

Alberta Energy And Utilities Board

ATCO Electric

2003 2005 General Tariff Application

Application No. 1275494

Written Evidence Of John McCormick

on Behalf of

the City of Calgary

February 18, 2003

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1 **Q.1 Please state your name, business address and occupation?**

2 A My name is John D. McCormick, and my business address is Suite 920, 910
3 7th Avenue South West, Calgary, Alberta. I am a financial consultant and
4 President of J. D. McCormick Financial Services, Inc. A description of my
5 professional qualifications is found in Attachment 1.

6 **Q.2 What is the purpose of your evidence at this proceeding?**

7 A The City of Calgary has requested that I provide my views with respect to rate of
8 return and capital structure that ATCO Electric seeks in this application for its
9 Transmission segment.

10 **Q.3 Was the evidence prepared by you or under your direct supervision and**
11 **control?**

12 A Yes.

13 **Q.4 How is your evidence organized?**

14 A I have divided my evidence into two parts. In the first part, I offer observations
15 on ATCO Electric's applied for equity return and capital structure for its
16 Transmission segment as compared to financial market requirements, and the
17 financial performance of utilities which have equity returns set by an adjustment
18 formula. In the second part, I reply to several statements in the materials filed in
19 this application with respect to the proposed capital structure, methodology and
20 changes in the financial markets.

21 **Q.5 Please summarize your conclusions.**

22 A The combination of the 11% equity return applied for and the 35% to 40%
23 common equity ratio appear to be in excess of the current requirements of the
24 financial markets, relative to the markets' perception of the underlying business
25 risk of the Transmission segment.

1 A more appropriate equity return would be one derived from a formula similar to
2 those used by the National Energy Board (“NEB”)¹ or the British Columbia
3 Utilities Commission (“BCUC”)², adjusted to recognize the shares of companies,
4 which are the owners of most regulated utilities subject to those formulas, are
5 trading at substantial premiums to the underlying book values.

6 The proposed capital structure places an unnecessary burden on the ratepayer as
7 the equity layer increases beyond that which was approved by this Board (the
8 “AEUB” of the “Board”) in Decision U99099 for stand alone Transmission
9 utilities.³

10 **Part I**

11 **Q.6 What facts do you rely on to support this conclusion?**

12 A The best evidence of the appropriateness of the current equity return
13 resulting from these adjustment mechanisms and the allowed capital structures is
14 found in the trading prices of the shares of the companies which are the owners of
15 the utilities that earn the returns allowed by these formula. The common shares of
16 TransCanada, the public entity that investors must buy to participate in owning
17 the Mainline and the BC System⁴, are trading at a material premium to book
18 value.⁵ The common shares of BC Gas Inc., the public entity that investors must

¹ The RH-2-94 Decision, which established the NEB adjustment mechanism, covered Alberta Natural Gas Company Ltd, Foothills Pipe Lines Ltd., TransCanada Pipelines Ltd., Trans Mountain Pipe Line Company Ltd., Trans Quebec & Maritimes Pipeline Inc. and Westcoast Energy Inc. From time to time, certain of these pipelines have entered into negotiated settlements with their shippers and returns under those negotiated settlements may vary from that determined under the adjustment mechanism.

² The June 10, 1994 Decision of the British Columbia Utilities Commission on “Return on Common Equity” covered BC Gas Utility Ltd., Pacific Northern Gas Ltd. and West Kootenay Power Ltd. The return for Centra Gas Fort St. John was also determined to be the average of the ROEs allowed to BC Gas and PNG. See page 35.

³ In Decision U99099, the Board determined that a 35% equity layer was appropriate for TransAlta Transco. See page 264 of the Decision.

⁴ TransCanada’s BC System is the former Alberta Natural Gas.

⁵ As at September 30, 2002, TransCanada shares were trading at 1.91 times book value. Since December 1995, calculated on a quarterly basis, the shares of TransCanada have traded at an average 1.64 times book value. During that period the low was 1.02 times book, which occurred at March 2000, following an announcement of a dividend cut and multimillion after tax write down of certain unregulated assets. The high was 2.10 times book value.

1 buy to participate in owning BC Gas Utility,⁶ Centra Gas British Columbia⁷ and
2 the Trans Mountain Pipe Line⁸, are trading at a material premium to book value⁹.
3 Although the corporate structure of Canadian Utilities is less weighted to
4 investments which enjoy the security of regulated returns than TransCanada, the
5 prices of its securities also support this view¹⁰. The common shares of Canadian
6 Utilities, the first public entity above ATCO Electric in the ownership chain that
7 investors could buy to participate in owning ATCO Electric, are trading at a
8 material premium to book value.¹¹

9 **Q.7 Why should we care whether utility holding companies are trading above**
10 **book?**

11 A While regulatory boards have many responsibilities, one of them might be
12 described as assuring the continued financial health of the utility. One of the tests
13 to be met in the process of awarding the utility an appropriate rate of return is the
14 capital attraction test¹². Real world current market data shows that capital is being
15 attracted to those companies as many utility holding companies in Canada are

⁶ The BCUC formula governs BC Gas Utility, but owing to the withdrawal of its 2002 application, the 2001 return on equity continued to apply in 2002. See the BC Gas 2002 Annual Information Form page 7.

⁷ Centra Gas British Columbia has negotiated an incentive regulatory arrangement which expires in 2002. See Order G-6-00.

⁸ Although Trans Mountain could be regulated under the NEB formula, since 1996 it has had a negotiated incentive toll settlement with its shippers. See the BC Gas 2002 Annual Information Form page 13.

⁹ As at September 30, 2002, BC Gas shares were trading at 2.03 times book value. In the last year, calculated on a quarterly basis, the shares of BC Gas have traded at an average of 1.84 times book value.

¹⁰ See CAL-ATCOGTA-125(a) in which ATCO Electric confirms the reply provided in CAL-AG-26(b) where ATCO Gas provides its calculation of the portion of assets that were subject to regulation for the period 1989 to 2001. For Canadian Utilities the portion of assets that were subject to regulation had fallen from a high of 97.23% in 1990 to 56.83% for 2001. For CU Inc. the portion of assets that were subject to regulation had fallen from a high of 99.99% in 1999 to 79.29% for 2001. In response to written questions by participants in RH-4-2001, TransCanada replied in ADOE 1.59 that the “unregulated business of TransCanada represents less than 10% of the total assets of the Company” and in CAPP 210, that the non-regulated businesses “do not have a material impact on TransCanada’s consolidated financial fundamentals.”

The directional importance of the change in the proportion of regulated investments can be inferred from the rating changes being applied to companies like TransAlta which have experienced a ratings reduction as the proportion of its regulated operations has declined. See also the DBRS Methodology in Rating Utilities, June 2002 in which the authors provide a general standard for Regulated, Mixed and Unregulated enterprises in which the debt capacity reduces from regulated to unregulated enterprises.

¹¹ As at September 30, 2002, Canadian Utilities shares were trading at approximately 1.95 times book value.

1 trading well above book, while earning a return on a large portion of those assets
2 which is generally calculated with reference to the book value of the rate base.

3 **Q.8 Is it correct to use the prices of securities of the publicly held parent of a**
4 **utility as a guide for determining whether the allowed return of the utility is**
5 **adequate in light of the business risks that the utility faces?**

6 A While the analysis would be easier with publicly traded stand-alone utilities,
7 important information can be drawn from the trading prices of the securities of
8 utility owners. Since TransCanada, the public entity which owns several NEB
9 regulated pipelines also owns other businesses, the view that we may obtain of the
10 required returns from the prices of securities is a little blurred by the inclusion of
11 those other businesses within the financing entity. Those other businesses have
12 included both regulated and unregulated¹³ businesses. To the extent that the other
13 regulated businesses have returns that move in parallel with the returns allowed
14 by the NEB formula, there is little blurring.¹⁴ To the extent that the proportion of
15 unregulated business increases relative to the regulated businesses and the
16 unregulated businesses have returns that vary from the returns allowed by the
17 NEB formula, there may be more blurring. Fortunately, the relative size of the
18 unregulated businesses within the financing entity has been reduced in recent
19 years.¹⁵ Share prices are the best evidence of the market reaction to TransCanada's
20 expected relative returns. Even Mr. Lackenbauer, one of TransCanada's capital
21 markets experts in the RH-4-2001 proceeding, testified that "the proxy for [the
22 mainline], which is not a perfect proxy, is the TransCanada common equity".¹⁶
23 While it would be ideal if the Mainline were in a separate financing vehicle so as

¹² *In British Columbia Electric Railway Company Limited vs. Public Utilities Commission of British Columbia*, 1960 SCR 837.

¹³ In response to written questions in RH-4-2001, TransCanada replied in ADOE 1.59, that the "unregulated business of TransCanada represents less than 10% of the total assets of the Company" and in CAPP 210, that the non-regulated businesses "do not have a material impact on TransCanada's consolidated financial fundamentals".

¹⁴ Certain of TransCanada's current pipeline investments were also part of the RH-2-94 decision, including Alberta Natural Gas Company Ltd, Foothills Pipe Lines Ltd., and Trans Quebec & Maritimes Pipeline Inc.

¹⁵ On December 23, 2002, TransCanada announced its participation in the purchase of certain nuclear generation assets in Ontario for a price of \$376 million.

¹⁶ RH-4-2001 Hearing Transcript February 28, 2002 at line 2073.

1 to remove any blurring, it remains the largest asset and is therefore a major driver
2 of TransCanada's results.

3 The same concepts apply to other companies, like BC Gas, where the major
4 portion of its financial results are related to its regulated utility businesses. The
5 relative importance of the regulated utility businesses will vary over time as each
6 corporation acquires¹⁷ and divests, but while the regulated utility businesses
7 remain a major portion of the business, their return on capital cannot help but be
8 reflected in the trading price of the shares.

9 Similarly, Canadian Utilities Limited holds both regulated and unregulated
10 investments and as such, consideration must be given to the changing risk
11 profile.¹⁸ The prospective returns of the unregulated business, the relative
12 proportion of regulated and unregulated businesses, and the capital structure of
13 each firm will also be of interest to prospective investors.

14 It is also noteworthy, that the NEB and BCUC formulas generate slightly different
15 returns. For 2002, the NEB formula provided a 9.53% return to the utilities
16 covered by its formula while the BCUC formula offered a 9.13% return to the low
17 risk benchmark utility¹⁹. For 2003, the comparative rates are 9.79% and 9.42%.
18 One of the factors giving rise to the difference is the cap on equity risk premium
19 that exists in the BCUC formula when the forecast yield on the long-term Canada
20 bond falls below 6%.

21 **Q.9 Surely the use of the prices of the utility holding company shares as a proxy**
22 **for the market required return on its regulated utility investment is a**

¹⁷ On November 19, 2002, BC Gas announced the acquisition of an interest in the Express Pipeline.

¹⁸ See CAL-ATCO GTA-125 (a) in which ATCO Electric confirms the reply provided to the similar question in CAL-AG-26(b) where ATCO Gas provides its calculation of the portion of assets that were subject to regulation for the period 1989 to 2001. For Canadian Utilities the portion of assets that were subject to regulation had fallen from a high of 97.23% in 1990 to 56.83% for 2001. For CU Inc. the portion of assets that were subject to regulation had fallen from a high of 99.99% in 1999 to 79.29% for 2001. See also FIRM-ATCOGTA-141(a).

¹⁹ BC Gas is the low risk benchmark utility, and the return on equity of other utilities covered by the formula will be slightly higher.

1 **violation of the stand-alone principle and a misapplication of the capital**
2 **attraction standard?**

3 A On the contrary, it is the use of the most obvious tool to arrive at a fair result.
4 TransCanada is arguing this point in its review and variance application in respect
5 of the RH-4-2001 decision, but there is no other route for an investor to supply
6 capital to the Mainline, in TransCanada's case, but through the public company.²⁰

7 In many proceedings, competing proponents of the mystical art of the
8 "comparable earnings" method and the "equity risk premium" method offer
9 complex analysis of corporate earnings, discount cash flows and select varying
10 time periods and geographical data sets²¹ to estimate long term equity risk
11 premiums and reach divergent conclusions as to the required utility rate of return.
12 Some of this evidence is apparently not perceived as helpful.²² In these debates
13 over the appropriate methods, I am reminded of the principle of "misdirection" in
14 magic²³ as the focus on method seems to overshadow the outcome of the process.
15 Those who would seek to misdirect regulators' attention may be hoping that those
16 regulators will not place emphasis on the real world current market data, which
17 shows many utility holding companies in Canada trading well above book while
18 earning a return on a large portion of those assets which is generally calculated
19 with reference to the book value of the rate base.

20 We should little wonder at the fact that so many regulators have approved an
21 adjustment formula when faced with differences between the company and
22 intervenor experts. Having heard sometimes repetitive testimony supporting a
23 range of recommended returns in each proceeding, and after making an award
24 within the ranges recommended by regulatory experts, regulators can see the
25 shares of the utilities trading at generous levels throughout the test period.

²⁰ See page 19 of the Application for Review and Variance, dated September 16, 2002.

²¹ The evidence filed in RH-4-2001 on behalf of TransCanada relied in large measure on U.S. data. TransCanada also proposed the use of the "ATWACC" method.

²² Decision 2001-96, page 57. See also page 27-1, lines 4 to 9 of the 2003/2005 General Tariff Application.

²³ Misdirection in magic is the practice of directing the attention of the audience away from the movement of the hand which is executing the trick and directing that attention toward some other object.

1 In this proceeding, and the ATCO Gas proceeding which precedes it in time, we
2 are being directed by the applicant to focus on a single table of bond spreads²⁴
3 rather than the market to book ratios of utility companies which are earning, in
4 part, formula generated returns below that which the applicant seeks.

5 **Q.10 Surely, the use of the comparable earnings and the equity risk premium**
6 **methods are enshrined in the legal precedents which establish the**
7 **responsibilities of the regulatory boards?**

8 A While this is primarily a legal question, the *Hope Natural Gas* decision relates, in
9 the language of its day that, “the return to the equity owner should be
10 commensurate with the returns on investments in other enterprises having
11 corresponding risks. That return should be sufficient to assure confidence in the
12 financial integrity of the enterprise, so as to maintain its credit and to attract
13 capital.”²⁵ It seems a very reasonable test, but like much of life, the devil is in the
14 details. The difficult task is figuring out which companies have corresponding or
15 similar risk, but we should not lose sight of the goal which is the adequate return,
16 not the process of considering what earnings are comparable or the process of
17 determining the optimal data to support the calculation of an equity risk premium.
18 Certain of the proponents of the mystical art of the “comparable earnings” method
19 and the “equity risk premium” analysis strive to ignore the obvious. What is
20 obvious to me is that the common shares of utilities are generally trading at
21 market to book multiples well above one. It is also obvious that major
22 acquisitions of utilities are taking place by utilities and others at premiums to the
23 trading market prices which were already at a premium to book value.²⁶ There is
24 nothing quite like a takeover bid to demonstrate that capital is being attracted to
25 the rate base of a utility.

²⁴ The Table is found on page 27-3 of the 2003-2005 General Tariff Application.

²⁵ 320 U.S. page 591 at 603. This concept has been adopted in Canadian cases as well. At page 602, the decision also suggests that “it is the result reached not the method employed that is controlling.”

²⁶ Recent transactions include the Duke acquisition of Westcoast, the Enbridge acquisition of interests in Alliance and the BC Gas acquisition of Express Pipeline.

1 While we are discussing an adequate return on equity as the goal of the “capital
2 attraction” test, the November 2002, filing by TransCanada of a shelf prospectus
3 for \$2 billion in Canada, and \$1 billion in the United States, covering common
4 and preferred shares and debt, gives evidence to their need to attract capital in the
5 future. As equity tends to be more permanent capital, utilities are more frequent
6 issuers of debt. While much of this capital may go to ventures other than their
7 NEB regulated assets, there is a constant need to refinance maturing debt. It is the
8 equity return that helps underpin the debt obligations. In the absence of an equity
9 return, the interest coverage would approach one. In that regard, one might have
10 expected TransCanada and other companies regulated by the NEB formula to
11 have been restricted in recent years in their capital market access by the allegedly
12 low rates of equity return. For TransCanada, that appears not to have been the
13 case.²⁷

14 The senior debentures of TransCanada are and have been rated by DBRS as “A”
15 since July 1998. The medium term note debentures of BC Gas are rated by DBRS
16 as “A (low)”. The long term debt of BC Gas Utility is and has been rated by
17 DBRS as “A” since at least 1992. The senior debentures of Canadian Utilities are
18 rated as “A” by DBRS and “A+” by S&P. Debentures of each of these firms will
19 trade at spreads over the comparable government bonds of similar term within the
20 range that ebbs and flows as demand for credit changes over time.

21 **Q.11 Do you agree that ATCO Electric need be awarded an equity return of 11%**
22 **for its Transmission segment?²⁸**

23 A No, I do not. The ROE resulting from the NEB and BCUC adjustment
24 mechanisms appear to be well within the range of what the market requires. In
25 other words, they are generous. Assuming that its allowed capital structure is
26 appropriate to its business, the 11% equity return ATCO Electric seeks is
27 materially above the levels which the various adjustment mechanisms allow. The

²⁷ See RH-4-2001 proceeding transcript for February 27, 2001 at lines 820-1, where Mr. Girling of TransCanada replies to the question “When, since early 1999, have you been unable to raise debt on reasonable terms and conditions?” by saying “We haven’t been.”

1 2002 NEB formula calculation produced an allowed ROE of 9.53% and, for 2003,
2 a ROE of 9.79%²⁹. The BCUC formula produced an allowed ROE of 9.13% for
3 2002 and a ROE of 9.42% for 2003, in each case for a low risk benchmark
4 utility³⁰. Each of these formulas operate based on expected future bond rates. It is
5 clear that they did not result in allowed ROEs of 11% for 2003. Based on the
6 current interest rate conditions, it is unlikely that these mechanisms will generate
7 a rate approaching 11% for 2004³¹. A host of utilities are able to access the
8 capital markets with the ROEs generated by these adjustment mechanisms. In my
9 view, ATCO Electric has presented no realistic justification for its request for a
10 return of 11%, which is about 120 basis points over what is allowed to companies
11 regulated under the NEB adjustment mechanism.

12 **Q.12 Are there other utilities that have been awarded or negotiated an equity**
13 **return of 11%?**

14 A Yes, there are examples of utilities being awarded or negotiating returns of 11%
15 but when discussing historical awards or negotiations it is important to remember
16 the time or business context of that decision or agreement. While it is difficult to
17 extract the equity return allowed in a “black box” or package negotiation, there
18 are examples of negotiated returns of 11%. In Canada, the Alliance Pipeline is
19 allowed 11.3% on its 30% equity layer and in the U.S. it is allowed 10.7% ROE.³²
20 Maritimes & Northeast is allowed a 13% return on its 25% equity layer for its

²⁸ 2003-2005 General Tariff Application, Page 27-1, line 12.

²⁹ The 2003 NEB return on equity was announced December 5, 2002.

³⁰ For 2003, see letter L-46-02 dated November 21, 2002 and for 2002, see letter L-43-01 dated November 26, 2001.

³¹ Using the NEB formula, which is the more generous than the BCUC formula in periods of low interest rates, to arrive at an 11% ROE for 2004 or 2005, the 10-year forecast yield would need to rise from the 5.50% rate used in the 2002 calculation to approximately 7.12%, assuming that the 10 to 30 year spread is held constant at 48 basis points. To achieve an average 11% ROE for the years 2003 and 2004 under the NEB formula, similar to the return the applicant seeks, the 2004 return under the NEB formula would need to rise to approximately 12.2% which would require the 10-year forecast yield to rise approximately 322 basis points from the 5.50% rate used in the 2003 calculation to approximately 8.72%. At an interest rate of 12.2% the equity risk premium would be approximately 300 basis points. To average an 11% return over the 3 years, the average return under the NEB formula would need to rise to approximately 11.61% in each of the last 2 years, which would require the 10-year forecast yield to rise approximately 242 basis points from the 5.50% rate used in the calculation for 2003 to approximately 7.92% in each of the last 2 years. At an interest rate of 11.6% the equity risk premium would be approximately 320 basis points.

1 first 5 years ending in 2004.³³ These rates of return were determined in the
2 recognition that Alliance and Maritimes & Northeast were new pipelines facing
3 different risks and were negotiated in advance of the construction.

4 For the sake of contrast between the ATCO Electric' request for a 11% ROE, I
5 compared that request to the allowed returns of some local gas and electric
6 utilities and found that most had been awarded returns in the 9.375% to 10%
7 range³⁴.

8 **Q.13 Do you agree that there have been “significant changes in financial markets
9 since the equity risk premium was determined for 1996”³⁵?**

10 A It would be difficult to argue that there have not been significant changes in the
11 financial markets over the last few years. Investors are all too well aware of the
12 term ‘irrational exuberance’³⁶ and the disclosures surrounding the accounting at
13 Enron, WorldCom and Global Crossing. With all those changes, in some respects
14 we have returned to levels similar to the time when the hearing for Decision
15 U97065 occurred and the decision was released.³⁷ The TSE 300 index began
16 1996 at 4,768 and ranged through the year between 4,707 and 6,019, closing the
17 year at 5,927. In 1997, that index ranged from 5,679 to 7,210. The index hit a

³² Alliance Pipeline Limited Partnership, Bond Rating DBRS, June 28, 2002, page 3.

³³ Maritimes & Northeast Pipeline Limited Partnership, Bond Rating DBRS, August 26, 2002, page 3.

³⁴ While not intending to be exhaustive, in July 2002, the BCUC allowed PNG, which had applied to increase the risk premium spread over the benchmark rate, equity returns of 9.63% and 9.88% on segments of its operations. Gaz Metropolitan, which is the subject of an incentive arrangement, was awarded 9.67% for 2002 with an incentive of 0.02%. For 2002, Enbridge Consumers Gas was entitled to 9.66% under the OEB formula. There are awarded rates outside this range, an example of which would be Newfoundland Power which was awarded 9.05% for 2002. For 2003, Gaz Metropolitan was allowed a rate of 10.34%, including the 9.89% formula return and 0.45% incentive for expected productivity gains. Union Gas is under a multi-year performance based regulation arrangement. In FIRM-ATCOGTA-131, the applicant comments on the capital structures of certain of these firms.

³⁵ 2003-2005 General Tariff Application, Page 27-2, lines 12 to 13. The reference to 1996 appears to be to the U97065 decision in respect of ATCO Electric.

³⁶ While not necessarily the first use of the term, please see the remarks of Mr. Alan Greenspan on December 5, 1996, found at <http://www.federalreserve.gov/boarddocs/speeches/1996/19961205.htm>. While the applicant viewed the technology bubble as a “relatively short-term phenomenon” in CAL-AG-3(g), which the applicant confirmed in CAL-ATCOGTA-105(a), we note that the period during which Mr. Greenspan was expressing concern about “irrational exuberance” began contemporaneously with or before the 1996 period the applicant has used as its base for changes in financial markets.

1 high of 11,388.8 in 2001 and has since retreated to a level of approximately
2 5,635³⁸ as the renamed S&P/TSX composite index. On December 27, 2002, the
3 index had returned to 6,595. On February 10, 2003, the index closed down at
4 6,444. The performance graph in the Management Proxy Circular for Canadian
5 Utilities, dated March 8, 2002, gives us an indication of the relative performance
6 of the gas and electrical utilities subindex to the broader market³⁹. This period
7 witnessed a dramatic rise and fall in the prices of technology stocks which have
8 been described by some commentators as a bubble. During this period there has
9 also been a tremendous growth in the number of income funds and trusts listed on
10 Canadian stock exchanges.

11 On the debt side, investors will be well aware that interest rates have fallen. The
12 monthly data for Government of Canada marketable bonds over ten years⁴⁰
13 provided average yields during 1996 that ranged between 6.42% and 8.07%.
14 During 1997 they ranged from 5.78% and 7.07%. In 1998 they ranged between
15 5.08% and 5.78%, and the rate as at February 13, 2003 was 5.42%.

16 The monthly data for Government of Canada real return bonds⁴¹ provided yields
17 during 1996 that ranged between 3.97% and 4.99%. During 1997, they ranged
18 from 3.95% and 4.34%. In 1998 they ranged between 3.85% and 4.17%. In 2002,
19 the monthly low was 3.25% and the rate as at February 13, 2003 was 3.14%.

20 Having noted the “round trip” in the equity markets and the falling interest rates, I
21 must say that these changes in broad indices do not mean that I accept the
22 proposition that ATCO Electric’s transmission segment has been disadvantaged
23 by changes in the capital markets. In my view, these events do not provide

³⁷ The hearing closed in October 1996 at a time when the TSE 300 was in the 5,500 range about 14% below current levels, and the decision was issued in October 1997 at a time when the TSE 300 was in the 6,800 range about 6% above current levels.

³⁸ October 9, 2002 close.

³⁹ For the period December 1996 to December 2001 the gas and electrical utilities subindex is shown as outperforming the TSE 300 by a ratio of 174 to 140. The Management Proxy Circular for Canadian Utilities is incorporated into the record through CAL-ATCOGTA-111(c).

⁴⁰ Bank of Canada Series B14013 provides monthly data, series B114022 provides daily data. Using the monthly series slightly compresses the range for each year since highs and lows may occur on days other than the final day of the month.

1 sufficient support for the requested increase in the equity risk premium sought by
2 the applicant.

3 **Q.14 Is there other market information which you considered relevant to the issue**
4 **of required return on equity capital?**

5 A There are three areas of market information which I would like to like to add to
6 the record. These three are the increasing investor interest in income funds and
7 trusts, the reversal of the major gains earned by technology stocks in the last few
8 years, and, the implications arising from the recent acquisition activity involving
9 utilities.

10 The first aspect, that I thought relevant to the issue of required returns on equity
11 capital, was the growth in recent years in the market for trusts and income funds.
12 These securities pay out a high proportion of the cash flow generated by the
13 underlying assets, an amount which is often in excess of the income earned. As
14 such, for tax purposes the distribution can be, in part, a return of capital. At the
15 end of 1996, there were approximately 37 of these trusts and funds listed on the
16 TSE. By September 2002, there were approximately 137 listed on the TSX. The
17 market capitalization of the issued units of these trusts and funds had risen from
18 just over \$7 billion at the end of 1996 to just over \$39 billion by September 2002,
19 a compound annual growth rate of over 34%. The largest fund at the end of 1996
20 had a market capitalization of just over \$700 million. By September 2002, there
21 were three⁴² that each had over \$2 billion in market capital and the 4 largest trusts
22 or funds exceeded the total market capitalization of all the trusts which had
23 existed at the end of 1996. In these 69 months, over 110 new trusts or funds were
24 launched and while the process of bringing new trusts to market may slow, it does
25 not seem to have stopped.⁴³ Clearly, these investment vehicles attracted a great
26 deal of new capital in recent years.

⁴¹ Bank of Canada Series B14081 provides monthly data, series B114018 provides daily data.

⁴² The 3 largest trusts were Enerplus, Canadian Oil Sands and RioCan.

⁴³ During the same period, a number of funds or trusts were consolidated. In the month of October 2002, 2 of the 8 new listings on the Toronto Stock Exchange were income funds or trusts of some type. Of the 6 other new TSX listings in October, 3 were transfers from the TSX Venture Exchange. In the month of

1 The table below presents the return on average equity earned by certain funds
2 during 1998, for the last 12 months ending September 2002, and their recent
3 distribution yields.⁴⁴

Fund	1998 Return	Sept. 2002 Return	Yield
Algonquin Power Income Fund	3.5%	3.7%	10.0%
Clean Power Income Fund ⁴⁵		3.2%	9.8%
Great Lakes Hydro Income Fund ⁴⁶		8.2%	8.0%
Northland Power Income Fund	5.6%	8.2%	9.2%
Pembina Pipeline Income Fund	3.5%	7.7%	9.6%
Average	4.2%	6.2%	9.3%

4 While the earned return of each fund will vary based on a host of factors,
5 including business cycles and commodity prices, none of the funds in the table
6 above earned a return on equity equal to that sought by the applicant. None of
7 these funds pay a pre-tax yield, which includes a partial return of capital, equal to
8 the 11% after tax return sought by the applicant, and in some cases these
9 distributions are up to 85% currently taxable.⁴⁷ For the 12 months ended
10 September 30, 2002, these funds earned between 3.2% and 8.2%, in all cases less
11 than the 11% return sought by the applicant. Without earning the return which the
12 applicant seeks, many of these funds have been able to attract capital.⁴⁸

November 2002, 7 of the 12 new listings on the Toronto Stock Exchange were income funds or trusts of some type. Of the 5 other new TSX listings in November, 3 were transfers from the TSX Venture Exchange. See pages 5-9 of the TSE Review for October and pages 5-13 of the TSE Review for November. During December, 2 new funds were listed, and in the initial offerings each of underwriter groups exercised its over-allotment privilege to increase the issue size.

⁴⁴ The funds were listed in a recent National Post article “Betting on a Shrinking Resource”, and included all the power and pipeline funds listed therein having approximately 12 months operating history. The yield was calculated as the annualized value of the latest distribution divided by a mid day price on December 11, 2002.

⁴⁵ Clean Power Income Fund was established in October 2001.

⁴⁶ Great Lakes Hydro Income Fund was established in September 1999.

⁴⁷ By way of example, Pembina has indicated that approximately 85% of 2002 distributions will be taxable. In February 2003, Northland’s web site was estimating that 65% of its 2003 distributions would be taxable as business income, with 35% as a return of capital. Northland Power indicated in its third quarter report that it expects that approximately 50% of distributions will be tax deferred for 2002. In February 2003, Great Lakes Hydro’s web site was estimating that 60% of its distributions would be taxable as business income, with 40% as a return of capital and tax deferred. Algonquin Power has indicated the approximately 50% of its distributions will be taxable in both 2002 and 2003. For 2001 Algonquin noted only that approximately 71% of distributions were return of capital. Not all funds provide estimates of future tax deferral characteristics.

⁴⁸ The Algonquin Power Income Fund filed a prospectus for \$85.1 million in trust units in October 2002, filed a prospectus for \$75.2 million in trust units in October 2001, filed a prospectus for \$65.3 million in

1 If one were to assume that the market's required equity return was in the
2 neighborhood of the 11% after tax return sought by the applicant, or even the
3 9.4% to 9.8% returns currently allowed under the BCUC and NEB formulas, it
4 might follow that income trusts averaging a rate of return of approximately 6%
5 should be trading at a discount to book value. The table below sets out the market
6 to book ratio of each of the income funds in the table above, calculated using the
7 quarter end market prices. Clean Power, the most recently created income fund
8 which began trading in mid November 2001, is trading the closest to book value.
9 The market prices and the history of issues by these funds, in my opinion, make a
10 significant statement about the adequacy of single digit returns on equity in the
11 current market.

Fund	30-Dec-01	30-Mar-02	30-Jun-02	30-Sep-02
Algonquin Power Income Fund	1.3 x	1.2 x	1.2 x	1.3 x
Clean Power Income Fund	1.0 x	1.1 x	1.1 x	1.2 x
Great Lakes Hydro Income Fund	1.3 x	1.4 x	1.3 x	1.3 x
Northland Power Income Fund	1.5 x	1.4 x	1.5 x	1.5 x
Pembina Pipeline Income Fund	1.3 x	1.3 x	1.4 x	1.4 x
Average	1.3 x	1.3 x	1.3 x	1.3 x

12 **Q.15 Will you comment on the recent reversal of the major gains earned by**
13 **technology stocks, the second aspect which you considered relevant to the**
14 **issue of required return on equity capital?**

15 The second aspect that I thought relevant to the issue of required returns on equity
16 capital in recent years was the reversal of the major gains earned by technology

trust units in June 2001, and filed a prospectus for \$65.0 million in trust units in January 2001. In addition to prospectus offerings, Pembina established a Distribution Reinvestment Plan in January 2003. The Clean Power Income Fund filed a prospectus for \$75.5 million in subscription receipts for trust units in October 2002 and for \$187.9 million in trust units in November 2001. The Great Lakes Hydro Income Fund filed a prospectus for \$205.8 million in trust units in May 2002 and for \$141.4 million in trust units in December 2001. The Northland Power Income Fund a preliminary prospectus for \$65.0 million in trust units in February 2003. The Pembina Pipeline Income Fund filed a prospectus for \$87.5 million in trust units and \$87.5 million principal amount of convertible debentures in November 2001 and \$60 million principal amount of convertible debentures in March 2001. In addition to prospectus offerings, Pembina established a Distribution Reinvestment Plan in January 2003 and estimated that it would issue \$24 million in equity in 2003 under that plan. In addition to the power income funds listed in the table, the Boralex Power Income Fund filed a prospectus for \$250 million in trust units in February 2002, and the Calpine Power Income Fund filed a prospectus for \$230 million in trust units in August 2002. In some of the issues the demand was sufficient to allow the underwriters to exercise an over-allotment right. By way of example, as a result

1 stocks in the last few years. In short, the returns on information technology stocks
2 have been dismal. In October 2000, the TSX information technology index hit
3 levels in excess of 110. In October 2002, the same index fell to levels below 10.
4 Nortel may be the most famous Canadian example of the irrational exuberance
5 that some saw gripping the capital markets. In July 2000, its shares were trading
6 as high as \$123 and in October 2002 they had fallen to prices as low as \$0.69. In
7 August 2000, Nortel represented 34.59% of the TSE 300 index but by September
8 2002, it had fallen dramatically and represented only 0.53% of the S&P/TSX
9 composite index.

10 I believe that the poor returns on shares of companies in the technology sector is a
11 factor which makes the returns available under a formula similar to the NEB
12 adjustment mechanism quite attractive in the current market. The billions of
13 dollars attracted to the units of the various income funds and trusts, some of
14 which, as shown in the preceding tables, are not achieving the returns available
15 under formula similar to the NEB adjustment mechanism, confirms this view.

16 **Q.16 Can you comment on the implications of the purchase of several utilities at**
17 **material premiums to the underlying book value?**

18 A In recent months there have been a number of acquisitions of companies which
19 own regulated utilities and regulated utility assets. These acquisitions have taken
20 place at substantial premiums to the trading market of the shares of the utility
21 owners or the rate base of the utility assets. I believe paying a substantial
22 premium for rate base assets indicates that the return on those assets is in excess
23 of the then market requirement.

24 In March 2002, Duke acquired Westcoast committing approximately U.S. \$8.5
25 billion.⁴⁹ Duke's offer was a cash and share offer valued at approximately \$43.80.
26 The market for Westcoast's shares had been approximately \$36 prior to the offer.
27 Westcoast's major assets included, in addition to the NEB regulated utilities,

of the over-allotment being exercised, the Calpine issue achieved \$264 million proceeds, and the Algonquin Power issue of October 2002 closed with \$98.5 million gross proceeds.

1 interests in the Alliance Pipeline, Union Gas and Centra Gas, and a number of
2 power generation projects. I was interested in comparing the proposition that the
3 applicant's calculation of widening spreads in utility bonds justified an 11% after
4 tax return equity⁵⁰ with the action by Duke in committing U.S. \$8.5 billion in the
5 purchase of Westcoast. Since Westcoast, in the absence of a negotiated settlement
6 involving a higher or incentive rate of return, is saddled with the apparently
7 inadequate NEB adjustment mechanism and ROE, I could not believe that the
8 synergies and returns on other aspects of their business outweigh the
9 comparatively⁵¹ low rate of return on Westcoast's NEB regulated pipeline
10 investments, which Duke will acquire as part of the purchase.

11 In November 2002, BC Gas acquired a one-third interest in the Express Pipeline
12 for consideration of approximately \$200 million⁵². In its November 20, 2002
13 conference call, the officers of BC Gas declined to provide a rate of return on
14 equity when asked to do so by one analyst. They noted that they anticipated
15 earning \$12 million in 2003 from the investment, operating management fees and
16 certain tax benefits which were described as "significant". As such, the return on
17 equity for 2003 appears to be approximately 6% or less. This return is based on
18 the full through-put volumes which were supported by a commitment of the
19 vendor to continue to ship volumes above committed capacity for a minimum of
20 two years.

21 In support of the acquisition, BC Gas offered 5.3 million shares to the market at a
22 price of \$38.00.⁵³

⁴⁹ The consideration was originally set out in a September 20, 2001 press release.

⁵⁰ 2003-2005 General Tariff Application, Pages 27-2 to 27-3. Comments on the applicant's manner of calculation of the spreads appear later in this document.

⁵¹ For clarity, the intended comparison is between the NEB rate and the rate sought by the applicant in this proceeding.

⁵² The November 19, 2002, press release reported "The consortium is paying approximately Can \$1,175 million for the Express Pipeline System, including assumed debt of approximately Can \$582 million".

⁵³ On December 3, 2002, BC Gas filed a prospectus for an issue of \$201.4 million of common shares. They had also undertaken a private placement of approximately \$100 of common shares on the same terms to assist in the financing of the Express pipeline purchase. In November 2001, BC Gas filed a prospectus for \$188 million of Subscription Receipts for common shares.

1 In our own province we have seen the recent AltaLink acquisition of TransAlta
2 distribution assets⁵⁴. In that transaction, AltaLink paid a premium of
3 approximately \$200 million for rate base assets of approximately \$644 million.
4 While we do not currently have an adjustment mechanism determining the return
5 on equity for Alberta utilities⁵⁵, AltaLink must have been aware of the recent
6 public record of decisions of the AEUB setting returns on equity⁵⁶. AltaLink is in
7 the process of applying for AEUB approval of its rates.⁵⁷

8 **Q.17 Isn't it the case that, under the NEB adjustment formula, equity risk**
9 **premiums increase as the interest rate expectation is reduced?**

10 A Yes, as the table below shows, the equity risk premium increases as the
11 expectation of interest rates is reduced. From a 3.30% equity risk premium in
12 1996, the 2002 equity risk premium increased 60 basis points to 3.90% as the long
13 Canada forecast yield fell 240 basis points from 8.03% to 5.63%. Effectively, the
14 equity risk premium allowed under the NEB formula increases by about 25% of
15 the amount of the decrease in forecast interest rates.

		1995	1996	1997	1998	1999	2000	2001	2002	2003
Unadjusted ROE for prior year ⁵⁸	A	12.25	11.34	10.67	10.21	9.58	9.90	9.61	9.53	
Long-term 30 Year forecast bond yield prior	B	9.25	8.03	7.14	6.53	5.69	6.12	5.73	5.63	
Average forecast yield 10 year Canadas [Consensus]	C	7.60	6.50	5.95	5.25	6.00	5.85	5.15	5.50	
Average yield diff. Between 10 an 30 year Canadas	D	0.43	0.64	0.58	0.44	0.12	-0.12	0.48	0.48	
Long Canadas 30 Year forecast yield (C+D)	E	9.25	8.03	7.14	6.53	5.69	6.12	5.73	5.63	5.98
Diff. Forecast Long Canadas yield (E-B)	F	-1.22	-0.89	-0.61	-0.84	0.43	-0.39	-0.10	0.35	
Interest Rates and Equity Risk Premium Adjustment (.75*F)	G	-0.92	-0.67	-0.46	-0.63	0.32	-0.29	-0.08	0.26	
Unadjusted ROE for current year (G+A)	H	12.25	11.33	10.67	10.21	9.58	9.90	9.61	9.53	9.79
Rounding to the nearest 25 basis point until 1997			11.25							
Resulting Equity Risk Premium (H-E)	I	3.00	3.30	3.53	3.68	3.89	3.78	3.88	3.90	3.81

16 Under the NEB formula, the maximum equity risk premium would be 5.31%
17 which would occur when interest rates fell to 0% and the minimum equity risk

⁵⁴ The transaction was announced in July 2001 and received regulatory approval in March 2002.

⁵⁵ A hearing on that matter is contemplated.

⁵⁶ These decisions would include the 2000-9 Decision which determined a return on equity of 9.375%, and U99099 (see page 328) which approved a range from 9% to 9.5%.

⁵⁷ In Application No. 1279345, AltaLink has sought a return on equity of 10.75%.

⁵⁸ The difference between 11.33% in line H for 1996 and 11.34% in line A for 1997 was rounding recognized in a later press release.

1 premium of 0% would occur with the interest rates forecast to achieve a rate of
2 21.24%.

3 For comparison, the BCUC formula caps the equity risk premium at 350 basis
4 points for returns derived from forecast interest rates below 6%⁵⁹.

5 **Part II**

6 **Q.18 Isn't the methodology⁶⁰ proposed by ATCO Electric similar to the method**
7 **used by the NEB in its adjustment mechanism?**

8 A The methodology is both similar and different. The NEB began with a starting
9 period and estimated a forward bond yield and established an equity risk premium
10 at that time which was intended to apply going forward for an indefinite period⁶¹
11 subject to annual adjustments. In subsequent years, the equity risk premium
12 changes inversely by 25% of the change in interest rates in an estimate of a 30-
13 year Canada bond and the overall equity return varies by 75% of the change in the
14 estimated 30-year yield. The NEB estimate of the 30-year Canada bond is
15 derived from a published 10-year Canada forecast and the then current spread
16 between 10-year and 30-year Canada bonds. The return on equity is the revised
17 equity risk premium plus the estimated 30-year Canada bond yield. ATCO
18 Electric looks back and identifies a Board decision when it approves of the
19 allowed equity risk premium in the context of the then bond rates and compares
20 the average interest rates achieved on Canada and Utility bonds based on month
21 end data going forward. They recommend adjusting the 2003/2004 equity risk
22 premium by an amount equal to the whole change in interest spreads from the
23 initial period, rather than the factor used in the NEB formula. Finally, ATCO
24 Electric derives their estimate of the 30-year Canada bond from a published 10-
25 year Canada forecast and adds the "normal spread" between 10-year and 30-year

⁵⁹ See page 24 of the August 26, 1999 Decision of the BCUC, "Return on Common Equity for a Benchmark Utility".

⁶⁰ 2003-2005 General Tariff Application, pages 27-2 and 27-3.

⁶¹ See page (ix) of the RH-2-94 Decision where the NEB did not set any time or interest rate boundaries on the adjustment mechanism.

1 Canada bonds. The return on equity derived by ATCO Electric is the revised
2 equity risk premium plus the estimated 30-year Canada bond yield.

3 While noting that the application proposing this methodology is only to apply to
4 the 2003/2005 years, I would offer two observations on its resiliency. Were it to
5 be proposed as a formula to cover a greater period of time, it would result in more
6 volatile changes in the equity risk premium due to the inclusion of the whole
7 change in interest rates rather than the factor used in the NEB formula. As actual
8 spreads can be either positive or negative and may vary from the norm materially,
9 using a “normal spread” will make the result less sensitive to current market
10 conditions.

11 **Q.19 Do you agree with the methodology⁶² used to support the 11% return on**
12 **common equity described in section 27 B?**

13 A No, I do not. The applicant has not addressed whether its base year 1996 was a
14 normal year⁶³ nor has it accounted for any variations in interest rates that arise
15 between the prevailing interest rates and spreads in the specific month in which
16 the Board heard evidence or delivered its decision and the averages for the year
17 1996.

18 The applicant has used annual averages of monthly Canada and Utility yields for
19 all but the last data point which is described as being of June 14, 2002.⁶⁴

20 The applicant wishes to determine its return on equity based on a Consensus
21 Forecast⁶⁵ interest rate. As forecasts are rarely achieved, the results more often
22 being higher or lower rather than right on the estimate, there may be some
23 variance between the then forecast and the achieved rate. Its analysis, though, is
24 premised on its calculation of the increasing difference in annual average of
25 achieved monthly Canada and Utility yields. The applicant has not explained

⁶² 2003-2005 General Tariff Application, pages 27-2 and 27-3.

⁶³ The extended table attached as BR-ATCOGTA-41 suggests that 1996-1997 period was the low point for Canada to utility bond spreads since 1975.

⁶⁴ See CAL-ATCOGTA-108(f).

⁶⁵ Recent Consensus Forecasts are attached to CAL-ATCOGTA-56.

1 whether the 7.5% Canada long term Bond rate for 1996 set out in the table on
2 page 27-3 was coincidentally equal to the forecast rate for 1996, similar to the
3 June 2002 Consensus Forecast rate of 6.10% upon which the applicant then builds
4 its calculation, or adjusted its calculation to address the variance in forecast and
5 achieved Canada rates to the allowed return on equity. In fact the risk free rate
6 put in evidence by the applicant's witness in the U97065 proceeding was 8%.⁶⁶

7 The applicant relies on A rated Utility bond yield data from one source⁶⁷, CBRS,
8 up to August 2000 and thereafter a second source, the *Globe and Mail*, without
9 demonstrating that the second source of data would have provided consistent
10 information for the earlier period. Calgary provided an opportunity for the
11 applicant to demonstrate the consistency of method in CAL-ATCOGTA-
12 108(g)(ii) in asking for an extension of data to January 1996. Being mindful that
13 the source of the data is Monday editions of the *Globe and Mail*⁶⁸, the applicant
14 replied "Neither ATCO Electric or Foster Associates **have access** to the data for
15 the sample identified in BR-ATCOGTA-42(a) prior to September 2000."

16 [Emphasis added.]

17 The applicant also relies upon the validity of the sample of bonds used to develop
18 the A rated utility debentures rate for September 2000 and thereafter, but it is not
19 clear the extent to which this sample has been biased upward by the exclusion of
20 shorter term bonds and the extent to which increased spreads within the sample
21 are the result of company specific events⁶⁹ such as downgrades⁷⁰ which may be
22 related to non-utility activities.

⁶⁶ See Decision U97065 page 239. At page 234, the Board chose to use a risk free rate based on long-term Canada bonds, in the range of 7.5% to 8% to which a spread of 25 to 50 basis points was added, resulting in a range of utility debt of 7.75% to 8.5%. It is important to remember that the decision in U97065 was rendered October 31, 1997. Applications were filed in late 1995, and after an attempt at a negotiated settlement, the matter was heard from July to October 1996.

⁶⁷ The Utility Bond yield data up to August 2000 is identified as CBRS data in BR-ATCOGTA-42(a). While the subsequent data is described as being drawn from a Foster Associates data base extracted from information published in certain Monday editions of the *Globe and Mail*.

⁶⁸ See CAL-ATCOGTA-108(c)(v).

⁶⁹ Although CAL-ATCOGTA-108(c)(iv) requested the data points used in the Utility debenture data, a similar question in the ATCO Gas proceeding, CAL-AG-6, elicited a broader reply. While the increase in yields quoted in CAL-AG-6(a2) for issues existing from September 2000 to October 2002 averages 38

1 Prior to September 2000, the utility bond sample is a CBRS A rated utility group.
2 In BR-ATCOGTA-42(a) we see that 4 of the 20 bonds and 4 of the 10 issuers in
3 the sample are described as being rated BBB+ in November 2002.
4 The utility bond sample subsequent to August 2000 excludes a number of issuers
5 which would have met the applicant's criteria for inclusion set out in CAL-
6 ATCOGTA-108(d)(iv), "Utility issues were viewed as eligible if they were rated
7 A by either rating agency."⁷¹ Effectively, the Utility Bond series developed by the
8 applicant is closer to a "benchmark" series, since only a few bonds were included
9 in that sample, while the Canada series is an un-weighted average of the
10 preponderance of all Canadian government bonds over 10 years⁷².

basis points per issue, the change was not universal. The three Enbridge Consumers Gas issues traded at marginally lower rather than higher yields. Two issues, EPCOR and TransAlta, each of which have been downgraded to BBB+ by S&P and for that reason should not be included in the A utility sample, accounted for 251 of the aggregate 643 net basis point change, approximately 39%. Including the other two issues that were downgraded, BC Gas Utility and Nova Scotia Power, accounts for 333 of the total 643 basis point change, approximately 52%.

⁷⁰ For the 10 issuers identified in BR-ATCOGTA-42(a) there were downgrades by DBRS in respect of two and downgrades by S&P in respect of eight. S&P increased the ratings of Westcoast and Union Gas. TransAlta was downgraded 2 rating categories from A(high) to A(low) by DBRS and 3 rating categories from A+ to BBB+ by S&P. At November 2002, four of the 10 issuers in the table had split ratings with one rating in a BBB category while at the beginning all were A rated by both rating agencies. In CAL-ATCOGTA-134(a) and BR-ATCOGTA-44(f) the applicant supplies data with respect to changes in spread between various A rating categories which would explain, in part, the increasing spreads over Canada bonds of the 8 firms downgraded by S&P.

⁷¹ While not intending to provide a complete list of A rated utility issues omitted from the ATCO Gas data, S&P rated Canadian Utilities, CU Inc., Hydro One, Maritime Electric, Newfoundland Power and Nova Gas Transmission in the A category at year end. DBRS in addition, as at December 27, 2002, rated certain of the debt instruments of the following issuers within the A rating category: Alliance Pipeline A(low); Aquila Networks Canada (Alberta) A; Caribbean Utilities A(low); Express Pipeline A(low); Maritimes & Northeast Pipeline A; Trans Mountain Pipe Line A(low). Yields on bonds of various terms greater than 10 years for Alliance Pipeline and Maritimes & Northeast Pipeline appeared in the Globe and Mail issue of Monday, October 28, 2002. While these issuers may have a split rating currently, at some prior period they may have been downgraded by CBRS/S&P and prior thereto would have properly fit within a CBRS/S&P "A" bond rating group. Since ATCO Electric was apparently attempting to extend a data series which was an average of 10, 20 and 30-year term bond yields over a period of time, the selection of appropriate bonds to estimate each of the 10, 20 and 30 year terms would exclude, at various times, the issuers for which trading information or bonds of appropriate maturities were unavailable, but should include bonds of a term less than 25 years.

⁷² Real Return Bonds are some of the few bonds excluded from the B14013 series. Government of Canada marketable bond series like B14013, are unweighted arithmetic averages of the yields on all direct debt payable in Canadian dollars with the exception of Canada Savings Bonds, Real Return Bonds and, in some cases, extendible issues.

1 The applicant has assumed that as spreads increase between mismatched series of
2 Canada and utility bonds, so too must the equity risk premium, basis point for
3 basis point without providing support for that proposition. Neither the NEB nor
4 BCUC formula assumes one for one changes in equity risk premiums as the risk
5 free rate changes.

6 Finally, there is no proof offered as to the superiority of using the “normal
7 spread” between 10 and 30 year Canada bonds as opposed to the current market
8 spread, nor why it is appropriate to add a “normal spread” to a time specific
9 spread between Long Canadas and Utilities bonds⁷³.

10 **Q.20 Are you satisfied that the use of the U97065 decision concerning 1996 is the**
11 **appropriate starting point for the adjustment to the equity risk premium?**

12 A No, I am not. In focusing on the U97065 Decision, the applicant appears to
13 ignore the more recent U99099⁷⁴ and 2001-96⁷⁵ decisions which came to a similar
14 conclusion as to equity risk premiums at a time when this table shows wider bond
15 spreads more similar to the recent market. The applicant appears to have chosen
16 1996 in part due to it being nearly the low point in its calculation of the spread
17 between annual averages of long Canada bonds and the CBRS A utility series.⁷⁶
18 This methodology attempts to relate the decision with respect to equity risk
19 premium to annual averages which differ from the interest rates used in the
20 Board’s decisions. In that respect the applicant is trying to look back and put a
21 square peg in a round hole.

22 In my evidence in the ATCO Gas proceeding, to examine the resiliency of this
23 method, I suggested that we also look at how the ATCO method might have

⁷³ See CAL-ATCOGTA-109(c) and its reply.

⁷⁴ See page 327, Decision U99099, related to certain electrical utilities. “The Board notes that the risk free rate is some 200 basis points lower than the risk free rate in 1996. The Board is persuaded that the historical data relating to market equity risk premium to the risk free rate does not indicate there exists a significant variation in risk premium over the range of interest rates experienced since 1996. For the purposes of this Decision, the Board is not persuaded that it should reflect any inverse relationship between interest rates and the equity risk premium that may or may not exist when the risk free rate drops from 7.75% to 5.75%.”

⁷⁵ See page 59, Decision 2001-96 related to ATCO Gas, in which the Board established a forecast long Canada rate of 6% and an a rate of return on common equity implying an equity risk premium of 3.75%.

⁷⁶ See BR-ATCOGTA-41.

1 applied to the decision of the Board in E93004 concerning the 1992 and 1993
2 Canadian Western Natural Gas Fair Return hearing which also set the return on
3 equity. I repeat those comments here, because they demonstrate that the decisions
4 of the Board are made on company specific parameters, not the average bond
5 spreads of a group of utilities. The importance of using company specific
6 parameters should be clear in the admission that there are yield differences
7 between A(high) and A(low) company's bonds⁷⁷. The annual average of all A
8 rated utilities would obscure those differences potentially benefiting some and
9 penalizing others. These comments also point out importance of timing in
10 regulatory decisions. In some decisions, the record closes early in the test year. In
11 others, the record may not close until late in the period or even beyond⁷⁸.

12 The E93004 decision was issued in February 1993 after the filing of evidence in
13 April and May 1992, and a hearing in June 1992⁷⁹. The table below provides the

⁷⁷ See CAL-ATCOGTA-108(e). If the equity risk premium is based on the spread between Canada bonds and a sample of A rated Utility bonds is based on the annual average of month end yields of a sample of A companies ranging from A(high) to A(low), the equity risk premium will be affected by the ratings changes of the financing companies rather than the utilities which may be a portion of their businesses. The mix of A(high) to A(low) ratings may change over time related to factors independent of the utility operations. A change in the mix of companies in each rating category would alter the calculated equity risk premium determined under this method irrespective of the risk a particular company faced. In BR-ATCOGTA-44(f) we are given an indication of how important the mix of the various classes of A credits could be. In that reply, for 30-year term debt, the increased spread is indicated as 86 basis points between A(high) and A(low). In CAL-ATCOGTA-134(a) for 20-year term debt, the increased spread is indicated as 40 basis points between A(high) and A. CAL-ATCOGTA-134(a) did not request a spread for A to A(low).

⁷⁸ See page 65 of Decision 2000-9, "the Board is of the view that the appropriate risk-free rate related to long Canada bonds is 6.7 per cent for 1997 and 5.6 per cent for 1998. These yields are based on actuals for 1997 and the most current data available at the time of the proceeding." The 2000-9 decision concerning Canadian Western Natural Gas was issued after the first year of the test period. The Board did know the actual risk free rate for 1997 and had several months of actual 1998 results available to it. Neither of the values expressed in the table on page 27.3 for Long Canada bonds for 1997 and 1998 are the values on which the Board made its decision in 2000-9.

⁷⁹ See page 15, Decision E93004.

1 data for 1992 which would have been used to calculate the average for that year
2 that appears in BR-ATCOGTA-41.

	A Rated LT	10+ CDA BONDS	Spread
January-92	10.42	8.92	1.50
February-92	10.50	8.97	1.53
March-92	10.87	9.28	1.59
April-92	10.94	9.51	1.43
May-92	10.17	9.17	1.00
June-92	9.91	8.87	1.04
July-92	9.26	8.21	1.05
August-92	9.19	8.19	1.00
September-92	9.73	8.53	1.20
October-92	9.51	8.33	1.18
November-92	9.96	8.66	1.30
December-92	9.69	8.54	1.15
Average	10.01	8.77	1.25

3 While the numbers in the table above may be of historical interest, they are not
4 the numbers upon which the Board's decision was based, since about half of them
5 occurred after the hearing closed. So to subsequently attempt to relate the
6 Board's decision to some average for the year, as is the practice in the ATCO
7 method, is likely a flaw in logic. At the time of the E93004 hearing, the Board
8 identified the risk free rate as 9%.⁸⁰ None of the monthly A rated Utility yields,
9 nor the annual average for 1992, are 9%. The Board also noted that the Company
10 would be able to finance at 70 basis points over a 10-year Canada. The Board
11 reached its decision on company specific parameters, not the average annual yield
12 of A rated utility bonds. In reaching its determination of equity risk premium, the
13 Board allowed 325 basis points, allowing CWNG a return on equity of 12.25%.

14 We know the Board determined that the appropriate equity risk premium for 1992
15 was 325 basis points. Were the formula suggested by the applicant to have been
16 applied to the 1992 numbers, because the average 1992 spread is 125 basis points,
17 approximately 65 basis points greater than the applicant's 1996 base year's
18 spreads of approximately 60 basis points, we would need to increase the equity
19 risk premium granted in that year from the applicant's 1996 base year's 375 basis

⁸⁰ See page 232, Decision E93004 lines 1 through 3.

1 points to 440 basis points (375+65 basis points). The applicant's method is
2 driven solely by the change in spreads rather than the more complex relationships
3 between spreads and estimates of future risk free rates which are used in the NEB
4 and BCUC formulas. The applicant's method would provide an equity risk
5 premium approximately 115 basis points (440-325=115 basis points) greater than
6 that awarded by the Board for 1992. While readers may object to looking back,
7 the same 440 basis point equity risk premium result would be obtained in a future
8 year where the anticipated risk free rate was 9% and the A utility spreads were
9 125 basis points.

10 **Q.21 Do you have any observations on the interest rate data points which**
11 **appeared in the Table on page 27.3?**

12 A Yes, I believe that it has an inherent inconsistency which renders suspect the
13 conclusions that are based upon the data. In BR-ATCOGTA-42(a) the applicant
14 notes that for the period up to August 2000, the data in the Table was the average
15 of the "month-end yields on the 10-, 20- and 30-year A rated Utility Bond"⁸¹
16 using CBRS data. For September 2000⁸² and forward, the data represented the
17 month end yields of certain utility issues listed in BG-ATCOGTA-42(a)⁸³.
18 Unfortunately for consistency, the bonds used in the later part of the data contain
19 no 10 or 20-year issues,⁸⁴ do not represent the full spectrum of utility issuers⁸⁵ and

⁸¹ BR-ATCOGTA-42, response (a).

⁸² It was not clear to me why the CBRS published 10, 20 and 30 year A utility bond data for September 2000 was not used. Those rates were, respectively, 6.67%, 7.02% and 7.37%. They would average 7.02% while the data point for September 2000 in the CAL-AG-6(a2) table filed in the ATCO Gas proceeding is 7.09%.

⁸³ While the list presented in BG-ATCOGTA-42(a) may list bonds that were used in most of the months beginning in September 2000, the Enbridge 6/18/32, Gaz Met 10/30/30, and the Westcoast 3/20/31 bonds were not issued in September 2000 and for that reason could not have been part of the average in that month.

⁸⁴ In CAL-ATCOGTA-108(g)(i), the applicant notes that its data after August 2000 was based on maturities of 25 or more years. This restriction makes the comparability an issue and were it not employed, bonds such as the Consumers Gas 10.625% July 2012 the Hydro One 5.77% November 2012 and the Canadian Utilities 9.92% April 2022 maturities are examples of a bonds the maturity dates which could provide indications of the missing 20-year and 10-year data points. For a list of maturities, prepared by the applicant, of other instruments of those issuers listed in its BR-ATCOGTA-42(a) attachment please see CAL-ATCOGTA-108(h)(i). For other CU or CUL maturities see schedule 26-E-2.

1 exclude issues by the applicant’s financing affiliate. In CAL-ATCOGTA-
2 108(g)(i), we are advised that the data for “September 2000 to present is the
3 average yield for a **sample** of long-term **A-** rated issues (**25+years** to maturity)
4 maintained by Foster Associates.” [Emphasis added]. Several inconsistencies
5 with the two data groups are made clear with that statement. The first
6 inconsistency is that second group excludes the shorter term issues. With a
7 normally sloped yield curve, when averaging yields of utility bonds, excluding
8 shorter-term issues inflates both the result and the calculated spread off the long
9 Canada bond index. At September 2000, the then outstanding bonds in the then
10 sample in BR-ATCOGTA-42(a) spreadsheet have an average life of
11 approximately 27.6 years. By November 2002, the average life of the selected
12 bonds had fallen only to 25.9 years, as a result of the passage of time being partly
13 offset by the addition of three new 30-year issues.

14 The degree of upward bias that results from ignoring utility bonds of 10 and 20-
15 year maturities in the later part of the data will depend on the slope of the yield
16 curve, but the applicant gave us a partial indication of the “normal spread between
17 10 year and 30 year GOC Bonds” which was estimated at 30 basis points.⁸⁶
18 Another indication of the upward bias can be found in BR-ATCOGTA-44(f) in
19 which the applicant provides an estimate of the “new issue average spread
20 indications” for utility bonds over benchmark Canada bonds in the 10 and 30 year
21 terms. The 10-year term is presented as having a 35 to 48 basis point spread
22 advantage over the 30-year term depending on the category of the A rating on the
23 spread over Canada bonds.⁸⁷

24 The second inconsistency with the data before and after August 2000 is that
25 second group excludes some of the A issues, by virtue of the fact that the
26 subsequent data is drawn from “a **sample** of long-term **A-** rated issues”. By

⁸⁵ In addition to excluding bonds in the 10 to 20-year maturity range, the data for September 2000 and thereafter excludes the bonds used to finance the applicant. I believe that it is unlikely that the CBRS data would have excluded those bonds from consideration while they were rated within the A category.

⁸⁶ 2003-2005 General Tariff Application, Page 27-3, lines 12 to 13.

⁸⁷ See also CAL-ATCOGTA-134(a).

1 ignoring many of the A issues after August 2000, whether by choice of the
2 arbitrary 25 year minimum⁸⁸ or otherwise, the spreads between Canada bonds and
3 utility bonds may appear wider than they otherwise would. The applicant has
4 selected a few relatively long-term utility bonds to compare to an unweighted
5 average of most of the government of Canada issues over 10 years. Assuming a
6 normally sloping yield curve, one would expect the spreads to appear to widen
7 whenever you compare a group of 25 to 30-year bonds, to a group of 10 to 30-
8 year bonds.

9 In addition to the general concern related to the exclusion of shorter term issues,
10 the rational for the choice of particular bonds is not made clear. Certain issuers
11 have several issues while others have only one of those issues that might have
12 fallen within the 10 to 30 year scope of the CBRS series. In CAL-ATCOGTA-
13 108(h)(ii), we are told that while “no specific weightings were selected; however,
14 **an attempt was made to ensure** that the long-term issues of a broad spectrum of
15 A-rated utilities were represented, but **that the data for a single company did**
16 **not dominate.**” [Emphasis added] The principal amount of bonds for companies
17 in the sample ranges from \$97 million from one company to \$490 million from
18 another. Of the 10 identified corporate groups, the company or group with the
19 least principal represented 4% of the sample while the greatest represented 22%.

20 The utility bond data up to August 2000 is the CBRS A Utility series. During the
21 time it published that data, CBRS also published a BBB Utility series. As four of
22 the issuers were downgraded by S&P at various dates⁸⁹ between September 2000
23 and November 2002, I believe that it is unlikely, had that firm continued to
24 publish its bond yield data series, that they would have continued to include the
25 securities of those downgraded issuers in the “A” series. It appears that the

⁸⁸ In CAL-ATCOGTA-108(k), we were informed that the CU bonds were excluded from the determination of the continuation of a CBRS 10 to 30 year average since “None of the CU Inc. issues reported in the *Globe and Mail* at the time the A rated series was started in September 2000 had a maturity date of at least 2025.”

⁸⁹ CAL-ATCOGTA-108(g)(iii) notes the dates of the downgrades of four issuers. While they have apparently adjusted the average yield to remove the downgraded companies, this would increase the dominance of several of the few remaining companies.

1 applicant may agree with that conclusion, since it advises in CAL-ATCOGTA-
2 108(i) that “it is unlikely they [CBRS] would have included bonds they rated
3 below A-“ in an A bond data series.

4 In an attempt to quantify the upward bias of the ignoring shorter term issues and
5 including certain BBB rated issuers in the latter data, on October 1, 2002, I
6 accessed a data stream published by Bloomberg which estimated A and BBB
7 Utility bond yields. The table below compares the October 1, 2002, 10, 20 and 30
8 year indicated yields to the result calculated for September 30, 2002 in CAL-
9 ATCOGTA-108(g)(iii), suggesting an upward bias of approximately 74 basis
10 points.

	Term	A 1-Oct	BBB ⁹⁰ 1-Oct
Bloomberg	10	6.13	6.48
	20	6.61	7.30
	30	6.84	7.43
	average	6.53	7.07
Sept 02 schedule CAL-AATCOGTA-108(g)		<u>7.27</u>	
	variance	.74	

11 In a limited number of instances, when I compared the yield data to data available
12 from sources available to me, I found variances which may have been due to the
13 use of different pricing sources or method of calculation.

14 While over some time period the spreads between 10-year and 30-year Canada
15 bonds may average 30 basis points, the spread at any particular time may vary
16 from this norm. The CBRS Data for the month of March 2000⁹¹ would provide a
17 good case in point. The 10-year GOC bond showed a yield of 5.92% while the

⁹⁰ After reviewing the IR replies in the ATCO Gas application which in content were similar to the CAL-AL-6 and BR-ATCOGTA-42, on November 26, 2002, I examined the list of instruments used by Bloomberg to develop the BBB rated yields and noted that the list included the EPCOR June 2029 and the TransAlta October 2029 issues used in the Foster Associates A rated group.

⁹¹ In my evidence filed in the ATCO Gas proceeding I observed calculation errors in the applicant’s Canadian A Rated Utility Debenture yields, one of which was the March 2000 data point for the average of the 10, 20 and 30 year A utility bonds appearing in the CAL-AG-6(b) attachment. The applicant had calculated a 6.58% yield for March 2000. I calculated the data point to be 6.84% based on the respective 10, 20 and 30 year A utility bonds rates of 6.67%, 6.85% and 6.99%. ATCO Electric has now corrected this data point and, although not discussed in our earlier evidence, the August 1996 data point. The corrections contained in CAL-ATCOGTA-108(g)(i) would result in small differences in the values presented in the table on page 27-3.

1 30-year was shown at 5.74%. The spread at this date was negative. Negative
2 spreads can occur for a number of different reasons including market perceptions
3 of restriction of supply of bonds which can arise as a result of the then
4 expectations of government surplus reducing financing requirements.

5 **Q.22 Why are you concerned with adding a normal 10-year and 30-year spread to**
6 **the current market for forecast 10-year bond rate?**

7 A My concern with this method is that it accepts one element which is based in part
8 upon current market conditions and, rather than taking the currently observable
9 spread as is done in the NEB and BCUC formulas, then adds a normalized rate.
10 In the period the NEB has used its adjustment mechanism, the 10-year to 30-year
11 spreads have varied from -12 basis points to +64 basis points⁹². Applying a
12 normalized spread over those years would have altered the forecast of 30-year
13 Canadas by over 30 basis points, which does not seem to me to be particularly
14 responsive to the then current market conditions.

15 **Q.23 Do you agree that “significant changes in financial markets since the equity**
16 **risk premium was determined for 1996 ... indicate that an increase in the**
17 **equity risk premium is warranted”?**⁹³

18 A If the increase contemplated is sufficiently large so as to take the return to 11%,
19 no, I do not. In the table which earlier presented the NEB formula returns and
20 resulting equity risk premium, there is a small increase in the equity risk premium
21 caused by changing interest rates between 1996 and 2003. I am of the opinion
22 that the NEB adjustment formula results in a rate of return on equity that is well
23 within the market requirements. In other words, it is generous. The table below
24 sets out the market to book ratios for TransCanada, and for comparison Canadian
25 Utilities Limited, calculated based on year end financial statements and the year
26 end share prices. Other than the 1999 data point for TransCanada, one cannot
27 help but observe the market to book ratios are well over one. The 1999 data point

⁹² See line “D” in the table showing the calculation of the NEB return on equity, above.

⁹³ 2003-2005 General Tariff Application, Page 27-2, lines 12 to 14.

1 for TransCanada was affected by, among other things, \$700 million in write
2 downs related to its unregulated investments and a cut in the dividend which was
3 announced on December 8, 1999.

Market to Book	Dec-96	Dec-97	Dec-98	Dec-99	Dec-00	Dec-01	Mar-02	Jun-02	Sep-02
TCPL	1.6 x	2.0 x	1.9 x	1.2 x	1.6 x	1.7 x	1.9 x	2.0 x	1.9 x
CU	1.6 x	2.1 x	2.3 x	1.7 x	2.1 x	1.9 x	2.1 x	2.1 x	2.0 x
NEB ROE	11.25%	10.67%	10.21%	9.58%	9.90%	9.61%	9.53%	9.53%	9.53%
ERP	3.30%	3.53%	3.68%	3.89%	3.78%	3.88%	3.90%	3.90%	3.90%

4 Under the premise that a regulated utility must have the ability to access the
5 capital markets by offering an appropriate return that will allow it to finance at a
6 price that represents at least book value, the market to book ratios in the above
7 table appear to be well in excess of the minimum standard. Some small reduction
8 in the allowed ROEs would appear to be possible without endangering the
9 strength of the balance sheets of the utilities governed by the NEB formula.

10 In the RH-4-2001 proceeding, TransCanada made a similar argument⁹⁴ suggesting
11 that the changes in the competitive environment and financial markets warranted
12 an increase in their ROE. The NEB did not increase their ROE⁹⁵, apparently
13 rejecting that argument. Fortunately or unfortunately, the market recognizes the
14 changes to which companies are exposed in the stock price on a minute-by-minute
15 basis. TransCanada, the public entity which owns the Mainline, is followed by a
16 host of equity analysts,⁹⁶ several bond rating firms and thousands of investors⁹⁷
17 and potential investors, all of whom to some degree make up the “market” and
18 affect securities prices with their behavior. The “market” has been aware of the

⁹⁴ In the Additional Written Evidence of TransCanada PipeLines Limited, November 2001, filed in the RH-4-2001 proceeding, at Page 3 of 9, Answer 3, lines 3 to 5, TransCanada observed that “changes in the competitive environment, combined with developments in financial markets, warrant an increase in the fair return of the Mainline.”

⁹⁵ The NEB did allow an increase in the equity layer from 30% to 33%. See page 59 of the RH-4-2001 Decision.

⁹⁶ On December 26, 2002, the TransCanada web site showed 10 Canadian based and 2 US based analysts as providing research on TransCanada including, BMO Nesbitt Burns, CIBC World Markets, Credit Suisse First Boston, Edward Jones, FirstEnergy, Goldman Sachs, J. P. Morgan, National Bank Financial, Raymond James, RBC Capital Markets, Scotia Capital and UBS Warburg.

⁹⁷ Page 68 of the TransCanada annual report for 2001 shows 36,350 registered shareholders up from 30,758 in the prior year. Registered shareholders represent a fraction of the total shareholders since many shareholders will own their shares through accounts registered with an investment dealer.

1 development of other pipelines for years.⁹⁸ The “market” is made aware of the
2 economic, competitive and political developments and regulatory changes
3 through a host of communication options⁹⁹. The “market” is aware of the return to
4 which the Mainline is entitled under the adjustment mechanism and may
5 anticipate the result in advance of publication since the formulas are known.¹⁰⁰
6 The “market” is aware of a cornucopia of alternative investment opportunities in
7 utilities and other industries in Canada and internationally and, with all this
8 knowledge, still awards TransCanada a large premium over its book value.
9 BC Gas is similarly well followed in the investment community.¹⁰¹
10 Canadian Utilities Limited is also followed by a number of equity analysts¹⁰²,
11 bond rating firms¹⁰³ and a host of investors and potential investors. The market
12 should be well aware of the transmission business of ATCO Electric through the
13 Canadian Utilities Limited public disclosure documents including its Annual
14 Information Form, Annual and Quarterly reports.

⁹⁸ In the RH-2-94 decision that gave rise to the current adjustment mechanism, the Board observed at page 8, that “TransCanada noted that it can no longer be viewed as a monopoly with respect to deliveries to eastern Canadian markets since it faces increased competition from alternative pipelines and supplies, including U.S.-sourced supply. TransCanada pointed out that eastern Canadian local distribution companies (“LDCs”) are diversifying their gas supply portfolios to include, in some cases, up to 30% U.S.-supplied gas and are proposing new pipeline facilities to connect their franchise areas with U.S. supply and storage facilities.”

Among other proposals, applications and decisions throughout the period, on July 3, 1997, Alliance Pipeline Ltd. applied for the necessary certificates and authorizations to construct the Alliance Pipeline which was authorized in decision GH-3-97 issued in November 1998.

⁹⁹ See page 27-9 of the application at lines 7 and 8.

¹⁰⁰ The NEB, on December 8, 2000, announced the approved rate of return on common equity of 9.61% for the year 2001, on December 6, 2001 announced the approved rate of return on common equity of 9.53% for the year 2002, and on December 5, 2002 announced the approved rate of return on common equity of 9.79% for the year 2003. Since the formulas are known, and as the inputs become known the results may be estimated and anticipated by market participants.

¹⁰¹ On December 11, 2002, the BC Gas web site showed 9 analysts as providing research on the firm including, BMO Nesbitt Burns, CIBC World Markets, Credit Suisse First Boston, Edward Jones, FirstEnergy, National Bank Financial, Raymond James, RBC Capital Markets and Scotia Capital.

¹⁰² Bloomberg, as of October 1, 2002, showed analyst coverage by BMO Nesbitt Burns, CIBC World Markets, Credit Suisse First Boston, Edward Jones, RBC Capital Markets, Raymond James, Scotia Capital.

¹⁰³ Canadian Utilities Limited is rated “A” and CU Inc. is rated “A(high)” by DBRS and S&P rates both companies “A+”. Ratings information is attached to BR-ATCOGTA-51 and FIRM-ATCOGTA-135 and referred to in the application at line 13 on page 27-14.

1 **Q.24 Do you agree that the business risk of ATCO Electric has materially**
2 **increased since 1993 as “evidenced by ... an increased risk of franchise**
3 **loss”¹⁰⁴?**

4 A. ATCO Electric’s franchise loss discussion appears to focus on the loss of
5 distribution franchises and for that reason this allegation of increased risk is of
6 little relevance to its Transmission segment. For that reason, I concluded that the
7 allegations of increase risk of loss of distribution franchises did not operate to
8 materially increase the risks of the Transmission segment.

9 Even if the loss of distribution franchises were material to the risks of the
10 Transmission segment, I did not view that risk as significant since the key issue
11 for me in the distribution franchise loss discussion is the price at which the
12 company is to be bought out by the relevant municipality. In my view the
13 analysis of the risk of franchise loss must start with the question “is there
14 harm”?¹⁰⁵ In my mind using the word “risk” to describe the probability of an
15 event that may not harm you is a misnomer. If the buyout price is at a price equal
16 to or greater than book, plus the cost of termination of redundant employees and
17 unbundling any debt financing [all on an after tax basis], I am hard pressed to
18 understand that the company would have suffered any significant harm¹⁰⁶.

¹⁰⁴ 2003-2005 General Tariff Application, Page 27-5 lines 17 to 19. See also BR-ATCOGTA-45 where the applicant refers to “forced sales” rather than less colorful terminology relating to the exercise of an option by a party to an agreement.

¹⁰⁵ CAL-ATCOGTA-116 sought information as to the quantification of franchise option prices and was advised that no formal analyses have been performed and that to do so would entail significant effort.

¹⁰⁶ A high price may represent an impediment from a purchaser’s point of view. On page 2 of the Airdrie letter to Grande Prairie which is partly attached to CAL-ATCOGTA-112(a), the author observes that in the event that the cost of purchase is “replacement of a system under existing development conditions ... , no municipality, or business for that matter, could make a business case to purchase its system.” While the applicant has not provided us with a numerical estimate of the purchase price for any of its individual franchises under the terms of the applicable agreements, if we assume that they are insuring the distribution assets for an amount approximately equal to the replacement cost, the insured values disclosed in FIRM-ATCOGTA-121 are 196% of book values, which may provide an estimate of the applicant’s view of the replacement cost. Were that representative of the values required under the purchase rights in the distribution franchise it would suggest that the applicant anticipates a material gain on the disposition of a franchise. The analysis notes a higher ratio to book for the insured value of Transmission assets to book value, and while explaining that this is due in part to some \$88 million in underground distribution lines, it is not clear whether that amount affects the numerator and the denominator or just the numerator of the fraction.

1 The public disclosure documentation¹⁰⁷ related to the distribution franchises shows
2 them to be long-term arrangements with the option exercise price to be set by the
3 regulator in the absence of a negotiated agreement¹⁰⁸. The applicant has suggested
4 that the “traditional method of valuation is based on Reconstruction New less
5 Depreciation”¹⁰⁹, although no source for this contention was offered, perhaps
6 because “ATCO Electric has never “lost” a franchise.”¹¹⁰ In the one case of a
7 franchise being lost in the last 30 years, it appears that ATCO Gas received an
8 amount greater than its book value. Although information requests¹¹¹ attempted to
9 have ATCO Electric demonstrate what would be the financial consequence of the
10 sale of some distribution franchise assets, the applicant did not provide a
11 quantitative reply. Considering the assertions of serious jeopardy of the loss of a
12 single franchise and the increasing importance of this matter, it is quite puzzling
13 to learn that the impact of the loss has not been quantitatively assessed.

14 I was interested in the contrast between the dire warning found in the application,
15 “the loss of a major franchise like Grande Prairie would challenge the viability of
16 the Company”,¹¹² with the proportion of total revenue and ATCO Electric
17 distribution rate base represented by Grande Prairie, which are respectively 7.9%
18 of distribution revenues and approximately 8% of distribution rate base.¹¹³
19 Distribution revenues and rate base are merely a portion of the company as a
20 whole.¹¹⁴ Clearly, the sale of any portion of the business would, to the extent not
21 mitigated by staff, cost reductions or the redeployment of the proceeds, require
22 some portion of the fixed or administrative costs to be allocated over a smaller

¹⁰⁷ See CAL-ATCOGTA-111 (b) & (c) which incorporate certain public disclosure documents into the record.

¹⁰⁸ See CAL-ATCOGTA-114 (c & d).

¹⁰⁹ See CAL-ATCOGTA-114 (d).

¹¹⁰ See CAL-ATCOGTA-115 (i-m).

¹¹¹ See CAL-ATCOGTA-116(b).

¹¹² See 2003-2005 General Tariff Application, page 27-7 at lines 24 and 25.

¹¹³ See CAL-ATCOGTA-116 (a).

¹¹⁴ Using the mid year rate base estimates for the mid year of the test period, 2004, the distribution rate base of \$759.1 million is approximately 49% of the total ATCO Electric transmission and distribution mid year rate base.

1 revenue base. That being said, to suggest that a sale for value, under an option¹¹⁵
2 that was one of the terms of the relevant contract, of 4% of the total distribution
3 and transmission rate base would challenge the company's viability seems to
4 suggest a much weaker entity than one with an equity layer over 35%¹¹⁶. The
5 warning attached to the sale of the Grande Prairie franchise seems puzzling
6 compared with the absence of concern arising out of the sale of the retail energy
7 business which must have generated some revenue to attract a purchase price
8 estimated to be \$128 million.¹¹⁷

9 **Q.25 Has Canadian Utilities Limited revised the disclosure in its Annual**
10 **Information Form to alert investors to the fact that business risk of ATCO**
11 **Electric has materially increased since 1993 as “evidenced by ... an increase**
12 **risk of franchise loss”¹¹⁸?**

13 A. Not materially. The applicant admits that the disclosure, to alert the capital
14 markets to the risk it alleges to exist in this application, has not been revised,
15 saying “There has been no material change in the AIF disclosure related to
16 franchises over the period 1990 to 2001.”¹¹⁹ Given the claim of a threat to “the
17 viability of the Company”¹²⁰ and the continuous disclosure obligations placed on a
18 public company, this is puzzling.

19 **Q.26 Do you agree that the business risk of ATCO Electric has materially**
20 **increased since 1993 as “evidenced by ... the investors’ perception of the**
21 **Alberta regulatory environment”¹²¹?**

22 A. No. In some respects this is one of the more puzzling aspects of the application.
23 While this topic is second to the distribution franchise renewal risk in section 27,

¹¹⁵ In CAL-ATCOGTA-116(f) the applicant confirms that “including an option to purchase an asset in a contract” is not exceptional in commerce.

¹¹⁶ In BR-ATCOGTA-45, “The loss of franchises for any utility challenges the ongoing viability of that utility.”

¹¹⁷ The December 10, 2002 press release by the ATCO Group refers to the estimated consideration. Page 1-2 of the application and BR-ATCOGTA-1 and 2 refer to the pending sale.

¹¹⁸ 2003-2005 General Tariff Application, Page 27-5 lines 17 to 19.

¹¹⁹ See CAL-ATCOGTA-115 (h).

¹²⁰ 2003-2005 General Tariff Application, Page 27-7 lines 24 and 25.

¹²¹ 2003-2005 General Tariff Application, Page 27-5 lines 17 to 19.

1 it requires over 5 pages where distribution franchise risk was covered in about 3
2 pages. Generally written in a conditional tense, we are advised of the “potential”
3 of investors forming a negative conclusion on the Alberta regulatory environment
4 “whether this conclusion is based upon facts is irrelevant”.¹²² For all the worry
5 over the potential of investors reaching negative conclusions, the actual
6 conclusions of investors are reflected in the share price of equities every day.
7 These investors still reward Canadian Utilities a handsome market to book ratio.

8 I do hope, though, that ATCO Electric will join me in urging the development of
9 an equity return adjustment formula for Alberta utilities so as to increase, in one
10 aspect, the relative certainty which investors would derive from such a decision.

11 **Q.27 Where do bond ratings fit within your analysis?**

12 A Bond ratings are one of many sources of information available to the market on an
13 issuer’s securities. Bond ratings provide the market with an independent
14 assessment or measure of the relative probability that the debt of the various
15 issuers will be repaid in accordance with the terms of the instruments. The rating
16 could be viewed as a proxy for an assessment of business risk and financing risk. I
17 do not believe that the opinions of bond rating agencies should drive the Canadian
18 regulatory process.

19 Bond rating does not appear to be an exact science. The ratings for individual
20 firms are developed through the individual judgment of those employed by the
21 various rating agencies. Consequently the changing and sometime divergent¹²³
22 judgments of bond raters, at any particular time, should not be the sole driver of
23 the allowed return for a regulated utility, and in my view, are no substitute for the
24 views of the regulator. This is particularly true when the financing entity is also
25 financing assets beyond those included in the rate base since the financing of

¹²² See 2003-2005 General Tariff Application, July 2002, page 27-10 line 1 and line 8.

¹²³ AltaLink has enjoyed an “A (high) rating from DBRS since July 2002, but it appears that S&P was unwilling to grant an “A-“ rating without AltaLink “securing its senior debt by granting a floating charge”. See paragraph 8 to the AltaLink financing approval application dated December 12, 2002.

1 those assets may affect the bond rating upon which the regulated entity will
2 market its bonds.

3 A company's debt instruments do not always trade in line with the bond rating.
4 As demand ebbs and flows, spreads will vary from those in the same rating
5 category. Spreads can widen out before downgrades occur because the debt
6 markets can respond more quickly to changes in circumstances than do the rating
7 agencies. Spreads can widen or narrow due to matters not directly related to the
8 credit quality of the specific company including anticipated financings and
9 anticipated shortages of new government bonds due to increasing government
10 surpluses.

11 **Q.28 What is more important an "A" rating or a 2.3 times¹²⁴ interest coverage**
12 **ratio?**

13 A Of the two, I would view the "A" rating as more important. However, neither of
14 those items, the rating or the interest coverage ratio, are as important as the
15 "market" reaction to the financial position of the company.

16 It is also clear that the various rating benchmarks, including interest coverage
17 ratios, "are not written in stone". I would observe that TransCanada has been able
18 to maintain an "A/A-" rating for a number of years without maintaining a 2 times
19 interest coverage ratio. Other issuers have been awarded an A rating by S&P
20 without meeting the benchmarks.

21 To propose a minimum interest coverage ratio target effectively makes the equity
22 return a function of the weighted average cost of the existing debt issues and the
23 current tax rate. The table below provides interest coverage numbers for a
24 simplified example of a 55.8% debt, 6.4% preferred equity and 37.8% common
25 equity capital structure using a 35.1% tax rate for a range of interest and equity

¹²⁴ In CAL-ATCOGTA-129 the lowest pre-tax interest coverage ratio for an "A" rated issuer with an S&P business position ranking of 2, is 2.3 times. See also BR-ATCOGTA-50 in which the applicant indicates that the business risk of transmission on the S&P rating scale would be between "1" and "2". In BR-ATCOGTA-44 the applicant provides calculations of interest coverage for ATCO Electric under several

1 return rates.¹²⁵ To maintain a 2.3 times interest coverage ratio as the imbedded
2 average debt costs increase from 7% to 14%, the after-tax equity return must
3 increase from approximately 70 basis points greater than the average imbedded
4 debt rate to 238 basis points greater than the average imbedded debt rate.

Rate Base	\$ 1,000		Pre Tax	Pre Tax
Tax Rate	35.1%	Rate	Rate	Return
Debt	55.8%	7.96%		\$ 44.42
Preferred	6.4%	6.09%	9.38%	\$ 6.01
Equity	37.8%	9.25%	14.25%	\$ 53.88
				\$ 104.30

Debt Rate	Interest Coverage						
	8.00%	9.00%	10.00%	11.00%	12.00%	13.00%	14.00%
7.0%	2.35	2.50	2.64	2.79	2.94	3.09	3.24
8.0%	2.18	2.31	2.44	2.57	2.70	2.83	2.96
9.0%	2.05	2.16	2.28	2.40	2.51	2.63	2.74
10.0%	1.94	2.05	2.15	2.26	2.36	2.46	2.57
11.0%	1.86	1.95	2.05	2.14	2.24	2.33	2.43
12.0%	1.79	1.87	1.96	2.05	2.13	2.22	2.31
13.0%	1.73	1.81	1.89	1.97	2.05	2.13	2.21
14.0%	1.67	1.75	1.82	1.90	1.97	2.05	2.12

5 **Q.29 Have you any observations on ATCO Electric's financing calendar?**

6 A Yes. For 2003, ATCO Electric advises that it will face the maturity of \$14.7
7 million principal amount of a 7.25% Debenture and anticipates issuing \$53
8 million 7% 20-year debenture. For 2004, ATCO Electric anticipates the
9 retirement of \$29.4 million 8.73% debenture and issue of \$80 million 7%
10 Debenture For 2005, ATCO Electric anticipates the retirement of \$38.2 million
11 8.43% debenture and issue of \$46million 7% 20-year debenture.¹²⁶
12 Recent financings by CU Inc. have been for shorter terms.¹²⁷ With only one issue
13 maturing between June 2011 and August 2019¹²⁸, the maturity calendar appears

approaches. In CAL-ATCOGTA-128, the applicant calculates interest coverage based on the BCUC and NEB allowed returns for 2003.

¹²⁵The tax rate was drawn from FIRM-ATCOGTA-139 for Transmission for 2004 and the capital structure numbers are from Schedule 26-E-1, ignoring no cost capital.

¹²⁶ 2003-2005 General Tariff Application, Section 26, page 26-5 lines 5 to 22. The principal of issues anticipated in CAL-ATCOGTA-134 (f-h) differ from that set out in Schedule 26-E-2.

¹²⁷ CU Inc. filed pricing supplements to its shelf prospectus for, \$175 million (5 year) debentures due November 2006 on October 31, 2001, \$50 million (5 year) debentures due November 2007, and \$150

1 open to shorter issues and the maturity curve would allow them to do a 10-year
2 bond which might save ratepayers between 50 and 70 basis points depending on
3 market conditions¹²⁹.

4 **Q.30 Is the 35-40%¹³⁰ Common Equity component of the capital structure**
5 **appropriate for ATCO Electric's Transmission segment?**

6 A The Board has not had to separately consider the appropriate common equity
7 component for ATCO Electric's Transmission segment as a result of the
8 negotiated settlement of many issues which would otherwise have been
9 considered as part of U99099. In that decision, the Board determined that a 35%
10 equity layer was appropriate for the transmission functions of the other utilities
11 before it¹³¹.

12 As I read the application, the major change in risk identified by the applicant is its
13 belief in the heightened possibility of the sale of one or more franchises at a
14 premium to going concern value, or as ATCO Electric puts it, the risk of franchise
15 loss has increased. As addressed above, I am hard pressed to see how the sale of
16 assets at prices above book, pursuant to the exercise of a contractual option,
17 places the company in grave jeopardy. More importantly, this risk would not
18 relate to the transmission segment.

19 Ignoring the ever-present worry that some investors may form conclusions not
20 supported by facts, the other major justification for the proposed increase in
21 equity layer appears to be the "requirement" for the applicant to do its share to

million (15 year) debentures due November 2017 on November 19, 2002. See also CAL-ATCOGTA-111(d).

¹²⁸ See Schedule 26-E-2 of the December 2002 Refiling.

¹²⁹ In CAL-ATCOGTA-134 the applicant estimated cost difference of 85 basis points between the 10 and 20 year maturity for an A(high) rated issuer, and 90 basis points for an A rated issuer. The applicant also confirmed, in part (c), that there is only one issue maturing between 2013 and 2018 and, in part (d), acknowledged the portfolio benefit of having staggered maturities. Using 10-year issues, rather than 20-year issues for the full \$179 million contemplated to be issued in Schedule 26-E-2 over the 3 year test period, assuming an 85 basis point saving would ultimately reduce the pre-tax interest burden by approximately \$1.5 million per year. The principal of issues anticipated in CAL-ATCOGTA-134 (f-h) differ from that set out in Schedule 26-E-2.

¹³⁰ 2003-2005 General Tariff Application, section 26, Page 26-3, line 12.

¹³¹ Decision U99099 at page 264 and 266.

1 maintain the current debt rating of its parents. The Standard and Poor's rating
2 outlook was revised for "ATCO Ltd. and subsidiaries Canadian Utilities Ltd and
3 CU Inc. to negative"¹³² on November 12, 2002. In that announcement, S&P
4 focused on the increase in "ATCO's business risk" including "growing
5 investments in nonregulated independent power ... growing merchant power
6 exposure ... and the growth of nonutility operations." S&P also noted "The
7 consolidated business risk profile of ATCO is supported by Alberta-based
8 regulated gas and electricity distribution and transmission operations, ...
9 Distribution businesses have virtually no exposure to market price and volume
10 risk, as they are permitted to flow through all electricity and natural gas supply
11 costs." While S&P has commented on what it perceives to be the relatively thin
12 equity layer allowed regulated Canadian utilities, the specific statements in the
13 November 12, 2002 S&P comment seem to me to demonstrate that the increasing
14 business risk is due to the "growth of nonutility operations". As such, it appears
15 that the transmission segment ATCO Electric is doing its share.

16 **Q.31 Will an adjustment mechanism work well in any circumstance?**

17 A Any system created by human beings suffers from limitations, and as such, there
18 may develop in the future a confluence of events in which the current adjustment
19 mechanisms used by the NEB and the BCUC would not provide an adequate
20 return for a regulated company. However, it seems clear to me that these
21 adjustment mechanisms have performed well for a number of years. TransCanada
22 has been able to access the capital markets on a reasonable basis. The high market
23 to book ratio currently enjoyed by TransCanada and BC Gas shareholders provide
24 tangible support for the view that these formulas continue to work well.

25 **Conclusion**

26 **Q.32 Please review your conclusions.**

27 A. The combination of the 11% equity return applied for and the 35% to 40%
28 common equity ratio appear to be in excess of the current requirements of the

¹³² See BR-ATCOGTA-51. See CAL-ATCOGTA-129 for the S&P targets of debt to total capital.

1 financial markets, relative to the markets' perception of the underlying business
2 risk of its Transmission segment.

3 A more appropriate equity return would be one derived from a formula similar to
4 those used by the NEB or the BCUC, adjusted to recognize the shares of
5 companies which are the owners of most regulated utilities subject to those
6 formulas are trading at substantial premiums to the underlying book values.

7 The proposed capital structure places an unnecessary burden on the ratepayer as
8 the equity layer increases beyond that which was approved by this Board in
9 Decision U99099 for stand alone Transmission utilities.

10 **Q.33 Before concluding, have you ever given evidence in a regulatory proceeding?**

11 A. Yes. I have appeared in two regulatory proceedings.

12 In 2001, I was retained by the Alberta Energy and Utilities Board as an
13 independent financial expert to give evidence at the 2000 Pool Price Deferral
14 Accounts Proceeding.¹³³ The 2000 Pool Price Deferral Accounts Proceeding was
15 convened to permit the AEUB to determine the amount payable to the owners of
16 six electrical distribution systems in respect of the prudent cost of financing of the
17 deferral accounts, which in aggregate were approximately \$632 million. Pursuant
18 to the relevant regulation, the prudent cost of financing of the deferral accounts
19 could include the costs of "debt financing, equity financing or a combination of
20 debt and equity financing."¹³⁴ My duties included, among other things, analysis of
21 the applications, and; filing a written submission on the prudent financing options,
22 cost of financing, impact of debt financing on capital structure and the impact of
23 the cost of financing for other corporate purposes.¹³⁵

24 In 2002, I filed evidence and appeared as a financial expert, having been retained
25 by the Canadian Association of Petroleum Producers ("CAPP") to give evidence

¹³³ See the various decisions related to the proceedings including Alberta Energy and Utilities Board Decision 2001-92. In addition to written evidence, Mr. McCormick was examined on July 27, 28, and 30, 2001.

¹³⁴ See section 4 of the Deferral Accounts Deficiency Correction Regulation, Alberta Regulation 240/2000.

1 in respect of the TransCanada Pipelines 2001 and 2002 Fair Return Application
2 heard before the NEB in proceeding RH-4-2001¹³⁶. The 2001 and 2002 Fair
3 Return Application Proceeding was convened to consider, among other things,
4 whether TransCanada's "currently-approved return, based on a deemed capital
5 structure of 30% common equity and the rate of return on common equity (ROE)
6 resulting from the RH-2-94 Formula"¹³⁷ was appropriate. My duties included,
7 among other things, analysis of the application, reviewing financial market data
8 with respect to TransCanada and certain companies and; filing a written
9 submission in which I concluded that the ROE adjustment mechanism had
10 performed well, allowing TransCanada to access the capital markets on a
11 reasonable basis.

12 In addition, I have filed evidence in respect of the AltaLink application number
13 1279345 and the ATCO Gas application number 1275466, which are currently
14 before the AEUB.

15 **Q.34 Is there anything else that you would like to add?**

16 A The first time I was a regulatory witness my wise counsel charged me to be as
17 helpful to the Board as I was able. It seemed a good rule. Being relatively new to
18 this regulatory world, I only read the cost order 2002-70 as I plowed through
19 some of the nearly 500 Information Requests filed in the ATCO Gas application.
20 I found that the Board's injunctions¹³⁸ to pose a significant challenge for any
21 witness but parallel with the first advice I was given in this area. As a result of
22 that advice and my first experience in answering a hoard of information requests,
23 I have attempted to footnote data sources relied upon. I would urge the Board to
24 encourage other parties to adopt this practice. In this case, the cost of capital

¹³⁵ Decision 2001-93, one of the decisions resulting from that proceeding, appears in the list of decisions cited by the applicant in CAL-ATCOGTA-119(a), which investors "may" view with concern.

¹³⁶ In addition to filing written evidence, Mr. McCormick was examined on March 19, 2002.

¹³⁷ RH-4-2001 Decision, page 1. In its decision, the NEB increased the Mainline's deemed common equity ratio to 33% from 30% and determined that the rate of return on common equity resulting from the RH-2-94 Decision should continue to apply. See pages 59 and 56. TransCanada filed an application for Review and Variance in respect of this decision dated September 16, 2002.

1 proposal by the applicant hinges on the data behind the table on page 27-3 and the
2 methodology used to analyze the perceived change. I spent a number of hours
3 attempting to identify the data sources and to determine whether we were dealing
4 with average or point-in-time data so that I might ask information requests that
5 touched the issue. The task was not rewarding since one of the data series
6 changed midstream and the final data points in both the Canada Bond and Utility
7 series appear to be a point-in-time data point,¹³⁹ where their predecessors were
8 averages of month-end data. I see that the Board and a number of the other
9 participants all chose, each in their own way, to ask about the data¹⁴⁰. Had the
10 data source been footnoted, work would have been saved.

11 **Q.35 Does this conclude your evidence?**

12 A Yes.

¹³⁸ The Board indicated that it wished the “best technical data” be available and preferred that it be filed earlier rather than later.

¹³⁹ See CAL-ATCOGTA-108(f).

¹⁴⁰ The Information requests on the data in the table on page 27-3 included, BR-ATCOGTA-41, BR-ATCOGTA-42, FIRM-ATCOGTA 127, LE/RD-ATCOGTA-4, CAL-ATCOGTA-106, and CAL-ATCOGTA-108.

ATTACHMENT 1

PROFESSIONAL QUALIFICATIONS OF JOHN D. McCORMICK

Academic Training

LL.B. from the University of Alberta (1978)
M.B.A. in Accounting from the University of Alberta (1975)
B.A. in Political Science, from the University of Calgary (1972)

Professional Organizations

Law Society of Alberta

Professional Experience

September 1975 - May 1978 - Sessional Lecturer for the Department of Accounting, the Faculty of Business Administration and Commerce, the University of Alberta

June 1978 - March 1983 – Barrister & Solicitor and Articling Student, Parlee, Irving, Henning, Mustard & Rodney, Edmonton

September 1980 - May 1982 - Sessional Lecturer (M.B.A. Tax) for the Department of Legal and Industrial Relations, the Faculty of Business Administration and Commerce, the University of Alberta

March 1983 - October 1991 – Associate rising to Vice-President and Director, ScotiaMcLeod, Toronto and Calgary

In this capacity, Mr. McCormick represented the firm in transactions ranging from small private placements to major financings including the initial public offerings of Telus and Petro-Canada. The transactions included the issuance of preferred and common shares, special warrants, rights, warrants, partnership units, and trust and royalty units . . . domestic deals and crossborder financings. He executed approximately \$5 billion of financing, wrote five trust deeds for major borrowers in the energy industry covering secured and unsecured obligations in the domestic and European markets, and assisted a major airline to renegotiate the terms of its convertible debentures with key financial institutions. In the utility area, he provided coverage of a number of western Canadian utility issuers including Nova, Alberta Natural Gas and Foothills Pipe Lines. He developed expertise in a number of industries including Canadian energy and petroleum services, pipelines, basic and specialty chemicals, airlines, pulp and forest products, telephone and telecommunications, and magnesium.

November 1991 – January 1994 – President, J. D. McCormick Financial Services, Inc., Calgary

January 1994 – January 1997 – Vice-President & Director, Levesque Beaubien Geoffrion, Calgary

In this capacity, Mr. McCormick was responsible for account coverage of over 125 account relationships in Alberta, British Columbia and Saskatchewan. He gained additional expertise in the banking, gold and satellite communications industries.

January 1997 – October 1997 – President, J. D. McCormick Financial Services, Inc., Calgary

October 1997 - May 1998 – Sprott Securities, Calgary

May 1998 – present – President, J. D. McCormick Financial Services, Inc., Calgary

In this capacity, Mr. McCormick secured and executed valuation and financial advice assignments with junior and senior public companies and government. He assisted a senior issuer in a securitization transaction. He provided financial advice with respect to the recapitalization of Sunoma and Barrington, which had over \$400 million in debt, fairness opinions to directors of TSE, CDNX and ASE listed companies. He provided financial advice in respect of several oil and gas industry merger and acquisition assignments, including advice to Tappit in respect of its attempted \$13 million hostile takeover of Backer, and expert testimony or reports in three securities cases in Alberta and Saskatchewan. Among other things, he was retained to provide, strategic advice with respect to several corporate reorganizations, a valuation of a U.S. corporation with equity valued at over \$200 million and strategic advice to its owner, advice in respect of a \$15 million equity financing, the negotiation of a long term joint venture, disposition of an oil services firm, and, advice in respect of software company concerning a private placement by a major industry partner.

Previous Expert Reports

Mr. McCormick was retained by the Alberta Energy and Utilities Board to give evidence at the 2000 Pool Price Deferral Accounts Proceeding, which resulted in Decision 2001-92, and by the Canadian Association of Petroleum Producers to give evidence at the TransCanada Pipelines 2001 and 2002 Fair Return Application proceeding, which resulted in Decision RH-4-2001. Mr. McCormick was retained by the City of Calgary to give evidence in respect of the AltaLink application number 1279345 and ATCO Gas application 1275466. He has provided expert reports in respect of a number of lawsuits related to securities matters.