility stock returns compared to the standard deviation, or volatility, of the returns on the TSX market index.

Q 92 What is the standard deviation, or volatility, of returns on Canadian utility stocks compared to the standard deviation of returns on the Canadian market index?

A 92 As shown below, over comparable annual time periods, the standard deviation of returns for Canadian utility stocks has exceeded or approximated the standard deviation of returns for the Canadian market index.

TABLE 2
STANDARD DEVIATION OF ANNUAL RETURNS
BMO CM UTILITIES STOCK DATA SET,
S&P/TSX UTILITIES, AND S&P/TSX COMPOSITE

PERIOD	BMO CM UTILITIES STOCK DATA SET	S&P/TSX UTILITIES INDEX	S&P/TSX COMPOSITE
1983 – 2011	16.41	17.40	16.58
1956 – 2011		15.26	16.67

Q 93 What conclusions do you draw from your evidence that the standard deviation of annual returns on Canadian utility stocks has exceeded or approximated the standard deviation of returns on the Canadian market as a whole?

A 93 I conclude that the risk of Canadian utility stocks compared to the risk of the Canadian stock market as a whole is greater than is implied by the ROE formula. Specifically, while the ROE Formula implies that Canadian utility stocks are only half as risky as the stock market as a whole (the ROE Formula assumes a beta equal to 0.60 for Canadian utility stocks), my evidence indicates that Canadian utility stocks have approximately the same risk as the Canadian stock market as a whole.

Q 94 What conclusions do you draw from your tests of the fairness of the results produced by the Board's ROE Formula?

A 94 I conclude that the Board's ROE Formula produces an ROE that fails to satisfy the fair rate of return standard. Thus, I conclude that the Board's ROE Formula should be suspended.

VI. Newfoundland Power's Cost of Equity

A. Comparable-risk Companies

Q 95 How do you estimate Newfoundland Power's cost of equity?

A 95 I estimate Newfoundland Power's cost of equity by first identifying companies of similar risk to Newfoundland Power and then applying several standard cost of equity methodologies to data for these companies.

Q 96 What criteria do you use to select companies whose risk is similar to that of Newfoundland Power?

A 96 I use the following criteria to select groups of similar risk companies: (1) must have stock that is publicly traded; (2) must have sufficient available data to reasonably apply standard cost of equity estimation techniques; (3) must be comparable in risk; and (4) taken together, must constitute a relatively large sample of companies.

Q 97 Why must comparable companies be publicly traded?

A 97 Comparable companies must be publicly traded because information on a company's stock price is a key input in standard cost of equity estimation methods. If the company is not publicly traded, the information required to estimate the cost of equity will not be available.

Q 98 Why is data availability a concern in estimating the cost of equity for Newfoundland Power?

A 98 Data availability is a concern because standard cost of equity estimation methods like the equity risk premium and the DCF require estimates of inputs, such as the required risk premium and the expected growth rate, that are inherently uncertain. If there is insufficient data available to estimate these inputs, there is little basis for arriving at a reasonable estimate of the cost of equity for the comparable risk companies.

Q 99 What companies do you consider as potential risk-comparable companies for the purpose of estimating the cost of equity for Newfoundland Power?

A 99 I consider two groups of Canadian utilities and two groups of U.S. utilities.

Q 100 What two groups of Canadian utilities do you consider?

A 100 I consider the small group of Canadian utilities included in the BMO CM's basket of utility and pipeline companies and a larger group consisting of the companies in the S&P/TSX utilities index.

Q 101 What companies are included in the BMO CM basket of Canadian utility stocks?

A 101 As noted above, the BMO CM basket of utility and pipeline companies includes Canadian Utilities Ltd., Emera Inc., Enbridge Inc., Fortis Inc., and TransCanada Corporation.

Q 102 Does the BMO CM basket of Canadian utilities include all large publicly-traded Canadian utilities with a significant percentage of assets devoted to regulated utility services?

A 102 Yes. The five companies in the BMO CM basket of Canadian utilities are the only large publicly-traded Canadian utilities with a significant percentage of assets devoted to regulated utility services.

Q 103 Can you provide a general overview of the business operations of the companies in the BMO CM basket of Canadian utilities?

A 103 Yes. The business operations of the companies in the BMO CM basket of Canadian utilities may be summarized as follows.

Canadian Utilities Ltd. An international energy company with business operations in Canada, Great Britain, and Australia. Major business segments include Utilities (pipelines, natural gas and electricity transmission and distribution), Energy (power generation, natural gas gathering, processing, storage, and liquids extraction); Structure & Logistics (manufacturing, logistics, and noise abatement); and Technologies (business systems solutions). Canadian Utilities has approximately 68 percent of total assets devoted to its utilities segment.

Emera Inc. Invests in electricity generation, transmission, and distribution, gas transmission, and utility energy services. Its business segments include NSPI, Maine Utility Operations, Caribbean Utility Operations, and Brunswick Pipelines. Emera has approximately 56 percent of total assets associated with its electric utility operations in Nova Scotia and an additional 26 percent associated with its electric utility operations in Maine and the Caribbean.

Enbridge Inc. A leader in energy transportation and distribution in North America and internationally. Enbridge has approximately 38 percent of its total assets associated with its Liquids Pipelines segment and 25 percent of total assets are associated with its Gas Distribution segment.

Fortis Inc. Invests in regulated electric and gas utility operations, non-regulated electric generation operations, and real estate operations.

Fortis Inc. has approximately 85 percent of its total assets associated with its Canadian utility operations. Fortis Inc. is the parent of Newfoundland Power.

TransCanada Corp. Operates the most extensive natural gas pipeline in Canada, owns and operates large natural gas and oil pipeline systems in North America, and invests in unregulated power projects. TransCanada has approximately 48 percent of its total assets associated with its natural gas pipeline operations, 19 percent with its oil pipeline operations, and 29 percent with its power generation and energy infrastructure operations.

Specific segment information for each of these companies is shown in Exhibit 9.

Q 104 What are the advantages of using the BMO CM basket of Canadian utilities as risk comparables for the purpose of estimating the cost of equity for Newfoundland Power?

A 104 The primary advantage of the BMO CM basket of Canadian utilities is that it only includes Canadian companies that receive a significant portion of their revenues from regulated utility operations. The primary disadvantage of the BMO CM basket of Canadian utilities is that three of the five companies also have significant investment in unregulated operations; and some of their investments in regulated operations are pipeline operations rather than electric or natural gas utility operations.

Q 105 What companies are included in the S&P/TSX utilities index?

A 105 The companies currently included in the S&P/TSX utilities stock index are Atco Ltd., Atlantic Power Corporation, Algonquin Power & Utilities Corp., Capital Power Corporation, Canadian Utilities Limited, Emera Incorporated, Fortis Inc., Just Energy Group Inc., Northland Power Inc., and TransAlta Corporation.

Q 106 Are any of the companies in the S&P/TSX utilities index related to one another?

A 106 Yes. Atco Ltd. is a utility holding company that owns 52 percent of Canadian Utilities Limited. Since Atco has a majority interest in Canadian

Utilities and only a small amount of assets that are not jointly owned with Canadian Utilities, Atco's financial statements reflect essentially the same information as Canadian Utilities' financial statements.

Q 107 The S&P/TSX utilities index contains six other companies that are not included in the BMO CM basket of Canadian utilities. Can you provide a general overview of the companies in the S&P/TSX utilities index that are not included either directly or indirectly in the BMO CM basket of Canadian utilities?

A 107 Yes. The business operations of these six companies can be summarized as follows.

Atlantic Power Corporation. An independent electric power producer that owns interests in a diversified portfolio of independent non-utility power generation projects and one transmission line in the United States.

Algonquin Power & Utilities Corp. Owns and operates a diversified portfolio of renewable energy and utility businesses through its subsidiary companies. Algonquin has two business segments: Algonquin Power Company generates and sells electric energy; and Liberty Utilities provides utility services related to electricity, natural gas, water, and wastewater. Algonquin has approximately 68 percent of its total assets that are related to its unregulated electric power generation and marketing segment and 21 percent related to its utilities segment.

Capital Power Corporation. An independent North American power producer that develops, acquires, and operates power generation from a variety of energy sources.

Just Energy Group Inc. Primarily involved in the sale of natural gas, electricity, and green energy products to residential and commercial customers under long-term contracts in the United States and Canada.

Northland Power Inc. Operates power generating stations and wind farms, sells electricity and steam, and implements environmental and monitoring systems.

TransAlta Corporation. A wholesale power generator and marketer with operations in Canada, the United States, and Australia.

Exhibit 10 shows segment information for the two companies in the S&P/TSX Utilities index with regulated utility operations that are not in the BMO CM data set. The remaining six companies' total assets are only associated with unregulated business operations.

Q 108 What are the advantages of using the S&P/TSX utilities index as comparables in this proceeding?

A 108 The primary advantage of using the S&P/TSX utilities index is that there are more companies in the index and return data for this index is available for a longer period of time than for the BMO CM basket of utility stocks. The primary disadvantage is that six of the ten companies in this group do not have a significant percentage of assets devoted to regulated utility service.

Q 109 What are the advantages of using U.S. utility groups to estimate the cost of equity for Newfoundland Power?

A 109 The primary advantages of using my U.S. utility groups to estimate Newfoundland Power's cost of equity are that: (1) they include a significantly larger sample of companies with traditional utility operations than my Canadian groups; (2) reasonable estimates of expected growth rates are available for these companies, whereas the same data are not available for the Canadian utilities; and (3) historical data for the U.S. utilities are available for a much longer length of time than for the Canadian utilities.

Q 110 What percent of total assets in your U.S. electric utility group are devoted to regulated utility services?

A 110 On average, the companies in my U.S. electric utility group have 85 percent of total assets associated with regulated utility operations (see Exhibit 11).

Q 111 What percent of total assets in your U.S. natural gas utility group are devoted to regulated utility services?

A 111 Approximately 84 percent of total assets of my U.S. natural gas utility group are devoted to regulated utility services (see Exhibit 12).

Q 112 What are the average bond ratings for the companies in your U.S. utility groups?

A 112 The average bond rating for the companies in my U.S. electric utility group is BBB+, and the average bond rating for the companies in my U.S. natural gas group is A (see Exhibit 13).

Q 113 What do bond ratings measure?

A 113 Bond ratings measure the risk that a company will be unable to pay the interest and principal on its debt. Hence, bond ratings are frequently considered to be a measure of the likelihood of a company declaring bankruptcy.

Q 114 Are bond ratings a reasonable measure of the risk of investing in a company's stock?

A 114 No. As discussed above, the risk of investing in a company's stock is best measured by the expected variability in the return on the stock investment.

Q 115 Do you have evidence that bond ratings are a poor indicator of the risk of investing in a company's equity?

A 115 Yes. I have examined the average allowed rate of return on equity for U.S. electric utilities in different bond rating categories, based on decisions beginning January 2010 through February 2012, to determine whether the allowed ROE depends on the utility's bond rating. If bond ratings are an indicator of the risk of investing in a utility's equity, one would expect that there would be an inverse relationship between a utility's bond rating and its allowed ROE, that is, that utilities with higher bond ratings would have lower allowed ROEs and vice versa. However, I find no difference in allowed ROEs for utilities in different bond rating categories (see Table 3 below).

TABLE 3
COMPARISON OF ALLOWED RATES OF RETURN
TO BOND RATING CATEGORY

BOND RATING CATEGORY	NUMBER OF COMPANIES IN CATEGORY	RETURN ON EQUITY	EQUITY RATIO
A- and above	55	10.3	50.7
BBB+	39	10.2	48.6
BBB	39	10.3	47.9
BBB-	28	10.1	48.5
Below investment grade	11	10.0	47.5
Total/Average	172	10.2	49.1

Q 116 Based on the evidence you have reviewed, should the Board give weight to cost of equity results for U.S. utilities?

A 116 Yes. As discussed above, the U.S. utilities included in my cost of equity studies are comparable in risk to the Canadian utilities. Furthermore, the U.S. utilities included in my studies are more involved in traditional utility operations than most of the companies included in the Canadian utilities indices. In addition, the sample of U.S. regulated utilities is significantly larger than the sample of Canadian regulated utilities, and the data required to estimate the cost of equity are more readily available for the U.S. utilities than for the Canadian utilities. For these reasons, the U.S. data provide important information on the cost of equity for Newfoundland Power and should be considered along with Canadian-specific evidence to estimate the cost of equity for Newfoundland Power.

Q 117 Has the National Energy Board ("NEB") determined that cost of equity evidence for U.S. utilities is useful in determining the cost of equity for Trans Québec & Maritimes Pipeline Inc. ("TQM")?

A 117 Yes. In Decision RH-1-2008 the Board finds:

> In light of the Board's views expressed above on the integration of U.S. and Canadian financial markets, the problems with comparisons to either Canadian negotiated or litigated returns, and the Board's view that risk differences between Canada and the U.S. can be understood and accounted for, the Board is of the view that U.S. comparisons are very informative for determining a fair return for TQM for 2007 and 2008. [RH-1-2008 at 71.]

B. Estimating the Cost of Equity

Q 118 What methods do you use to estimate the cost of equity for Newfoundland Power?

A 118 I use two generally accepted methods: the equity risk premium and the discounted cash flow ("DCF"). The equity risk premium method assumes that the investor's required rate of return on an equity investment is equal to the interest rate on a long-term bond plus an additional equity risk premium to compensate the investor for the risks of investing in equities compared to bonds. The DCF method assumes that the current market price of a firm's stock is equal to the discounted value of all expected future cash flows.

1. Equity Risk Premium Method

Q 119 Please describe the equity risk premium method.

A 119 The equity risk premium method is based on the principle that investors expect to earn a return on an equity investment that reflects a "premium" over and above the return they expect to earn on an investment in a portfolio of bonds. This equity risk premium compensates equity investors for the additional risk they bear in making equity investments versus bond investments.

Q 120 How do you measure the required risk premium on an equity investment in your comparable risk companies?

A 120 I use two methods to estimate the required risk premium on an equity investment in my comparable risk companies. The first is called the ex post risk premium method and the second is called the ex ante risk premium method.

a) Ex Post Risk Premium

Q 121 Please describe your ex post risk premium method for measuring the required risk premium on an equity investment.

A 121 My ex post risk premium method measures the required risk premium on an equity investment in Newfoundland Power from historical data on the returns experienced by investors in Canadian utility stocks compared to investors in long-term Canada bonds.

Q 122 How do you measure the returns experienced by investors in Canadian utility stocks?

A 122 I measure the returns experienced by investors in Canadian utility stocks from historical data on returns earned by investors in: (1) the S&P/TSX utilities stock index; and (2) a basket of Canadian utility stocks created by the BMO CM.

Q 123 Does your ex post risk premium cost of equity study use the same investor experienced return data that you discussed above when you described your tests of the reasonableness of the results of the ROE Formula?

A 123 Yes, it does.

Q 124 How do you measure the forecast bond yield for your ex post risk premium studies?

A 124 I measure the forecast bond yield from information on the forecast yield on long-term Canada bonds as reported by Consensus Economics.

Q 125 What average risk premium results do you obtain from your analysis of returns experienced by investors in Canadian utility stocks?

A 125 As shown above in Table 1 and duplicated in Table 4 below, I obtain an average experienced risk premium equal to 6.7 percent (the annual data that produce these results are shown in Exhibit 1 and Exhibit 2).

TABLE 4
EX POST RISK PREMIUM RESULTS

COMPARABLE GROUP	PERIOD OF STUDY	AVERAGE STOCK RETURN	AVERAGE BOND YIELD	RISK PREMIUM
S&P/TSX Utilities	1956 – 2011	11.99	7.33	4.7
BMO CM Utilities Stock Data Set	1983 – 2011	16.01	7.24	8.8
Average				6.7

Q 126 What conclusions do you draw from your ex post risk premium analyses about your comparable companies' cost of equity?

A 126 My studies provide evidence that investors in these companies require an equity return equal to at least 6.7 percentage points above the interest rate on long-term Canada bonds. The Consensus Economics forecast interest rate on long-term Canada bonds for 2012 as of November 2011 is 3.06 percent. Adding a 6.7 percentage point risk premium to an expected yield of 3.06 percent on long-term Canada bonds and including a fifty-basis point allowance for flotation costs and financial flexibility produces an expected return on equity equal to 10.3 percent from my ex post risk premium studies.

b) Ex Ante Risk Premium Method

Q 127 Please describe your ex ante risk premium approach for measuring the required risk premium on an equity investment in Newfoundland Power.

A 127 My ex ante risk premium method is based on studies of the expected return on a comparable group of electric utilities in each month of my study period compared to the interest rate on long-term government bonds.

Q 128 Does your ex ante risk premium cost of equity study use the same forward looking, or ex ante, risk premium data that you discussed above when you described your analysis of the sensitivity of the forward looking required equity risk premium on utility stocks to changes in interest rates?

A 128 Yes, it does.

Q 129 What risk premium estimate do you obtain from your ex ante risk premium studies?

A 129 I obtain an ex ante risk premium estimate equal to 7.67 percent.

Q 130 What cost of equity result do you obtain from your ex ante risk premium studies?

A 130 As described above, in the ex ante risk premium approach, one must add the expected interest rate on long-term government bonds to the estimated risk premium to calculate the cost of equity. Since Newfoundland Power is a Canadian utility, I estimate the expected yield on long-term government bonds using the forecast interest rate on long-term Canada bonds, 3.06 percent. Adding this 3.06 percent interest rate to my 7.67 percent ex ante risk premium estimate, I obtain a cost of equity estimate equal to 10.7 percent (3.06 + 7.67 = 10.73). A more detailed description of my ex ante risk premium approach and results is described in Exhibit 7 and Exhibit 20, Appendix 3. (As discussed in Exhibit 20, Appendix 3, my ex ante risk premium studies include an allowance for financial flexibility approximately equal to twenty-five basis points.)

2. Discounted Cash Flow Model

Q 131 How do you use the DCF model to estimate the cost of equity on an investment in your comparable risk companies?

A 131 I apply the DCF model to the Value Line electric and natural gas utilities shown in Exhibit 14 and Exhibit 15.

Q 132 How do you select your comparable groups of Value Line utilities?

A 132 I select all the Value Line electric and natural gas utilities that: (1) pay dividends during every quarter and did not decrease dividends during any quarter of the past two years; (2) have at least two I/B/E/S growth forecasts; (3) are not in the process of being acquired; (4) have a Value Line Safety Rank of 1, 2, or 3; and (5) have an investment grade bond rating.

Q 133 Why do you eliminate companies that have either decreased or eliminated their dividend during the past two years?

A 133 The DCF model requires the assumption that dividends will grow at a constant positive rate into the indefinite future. If a company has decreased its dividend in recent years, an assumption that the company's dividend will grow at the same positive rate into the indefinite future is questionable.

Q 134 Why do you eliminate companies that have fewer than two analysts' estimates included in the I/B/E/S mean forecast?

A 134 The DCF model also requires a reliable estimate of a company's expected future growth. For most companies, the I/B/E/S mean growth forecast is the best available estimate of the growth term in the DCF Model. However, the I/B/E/S estimate may be less reliable if the mean estimate is based on the input of only one analyst. On the basis of my professional judgment, I believe that at least two analysts' estimates are a reasonable minimum number.

Q 135 Why do you eliminate companies that are in the process of being acquired?

A 135 I eliminate companies that are in the process of being acquired because a merger announcement generally increases the target company's stock price, but not the acquiring company's stock price. Analysts' growth forecasts for the target company, on the other hand, are necessarily related to the company as it currently exists. The use of a stock price that includes the growth-enhancing prospects of potential mergers in conjunction with growth forecasts that do not include the growth-enhancing prospects of potential mergers produces DCF results that tend to distort a company's cost of equity.

Q 136 Please summarize the results of your application of the DCF model to your comparable groups of companies.

A 136 My application of the DCF model to my comparable group of electric utilities produces a result of 10.1 percent without an allowance for financial flexibility and 10.6 percent including a fifty-basis-point allowance for financial flexibility; and to my comparable group of natural gas utilities, a result of 9.4 percent without a financial flexibility allowance and 9.9 percent including a fifty-basis-point allowance for financial flexibility(see Exhibit 14 and Exhibit 15). The average DCF result including a fifty-basis-point allowance for financial flexibility for my two comparable groups is 10.3 percent.

Q 137 Based on your application of the equity risk premium and DCF methods to your comparable risk companies, what is your conclusion regarding your comparable risk companies' cost of equity?

A 137 I conservatively conclude that my comparable companies' cost of equity is 10.4 percent. As shown below in Table 5, 10.4 percent is the simple average of the cost of equity results I obtain from my cost of equity models.

TABLE 5
SUMMARY OF COST OF EQUITY RESULTS

METHOD	COST OF EQUITY
Ex Post Risk Premium	10.3
Ex Ante Risk Premium	10.7
Discounted Cash Flow	10.3
Average	10.4

VII. Comparable Risk Utilities Have Higher Allowed Equity Ratios than Newfoundland Power.

Q 138 What common equity ratio did the Board approve for Newfoundland Power in its most recent cost of capital order?

A 138 The Board approved a 45 percent equity ratio for Newfoundland Power.

Q 139 How does the approved equity ratio for Newfoundland Power compare to approved equity ratios for U.S. utilities?

A 139 As noted above and as shown in Exhibit 5 and Exhibit 6, the average approved equity ratio for U.S. electric and natural gas utilities during the period 2009 through 2011 is 49 percent. Thus, the average approved equity ratio for U.S. utilities is higher than the approved equity ratio for Newfoundland Power.

Q 140 How does the approved equity ratio for Newfoundland Power compare to market value equity ratios for electric and natural gas utilities in your U.S. utility groups?

A 140 The average market value equity ratio for the electric utilities is approximately 59 percent, and, for natural gas utilities, 67 percent (see Exhibit 16 and Exhibit 17).

Q 141 Why do you present evidence on market value equity ratios for U.S. utilities as well as book value equity ratios?

A 141 I present evidence on market value equity ratios as well as book value equity ratios because financial risk depends on the market value percentages of debt and equity in a company's capital structure rather than on the book value percentages of debt and equity in the company's capital structure.

Q 142 How does the business risk of Newfoundland Power compare to the average business risk of U.S. electric and natural gas utilities?

A 142 As discussed above, the business risk of Newfoundland Power is approximately equal to the average business risk of U.S. electric and natural gas utilities.

Q 143 How does the financial risk of Newfoundland Power compare to the average financial risk of U.S. electric and natural gas utilities?

A 143 Since Newfoundland Power has an allowed equity ratio of 45 percent, and the U.S. electric and natural gas utilities have average allowed equity ratios of 49 percent, the financial risk of U.S. electric and natural gas utilities is less than the financial risk of Newfoundland Power. This conclusion is further supported by the observation that the average market value equity ratio for U.S. electric utilities is approximately 59 percent, and for natural gas utilities, 67 percent. This observation is important because financial risk is best measured using market value equity ratios rather than book value equity ratios.

VIII. Summary and Recommendations

Q 144 Please summarize your written evidence in this proceeding.

A 144 My written evidence may be summarized as follows:

1. Experienced equity risk premiums on investments in Canadian utility stocks average 6.7 percent, whereas the ROE Formula implies an equity risk premium of only 4.79 percent.
2. U.S. utilities' cost of equity data provide important information on the cost of equity for Newfoundland Power.
3. The U.S. utilities included in my studies are more involved in traditional utility operations than most of the companies included in the Canadian utilities indices.
4. The sample of U.S. regulated utilities is larger than the sample of Canadian regulated utilities, and the data required to estimate the cost of equity are more readily available for the U.S. utilities than for the Canadian utilities.

5. Recent average allowed returns on equity for U.S. utilities are in the range 10.0 percent to 10.4 percent, whereas the ROE Formula implies an ROE equal to 7.85 percent based on capital market data at November 2011.
6. The forward-looking required ROE on utility stocks is less sensitive to changes in government bond yields than is implied by the ROE Formula.
7. The allowed ROE for U.S. utilities is less sensitive to changes in government bond yields than is implied by the ROE Formula.
8. The risk of investing in Canadian utility stocks is higher relative to the Canadian stock market as a whole than is implied by the ROE Formula.
9. The cost of equity for investments in comparable risk utilities is 10.4 percent based on ex post risk premium, ex ante risk premium, and discounted cash flow studies.
10. Allowed equity ratios for U.S. utilities are approximately 49 percent, whereas the allowed equity ratio for Newfoundland Power is 45 percent.
11. The business risk of Newfoundland Power is approximately equal to the average business risk of my groups of Canadian and U.S. utilities.
12. The average financial risk of Newfoundland Power is slightly less than the average financial risk of regulated Canadian utilities and slightly greater than the average financial risk of my U.S. utility groups.

Q 145 What conclusion do you reach from this evidence?

A 145 I conclude that: (1) the Board should suspend its ROE Formula for Newfoundland Power; (2) the Board should examine cost of equity evidence based on proxy groups of U.S. utilities as well as Canadian utilities; and (3) Newfoundland Power should be allowed to earn a rate of return on equity equal to 10.4 percent.

Q 146 Does this conclude your written evidence?

A 146 Yes, it does.

EXHIBIT 1
EXPERIENCED RISK PREMIUMS ON
S&P/TSX CANADIAN UTILITIES STOCK INDEX
1956—2011

LINE NO.	YEAR	S&P/TSX CANADIAN UTILITIES STOCK INDEX TOTAL RETURN	YIELD LONG-TERM CANADA BOND	RISK PREMIUM
1	1956	0.17	3.63	-3.45
2	1957	-3.43	4.11	-7.54
3	1958	9.81	4.15	5.66
4	1959	0.21	5.08	-4.86
5	1960	26.81	5.19	21.62
6	1961	19.17	5.05	14.12
7	1962	-0.72	5.11	-5.83
8	1963	6.19	5.09	1.10
9	1964	21.59	5.18	16.41
10	1965	4.23	5.21	-0.98
11	1966	-13.17	5.69	-18.86
12	1967	5.07	5.94	-0.87
13	1968	7.41	6.75	0.66
14	1969	-8.62	7.58	-16.20
15	1970	23.34	7.91	15.43
16	1971	4.29	6.95	-2.66
17	1972	-0.44	7.23	-7.68
18	1973	-4.14	7.56	-11.70
19	1974	14.38	8.90	5.48
20	1975	5.75	9.04	-3.28
21	1976	15.02	9.18	5.84
22	1977	19.00	8.70	10.30
23	1978	27.28	9.27	18.01
24	1979	12.61	10.21	2.40
25	1980	5.74	12.48	-6.74
26	1981	-0.55	15.22	-15.77
27	1982	35.90	14.26	21.65
28	1983	40.97	11.79	29.17
29	1984	24.31	12.75	11.56
30	1985	10.04	11.04	-1.00
31	1986	11.48	9.52	1.96
32	1987	1.07	9.95	-8.88
33	1988	5.63	10.22	-4.59
34	1989	22.07	9.92	12.15
35	1990	0.58	10.85	-10.28

LINE NO.	YEAR	S&P/TSX CANADIAN UTILITIES STOCK INDEX TOTAL RETURN	YIELD LONG-TERM CANADA BOND	RISK PREMIUM
36	1991	27.02	9.76	17.25
37	1992	-2.24	8.77	-11.00
38	1993	23.52	7.85	15.67
39	1994	-6.04	8.63	-14.68
40	1995	18.44	8.28	10.16
41	1996	32.68	7.50	25.18
42	1997	37.33	6.42	30.91
43	1998	36.55	5.47	31.09
44	1999	-27.14	5.69	-32.83
45	2000	50.06	5.89	44.17
46	2001	10.83	5.78	5.05
47	2002	6.33	5.66	0.67
48	2003	24.94	5.28	19.66
49	2004	9.42	5.08	4.34
50	2005	38.29	4.39	33.90
51	2006	7.01	4.30	2.71
52	2007	11.89	4.34	7.55
53	2008	-20.46	4.04	-24.50
54	2009	19.00	3.89	15.11
55	2010	18.39	3.66	14.73
56	2011	6.47	3.21	3.26
57	Average	11.99	7.33	4.66

EXHIBIT 2
EXPERIENCED RISK PREMIUMS ON BMO CAPITAL MARKETS UTILITIES STOCK DATA SET
1983—2011

LINE NO.	YEAR	BMO CAPITAL MARKETS UTILITIES & PIPELINE TOTAL RETURN	YIELD LONG-TERM CANADA BOND	RISK PREMIUM
1	1983	25.84	11.79	14.05
2	1984	6.89	12.75	-5.86
3	1985	20.09	11.04	9.04
4	1986	-1.22	9.52	-10.74
5	1987	11.98	9.95	2.03
6	1988	6.67	10.22	-3.56
7	1989	23.80	9.92	13.88
8	1990	10.00	10.85	-0.86
9	1991	12.92	9.76	3.16
10	1992	0.75	8.77	-8.02
11	1993	33.00	7.85	25.15
12	1994	-1.22	8.63	-9.85
13	1995	15.13	8.28	6.85
14	1996	31.66	7.50	24.15
15	1997	50.16	6.42	43.74
16	1998	4.12	5.47	-1.34
17	1999	-24.11	5.69	-29.80
18	2000	59.57	5.89	53.69
19	2001	16.05	5.78	10.27
20	2002	14.46	5.66	8.80
21	2003	28.74	5.28	23.46
22	2004	15.56	5.08	10.48
23	2005	33.36	4.39	28.97
24	2006	17.77	4.30	13.47
25	2007	4.90	4.34	0.57
26	2008	-4.21	4.04	-8.25
27	2009	20.24	3.89	16.35
28	2010	5.39	3.66	1.73
29	2011	25.89	3.21	22.68
30	Average	16.01	7.24	8.77

EXHIBIT 3
ALLOWED RETURNS ON EQUITY
U.S. ELECTRIC UTILITIES
2009 – 2011[3]

LINE NO.	COMPANY	STATE	ORDER DATE	ALLOWED ROE
1	Nevada Power Co.	Nevada	23-Dec-11	10.19
2	Northern States Power Co – WI	Wisconsin	22-Dec-11	10.40
3	Black Hills Colorado Electric	Colorado	22-Dec-11	9.90
4	Northern IN Public Svc Co.	Indiana	21-Dec-11	10.20
5	Upper Peninsula Power Co.	Michigan	20-Dec-11	10.20
6	Columbus Southern Power Co.	Ohio	14-Dec-11	10.00
7	Ohio Power Co.	Ohio	14-Dec-11	10.30
8	Appalachian Power Co.	Virginia	30-Nov-11	10.90
9	Detroit Edison Co.	Michigan	20-Oct-11	10.50
10	Kentucky Utilities Co.	Virginia	12-Oct-11	10.30
11	South Carolina Electric & Gas	South Carolina	30-Sep-11	11.00
12	PacifiCorp	Wyoming	22-Sep-11	10.00
13	Oncor Electric Delivery Co.	Texas	19-Aug-11	10.25
14	Interstate Power & Light Co.	Minnesota	12-Aug-11	10.35
15	PacifiCorp	Utah	11-Aug-11	10.00
16	Public Service Co. of NM	New Mexico	8-Aug-11	10.00
17	Fitchburg Gas & Electric Light	Massachusetts	1-Aug-11	9.20
18	Union Electric Co.	Missouri	13-Jul-11	10.20
19	Oklahoma Gas and Electric Co.	Arkansas	17-Jun-11	9.95
20	Orange & Rockland Utlts Inc.	New York	16-Jun-11	9.20
21	MDU Resources Group Inc.	North Dakota	8-Jun-11	10.75
22	Commonwealth Edison Co.	Illinois	24-May-11	10.50
23	Pacific Gas and Electric Co.	California	13-May-11	11.35
24	KCP&L Greater Missouri Op Co	Missouri	4-May-11	10.00
25	KCP&L Greater Missouri Op Co	Missouri	4-May-11	10.00
26	Southern Indiana Gas & Elec Co	Indiana	27-Apr-11	10.40
27	Unitil Energy Systems Inc.	New Hampshire	26-Apr-11	9.67
28	Otter Tail Power Co.	Minnesota	25-Apr-11	10.74
29	Kansas City Power & Light	Missouri	12-Apr-11	10.00
30	Appalachian Power Co.	West Virginia	30-Mar-11	10.00
31	PacifiCorp	Washington	25-Mar-11	9.80
32	Virginia Electric & Power Co.	Virginia	22-Mar-11	12.30
33	Virginia Electric & Power Co.	Virginia	22-Mar-11	12.30
34	Hawaiian Electric Co.	Hawaii	25-Feb-11	10.00
35	CenterPoint Energy Houston	Texas	3-Feb-11	10.00
36	Western Massachusetts Electric	Massachusetts	31-Jan-11	9.60
37	Niagara Mohawk Power Corp.	New York	20-Jan-11	9.30
38	Texas-New Mexico Power Co.	Texas	20-Jan-11	10.13
39	Delmarva Power & Light Co.	Delaware	18-Jan-11	10.00

[3] Data from Regulatory Research Associates, SNL Financial, February 17, 2012.

LINE NO.	COMPANY	STATE	ORDER DATE	ALLOWED ROE
40	Wisconsin Public Service Corp.	Wisconsin	13-Jan-11	10.30
41	Madison Gas and Electric Co.	Wisconsin	12-Jan-11	10.30
42	Public Service Co. of OK	Oklahoma	5-Jan-11	10.15
43	Georgia Power Co.	Georgia	29-Dec-10	11.15
44	PacifiCorp	Idaho	27-Dec-10	9.90
45	Upper Peninsula Power Co.	Michigan	21-Dec-10	10.30
46	Sierra Pacific Power Co.	Nevada	20-Dec-10	10.60
47	Portland General Electric Co.	Oregon	17-Dec-10	10.00
48	Interstate Power & Light Co.	Iowa	15-Dec-10	10.44
49	PacifiCorp	Oregon	14-Dec-10	10.13
50	Virginia Electric & Power Co.	North Carolina	13-Dec-10	10.70
51	NorthWestern Energy Division	Montana	9-Dec-10	10.25
52	Baltimore Gas and Electric Co.	Maryland	6-Dec-10	9.86
53	Entergy Texas Inc.	Texas	1-Dec-10	10.13
54	Kansas City Power & Light	Kansas	22-Nov-10	10.00
55	Avista Corp.	Washington	19-Nov-10	10.20
56	Consumers Energy Co.	Michigan	4-Nov-10	10.70
57	ALLETE (Minnesota Power)	Minnesota	2-Nov-10	10.38
58	Hawaii Electric Light Co	Hawaii	28-Oct-10	10.70
59	Indiana Michigan Power Co.	Michigan	14-Oct-10	10.35
60	UNS Electric Inc.	Arizona	30-Sep-10	9.75
61	South Carolina Electric & Gas	South Carolina	30-Sep-10	11.00
62	NY State Electric & Gas Corp.	New York	16-Sep-10	10.00
63	Rochester Gas & Electric Corp.	New York	16-Sep-10	10.00
64	Hawaiian Electric Co.	Hawaii	14-Sep-10	10.70
65	PacifiCorp	California	3-Sep-10	10.60
66	Northern IN Public Svc Co.	Indiana	25-Aug-10	9.90
67	Potomac Electric Power Co.	Maryland	6-Aug-10	9.83
68	Black Hills Colorado Electric	Colorado	4-Aug-10	10.50
69	Maui Electric Company Ltd	Hawaii	30-Jul-10	10.70
70	Appalachian Power Co.	Virginia	15-Jul-10	10.53
71	South Carolina Electric & Gas	South Carolina	15-Jul-10	10.70
72	Wisconsin Electric Power Co.	Michigan	1-Jul-10	10.25
73	Connecticut Light & Power Co.	Connecticut	30-Jun-10	9.40
74	Public Service Co. of NH	New Hampshire	28-Jun-10	9.67
75	Kentucky Power Co.	Kentucky	28-Jun-10	10.50
76	Central Hudson Gas & Electric	New York	16-Jun-10	10.00
77	Public Service Electric Gas	New Jersey	7-Jun-10	10.30
78	Entergy Arkansas Inc.	Arkansas	28-May-10	10.20
79	Union Electric Co.	Missouri	28-May-10	10.10
80	Rockland Electric Company	New Jersey	12-May-10	10.30
81	Atlantic City Electric Co.	New Jersey	12-May-10	10.30
82	Ameren Illinois	Illinois	29-Apr-10	10.06
83	Ameren Illinois	Illinois	29-Apr-10	9.90
84	Ameren Illinois	Illinois	29-Apr-10	10.26
85	MDU Resources Group Inc.	Wyoming	27-Apr-10	10.00

LINE NO.	COMPANY	STATE	ORDER DATE	ALLOWED ROE
86	Puget Sound Energy Inc.	Washington	2-Apr-10	10.10
87	Consolidated Edison Co. of NY	New York	25-Mar-10	10.15
88	Florida Power & Light Co.	Florida	17-Mar-10	10.00
89	Virginia Electric & Power Co.	Virginia	11-Mar-10	12.30
90	Virginia Electric & Power Co.	Virginia	11-Mar-10	12.30
91	Virginia Electric & Power Co.	Virginia	11-Mar-10	11.90
92	Florida Power Corp.	Florida	5-Mar-10	10.50
93	Kentucky Utilities Co.	Virginia	4-Mar-10	10.50
94	Potomac Electric Power Co.	District of Columbia	2-Mar-10	9.63
95	Idaho Power Co.	Oregon	24-Feb-10	10.18
96	PacifiCorp	Utah	18-Feb-10	10.60
97	Narragansett Electric Co.	Rhode Island	9-Feb-10	9.80
98	Duke Energy Carolinas LLC	South Carolina	27-Jan-10	10.70
99	Kansas Gas and Electric Co.	Kansas	27-Jan-10	10.40
100	Westar Energy Inc.	Kansas	27-Jan-10	10.40
101	PacifiCorp	Oregon	26-Jan-10	10.13
102	Detroit Edison Co.	Michigan	11-Jan-10	11.00
103	Interstate Power & Light Co.	Iowa	4-Jan-10	10.80
104	Delmarva Power & Light Co.	Maryland	30-Dec-09	10.00
105	Avista Corp.	Washington	22-Dec-09	10.20
106	Madison Gas and Electric Co.	Wisconsin	22-Dec-09	10.40
107	Northern States Power Co - WI	Wisconsin	22-Dec-09	10.40
108	Wisconsin Electric Power Co.	Wisconsin	18-Dec-09	10.40
109	Wisconsin Power and Light Co	Wisconsin	18-Dec-09	10.40
110	Upper Peninsula Power Co.	Michigan	16-Dec-09	10.90
111	Arizona Public Service Co.	Arizona	16-Dec-09	11.00
112	Duke Energy Carolinas LLC	North Carolina	7-Dec-09	10.70
113	Public Service Co. of CO	Colorado	3-Dec-09	10.50
114	Massachusetts Electric Co.	Massachusetts	30-Nov-09	10.35
115	Otter Tail Power Co.	North Dakota	25-Nov-09	10.75
116	Southwestern Electric Power Co	Arkansas	24-Nov-09	10.25
117	Sierra Pacific Power Co.	California	3-Nov-09	10.70
118	Consumers Energy Co.	Michigan	2-Nov-09	10.70
119	Northern States Power Co. - MN	Minnesota	23-Oct-09	10.88
120	Cleco Power LLC	Louisiana	14-Oct-09	10.70
121	Oncor Electric Delivery Co.	Texas	31-Aug-09	10.25
122	Avista Corp.	Idaho	17-Jul-09	10.50
123	Duke Energy Ohio Inc.	Ohio	8-Jul-09	10.63
124	Nevada Power Co.	Nevada	24-Jun-09	10.80
125	Central Hudson Gas & Electric	New York	22-Jun-09	10.00
126	Idaho Power Co.	Idaho	29-May-09	10.50
127	Public Service Co. of NM	New Mexico	28-May-09	10.50
128	Oklahoma Gas and Electric Co.	Arkansas	20-May-09	10.25
129	ALLETE (Minnesota Power)	Minnesota	4-May-09	10.74
130	Tampa Electric Co.	Florida	30-Apr-09	11.25
131	Consolidated Edison Co. of NY	New York	24-Apr-09	10.00

LINE NO.	COMPANY	STATE	ORDER DATE	ALLOWED ROE
132	PacifiCorp	Utah	21-Apr-09	10.61
133	Entergy New Orleans Inc.	Louisiana	2-Apr-09	11.10
134	Southern California Edison Co.	California	12-Mar-09	11.50
135	Indiana Michigan Power Co.	Indiana	4-Mar-09	10.50
136	United Illuminating Co.	Connecticut	4-Feb-09	8.75
137	Idaho Power Co.	Idaho	30-Jan-09	10.50
138	Union Electric Co.	Missouri	27-Jan-09	10.76
139	Cleveland Elec Illuminating Co	Ohio	21-Jan-09	10.50
140	Ohio Edison Co.	Ohio	21-Jan-09	10.50
141	Toledo Edison Co.	Ohio	21-Jan-09	10.50
142	Appalachian Power Co.	Virginia	14-Jan-09	10.60
143	Public Service Co. of OK	Oklahoma	14-Jan-09	10.50
144	Average 2009	Average 2009		10.5
145	Average 2010	Average 2010		10.4
146	Average 2011	Average 2011		10.3
147	Average 2009 - 2011	Average 2009 – 2011		10.4

EXHIBIT 4
ALLOWED RETURNS ON EQUITY
U.S. NATURAL GAS UTILITIES
2009 – 2011[4]

LINE NO.	COMPANY	STATE	ORDER DATE	ALLOWED ROE
1	Northern States Power Co - WI	Wisconsin	22-Dec-11	10.40
2	Virginia Natural Gas Inc.	Virginia	20-Dec-11	10.00
3	Southwest Gas Corp.	Arizona	13-Dec-11	9.50
4	Washington Gas Light Co.	Maryland	14-Nov-11	9.60
5	Public Service Co. of CO	Colorado	1-Sep-11	10.10
6	Fitchburg Gas & Electric Light	Massachusetts	1-Aug-11	9.20
7	Yankee Gas Services Co.	Connecticut	29-Jun-11	8.83
8	Delmarva Power & Light Co.	Delaware	21-Jun-11	10.00
9	Consumers Energy Co.	Michigan	26-May-11	10.50
10	Pacific Gas and Electric Co.	California	13-May-11	11.35
11	Washington Gas Light Co.	Virginia	21-Apr-11	10.00
12	CenterPoint Energy Resources	Texas	18-Apr-11	10.05
13	New England Gas Company	Massachusetts	31-Mar-11	9.45
14	Avista Corp.	Oregon	10-Mar-11	10.10
15	Wisconsin Public Service Corp.	Wisconsin	13-Jan-11	10.30
16	Madison Gas and Electric Co.	Wisconsin	12-Jan-11	10.30
17	SEMCO Energy Inc.	Michigan	6-Jan-11	10.35
18	SourceGas Distribution LLC	Wyoming	23-Dec-10	9.92
19	Sierra Pacific Power Co.	Nevada	20-Dec-10	10.10
20	Columbia Gas of Virginia Inc	Virginia	17-Dec-10	10.10
21	Texas Gas Service Co.	Texas	14-Dec-10	10.33
22	NorthWestern Energy Division	Montana	9-Dec-10	10.25
23	Baltimore Gas and Electric Co.	Maryland	6-Dec-10	9.56
24	Northern States Power Co. - MN	Minnesota	6-Dec-10	10.09
25	SourceGas Distribution LLC	Colorado	1-Dec-10	10.00
26	Avista Corp.	Washington	19-Nov-10	10.20
27	Atlanta Gas Light Co.	Georgia	3-Nov-10	10.75
28	Boston Gas Co.	Massachusetts	2-Nov-10	9.75
29	Colonial Gas Co.	Massachusetts	2-Nov-10	9.75
30	Delta Natural Gas Co.	Kentucky	21-Oct-10	10.40
31	South Jersey Gas Co.	New Jersey	16-Sep-10	10.30
32	Consolidated Edison Co. of NY	New York	16-Sep-10	9.60
33	NY State Electric & Gas Corp.	New York	16-Sep-10	10.00
34	Rochester Gas & Electric Corp.	New York	16-Sep-10	10.00
35	Black Hills Nebraska Gas	Nebraska	17-Aug-10	10.10
36	Public Service Electric Gas	New Jersey	18-Jun-10	10.30
37	Central Hudson Gas & Electric	New York	16-Jun-10	10.00
38	Michigan Consolidated Gas Co.	Michigan	3-Jun-10	11.00
39	Chattanooga Gas Company	Tennessee	24-May-10	10.05

[4] Data from Regulatory Research Associates, SNL Financial, February 17, 2012.

LINE NO.	COMPANY	STATE	ORDER DATE	ALLOWED ROE
40	Consumers Energy Co.	Michigan	17-May-10	10.55
41	Ameren Illinois	Illinois	29-Apr-10	9.40
42	Ameren Illinois	Illinois	29-Apr-10	9.19
43	Ameren Illinois	Illinois	29-Apr-10	9.40
44	Questar Gas Co.	Utah	8-Apr-10	10.35
45	Puget Sound Energy Inc.	Washington	2-Apr-10	10.10
46	UNS Gas Inc.	Arizona	1-Apr-10	9.50
47	Atmos Energy Corp.	Georgia	31-Mar-10	10.70
48	MidAmerican Energy Co.	Illinois	24-Mar-10	10.13
49	SourceGas Distribution LLC	Nebraska	9-Mar-10	9.60
50	CenterPoint Energy Resources	Texas	23-Feb-10	10.50
51	Missouri Gas Energy	Missouri	10-Feb-10	10.00
52	Atmos Energy Corp.	Texas	26-Jan-10	10.40
53	North Shore Gas Co.	Illinois	21-Jan-10	10.33
54	Peoples Gas Light & Coke Co.	Illinois	21-Jan-10	10.23
55	CenterPoint Energy Resources	Minnesota	11-Jan-10	10.24
56	Duke Energy Kentucky Inc.	Kentucky	29-Dec-09	10.38
57	Avista Corp.	Washington	22-Dec-09	10.20
58	Madison Gas and Electric Co.	Wisconsin	22-Dec-09	10.40
59	Wisconsin Electric Power Co.	Wisconsin	18-Dec-09	10.40
60	Wisconsin Gas LLC	Wisconsin	18-Dec-09	10.50
61	Wisconsin Power and Light Co	Wisconsin	18-Dec-09	10.40
62	Pivotal Utility Holdings Inc.	New Jersey	17-Dec-09	10.30
63	Michigan Gas Utilities Corp	Michigan	16-Dec-09	10.75
64	ONEOK Inc.	Oklahoma	14-Dec-09	10.50
65	Hope Gas Inc	West Virginia	20-Nov-09	9.45
66	Columbia Gas of Massachusetts	Massachusetts	30-Oct-09	9.95
67	Southwest Gas Corp.	Nevada	28-Oct-09	10.15
68	Southwest Gas Corp.	Nevada	28-Oct-09	10.15
69	Avista Corp.	Oregon	26-Oct-09	10.10
70	Orange & Rockland Utlts Inc.	New York	16-Oct-09	10.40
71	Southern Connecticut Gas Co.	Connecticut	17-Jul-09	9.26
72	Avista Corp.	Idaho	17-Jul-09	10.50
73	CT Natural Gas Corp.	Connecticut	30-Jun-09	9.31
74	Minnesota Energy Resources	Minnesota	29-Jun-09	10.21
75	Central Hudson Gas & Electric	New York	22-Jun-09	10.00
76	Black Hills Iowa Gas Utility	Iowa	3-Jun-09	10.10
77	EnergyNorth Natural Gas Inc.	New Hampshire	29-May-09	9.54
78	Florida Public Utilities Co.	Florida	27-May-09	10.85
79	Niagara Mohawk Power Corp.	New York	15-May-09	10.20
80	Peoples Gas System	Florida	5-May-09	10.75
81	Entergy New Orleans Inc.	Louisiana	2-Apr-09	10.75
82	Northern Illinois Gas Co.	Illinois	25-Mar-09	10.17
83	Atmos Energy Corp.	Tennessee	9-Mar-09	10.30
84	New England Gas Company	Massachusetts	2-Feb-09	10.05
85	Michigan Gas Utilities Corp	Michigan	13-Jan-09	10.45

LINE NO.	COMPANY	STATE	ORDER DATE	ALLOWED ROE
86	Average 2009			10.2
87	Average 2010			10.1
88	Average 2011			10.0
89	Average 2009 – 2011			10.1

EXHIBIT 5
ALLOWED EQUITY RATIOS
U.S. ELECTRIC UTILITIES
2009 – 2011[5]

LINE NO.	COMPANY	STATE	ORDER DATE	EQUITY RATIO(%)
1	Nevada Power Co.	Nevada	23-Dec-11	44.38
2	Black Hills Colorado Electric	Colorado	22-Dec-11	49.10
3	Northern States Power Co - WI	Wisconsin	22-Dec-11	52.59
4	Northern IN Public Svc Co.	Indiana	21-Dec-11	46.53
5	Upper Peninsula Power Co.	Michigan	20-Dec-11	45.74
6	Columbus Southern Power Co.	Ohio	14-Dec-11	50.64
7	Ohio Power Co.	Ohio	14-Dec-11	53.79
8	Appalachian Power Co.	Virginia	30-Nov-11	42.69
9	Kentucky Utilities Co.	Virginia	12-Oct-11	53.37
10	South Carolina Electric & Gas	South Carolina	30-Sep-11	54.67
11	PacifiCorp	Wyoming	22-Sep-11	52.30
12	Oncor Electric Delivery Co.	Texas	19-Aug-11	40.00
13	Interstate Power & Light Co.	Minnesota	12-Aug-11	47.74
14	PacifiCorp	Utah	11-Aug-11	51.90
15	Public Service Co. of NM	New Mexico	8-Aug-11	51.28
16	Fitchburg Gas & Electric Light	Massachusetts	1-Aug-11	42.88
17	Union Electric Co.	Missouri	13-Jul-11	52.24
18	Orange & Rockland Utlts Inc.	New York	16-Jun-11	48.00
19	MDU Resources Group Inc.	North Dakota	8-Jun-11	53.34
20	Commonwealth Edison Co.	Illinois	24-May-11	47.28
21	Pacific Gas and Electric Co.	California	13-May-11	52.00
22	KCP&L Greater Missouri Op Co	Missouri	4-May-11	46.58
23	KCP&L Greater Missouri Op Co	Missouri	4-May-11	46.58
24	Southern Indiana Gas & Elec Co	Indiana	27-Apr-11	43.46
25	Unitil Energy Systems Inc.	New Hampshire	26-Apr-11	45.45
26	Otter Tail Power Co.	Minnesota	25-Apr-11	51.70
27	Kansas City Power & Light	Missouri	12-Apr-11	46.30
28	Appalachian Power Co.	West Virginia	30-Mar-11	42.20
29	PacifiCorp	Washington	25-Mar-11	49.10
30	Virginia Electric & Power Co.	Virginia	22-Mar-11	49.37
31	Virginia Electric & Power Co.	Virginia	22-Mar-11	49.37
32	Hawaiian Electric Co.	Hawaii	25-Feb-11	55.81
33	CenterPoint Energy Houston	Texas	3-Feb-11	45.00
34	Western Massachusetts Electric	Massachusetts	31-Jan-11	50.70
35	Niagara Mohawk Power Corp.	New York	20-Jan-11	48.00
36	Texas-New Mexico Power Co.	Texas	20-Jan-11	45.00
37	Delmarva Power & Light Co.	Delaware	18-Jan-11	47.52
38	Wisconsin Public Service Corp.	Wisconsin	13-Jan-11	51.65
39	Madison Gas and Electric Co.	Wisconsin	12-Jan-11	58.06

[5] Data from Regulatory Research Associates, SNL Financial, February 17, 2012.

LINE NO.	COMPANY	STATE	ORDER DATE	EQUITY RATIO(%)
40	Public Service Co. of OK	Oklahoma	5-Jan-11	45.84
41	PacifiCorp	Idaho	27-Dec-10	52.10
42	Upper Peninsula Power Co.	Michigan	21-Dec-10	50.42
43	Sierra Pacific Power Co.	Nevada	20-Dec-10	44.11
44	Portland General Electric Co.	Oregon	17-Dec-10	50.00
45	Kansas City Power & Light	Kansas	22-Nov-10	49.66
46	Avista Corp.	Washington	19-Nov-10	46.50
47	Consumers Energy Co.	Michigan	4-Nov-10	41.59
53	ALLETE (Minnesota Power)	Minnesota	2-Nov-10	54.29
54	Hawaii Electric Light Co	Hawaii	28-Oct-10	51.19
55	Indiana Michigan Power Co.	Michigan	14-Oct-10	44.14
56	UNS Electric Inc.	Arizona	30-Sep-10	45.76
57	South Carolina Electric & Gas	South Carolina	30-Sep-10	53.52
58	NY State Electric & Gas Corp.	New York	16-Sep-10	48.00
59	Rochester Gas & Electric Corp.	New York	16-Sep-10	48.00
60	Hawaiian Electric Co.	Hawaii	14-Sep-10	55.10
61	PacifiCorp	California	3-Sep-10	52.20
62	Northern IN Public Svc Co.	Indiana	25-Aug-10	49.95
63	Potomac Electric Power Co.	Maryland	6-Aug-10	48.87
64	Black Hills Colorado Electric	Colorado	4-Aug-10	52.00
65	Maui Electric Company Ltd	Hawaii	30-Jul-10	54.89
66	South Carolina Electric & Gas	South Carolina	15-Jul-10	52.96
67	Appalachian Power Co.	Virginia	15-Jul-10	41.53
68	Wisconsin Electric Power Co.	Michigan	1-Jul-10	47.61
69	Connecticut Light & Power Co.	Connecticut	30-Jun-10	49.20
70	Public Service Co. of NH	New Hampshire	28-Jun-10	52.40
71	Central Hudson Gas & Electric	New York	16-Jun-10	48.00
72	Public Service Electric Gas	New Jersey	7-Jun-10	51.20
73	Union Electric Co.	Missouri	28-May-10	51.26
74	Atlantic City Electric Co.	New Jersey	12-May-10	49.10
75	Rockland Electric Company	New Jersey	12-May-10	49.85
76	Ameren Illinois	Illinois	29-Apr-10	43.55
77	Ameren Illinois	Illinois	29-Apr-10	43.61
78	Ameren Illinois	Illinois	29-Apr-10	48.67
79	MDU Resources Group Inc.	Wyoming	27-Apr-10	49.77
80	Puget Sound Energy Inc.	Washington	2-Apr-10	46.00
81	Consolidated Edison Co. of NY	New York	25-Mar-10	48.00
82	Florida Power & Light Co.	Florida	17-Mar-10	47.00
83	Virginia Electric & Power Co.	Virginia	11-Mar-10	47.41
84	Virginia Electric & Power Co.	Virginia	11-Mar-10	47.71
85	Florida Power Corp.	Florida	5-Mar-10	46.74
86	Kentucky Utilities Co.	Virginia	4-Mar-10	53.62
87	Potomac Electric Power Co.	District of Columbia	2-Mar-10	46.18
88	Idaho Power Co.	Oregon	24-Feb-10	49.80
89	PacifiCorp	Utah	18-Feb-10	51.00
90	Narragansett Electric Co.	Rhode Island	9-Feb-10	42.75

LINE NO.	COMPANY	STATE	ORDER DATE	EQUITY RATIO(%)
91	Kansas Gas and Electric Co.	Kansas	27-Jan-10	50.13
92	Westar Energy Inc.	Kansas	27-Jan-10	50.13
93	Duke Energy Carolinas LLC	South Carolina	27-Jan-10	53.00
94	PacifiCorp	Oregon	26-Jan-10	51.00
95	Interstate Power & Light Co.	Iowa	4-Jan-10	49.52
96	Delmarva Power & Light Co.	Maryland	30-Dec-09	49.87
97	Avista Corp.	Washington	22-Dec-09	46.50
98	Northern States Power Co - WI	Wisconsin	22-Dec-09	52.30
99	Madison Gas and Electric Co.	Wisconsin	22-Dec-09	55.34
100	Wisconsin Power and Light Co	Wisconsin	18-Dec-09	50.38
101	Wisconsin Electric Power Co.	Wisconsin	18-Dec-09	53.02
102	Upper Peninsula Power Co.	Michigan	16-Dec-09	49.52
103	Arizona Public Service Co.	Arizona	16-Dec-09	53.79
104	Duke Energy Carolinas LLC	North Carolina	7-Dec-09	52.50
105	Public Service Co. of CO	Colorado	3-Dec-09	58.56
106	Massachusetts Electric Co.	Massachusetts	30-Nov-09	49.99
107	Otter Tail Power Co.	North Dakota	25-Nov-09	53.30
108	Sierra Pacific Power Co.	California	3-Nov-09	43.71
109	Northern States Power Co. - MN	Minnesota	23-Oct-09	52.47
110	Cleco Power LLC	Louisiana	14-Oct-09	51.00
111	Oncor Electric Delivery Co.	Texas	31-Aug-09	40.00
112	Avista Corp.	Idaho	17-Jul-09	50.00
113	Duke Energy Ohio Inc.	Ohio	8-Jul-09	51.59
114	Nevada Power Co.	Nevada	24-Jun-09	44.15
115	Central Hudson Gas & Electric	New York	22-Jun-09	47.00
116	Idaho Power Co.	Idaho	29-May-09	49.27
117	Public Service Co. of NM	New Mexico	28-May-09	50.47
118	ALLETE (Minnesota Power)	Minnesota	4-May-09	54.79
119	Tampa Electric Co.	Florida	30-Apr-09	47.49
120	Consolidated Edison Co. of NY	New York	24-Apr-09	48.00
121	PacifiCorp	Utah	21-Apr-09	51.00
122	Southern California Edison Co.	California	12-Mar-09	48.00
123	Indiana Michigan Power Co.	Indiana	4-Mar-09	45.80
124	United Illuminating Co.	Connecticut	4-Feb-09	50.00
125	Idaho Power Co.	Idaho	30-Jan-09	49.27
126	Union Electric Co.	Missouri	27-Jan-09	52.01
127	Cleveland Elec Illuminating Co	Ohio	21-Jan-09	49.00
128	Ohio Edison Co.	Ohio	21-Jan-09	49.00
129	Toledo Edison Co.	Ohio	21-Jan-09	49.00
130	Public Service Co. of OK	Oklahoma	14-Jan-09	44.10
131	Appalachian Power Co.	Virginia	14-Jan-09	41.53
132	Average 2009			49.5
133	Average 2010			49.0
134	Average 2011			48.8
135	Average 2009 - 2011			49.1

EXHIBIT 6
ALLOWED EQUITY RATIOS
U.S. NATURAL GAS UTILITIES
2009 – 2011[6]

LINE NO.	COMPANY	STATE	ORDER DATE	EQUITY RATIO(%)
1	Northern States Power Co - WI	Wisconsin	22-Dec-11	52.59
2	Virginia Natural Gas Inc.	Virginia	20-Dec-11	45.36
3	Southwest Gas Corp.	Arizona	13-Dec-11	52.30
4	Washington Gas Light Co.	Maryland	14-Nov-11	57.88
5	Public Service Co. of CO	Colorado	1-Sep-11	56.00
6	Fitchburg Gas & Electric Light	Massachusetts	1-Aug-11	42.88
7	Yankee Gas Services Co.	Connecticut	29-Jun-11	52.20
8	Pacific Gas and Electric Co.	California	13-May-11	52.00
9	Washington Gas Light Co.	Virginia	21-Apr-11	55.70
10	CenterPoint Energy Resources	Texas	18-Apr-11	55.44
11	New England Gas Company	Massachusetts	31-Mar-11	50.17
12	Avista Corp.	Oregon	10-Mar-11	50.00
13	Wisconsin Public Service Corp.	Wisconsin	13-Jan-11	51.65
14	Madison Gas and Electric Co.	Wisconsin	12-Jan-11	58.06
15	SourceGas Distribution LLC	Wyoming	23-Dec-10	50.34
16	Sierra Pacific Power Co.	Nevada	20-Dec-10	44.11
17	Columbia Gas of Virginia Inc	Virginia	17-Dec-10	42.70
18	Texas Gas Service Co.	Texas	14-Dec-10	59.24
19	NorthWestern Energy Division	Montana	9-Dec-10	48.00
20	Baltimore Gas and Electric Co.	Maryland	6-Dec-10	51.93
21	Northern States Power Co. - MN	Minnesota	6-Dec-10	52.46
22	SourceGas Distribution LLC	Colorado	1-Dec-10	50.48
23	Avista Corp.	Washington	19-Nov-10	46.50
24	Northern IN Public Svc Co.	Indiana	4-Nov-10	46.29
25	Atlanta Gas Light Co.	Georgia	3-Nov-10	51.00
26	Boston Gas Co.	Massachusetts	2-Nov-10	50.00
27	Colonial Gas Co.	Massachusetts	2-Nov-10	50.00
28	Delta Natural Gas Co.	Kentucky	21-Oct-10	44.49
29	Consolidated Edison Co. of NY	New York	16-Sep-10	48.00
30	NY State Electric & Gas Corp.	New York	16-Sep-10	48.00
31	Rochester Gas & Electric Corp.	New York	16-Sep-10	48.00
32	South Jersey Gas Co.	New Jersey	16-Sep-10	51.20
33	Black Hills Nebraska Gas	Nebraska	17-Aug-10	52.00
34	Public Service Electric Gas	New Jersey	18-Jun-10	51.20
35	Central Hudson Gas & Electric	New York	16-Jun-10	48.00
36	Chattanooga Gas Company	Tennessee	24-May-10	46.06
37	Ameren Illinois	Illinois	29-Apr-10	43.55
38	Ameren Illinois	Illinois	29-Apr-10	43.61

[6] Data from Regulatory Research Associates, SNL Financial, February 17, 2012.

LINE NO.	COMPANY	STATE	ORDER DATE	EQUITY RATIO(%)
39	Ameren Illinois	Illinois	29-Apr-10	48.67
40	Questar Gas Co.	Utah	8-Apr-10	52.91
41	Puget Sound Energy Inc.	Washington	2-Apr-10	46.00
42	UNS Gas Inc.	Arizona	1-Apr-10	49.90
43	Atmos Energy Corp.	Georgia	31-Mar-10	47.70
44	MidAmerican Energy Co.	Illinois	24-Mar-10	47.08
45	SourceGas Distribution LLC	Nebraska	9-Mar-10	49.96
46	CenterPoint Energy Resources	Texas	23-Feb-10	55.60
47	Missouri Gas Energy	Missouri	10-Feb-10	38.66
48	Atmos Energy Corp.	Texas	26-Jan-10	48.91
49	North Shore Gas Co.	Illinois	21-Jan-10	56.00
50	Peoples Gas Light & Coke Co.	Illinois	21-Jan-10	56.00
51	CenterPoint Energy Resources	Minnesota	11-Jan-10	52.55
52	Duke Energy Kentucky Inc.	Kentucky	29-Dec-09	49.90
53	Avista Corp.	Washington	22-Dec-09	46.50
54	Madison Gas and Electric Co.	Wisconsin	22-Dec-09	55.34
55	Wisconsin Gas LLC	Wisconsin	18-Dec-09	46.62
56	Wisconsin Power and Light Co	Wisconsin	18-Dec-09	50.38
57	Wisconsin Electric Power Co.	Wisconsin	18-Dec-09	53.02
58	Pivotal Utility Holdings Inc.	New Jersey	17-Dec-09	47.89
59	Michigan Gas Utilities Corp	Michigan	16-Dec-09	47.27
60	ONEOK Inc.	Oklahoma	14-Dec-09	55.30
61	Hope Gas Inc	West Virginia	20-Nov-09	42.34
62	Columbia Gas of Massachusetts	Massachusetts	30-Oct-09	53.57
63	Southwest Gas Corp.	Nevada	28-Oct-09	47.09
64	Southwest Gas Corp.	Nevada	28-Oct-09	47.09
65	Avista Corp.	Oregon	26-Oct-09	50.00
66	Orange & Rockland Utlts Inc.	New York	16-Oct-09	48.00
67	Avista Corp.	Idaho	17-Jul-09	50.00
68	Southern Connecticut Gas Co.	Connecticut	17-Jul-09	52.00
69	CT Natural Gas Corp.	Connecticut	30-Jun-09	52.52
70	Minnesota Energy Resources	Minnesota	29-Jun-09	48.77
71	Central Hudson Gas & Electric	New York	22-Jun-09	47.00
72	Black Hills Iowa Gas Utility	Iowa	3-Jun-09	51.38
73	EnergyNorth Natural Gas Inc.	New Hampshire	29-May-09	50.00
74	Florida Public Utilities Co.	Florida	27-May-09	42.17
75	Niagara Mohawk Power Corp.	New York	15-May-09	43.70
76	Peoples Gas System	Florida	5-May-09	48.51
77	Northern Illinois Gas Co.	Illinois	25-Mar-09	51.07
78	Atmos Energy Corp.	Tennessee	9-Mar-09	48.12
79	New England Gas Company	Massachusetts	2-Feb-09	34.19
80	Michigan Gas Utilities Corp	Michigan	13-Jan-09	46.49
81	Average 2009			48.5
82	Average 2010			49.1
83	Average 2011			52.3
84	Average 2009 - 2011			49.4

EXHIBIT 7
COMPARISON OF DCF EXPECTED RETURN ON AN INVESTMENT IN ELECTRIC UTILITIES TO THE INTEREST RATE ON LONG-TERM GOVERNMENT BONDS

LINE NO.	DATE	DCF	BOND YIELD	RISK PREMIUM
1	Sep-99	0.1155	0.0650	0.0505
2	Oct-99	0.1159	0.0666	0.0493
3	Nov-99	0.1190	0.0648	0.0542
4	Dec-99	0.1234	0.0669	0.0565
5	Jan-00	0.1219	0.0686	0.0533
6	Feb-00	0.1267	0.0654	0.0613
7	Mar-00	0.1311	0.0638	0.0673
8	Apr-00	0.1235	0.0618	0.0617
9	May-00	0.1225	0.0655	0.0570
10	Jun-00	0.1240	0.0628	0.0612
11	Jul-00	0.1245	0.0620	0.0625
12	Aug-00	0.1226	0.0602	0.0624
13	Sep-00	0.1163	0.0609	0.0554
14	Oct-00	0.1169	0.0604	0.0565
15	Nov-00	0.1190	0.0598	0.0592
16	Dec-00	0.1164	0.0564	0.0600
17	Jan-01	0.1192	0.0565	0.0627
18	Feb-01	0.1202	0.0562	0.0640
19	Mar-01	0.1206	0.0549	0.0657
20	Apr-01	0.1231	0.0578	0.0653
21	May-01	0.1277	0.0592	0.0685
22	Jun-01	0.1284	0.0582	0.0702
23	Jul-01	0.1293	0.0575	0.0718
24	Aug-01	0.1300	0.0558	0.0742
25	Sep-01	0.1319	0.0553	0.0766
26	Oct-01	0.1311	0.0534	0.0777
27	Nov-01	0.1294	0.0533	0.0761
28	Dec-01	0.1291	0.0576	0.0715
29	Jan-02	0.1272	0.0569	0.0703
30	Feb-02	0.1284	0.0561	0.0723
31	Mar-02	0.1246	0.0593	0.0653
32	Apr-02	0.1226	0.0585	0.0641
33	May-02	0.1235	0.0581	0.0654
34	Jun-02	0.1252	0.0565	0.0687
35	Jul-02	0.1336	0.0551	0.0785
36	Aug-02	0.1298	0.0519	0.0779
37	Sep-02	0.1270	0.0487	0.0783
38	Oct-02	0.1289	0.0500	0.0789

LINE NO.	DATE	DCF	BOND YIELD	RISK PREMIUM
39	Nov-02	0.1240	0.0504	0.0736
40	Dec-02	0.1224	0.0501	0.0723
41	Jan-03	0.1194	0.0502	0.0692
42	Feb-03	0.1231	0.0487	0.0744
43	Mar-03	0.1211	0.0482	0.0729
44	Apr-03	0.1169	0.0491	0.0678
45	May-03	0.1094	0.0452	0.0642
46	Jun-03	0.1045	0.0434	0.0611
47	Jul-03	0.1071	0.0492	0.0579
48	Aug-03	0.1063	0.0539	0.0524
49	Sep-03	0.1027	0.0521	0.0506
50	Oct-03	0.1008	0.0521	0.0487
51	Nov-03	0.0983	0.0517	0.0466
52	Dec-03	0.0944	0.0511	0.0433
53	Jan-04	0.0920	0.0501	0.0419
54	Feb-04	0.0915	0.0494	0.0421
55	Mar-04	0.0911	0.0472	0.0439
56	Apr-04	0.0924	0.0516	0.0408
57	May-04	0.0961	0.0546	0.0415
58	Jun-04	0.0960	0.0545	0.0415
59	Jul-04	0.0952	0.0524	0.0428
60	Aug-04	0.0965	0.0507	0.0458
61	Sep-04	0.0950	0.0489	0.0461
62	Oct-04	0.0952	0.0485	0.0467
63	Nov-04	0.0917	0.0489	0.0428
64	Dec-04	0.0919	0.0488	0.0431
65	Jan-05	0.0923	0.0477	0.0446
66	Feb-05	0.0916	0.0461	0.0455
67	Mar-05	0.0917	0.0489	0.0428
68	Apr-05	0.0922	0.0475	0.0447
69	May-05	0.0908	0.0456	0.0452
70	Jun-05	0.0910	0.0435	0.0475
71	Jul-05	0.0897	0.0448	0.0449
72	Aug-05	0.0899	0.0453	0.0446
73	Sep-05	0.0922	0.0451	0.0471
74	Oct-05	0.0933	0.0474	0.0459
75	Nov-05	0.0980	0.0483	0.0497
76	Dec-05	0.0979	0.0473	0.0506
77	Jan-06	0.0979	0.0465	0.0514
78	Feb-06	0.1070	0.0473	0.0597
79	Mar-06	0.1053	0.0491	0.0562
80	Apr-06	0.1075	0.0522	0.0553
81	May-06	0.1087	0.0535	0.0552
82	Jun-06	0.1117	0.0529	0.0588

LINE NO.	DATE	DCF	BOND YIELD	RISK PREMIUM
83	Jul-06	0.1110	0.0525	0.0585
84	Aug-06	0.1072	0.0508	0.0564
85	Sep-06	0.1111	0.0493	0.0618
86	Oct-06	0.1074	0.0494	0.0580
87	Nov-06	0.1078	0.0478	0.0600
88	Dec-06	0.1071	0.0478	0.0593
89	Jan-07	0.1096	0.0495	0.0601
90	Feb-07	0.1085	0.0493	0.0592
91	Mar-07	0.1094	0.0481	0.0613
92	Apr-07	0.1042	0.0495	0.0547
93	May-07	0.1068	0.0498	0.0570
94	Jun-07	0.1123	0.0529	0.0594
95	Jul-07	0.1130	0.0519	0.0611
96	Aug-07	0.1104	0.0500	0.0604
97	Sep-07	0.1078	0.0484	0.0594
98	Oct-07	0.1084	0.0483	0.0601
99	Nov-07	0.1116	0.0456	0.0660
100	Dec-07	0.1132	0.0457	0.0675
101	Jan-08	0.1193	0.0435	0.0758
102	Feb-08	0.1133	0.0449	0.0684
103	Mar-08	0.1170	0.0436	0.0734
104	Apr-08	0.1159	0.0444	0.0715
105	May-08	0.1162	0.0460	0.0702
106	Jun-08	0.1136	0.0474	0.0662
107	Jul-08	0.1172	0.0462	0.0710
108	Aug-08	0.1191	0.0453	0.0738
109	Sep-08	0.1185	0.0432	0.0753
110	Oct-08	0.1280	0.0445	0.0835
111	Nov-08	0.1312	0.0427	0.0885
112	Dec-08	0.1301	0.0318	0.0983
113	Jan-09	0.1241	0.0346	0.0895
114	Feb-09	0.1269	0.0383	0.0886
115	Mar-09	0.1286	0.0378	0.0908
116	Apr-09	0.1266	0.0384	0.0882
117	May-09	0.1242	0.0422	0.0820
118	Jun-09	0.1220	0.0451	0.0769
119	Jul-09	0.1174	0.0438	0.0736
120	Aug-09	0.1158	0.0433	0.0725
121	Sep-09	0.1152	0.0414	0.0738
122	Oct-09	0.1153	0.0416	0.0737
123	Nov-09	0.1196	0.0424	0.0772
124	Dec-09	0.1095	0.0440	0.0655
125	Jan-10	0.1112	0.0450	0.0662
126	Feb-10	0.1091	0.0448	0.0643

LINE NO.	DATE	DCF	BOND YIELD	RISK PREMIUM
127	Mar-10	0.1076	0.0449	0.0627
128	Apr-10	0.1111	0.0453	0.0658
129	May-10	0.1093	0.0411	0.0682
130	Jun-10	0.1088	0.0395	0.0693
131	Jul-10	0.1078	0.0380	0.0698
132	Aug-10	0.1057	0.0352	0.0705
133	Sep-10	0.1059	0.0347	0.0712
134	Oct-10	0.1044	0.0352	0.0692
135	Nov-10	0.1051	0.0382	0.0669
136	Dec-10	0.1053	0.0417	0.0636
137	Jan-11	0.1044	0.0428	0.0616
138	Feb-11	0.1041	0.0442	0.0599
139	Mar-11	0.1044	0.0427	0.0617
140	Apr-11	0.0977	0.0428	0.0549
141	May-11	0.0994	0.0401	0.0593
142	Jun-11	0.0992	0.0391	0.0601
143	Jul-11	0.0968	0.0395	0.0573
144	Aug-11	0.1006	0.0324	0.0682
145	Sep-11	0.0972	0.0283	0.0689
146	Oct-11	0.0998	0.0287	0.0711
147	Nov-11	0.0982	0.0272	0.0710
148	Dec-11	0.0984	0.0267	0.0717
149	Jan-12	0.0977	0.0270	0.0707

Notes: See written evidence above and Exhibit 20, Appendix 3, for a description of the ex ante methodology and data employed. Government bond yield data are from Ibbotson Associates. DCF results are calculated using a quarterly DCF model as follows:

d_0	=	Latest quarterly dividend per Thomson Reuters
P_0	=	Average of the monthly high and low stock prices for each month per Thomson Reuters
FC	=	Flotation costs expressed as a percent of gross proceeds
g	=	I/B/E/S forecast of future earnings growth for each month
k	=	Cost of equity using the quarterly version of the DCF model

$$k = \left[\frac{d_0 (1+g)^{\frac{1}{4}}}{P_0 (1-FC)} + (1+g)^{\frac{1}{4}} \right]^4 - 1$$

EXHIBIT 8
IMPLIED ALLOWED EQUITY RISK PREMIUM[7]

YEAR	AVERAGE ALLOWED RETURN ELECTRIC UTILITIES	20-YEAR U.S. TREASURY BOND	RISK PREMIUM
1988	12.80	9.12	3.68
1989	12.97	8.59	4.38
1990	12.70	8.83	3.87
1991	12.54	8.19	4.35
1992	12.09	7.56	4.53
1993	11.46	6.69	4.77
1994	11.21	7.54	3.67
1995	11.58	6.90	4.68
1996	11.40	6.84	4.57
1997	11.33	6.66	4.67
1998	11.77	5.69	6.08
1999	10.72	6.23	4.49
2000	11.58	6.14	5.44
2001	11.07	5.61	5.46
2002	11.21	5.42	5.79
2003	10.96	4.95	6.02
2004	10.81	5.02	5.79
2005	10.51	4.62	5.89
2006	10.32	4.98	5.34
2007	10.30	4.87	5.43
2008	10.41	4.34	6.07
2009	10.52	4.13	6.39
2010	10.37	3.97	6.40
2011	10.25	3.54	6.71

IMPLIED ALLOWED EQUITY RISK PREMIUM
REGRESSION RESULTS

1	INTERCEPT COEFFICIENT	8.356
2	Slope Coefficient	(0.520)
3	Canada Forecast LT Yield	3.06
4	Slope x Bond Yield	-1.590
5	Forecast Risk Premium (Line 1 + Line 4)	6.77

[7] Average annual allowed returns on equity from Regulatory Research Associates, SNL Financial; yield on long-term U.S. Treasury bonds from Ibbotson Associates.

EXHIBIT 9
SEGMENT INFORMATION
BMO CM CANADIAN UTILITIES COMPANIES

Canadian Utilities Limited

Segment Assets ($Canadian millions)						
Year	Total	Utilities	Energy	ATCO Australia	Corporate and Other	Intersegment Eliminations
2011	$11,696	$7,903	$1,891	$1,340	$728	-$166

Percentage of Total Assets						
Year	Total	Utilities	Energy	ATCO Australia	Corporate and Other	Intersegment Eliminations
2011	100.00%	68%	16%	11%	6%	-1%

SEGMENT INFORMATION
BMO CM CANADIAN UTILITIES COMPANIES

Emera Incorporated

Segment Assets ($Canadian millions)						
Year	Total	NSPI	Maine Utility Operations	Caribbean Utility Operations	Brunswick Pipeline	Other
2011	$6,924	$3,897	$963	$849	$546	$669

Percentage of Total Assets						
Year	Total	NSPI	Maine Utility Operations	Caribbean Utility Operations	Brunswick Pipeline	Other
2011	100.00%	56%	14%	12%	8%	10%

SEGMENT INFORMATION
BMO CM CANADIAN UTILITIES COMPANIES

Enbridge Inc.

Segment Assets ($Canadian millions)						
Year	Total	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing, & Energy Services	Sponsored Investments	Corporate
2011	$30,220	$11,508	$7,594	$5,536	$3,833	$1,749

Percentage of Total Assets						
Year	Total	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing, & Energy Services	Sponsored Investments	Corporate
2011	100.00%	38%	25%	18%	13%	6%

SEGMENT INFORMATION
BMO CM CANADIAN UTILITIES COMPANIES

Fortis Inc.

Segment Assets ($Canadian millions)						
Year	Total	Regulated Gas Utilities - Canadian	Regulated Electric Utilities - Canadian	Regulated Electric Utilities - Caribbean	Non-Regulated - Fortis Generation	Non-Regulated Fortis Properties
2011	$13,471	$5,316	$6,143	$856	$542	$614

Percentage of Total Assets						
Year	Total	Regulated Gas Utilities - Canadian	Regulated Electric Utilities - Canadian	Regulated Electric Utilities - Caribbean	Non-Regulated - Fortis Generation	Non-Regulated Fortis Properties
2011	100.00%	39%	46%	6%	4%	5%

SEGMENT INFORMATION
BMO CM CANADIAN UTILITIES COMPANIES

TransCanada Corporation

Segment Assets ($Canadian millions)					
Year	Total	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate
2011	$48,995	$23,669	$9,439	$14,276	$1,611

Percentage of Total Assets					
Year	Total	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate
2011	100.00%	48%	19%	29%	3%

EXHIBIT 10
SEGMENT INFORMATION
S&P/TSX UTILITIES

ATCO Limited

Segment Assets ($Canadian millions)						
Year	Total	Structures & Logistics	Utilities	Energy	ATCO Australia	Corporate & Other
2011	$12,555	$721	$7,903	$1,891	$1,340	$700

Percentage of Total Assets						
Year	Total	Structures & Logistics	Utilities	Energy	ATCO Australia	Corporate & Other
2011	100.00%	6%	63%	15%	11%	6%

SEGMENT INFORMATION
S&P/TSX UTILITIES

Algonquin Power & Utilities Corp.

Segment Assets ($Canadian millions)				
Year	*Total*	*Algonquin Power*	*Liberty Utilities*	*Corporate*
2010	*$981*	*$663*	*$206*	*$112*

Percentage of Total Assets				
Year	*Total*	*Algonquin Power*	*Liberty Utilities*	*Corporate*
2010	*100.00%*	*68%*	*21%*	*11%*

EXHIBIT 11
PERCENT OF TOTAL ASSETS
FOR REGULATED UTILITY SERVICES
U.S. ELECTRIC UTILITY GROUP

COMPANY	% REGULATED ASSETS
Alliant Energy	87%
Amer. Elec. Power	97%
Avista Corp.	91%
CenterPoint Energy	72%
Consol. Edison	89%
Dominion Resources	63%
DTE Energy	81%
Duke Energy	77%
G't Plains Energy	100%
Integrys Energy	83%
NextEra Energy	54%
Northeast Utilities	95%
OGE Energy	77%
Pepco Holdings	73%
Pinnacle West Capital	99%
Portland General	100%
PPL Corp.	62%
SCANA Corp.	77%
Sempra Energy	66%
Southern Co.	93%
TECO Energy	94%
UIL Holdings	99%
Vectren Corp.	98%
Westar Energy	100%
Wisconsin Energy	92%
Xcel Energy Inc.	95%
Average	**85%**

EXHIBIT 12
PERCENT OF TOTAL ASSETS
FOR REGULATED UTILITY SERVICES
U.S. NATURAL GAS GROUP

COMPANY	% REGULATED ASSETS
AGL Resources	80%
NiSource Inc.	77%
Northwest Nat. Gas	90%
Piedmont Natural Gas Company, Inc.	97%
Questar Corporation	80%
South Jersey Inds.	77%
WGL Holdings Inc.	89%
Average	**84%**

EXHIBIT 13
STANDARD & POOR'S BOND RATINGS
U.S. ELECTRIC AND NATURAL GAS UTILITY GROUPS

LINE NO.	COMPANY	S&P BOND RATING	S&P BOND RATING (NUMERICAL)
1	Alliant Energy	BBB+	6
2	Amer. Elec. Power	BBB	7
3	Avista Corp.	BBB	7
4	CenterPoint Energy	BBB+	6
5	Consol. Edison	A-	5
6	Dominion Resources	A-	5
7	DTE Energy	BBB+	6
8	Duke Energy	A-	5
9	G't Plains Energy	BBB	7
10	Integrys Energy	BBB+	6
11	NextEra Energy	A-	5
12	Northeast Utilities	BBB	7
13	OGE Energy	BBB+	6
14	Pepco Holdings	BBB+	6
15	Pinnacle West Capital	BBB	7
16	Portland General	BBB	7
17	PPL Corp.	BBB	7
18	SCANA Corp.	BBB+	6
19	Sempra Energy	BBB+	6
20	Southern Co.	A	4
21	TECO Energy	BBB	7
22	UIL Holdings	BBB	7
23	Vectren Corp.	A-	5
24	Westar Energy	BBB	7
25	Wisconsin Energy	A-	5
26	Xcel Energy Inc.	A-	5
27	Average	BBB+	6

STANDARD & POOR'S BOND RATINGS
U.S. ELECTRIC AND NATURAL GAS UTILITY GROUPS

LINE NO.	COMPANY	S&P BOND RATING	S&P BOND RATING (NUMERICAL)
1	AGL Resources	AA	1
2	NiSource Inc.	BBB-	8
3	Northwest Nat. Gas	A+	3
4	Piedmont Natural Gas	A	4
5	Questar Corp.	A	4
6	South Jersey Inds.	BBB+	6
7	WGL Holdings Inc.	AA-	2
8	Average	A	4

EXHIBIT 14
SUMMARY OF DISCOUNTED CASH FLOW ANALYSIS
FOR VALUE LINE ELECTRIC UTILITIES

LINE NO.	COMPANY	D_0	P_0	GROWTH	COST OF EQUITY
1	Alliant Energy	0.450	42.342	4.90%	9.3%
2	Amer. Elec. Power	0.470	39.740	3.80%	8.8%
3	Avista Corp.	0.275	25.108	4.50%	9.2%
4	CenterPoint Energy	0.198	19.613	5.73%	10.1%
5	Consol. Edison	0.605	59.441	3.59%	7.9%
6	Dominion Resources	0.493	51.313	3.66%	7.8%
7	DTE Energy	0.588	52.638	3.84%	8.5%
8	Duke Energy	0.250	21.025	3.87%	8.9%
9	G't Plains Energy	0.213	21.043	4.10%	8.4%
10	Integrys Energy	0.680	52.067	9.40%	15.4%
11	NextEra Energy	0.550	57.710	5.77%	10.0%
12	Northeast Utilities	0.275	34.678	6.82%	10.3%
13	OGE Energy	0.393	53.477	7.80%	11.0%
14	Pepco Holdings	0.270	19.703	4.80%	10.8%
15	Pinnacle West Capital	0.525	46.877	5.02%	9.9%
16	Portland General	0.265	24.763	5.88%	10.6%
17	PPL Corp.	0.350	29.033	8.40%	13.9%
18	SCANA Corp.	0.485	43.512	4.48%	9.3%
19	Sempra Energy	0.480	54.193	7.43%	11.4%
20	Southern Co.	0.473	44.483	5.88%	10.6%
21	TECO Energy	0.220	18.522	4.93%	10.0%
22	UIL Holdings	0.432	34.345	4.05%	9.5%
23	Vectren Corp.	0.350	29.000	5.50%	10.8%
24	Westar Energy	0.320	27.711	5.20%	10.2%
25	Wisconsin Energy	0.300	33.546	7.65%	11.3%
26	Xcel Energy Inc.	0.260	26.440	4.87%	9.1%
27	Average				10.1%

Notes:

d_0	=	Most recent quarterly dividend
d_1,d_2,d_3,d_4	=	Next four quarterly dividends, calculated by multiplying the last four quarterly dividends per *Value Line* by the factor (1 + g)
P_0	=	Average of the monthly high and low stock prices during the three months ending January 2012 per Thomson Reuters
FC	=	Flotation costs expressed as a percent of gross proceeds
g	=	I/B/E/S forecast of future earnings growth January 2012
k	=	Cost of equity using the quarterly version of the DCF model:

$$k = \frac{d_1(1+k)^{.75} + d_2(1+k)^{.50} + d_3(1+k)^{.25} + d_4}{P_0} + g$$

EXHIBIT 15
SUMMARY OF DISCOUNTED CASH FLOW ANALYSIS
FOR VALUE LINE NATURAL GAS UTILITIES

LINE NO.	COMPANY	D_0	P_0	GROWTH	COST OF EQUITY
1	AGL Resources	0.450	40.950	3.73%	8.4%
2	NiSource Inc.	0.230	22.687	8.37%	13.0%
3	Northwest Nat. Gas	0.445	47.082	3.63%	7.6%
4	Piedmont Natural Gas	0.290	32.767	4.30%	8.1%
5	Questar Corp.	0.163	19.362	5.65%	9.2%
6	South Jersey Inds.	0.403	55.455	8.67%	11.7%
7	WGL Holdings Inc.	0.388	42.932	3.93%	7.8%
8	Average				9.4%

Notes:

d_0	=	Most recent quarterly dividend.
d_1,d_2,d_3,d_4	=	Next four quarterly dividends, calculated by multiplying the last four quarterly dividends per *Value Line* by the factor (1 + g)
P_0	=	Average of the monthly high and low stock prices during the three months ending January 2012 per Thomson Reuters
g	=	I/B/E/S forecast of future earnings growth January 2012
k	=	Cost of equity using the quarterly version of the DCF model

$$k = \frac{d_1(1+k)^{.75} + d_2(1+k)^{.50} + d_3(1+k)^{.25} + d_4}{P_0} + g$$

EXHIBIT 16
MARKET VALUE EQUITY RATIOS FOR U.S. ELECTRIC UTILITIES

LINE NO.	COMPANY	LONG-TERM DEBT	PREFERRED EQUITY	MARKET CAP $ (MIL)	% LONG-TERM DEBT	% PREFERRED	% MARKET EQUITY
1	Alliant Energy	2,703	244	4,705	35.3%	3.2%	61.5%
2	Amer. Elec. Power	15,502	60	19,104	44.7%	0.2%	55.1%
3	Avista Corp.	1,200	0	1,475	44.8%	0.0%	55.2%
4	CenterPoint Energy	9,001	0	7,867	53.4%	0.0%	46.6%
5	CMS Energy Corp.	6,636	44	5,535	54.3%	0.4%	45.3%
6	Consol. Edison	10,671	0	17,270	38.2%	0.0%	61.8%
7	Dominion Resources	15,758	257	28,503	35.4%	0.6%	64.0%
8	DTE Energy	7,089	0	9,006	44.0%	0.0%	56.0%
9	Duke Energy	17,935	0	28,365	38.7%	0.0%	61.3%
10	G't Plains Energy	2,943	39	2,806	50.8%	0.7%	48.5%
11	Integrys Energy	2,162	51	4,064	34.4%	0.8%	64.7%
12	NextEra Energy	18,013	0	25,289	41.6%	0.0%	58.4%
13	Northeast Utilities	4,814	116	6,152	43.4%	1.0%	55.5%
14	OGE Energy	2,363	0	5,183	31.3%	0.0%	68.7%
15	Pepco Holdings	4,062	0	4,462	47.7%	0.0%	52.3%
16	Pinnacle West Capital	3,046	0	5,160	37.1%	0.0%	62.9%
17	Portland General	1,798	0	1,879	48.9%	0.0%	51.1%
18	PPL Corp.	12,161	250	16,071	42.7%	0.9%	56.4%
19	SCANA Corp.	4,152	0	5,812	41.7%	0.0%	58.3%
20	Sempra Energy	8,980	179	13,646	39.4%	0.8%	59.8%
21	Southern Co.	18,154	1,082	39,269	31.0%	1.8%	67.1%
22	TECO Energy	3,148	0	3,895	44.7%	0.0%	55.3%
23	UIL Holdings	1,512	0	1,748	46.4%	0.0%	53.6%
24	Vectren Corp.	1,435	0	2,340	38.0%	0.0%	62.0%
25	Westar Energy	2,777	21	3,333	45.3%	0.3%	54.4%
26	Wisconsin Energy	3,932	30	7,863	33.3%	0.3%	66.5%
27	Xcel Energy Inc.	9,263	105	12,900	41.6%	0.5%	57.9%
28	Composite	191,209	2,479	283,701	40.1%	0.5%	59.4%

Data are from The Value Line Investment Analyzer, February 2012.

EXHIBIT 17
MARKET VALUE EQUITY RATIOS FOR U.S. NATURAL GAS UTILITIES

LINE NO.	COMPANY	LONG-TERM DEBT	PREFERRED EQUITY	MARKET CAP $ (MIL)	% LONG-TERM DEBT	% PREFERRED	% MARKET EQUITY
1	AGL Resources	1,673	0	4,845	25.7%	0.0%	74.3%
2	NiSource Inc.	5,936	0	6,390	48.2%	0.0%	51.8%
3	Northwest Nat. Gas	592	0	1,270	31.8%	0.0%	68.2%
4	Piedmont Natural Gas	675	0	2,382	22.1%	0.0%	77.9%
5	Questar Corp.	899	0	3,427	20.8%	0.0%	79.2%
6	South Jersey Inds.	340	0	1,654	17.1%	0.0%	82.9%
7	WGL Holdings Inc.	587	28	2,196	20.9%	1.0%	78.1%
8	Average				26.6%	0.1%	73.2%
9	Composite	10,702	28	22,164	32.5%	0.1%	67.4%

Data are from The Value Line Investment Analyzer, February 2012.

EXHIBIT 18
APPENDIX 1
QUALIFICATIONS OF JAMES H. VANDER WEIDE, PH.D.

James H. Vander Weide is Research Professor of Finance and Economics at Duke University, the Fuqua School of Business. Dr. Vander Weide is also founder and President of Financial Strategy Associates, a consulting firm that provides strategic, financial, and economic consulting services to corporate clients, including cost of capital and valuation studies.

Educational Background and Prior Academic Experience

Dr. Vander Weide holds a Ph.D. in Finance from Northwestern University and a Bachelor of Arts in Economics from Cornell University. He joined the faculty at Duke University and was named Assistant Professor, Associate Professor, Professor, and then Research Professor of Finance and Economics.

Since joining the faculty at Duke, Dr. Vander Weide has taught courses in corporate finance, investment management, and management of financial institutions. He has also taught courses in statistics, economics, and operations research, and a Ph.D. seminar on the theory of public utility pricing. In addition, Dr. Vander Weide has been active in executive education at Duke and Duke Corporate Education, leading executive development seminars on topics including financial analysis, cost of capital, creating shareholder value, mergers and acquisitions, real options, capital budgeting, cash management, measuring corporate performance, valuation, short-run financial planning, depreciation policies, financial strategy, and competitive strategy. Dr. Vander Weide has designed and served as Program Director for several executive education programs, including the Advanced Management Program, Competitive Strategies in Telecommunications, and the Duke Program for Manager Development for managers from the former Soviet Union.

Publications

Dr. Vander Weide has written a book entitled *Managing Corporate Liquidity: An Introduction to Working Capital Management* published by John Wiley and Sons, Inc. He has also written a chapter titled, "Financial Management in the Short Run" for *The Handbook of Modern Finance*; a chapter titled "Principles for Lifetime Portfolio Selection: Lessons from Portfolio Theory" for *The Handbook of Portfolio Construction: Contemporary Applications of Markowitz Techniques;* and research papers on such topics as portfolio management, capital budgeting, investments, the effect of regulation on the performance of public utilities, and cash management. His articles have been published in *American*

Economic Review, Financial Management, International Journal of Industrial Organization, Journal of Finance, Journal of Financial and Quantitative Analysis, Journal of Bank Research, Journal of Portfolio Management, Journal of Accounting Research, Journal of Cash Management, Management Science, Atlantic Economic Journal, Journal of Economics and Business, and *Computers and Operations Research*.

Professional Consulting Experience

Dr. Vander Weide has provided financial and economic consulting services to firms in the telecommunications, electric, gas, insurance, and water industries for more than twenty-five years. He has testified on the cost of capital, competition, risk, incentive regulation, forward-looking economic cost, economic pricing guidelines, depreciation, accounting, valuation, and other financial and economic issues in more than 400 cases before the United States Congress, the Canadian Radio-Television and Telecommunications Commission, the Federal Communications Commission, the National Energy Board (Canada), the National Telecommunications and Information Administration, the Federal Energy Regulatory Commission, the public service commissions of forty-three states, the District of Columbia, four Canadian provinces, the insurance commissions of five states, the Iowa State Board of Tax Review, the National Association of Securities Dealers, and the North Carolina Property Tax Commission. In addition, he has testified as an expert witness in telecommunications-related proceedings before the United States District Court for the District of New Hampshire, United States District Court for the Northern District of California, United States District Court for the Northern District of Illinois, Montana Second Judicial District Court Silver Bow County, the United States Bankruptcy Court for the Southern District of West Virginia, and United States District Court for the Eastern District of Michigan. He also testified as an expert before the United States Tax Court, United States District Court for the Eastern District of North Carolina; United States District Court for the District of Nebraska, and Superior Court of North Carolina. Dr. Vander Weide has testified in thirty states on issues relating to the pricing of unbundled network elements and universal service cost studies and has consulted with Bell Canada, Deutsche Telekom, and Telefónica on similar issues. He has also provided expert testimony on issues related to electric and natural gas restructuring. He has worked for Bell Canada/Nortel on a special task force to study the effects of vertical integration in the Canadian telephone industry and has worked for Bell Canada as an expert witness on the cost of capital. Dr. Vander Weide has provided consulting and expert witness testimony to the following companies:

ELECTRIC, GAS, WATER, OIL COMPANIES	
Alcoa Power Generating, Inc.	Maritimes & Northeast Pipeline
Alliant Energy and subsidiaries	MidAmerican Energy and subsidiaries
AltaLink, L.P.	National Fuel Gas
Ameren	Newfoundland Power Inc.
American Water Works	Nevada Power Company
Atmos Energy and subsidiaries	NICOR
BP p.l.c.	North Carolina Natural Gas
Central Illinois Public Service	North Shore Gas
Centurion Pipeline L.P.	Northern Natural Gas Company
Citizens Utilities	NOVA Gas Transmission Ltd.
Consolidated Natural Gas and subsidiaries	PacifiCorp
Dominion Resources and subsidiaries	Peoples Energy and its subsidiaries
Duke Energy and subsidiaries	PG&E
Empire District Electric Company	Progress Energy
EPCOR Distribution & Transmission Inc.	PSE&G
EPCOR Energy Alberta Inc.	Public Service Company of North Carolina
FortisAlberta Inc.	Sempra Energy/San Diego Gas and Electric
Hope Natural Gas	South Carolina Electric and Gas
Interstate Power Company	Southern Company and subsidiaries
Iberdrola Renewables	Tennessee-American Water Company
Iowa Southern	The Peoples Gas, Light and Coke Co.
Iowa-American Water Company	TransCanada
Iowa-Illinois Gas and Electric	Trans Québec & Maritimes Pipeline Inc.
Kentucky Power Company	Union Gas
Kentucky-American Water Company	United Cities Gas Company
Kinder Morgan Energy Partners	Virginia-American Water Company
	Xcel Energy

TELECOMMUNICATIONS COMPANIES	
ALLTEL and subsidiaries	Phillips County Cooperative Tel. Co.
Ameritech (now AT&T new)	Pine Drive Cooperative Telephone Co.
AT&T (old)	Roseville Telephone Company (SureWest)
Bell Canada/Nortel	SBC Communications (now AT&T new)
BellSouth and subsidiaries	Sherburne Telephone Company
Centel and subsidiaries	Siemens
Cincinnati Bell (Broadwing)	Southern New England Telephone
Cisco Systems	Sprint/United and subsidiaries
Citizens Telephone Company	Telefónica
Concord Telephone Company	Tellabs, Inc.
Contel and subsidiaries	The Stentor Companies
Deutsche Telekom	U S West (Qwest)
GTE and subsidiaries (now Verizon)	Union Telephone Company
Heins Telephone Company	United States Telephone Association
JDS Uniphase	Valor Telecommunications (Windstream)

TELECOMMUNICATIONS COMPANIES	
Lucent Technologies	Verizon (Bell Atlantic) and subsidiaries
Minnesota Independent Equal Access Corp.	Woodbury Telephone Company
NYNEX and subsidiaries (Verizon)	
Pacific Telesis and subsidiaries	

INSURANCE COMPANIES
Allstate
North Carolina Rate Bureau
United Services Automobile Association (USAA)
The Travelers Indemnity Company
Gulf Insurance Company

Other Professional Experience

Dr. Vander Weide conducts in-house seminars and training sessions on topics such as creating shareholder value, financial analysis, competitive strategy, cost of capital, real options, financial strategy, managing growth, mergers and acquisitions, valuation, measuring corporate performance, capital budgeting, cash management, and financial planning. Among the firms for whom he has designed and taught tailored programs and training sessions are ABB Asea Brown Boveri, Accenture, Allstate, Ameritech, AT&T, Bell Atlantic/Verizon, BellSouth, Progress Energy/Carolina Power & Light, Contel, Fisons, GlaxoSmithKline, GTE, Lafarge, MidAmerican Energy, New Century Energies, Norfolk Southern, Pacific Bell Telephone, The Rank Group, Siemens, Southern New England Telephone, TRW, and Wolseley Plc. Dr. Vander Weide has also hosted a nationally prominent conference/workshop on estimating the cost of capital. In 1989, at the request of Mr. Fuqua, Dr. Vander Weide designed the Duke Program for Manager Development for managers from the former Soviet Union, the first in the United States designed exclusively for managers from Russia and the former Soviet republics.

Early in his career, Dr. Vander Weide helped found University Analytics, Inc., which was one of the fastest growing small firms in the country. As an officer at University Analytics, he designed cash management models, databases, and software packages that are still used by most major U.S. banks in consulting with their corporate clients. Having sold his interest in University Analytics, Dr. Vander Weide now concentrates on strategic and financial consulting, academic research, and executive education.

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JAMES H. VANDER WEIDE

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SUMMARY EXPERT TESTIMONY
JAMES H. VANDER WEIDE

SPONSOR	JURISDICTION	DATE	DOCKET NO.
Virginia-American Water Company	Virginia	Feb-11	
SFPP, L.P.	FERC	Dec-11	IS11-444-001
Union Gas	Ontario Energy Board	Nov-11	
Mississippi Power Company	FERC	Nov-11	ER12-337
National Fuel Gas	FERC	Oct-11	RP12-888-000
Gulf Power Florida	Florida	Jul-11	110138-EI
Empire District Electric Company	Oklahoma Corporation Commission	Jul-11	11-EPDE-856-RTS
Atmos Energy (West Texas)	Railroad Commission of Texas	Jun-11	
Atmos Energy (Lubbock)	Railroad Commission of Texas	Jun-11	
Iberdrola Renewables Holdings, Inc.	United States Tax Court	Apr-11	525-10
North Carolina Rate Bureau (dwelling fire)	North Carolina Dept. of Insurance	Jan-11	
Atmos Energy	Railroad Commission of Texas	Dec-10	GUD 10041
Mississippi Power Company	FERC	Oct-10	
Empire District Electric Company	Missouri	Sep-10	ER-2011-0004
Tennessee-American Water Company	Tennessee	Sep-10	10-00189
Empire District Electric Company	Arkansas	Aug-10	10-052-U
Maritimes & Northeast Pipelines Limited Partnership	National Energy Board (Canada)	Jul-10	RH 4-2010
Georgia Power Company	Georgia	Jun-10	31958
West Virginia American Water Company	West Virginia	Jun-10	Case No. 10-0920-W-42T
Atmos Energy	Mississippi	Apr-10	2005-UN-503
BP Pipelines (Alaska) Inc.	FERC	Apr-10	IS09-348-000
Empire District Electric Company	FERC	Mar-10	ER10-877-000
Kentucky-American Water Company	Kentucky	Feb-10	2010-00036
Virginia-American Water Company	Virginia	Feb-10	PUE-2010-00001
Virginia Electric and Power	North Carolina	Feb-10	E-22 SUB 459
SFPP, L.P.	FERC	Dec-09	ISO9-437-000
Atmos Energy	Missouri	Dec-09	Gr-2010-0192
Empire District Electric Company	Kansas	Nov-09	10-EPDE-314-RTS
Empire District Electric Company	Missouri	Nov-09	ER-2010-0130
Atmos Energy	Kentucky	Oct-09	2009-00354
Atmos Energy	Georgia	Oct-09	30442
SFPP, L.P. and Calnev Pipeline, L.L.C.	California	Sep-09	09-05-014 et al
Union Gas	Ontario Energy Board	Sep-09	EB-2009-0084
Atmos Energy	Mississippi	Sep-09	05-UN-503
North Carolina Rate Bureau (workers)	North Carolina Dept. of Insurance	Sep-09	
Sidley Austin LLP, Tellabs, Inc. Securities Litigation	U.S. District Court Northern Dist. Illinois	Aug-09	C.A. No. 02-C-4356
Duke Energy Carolinas	South Carolina	Jul-09	2009-226-E
MidAmerican Energy Company	Iowa	Jul-09	RPU-2009-0003
Duke Enegy Carolinas	North Carolina	Jun-09	E-7, SUB 909
Empire District Electric Company	Missouri	Jun-09	ER-2008-009
Terasen Gas Inc.	British Columbia Utilities Commission	May-09	
Atmos Energy	Railroad Commission of Texas	Apr-09	GUD-9869
Progress Energy	Florida	Mar-09	090079-EI
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Jan-09	
EPCOR, FortisAlberta, AltaLink	Alberta Utilities Commission	Nov-08	1578571, ID-85
Trans Québec & Maritimes Pipeline Inc.	Alberta Utilities Commission	Nov-08	1578571, ID-85
Kentucky-American Water Company	Kentucky Public Service	Oct-08	2008-00427

SPONSOR	JURISDICTION	DATE	DOCKET NO.
	Commission		
Atmos Energy	Tennessee Regulatory Authority	Oct-08	0800197
North Carolina Rate Bureau (workers compensation)	North Carolina Dept. of Insurance	Aug-08	
Dorsey & Whitney LLP-Williams v. Gannon	Montana 2nd Judicial Dist. Ct. Silver Bow County	Apr-08	DV-02-201
Atmos Energy	Georgia	Mar-08	27163-U
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Jan-08	
Trans Québec & Maritimes Pipeline Inc.	National Energy Board (Canada)	Dec-07	RH-1-2008
Xcel Energy	North Dakota	Dec-07	PU-07-776
Verizon Southwest	Texas	Nov-07	34723
Empire District Electric Company	Missouri	Oct-07	ER-2008-0093
North Carolina Rate Bureau (workers compensation)	North Carolina Dept. of Insurance	Sep-07	
Verizon North Inc. Contel of the South Inc.	Michigan	Aug-07	Case No. U-15210
Georgia Power Company	Georgia	Jun-07	25060-U
Duke Energy Carolinas	North Carolina	May-07	E-7 Sub 828 et al
MidAmerican Energy Company	Iowa	May-07	SPU-06-5 et al
Morrison & Foerster LLP-JDS Uniphase Securities Litigation	U.S. District Court Northern District California	Feb-07	C-02-1486-CW
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	Dec-06	
San Diego Gas & Electric	FERC	Nov-06	ER07-284-000
North Carolina Rate Bureau (workers compensation)	North Carolina Dept. of Insurance	Aug-06	
Union Electric Company d/b/a AmerenUE	Missouri	Jun-06	ER-2007-0002
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	May-06	
North Carolina Rate Bureau (dwelling fire)	North Carolina Dept. of Insurance	Mar-06	
Empire District Electric Company	Missouri	Feb-06	ER-2006-0315
PacifiCorp Power & Light Company	Washington	Jan-06	UE-050684
Verizon Maine	Maine	Dec-05	2005-155
Winston & Strawn LLP-Cisco Systems Securities Litigation	U.S. District Court Northern District California	Nov-05	C-01-20418-JW
Dominion Virginia Power	Virginia	Nov-05	PUE-2004-00048
Bryan Cave LLP--Omniplex Comms. v. Lucent Technologies	U.S. District Court Eastern District Missouri	Sep-05	04CV00477 ERW
North Carolina Rate Bureau (workers comp)	North Carolina Dept. of Insurance	Sep-05	
Empire District Electric Company	Kansas	Sep-05	05-EPDE-980-RTS
Verizon Southwest	Texas	Jul-05	29315
PG&E Company	FERC	Jul-05	ER-05-1284
Dominion Hope	West Virginia	Jun-05	05-034-G42T
Empire District Electric Company	Missouri	Jun-05	EO-2005-0263
Verizon New England	U.S. District Court New Hampshire	May-05	04-CV-65-PB
San Diego Gas & Electric	California	May-05	05-05-012
Progress Energy	Florida	May-05	50078
Verizon Vermont	Vermont	Feb-05	6959
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	Feb-05	
Verizon Florida	Florida	Jan-05	050059-TL
Verizon Illinois	Illinois	Jan-05	00-0812
Dominion Resources	North Carolina	Sep-04	E-22 Sub 412
Tennessee-American Water Company	Tennessee	Aug-04	04-00288
Valor Telecommunications of Texas, LP.	New Mexico	Jul-04	3495 Phase C
Alcoa Power Generating Inc.	North Carolina Property Tax Commission	Jul-04	02 PTC 162 and 02 PTC 709
PG&E Company	California	May-04	04-05-21
Verizon Northwest	Washington	Apr-04	UT-040788
Verizon Northwest	Washington	Apr-04	UT-040788
Kentucky-American Water Company	Kentucky	Apr-04	2004-00103

SPONSOR	JURISDICTION	DATE	DOCKET NO.
MidAmerican Energy	South Dakota	Apr-04	NG4-001
Empire District Electric Company	Missouri	Apr-04	ER-2004-0570
Interstate Power and Light Company	Iowa	Mar-04	RPU-04-01
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Feb-04	
Northern Natural Gas Company	FERC	Feb-04	RP04-155-000
Verizon New Jersey	New Jersey	Jan-04	TO00060356
Verizon	FCC	Jan-04	03-173, FCC 03-224
Verizon	FCC	Dec-03	03-173, FCC 03-224
Verizon California Inc.	California	Nov-03	R93-04-003,I93-04-002
Phillips County Telephone Company	Colorado	Nov-03	03S-315T
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	Oct-03	
PG&E Company	FERC	Oct-03	ER04-109-000
Allstate Insurance Company	Texas Department of Insurance	Sep-03	2568
Verizon Northwest Inc.	Washington	Jul-03	UT-023003
Empire District Electric Company	Oklahoma	Jul-03	Case No. PUD 200300121
Verizon Virginia Inc.	FCC	Apr-03	CC-00218,00249,00251
North Carolina Rate Bureau (dwelling fire)	North Carolina Dept. of Insurance	Apr-03	
Northern Natural Gas Company	FERC	Apr-03	RP03-398-000
MidAmerican Energy	Iowa	Apr-03	RPU-03-1, WRU-03-25-156
PG&E Company	FERC	Mar-03	ER03666000
Verizon Florida Inc.	Florida	Feb-03	981834-TP/990321-TP
Verizon North	Indiana	Feb-03	42259
San Diego Gas & Electric	FERC	Feb-03	ER03-601000
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Jan-03	
Gulf Insurance Company	Superior Court, North Carolina	Jan-03	2000-CVS-3558
PG&E Company	FERC	Jan-03	ER03409000
Verizon New England Inc. New Hampshire	New Hampshire	Dec-02	DT 02-110
Verizon Northwest	Washington	Dec-02	UT 020406
PG&E Company	California	Dec-02	
MidAmerican Energy	Iowa	Nov-02	RPU-02-3, 02-8
MidAmerican Energy	Iowa	Nov-02	RPU-02-10
Verizon Michigan	US District Court Eastern District of Michigan	Sep-02	Civil Action No. 00-73208
North Carolina Rate Bureau (workers comp)	North Carolina Dept. of Insurance	Sep-02	
Verizon New England Inc. New Hampshire	New Hampshire	Aug-02	DT 02-110
Interstate Power Company	Iowa Board of Tax Review	Jul-02	832
PG&E Company	California	May-02	A 02-05-022 et al
Verizon New England Inc. Massachusetts	FCC	May-02	EB 02 MD 006
Verizon New England Inc. Rhode Island	Rhode Island	May-02	Docket No. 2681
NEUMEDIA, INC.	US Bankruptcy Court Southern District W. Virginia	Apr-02	Case No. 01-20873
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	Mar-02	
MidAmerican Energy Company	Iowa	Mar-02	RPU 02 2
North Carolina Natural Gas Company	North Carolina	Feb-02	G21 Sub 424
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Jan-02	
Verizon Pennsylvania	Pennsylvania	Dec-01	R-00016683
Verizon Florida	Florida	Nov-01	99064B-TP
PG&E Company	FERC	Nov-01	ER0166000
Verizon Delaware	Delaware	Oct-01	96-324 Phase II
Florida Power Corporation	Florida	Sep-01	000824-EL
North Carolina Rate Bureau (workers comp)	North Carolina Dept. of Insurance	Sep-01	
Verizon Washington DC	District of Columbia	Jul-01	962
Verizon Virginia	FCC	Jul-01	CC-00218,00249,00251
Sherburne County Rural Telephone Company	Minnesota	Jul-01	P427/CI-00-712
Verizon New Jersey	New Jersey	Jun-01	TO01020095

SPONSOR	JURISDICTION	DATE	DOCKET NO.
Verizon Maryland	Maryland	May-01	8879
Verizon Massachusetts	Massachusetts	May-01	DTE 01-20
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Apr-01	
PG&E Company	FERC	Mar-01	ER011639000
Maupin Taylor & Ellis P.A.	National Association of Securities Dealers	Jan-01	99-05099
USTA	FCC	Oct-00	RM 10011
Verizon New York	New York	Oct-00	98-C-1357
Verizon New Jersey	New Jersey	Oct-00	TO00060356
PG&E Company	FERC	Oct-00	ER0166000
Verizon New Jersey	New Jersey	Sep-00	TO99120934
North Carolina Rate Bureau (workers comp)	North Carolina Dept. of Insurance	Sep-00	
PG&E Company	California	Aug-00	00-05-018
Verizon New York	New York	Jul-00	98-C-1357
PG&E Company	California	May-00	00-05-013
PG&E Company	FERC	Mar-00	ER00-66-000
PG&E Company	FERC	Mar-00	ER99-4323-000
Bell Atlantic	New York	Feb-00	98-C-1357
USTA	FCC	Jan-00	94-1, 96-262
MidAmerican Energy	Iowa	Nov-99	SPU-99-32
PG&E Company	California	Nov-99	99-11-003
PG&E Company	FERC	Nov-99	ER973255,981261,981685
North Carolina Rate Bureau (workers comp)	North Carolina Dept. of Insurance	Sep-99	
MidAmerican Energy	Illinois	Sep-99	99-0534
PG&E Company	FERC	Sep-99	ER99-4323-000
MidAmerican Energy	FERC	Jul-99	ER99-3887
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	Jun-99	
Bell Atlantic	Vermont	May-99	6167
Nevada Power Company	FERC	May-99	
Bell Atlantic, GTE, US West	FCC	Apr-99	CC98-166
Nevada Power Company	Nevada	Apr-99	
Bell Atlantic, GTE, US West	FCC	Mar-99	CC98-166
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Mar-99	
PG&E Company	FERC	Mar-99	ER99-2326-000
MidAmerican Energy	Illinois	Mar-99	099-0310
PG&E Company	FERC	Feb-99	ER99-2358,2087,2351
MidAmerican Energy	US District Court, District of Nebraska	Feb-99	8:97 CV 346
Bell Atlantic, GTE, US West	FCC	Jan-99	CC98-166
The Southern Company	FERC	Jan-99	ER98-1096
Deutsche Telekom	Germany	Nov-98	
Telefonica	Spain	Nov-98	
Cincinnati Bell Telephone Company	Ohio	Oct-98	96899TPALT
MidAmerican Energy	Iowa	Sep-98	RPU 98-5
MidAmerican Energy	South Dakota	Sep-98	NG98-011
MidAmerican Energy	Iowa	Sep-98	SPU 98-8
GTE Florida Incorporated	Florida	Aug-98	980696-TP
GTE North and South	Illinois	Jun-98	960503
GTE Midwest Incorporated	Missouri	Jun-98	TO98329
GTE North and South	Illinois	May-98	960503
MidAmerican Energy	Iowa Board of Tax Review	May-98	835
San Diego Gas & Electric	California	May-98	98-05-024
GTE Midwest Incorporated	Nebraska	Apr-98	C1416
Carolina Telephone	North Carolina	Mar-98	P100Sub133d
GTE Southwest	Texas	Feb-98	18515

SPONSOR	JURISDICTION	DATE	DOCKET NO.
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Feb-98	P100sub133d
Public Service Electric & Gas	New Jersey	Feb-98	PUC734897N,-734797N,BPUEO97070461,-07070462
GTE North	Minnesota	Dec-97	P999/M97909
GTE Northwest	Oregon	Dec-97	UM874
The Southern Company	FERC	Dec-97	ER981096000
GTE North	Pennsylvania	Nov-97	A310125F0002
Bell Atlantic	Rhode Island	Nov-97	2681
GTE North	Indiana	Oct-97	40618
GTE North	Minnesota	Oct-97	P442,407/5321/CI961541
GTE Southwest	New Mexico	Oct-97	96310TC,96344TC
GTE Midwest Incorporated	Iowa	Sep-97	RPU-96-7
North Carolina Rate Bureau (workers)	North Carolina Dept. of Insurance	Sep-97	
GTE Hawaiian Telephone	Hawaii	Aug-97	7702
The Stentor Companies	Canadian Radio-television and Telecommunications Commission	Jul-97	CRTC97-11
New England Telephone	Vermont	Jul-97	5713
Bell-Atlantic-New Jersey	New Jersey	Jun-97	TX95120631
Nevada Bell	Nevada	May-97	96-9035
New England Telephone	Maine	Apr-97	96-781
GTE North, Inc.	Michigan	Apr-97	U11281
Bell Atlantic-Virginia	Virginia	Apr-97	970005
Cincinnati Bell Telephone	Ohio	Feb-97	96899TPALT
Bell Atlantic - Pennsylvania	Pennsylvania	Feb-97	A310203,213,236,258F002
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Feb-97	
Bell Atlantic-Washington, D.C.	District of Columbia	Jan-97	962
Pacific Bell, Sprint, US West	FCC	Jan-97	CC 96-45
United States Telephone Association	FCC	Jan-97	CC 96-262
Bell Atlantic-Maryland	Maryland	Jan-97	8731
Bell Atlantic-West Virginia	West Virginia	Jan-97	961516, 1561, 1009TPC,961533TT
Poe, Hoof, & Reinhardt	Durham Cnty Superior Court Kountis vs. Circle K	Jan-97	95CVS04754
Bell Atlantic-Delaware	Delaware	Dec-96	96324
Bell Atlantic-New Jersey	New Jersey	Nov-96	TX95120631
Carolina Power & Light Company	FERC	Nov-96	OA96-198-000
New England Telephone	Massachusetts	Oct-96	DPU 96-73/74,-75, -80/81, -83, -94
New England Telephone	New Hampshire	Oct-96	96-252
Bell Atlantic-Virginia	Virginia	Oct-96	960044
Citizens Utilities	Illinois	Sep-96	96-0200, 96-0240
Union Telephone Company	New Hampshire	Sep-96	95-311
Bell Atlantic-New Jersey	New Jersey	Sep-96	TO-96070519
New York Telephone	New York	Sep-96	95-C-0657, 94-C-0095,91-C-1174
North Carolina Rate Bureau (workers comp)	North Carolina Dept. of Insurance	Sep-96	
MidAmerican Energy Company	Illinois	Sep-96	96-0274
MidAmerican Energy Company	Iowa	Sep-96	RPU96-8
United States Telephone Association	FCC	Mar-96	AAD-96.28
United States Telephone Association	FCC	Mar-96	CC 94-1 PhaseIV
Bell Atlantic - Maryland	Maryland	Mar-96	8715
Nevada Bell	Nevada	Mar-96	96-3002
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Mar-96	
Carolina Tel. and Telegraph Co, Central Tel Co	North Carolina	Feb-96	P7 sub 825, P10 sub 479
Oklahoma Rural Telephone Coalition	Oklahoma	Oct-95	PUD950000119
BellSouth	Tennessee	Oct-95	95-02614
Wake County, North Carolina	US District Court, Eastern Dist. NC	Oct-95	594CV643H2
Bell Atlantic - District of Columbia	District of Columbia	Sep-95	814 Phase IV

SPONSOR	JURISDICTION	DATE	DOCKET NO.
South Central Bell Telephone Company	Tennessee	Aug-95	95-02614
GTE South	Virginia	Jun-95	95-0019
Roseville Telephone Company	California	May-95	A.95-05-030
Bell Atlantic - New Jersey	New Jersey	May-95	TX94090388
Cincinnati Bell Telephone Company	Ohio	May-95	941695TPACE
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	May-95	727
Northern Illinois Gas	Illinois	May-95	95-0219
South Central Bell Telephone Company	Kentucky	Apr-95	94-121
Midwest Gas	South Dakota	Mar-95	
Virginia Natural Gas, Inc.	Virginia	Mar-95	PUE940054
Hope Gas, Inc.	West Virginia	Mar-95	95-0003G42T
The Peoples Natural Gas Company	Pennsylvania	Feb-95	R-943252
and Coke Co., North Shore Gas, Iowa-Illinois Gas	Illinois	Jan-95	94-0403
and Electric, Central Illinois Public Service,	Illinois	Jan-95	94-0403
Northern Illinois Gas, The Peoples Gas, Light	Illinois	Jan-95	94-0403
United Cities Gas, and Interstate Power	Illinois	Jan-95	94-0403
Cincinnati Bell Telephone Company	Kentucky	Oct-94	94-355
Midwest Gas	Nebraska	Oct-94	
Midwest Power	Iowa	Sep-94	RPU-94-4
Bell Atlantic	FCC	Aug-94	CS 94-28, MM 93-215
Midwest Gas	Iowa	Jul-94	RPU-94-3
Bell Atlantic	FCC	Jun-94	CC 94-1
Nevada Power Company	Nevada	Jun-94	93-11045
Cincinnati Bell Telephone Company	Ohio	Mar-94	93-551-TP-CSS
Cincinnati Bell Telephone Company	Ohio	Mar-94	93-432-TP-ALT
GTE South/Contel	Virginia	Feb-94	PUC9300036
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Feb-94	689
Bell of Pennsylvania	Pennsylvania	Jan-94	P930715
GTE South	South Carolina	Jan-94	93-504-C
United Telephone-Southeast	Tennessee	Jan-94	93-04818
C&P of VA, GTE South, Contel, United Tel. SE	Virginia	Sep-93	PUC920029
Bell Atlantic, NYNEX, Pacific Companies	FCC	Aug-93	MM 93-215
C&P, Centel, Contel, GTE, & United	Virginia	Aug-93	PUC920029
Chesapeake & Potomac Tel Virginia	Virginia	Aug-93	93-00-
GTE North	Illinois	Jul-93	93-0301
Midwest Power	Iowa	Jul-93	INU-93-1
Midwest Power	South Dakota	Jul-93	EL93-016
Chesapeake & Potomac Tel. Co. DC	District of Columbia	Jun-93	926
Cincinnati Bell	Ohio	Jun-93	93432TPALT
North Carolina Rate Bureau (dwelling fire)	North Carolina Dept. of Insurance	Jun-93	671
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	Jun-93	670
Pacific Bell Telephone Company	California	Mar-93	92-05-004
Minnesota Independent Equal Access Corp.	Minnesota	Mar-93	P3007/GR931
South Central Bell Telephone Company	Tennessee	Feb-93	92-13527
South Central Bell Telephone Company	Kentucky	Dec-92	92-523
Southern New England Telephone Company	Connecticut	Nov-92	92-09-19
Chesapeake & Potomac Tel. Co.CDC	District of Columbia	Nov-92	814
Diamond State Telephone Company	Delaware	Sep-92	PSC 92-47
New Jersey Bell Telephone Company	New Jersey	Sep-92	TO-92030958
Allstate Insurance Company	New Jersey Dept. of Insurance	Sep-92	INS 06174-92
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Aug-92	650
North Carolina Rate Bureau (workers' comp)	North Carolina Dept. of Insurance	Aug-92	647
Midwest Gas Company	Minnesota	Aug-92	G010/GR92710

SPONSOR	JURISDICTION	DATE	DOCKET NO.
Pennsylvania-American Water Company	Pennsylvania	Jul-92	R-922428
Central Telephone Co. of Florida	Florida	Jun-92	920310-TL
C&P of VA, GTE South, Contel, United Tel. SE	Virginia	Jun-92	PUC920029
Chesapeake & Potomac Tel. Co. Maryland	Maryland	May-92	8462
Pacific Bell Telephone Company	California	Apr-92	92-05-004
Iowa Power Inc.	Iowa	Mar-92	RPU-92-2
Contel of Texas	Texas	Feb-92	10646
Southern Bell Telephone Company	Florida	Jan-92	880069-TL
Nevada Power Company	Nevada	Jan-92	92-1067
GTE South	Georgia	Dec-91	4003-U
GTE South	Georgia	Dec-91	4110-U
Allstate Insurance Company (property)	Texas Dept. of Insurance	Dec-91	1846
IPS Electric	Iowa	Oct-91	RPU-91-6
GTE South	Tennessee	Aug-91	91-05738
North Carolina Rate Bureau (workers' comp)	North Carolina Dept. of Insurance	Aug-91	609
Midwest Gas Company	Iowa	Jul-91	RPU-91-5
Pennsylvania-American Water Company	Pennsylvania	Jun-91	R-911909
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Jun-91	606
Allstate Insurance Company	California Dept. of Insurance	May-91	RCD-2
Nevada Power Company	Nevada	May-91	91-5055
Kentucky Power Company	Kentucky	Apr-91	91-066
Chesapeake & Potomac Tel. Co.CD.C.	District of Columbia	Feb-91	850
Allstate Insurance Company	New Jersey Dept. of Insurance	Jan-91	INS-9536-90
GTE South	South Carolina	Nov-90	90-698-C
Southern Bell Telephone Company	Florida	Oct-90	880069-TL
GTE South	West Virginia	Aug-90	90-522-T-42T
North Carolina Rate Bureau (workers' comp)	North Carolina Dept. of Insurance	Aug-90	R90-08-
The Travelers Indemnity Company	Pennsylvania Dept. of Insurance	Aug-90	R-90-06-23
Chesapeake & Potomac Tel. Co.-Maryland	Maryland	Jul-90	8274
Allstate Insurance Company	Pennsylvania Dept. of Insurance	Jul-90	R90-07-01
Central Tel. Co. of Florida	Florida	Jun-90	89-1246-TL
Citizens Telephone Company	North Carolina	Jun-90	P-12, SUB 89
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Jun-90	568
Iowa Resources, Inc. and Midwest Energy	Iowa	Jun-90	SPU-90-5
Contel of Illinois	Illinois	May-90	90-0128
Southern New England Tel. Co.	Connecticut	Apr-90	89-12-05
Bell Atlantic	FCC	Apr-90	89-624 II
Pennsylvania-American Water Company	Pennsylvania	Mar-90	R-901652
Bell Atlantic	FCC	Feb-90	89-624
GTE South	Tennessee	Jan-90	
Allstate Insurance Company	California Dept. of Insurance	Jan-90	REB-1002
Bell Atlantic	FCC	Nov-89	87-463 II
Allstate Insurance Company	California Dept. of Insurance	Sep-89	REB-1006
Pacific Bell	California	Mar-89	87-11-0033
Iowa Power & Light	Iowa	Dec-88	RPU-88-10
Pacific Bell	California	Oct-88	88-05-009
Southern Bell	Florida	Apr-88	880069TL
Carolina Independent Telcos.	North Carolina	Apr-88	P-100, Sub 81
United States Telephone Association	U. S. Congress	Apr-88	
Carolina Power & Light	South Carolina	Mar-88	88-11-E
New Jersey Bell Telephone Co.	New Jersey	Feb-88	87050398
Carolina Power & Light	FERC	Jan-88	ER-88-224-000
Carolina Power & Light	North Carolina	Dec-87	E-2, Sub 537

SPONSOR	JURISDICTION	DATE	DOCKET NO.
Bell Atlantic	FCC	Nov-87	87-463
Diamond State Telephone Co.	Delaware	Jul-87	86-20
Central Telephone Co. of Nevada	Nevada	Jun-87	87-1249
ALLTEL	Florida	Apr-87	870076-PU
Southern Bell	Florida	Apr-87	870076-PU
Carolina Power & Light	North Carolina	Apr-87	E-2, Sub 526
So. New England Telephone Co.	Connecticut	Mar-87	87-01-02
Northern Illinois Gas Co.	Illinois	Mar-87	87-0032
Bell of Pennsylvania	Pennsylvania	Feb-87	860923
Carolina Power & Light	FERC	Jan-87	ER-87-240-000
Bell South	NTIA	Dec-86	61091-619
Heins Telephone Company	North Carolina	Oct-86	P-26, Sub 93
Public Service Co. of NC	North Carolina	Jul-86	G-5, Sub 207
Bell Atlantic	FCC	Feb-86	84-800 III
BellSouth	FCC	Feb-86	84-800 III
ALLTEL Carolina, Inc	North Carolina	Feb-86	P-118, Sub 39
ALLTEL Georgia, Inc.	Georgia	Jan-86	3567-U
ALLTEL Ohio	Ohio	Jan-86	86-60-TP-AIR
Western Reserve Telephone Co.	Ohio	Jan-86	85-1973-TP-AIR
New England Telephone & Telegraph	Maine	Dec-85	
ALLTEL-Florida	Florida	Oct-85	850064-TL
Iowa Southern Utilities	Iowa	Oct-85	RPU-85-11
Bell Atlantic	FCC	Sep-85	84-800 II
Pacific Telesis	FCC	Sep-85	84-800 II
Pacific Bell	California	Apr-85	85-01-034
United Telephone Co. of Missouri	Missouri	Apr-85	TR-85-179
South Carolina Generating Co.	FERC	Apr-85	85-204
South Central Bell	Kentucky	Mar-85	9160
New England Telephone & Telegraph	Vermont	Mar-85	5001
Chesapeake & Potomac Telephone Co.	West Virginia	Mar-85	84-747
Chesapeake & Potomac Telephone Co.	Maryland	Jan-85	7851
Central Telephone Co. of Ohio	Ohio	Dec-84	84-1431-TP-AIR
Ohio Bell	Ohio	Dec-84	84-1435-TP-AIR
Carolina Power & Light Co.	FERC	Dec-84	ER85-184000
BellSouth	FCC	Nov-84	84-800 I
Pacific Telesis	FCC	Nov-84	84-800 I
New Jersey Bell	New Jersey	Aug-84	848-856
Southern Bell	South Carolina	Aug-84	84-308-C
Pacific Power & Light Co.	Montana	Jul-84	84.73.8
Carolina Power & Light Co.	South Carolina	Jun-84	84-122-E
Southern Bell	Georgia	Mar-84	3465-U
Carolina Power & Light Co.	North Carolina	Feb-84	E-2, Sub 481
Southern Bell	North Carolina	Jan-84	P-55, Sub 834
South Carolina Electric & Gas	South Carolina	Nov-83	83-307-E
Empire Telephone Co.	Georgia	Oct-83	3343-U
Southern Bell	Georgia	Aug-83	3393-U
Carolina Power & Light Co.	FERC	Aug-83	ER83-765-000
General Telephone Co. of the SW	Arkansas	Jul-83	83-147-U
Heins Telephone Co.	North Carolina	Jul-83	No.26 Sub 88
General Telephone Co. of the NW	Washington	Jul-83	U-82-45
Leeds Telephone Co.	Alabama	Apr-83	18578
General Telephone Co. of California	California	Apr-83	83-07-02
North Carolina Natural Gas	North Carolina	Apr-83	G21 Sub 235
Carolina Power & Light	South Carolina	Apr-83	82-328-E

SPONSOR	JURISDICTION	DATE	DOCKET NO.
Eastern Illinois Telephone Co.	Illinois	Feb-83	83-0072
Carolina Power & Light	North Carolina	Feb-83	E-2 Sub 461
New Jersey Bell	New Jersey	Dec-82	8211-1030
Southern Bell	Florida	Nov-82	820294-TP
United Telephone of Missouri	Missouri	Nov-82	TR-83-135
Central Telephone Co. of NC	North Carolina	Nov-82	P-10 Sub 415
Concord Telephone Company	North Carolina	Nov-82	P-16 Sub 146
Carolina Telephone & Telegraph	North Carolina	Aug-82	P-7, Sub 670
Central Telephone Co. of Ohio	Ohio	Jul-82	82-636-TP-AIR
Southern Bell	South Carolina	Jul-82	82-294-C
General Telephone Co. of the SW	Arkansas	Jun-82	82-232-U
General Telephone Co. of Illinois	Illinois	Jun-82	82-0458
General Telephone Co. of the SW	Oklahoma	Jun-82	27482
Empire Telephone Co.	Georgia	May-82	3355-U
Mid-Georgia Telephone Co.	Georgia	May-82	3354-U
General Telephone Co. of the SW	Texas	Apr-82	4300
General Telephone Co. of the SE	Alabama	Jan-82	18199
Carolina Power & Light Co.	South Carolina	Jan-82	81-163-E
Elmore-Coosa Telephone Co.	Alabama	Nov-81	18215
General Telephone Co. of the SE	North Carolina	Sep-81	P-19, Sub 182
United Telephone Co. of Ohio	Ohio	Sep-81	81-627-TP-AIR
General Telephone Co. of the SE	South Carolina	Sep-81	81-121-C
Carolina Telephone & Telegraph	North Carolina	Aug-81	P-7, Sub 652
Southern Bell	North Carolina	Aug-81	P-55, Sub 794
Woodbury Telephone Co.	Connecticut	Jul-81	810504
Central Telephone Co. of Virginia	Virginia	Jun-81	810030
United Telephone Co. of Missouri	Missouri	May-81	TR-81-302
General Telephone Co. of the SE	Virginia	Apr-81	810003
New England Telephone	Vermont	Mar-81	4546
Carolina Telephone & Telegraph	North Carolina	Aug-80	P-7, Sub 652
Southern Bell	North Carolina	Aug-80	P-55, Sub 784
General Telephone Co. of the SW	Arkansas	Jun-80	U-3138
General Telephone Co. of the SE	Alabama	May-80	17850
Southern Bell	North Carolina	Oct-79	P-55, Sub 777
Southern Bell	Georgia	Mar-79	3144-U
General Telephone Co. of the SE	Virginia	Mar-76	810038
General Telephone Co. of the SW	Arkansas	Feb-76	U-2693, U-2724
General Telephone Co. of the SE	Alabama	Sep-75	17058
General Telephone Co. of the SE	South Carolina	Jun-75	D-18269

EXHIBIT 19
APPENDIX 2
ESTIMATING THE EXPECTED RISK PREMIUM ON UTILITY STOCKS USING THE DCF MODEL

The DCF model is based on the assumption that investors value an asset on the basis of the future cash flows they expect to receive from owning the asset. Thus, investors value an investment in a bond because they expect to receive a sequence of semi-annual coupon payments over the life of the bond and a terminal payment equal to the bond's face value at the time the bond matures. Likewise, investors value an investment in a firm's stock because they expect to receive a sequence of dividend payments and, perhaps, expect to sell the stock at a higher price sometime in the future.

A second fundamental principle of the DCF method is that investors value a dollar received in the future less than a dollar received today. A future dollar is valued less than a current dollar because investors could invest a current dollar in an interest earning account and increase their wealth. This principle is called the time value of money.

Applying the two fundamental DCF principles noted above to an investment in a bond leads to the conclusion that investors value their investment in the bond on the basis of the present value of the bond's future cash flows. Thus, the price of the bond should be equal to:

EQUATION 1

$$P_B = \frac{C}{(1+i)} + \frac{C}{(1+i)^2} + \ldots + \frac{C+F}{(1+i)^n}$$

where:

P_B	=	Bond price;
C	=	Cash value of the coupon payment (assumed for notational convenience to occur annually rather than semi-annually);
F	=	Face value of the bond;

i	=	The rate of interest the investor could earn by investing his money in an alternative bond of equal risk; and
n	=	The number of periods before the bond matures.

Applying these same principles to an investment in a firm's stock suggests that the price of the stock should be equal to:

EQUATION 2

$$P_s = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_n + P_n}{(1+k)^n}$$

where:

P_S	=	Current price of the firm's stock;
$D_1, D_2 \ldots D_n$	=	Expected annual dividend per share on the firm's stock;
P_n	=	Price per share of stock at the time the investor expects to sell the stock; and
k	=	Return the investor expects to earn on alternative investments of the same risk, i.e., the investor's required rate of return.

Equation (2) is frequently called the annual discounted cash flow model of stock valuation. Assuming that dividends grow at a constant annual rate, *g*, this equation can be solved for *k*, the cost of equity. The resulting cost of equity equation is $k = D_1/P_s + g$, where *k* is the cost of equity, D_1 is the expected next period annual dividend, P_s is the current price of the stock, and *g* is the constant annual growth rate in earnings, dividends, and book value per share. The term D_1/P_s is called the dividend yield component of the annual DCF model, and the term *g* is called the growth component of the annual DCF model.

The annual DCF model is only a correct expression for the present value of future dividends if dividends are paid annually at the end of each year. Since most industrial and utility firms pay dividends quarterly, the annual DCF model produces downwardly biased estimates of the cost of equity. Investors can expect to earn a higher annual effective return on an investment in a firm that pays quarterly dividends than in one which pays the same amount of dollar dividends once at the end of each year.

The Dividend Component

The quarterly DCF model requires an estimate of the expected dividends for the next four quarters. I estimated the expected dividends for the next four quarters by multiplying the actual dividends for the last four quarters by the factor, (1 + the growth rate, g).

The Growth Component

To estimate the growth component of the DCF model, I used the analysts' estimates of future earnings per share (EPS) growth reported by I/B/E/S Thomson Financial. As part of their research, financial analysts working at Wall Street firms periodically estimate EPS growth for each firm they follow. The EPS forecasts for each firm are then published. Investors who are contemplating purchasing or selling shares in individual companies review the forecasts. These estimates represent five-year forecasts of EPS growth. I/B/E/S is a firm that reports analysts' EPS growth forecasts for a broad group of companies. The forecasts are expressed in terms of a mean forecast and a standard deviation of forecast for each firm. Investors use the mean forecast as a consensus estimate of future firm performance. The I/B/E/S growth rates: (1) are widely circulated in the financial community, (2) include the projections of reputable financial analysts who develop estimates of future EPS growth, (3) are reported on a timely basis to investors, and (4) are widely used by institutional and other investors.

I relied on analysts' projections of future EPS growth because there is considerable empirical evidence that investors use analysts' forecasts to estimate future earnings growth. To test whether investors use analysts' growth forecasts to estimate future dividend and earnings growth, I prepared a study in conjunction with Willard T. Carleton, Karl Eller Professor of Finance at the University of Arizona, on why analysts' forecasts are the best estimate of investors' expectation of future long-term growth. This study is described in a paper entitled "Investor Growth Expectations and Stock Prices: the Analysts versus Historical Growth Extrapolation," published in the Spring 1988 edition of *The Journal of Portfolio Management*.

In our paper, we describe how we first performed a correlation analysis to identify the historically-oriented growth rates which best described a firm's stock price. Then we did a regression study comparing the historical growth rates with the consensus analysts' forecasts. In every case, the regression equations containing the average of analysts' forecasts statistically outperformed the regression equations containing the historical growth estimates. These results are consistent with those found by Cragg and Malkiel, the early major research in this area (John G. Cragg and Burton G. Malkiel, *Expectations and the Structure of Share Prices*, University of Chicago Press, 1982). These results are also consistent with the hypothesis that investors use analysts' forecasts, rather than historically-oriented growth calculations, in making stock buy and sell decisions. They provide overwhelming evidence that the analysts' forecasts of future growth are superior to historically-oriented growth measures in predicting a firm's stock price.

My study has been updated to include more recent data. Researchers at State Street Financial Advisors updated my study using data through year-end 2003. Their results continue to confirm that analysts' growth forecasts are superior to historically-oriented growth measures in predicting a firm's stock price.

The Price Component

To measure the price component of the DCF model, I used a simple average of the monthly high and low stock prices for each firm over a three-month period. These high and low stock prices were obtained from Thomson Financial. I used the three-month average stock price in applying the DCF method because stock prices fluctuate daily, while financial analysts' forecasts for a given company are generally changed less frequently, often on a quarterly basis. Thus, to match the stock price with an earnings forecast, it is appropriate to average stock prices over a three-month period.

EXHIBIT 20
APPENDIX 3
THE SENSITIVITY OF THE FORWARD-LOOKING
REQUIRED EQUITY RISK PREMIUM ON UTILITY STOCKS
TO CHANGES IN INTEREST RATES

My estimate of the required equity risk premium on utility stocks is based on studies of the discounted cash flow ("DCF") expected return on comparable groups of utilities in each month of my study period compared to the interest rate on long-term government bonds. Specifically, for each month in my study period, I calculate the risk premium using the equation

$$RP_{COMP} = DCF_{COMP} - I_B$$

where:

RP_{COMP}	=	the required risk premium on an equity investment in the comparable companies,
DCF_{COMP}	=	average DCF expected rate of return on a portfolio of comparable companies; and
I_B	=	the yield to maturity on an investment in long-term U.S. Treasury bonds.

<u>Electric Company Ex Ante Risk Premium Analysis</u>. For my electric company ex ante risk premium analysis, I began with the Moody's group of twenty-four electric utilities shown in Table 1 below. I use the Moody's group of electric utilities because they are a widely followed group of electric utilities, and use of this constant group greatly simplifies the data collection task required to estimate the ex ante risk premium over the months of my study. Simplifying the data collection task is desirable because the ex ante risk premium approach requires that the DCF model be estimated for every company in every month of the study period. Exhibit 7 displays the average DCF expected return on an investment in the portfolio of electric utilities and the yield to maturity on long-term Treasury bonds in each month of the study.

Previous studies have shown that the ex ante risk premium tends to vary inversely with the level of interest rates, that is, the risk premium tends to increase when interest rates decline, and decrease when interest rates go up. To test whether my studies also indicate that the ex ante risk premium varies inversely with the level of interest rates, I perform a regression analysis of the relationship between the ex ante risk premium and the yield to maturity on long-term Treasury bonds, using the equation,

$$RP_{COMP} = a + (b \times I_B) + e$$

where:

RP_{COMP}	=	risk premium on comparable company group;
I_B	=	yield to maturity on long-term U.S. Treasury bonds;
e	=	a random residual; and
a, b	=	coefficients estimated by the regression procedure.

Regression analysis assumes that the statistical residuals from the regression equation are random. My examination of the residuals reveals that there is a significant probability that the residuals are serially correlated (non-zero serial correlation indicates that the residual in one time period tends to be correlated with the residual in the previous time period). Therefore, I make adjustments to my data to correct for the possibility of serial correlation in the residuals.

The common procedure for dealing with serial correlation in the residuals is to estimate the regression coefficients in two steps. First, a multiple regression analysis is used to estimate the serial correlation coefficient, *r*. Second, the estimated serial correlation coefficient is used to transform the original variables into new variables whose serial correlation is approximately zero. The regression coefficients are then re-estimated using the transformed variables as inputs in the regression equation. Based on my regression analysis of the statistical relationship between the yield to maturity on long-term Treasury bonds and the required risk premium, my estimate of the ex ante risk premium on an investment in my proxy electric company group as compared to an investment in long-term Treasury bonds is given by the equation:

$$RP_{COMP} = \underset{(13.25)}{10.40} - \underset{(-7.53)}{.892} \times I_B$$[8].

This equation suggests that the ex ante risk premium on electric utility stocks increases by eighty-nine basis points when the interest rate on long-term Treasury bonds declines by one hundred basis points. Equivalently, this regression equation suggests that the cost of equity for electric utilities declines by significantly less than fifty basis points when the interest rate on long-term Treasury bonds declines by one hundred basis points. These data suggest that

[8] The t-statistics are shown in parentheses.

the ROE Formula, which assumes that the cost of equity declines by eighty basis points when the yield to maturity on long Canada bonds declines by one hundred basis points, is not appropriate for estimating the cost of equity.

Using the November 2011 forecast 3.06 percent yield to maturity on long-term Canada bonds obtained from Consensus Economics, the regression equation produces an ex ante risk premium equal to 7.67 percent (10.4 – .892 x 3.06 = 7.67).

As described above, my ex ante risk premium regression analysis indicates that the cost of equity for utilities is significantly less sensitive to interest rate changes than the ROE Formula implies. Rather than declining by eighty basis points when the yield to maturity on long-term government bonds declines by one hundred basis points, my analysis indicates that the cost of equity declines by significantly less than fifty basis points when interest rates decline by one hundred basis points.

TABLE 1
MOODY'S ELECTRIC UTILITIES

American Electric Power
Constellation Energy
Progress Energy
CH Energy Group
Cinergy Corp.
Consolidated Edison Inc.
DPL Inc.
DTE Energy Co.
Dominion Resources Inc.
Duke Energy Corp.
Energy East Corp.
FirstEnergy Corp.
Reliant Energy Inc.
IDACORP. Inc.
IPALCO Enterprises Inc.
NiSource Inc.
OGE Energy Corp.
Exelon Corp.
PPL Corp.
Potomac Electric Power Co.
Public Service Enterprise Group
Southern Company
Teco Energy Inc.
Xcel Energy Inc.

Source of data: *Mergent Public Utility Manual*, August 2002. Of these twenty-four companies, I do not include utilities in my ex ante risk premium analysis in the months in which there are insufficient data to perform a DCF analysis. In addition, since the beginning period of my study, several companies have disappeared through mergers and acquisitions.