COST OF CAPITAL FOR ONTARIO'S ELECTRICITY DISTRIBUTORS

Evidence of

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Before the

Ontario Energy Board

FILED ON BEHALF OF

Vulnerable Energy Consumers Coalition, Consumers Council of Canada, the Industrial Gas Users Association and the London Property Management Association

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1.0 INTRODUCTION

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. Laurence Booth is a professor of finance and finance area co-ordinator in the Rotman School of Management at the University of Toronto, where he holds the CIT Chair in Structured Finance. Professor Booth, either alone or with the late Professor M. K. Berkowitz,[1] has previously filed testimony with this Board in rate hearings involving Union Gas, Centra Gas Ontario and EGDI, as well as in the generic hearing in 2003 to review the Board's ROE adjustment mechanism. A detailed resume is attached as Appendix A.

Q. PLEASE DISCUSS HOW YOUR TESTIMONY IS ORGANISED AND THE ISSUES THAT YOU DEAL WITH.

A. The Industrial Gas Users Association, the Vulnerable Energy Consumers Coalition, the Consumers Council of Canada and the London Property Management Association have asked me to provide an independent assessment of the reasonableness of Board Staff's (Staff) cost of capital recommendations as contained in their July 25, 2006 discussion paper.[2]

Q. WHAT IS YOUR OVERALL JUDGMENT?

A. If I had been asked to submit formal cost of capital evidence, I am sure that I would have recommended both a lower ROE and less common equity than the staff have recommended, since it is my perception that there is minimal risk attached to investing in regulated utilities in Canada and the overall financial parameters allow these types of assets to sell at significant premiums to book value. As a result, in addition to earning a "fair" return, investors in regulated utility assets see any dollars that are reinvested in rate base become immediately worth ***more*** than a dollar. Consequently, the overall return including this

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[1] Professor Berkowitz died August 8, 2004.

[2] "Staff Discussion paper on the cost of capital and 2nd generation incentive regulation for Ontario's electricity distributors," Ontario Energy Board, July 25, 2006.

additional capital gain exceeds what I would regard as a fair return. As I have indicated to regulatory boards before it should be a concern to see Canadian regulated assets being flipped for twice book value. This is incontrovertible evidence that the allowed financial parameters for Canadian utilities are too generous.

Q. DOES THIS MEAN THAT YOU DO NOT ACCEPT BOARD STAFF'S RECOMMENDATUONS?

A. No, I accept Board Staff's recommendations as fair and reasonable. In my judgment if the Board had a "generic" electricity distribution (Disco) cost of capital hearing with company witnesses filing evidence, followed by interveners, the ultimate decision would be very similar to Board Staff's recommendations. Further Board Staff's recommendations are very similar to decisions from other regulatory hearings elsewhere in Canada. In this sense I accept the recommendations as fair and reasonable.

Q. HOW IS YOUR EVIDENCE ORGANISED?

A. Section II provides a rather lengthy overview of regulation; Section III the allowed ROE; Section IV the allowed common equity ratio, Section V the determination of the cost of debt and finally in Section VI my views on the overall reasonableness of the financial parameters. In Sections III-V I will outline Board Staff's recommendations, what has been allowed elsewhere and what in all likelihood I would have recommended given recent evidence that I have filed elsewhere. However, what my recommendations would have been should be taken as preliminary, due to the very limited time available imposed by the August 14 submission deadline.

II REGULATION

Q WHY ARE UTILITIES REGULATED?

A. Regulated firms operate with large immobile fixed costs, negligible marginal costs and "transmit" a service that cannot be effectively arbitraged. The cost structure means that average costs decline with output to a scale that makes entry difficult for a potential competitor, since an incumbent can lower prices to deter entry by imposing significant losses. In the extreme case an incumbent can simply cross subsidise from other operations to make it uneconomic for any entry and merely the threat of this acts as a deterrent. The incumbent can then charge monopolistic prices that cause economic inefficiency. If a good is produced or the service is not location specific then competition will deter this monopolistic behaviour, but when it is a non-arbitrageable service by definition this is not possible. This is why these types of firms are regulated to mimic the pricing behaviour of competitive firms, rather than being left to act like monopolists. Further due to the capital intensive nature of their operations large amounts of equity capital are contributed early and "locked in" creating a subsequent requirement to ensure that the shareholders are treated fairly and the financial costs generate fair and reasonable rates.[3]

The "fair and reasonable" standard means one thing to an economist: rates should reflect the operation of the utility at minimum long run average cost. Costs in a competitive market naturally gravitate towards minimum long run average cost and by definition do not include charges that are unfair and unreasonable (or unjust), while this cost ensures that the regulated services are provided at a cost that promotes the overall efficiency of the economic system.

Q. HOW DOES THIS APPLY TO THEIR FINANCIAL COSTS?

A. The financial costs include the costs of debt and equity, which in turn includes preferred and common shares. In the case of debt and preferred shares the payment to the investor is fixed at the time of issue. As a result the embedded cost is passed on to the ratepayer unless the regulator decides that the costs were imprudently incurred or that they did not reflect the operation of the utility, but reflected instead the impact of non-utility operations. For a normal utility the major problem is the cost of common equity financing, which does not have an explicit, easily calculated, cost. Here the benchmark decision is the *BC Electric* decision where

[3] Most utilities are regulated under acts that stipulate that rates be "fair and reasonable" or "fair and just."

the Supreme Court of Canada adopted Mr. Justice Lamont's definition of a fair rate of return as enunciated in the *Northwestern Utilities Limited v. City of Edmonton* ([1929] S.C.R. 186) decision that:

> "By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness stability and certainty to that of the company's enterprise."

Mr. Justice Lamont's definition embodies what a financial economist would call a risk-adjusted rate of return or "opportunity cost."

There are two key elements to Mr. Justice Lamont's definition. The first is that it is a ***market based opportunity cost.*** Mr. Justice Lamont specifically stated that the return should be that which could be earned if the capital were taken out of the regulated firm and invested in securities elsewhere. Mr Justice Lamont seemed aware that the regulated firm's assets could not be "taken out" and invested in the book assets of other firm's, since investors cannot invest at book values.[4] Instead they have to invest at the rate they earn by buying those assets in the market place. These comments are consistent with the basic economic definition of an opportunity cost, which is that it reflects what can be earned elsewhere by reallocating resources.

In implementing this criterion, expert witnesses have traditionally used the discounted cash flow (DCF) model that estimates what the investor expects to earn in terms of dividends and capital gains and risk based models, such as the capital asset pricing model (CAPM) and other risk premium based models. Following from this is the second element, that the fair return is based on risk. Mr Justice Lamont was aware that investors required higher rates of return if the investment risk is higher. As a result, the first step in analysing fair and reasonable financial costs is to assess the risk of the firm and then the fair opportunity cost that flows from that.

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[4] So-called "comparable earnings" (CE) testimony, sometimes presented to this board, fails Mr. Justice Lamont's definition, since it is based on accounting ROEs that are not an opportunity cost. As well, CE evidence has no basis in economic or financial theory.

Q. HOW DO BOARDS ASSESS RISK?

A. Investors are concerned about the overall risk they face on the market value of their investment. For all firms this reflects three basic elements:

- Business risk
- Financial risk
- Investment risk

Business risk is the risk that originates from the firm's underlying "real" operations. These risks are the typical risks stemming from uncertainty in the demand for the firm's product resulting, for example, from changes in the economy, the actions of competitors, and the possibility of product obsolescence. This demand uncertainty is compounded by the method of production used by the firm and the uncertainty in the firm's cost structure, caused, for example, by uncertain input costs, like those for labour or critical raw or semi-manufactured materials. Business risk, to a greater or lesser degree, is borne by all the investors in the firm. In terms of the firm's income statement, business risk is the risk involved in the firm's earnings before interest and taxes (EBIT). It is the EBIT, which is available to pay the claims that arise from all the invested capital of the firm, that is, the preferred and common equity, the long-term debt, and any short-term debt, such as debt currently due, bank debt and commercial paper.

If the firm has no debt or preferred shares, the common stock holders "own" the EBIT, after payment of corporate taxes, which is the firm's net income. This amount divided by the funds committed by the equity holders (shareholder's equity) is defined to be the firm's return on invested capital or ROI, and reflects the firm's operating performance, independent of financing effects. For 100% equity financed firms, this ROI is also their return on equity (ROE), since by definition the entire invested capital has been provided by the equity holders. The uncertainty attached to the ROI therefore reflects all the risks prior to the effects of the firm's financing and is commonly used to measure the ***business risk*** of the firm.

As the firm reduces the amount of equity financing and replaces it with debt or preferred shares, two effects are at work: first the earnings to the common stock holder are reduced as interest and preferred dividends are deducted from EBIT and, second the reduced earnings are spread over a smaller investment. The result of these two effects is called financial leverage. The basic equation is as follows:

$$ROE = ROI + [ROI - R_d(1-T)]\frac{D}{S} \tag{1}$$

where D, and S are the book values of debt and equity respectively, T is the corporate tax rate and R_d is the embedded debt cost. If the firm has no debt financing (D/S =0), the return to the common stockholders (*ROE*) is the same as the return on investment *(ROI*). In this case, the equity holders are only exposed to business risk. As the debt equity ratio increases, the spread between what the firm earns and its borrowing costs is magnified. This magnification is called financial leverage and measures the ***financial risk*** of the firm.

Investment risk is then the sum of the risks faced by investors in valuing the stream of cash flows generated from the firm's business after making its commitments to the bondholders. These risks include, for example, interest rate risk, where common share values tend to change inversely with interest rates, so that even if a utility had no business or financial risk, similar to a Government of Canada bond, it would still have interest rate risk and require an interest rate risk premium. Also investors constantly revise their expectations concerning future expected cash flows and these information risks cause share prices to rise and fall making them risky. These problems tend to be particularly acute for firms in high growth industries where there are significant information problems and smaller firms where there are fewer analyst reports and investors face huge information asymmetries, since less information is "in the market."

For regulated firms we recognise that their cash flows and values are affected by the actions of the regulator. This is often called ***regulatory risk***, but in my judgment in almost all cases Canadian regulators reduce and do not increase the risk of the utility. They do this in several ways depending on their particular style.

One style is to take a "hands off" approach, which would be to have very few hearings and act on a complaint basis. As a result allowed returns are often not reviewed for long periods of time and returns are often high and volatile. Many US utilities are regulated in this way where even major companies can go years without their allowed ROEs being reset. This approach is not often followed in Canada except for smaller utilities where the regulatory costs outweigh their benefits.

A second style is to offset business risk with financial risk. As indicated above increasing debt levels exaggerate any business risks. As a result a regulator can increase the debt levels for lower business risk utilities to equalise the sum of business and financial risk. This is the policy actively followed by the National Energy Board, the Alberta Energy and Utilities Board and the CRTC.[5] The advantage of this approach is that all the utilities are then allowed the same ROE. Alternatively the same common equity ratio can be awarded and then a differential allowed risk premium used to offset business risk differences. This board has done this in the past by allowing both Union Gas and EGDI the same 35% common equity ratio but Union Gas a marginally higher allowed ROE. The final possibility is a combination of the two where, for example, the BCUC has allowed both capital structure and risk premium differences form its low risk utility benchmark (Terasen or BC Gas)

A third style is for the regulator to actively intervene to lower the risk of the utility which then allows it to carry more tax efficient debt. This is important since equity costs are paid out of **after-tax** income, whereas debt costs are tax deductible. Hence, for example, if debt costs are 7.0% and equity costs are 9.0%, then at a 50% tax rate (for simplicity), the **pre-tax costs** are actually 18.0% for the equity (.09/(1-.50)) compared to 7.0% for the debt. Conversely the after tax costs are 3.5% and 9.0%; either way the costs of debt versus equity have to be compared on the same tax basis.[6] It then follows that the firm can reduce its financing costs by using more

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[5] The OEB has also used this approach for NRG, where they received the OEB formula ROE, but were allowed a deemed equity component of 50%. In NRG's last rate case NRG requested a deemed equity component of 35% and a 150 basis point increase over the OEB formula allowed ROE.

[6] This also applies to utilities that make "payments in lieu of taxes" (PILS) and face the same cost comparisons.

debt. It is these “same tax” cost comparisons, whether before or after tax, that competitive firms make in deciding their financing, and which a regulator should also use. However, unlike a competitive firm the tax advantages of debt flow though to the ratepayers in a lower revenue requirement, rather than to the shareholders so regulated firms rarely request lower common equity ratios, since there is nothing “in it” for them.

The most basic way a board can lower a utility’s risk is through frequent rate hearings and setting annual rates on a forward test year to ensure that all system costs are recovered. The regulator can then establish deferral accounts to capture major forecasting errors. Instead of having the utility’s stockholders “eat” any cost over runs in terms of a lower earned rate of return, the regulator can simply pass the extra costs to a balance sheet deferral account. The value of the deferral account is then charged to the ratepayers over some future time period. In this way “ratepayers” always pay the full cost of service and stockholder risk is lowered.

I have always advocated deferral accounts in areas where the utility cannot control the costs, so there are no efficiency losses. The reason for this is simply that the ratepayers as a class can bear these risks more easily than the shareholders. This Board has set up purchased gas variance accounts to make sure that all the costs of purchasing natural gas, for example are passed on to ratepayer thereby lowering the risk of Union Gas and EGDI. The BCUC has gone further in allowing a Revenue Stabilisation Adjustment Mechanism (RSAM) to capture forecast versus actual residential and commercial customer use of natural gas. This effectively removes weather risk from its gas distribution companies as well.

Flexible regulation also lowers business risk. By flexible regulation I mean the regulator being responsive to changing business risk. This is a hallmark of Canadian regulation, where any changes in the risk faced by the regulated firm invariably lead to a hearing to reallocate this risk to ratepayers. There are many examples of this, for example the shift from historic to forward test years dramatically lowered the risk of Canadian utilities during the 1970s and

1980s due to the very high rate of inflation during that period.[7] Similarly we have seen the NEB allowing higher depreciation rates for the mainline gas transmission companies such as the TransCanada mainline to reflect declining production from the Western Canadian Sedimentary Basin and increased risk of stranded pipeline assets.

Q. WHAT IS YOUR OVERALL ASSESSMENT OF THE RISK OF INVESTING IN CANADIAN UTILITIES?

A. It is minimal if not non-existent for many utilities, where the risk differences that remain are largely the result of the different regulatory styles discussed above rather than the underlying business risk. The most basic evidence for this is to examine the earned ROEs for regulated utilities and compare them with those allowed by the regulator. A risky utility would then confront factors that cause it to periodically over or under earn, in much the same that unregulated firms fail to meet analyst expectations and have to constantly revise their earnings forecasts.

The data for allowed versus actual returns usually only becomes available in rate hearings, since it is rarely reported to investors as regulated operations are usually rolled in to more diversified operations. It is these overall results that are reported in formal filings with securities regulators. However the data in Schedule 1 provides the earned vs. allowed Roes for the pipelines that are part of TransCanada Corporation and that in Schedule 2 the same data for three major gas LDCs.

There is a distinction between full cost of service pipelines regulated by the National Energy Board and those regulated on a forward test year basis. The Foothills pipeline bills its shippers for its full costs and exactly earns its allowed ROE. The TransCanada BC system (formerly ANG) is regulated on a similar basis to Foothills and the only difference is that on its full acquisition by TransCanada there were some reorganisation costs it absorbed so in 2003 it “voluntarily” under-earned its allowed ROE. I have always regarded Foothills and ANG as the

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[7] In the current low inflationary period the justification for a forward test year basis of regulation is much reduced. Moreover, it seems to lead to over-earning due to persistent over estimation of costs.

lowest risk regulated entities in Canada, since there is NO deviation of the earned from allowed ROE so in this sense there is no business or financial risk at all. Without any business risk, both these pipelines can finance with large amounts of debt, in fact prior to RH-2-94 they financed with 25-28% common equity.

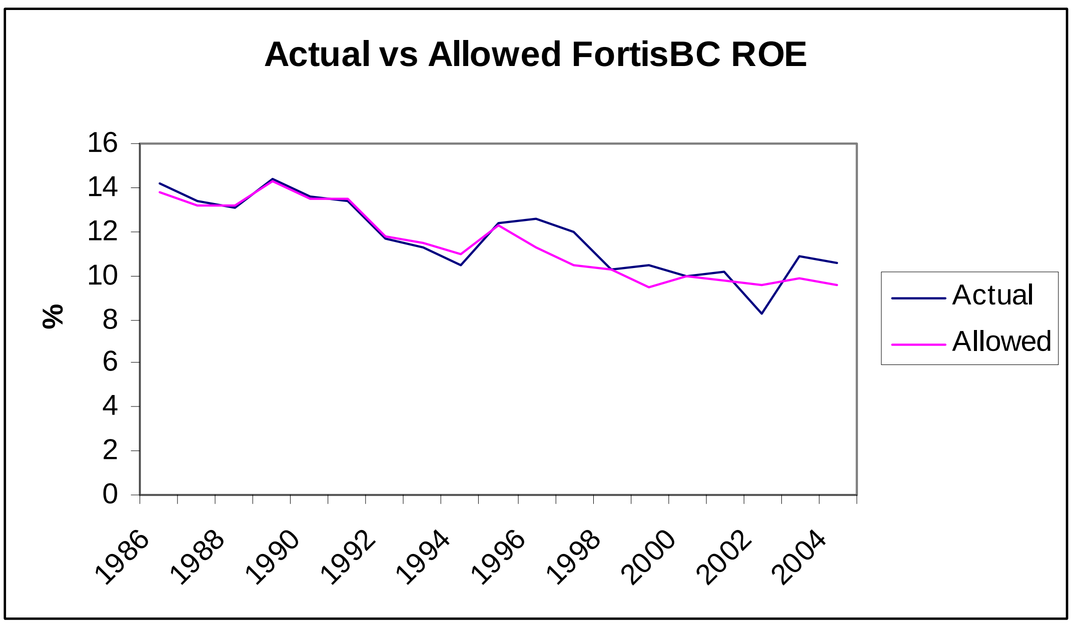
Unlike Foothills and ANG the TransCanada Mainline and TQ&M are regulated on a forward test year basis. This leaves the companies exposed to minor forecasting risks where the actual revenues and expenses may deviate from those expected and included in the revenue requirement. However, the use of deferral accounts and long term contracting with shippers that pay fixed demand charges significantly reduces this forecasting risk. The result is that both the Mainline and TQ&M consistently over-earn their allowed ROEs. Over this whole period the Mainline only failed to earn its allowed ROE once and on average over-earned by just over 0.25%, whereas TQ&M over-earned by slightly more and never failed to earn its allowed return.

In Schedule 2 is similar data for Union Gas, EGDI and Terasen (formerly BC) Gas. The data for Union and EGDI is based on weather normalised ROE's, since these utilities are not allowed deferral accounts for variances due to weather. In contrast, Terasen is allowed a comprehensive RSAM that takes into account not just the cost of purchased natural gas but also volume variances due to weather. Of note is that Terasen's over-earning is similar to that of the TransCanada Mainline. In contrast Union and EGDI do not have as many deferral accounts and over-earned to a much higher degree than the other comparators.

If risk is the possibility of incurring harm or a loss the insight from the data in Schedules 1 & 2 is that regulated utilities in Canada have very little risk. It is also interesting that the degree of over earning decreases with the use of deferral accounts. The full cost of service pipes can be regarded as having 100% protection, since they neither over nor under-earn. The Mainline and TQ&M have limited room to improve their earnings, since a large part of their revenue and costs are fixed. The same goes for Terasen Gas with its comprehensive deferral accounts so that it looks like the NEB forward test year pipes. The two Ontario LDCs with fewer deferral accounts have over-earned the most. In contrast, Terasen Gas has been on performance based regulation (PBR) since 1998 and its over-earning has increased. Terasen Gas has generated cost savings and even though these savings have shared with ratepayers, they have also enhanced its ROE.

Q. ARE THERE ANY ELECTRICITY COMPARATORS?

A. The closest comparator that I am aware of would be FortisBC, formerly West Kootenay Power. It is a very small integrated electric utility in BC with a revenue requirement in 2005 of about $184 million. FortisBC generates its power from very low cost hydro and long term power purchase contracts with BC Hydro, so it is similar to the Discos covered by Board Staff's proposals. In February 2005 in answer to BCOAPO IR #91.2 Fortis BC provided the actual versus allowed ROE for its regulated operations back to 1986. The following graph summarises this data:



FortisBC felt that this allowed vs. actual ROE performance is important, since they provided similar data in a presentation to DBRS in October 2004 with a sub heading "a consistent history of earning the regulated ROE." My only qualification is that the correct sub heading should have been "over earning." However, the most important insight is the very limited variability in the actual ROE around the regulated ROE until 1996, when FortisBC moved to a

PBR mechanism. After 1996 the actual ROE clearly moves above the allowed ROE indicating, "over earning." The only exception is 2002 when the failure to earn the allowed ROE was due to integration expenses and software write-offs unrelated to its operations. From 1996-2004 the average ROE exceeded the allowed by 0.56% and if 2002 is ignored the excess increases to 0.78%. This data indicates the basic fact that PBR tends to increase allowed ROEs without any increase in risk, since the possibility of under earning is minimal.

Q. HOW WOULD YOU RANK CANADIAN UTILITIES IN TERMS OF RISK?

A. Trying to rank Canadian utilities on the basis of risk is difficult since it is like splitting hairs. However, before the Alberta EUB in their 2003 generic hearing I compared the different utilities in the Alberta generic hearing on the following basis:

I: The major short term risks caused by cost and revenue uncertainty:

- On the cost side since regulated utilities are capital-intensive most of their costs are fixed. The major risks are in *operations and maintenance* expenditures. However, over runs are usually under the control of the regulated firm and can be time shifted between different test years.

- On the revenue side the risks largely stem from rate design, critical features are:

  - Who is the customer and what *credit risk* is involved. For example, electricity transmission operators who recover their revenue requirement in fixed monthly payments from the provincially appointed TA, who is responsible for system integrity, have less exposure than the local gas and electricity distributors who recover their revenue requirement from a more varied customer mix involving industrial, commercial and retail customers.

  - Is there a *commodity charge* involved? The basic distribution function is very similar to transmission, except when the distributor buys the gas or electricity wholesale and then also retails the commodity. The distributor is then exposed to weather and price fluctuations depending on rate design.

  - Even if there is no commodity charge, how much of the revenue is recovered in a *fixed versus a variable usage* charge? Utilities that recover their revenue in a fixed demand charge face less risk than those where the revenues have a variable component based on usage.

II: The medium and long-term risks are mainly as follows:

- *Bypass risk*. The economics of regulated industries are as natural monopolists involved in "transportation" of one kind or another. However, one utility may not own all the transportation system so that it may be economically feasible to bypass one part of the system. This happens for local gas distributors, when a customer can access the main gas transmission line directly, rather than through the LDC, or when a large customer may be able to bypass part of the transmission system. This is often a rate design issue: a postage stamp toll clearly leads to uneconomic tolls and potential bypass problems, whereas distance or usage sensitive tolls will discourage it. Similarly, rolled in tolling will encourage predatory pricing by potential regulated competitors.

- *Capital recovery* risk. Since most utilities are transportation utilities, the critical question is the underlying supply and demand of the commodity. If supply or demand does not materialise then tolls may have to rise and the utility may not be able to recover the cost of its capital assets. Depreciation rates are set to mitigate this risk to ensure that the future revenues are matched with the future costs of the system.

A common thread running through the above discussion is rate design and regulatory protection. There can be significant differences in underlying business risk that are moderated by the regulator in response to those differences. The lowest risk utility is then one with the strongest underlying fundamentals and the least need to resort to regulatory protection. In contrast, another utility may have similar short-term income risk, but only because of its need to resort to more extensive regulatory protection. In this case it faces more problematic longer-term risks.

On this basis I judged the lowest risk regulated utilities in Canada to be electricity transmission assets, since these have the following characteristics:

- Minimal forecasting risks attached to O&M
- Revenue recovery via the TA through fixed monthly charges
- Limited (non existent) by-pass problems
- Minimal capital recovery problems, since there are many suppliers of electricity as a basic commodity.
- Deferral account for capital expenditures

and recommended 30% common equity ratios.

I then placed the gas transmission pipelines as the second lowest risk group. Here I classified Foothills and the TCPL BC System (formerly ANG) as of equivalent risk to electricity transmission assets with NGTL having marginally more risk, since it is exposed to bypass and recovers its revenues through a forward test year. However, the combination of distance sensitive tolls, the ability to offer load retention service and a more rapid depreciation rate significantly reduce any increase in risk NGTL may have faced since 1995. I therefore judged that on its own NGTL could maintain its financial flexibility on the same 30% common equity ratio allowed mainline gas transmission assets. However, because NGTL was then allowed 32% and was almost "indistinguishable" from the TCPL Mainline, I recommended the same 33% common equity ratio then allowed the Mainline.

I then judged the local distribution companies (LDCs), including both gas and electric as the next riskiest. These companies are distinguished by their retail operations, which mean that their revenues are recovered from a large number of industrial, commercial and residential consumers. This exposes them to both the business cycle and weather fluctuations. This revenue recovery is also a function of their rate design that may expose them to commodity charges and a fixed and variable recovery charge. Within this group the conventional yardstick for LDCs is that Consumers (Enbridge Gas Distribution Inc) and Union Gas are both allowed 35% common equity.[8] However, whereas the Ontario Energy Board allows a purchased gas variance account (PGVA) to ensure that the full costs of gas are recovered, they are still subject to volume related variances. In contrast, the BCUC allows BC Gas (Terasen Gas) a more comprehensive deferral account, but limits the allowed common equity ratio to 33%. With these yardsticks I recommended 35% common equity ratio for a typical local distribution companies.

Finally, I recommended 42% as the upper end of a reasonable range for the common equity of ATCO pipelines, given that the BCUC allows PNG, a smaller and much riskier pipeline, 36% common equity. However, this ranking was provisional being dependent on the EUB

[8] In a 2006 settlement Union settled a number of issues, one of which increased its common equity to 36%.

developing clear rules on intra Alberta pipeline competition and a rate design that lowers ATCO Pipeline's risk. In the years since the Alberta generic hearing I have testified in business risk hearings for the TransCanada Mainline, FortisBC, Terasen Gas and Union Gas and have not changed the above judgment.

III ALLOWED RETURN ON EQUITY (ROE)

Board Staff proposes an allowed ROE of 8.37% for existing distribution assets and has suggested an enhanced return of 8.87-9.87% for new assets by allowing the floatation allowance to increase from 0.50% to 1.00-2.0%. These estimates seem to be based loosely on the work of Lazar and Prisman (LP) (the Schulich Report) and would be updated annually, possibly by consulting a "panel" of experts.

I generally agree with the range of estimates that Board staff recommends but caution against allowing a two tier rate base, where some equity dollars earn one rate and others another. This seems to be unnecessarily complicated and adds to the regulatory burden for some relatively small utilities. Further, and as I will discuss later there is no evidence that utilities have any market access problems at current allowed financial parameters. That is, the capital attraction test is met by current financial parameters and an extra premium of 1.0-2.0% is unjustified and based as far as I can tell on no evidentiary basis.[9] I am not aware of floatation costs ever being allowed in this range. In terms of the ROE I will not comment in detail on how LP arrived at their estimates but will point out that their estimates have not been tested through information requests or cross examination, further they are not standard estimation techniques.

The Board had evidence in this year's Union Gas hearing on current estimates of the fair return. Dr. Vilbert provided the following DCF estimates that I extracted from his testimony and included in my own Union Gas evidence

	DCF MJV-4	DCF Multi MJV-6	CAPM MJV-11

[9] There is also the question of whether the floatation cost allowance should be allowed for municipally owned utilities. However, given the Alberta EUB's decision as to determining the ultimate owner, I see no reason to change the OEB formula allowed ROE.

Canadian Utilities	5.7	6.8	8.2
Emera	9.6	9.1	5.1
Enbridge	10.0	7.8	9.0
TransCanada	8.5	8.0	7.8
Fortis	7.4	6.9	6.0
GMI			6.8
Average	8.24	7.72	7.15

To be fair to Dr. Vilbert he then went on to make "leverage adjustments," since he regarded these estimates as being based on market values, whereas the book value leverage is higher. However, I disagree with the rationale behind these leverage adjustments, as has the Alberta EUB when confronted with the same arguments. As a result, I regard these estimates as being broadly consistent with the LP estimates subject to the addition of a floatation cost allowance. The last time I presented fair return estimates was in the Terasen Gas hearing in the fall of 2005. At that time I recommended a 7.75% ROE, so the estimates of LP, Dr. Vilbert and I are all broadly consistent. However allowed ROEs are higher.

For 2006 Board Staff explain (page 7) that the allowed ROE was 9.0% for the electricity distributors. For reference purposes the allowed ROE that followed from board adjustment mechanisms used elsewhere was 8.89% for the National Energy Board, 8.95% for GMI, 8.93% for the Alberta EUB regulated utilities and 8.74% for EGDI. Broadly speaking the 9.0% allowed ROE for the Discos was in line with what was being allowed elsewhere. I would therefore expect that the Ontario Discos should continue to get the fair ROE that is being allowed elsewhere ***unless*** there is a full hearing to test the assumptions behind the allowed ROE. In this respect it is important to note that the OEB fully reviewed its adjustment mechanism in 2003 and subsequently both the NEB and BCUC have fully investigated their adjustment mechanisms, so there is a full evidentiary basis for their decisions.[10]

Q. HOW DOES THE ALLOWED ROE CHANGE YEAR BY YEAR?

[10] I participated in all three hearings, Ms McShane in two of them and Drs. Kolbe and Vilbert and Dr. Cannon in one.

A. My understanding is that the major motivation behind the adjustment mechanisms is the desire to avoid repetitive hearings and any confusion over how the ROE is determined. By putting a utility on an automatic adjustment mechanism, the capital markets have a clear picture of future profits and the risk of being awarded an unexpectedly low allowed ROE is reduced along with regulatory lag. It is my perception from reading analyst reports that the adjustment mechanisms have been well received because of this.

In terms of estimating the fair return the two basic methods are the risk premium and the DCF method. The standard DCF or Gordon growth model is

$$K = \frac{d_1}{P_0} + g \qquad (2)$$

With the Gordon model the investor's opportunity cost or fair return is the sum of the forecast dividend yield (d_1 / P_0) plus growth (g). The assumption is that, all else constant, the stock price will grow with the underling growth in earnings and dividends. This is how Dr. Vilbert estimated the fair return in his exhibit MJV-4 referenced above. If growth is not expected to be constant then the stock price will not grow with the underlying earnings so two or three stage growth models are used to capture more realistic growth patterns. These are the estimates Dr. Vilbert provided in MJV-6 “multi DCF” reference above.

The DCF model has the advantage of using firm specific information and some of it, the dividend yield, is directly observable. However, the decline in pure play utilities and the difficulty in estimating growth expectations reduce the model's usefulness. For a time people believed that analyst growth expectations were useful proxies for growth. However, the rampart conflicts of interest on Wall Street, brought out by the US Attorney General for New York in his settlement with major US brokerage firms, has provided the logic behind academic research that has shown that these estimates are biased, that is, they are persistently over-optimistic. Further the big problem with the DCF model is that it is not easy to automatically update since both the dividend yield and growth expectations will change with the business cycle.

The other model is the risk-based model, of which the Capital Asset Pricing Model or CAPM is the overwhelming favourite. The CAPM is as follows:

$$K = R_F + MRP * \beta \qquad (3)$$

In this case the investor's opportunity cost is the return for bearing risk plus a risk premium. Unique to the CAPM is that the risk premium is that required of the overall market, the market risk premium (MRP) plus an adjustment for the risk of an individual firm, its beta coefficient.

The developers of the CAPM won the Nobel Prize in economics and it is the premier model in finance since like the DCF model it captures what is of interest to an investor. In this case the time value money is reflected in the risk free rate and the risk value of money is reflected in the risk premium.

The ***risk-free rate*** *(R_F)* reflects the investor's holding period, which can be anywhere from one day to forever. However, since one equity holder simply sells the shares to another, the market's risk free rate is the longest available, since in aggregate the stock has to be held. It is for this reason that we use the longest risk free rate that on 30-year government of Canada bonds, as the proxy for the risk-free rate. The risk free rate on the long bond assumes that the coupons are reinvested, similar to the earnings from the utility, which means that the reinvestment rate assumptions are also reasonable. The ***market risk premium*** (MRP) is then estimated over very long time periods, since equity returns on the stock market over very short time periods are highly unlikely to reflect investor expectations. The final piece of information is the ***beta*** **(β)** coefficient. This measures the way in which a share price behaves in a diversified portfolio. A low beta coefficient simply indicates that the shares add very little risk to a diversified portfolio, whereas a high one indicates that there is a larger increase in risk.

Since diversified portfolios are the core of finance and are reflected in the institutional nature of the stock market it is difficult to escape the logic of the CAPM.[11]

The CAPM is only one version of a risk premium model, but conceptually it has the advantage of splitting the risk premium into the market risk premium, which benchmarks overall risk and a specific risk adjustment for the firm or industry. However, an adjustment mechanism does not need either the beta coefficient or the market risk premium. To see this note that we can estimate the utility risk premium as the market risk premium times a utility beta or through other means and determine a going in risk premium. For example in its 1994 generic hearing the NEB determined that the pipeline risk premium was 3.0% at a forecast long Canada bond yield of 9.25% for a fair return of 12.25%. The question is then simply how does this 12.25% vary with changes in the long Canada bond yield? Objectively we know that the fair return will change with the risk free rate, but whether it moves 100% or less depends on the behaviour of the utility risk premium.

In 1994 I testified before the BCUC with my late colleague Dr. Berkowitz and recommended an 80% adjustment of the allowed ROE to changes in the long Canada yield. I have subsequently testified that the 75% adjustment allowed by the NEB, the OEB and the Alberta EUB is reasonable and has given approximately correct answers. In contrast until recently the BCUC formula has used a 100% adjustment for long Canada yields below 6.0%, but it too has now moved to a 75% adjustment.

The reason why the fair return does not adjust 100% with the long Canada bond yield is that the long Canada bond yield is determined by three basic factors, the real return, an adjustment for expected inflation and taxes. As inflation increased in the 1970s and 1980s the spread between the long Canada bond and the utility fair return narrowed, as the long Canada bond became very risky due to the budgetary problems at all levels of government. This produced a

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[11] I would disagree with the LP estimates to the extent that they are based on a forward rate for the risk free rate, a very short time period for estimating the market risk premium and one recent beta estimation period. The latter two estimation methods leave the estimates unreliable and the former approach to estimating the risk free rate is unnecessarily complicated and of little value.

legitimate concern that government would inflate itself out of its budgetary problems causing real losses to bond holders. This combined with the fact that interest is fully taxable meant that we had periods in the early 1990s when in my judgment the utility risk premium was very low if not non-existent.

Since the government budget deficits moved into surplus in 1997 we have seen government debt being retired and gradually the markets have come to believe that the core inflation rate will stay in the Bank of Canada's 1.0-3.0% range. Consequently we have been in a declining interest rate period for some time and long Canada bond yields have stayed around 4.5% over the last year despite concerns about short run energy induced inflation. The result has been that the utility risk premium over the long Canada bond has increased as the risk of the long Canada bond has declined. This is the underlying phenomenon that the 75% adjustment mechanism has captured. As a result even though I do not believe in mechanical formula adjustments, in my judgment the 75% adjustment of the allowed return to long Canada bond yields has worked out remarkably well.

Another important point is that since the NEB's 1994 hearing many of the utilities that were used to estimate the fair return have disappeared, either due to consolidation or a change in the nature of their business. This has made it increasingly difficult to derive a reasonable sample of Canadian utilities to use as proxies for beta estimation, as well as DCF estimates. As a result ROE evidence is now more subjective and contentious than it was then. This further enhances the usefulness of the formula approach to setting the allowed ROE.

For these reasons I would recommend that Board Staff reject their proposed "panel of experts" and their new estimate of the ROE. Instead I see no reason to change the ROE adjustment mechanism that the OEB reviewed in RP-2002-0158. In its January 16, 2004 decision the Board stated (paragraph 142)

> "Therefore, with respect to the first and primary issue of whether a new benchmark ROE should be established for EGDI and Union, we find that the current ROE Guidelines methodology continues to produce appropriate prospective results. We have not found any demonstrated need to set a new benchmark ROE."

Quite simply nothing of substance has changed in the past 2 ½ years to justify amending the OEB decision without a full evidentiary record. In my judgment this represents a fairer and transparent way of determining the allowed ROE than that proposed by Board Staff.

IV Capital Structure

Q. WHAT ARE BOARD STAFF'S PROPOSALS?

A. Board staff is recommending 36% common equity, up to a 4% preferred share component and 60% debt composed of both long and short-term debt. They propose doing away with the size-based adjustments included in the original Cannon proposals.

Q. HOW DOES THIS COMPARE WITH OTHER JURISDICTIONS?

A. It is broadly in line with what is allowed elsewhere. The most obvious comparator is the Alberta Generic hearing in 2003 where the EUB stated (Generic Cost of Capital Decision page 35)

> "To determine the appropriate equity ratio for each Applicant, the Board will consider the evidence and, where applicable, the experts' views and rationales in each of the following topic areas:
>
> 1. The business risk of each utility sector and Applicant;
> 2. The Board's last-approved equity ratio for each Applicant (where applicable);
> 3. Comparable awards by regulators in other jurisdictions;
> 4. Interest coverage ratio analysis; and
> 5. Bond rating analysis."

The EUB in its decision 2004-052 (page 55) examined the appropriate equity ratios across a very large class of utilities of varying sizes and approved the following ratios.

Table 13 Board Approved Equity Ratios

	Last Board-Approved Common Equity Ratios (%)	2004 Board Approved Common Equity Ratios (%)	Change in Approved Common Equity Ratio (%)
ATCO TFO	32.0	33.0	1.0
AltaLink	34.0	35.0	1.0
EPCOR TFO	35.0	35.0	0.0
NGTL	32.0	35.0	3.0
ATCO Electric DISCO	35.0	37.0	2.0
FortisAlberta (Aquila)	N/A	37.0	N/A
ATCO Gas	37.0	38.0	1.0
ENMAX DISCO	N/A	39.0	N/A
EPCOR DISCO	N/A	39.0	N/A
AltaGas	41.0	41.0	0.0
ATCO Pipelines	43.5	43.0	(0.5)

The EUB stated (page 49) "The Board considers that business risk, in isolation, would indicate that gas distribution companies should have a common equity ratio that is 0-2 % higher than the equity ratio for fully taxable electric distribution companies." Taking EGDI as the benchmark in Ontario this would indicate a 33% common equity ratio for an Ontario Disco. However, after considering the other factors mentioned above the Alberta EUB awarded a 37% common equity ratio for the Discos and 38% for gas LDCs. It then allowed another 2% for the non-taxable municipal Discos. In discussing the major Alberta Discos the EUB made the following conclusions.

"ATCO Electric Distribution

The Board considers that ATCO Electric Distribution does not have any material differences in business risk from the typical electric distribution company.

The Board also notes that ATCO Electric Distribution has preferred shares in its capital structure. Although the preferred shares provide additional support to the capital structure, in this analysis, the Board has evaluated the appropriate common equity ratio as if the company had no support from its preferred shares.

The Board concludes that an appropriate common equity ratio for ATCO Electric Distribution is 37.0%.

The Board will further address the issue of ATCO's preferred shares below.

ENMAX Distribution

The Board considers that ENMAX Distribution does not have any material differences in business risk from the typical electric distribution company.

The Board notes ENMAX's argument that it has additional risks due to its municipal ownership, including a fixed dividend requirement, lack of equity access, and the change in regulator, and that as a result it required a capital structure with 50% common equity.

The Board does not agree with ENMAX that its fixed dividend or lack of access to public equity markets raises its risks in the circumstances. In the Board's view, having established a fair return, the Board need not concern itself with the particular internal policies to which a utility may be subject regarding distributions of dividends or acquisition of equity. The Board also considers that the change in regulator for ENMAX does not result in ENMAX having higher risks, all else being equal, than other electric distribution companies regulated by the Board.

With respect to the ENMAX DISCO, which just came under Board jurisdiction in 2004, the capital structure determined in this Proceeding is based on the assumption that the deferral accounts that the Board will ultimately approve for this Applicant will not be materially different than those in existence at the time of this Proceeding for FortisAlberta/Aquila and ATCO Electric Distribution.

For the same reasons that were provided with respect to EPCOR Transmission above, the Board concludes that the equity ratio for a non-taxable electric distribution company should be 2.0% higher than the equity ratio for a fully taxable electric distribution company.

Therefore, the Board concludes that an appropriate common equity ratio for ENMAX Distribution is 39.0%.

EPCOR Distribution

The Board considers that EPCOR Distribution does not have any material differences in business risk from the typical electric distribution company.

With respect to the EPCOR Distribution, which came under Board jurisdiction in 2004, the capital structure determined in this Proceeding is based on the assumption that the deferral accounts that the Board will ultimately approve for this Applicant will not be materially different than those in existence at the time of this Proceeding for FortisAlberta/Aquila and ATCO Electric distribution companies.

For the same reasons that were provided with respect to ENMAX Distribution above, the Board concludes that an appropriate common equity ratio for EPCOR Distribution is 39.0%."

In my judgment these allowed common equity ratios are marginally generous, since I recommended a 35% common equity ratio for both the Discos and gas LDCs. However, Board Staff's recommended 36% common equity ratio brackets the Alberta EUB's decision of 37% and my recommended 35% and I regard this as fair and reasonable.

Q. WHAT ARE YOUR VIEWS ON A PREFERRED SHARE COMPONENT?

A. I don't think that it is appropriate or needed for municipal discos. Preferred shares are issued by companies with private shareowners as a means of increasing key coverage ratio targets and thus improving access to capital markets. I don't believe that the municipal Discos currently have any financial access problems. As a result I would recommend a 36% common equity ratio and the balance in debt.

Q. DO YOU AGREE ON SIZE BASED CAPITAL STRUCTURES?

A. No. It is undoubtedly true that smaller utilities have inferior bond ratings and their debt sells on higher spreads than larger ones. This is due not to default risk but to the lesser liquidity in their bonds. Normally if they can access public bond markets it is through private placements so that the debt is difficult to trade and thus attracts a yield premium. At the extreme for very small utilities they may not be able to access the public markets at all and are restricted to bank debt and the term loan market. However, there are severe conceptual problems with allowing higher common equity ratios for smaller utilities, since it results in higher utility rates.

It has to be remembered that utilities are regulated to generate the scale economics of natural monopolies and the pricing benefits of competition. In my judgment in a competitive market many of the smaller utilities would not survive if they were not regulated, since they would be taken over or subject to predatory pricing. In this case regulating them to allow higher rates is in some sense contrary to the economic objectives of regulation. At a fundamental level it is questionable that one citizen of Ontario has to pay higher rates simply because their Disco is small and inefficient. By imputing a standard ROE, standard capital structure and standard cost of debt there is by definition a standard financial charge applicable to all Ontario Discos. This satisfies a broader definition of fairness and may be closer to the economic justification for regulation.

Related to the same issue, I see no need for a bonus due to financing "problems" faced by any Ontario Disco due to their municipal ownership. While it is true that they can not float a new equity issue, they can receive new funds from their owner. As the Alberta EUB decided when faced with the same issue for ENMAX

> *"The Board does not agree with ENMAX that its fixed dividend or lack of access to public equity markets raises its risks in the circumstances. In the Board's view, having established a fair return, the Board need not concern itself with the particular internal policies to which a utility may be subject regarding distributions of dividends or acquisition of equity."*

That is, a Board should not look at the ultimate owner of a utility, but just set fair financial parameters [12]

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[12] In this respect it also has to be remembered that the "equity" in a municipal Disco has not been raised in the capital market from investors seeking a fair rate of return. It has been raised from ratepayers through earnings retained and backed by the taxing power of the municipality. It is a deep question as to who the equity owner is in a municipal Disco and what return they require on their investment.

V DEBT COSTS

Board Staff envision that utilities be allowed their embedded debt cost except on inter-affiliate debt where a typical spread over long Canada's be used to impute a debt cost. This imputed debt cost would be based on a "suitable sample of corporate A/BBB bonds." They further propose a limit of 8% on short term debt and recommend matching the maturity of the debt to the rate base. In my judgment these recommendations if adopted could cause some minor problems.

In terms of the spread over equivalent maturity Canadas the recommendations of LP do not recognise that frequently utility debt trades on significantly lower spreads than non-utility debt with the same rating. In contrast to competitive firms, ROE regulated firms have much more stable earnings. Consequently, even during recessions they have access to capital markets on reasonable terms. The following table gives the yield spread on CBRS Utility and Non-Utility indexes during the last major downturn.[13]

Utility vs. Non-Utility Yield Spreads

	CBRS Non-Utility Less Utility Yield Spreads		
	A+	A	BBB
1989	15	8	-9
1990	18	0	6
1991	-8	-18	17
1992	49	48	138
1993	145	36	271
1994	68	36	105

[13] CBRS has now been taken over by S&P as a result the format of the data has changed and the table cannot be updated.

A positive value in the first column, for example, means that in 1989 non-utility A+ rated debt yielded on average 15 basis points *more* than A+ utility debt. The rating categories run from the effective best in Canada, A+ to the lowest investment grade, which is BBB.[14] Within the grade there are sub grades and firms often trade at a higher level before being upgraded from say BBB to A. However, we would expect that the yield spread would average out to zero, that is non-utility A bonds would yield the same as utility A bonds. As can be seen in the above table, this was not the case during the last recession. As the economy weakened in 1990 and 1991 and hit bottom in 1992 concern over credit risk heightened and spreads widened dramatically. From 1992-1994 non-utility issuers saw a dramatic widening of their spreads compared to "equivalent" utility issuers. In many cases they found it difficult to raise capital on reasonable terms. However, as the CBRS data shows, utility issuers were not affected to the same degree and the capital market financed utility debt at lower yields across all rating categories during the last recession. Effectively, a "flight to quality" often makes it easier for utilities to raise capital during weaker economic times than non-utilities.

For this reason I suggest that the Board set an imputed debt cost on inter-affiliate debt based on the borrowing cost of EGDI's traded debt plus a 20 basis point liquidity premium reflecting that EGDI debt is well traded in the capital market. At the end of 2005 EGDI debt was rated DBRS A the same as Toronto Hydro and their 7 year bond issues were both trading at about a 50 basis point spread over similar maturity Canada bonds. This was also the same spread for EPCOR Utilities that has a DBRS A (low) rating. Quotes for the current yields on utility debt can readily be obtained from any of the major investment dealers.

In terms of setting the maturity of the debt, Board Staff proposals are unnecessarily restrictive. Larger utilities can match since they have larger amounts of debt outstanding. However, smaller utilities frequently have to wait and aggregate their borrowing needs so that they have the volume to access the private placement or the public markets. Until this happens they are often restricted to bank term loans or shorter term loans with interest rate swaps to fix their

[14] There were and still are very few AAA rated corporate issuers to the extent that CBRS stopped calculating AAA-rated average yields.

interest rate exposure. Imposing a straight jacket maturity policy will increase costs since spreads tend to decline with size and marketability. Also many smaller utilities have to be opportunistic in raising capital when it is available. There have been times in the Canadian capital market when BBB rated debt was difficult to place on reasonable terms as to maturity and cost.

VI FINANCIAL ATTRACTION

Q. CAN UTILITIES ATTRACT CAPITAL ON REASONABLE TERMS WITH 36% COMMON EQUITY AND THE OEB ADJUSTMENT MECHANISM?

A. Yes. The crucial test is in the capital market in terms of are investors happy with these financial parameters. If they are happy then they are willing to pay a premium to control these assets and earn the allowed ROE. On the other hand if they are unhappy then these assets will sell at a discount. As a result we can observe how happy investors are simply by observing the prices paid for regulated assets. In this respect there have been several transactions over the last few years while utilities have been an ROE adjustment mechanism:

- TCPL purchased the 50% of Foothills that it did not own at a market to book of 1.6 based on the common equity. Moreover since TCPL already owned 50% of Foothills the number of potential buyers was limited, which reduced the price.
- Aquila purchased TransAlta's distribution and retail business at a market to book of 1.5 based on a total rate base of $472mm (premium of $238mm);
- Fortis purchased Aquila's Alberta interests for a premium of $215mm over a rate base of $601mm.
- AltaLink purchased TransAlta's transmission business for a $200mm premium over a rate base of $644mm.
- Hydro Quebec recently announced a $266mm gain on the sale of its interest in the gas distribution assets in the province.
- KMI paid 2.7X equity book value in its purchase of Terasen Gas Inc.

In all these transactions the market value paid was very significantly in excess of the book value, whether estimated using the equity or the total book value. What this means is, that in addition to the fair return, utility investors also received a capital gain so their actual return was in excess of the fair return. It also means that investors are willing to “eat through” the non-earning takeover premium in order to earn the current allowed ROEs. This is direct evidence that the current financial parameters are attractive to investors.

In terms of debt capital the following are the DBRS bond ratings as of the end of 2005 for the major utilities with traded outstanding:

A	CU Ltd, EGDI, Terasen Gas Ltd, Union Gas Ltd, Toronto Hydro
A (Low)	EPCOR Utilities, Nova Scotia Power, TransAlta Utilities,
BBB (high)	Fortis

These are all good investment grade bond ratings indicating good access to capital.

Q DOES THIS COMPLETE YOUR COMMENTS ON BOARD STAFF PROPOSALS

A. Yes.

Appendix A: CV for Professor Laurence

ROE Performance of TransCanada Owned Pipelines

EARNED ROE vs ALLOWED

	TCPL		Foothills		TCPL BC (ANG)		TQM	
	Allowed	Actual	Allowed	Actual	Allowed	Actual	Allowed	Actual
1990	13.25	13.34	14.25	14.25	13.25	13.25	13.75	14.87
1991	13.5	13.65	14.25	14.25	13.38	13.38	13.75	13.94
1992	13.25	13.43	13.83	13.83	13.43	13.43	13.75	13.97
1993	12.25	12.31	11.73	11.73	12.08	12.08	12.25	12.5
1994	11.25	11.16	11.5	11.5	12	12	12.25	12.55
1995	12.25	12.56	12.25	12.25	12.25	12.25	12.25	12.65
1996	11.25	11.83	11.25	11.25	11.25	11.25	11.25	11.83
1997	10.67	11.15	10.67	10.67	10.67	10.67	10.67	10.94
1998	10.21	10.63	10.21	10.21	10.21	10.21	10.21	10.32
1999	9.58	9.64	9.58	9.58	9.58	9.58	9.58	9.94
2000	9.9	9.99	9.9	9.9	9.9	9.9	9.9	9.96
2001	9.61	10.01	9.61	9.61	9.61	6.86	9.61	10.21
2002	9.53	9.95	9.53	9.53	9.53	9.53	9.53	9.8
2003	9.79	10.18	9.79	9.79	9.79	8.21	9.79	10.21
2004	9.56	10.18	9.56	9.56	9.56	8.51	9.56	9.84
2005	9.46	9.66	9.46	9.46	9.46	9.46	9.46	9.82
Average	10.96	11.23	11.09	11.09	11.00	10.66	11.10	11.46
ovrearn		0.27		0.00		-0.34		0.36

NEB Regulated pipelines controlled by TransCanada Corporation, confirmed by TCPL in CAPP 31(a) in RH-2-2004 updated to 2005 from surveillance reports

ROE Performance of Three Major Gas LDCs

		EGDI		UNION		Terasen
	Allowed	Actual	Allowed	Actual	Allowed	Actual
1990	13.25	13.60	13.50	13.40		
1991	13.13	13.29	13.50	12.50		
1992	13.13	13.40	13.00	13.70	12.25	9.06
1993	12.30	14.43	12.50	14.30	n/a	11.91
1994	11.60	12.49	11.75	12.14	10.65	9.73
1995	11.65	12.66	11.75	12.12	12.00	12.03
1996	11.88	13.14	11.75	12.52	11.00	11.80
1997	11.50	13.00	11.00	12.26	10.25	11.27
1998	10.30	11.97	10.44	11.14	10.00	9.41
1999	9.51	10.77	9.61	10.10	9.25	10.70
2000	9.73	10.83	9.95	10.11	9.50	10.75
2001	9.54	10.03	9.95	11.45	9.25	9.38
2002	9.66	11.81	9.95	12.36	9.13	10.03
2003			9.95	12.08	9.42	10.23
2004			9.62	10.45	9.15	9.46
Average	11.32	12.42	11.21	12.04	10.15	10.44
Overearn		**1.10**		**0.83**		**0.29**

Terasen data is from the company’s response to the BCUC information request #1 in the BCUC review of its adjustment mechanism. The data for EGDI and Union is taken from Appendix B Schedule 10 of the pre-filed testimony of Dr. William Cannon in RP-2002-0158 updated with data from Information request J2-31.