

Alberta Energy And Utilities Board

ATCO Gas

2003 2004 General Rate Application

Application No. 1275466

Written Evidence Of John McCormick

on Behalf of

the City of Calgary

January 3, 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 Gas seeks in this application.

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

11 A Yes.

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

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

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

20 A The combination of the 11% equity return applied for and the 37% to 42%
21 common equity ratio appear to be in excess of the current requirements of the
22 financial markets, relative to the markets' perception of the underlying business
23 risk.

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 2001-97.³

9 **Part I**

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

11 A The best evidence of the appropriateness of the current equity return
12 resulting from these adjustment mechanisms and the allowed capital structures is
13 found in the trading prices of the shares of the companies which are the owners of
14 the utilities that earn the returns allowed by these formula. The common shares of
15 TransCanada, the public entity that investors must buy to participate in owning
16 the Mainline and the BC System⁴, are trading at a material premium to book
17 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 2001-97, the Board determined that a 37% equity layer was appropriate for ATCO Gas South and a 45.5% equity layer was appropriate for ATCO Pipelines. Assuming that the risks facing ATCO Gas North are similar to those facing ATCO Gas South and it is appropriate to weight the equity returns by relative rate bases, the appropriate equity layer should not be 45% but should be approximately 37%.

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

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 Gas in the ownership chain that
7 investors could buy to participate in owning ATCO Gas, are trading at a material
8 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

announcement of a dividend cut and multimillion after tax write down of certain unregulated assets. The high was 2.10 times book value.

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-AG-26(b) in which 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 capital attraction test¹². Real world current market data shows that capital is being
2 attracted to those companies as many utility holding companies in Canada are
3 trading well above book, while earning a return on a large portion of those assets
4 which is generally calculated with reference to the book value of the rate base.

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

8 A While the analysis would be easier with publicly traded stand-alone utilities,
9 important information can be drawn from the trading prices of the securities of
10 utility owners. Since TransCanada, the public entity which owns several NEB
11 regulated pipelines also owns other businesses, the view that we may obtain of the
12 required returns from the prices of securities is a little blurred by the inclusion of
13 those other businesses within the financing entity. Those other businesses have
14 included both regulated and unregulated¹³ businesses. To the extent that the other
15 regulated businesses have returns that move in parallel with the returns allowed
16 by the NEB formula, there is little blurring.¹⁴ To the extent that the proportion of
17 unregulated business increases relative to the regulated businesses and the
18 unregulated businesses have returns that vary from the returns allowed by the
19 NEB formula, there may be more blurring. Fortunately, the relative size of the
20 unregulated businesses within the financing entity has been reduced in recent
21 years.¹⁵ Share prices are the best evidence of the market reaction to TransCanada's
22 expected relative returns. Even Mr. Lackenbauer, one of TransCanada's capital
23 markets experts in the RH-4-2001 proceeding, testified that "the proxy for [the

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.

1 mainline], which is not a perfect proxy, is the TransCanada common equity”.¹⁶
2 While it would be ideal if the Mainline were in a separate financing vehicle so as
3 to remove any blurring, it remains the largest asset and is therefore a major driver
4 of TransCanada’s results.

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

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

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

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

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

¹⁸ See CAL-AG-26(b) in which 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.

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 **Q.9 Surely the use of the prices of the utility holding company shares as a proxy**
2 **for the market required return on its regulated utility investment is a**
3 **violation of the stand-alone principle and a misapplication of the capital**
4 **attraction standard?**

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

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

22 We should little wonder at the fact that so many regulators have approved an
23 adjustment formula when faced with differences between the company and
24 intervenor experts. Having heard sometimes repetitive testimony supporting a
25 range of recommended returns in each proceeding, and after making an award

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 3.1-1, lines 3 to 8 of the 2003/2004 General Rate Application.

1 within the ranges recommended by regulatory experts, regulators can see the
2 shares of the utilities trading at generous levels throughout the test period.

3 In this proceeding, and the ATCO Electric proceeding which will follow in its
4 wake, we are being directed by the applicant to focus on a single table of bond
5 spreads²⁴ rather than the market to book ratios of utilities companies which are
6 earning, in part, formula generated returns below that which the applicant seeks.

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

10 A While this is primarily a legal question, the *Hope Natural Gas* decision relates, in
11 the language of its day that, “the return to the equity owner should be
12 commensurate with the returns on investments in other enterprises having
13 corresponding risks. That return should be sufficient to assure confidence in the
14 financial integrity of the enterprise, so as to maintain its credit and to attract
15 capital.”²⁵ It seems a very reasonable test, but like much of life, the devil is in the
16 details. The difficult task is figuring out which companies have corresponding or
17 similar risk, but we should not lose sight of the goal which is the adequate return,
18 not the process of considering what earnings are comparable or the process of
19 determining the optimal data to support the calculation of an equity risk premium.

20 Certain of the proponents of the mystical art of the “comparable earnings” method
21 and the “equity risk premium” analysis strive to ignore the obvious. What is
22 obvious to me is that the common shares of utilities are generally trading at
23 market to book multiples well above one. It is also obvious that major
24 acquisitions of utilities are taking place by utilities and others at premiums to the

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.

²⁴ The Table is found on page 3.1-3 of the 2003/2004 General Rate 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.”

1 trading market prices which were already at a premium to book value.²⁶ There is
2 nothing quite like a takeover bid to demonstrate that capital is being attracted to
3 the rate base of a utility.

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

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

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

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 **Q.11 Do you agree that ATCO Gas need be awarded an equity return of 11%?**²⁸

2 A No, I do not. The ROE resulting from the NEB and BCUC adjustment
3 mechanisms appear to be well within the range of what the market requires. In
4 other words, they are generous. Assuming that its allowed capital structure is
5 appropriate to its business, the 11% equity return ATCO Gas seeks is materially
6 above the levels which the various adjustment mechanisms allow. The 2002 NEB
7 formula calculation produced an allowed ROE of 9.53% and, for 2003, a ROE of
8 9.79%²⁹. The BCUC formula produced an allowed ROE of 9.13% for 2002 and a
9 ROE of 9.42% for 2003, in each case for a low risk benchmark utility³⁰. Each of
10 these formulas operate based on expected future bond rates. It is clear that they
11 did not result in allowed ROEs of 11% for 2003. Based on the current interest rate
12 conditions, it is unlikely that these mechanisms will generate a rate approaching
13 11% for 2004³¹. A host of utilities are able to access the capital markets with the
14 ROEs generated by these adjustment mechanisms. In my view, ATCO Gas has
15 presented no realistic justification for its request for a return of 11%, which is
16 about 120 basis points over what is allowed to companies regulated under the
17 NEB adjustment mechanism.

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

20 A Yes, there are examples of utilities being awarded or negotiating returns of 11%
21 but when discussing historical awards or negotiations it is important to remember

²⁸ 2003/2004 General Rate Application, Page 3.1-1, line 11.

²⁹ The 2003 NEB return on equity was announced December 5, 2002. See CG-AG-50(a) attachment which provides copies of NEB communications which state the ROE for the years 1996 to 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, 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 2002 calculation to approximately 8.72%.

1 the time or business context of that decision or agreement. While it is difficult to
2 extract the equity return allowed in a “black box” or package negotiation, there
3 are examples of negotiated returns of 11%. In Canada, the Alliance Pipeline is
4 allowed 11.3% on its 30% equity layer and in the U.S. it is allowed 10.7% ROE.³²
5 Maritimes & Northeast is allowed a 13% return on its 25% equity layer for its
6 first 5 years ending in 2004.³³ These rates of return were determined in the
7 recognition that Alliance and Maritimes & Northeast were new pipelines facing
8 different risks and were negotiated in advance of the construction.

9 For the sake of contrast between the ATCO Gas’ request for a 11% ROE on the
10 37% to 42% equity layer, I compared that request to the allowed returns of some
11 local gas and electric utilities and found that most had been awarded returns in the
12 9.375% to 10% range³⁴.

13 **Q.13 Do you agree that there have been “significant changes in financial markets**
14 **since the equity risk premium was determined for 1997/98”³⁵?**

15 A It would be difficult to argue that there have not been significant changes in the
16 financial markets over the last few years. Investors are all too well aware of the
17 term ‘irrational exuberance’³⁶ and the disclosures surrounding the accounting at
18 Enron, WorldCom and Global Crossing. With all those changes, in some respects

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 Metropolitain, 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 Metropolitain 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.

³⁵ 2003/2004 General Rate Application, July 2002, Page 3.1-2, lines 13 to 15. The reference to 1997/1998 appears to be to the 2000-9 decision in respect of Canadian Western Natural Gas.

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), we note that the period during which Mr. Greenspan was expressing concern about “irrational exuberance” began before the 1997/98 period the applicant has used as its base for changes in financial markets.

1 we have returned to levels similar to the time when prospective data for Decision
2 2000-9 would have been collected. The TSE 300 index began 1996 at 4,768 and
3 ranged through the year between 4,707 and 6,019, closing the year at 5,927. In
4 1997, that index ranged from 5,679 to 7,210. The index hit a high of 11,388.8 in
5 2001 and has since retreated to a level of approximately 5,635³⁷ as the renamed
6 S&P/TSX index. On December 27, 2002, the index had returned to 6,595. The
7 performance graph in the Management Proxy Circular for Canadian Utilities,
8 dated March 8, 2002, gives us an indication of the relative performance of the gas
9 and electrical utilities subindex to the broader market³⁸. This period witnessed a
10 dramatic rise and fall in the prices of technology stocks which have been
11 described by some commentators as a bubble. During this period there has also
12 been a tremendous growth in the number of income funds and trusts listed on
13 Canadian stock exchanges.

14 On the debt side, investors will be well aware that interest rates have fallen. The
15 monthly data for Government of Canada marketable bonds over ten years³⁹
16 provided average yields during 1996 that ranged between 6.42% and 8.07%.
17 During 1997 they ranged from 5.78% and 7.07%. In 1998 they ranged between
18 5.08% and 5.78%, and the rate as at December 24, 2002 was 5.37%.

19 The monthly data for Government of Canada real return bonds⁴⁰ provided yields
20 during 1996 that ranged between 3.97% and 4.99%. During 1997, they ranged
21 from 3.95% and 4.34%. In 1998 they ranged between 3.85% and 4.17%. In 2002,
22 the monthly low was 3.25% and the rate as at December 24, 2002 was 3.33%.

³⁷ October 9, 2002 close.

³⁸ 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-AG-11(c).

³⁹ 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.

⁴⁰ Bank of Canada Series B14081 provides monthly data, series B114018 provides daily data.

1 Having noted the “round trip” in the equity markets and the falling interest rates, I
2 must say that these changes in broad indices do not mean that I accept the
3 proposition that ATCO Gas has been disadvantaged by changes in the capital
4 markets. In my view, these events do not provide sufficient support for the
5 requested increase in the equity risk premium sought by the applicant.

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

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

13 The first aspect, that I thought relevant to the issue of required returns on equity
14 capital, was the growth in recent years in the market for trusts and income funds.
15 These securities pay out a high proportion of the cash flow generated by the
16 underlying assets, an amount which is often in excess of the income earned. As
17 such, for tax purposes the distribution can be, in part, a return of capital. At the
18 end of 1996, there were approximately 37 of these trusts and funds listed on the
19 TSE. By September 2002, there were approximately 137 listed on the TSX. The
20 market capitalization of the issued units of these trusts and funds had risen from
21 just over \$7 billion at the end of 1996 to just over \$39 billion by September 2002,
22 a compound annual growth rate of over 34%. The largest fund at the end of 1996
23 had a market capitalization of just over \$700 million. By September 2002, there
24 were three⁴¹ that each had over \$2 billion in market capital and the 4 largest trusts
25 or funds exceeded the total market capitalization of all the trusts which had
26 existed at the end of 1996. In these 69 months, over 110 new trusts or funds were
27 launched and while the process of bringing new trusts to market may slow, it does

⁴¹ The 3 largest trusts were Enerplus, Canadian Oil Sands and RioCan.

1 not seem to have stopped.⁴² Clearly, these investment vehicles attracted a great
2 deal of new capital in recent years.

3 The table below presents the return on average equity earned by certain funds
4 during 1998, for the last 12 months ending September 2002, and their recent
5 distribution yields.⁴³

Fund	1998 Return	Sept. 2002 Return	Yield
Algonquin Power Income Fund	3.5%	3.7%	10.0%
Clean Power Income Fund ⁴⁴		3.2%	9.8%
Great Lakes Hydro Income Fund ⁴⁵		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%

6 While the earned return of each fund will vary based on a host of factors,
7 including business cycles and commodity prices, none of the funds in the table
8 above earned a return on equity equal to that sought by the applicant. None of
9 these funds pay a pre-tax yield, which includes a partial return of capital, equal to
10 the 11% after tax return sought by the applicant.⁴⁶ For the 12 months ended
11 September 30, 2002, these funds earned between 3.2% and 8.2%, in all cases less

⁴² 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 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.

⁴³ 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.

⁴⁴ Clean Power Income Fund was established in October 2001.

⁴⁵ Great Lakes Hydro Income Fund was established in September 1999.

⁴⁶ By way of example, Northland Power indicated in its third quarter report that it expects that approximately 50% of distributions will be tax deferred for 2002. Pembina has indicated that approximately 85% of 2002 distributions will be taxable. Not all funds provide estimates of future tax deferral characteristics. Algonquin noted only that approximately 71% of 2001 distributions were return of capital.

1 than the 11% return sought by the applicant. Without earning the return which the
2 applicant seeks, many of these funds have been able to attract capital.⁴⁷

3 If one were to assume that the market's required equity return was in the
4 neighborhood of the 11% after tax return sought by the applicant, or even the
5 9.4% to 9.8% returns currently allowed under the BCUC and NEB formulas, it
6 might follow that income trusts averaging a rate of return of approximately 6%
7 should be trading at a discount to book value. The table below sets out the market
8 to book ratio of each of the income funds in the table above, calculated using the
9 quarter end market prices. Clean Power, the most recently created income fund
10 which began trading in mid November 2001, is trading the closest to book value.
11 The market prices and the history of issues by these funds, in my opinion, make a
12 significant statement about the adequacy of single digit returns on equity in the
13 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

⁴⁷ 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 trust units in June 2001, and filed a prospectus for \$65.0 million in trust units in January 2001. 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 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 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 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 **Q.15 Will you comment on the recent reversal of the major gains earned by**
2 **technology stocks, the second aspect which you considered relevant to the**
3 **issue of required return on equity capital?**

4 The second aspect that I thought relevant to the issue of required returns on equity
5 capital in recent years was the reversal of the major gains earned by technology
6 stocks in the last few years. In short, the returns on information technology stocks
7 have been dismal. In October 2000, the TSX information technology index hit
8 levels in excess of 110. In October 2002, the same index fell to levels below 10.
9 Nortel may be the most famous Canadian example of the irrational exuberance
10 that some saw gripping the capital markets. In July 2000, its shares were trading
11 as high as \$123 and in October 2002 they had fallen to prices as low as \$0.69. In
12 August 2000, Nortel represented 34.59% of the TSE 300 index but by September
13 2002, it had fallen dramatically and represented only 0.53% of the S&P/TSX
14 composite index.

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

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

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

1 In March 2002, Duke acquired Westcoast committing approximately U.S. \$8.5
2 billion.⁴⁸ Duke's offer was a cash and share offer valued at approximately \$43.80.
3 The market for Westcoast's shares had been approximately \$36 prior to the offer.
4 Westcoast's major assets included, in addition to the NEB regulated utilities,
5 interests in the Alliance Pipeline, Union Gas and Centra Gas, and a number of
6 power generation projects. I was interested in comparing the proposition that the
7 applicant's calculation of widening spreads in utility bonds justified an 11% after
8 tax return equity⁴⁹ with the action by Duke in committing U.S. \$8.5 billion in the
9 purchase of Westcoast. Since Westcoast, in the absence of a negotiated settlement
10 involving a higher or incentive rate of return, is saddled with the apparently
11 inadequate NEB adjustment mechanism and ROE, I could not believe that the
12 synergies and returns on other aspects of their business outweigh the
13 comparatively⁵⁰ low rate of return on Westcoast's NEB regulated pipeline
14 investments, which Duke will acquire as part of the purchase.

15 In November 2002, BC Gas acquired a one-third interest in the Express Pipeline
16 for consideration of approximately \$200 million⁵¹. In its November 20, 2002
17 conference call, the officers of BC Gas declined to provide a rate of return on
18 equity when asked to do so by one analyst. They noted that they anticipated
19 earning \$12 million in 2003 from the investment, operating management fees and
20 certain tax benefits which were described as "significant". As such, the return on
21 equity for 2003 appears to be approximately 6% or less. This return is based on
22 the full through-put volumes which were supported by a commitment of the
23 vendor to continue to ship volumes above committed capacity for a minimum of
24 two years.

⁴⁸ The consideration was originally set out in a September 20, 2001 press release.

⁴⁹ 2003/2004 General Rate Application, July 2002, Pages 3.1-2 to 3.1-4. Comments on the applicant's manner of calculation of the spreads appear later in this document.

⁵⁰ For clarity, the intended comparison is between the NEB rate and the rate sought by the applicant in this proceeding.

⁵¹ 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".

1 In support of the acquisition, BC Gas offered 5.3 million shares to the market at a
2 price of \$38.00.⁵²

3 In our own province we have seen the recent AltaLink acquisition of TransAlta
4 distribution assets⁵³. In that transaction, AltaLink paid a premium of
5 approximately \$200 million for rate base assets of approximately \$644 million.
6 While we do not currently have an adjustment mechanism determining the return
7 on equity for Alberta utilities⁵⁴, AltaLink must have been aware of the recent
8 public record of decisions of the AEUB setting returns on equity⁵⁵. AltaLink is in
9 the process of applying for AEUB approval of its rates.⁵⁶

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

12 A Yes, as the table⁵⁷ below shows, the equity risk premium increases as the
13 expectation of interest rates is reduced. From a 3.30% equity risk premium in
14 1996, the 2002 equity risk premium increased 60 basis points to 3.90% as the long
15 Canada forecast yield fell 240 basis points from 8.03% to 5.63%. Effectively, the

⁵² 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.

⁵³ The transaction was announced in July 2001 and received regulatory approval in March 2002.

⁵⁴ A hearing on that matter is contemplated.

⁵⁵ 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%.

⁵⁶ In Application No. 1279345, AltaLink has sought a return on equity of 10.75%.

⁵⁷ See also CG-AG-50(a) attachment which provides copies of NEB communications which state the ROE for the years 1996 to 2002.

1 equity risk premium allowed under the NEB formula increases by about 25% of
2 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	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

3 Under the NEB formula, the maximum equity risk premium would be 5.31%
4 which would occur when interest rates fell to 0% and the minimum equity risk
5 premium of 0% would occur with the interest rates forecast to achieve a rate of
6 21.24%.

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

9 **Part II**

10 **Q.18 Isn't the methodology⁶⁰ proposed by ATCO Gas similar to the method used**
11 **by the NEB in its adjustment mechanism?**

12 A The methodology is both similar and different. The NEB began with a starting
13 period and estimated a forward bond yield and established an equity risk premium
14 at that time which was intended to apply going forward for an indefinite period⁶¹
15 subject to annual adjustments. In subsequent years, the equity risk premium

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.

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

⁶⁰ 2003/2004 General Rate Application, Section 3.1.2.

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 changes inversely by 25% of the change in interest rates in an estimate of a 30-
2 year Canada bond and the overall equity return varies by 75% of the change in the
3 estimated 30-year yield. The NEB estimate of the 30-year Canada bond is
4 derived from a published 10-year Canada forecast and the then current spread
5 between 10-year and 30-year Canada bonds. The return on equity is the revised
6 equity risk premium plus the estimated 30-year Canada bond yield. ATCO Gas
7 looks back and identifies a decision when it approves of the allowed equity risk
8 premium in the context of the then bond rates and compares the average interest
9 rates achieved on Canada and Utility bonds based on month end data going
10 forward. They recommend adjusting the 2003/2004 equity risk premium by an
11 amount equal to the whole change in interest spreads from the initial period,
12 rather than the factor used in the NEB formula. Finally, ATCO Gas derives their
13 estimate of the 30-year Canada bond from a published 10-year Canada forecast
14 and adds the “normal spread” between 10-year and 30-year Canada bonds. The
15 return on equity derived by ATCO Gas is the revised equity risk premium plus the
16 estimated 30-year Canada bond yield.

17 While noting that the application proposing this methodology is only to apply to
18 the 2003/2004 years, I would offer two observations on its resiliency. Were it to
19 be proposed as a formula to cover a greater period of time, it would result in more
20 volatile changes in the equity risk premium due to the inclusion of the whole
21 change in interest rates rather than the factor used in the NEB formula. As actual
22 spreads can be either positive or negative and may vary from the norm materially,
23 using a “normal spread” will make the result less sensitive to current market
24 conditions.

1 **Q.19 Do you agree with the methodology⁶² used to support the 11% return on**
2 **common equity described in section 3.1.2?**

3 A No, I do not. The applicant has not addressed whether its base year 1997 was a
4 normal year⁶³ nor has it accounted for any variations in interest rates that arise
5 between the prevailing interest rates and spreads in the specific month in which
6 the Board heard evidence or delivered its decision and the averages for the year
7 1997.

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

10 The applicant wishes to determine its return on equity based on a Consensus
11 Forecast interest rate. As forecasts are rarely achieved, the results more often
12 being higher or lower rather than right on the estimate, there may be some
13 variance between the then forecast and the achieved rate. Its analysis, though, is
14 premised on its calculation of the increasing difference in annual average of
15 achieved monthly Canada and Utility yields. The applicant has not explained
16 whether the 6.42% Canada long term Bond rate for 1997 set out in the table on
17 page 3.1-3 was coincidentally equal to the forecast rate for 1997, similar to the
18 June 2002 Consensus Forecast rate of 6.10% upon which the applicant then builds
19 its calculation, or adjusted its calculation to address the variance in forecast and
20 achieved Canada rates to the allowed return on equity. In fact the long Canada
21 forecast estimate put in evidence by the applicant's witness was a range of 7% to
22 7.5%.⁶⁵

⁶² 2003/2004 General Rate Application, Section 3.1.2.

⁶³ The extended table attached as CAL-AG-6(a1) suggests that 1997 average was the low point for Canada to utility bond spreads.

⁶⁴ See CAL-AG-6(f).

⁶⁵ See Decision 2000-9 page 49. At page 65, the Board chose to use a rate of 6.7% as the appropriate risk free long Canada rate.

1 The applicant relies on A rated Utility bond yield data from one source⁶⁶ up to
2 August 2000 and a second source thereafter, without demonstrating that the
3 second source of data would have provided consistent information for the earlier
4 period.

5 The applicant also relies upon the validity of the sample of bonds used to develop
6 the A rated utility debentures rate for September 2000 and thereafter, but it is not
7 clear the extent to which this sample has been biased upward by the exclusion of
8 shorter term bonds and the extent to which increased spreads within the sample
9 are the result of company specific events⁶⁷ such as downgrades⁶⁸ which may be
10 related to non-utility activities.

11 Prior to September 2000, the utility bond sample is a CBRS A rated utility group.
12 In BR-AG-39(a) we see that 4 of the 20 bonds in the sample are described as
13 being rated BBB+ in November 2002.

14 The utility bond sample subsequent to August 2000 excludes a number of issuers
15 which would have met the applicant's criteria for inclusion set out in CAL-AG-
16 6(d)(iv), "Utility issues were viewed as eligible if they were rated A by either
17 Standard & Poor's or DBRS."⁶⁹ Effectively, the Utility Bond series developed by

⁶⁶ The Utility Bond yield data up to August 2000 is identified as CBRS data in BR-AG-39(a). While the subsequent data is described as being drawn from a Foster Associates data base, I was unable to see that the underlying source of that yield data was identified in any of AUMA/ED-36, CAL-AG-6, CG-AG-55, or BR-AG-39.

⁶⁷ While the increase in yields quoted in CAL-AG-6(a2) for issues existing from September 2000 to October 2002 averages 38 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%.

⁶⁸ For the 10 issuers identified in BR-AG-39(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.

⁶⁹ 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

1 the applicant is closer to a “benchmark” series, since only a few bonds were
2 included in that sample, while the Canada series is an un-weighted average of the
3 preponderance of all Canadian government bonds over 10 years⁷⁰.

4 The applicant has assumed that as spreads increase, so too must the equity risk
5 premium, basis point for basis point without providing support for that
6 proposition. Neither the NEB nor BCUC formula assumes one for one changes in
7 equity risk premiums as the risk free rate changes.

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

12 **Q.20 Are you satisfied that the use of the 2000-9 decision concerning 1997 and**
13 **1998 is the appropriate starting point for the adjustment to the equity risk**
14 **premium?**

15 A No, I am not. In focusing on the 2000-9 Decision, the applicant appears to ignore
16 the more recent 2001-96⁷¹ decision which came to a similar conclusion as to
17 equity risk premium for 2001 and 2002 at a time when this table shows wider
18 bond spreads more similar to the recent market. The applicant appears to have
19 chosen 1997 in part due to it being the low point in its calculation of the spread

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). 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 Gas was dealing with bond yields over a period of time, the selection of approximately 10, 20 and 30 year terms would exclude, at various times, the issuers for which trading information or bonds of appropriate maturities were unavailable.

⁷⁰ 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.

⁷¹ See page 59, Decision 2001-96.

1 between annual averages of long Canada bonds and the CBRS A utility series.⁷²
2 This methodology attempts to relate the decision with respect to equity risk
3 premium to annual averages which differ from the interest rates used in the
4 Board's decisions. In that respect the applicant is trying to look back and put a
5 square peg in a round hole.

6 To examine the resiliency of this method, I would suggest that we also look at
7 how the ATCO Gas method might have applied to the decision of the Board in
8 E93004 concerning the 1992 and 1993 Canadian Western Natural Gas Fair Return
9 hearing which also set the return on equity. The decision was issued in February
10 1993 after the filing of evidence in April and May 1992, and a hearing in June
11 1992⁷³. The table below provides the data for 1992 taken from CAL-AG-6(b) and
12 the average for that year from CAL-AG-6(a1).

	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

13 While the numbers in the table above may be of historical interest, they are not
14 the numbers upon which the Board's decision was based, since about half of them
15 occurred after the hearing closed. So to subsequently attempt to relate the
16 Board's decision to some average for the year, as is the 1997 practice in the
17 ATCO method, is likely a flaw in logic. At the time of the E93004 hearing, the

⁷² See CAL-AG-6(a1).

⁷³ See page 15, Decision E93004.

1 Board identified the risk free rate as 9%.⁷⁴ None of the monthly A rated Utility
2 yields, nor the annual average for 1992, are 9%. The Board also noted that the
3 Company would be able to finance at 70 basis points over a 10-year Canada. The
4 Board reached its decision on company specific parameters, not the average
5 annual yield of A rated utility bonds. In reaching its determination of equity risk
6 premium, the Board allowed 325 basis points, allowing CWNG a return on equity
7 of 12.25%.

8 We know the Board determined that the appropriate equity risk premium for 1992
9 was 325 basis points. Were the formula suggested by the applicant to have been
10 applied to the 1992 numbers, because the average 1992 spread is 125 basis points,
11 approximately 73 basis points greater than the applicant's 1997 base year's
12 spreads of approximately 52 basis points, we would need to increase the equity
13 risk premium granted in that year from the applicant's 1997 base year's 375 basis
14 points to 448 basis points (375+73 basis points). The applicant's method is
15 driven solely by the change in spreads rather than the more complex relationships
16 between spreads and estimates of future risk free rates which are used in the NEB
17 and BCUC formulas. The applicant's method would provide an equity risk
18 premium approximately 123 basis points (448-325=123 basis points) greater than
19 that awarded by the Board for 1992. While readers may object to looking back,
20 the same 448 basis point equity risk premium result would be obtained in a future
21 year where the anticipated risk free rate was 9% and the A utility spreads were
22 125 basis points.

23 In Decision 2000-9 relating to 1997 and 1998, the Board allowed an equity risk
24 premium of 375 basis points, but it would appear that this was related to
25 conditions in the capital markets rather than changing increasing business risk.⁷⁵
26 In decision 2001-96 relating to 2001 and 2002, the Board also allowed an equity
27 risk premium of 375 basis points.

⁷⁴ See page 232, Decision E93004 lines 1 through 3.

1 The 2000-9 decision was issued after the test period. The Board did know the
2 actual risk free rate for 1997 and had several months of actual 1998 results
3 available to it. Neither of the values expressed in the table on page 3.1-3 for Long
4 Canada bonds for 1997 and 1998 are the values on which the Board made its
5 decision.⁷⁶

6 **Q.21 Do you have any observations on the interest rate data points which**
7 **appeared in the Table on page 3.1-3?**

8 A Yes, I believe that it has an inherent inconsistency which renders suspect the
9 conclusions that are based upon the data. In BR-AG-39(a) the applicant notes that
10 for the period up to August 2000, the data in the Table was the average of the
11 “month-end yields on the 10-, 20- and [30]-year A rated Utility Bond”⁷⁷ using
12 CBRS data. For September 2000⁷⁸ and forward, the data represented the month
13 end yields of certain utility issues listed in BG-AG-39(a). Unfortunately for
14 consistency, the bonds used in the later part of the data contain no 10 or 20-year
15 issues,⁷⁹ do not represent the full spectrum of utility issuers⁸⁰ and exclude issues
16 by the applicant’s financing affiliate.⁸¹ With a normally sloped yield curve, when
17 averaging yields of Utility bonds, excluding shorter-term issues inflates both the

⁷⁵ See page 77, Decision 2000-9 where on March 2, 2002, “the Board is of the view that CWNG’s business risk has not changed significantly since 1993.”

⁷⁶ 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.

⁷⁷ BR-AG-39, response (a) second paragraph actually reads “month-end yields on the 10-, 20- and 20-year A rated Utility Bond”, but the data appears to support an average which includes 30-year bonds.

⁷⁸ 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 is 7.09%.

⁷⁹ 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 other CU or CUL maturities see CAL-AG-34(i) attachment.

⁸⁰ 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.

⁸¹ The exclusion of data on CU and CUL bonds is puzzling since at CAL-AG-34(j) we are told, “CU Inc. continually monitors all outstanding debt with the objective of minimizing interest costs.” That statement

1 result and the calculated spread off the long Canada bond index. At September
2 2000, the bonds in the then sample in CAL-AG-6(a2) spreadsheet have an
3 average life of approximately 27.6 years. By November 2002, the average life of
4 the selected bonds had fallen only to 25.9 years, as a result of the passage of time
5 being partly offset by the addition of three new 30-year issues.

6 The degree of upward bias that results from ignoring utility bonds of 10 and 20-
7 year maturities in the later part of the data will depend on the slope of the yield
8 curve, but the applicant gave us a partial indication of the “normal spread between
9 10 year and 30 year GOC Bonds” which was estimated at 30 basis points.⁸²
10 Another indication of the upward bias can be found in CAL-AG-34(g) in which
11 the applicant provides an estimate of the “current yield spreads” for utility bonds
12 over benchmark Canada bonds in the 10, 20 and 30 year terms. The 10-year term
13 is described as having an 80 to 85 basis point spread. The 30-year term is
14 described as having a 115 to 130 basis point spread.

15 In addition to the general concern related to the exclusion of shorter term issues,
16 the rationale for the choice of particular bonds is not made clear. Certain issuers
17 have several issues while others have only one of those issues that might have
18 fallen within the 10 to 30 year scope of the CBRS series.

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

25 In an attempt to quantify the upward bias of the ignoring shorter term issues and
26 including certain BBB rated issuers in the latter data, on October 1, 2002, I

is in marked contrast to AUMA/EDM-AG-36(b & c), where we are told that ATCO Gas does not have yield information on several series of Canadian Utilities debt instruments.

1 accessed a data stream published by Bloomberg which estimated A and BBB
2 Utility bond yields. The table below compares the October 1, 2002, 10, 20 and 30
3 year indicated yields to the result calculated for September 30, 2002 in CAL-AG-
4 6(b), suggesting an upward bias of approximately 74 basis points.

		A	BBB ⁸³
	Term	1-Oct	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-AG-6(a2)		<u>7.27</u>	
	variance	.74	

5 While I would have liked to be able to confirm the prices of the various utility
6 bonds used in the latter A rated Utility data, the pricing source and method were
7 not provided in CAL-AG-6(b)⁸⁴. In a limited number of instances, when I
8 compared the yield data to data available from sources available to me, I found
9 variances which may have been due to the use of different pricing sources or
10 method of calculation.

11 While over some time period the spreads between 10-year and 30-year Canada
12 bonds may average 30 basis points, the spread at any particular time may vary
13 from this norm. The CBRS Data for the month of March 2000⁸⁵ would provide a
14 good case in point. The 10-year GOC bond showed a yield of 5.92% while the
15 30-year was shown at 5.74%. The spread at this date was negative. Negative
16 spreads can occur for a number of different reasons including market perceptions

⁸² 2003/2004 General Rate Application, Page 3.1-4, lines 1 to 3.

⁸³ After reviewing CAL-AL-6 and BR-AG-39, 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.

⁸⁴ CAL-AG-6(b) refers the reader to BR-AG-39(a) but neither its text nor the attached spreadsheet prepared by Foster Associates gives the source of the utility bond yield data.

⁸⁵ The March 2000 data point for the average of the 10, 20 and 30 year A utility bonds appearing in CAL-AG-6(b) attachment provides a 6.58% yield. I have 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%. The 26 basis point difference in our calculations would represent a further 2 basis point difference in the annual average for that year. Since the utility bond rate would increase, the spread would also increase in the table.

1 of restriction of supply of bonds which can arise as a result of the then
2 expectations of government surplus reducing financing requirements.

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

5 A My concern with this method is that it accepts one element which is based in part
6 upon current market conditions and, rather than taking the currently observable
7 spread as is done in the NEB and BCUC formulas, then adds a normalized rate.
8 In the period the NEB has used its adjustment mechanism, the 10-year to 30-year
9 spreads have varied from -12 basis points to +64 basis points⁸⁶. Applying a
10 normalized spread over those years would have altered the forecast of 30-year
11 Canadas by over 30 basis points, which does not seem to me to be particularly
12 responsive to the then current market conditions.

13 **Q.23 Do you agree that “significant changes in financial markets since the equity**
14 **risk premium was determined for 1997/98 ... indicate that an increase in the**
15 **equity risk premium is warranted”?**⁸⁷

16 A If the increase contemplated is sufficiently large so as to take the return to 11%,
17 no, I do not. In the table which earlier presented the NEB formula returns and
18 resulting equity risk premium, there is a small increase in the equity risk premium
19 caused by changing interest rates between 1997 or 1998 and 2003. I am of the
20 opinion that the NEB adjustment formula results in a rate of return on equity that
21 is well within the market requirements. In other words, it is generous. The table
22 below sets out the market to book ratios for TransCanada, and for comparison
23 Canadian Utilities Limited, calculated based on year end financial statements and
24 the year end share prices. Other than the 1999 data point for TransCanada, one
25 cannot help but observe the market to book ratios are well over one. The 1999
26 data point for TransCanada was affected by, among other things, \$700 million in

⁸⁶ See line “D” in the table showing the calculation of the NEB return on equity, above.

⁸⁷ 2003/2004 General Rate Application, Page 3.1-2, lines 13 to 15.

1 write downs related to its unregulated investments and a cut in the dividend which
2 was 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%

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

9 In the RH-4-2001 proceeding, TransCanada made a similar argument⁸⁸ suggesting
10 that the changes in the competitive environment and financial markets warranted
11 an increase in their ROE. The NEB did not increase their ROE⁸⁹, apparently
12 rejecting that argument. Fortunately or unfortunately, the market recognizes the
13 changes to which companies are exposed in the stock price on a minute-by-minute
14 basis. TransCanada, the public entity which owns the Mainline, is followed by a
15 host of equity analysts,⁹⁰ several bond rating firms and thousands of investors⁹¹
16 and potential investors, all of whom to some degree make up the “market” and
17 affect securities prices with their behavior. The “market” has been aware of the

⁸⁸ 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.”

⁸⁹ The NEB did allow an increase in the equity layer from 30% to 33%. See page 59 of the RH-4-2001 Decision.

⁹⁰ 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.

⁹¹ 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.⁹² The “market” is made aware of the
2 economic, competitive and political developments and regulatory changes
3 through a host of communication options⁹³. 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.⁹⁴ The
6 “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.⁹⁵

10 Canadian Utilities Limited is also followed by a number of equity analysts⁹⁶, bond
11 rating firms⁹⁷ and a host of investors and potential investors. The market should
12 be well aware of the business of ATCO Gas through the Canadian Utilities
13 Limited public disclosure documents including its Annual Information Form,
14 Annual and Quarterly reports.

⁹² 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.

⁹³ See page 3.1-8 of the application at lines 18 and 19.

⁹⁴ 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.

⁹⁵ 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.

⁹⁶ 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.

⁹⁷ 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-AG-43, BR-AG-47 and CAL-AG-15 and referred to in the application at line 10 on page 3.1-14.

1 **Q.24 Do you agree that the “business risk of ATCO Gas has materially increased**
2 **since 1993 as evidenced by ... an increased risk of franchise loss”⁹⁸?**

3 A. The key issue for me in franchise loss discussion is the price at which the
4 company is to be bought out by the relevant municipality. In my view the
5 analysis of the risk of franchise loss must start with the question “is there harm”⁹⁹
6 In my mind using the word “risk” to describe the probability of an event that may
7 not harm you is a misnomer. If the buyout price is at a price equal to or greater
8 than book, plus the cost of termination of redundant employees and unbundling
9 any debt financing [all on an after tax basis], I am hard pressed to understand that
10 the company would have suffered any significant harm¹⁰⁰.

11 The public disclosure documentation¹⁰¹ related to franchises shows them to be
12 long-term arrangements with the price to be set by the regulator in the absence of
13 a negotiated agreement¹⁰². In the case of the Edmonton franchise among others,
14 the price is a going concern value plus 10%.¹⁰³ In the one case of a franchise
15 being lost in the last 30 years, it appears that ATCO Gas received an amount
16 greater than its book value.¹⁰⁴ Although information requests¹⁰⁵ attempted to have
17 ATCO Gas demonstrate what would be the financial consequence of the sale of
18 some franchise assets, the applicant did not provide a quantitative reply.

⁹⁸ 2003/2004 General Rate Application, Page 3.1-5 lines 18 to 20.

⁹⁹ CAL-AG-16(d) sought information as to ATCO Gas’ estimate of the book value and purchase price of the Edmonton assets, but ATCO Gas advised that “An unreasonable amount of effort is required to provide the information” in Diane Wilson’s letter of November 15, 2002.

¹⁰⁰ A high price may represent an impediment from a purchaser’s point of view. On page 2 of the Airdrie letter to Grande Prairie attached to CAL-AG-13(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.”

¹⁰¹ See CAL-AG-11 (b) & (c) which incorporate certain 2001 public disclosure documents into the record.

¹⁰² See CAL-AG-9 (c & d) the franchise agreements with Nanton, Brooks, Claresholm, Granum and Okotoks, contain a reference to an arbitrator rather than the AEUB.

¹⁰³ See CAL-AG-9 (c & d) A similar provision is found in the franchise agreements with Nanton, Brooks, Claresholm, Granum and Okotoks, as well as the Edmonton franchise.

¹⁰⁴ See CAL-AG-10 (a) and (c). Although the filed evidence made reference to a franchise lost in 1972, this reply to an information request refers to a sale in 1974 at a price which was more than book value. While providing the aggregate compensation, ATCO Gas did not provide the book value and as such we are unable to estimate the percentage premium to book or profit.

¹⁰⁵ See CAL-AG-16(d) and CAL-AG-17(b) and (d).

1 Considering the assertions of serious jeopardy of the loss of a single franchise and
2 the increasing importance of this matter since 1993, it is quite puzzling to learn
3 that “No formal analyses have been performed in the past to determine the impact
4 of a franchise loss.”¹⁰⁶

5 I was interested in the contrast between the dire warning found in the application,
6 “The loss of a major franchise like Edmonton or Grande Prairie would challenge
7 the viability of the Company”,¹⁰⁷ with the proportion of total revenue and ATCO
8 Gas rate base represented by Grande Prairie, which are respectively 1.5% of
9 revenues and 0.86% of rate base.¹⁰⁸ Clearly, the sale of any portion of the
10 business would, to the extent not mitigated by staff, cost reductions or the
11 redeployment of the proceeds, require some portion of the fixed or administrative
12 costs to be allocated over a smaller revenue base. That being said, to suggest that
13 a 1.5% loss of revenues would challenge its viability seems to suggest a much
14 weaker entity than one with an equity layer over 37%¹⁰⁹. The warning attached to
15 the sale of the Grande Prairie franchise seems puzzling compared with the
16 absence of concern arising out of the sale of the retail energy business which must
17 have generated some revenue to attract a purchase price estimated to be \$128
18 million.¹¹⁰

19 ATCO Gas has used 1993 as the starting point in its discussion of franchise risk.
20 The rationale for this starting point is not explained in the application. The choice
21 of 1993 as the starting point, was puzzling to me, due to the fact that matter was
22 considered in two subsequent decisions and that in the 1997/1998¹¹¹ decision Ms.

¹⁰⁶ See CAL-AG-17(b).

¹⁰⁷ See 2003/2004 General Rate Application, July 2002, page 3.1-7 at lines 22 and 23.

¹⁰⁸ See CAL-AG-17 (c).

¹⁰⁹ In BR-AG-42, “The loss of any franchise, no matter how small the direct rate base component of the franchise, will have a significant impact on ATCO Gas.” Emphasis added.

¹¹⁰ The December 10, 2002 press release by the ATCO Group refers to the estimated consideration. Page 1.0-1 of the application and BR-AG-1 refer to the pending sale.

¹¹¹ In Decision 2000-9 at page 48, where the Board summarizes four elements of business risk identified by Ms. McShane, the words “franchise renewal” do not appear in that passage, although they are discussed later in the decision with respect to the construction of a building in Cochrane. At page 77, “Ms. McShane submitted in her evidence that the business risks faced by CWNG during 1997 and 1998 have not changed

1 McShane did not appear to support the change in degree of risk of franchise loss
2 claimed by the company in this application.¹¹² The issue of franchise risk¹¹³ was
3 also considered in the 2001-97 decision, but there is only one specific reference to
4 the issue in that decision and in summary the Board was “of the view that there
5 have been no significant changes in the business risks facing AGS”.¹¹⁴

6 **Q.25 Has Canadian Utilities Limited revised the disclosure in its Annual**
7 **Information Form to alert investors to the fact that “business risk of ATCO**
8 **Gas has materially increased since 1993 as evidenced by ... an increase risk**
9 **of franchise loss”¹¹⁵?**

10 A. Not materially. The table below compares the disclosure in the Canadian Utilities
11 Limited 1993 and 2001 Annual Information Forms with respect to franchises.
12 The disclosure is very similar. In my view, the differences mainly arise as a result
13 of the fact that the disclosure in the 2001 Annual Information Form specifically
14 names a number of subsidiary companies and there is a difference in the
15 description of the scope of the Edmonton franchise.

2001 AIF ¹¹⁶	1993 AIF ¹¹⁷
<p>“AGP, ATCO Electric, YECL, NUY and NLD distribute natural gas and electricity in incorporated communities under the authority of franchises or by-laws and in rural areas under approvals, permits or orders issued pursuant to applicable statutes.</p>	<p>“The Company distributes natural gas in incorporated communities under the authority of franchises or by-laws and in rural areas under approvals, permits or orders issued pursuant to applicable statutes</p>

significantly in comparison to the risks experienced in 1992-1993” While noting a similarity of views of company and intervenor witnesses on overall risk, the Board did not appear to make a specific finding with respect to franchise risk.

¹¹² At page 3.1-7, line 23, the applicant notes that the loss of certain franchises “would challenge the viability of the company.”

¹¹³ Decision 2001-97 at page 39.

¹¹⁴ Decision 2001-97 at page 44.

¹¹⁵ 2003/2004 General Rate Application, Page 3.1-5 lines 18 to 20.

¹¹⁶ See pages 17 and 18 of the 2001 Canadian Utilities Limited Annual Information Form. Changes have been marked in bold type to facilitate comparison. The defined terms are: AGP, which refers to ATCO Gas and Pipelines Ltd.; ATCO Electric, which refers to ATCO Electric Ltd.; YECL, which refers to The Yukon Electric Company Limited; NUY, which refers to Northland Utilities (Yellowknife) Limited; and NLD, which refers to Northland Utilities (NWT) Limited. See pages 2 through 4 of the AIF.

¹¹⁷ See page 9 of the 1993 Canadian Utilities Limited Annual Information Form.

1

2001 AIF	1993 AIF
<p>In Edmonton, distribution of natural gas is carried on under the authority of an exclusive franchise. AGP has entered into an agreement with the City of Edmonton for a 10 year renewal of the franchise to November 15, 2005. The franchise renewal is subject to the right of the City of Edmonton, at the end of the renewal period, to purchase all of AGP's assets within the city and its assets outside the city used in supplying natural gas to the city. The purchase price would be the amount of the actual value thereof as a going concern plus 10% of such value. Although the franchise agreement gives the city certain rights of purchase, since 1935 the city has granted renewals for 10 year periods.</p>	<p>In Edmonton, distribution of natural gas is carried on under the authority of a franchise which is exclusive for domestic and heating purposes and non-exclusive for manufacturing and electric generation purposes. The Company has entered into an agreement with the City of Edmonton for a 10 year renewal of the franchise to November 15, 1995. The franchise renewal is subject to the right of the City of Edmonton, at the end of the renewal period, to purchase all of the Company's assets within the city and its assets outside the city used in supplying natural gas to the city. The purchase price would be the amount of the actual value thereof as a going concern plus 10% of such value. Although the franchise agreement gives the city certain rights of purchase, since 1935 the city has granted renewals for 10 year periods</p>
<p>In Calgary, distribution of natural gas is carried on under the authority of a municipal by-law. The rights of AGP under this by-law, while not exclusive, are unrestricted as to time. The by-law does not confer any right on the City of Calgary to acquire the facilities used in providing the service.</p>	<p>In Calgary, distribution of natural gas is carried on under the authority of a municipal by-law. The rights of the Company under this by-law, while not exclusive, are unrestricted as to time. The by-law does not confer any right on the City of Calgary to acquire the facilities used in providing the service.</p>
<p>The franchises under which service is provided in other incorporated communities in Alberta and in the Northwest Territories have been granted for periods of up to 20 years. These franchises are exclusive to AGP, ATCO Electric, NUY and NLD and are renewable by agreement for further periods not exceeding 20 years each in the case of AGP and 10 years in the case of ATCO Electric, NUY and NLD. If any franchise is not renewed, it remains in effect until such time as either party, with the approval of the prevailing regulatory authority, terminates it on six months written notice. Upon termination of a franchise the municipality may purchase the facilities used in connection with that franchise at a price to be agreed upon or, failing agreement, to be established by the prevailing regulatory authority. ...</p>	<p>The franchises under which service is provided in other incorporated communities in Alberta have been granted for periods of up to 20 years. These franchises are exclusive to the Company and are renewable by agreement for further periods not exceeding 10 years each. If any franchise is not renewed, it remains in effect until such time as either party, with the approval of the PUB, terminates it on six months written notice. Upon termination of a franchise the municipality may purchase the facilities used in connection with that franchise at a price to be agreed upon or, failing agreement, to be established by the PUB.”</p>

2 ATCO Gas has warned in its application that “An immediate risk faced by ATCO
3 Gas lies with the franchise renewal with the City of Edmonton in 2005”,¹¹⁸ and
4 that “the loss of a major franchise like Edmonton or Grande Prairie would

¹¹⁸ 2003/2004 General Rate Application, Page 3.1-7 lines 9 and 10.

1 challenge the viability of the Company.”¹¹⁹ While ATCO Gas suggests that the
2 sale of the Edmonton franchise “could well jeopardize the very existence of
3 ATCO Gas”,¹²⁰ the disclosure does not reflect an increase of risk over the last few
4 years. I wondered whether the consistent disclosure might be due to the different
5 materiality tests at the Canadian Utilities level, but found that the disclosure at the
6 CU Inc. level, where the risk would be even more material, is similar.¹²¹

7 **Q.26 Do you agree that the “business risk of ATCO Gas has materially increased**
8 **since 1993 as evidenced by ... the investors’ perception of the Alberta**
9 **regulatory environment”¹²²?**

10 A. No. In some respects this is one of the more puzzling aspects of the application.
11 While this topic is second to the franchise renewal risk in section 3.1, it requires
12 over 5 pages where franchise risk was covered in about 3 pages. Generally written
13 in a conditional tense, we are advised of the “potential” of investors forming a
14 negative conclusion on the Alberta regulatory environment “whether this
15 conclusion is based on facts is irrelevant”.¹²³ For all the worry over the potential
16 of investors reaching negative conclusions¹²⁴, the actual conclusions of investors
17 are reflected in the share price of equities every day. These investors still reward
18 Canadian Utilities a handsome market to book ratio.

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

¹¹⁹ 2003/2004 General Rate Application, Page 3.1-7 lines 22 and 23.

¹²⁰ 2003/2004 General Rate Application, Page 3.1-7 lines 16 and 17.

¹²¹ The disclosure with respect to franchises on pages 10 and 11 of the CU Inc. 2001 Annual Information Form is substantially similar to that contained in the similar passage of the Canadian Utilities Limited Annual Information Form.

¹²² 2003/2004 General Rate Application, Page 3.1-5 lines 18 to 21.

¹²³ See 2003/2004 General Rate Application, July 2002, page 3.1-9 line 11, and lines 17 to 18.

¹²⁴ See CAL-AG-27 (b) where “ATCO Gas takes [one of its observation] as evidence of a growing perception by investors of a deteriorating regulatory climate”.

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

2 A Bond ratings are one of many sources of information available to the market on an
3 issuer's securities. Bond ratings provide the market with an independent
4 assessment or measure of the relative probability that the debt of the various
5 issuers will be repaid in accordance with the terms of the instruments. The rating
6 could be viewed as a proxy for an assessment of business risk and financing risk. I
7 do not believe that the opinions of bond rating agencies should drive the Canadian
8 regulatory process.

9 Bond rating does not appear to be an exact science. The ratings for individual
10 firms are developed through the individual judgment of those employed by the
11 various rating agencies. Consequently the changing and sometime divergent¹²⁵
12 judgments of bond raters, at any particular time, should not be the sole driver of
13 the allowed return for a regulated utility, and in my view, are no substitute for the
14 views of the regulator. This is particularly true when the financing entity is also
15 financing assets beyond those included in the rate base since the financing of
16 those assets may affect the bond rating upon which the regulated entity will
17 market its bonds.

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

¹²⁵ 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 **Q.28 What is more important an “A” rating or a 2.3 times¹²⁶ interest coverage**
2 **ratio?**

3 A Of the two, I would view the “A” rating as more important. However, neither of
4 those items, the rating or the interest coverage ratio, are as important as the
5 “market” reaction to the financial position of the company.

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

11 To propose a minimum interest coverage ratio target effectively makes the equity
12 return a function of the weighted average cost of the existing debt issues and the
13 current tax rate. The table below provides interest coverage numbers for a
14 simplified example of a 56.3% debt, 6.7% preferred equity and 37% common
15 equity capital structure using a 37.3% tax rate for a range of interest and equity
16 return rates.¹²⁷ To maintain a 2.3 times interest coverage ratio as the imbedded
17 average debt costs increase from 7% to 14%, the after-tax equity return must

¹²⁶ In BR-AG-46(c) 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.

¹²⁷ The attachment to BR-AG-46(a) estimates an 8.005% interest cost in respect of the outstanding long term debt and 4.5% for short term debt for 2003. For simplicity in the example, I have used an arbitrary rate of interest of 7.85% for all debt. Updated tax rates of approximately 37.3% are found in BR-AG-156.

1 increase from approximately 70 basis points greater than the average imbedded
2 debt rate to 238 basis points greater than the average imbedded debt rate.

3

Rate Base	\$	1,000	Pre Tax	Pre Tax
Tax Rate		37.3%	Rate	Return
Debt		56.3%	7.85%	\$ 44.20
Preferred		6.7%	5.50%	8.74% \$ 5.88
Equity		37.0%	9.25%	14.71% \$ 54.59
				\$ 104.66

Debt Rate	Interest Coverage						
	Equity Return						
	8.00%	9.00%	10.00%	11.00%	12.00%	13.00%	14.00%
7.0%	2.35	2.50	2.65	2.80	2.95	3.10	3.25
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	2.75
10.0%	1.94	2.05	2.15	2.26	2.36	2.47	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	2.14	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

4 **Q.29 Have you any observations on ATCO Gas' financing calendar?**

5 A Yes. For 2003, ATCO Gas advises that it will face the maturity of \$22.2 million
6 principal amount of a 7.25% Debenture and anticipates issuing \$100 million 7%
7 20-year debenture. For 2004, ATCO Gas anticipates the retirement of \$31.5
8 million 8.73% debenture and issue of \$85 million 7% 20-year debenture.¹²⁸

9 Recent financings by CU Inc. have been for shorter terms.¹²⁹ With only one issue
10 maturing between June 2011 and August 2019¹³⁰, the maturity calendar appears
11 open to shorter issues and the maturity curve would allow them to do a 10-year
12 bond which might save ratepayers between 50 and 70 basis points depending on
13 market conditions.

¹²⁸ 2003/2004 General Rate Application, July 2002, Section 3.2-2 lines 18 to 23.

¹²⁹ 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 million (15 year) debentures due November 2017 on November 19, 2002. See also AUMA/ED-AG-89.

1 **Q.30 Is the 37-42%¹³¹ Common Equity component of the capital structure**
2 **appropriate for ATCO Gas?**

3 A The Board has considered the appropriate common equity component in several
4 recent proceedings. In Decision 2001-97 relating to ATCO Gas South (“AGS”)
5 and ATCO Pipelines (“AP”), the Board determined that a 37% equity layer was
6 appropriate for AGS and a 45.5% equity layer was appropriate for AP¹³². In result,
7 the Board allowed a common equity layer which blended the respective equity
8 layers based on the relative size of the rate base, resulting in an overall equity
9 layer for 2001 of 38.94%. In this proceeding the application also covers ATCO
10 Gas North (“AGN”). The applicant tells us¹³³, that there are no significant
11 differences between the risks of AGS and AGN. Applying the same methodology
12 in the current case would result in a common equity layer closer to 37%.¹³⁴
13 Consequently, the 37% - 42% range would appear high even if the Board’s
14 previous decision is taken as a given.

15 As I read the application, the major change in risk identified by the applicant is its
16 belief in the heightened possibility of the sale of one or more franchises at a
17 premium to going concern value, or as ATCO Gas puts it, the risk of franchise
18 loss has increased. As addressed above, I am hard pressed to see how the sale of
19 assets at prices above book, places the company in grave jeopardy.

20 Ignoring the ever-present worry that some investors may form conclusions not
21 supported by facts, the other major justification for the proposed increase in
22 equity layer appears to be the “requirement” for the applicant to do its share to
23 maintain the current debt rating of its parents. The Standard and Poor’s rating
24 outlook was revised for “ATCO Ltd. and subsidiaries Canadian Utilities Ltd and

¹³⁰ See the attachment to CAL-AG-34(i).

¹³¹ 2003/2004 General Rate Application, July 2002, section 3.1-14 line 7.

¹³² Decision 2001-97 at page 44.

¹³³ See 2003/2004 General Rate Application, July 2002, section 3.1 page 4 and BR-AG-41(a).

¹³⁴ My calculation would be based on multiplying the approved equity layers of 37% for AGS, 37% for AGN and 45.5% for AP by their relative rate bases and dividing the result by the total rate base, as those rate bases change from year to year. See Decision 2001-97 at page 44.

1 CU Inc. to negative”¹³⁵ on November 12, 2002. In that announcement, S&P
2 focused on the increase in “ATCO’s business risk” including “growing
3 investments in nonregulated independent power ... growing merchant power
4 exposure ... and the growth of nonutility operations.” S&P also noted “The
5 consolidated business risk profile of ATCO is supported by Alberta-based
6 regulated gas and electricity distribution and transmission operations, ...
7 Distribution businesses have virtually no exposure to market price and volume
8 risk, as they are permitted to flow through all electricity and natural gas supply
9 costs.” While S&P has commented on what it perceives to be the relatively thin
10 equity layer allowed regulated Canadian utilities, the specific statements in the
11 November 12, 2002 S&P comment seem to me to demonstrate that the increasing
12 business risk is due to the “growth of nonutility operations”. As such, it appears
13 that ATCO Gas is doing its share.

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

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

23 **Conclusion**

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

25 A. The combination of the 11% equity return applied for and the 37% to 42%
26 common equity ratio appear to be in excess of the current requirements of the

¹³⁵ See BR-AG-47.

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

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 2001-97.

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.¹³⁶ 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."¹³⁷ 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.¹³⁸

¹³⁶ 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.

¹³⁷ See section 4 of the Deferral Accounts Deficiency Correction Regulation, Alberta Regulation 240/2000.

¹³⁸ Decision 2001-93, one of the decisions resulting from that proceeding, appears in the list of decisions cited by the applicant in CAL-AG-19(a), which investors "may" view with concern.

1 In 2002, I filed evidence and appeared as a financial expert, having been retained
2 by the Canadian Association of Petroleum Producers (“CAPP”) to give evidence
3 in respect of the TransCanada Pipelines 2001 and 2002 Fair Return Application
4 heard before the NEB in proceeding RH-4-2001¹³⁹. The 2001 and 2002 Fair
5 Return Application Proceeding was convened to consider, among other things,
6 whether TransCanada’s “currently-approved return, based on a deemed capital
7 structure of 30% common equity and the rate of return on common equity (ROE)
8 resulting from the RH-2-94 Formula”¹⁴⁰ was appropriate. My duties included,
9 among other things, analysis of the application, reviewing financial market data
10 with respect to TransCanada and certain companies and; filing a written
11 submission in which I concluded that the ROE adjustment mechanism had
12 performed well, allowing TransCanada to access the capital markets on a
13 reasonable basis.

14 In addition, I have filed evidence in respect of the AltaLink application number
15 1279345, which is currently before the AEUB.

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

17 A The first time I was a regulatory witness my wise counsel charged me to be as
18 helpful to the Board as I was able. It seemed a good rule. Being relatively new to
19 this regulatory world, I only read the cost order 2002-70 as I plowed through
20 some of the nearly 500 Information Requests filed in this application. I found that
21 the Board’s injunctions¹⁴¹ to pose a significant challenge for any witness but
22 parallel with the first advice I was given in this area. As a result of that advice
23 and my first experience in answering a hoard of information requests, I have
24 attempted to footnote data sources relied upon. I would urge the Board to

¹³⁹ In addition to filing written evidence, Mr. McCormick was examined on March 19, 2002.

¹⁴⁰ 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.

¹⁴¹ The Board indicated that it wished the “best technical data” be available and preferred that it be filed earlier rather than later.

1 encourage other parties to adopt this practice. In this case, the cost of capital
2 proposal by the applicant hinges on the data behind the table on page 3.1-3 and
3 the methodology used to analyze the perceived change. I spent a number of hours
4 attempting to identify the data sources and to determine whether we were dealing
5 with average or point-in-time data so that I might ask information requests that
6 touched the issue. The task was not rewarding since one of the data series
7 changed midstream and the final data points in both the Canada Bond and Utility
8 series appear to be a point-in-time data point,¹⁴² where their predecessors were
9 averages of month-end data. I see that the Board and a number of the other
10 participants all chose, each in their own way, to ask about the data¹⁴³. Had the
11 data source been footnoted, work would have been saved.

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

13 A Yes.

¹⁴² See CAL-AG-6(f).

¹⁴³ The Information requests on the data in the table on page 3.1-3 included, BR-AG-39, AUMA/EDM-AG 36, AUMA/EDM-AG 37, CAL-AG-4, CAL-AG-6, and CG-AG-55.

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. He has provided expert reports in respect of a number of lawsuits related to securities matters.