EB-2011-0354

IN THE MATTER OF the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2013

BOMA's Cost of Capital Submissions

Introduction

Enbridge has failed to meet the Board's test for increasing the equity thickness of a gas distribution utility. That test is set out in EB-2009-0084 (the "Report") at p50. It states:

- "The Board has determined that a split of 60% debt, 40% equity is appropriate for all electricity distributors. Capital structure was not a primary focus of the consultation and the Board notes that the comments made by participants in the consultation largely supported the continuation of the Board's existing policy."
- "For electricity transmitters, generators, and gas utilities, the deemed capital structure is determined on a case by case basis. The Board's Draft Guidelines assume that the base capital structure will remain constant over time and that a full reassessment of a gas utility's capital structure will only be undertaken in the event of significant changes in the Company's business and/or financial risk.

The Board's Draft Guidelines [Draft Guidelines on a Formal Board Return on Common Equity for Regulated Utilities and its attached Compendium March 1997, Ontario] the sentence in the previous paragraph (Compendium, p30).

Finally, the Board stated at page 49 of the Report that:

> "The Board's current policy with regard to capital structure for all regulated utilities continues to be appropriate".

Enbridge has not met the test because its evidence does not demonstrate that the business risks, including financial risks, facing Enbridge have increased materially, since the Board's decision in EB-2006-0034, the last time the Board considered this issue. In that case, the Board increased Enbridge's equity thickness from 35% to 36%. In BOMA's view, Enbridge has not demonstrated that its business risk, including its financial risk, has increased since 2007.

The policy is not an issue in this proceeding. It is not on the issues list. Enbridge's evidence and, in particular, Concentric's evidence are replete with suggestions as to how the Board's policy on equity thickness might be improved, evolved, or refashioned to remedy its deficiencies (eg. J2.14, p1).

BOMA would take in issue with many of the assertions, but the point is that the Board's policy is clear and it is not up for review in this case. Had it been, these submissions would have taken a very different approach.

One of the more blatant examples of overly aggressive behavior in this proceeding in Enbridge/Concentric's continued insistence on comparing the business risks of Enbridge to the risks in 1993 (see, for example, Enbridge's assertion at point 9 on p3 of E2, T1, Sch2), blithely ignoring the fact that the Board's stated policy is that Enbridge must show changes in business risk that have occurred since the equity thickness issue was last addressed by the Board, namely 2007. This approach is overly aggressive, and wasteful of the Board's and intervenors' time and resources.

Finally, Enbridge/Concentric argue that it is unfair to establish that the only factor to evaluate the appropriateness of the utility's equity ratio is whether or not its risks have increased since the last Board decision (JT2.14). It does not say why.

Business Risk

The Board's test for the application of its capital structure policy, as stated above, is illustrated by the Board's decision in EB-2006-0034, the last time the issue was litigated.

In that case, Enbridge asked for an increase in its equity thickness from 36% to 38%. Enbridge submitted expert testimony of Mr. John Carpenter of the Brattle Institute, as its independent evidence that material changes had occurred (a business risk) since 1993 to justify a thicker common equity.

The Company had claimed that its business risk had increased over the last ten to fifteen years. However, the Board stated:

> "The Board agrees with parties who required that the regulatory and legislative risks which Enbridge currently faces are not greater than they were last year or in prior years, at least not materially greater" (p63).

The Board went on to note that:

> "Even if there was some recognition of increased business risk in the totality of the Company's arguments, this must be verified against the other positive considerations. For example, the Company's evidence indicates that customer growth continues to be strong, and natural gas remains the predominant fuel of choice in Enbridge's franchise area. Enbridge's customer base is consistently growing year after year. The Board does not see this as indicative of increased business risk".

BOMA suggests that these positive factors still apply today.

Consumer's customer base continues to grow at a rate of about 40,000 per year, and the evidence in this case demonstrates, if anything, the comparative advantage of gas over electricity has only increased. (See, for example, Ex. 1, E2, Sch 21.3, p7). Electricity and oil are not competitive with natural gas for space heating and water heating in Ontario.

Moreover, natural gas prices (commodity prices) have declined sharply since 2007, and are generally predicted to remain flat (low) for many years, due to the exploitation of shale gas in Canada and the United States. The Board will recall that, in its evidence in its recent rate case, Union stated that lower gas commodity prices benefitted the utility, both by reducing the costs of inventory and compressor fuel and by reducing the overall bill to customers. Union also noted that the greenhouse owners were its only group of the industrial customers in their franchise that even retained dual fuel capability [natural gas and residual oil]. The gas price advantages over oil and electricity are, if anything, even greater today than in 2007.

During the hearing, in responding to questions from the Chair, Mr. Coyne conceded that lower gas prices are a positive factor (they diminish the utility's business risk (V2, p198).

Enbridge's evidence (JT2.14, p2) suggests that the Company business risk is decreased by factors such as a lower number of gas leaks in 2011 than in 2007, lower gas price risk due to greater production from shale gas, and a neutral impact of technological change, since it states "technologies remain relatively comparative now and in 2007".

As noted above, Dr. Cannon assessed both the long term risk, which he calls Long-Run – Enterprise Viability or Recovery-of-Capital Risk, and the shorter term "return on capital" risk of both gas and electricity utilities in Ontario, in his December 1998 Discussion Paper on the Determination of Return on Equity in Ontario.

He defines return of capital risk as a risk associated with the events and trends which may permanently undermine the capacity of the utility to generate, on an ongoing basis, the cash flows necessary to permit the utility's owners to recover their investment and earn a fair rate of return on the funds they have committed to the business (p7).

He concludes that:

> "At a macro level, it is hard to imagine that there is any credible threat to long-run viability of either the electricity distribution industry, or the natural gas distribution industry in Ontario. The same conclusion holds at the micro level for the typical MEU and the typical gas LDC in Ontario" (p8).

BOMA agrees with Dr. Cannon's assessment.

Enbridge states that business risk normally includes supply risk, competitive risk, market risk, and regulatory risk (J1.3, p3) (Ex I, E2, Tab 1, Sch. 1, p2).

Enbridge goes on to state that the main factors that have increased its risk since 1993 are the "volumetric demand profile", "system size and complexity" and "environmental and technological advancements" [Ibid].

To the first point, "volumetric demand profile", Enbridge asserts that average residential weather normalized consumption declined an average of 1.2% per year from 2006 to 2013 (Ex I, Tab 1, Sch. 2, p4). Enbridge fails to mention that the principle reason for the gradual decline is the increasing effectiveness of Enbridge's own conservation and demand management programs. Enbridge is protected by a Lost Revenue Adjustment Mechanism ("LRAM") for any margin lost on account of the reduced consumption arising from the implementation of its CDM programs. More important, Enbridge has earned substantial profits over the last several years through the Shared Savings Performance Bonus. Enbridge has developed some effective DSM initiatives and has profited substantially from their success. BOMA supports Enbridge's efforts in DSM but is of the view it has already realized additional profits from these programs.

Second, the Average Use True Up Variance Account has protected Enbridge as it ensures that annual revenues are not affected by variances from the forecast average use decline. If the actual average use decline is less than forecast, Rate 1 and Rate 6 customers are credited for the difference through the disposition of the variance account. Alternatively, if the actual average use decline is greater than forecast, customers are debited for the difference. In some recent years, due to weather factors, consumption has exceeded the forecast consumption. While the average residential/small commercial gas use continues to decline, the Enbridge benefits enormously from an increase of 40,000 to 50,000 new customers every year (Ex. C1, T3, Sch 1, App A). It has the franchise for all of Toronto, and the better part of the GTA, which is one of the most stable growth markets in Canada. As Dr. Booth noted, its franchise is generally considered to be the most attractive in Canada, and should continue to maintain that distinction, and given the pace of new construction in the GTA since 2007, a growth rate that may moderate, but is not expected to change very much, as it is driven principally by inbound migration.

Third, Enbridge's rate design increasingly provides for fixed charge recovery. For 2011, the figure is 52%. In other words, 52% of Enbridge's revenue does not vary with the amount of gas supplied.

While there has been some reduction in large volume industrial demand, as Enbridge noted (Footnote 2 at Tab 1, Sch 2, p5), much of this can be due to a shift from customers moving from the large volume rates to rate 6 - a general service rate. More important, the industrial demand, or at least large scale industrial demand is, unlike the case with Union, a relatively small component of Enbridge's load and margin. Most of Enbridge's revenues and margins, over 90%, come from general service customers, rather than large industrial customers, consisting of residential, commercial, and institutional customers.

Finally, this power market consumption of natural gas is widely projected to increase over the next few years, and has increased since 2007. Enbridge has several major power generation facilities in its franchise, including Goreway, Portlands Energy Centre, and the York Region Energy Centre and Thorold Cogeneration Facility. They are mainly all large combined cycle gas plants. In addition, it is likely that a number of smaller gas fuelled power plants will be constructed over the next few years throughout its franchise area, as part of an effort to reduce the large costs of renewing or replacing obsolete electricity distribution infrastructure.

It is generally accepted by practitioners and policymakers in the power industry in Ontario that natural gas power plants will increase because they are required to effectively backstop intermittent wind and solar production, a role that would have been previously played by Ontario's coal plants. For example, the IESO has estimated wind power plants total energy contribution at 29% of installed capacity [IESO's 18-Month Outlook from December 2012 to May 2014]. The amount of hydro that can be used is limited because much of it has little "ramping" capacity. Nuclear power plants also have limited ramping capacity and can be damaged by too frequent stops and starts. This role must be increasingly filled by natural gas plants.

There is currently (as of November 8, 2012) total installed gas fired capacity in Ontario of 9,987 MW, with forecast capability of 9,145 MW. There are 29 gas fired power plants in Ontario.

In the same Outlook report, the IESO noted that, as Ontario's coal fired generation is fully shut down over the next two years, its associated flexibility, which has been used for ramping operating reserve, and regulation, will be lost. Therefore, future capacity addition should also possess the flexibility to help facilitate the management of maintenance outages, provide effective ramping capability, supply operating reserves, and even provide regulation, when necessary [Ibid, p16]. This points the way to more gas plants, not less, a feature that Union has recognized as a large growth driver over the next few years.

Finally, the IESO's report notes transmission enhancements are being constructed to enable the construction of additional generation in different parts of the province, including Ottawa, and Niagara Region (both part of Enbridge's franchise).

System Size and Complexity

Enbridge asserts that its company has grown larger, more complex and, therefore, riskier (E2, T1, Sch 2, pp5-8).

BOMA finds the argument unpersuasive, and lacking evidentiary support. In BOMA's view, Enbridge has not made the case that operational risks have increased since July 2007, notwithstanding some increase in size since that time.

First, contrary to Enbridge's suggestion, at paragraph 19 of E2, T1, Sch 2, p6, the physical extent of the Enbridge franchise system has not changed appreciably since 2007. While the number of employees have probably increased since 2007 (the number was not provided; it was not likely very high). Since the evidence shows that from 2000 to 2010, the employee count increased by 3% on a base of 1,624 people, an increase of about 2.5% per year. That is not exponential growth and should be well within the resources of a skilled team of executives and managers to direct. The same can be said for increased capital budgets and operating budgets. Management's job is to manage growth and complexity. There does not appear to be any major discontinuity in the business of the Company since 2007; No quantum leap in activity or marked change in direction. Certainly nothing the rating agencies have focused on.

Enbridge has continued to earn in excess of its allowed return. As Dr. Booth notes in his prefiled evidence:

> "In not one year since 1985 has EGDI failed to earn its allowed ROE as a weather normalized basis". (p31)

The "interface" between gas and electricity has increased as a result of the increase in gas fuel power plants in the franchise, but the changes implemented by the NGEIR proceeding have established processes to facilitate the required coordination, for example, more frequent nomination windows. Enbridge was an active participant in that process.

BOMA does not agree that the TSSA increasing focus on pipeline safety mostly as a result of initiatives by the utilities on issues such as cross-bore contributes to an increase in risk. To the contrary, these enhanced practices and the TSSA orders ensure higher operating standards, as described by Enbridge at p7 of E2, T1, Sch 1, p1. BOMA does not agree with Enbridge's comment that "being held to higher standards than existed in 1993 is another demonstration of additional incremental risk" [Ibid p7, par 22]. For example, new requirements for cross-bore related monitoring inspections, timely information, and where necessary, remediation, should decrease the risk of explosion, and injuries, and increase customers acceptance of natural gas.

Environmental and Technological Advancements

Enbridge cites the Green Energy Act with its incentive for renewables as a threat to natural gas market share [E2, T1, Sch 2, pp 8-9]. BOMA suggests that while solar and wind energy have increased their share of the Ontario electricity market, that advice has been largely at the expense of the coal producer. Some coal plants are no longer operating; others are being converted to natural gas, and all are scheduled to be cleaned by 2014. Their sites are being used to accommodate new natural gas plants, Lennox for a TCPL plant, and Lambton for an Atlantic power plant. Concentric introduced new evidence in its final experts submission, claiming that Ontario's carbon policy was a long term threat to Enbridge's growth in the province. However, unlike British Columbia, Ontario does not have a robust carbon policy. It has done very little in the last few years to achieve its CO2 agenda. It has recently reduced funding for electric vehicles. It has no carbon tax, and has delayed indefinitely the implication of WCI proposals for cap and trade. The Environmental Commissioner of Ontario, in its report released earlier this week, stated as follows:

> "With the release of its Climate Change Action Plan in August 2007, the Government of Ontario made a commitment to play a leadership role in the province's transition toward a low-carbon future. To do this, it established a policy framework comprising a range of measures to reduce Ontario's carbon footprint across the major greenhouse gas emitting sectors: electricity, transportation, industry, buildings, agriculture and waste. A Climate Change Secretariat was established in Cabinet Office to co-ordinate government-wide actions and to work horizontally across ministries to ensure that policies and programs were effective. The Plan established province-wide targets and timelines to track progress. It also included a commitment to be accountable to the Ontario Legislature and the people of Ontario by reporting annually on progress in achieving the emissions reduction goals set out in the Plan.
>
> To date, progress has been made in some areas. For example, in the electricity sector, the ongoing phase-out of coal has driven emissions down significantly and sets the stage for reductions in other sectors if co-ordinated action is taken. Unfortunately, the government has not implemented measures that will effectively confront the largest remaining emissions sources."

Relative Riskiness; Gas and Electric Distribution Utilities

Enbridge, through its expert, Concentric, suggested that Enbridge's equity thickness should be 42%, which was 2% above the equity thickness that the Board proposed for Ontario's electricity distribution and utilities in its 2006 Report of the Board on Cost of Capital and 2nd Generation

Incentive Regulation for Ontario Electricity Distributors, because gas distribution was a riskier business than electricity distribution.

However, Dr. W.T. Cannon, a frequent advisor to the Board, conducted a detailed analysis of the relative business risks of the Ontario gas distribution and electricity distribution industries in a paper prepared for the Board in 1998, at the onset of the Board's regulation of the electricity distribution industry [A Discussion Paper on The Determination of Return on Equity and Return on Rate Base for Electricity Distribution Utilities in Ontario]. In his Summary of Conclusion and Recommendation, he stated:

> "In Section 2 of this paper, I provide a comparison of the Ontario gas LDC and MEU industries in terms of organizational goals, structures, diversity, ownership, and business risk profiles. At the end of Section 2.3, and based on my analysis throughout Section 2, I conclude that, controlling for organizational size and diversity, Ontario's MEUs are marginally less risky, in terms of overall business risk exposure than gas LDCs. It is doubtful, however, that the small magnitude of this overall difference in business riskiness would, by itself, justify different deemed capital structure proportions, or different degrees of acceptable financial leverage risk, between similarly-sized and similarly-diversified MEUs and gas LDCs. I further conclude that there is a remarkable similarity in the nature and pattern (if not always the intensity) of the business risks facing individual enterprises in the Ontario gas and electricity distribution industries".

Unfortunately, both Concentric and Enbridge dropped the second part of Dr. Cannon's conclusion when they cited his study in support of the proposition that gas distribution is a riskier business than electricity distribution in Ontario. The Company stated that:

> "EGD submits that gas distribution is relatively riskier than electric distribution, and therefore should require higher equity ratios…As Concentric points out in their report, a Board commissioned reserve authored by Dr. Cannon, states that all else equal, gas distribution is a riskier proposition than electric distribution". [E2, T1, Sch 2, p30]

That is not what Dr. Cannon said.

As for Concentric, it referred to Dr. Cannon's conclusions as follows:

> "The research paper concluded that although gas utilities were more risky than electric utilities in term of a business risk…". [E2, T2, Sch 1, p13]

Like Enbridge, Concentric misstated Dr. Cannon's conclusion.

However, the Board has already signaled its understanding of the relative risks of the two industries and the various utilities in those industries, in EB-2010-0018, in January 2010, when it awarded Natural Resource Gas, a very small local gas utility which operated in and around the town of Aylmer in southwestern Ontario with assets of $15,260,485, December 31, 2011, and total revenues of $10,528,533 (2011) and net income of $243,000 (2011)[1], an equity thickness of 40%. That percentage is identical to the equity thickness of the 77 Ontario electricity utilities remaining at the time, many of which were not much larger, or more diversified than NRG.

The Board justified the 40% equity thickness, substantially higher than the 36% then (and now) enjoyed by Enbridge and Union as in the following passage:

> "The Board has a Cost of Capital policy in place that is applicable to all electrics and NRG's size and profile is similar to a number of electric utilities as opposed to the other two large gas utilities (Enbridge and Union). The Board policy on the appropriate equity ratio is 40% and is not considerably different from the ratio sought by NRG." (EB-2010-0018, p26).

While the Board's statement speaks for itself, BOMA takes the Board panel to be saying that "NRG" is, like many (most), of electrics, small and local, and of similar riskiness, and therefore should be given the same equity thickness. BOMA infers from the words "as opposed to" in the passage cited, that it considers the two large gas utilities as substantially less risky than NRG. It follows that Enbridge's equity thickness should be substantially less than that of NRG.

---

[1] All figures from the 2011 Yearbook of National Gas Distributors, Ontario Energy Board.

Fair Return Principle

Enbridge and its consultant, Concentric, argued that in applying its policy on equity thickness, the Board is subject to what Concentric called the "overarching" requirements of what it called the Fair Return Standard (the capital letters are Enbridge's) and the Fair Return Standard includes equity thickness. BOMA strongly disagrees with Enbridge's position. As Dr. Booth pointed out in his presentation to the Board during the hearing (Ex. K2.1, p1), the principle that a shareholder is entitled to a fair return on its investment, as decided by the Supreme Court of Canada, and adopted by the many Canadian utility regulators, does not speak to equity thickness at all. The principal speaks to the return on the shareholder's investment. Even a cursory reading of the relevant Supreme Court of Canada cases makes this clear (and BOMA provides a more detailed analysis of those cases below). The capital structure of the utility, including common shares, preferred shares, and the various types of debt securities outstanding and return to the shareholders on common equity, are two different things.

The National Energy Board ("NEB"), in RH-2-2004, a TransCanada Pipeline case, discussed whether the Board is legally compelled to employ a specific methodology in arriving at its determination of an appropriate capital structure for the mainline. The Board discussed that issue from four different perspectives:

- the (NEB) Act's requirement for just and reasonable tolls;
- cost of service regulation;
- the fair return standard; and
- the methodology used to determine capital structure.

On the first point, the Board cited section 62 of the National Energy Board Act, which stated:

> "All tolls shall be just and reasonable, and shall always, under substantially similar circumstances and conditions with respect to all traffic of the same description carried over the same route, be charged equally to all persons at the same rate".

The Board then noted that:

> "The methodology that the Board must comply in setting just and reasonable tolls is not prescribed by law, nor is that any statutory obligation requiring the Board to specifically consider and establish a rate of return for the companies it regulates".

The Board further cited the judgement of the Federal Court of Appeal in BC Hydro and Power Authority vs. Westcoast Transmission Company et al[2], which distinguished the wording of section 62 of the National Energy Board Act cited above from the wording of the British Columbia Gas Utilities Act, that the Supreme Court of Canada was asked to interpret in the Northwestern Utilities (1929) case. [See below for a discussion of the Northwestern Utilities case].

The point BOMA takes from the discussion is that the duties of the Board to fix rates (tolls) and the manner in which it does so will be informed by its enabling statute.

Cost of Service Regulation

The Board noted that it had traditionally used a cost of service approach to ratemaking (but, like the OEB, it is not required to do so).

The Board went on to state that:

> "Under the Board's traditional approach, once the Board has established a rate of return on equity and debt, the two numbers are consolidated into a composite rate of return on

[2] BC Hydro and Power Authority vs. Westcoast Transmission Company Ltd. et al [1981] 2 F.C. 646 (C.A.)

> capital, based upon the relative amounts of debt and equity in the capital structure. The Board constructs for each pipeline a capital structure, which reflects the amount of debt and equity the pipeline needs to finance its prudently incurred costs. This assessment is made with the assistance of expert evidence. In order to account for the greater or lesser risk attributed to an individual pipeline, the equity component of the capital structure is adjusted. The higher the risk attributed to a pipeline, the greater the required equity component of its capital structure. This is so, because equity serves as support for debt, whose repayment is most often fixed. A higher level of equity provides comfort to debt lenders by improving the likelihood that their investment will be recovered in the event the corporation cannot meet its financial obligations".

<u>Fair Return Standard</u>

The Board reproduced passages from the cases that had been cited by the parties to the proceeding (mainly TransCanada), including Northwestern Utilities decision of the Supreme Court of Canada, and two decisions of the United States Supreme Court, Bluefield, and Hope.

The Board distilled from these decisions, the following:

> " Specifically, a fair or reasonable return on capital should:
>
> - be comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable investment standard);
> - enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and
> - permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).
>
> In the Board's view, the determination of a fair return in accordance with these enunciated standards will, when combined with other aspects for the Mainline's revenue requirement, result in tolls that are just and reasonable."

BOMA emphasizes that the NEB's articulation of the fair return standard does not speak to capital structure at all. The OEB essentially adopted the NEB formulation in its 2009 Report [EB-2009-0084].

The OEB adopted the NEB's version of the three tests, in its Cost of Capital Review in EB-2009-0084.

BOMA notes that, like the two Supreme Court decisions, the three tests deal with the return on capital, not the common equity thickness.

As the Board well knows, the Cost of Capital Review, launched by the Board in 2009, in response in part to utilities' requests to modify the Board's generic ROE formula, which had put in place in 1997, and not been changed since that time. The Report (EB-2009-0084) did not deal extensively with equity thickness. On the last two pages of the 50-page report, the Board reminded parties of its longstanding policy on equity thickness for the electricity distribution, electricity transmission, and gas distribution utilities.

However, the Board did modify the formula used to calculate the utilities' return on common equity very substantially in its Report. It increased the "base" rate of return to which the annual formula adjustments would be applied by about 500 basis points; by any standards, in BOMA's view, a very generous increase. As Dr. Booth noted, it was, at the time, higher than the actual equity risk premium in the Canadian equity markets, and higher than that market premium had been since 1926. It also modified the annual adjustment mechanism to take into account the utility's spread between the utility base index, and a Canadian corporate bond index, as well as the traditional Canadian federal government bonds index. Applying the adjustment for the year 2010 resulted in a generic return on equity for Ontario utilities of 9.78%, up from 8.01% in 2008. That rate was higher than the generic rates in British Columbia, Alberta, and Quebec, and the approved rate for Emera (Nova Scotia Power) at that time.

Comparison of Enbridge With Other Utilities of Like Risk

The Board's practice in implementing its policy on equity thickness to focus on the specific business risks of the gas utility under review in deciding on the common equity thickness for that utility. For example, in EB-2006-0034, the Board stated that the Board did not generally find a comparison of Enbridge's common equity with those in other jurisdictions to be necessarily determinative of this issue. It stated:

> "An applicant must still satisfy the threshold requirement of independent evidence that material changes have occurred to justify a thicker common equity. Moreover, the hazard in doing so [in looking too closely at the rate approval in other jurisdictions], is that it engages issues of oversimplification and circularity, which downgrades the specificity that is required to make decisions pertaining to a particular utility" (p63).

However, the Board went on to emphasize that:

> "There is some value in considering evidence on the relative risk profile of the two large Ontario gas utilities. While Union's current 36% common equity was the result of a negotiated settlement, Enbridge's proposal for a 38% common equity level is materially higher than Union's, which is not consistent with the relative risk profile of the two utilities. In fact, there was no dispute that Enbridge is a lower risk utility than Union" (p63).

Enbridge/Concentric, for their part, have conceded that the risks of the two utilities are virtually the same. BOMA's view is that Union is somewhat riskier because of its greater reliance on large industrials' load, the challenge of servicing its northern region, and the size of its gas transmission business.

While the Board's statements can speak for themselves, BOMA is of the view that what the Board is saying is that in setting equity thickness, its policy is that the company asking for the increase must justify the increase by showing material increase in its business and financial risk. The Board will look to other utilities of similar risks for context and as a check, and in particular, it will look at Union Gas, because it is much more familiar with the risks of Union Gas than with the business risks of utilities in other provinces, let alone utilities in the United States or other countries.

This is not to say the Board does not keep an eye on regulatory developments in other jurisdictions, such as the Canadian provinces as well as countries like the United States with similar statutory and regulatory regimes comparable to our own. They should, and they do.

Enbridge suggested the Board not look to a sample of comparable Canadian Gas Utilities, because of the comments of the Board in EB-2006-0034 [T1, p147]. Enbridge also stated that the Board's decision in the Union case is not relevant to the current case. At the same time, Enbridge suggests that the Board look for a precedent to a group of US gas distributors, selected by Concentric, which it states have business risk similar to that of Enbridge. Enbridge's position does not make sense. Why would a Canadian regulator look only to alleged US comparables but not accepted Canadian comparables, including a gas utility with similar risk to that of Enbridge, that it also regulates and about which it is very well informed. Enbridge appears to have misunderstood the Board's comments in EB-2006-0034, quoted above. All the Board was saying, in BOMA's view, was that one must be cautious in adopting findings of regulators in other jurisdictions. One must make the necessary adjustments to account for differences in political or constitutional realities, the detailed regulatory protections afforded utilities in the other jurisdictions, and regulatory practices.

Unlike Enbridge, Concentric agrees that it is appropriate for the Board to have regard to other comparable Canadian gas distribution utilities, which it considered to be ATCO Gas, Fortis BC (formerly Terasen) and Gaz Met (perhaps).

Concentric did not include Union Gas, on the grounds that the Board regulated them. BOMA strongly disagrees with that position for the reasons given above. It is illogical and an overly aggressive response in the face of the Board's determination in EB-2006-0034. Moreover, BOMA disagrees with Concentric's point that, in that case, the Board was constrained by the fact that Union Gas had recently accepted a 36% common equity thickness as part of a Settlement Agreement, in EB-2005-0520 [Concentric Evidence]. The Board was not so constrained at all. It held Enbridge to 36% because it was clearly of the view that Enbridge was less risky than Union. The parties and the Board are well aware that it is well accepted in Canada (and United States) that regulators do not consider that individual components of a settlement agreement set precedent, since they are part of a comprehensive package. Ms. McShane confirmed that view in the Alberta Utilities Commission Generic Proceeding in 2009, in which Concentric participated. It is also the case that prior to the Board's decision to utilize a formulaic single ROE in its 1997 Guidelines, Union had received a 15-20 basis point premium over Enbridge, to reflect the higher risk, in part due to its merger with Centra Gas Ontario in 1993.

Mr. Coyne also agreed in cross-examination that in arriving at an "average equity thickness" for other Canadian utilities, against which to compare Enbridge, it was appropriate to use only the truly comparable utilities, and not include the very small and/or development stage utilities that were included in Concentric's prefiled evidence to arrive at an average thickness of 41%. If one used just Union, ATCO Gas, Fortis BC Gas, and Gaz Met, one gets an average of 38.7%. However, Concentric had used the number 41.9% in the conclusions to his study to make the claim for a 42% equity thickness for Enbridge. Clearly utilities such as AltaGas, Pacific Northern Gas, Centra Gas, Manitoba Gas, New Brunswick and Heritage Gas, are not appropriate comparators for Enbridge; no one would argue that they are.

In BOMA's view, Enbridge is a less risky utility than either Fortis BC Gas, ATCO Gas, or Gaz Met, which have equity thickness of 40%, 39%, and 38.5%, respectively.

With respect to Fortis BC Gas, as Dr. Booth noted in a reply to a Board question on Tuesday, the pressure of relatively inexpensive hydroelectricity, supplied by a Crown Corporation, as a competitive fuel for natural gas increases the Fortis BC Gas risk, in particular, its competitive position in multi-family dwellings. In addition, as the British Columbia Utilities Commission noted in its decision, the Government of British Columbia passed carbon tax legislation several years ago, which must be paid in part by natural gas users. The tax is now at a significant level where it is affecting people's decisions, since electricity in British Columbia is virtually all hydro, and carbon text tax exempt. Energy users now have a further incentive to use electricity in new structures or retrofits. Ontario has no such competitive fuel threat and no coherent implementation of its carbon policy. Finally, the Commission noted that British Columbia fares unique First Nations challenges, due to the absence of treaties and the number of energy projects forecast for their historic territories [Ex. 1, E2, Sch 14.1, Attachment 2]. The Commission also took into account the fact that, unlike ATCO Gas, Enbridge, and Union, Fortis BC Gas does not have preferred shares in its capital structure (pp 3-6, 30), and further, that the difference between US and Canadian actual natural gas LDCs' equity ratio is not of itself determinative.

<u>Comparing the Canadian and US Distribution Utility Business Risks and Capital Structures</u>

In BOMA's view, the business risk for gas distribution (and electricity distribution) utilities is higher in the United States than in Canada because the regulatory risk is higher.

In BOMA's view, the US regulatory structure is much less "protective" of gas and electricity distribution companies than most Canadian regulators. In particular,

- there have been frequent disallowances of major investments of gas and electric utilities in the United States;

- recent United States Supreme Court decisions, in particular Dusquesne Light vs. Barasch have increased the uncertainty of recovery of even prudently incurred capital expenditures, in the face of retrospective legislation with confiscatory effects;

- the interventions of several state and federal regulators since the deregulation of the gas and electricity commodity markets in the United States since the mid-80's have been extremely aggressive, and somewhat unpredictable;

- the rating agencies, in particular Moody's, have clearly noted the difference in regulatory risks that have placed utilities in different positions in the United States and Canada.

<u>Moody's Analysis</u>

At page 4 of Moody's August 2009 publication, Moody's Global Infrastructure Finance, Regulated Electric and Gas Utilities [E2, Sch 21.12, Attachment 2], in explaining its rating methodology, it states:

> "In general, Moody's ratings committees for the regulated gas and utilities sector focus on a number of key rating factors which we identify and quantify in this methodology. A change in one or more of these factors depending on its weighting is likely to influence a utility's overall business and financial risk. We have identified the following four key rating factors and nine subfactors when assigning ratings to regulated electric and gas utility issuers, which are likely to influence a utility's overall business risk and financial risk".

The four factors are regulatory risk, 25%, ability to recover costs and earn returns, 25%, diversification, 10%, and financial strength, liquidity, and key financial metrics, 40%.

BOMA notes, when looking at the four factors, in that "regulatory risk", and the "ability to recover costs and earn returns", which turns mainly on the regulatory structure and approach, together account for fully 50% of their assessment of the utility's business risk. The balance is mainly financial strength and liquidity ("key financial metrics") and 10% for diversification. So the regulatory environment is critical.

Moody's goes on, at page 6, to discuss how it measures regulatory risk. It states:

> "For a regulated utility company, we consider the characteristics of the regulatory environment in which it operates. These include how developed the regulatory framework is; its track record for predictability and stability in terms of decision making; and the strength of the regulator's authority over utility regulatory issues. A utility operating in a stable, reliable, and highly predictable regulatory environment will be scored higher in this factor than a utility that exhibits a high degree of uncertainty or unpredictability".

In the last paragraph on page 6, it observes:

> Moody's views the regulatory risk of US utilities as being higher in most cases than that of utilities located in some other developed countries, including Japan, Australia and Canada. The difference in risk reflects our view that individual state regulation is less predictable than national regulation; a highly fragmented market in the US results in stronger competition in wholesale power markets; US gas and power markets are more volatile; there is a low likelihood of extraordinary political action to support a failing company in the US; holding company structures, limited regulatory oversight, and overlapping or unclear regulatory jurisdictions characterize the US market".

Concentric compares some detailed aspects of the regulatory practices, between Ontario and various US state commissions in its evidence [Appendix B, pB-3]. But it compares the "plumbing" of regulation rather than the broader political legislative judicial regulatory characteristics of the two countries. Concentric compares the use of deferral accounts, the availability of CWIP or AFUDC, the use of the future or historic test years, and purchased gas adjustment accounts, and the results are mixed. Perhaps the largest difference, and an important one, demonstrable in Figure 10 in Appendix B, to some extent, but discussed by Phillips, among other authors in greater detail, is that the historic test year is still the norm in the United States. In the Phillips, the History of Utility Regulation in the United States, 1991 Edition, the authors state:

> "A hypothetical capital structure is only used where a utility's actual capitalization is clearly out of line with those of others in the industry or where a utility is diversified". (p391)

It is generally understood that using an historic test year approach heightens the utilities regulatory risk due to the general inability to recover costs incurred since the end of the test (historic) year.

An example of a Commission that used the historic test year is in a recent case before the Maryland Public Utilities Commission dated November 14, 2011 (Public Utilities Report, 293 PUR 4th, p202) involving one of the utilities owned by the Washington Gas Light Holdings Inc., one of Concentric's 8 US "comparables" to Enbridge. BOMA notes that Washington Gas Light Company owns separate utilities in Maryland, in the District of Columbia and in Virginia.

The Maryland Commission stated:

> "The Board on the record in this case, and given our historic preference for reality as opposed to hypothetical capital structure, the Commission adopts the Company's actual capital structure, at the end of the [historic] test year, the Commission rejects the hypothetical capital structure proposed by staff and the AOBM. Both witnesses propose capital structures that are not based on the company's financial conditions as of the end of the test year". (p206)

As an aside, BOMA notes that one use of the historic test year rate cases, together with the reluctance of US utilities not to institute proceedings unless costs have substantially increased, and the reluctance or inability of some regulators to require the utilities to appear, may result in no change in capital structure over a very long period of time, even if business risks have changed.

US Regulators Do Not Deem Capital Structures

In addition, and this is a critical difference in US and Canadian practices, in the United States, most regulators do not deem an equity ratio (our emphasis). Rather, they accept the capital structure the Company has adopted, unless it was egregiously out of line with the rest of the industry. Ms. McShane testified before, in the 2009 rate case, that the US equity ratios were higher because of this practice.

Disallowances

A recent article in the Energy Law Journal, Vol. 22, #2, 2001, authored by two lawyers in the New York, and Washington offices of LeBoeuf Lamb Greene and MacRae, entitled Reorganization of Utility Companies in the United States, Chapter Eleven, discusses recent major utility bankruptcies in the United States. The first case discussed was that of Pacific Gas and Electric (PG&E), which filed for Chapter 11 on April 6, 2001.

PG&E is among the largest, if not the largest, combination gas/electric distribution utility in the United States. It serves most of northern California, including the Bay area.

The authors summarized the bankruptcy filing as follows:

> "PG&E filed for Chapter 11 after spending $9 billion in excess of revenues to supply its customers, exhausting its ability to borrow, while consumer rates remained frozen by the California Public Utilities Commission (CPUC) at a level far below prices at which PG&E could buy power on the wholesale market". (p293)

On the day of the bankruptcy, the PG&E Chair, Robert Ginn, stated:

> "PG&E chose to file for Chapter 11 reorganization affirmatively because we expect the Court will provide the venue needed to reach a solution, which thus far, the State and the State's regulators have been unable to achieve. The regulatory and political processes have failed us, and now we are turning to the Court". (p290)

As the Board is probably well aware, the case and its aftermath resulted in a torrent of commentary in legal and financial journals and the business press. A second high profile bankruptcy filing was that of the Public Service Company of New Hampshire on January 28, 1988. The authors summarized it as follows (p283):

> "PSNH is New Hampshire's largest electric utility, providing service to more than 400,000 homes and businesses. It currently has over 1,110 megawatts of generating capacity, with three fossil fuel-fired generating plants and nine hydroelectric facilities. At the time it filed for bankruptcy, PSNH also held an approximately 36% stake in the Seabrook Station nuclear power facility. Because of construction delays and problems in obtaining regulatory approval from the Nuclear Regulatory Commission, construction costs continued to rise, and eventually PSNH had invested some $2.9 billion dollars in the Seabrook plant, much of this amount borrowed. At the same time, New Hampshire law prevented PSNH from recovering costs of incomplete construction work in progress in its rate base. Consequently, PSNH found itself unable to service the debt it had incurred and filed for bankruptcy on January 28, 1988".

The third case they discussed was Columbia Gas System, a large natural gas transmission and distribution utility, filed for bankruptcy in 1992. Columbia owned gas distribution utilities in several mid-west and mid-Atlantic states. The authors state:

> "Columbia and its subsidiaries comprise one of the largest natural gas systems in the United States. Several of these subsidiaries included gas utility companies. Columbia filed for Chapter 11 largely in order to reject certain long term "take or pay" contracts that required Columbia to purchase natural gas at above-market prices".

The bankruptcy allowed Columbia Gas to reject its remaining long-term take or pay gas purchase contracts, which resulted in the rejection of damage claims in excess of $13 billion against Columbia Gas, which claims were eventually settled for one-tenth of their face amount.

There were also several other smaller utility bankruptcies over the same period including the El Paso Electric Company, and the Cajun Electric Power Cooperative Inc.

These cases cited, in particular, the PG&E, Public Service Company of New Hampshire, and Columbia, achieved notoriety in the financial, and business press and were the subject of countless law review and finance journal articles over the ensuing years. They clearly had an impact on investors' perception of utilities' business risk and financial risk.

Returning to Moody's explanation of its methods of assessing risk, Moody's in discussing why regulatory risk is so important, commented:

> "The ability to recover prudently incurred costs in a timely manner is perhaps the single most important credit consideration for regulated utilities as the lack of timely recovery of such costs has caused financial stress for utilities on several occasions. For example, in four of the six major investor-owned utilities over the last 50 years, there were regulatory disputes, resulting in insufficient or delayed rate relief for the recovery of costs and/or capital investment in utility plant".

There have been no comparable bankruptcies of significant Canadian utilities over the comparable period. To the contrary, when Pacific Northern Gas (British Columbia) encountered financial difficulty because of the failure of a large industrial client(s), the BCUC developed a solution which enabled the utility to recover. When Canadian eastern gas distributor companies, and their customers, pressured the federal and provincial governments and the regulators to allow them to terminate the long term commodity contracts with TransCanada (Western Gas Marketing) in 1986, the regulators, working in tandem, developed a compromise under which end users would be free to purchase gas directly from producers, but a regulatory change (the Top Gas Levy) would be paid by all users to TCPL to ensure TCPL was held harmless through the deregulation process.

Mr. Coyne raised the issue of Enbridge Gas New Brunswick as an example of harsh treatment of a utility by a Canadian regulator and provincial government. However, that case is very unique. BOMA's understanding of that situation is that Enbridge became involved in a complex commercial joint venture with 13 local partners to ensure it was successful in obtaining the bid. Enbridge also made substantial commitments made to the NB government in order to win the franchise, in a competitive process. The actual costs to fulfill those commitments turned out to be an order of magnitude larger than the forecast cost. Enbridge has sought to recover the entire amount from ratepayers or the NB government. It has not yet resulted in a bankruptcy.

Recent United States Court Decisions

In recent United States Supreme Court decisions, in particular, Dusquesne Light Company vs. Barasch (488 US 299 (1989)), the United States Supreme Court upheld a law enacted by the State of Pennsylvania mid-way through a regulatory proceeding which (the law) prohibited the Pennsylvania Public Utilities Commission from allowing Dusquesne to include its investment in a partnership to develop and build several nuclear plants into its rate base.

Dusquesne had invested an initial $35 million in a joint venture, created by several utilities in the mid-Atlantic region, to construct seven nuclear reactors in Pennsylvania. Due to changing market demand, the partnership constructed (and owned) only three of the seven planned reactors. The Pennsylvania Public Utilities Commission allowed the expenditures as being prudent, notwithstanding that not all of the reactors were built. After the decision was rendered, but before a motion for rehearing could be heard, the Pennsylvania legislature enacted a statute (State Law 335) in question which stated that the utility could not recover the amounts because a majority of the planned reactors were never built.

The Supreme Court of the United States upheld the state law, in part because it viewed that the $35 million loss to investors in Dusquesne was slight relative to the aggregate of the investment.

The decision sent ripples through the utility business world and generated much reaction. For example, in an article entitled "The Dusquesne Opinion: How Much "Hope" is There for Investors in Regulated Firms?" in 8 Yale Journal on Regulation, Drs. Kolbe and Tye of the Brattle Group were highly critical of the decision. They stated, by way of preamble:

> "High costs for new electric power plants have led to a series of regulatory and legislative decisions that may retroactively rewrite the rules that utility investors relied upon when they supplied capital for these projects. In Duquesne Light Co. v. Barasch, a case involving the recovery of capital invested in constructing nuclear power plants that were ultimately never completed, the Supreme Court upheld one such change".

They then argued (p3):

> "In the regulatory environment after Duquesne, investors are exposed to substantial risks from very large cost disallowances without equivalent opportunities for gain. This asymmetry in regulatory outcomes requires a rate of return in excess of the cost of capital, defined as the expected rate of return in capital markets on alternative investments of equivalent risk. These findings are fully in the spirit of the Supreme Court's express intention in Duquesne to reaffirm the teachings of Federal Power Comm'n v. Hope Natural Gas. The Hope opinion requires that the 'return to the equity owner should be commensurate with return on investments in other enterprises having corresponding risks.'" [Hope was the US equivalent to the Northwest Utilities case in Canada]

In the author's view:

> "The particular legal question facing the Court was whether the statute violated a prior 'regulatory contract' and thereby represented an unconstitutional taking of property. The Court held that under the 'end result' test, the new rules did not reach the stature to constitute a taking in this case."

Sections 5 and 14 of the United States Constitution prohibit taking of property without compensation, and many of the early US court cases on a fair return relied on these constitutional provisions. However, there is no comparable constitutional protection in Canada. It has been held, for example, that the Canadian Bill of Rights does not protect property rights.

They concluded (at p22), that:

> "Many things will have to go right for regulatory institutions to return to anything like the world we used to know. 'Constitutional magnitude' may be too vague a test for investors, and the necessary allowed rate of return may be unacceptably large for regulatory commissions. The stated or unstated intention of many electric utilities to avoid new construction of generating capacity reflects a situation where perceived regulatory risks have driven the necessary allowed rate of return to levels that regulatory commissions find unacceptable".

The authors are respected professionals in their fields who will be familiar to the Board.

In Phillips, the authors note (p409):

> "The business and financial risk of public utilities have been discussed at length for many years. So too have the regulatory risk been mentioned on several occasions, particularly as it relates to the impact of regulatory risk on the cost of capital. But the huge prudence disallowances of more recent years, together with the Supreme Court's Dusquesne decision (1991) has resulted in a new debate over regulatory fairness".

A number of other Canadian public utility commissions have agreed that regulatory risk for US gas distribution utilities is higher in the United States than in Canada. For example, in the 2009 Generic Cost of Capital Proceeding, the Alberta Utilities Commission (the "Commission") noted:

> "The Commission agrees with Mr. Coyne, Dr. Vander Weide and the other proponents in the proceeding who suggest that the regulatory framework and the regulatory philosophies of both the U.S. and Canada are similar. The Commission agrees, however with Dr. Safir that there have been some significant differences in regulatory policy between the U.S. and Canada which have created additional regulatory risk for American utilities. The Commission further agrees that disallowances in the U.S. have had significant impacts on investor confidence and risk perceptions that once such events have occurred they will have ongoing effects on future investor expectations" [paragraph 156].

Mr. Coyne agreed in his evidence that:

> "…sometimes they did go wrong, as evidenced with PG&E in California, as evidenced by these nuclear cost disallowances. And those are risks that I think investors do take into account when they determine the cost of equity required to invest in these businesses".

At paragraph 166, the Commission states:

> "The Commission considers that there is ample evidence to demonstrate that the support provided by the legislative and regulatory context in Alberta materially reduces regulatory and other business risks of Alberta utilities when compared to the evidence proffered on US utilities in the hearing".

At paragraph 168, the Commission noted:

> "While US utilities have benefited from the application of some of the attributes of Canadian regulation, identified by Dr. Booth above, and while the difference in regulatory practice between the US and Canada may be narrower than they may have been at the time that the EUB [predecessor to the Commission] last considered this matter (2004), on the whole the Commission considers based on the evidence before it that these attributes are more pervasive in Canada and continue to suggest that the Canadian utilities enjoy a more supportive regulatory environment and have less regulatory risk than their American counterparts. Further, the Commission considers that the reliance on historical test years and the DCF methodology by the majority of U.S. regulators are further reasons for higher awarded ROEs in the United States. These conclusions are affirmed by the Commission's analysis with respect to credit metrics and bond ratings discussed below".

Finally, at p190, the Commission states, with respect to allowed returns:

> "With respect to U.S. data on allowed returns for natural gas and electric LDCs and other state regulated utilities, the Commission finds, based on the evidence and analysis referred to above, that the regulatory risk faced by these U.S. utilities in general remain materially higher than the regulatory risk of Alberta utilities. As a consequence, the returns awarded by U.S. regulators for U.S. LDCs would be expected to reflect this materially higher level of risk leading the Commission to conclude that U.S. allowed returns should not be used in determining a fair return for Alberta utilities".

Financial risk for utility investors and ultimately shareholders, is higher in the United States because the lenders and investors do not have the protection of financial covenants that are widely utilized in Canadian capital markets.

In the Board's recent consultation on cost of capital, leading to its Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084) (the "Report"), Ms. Stephanie Zvarich, Director, Public Debt Income with SunLife Financial, presented evidence that Canadian levels have more restrictive covenants than US bonds. She stated:

> "In the United States, new bond issues generally lack any kind of bond covenants, unless the bond issues were done for historical trust indentures or older trust indentures, which is often not the case" (September 21, 2009, p51).

She went on to cite the covenants that SunLife requires of Canadian issues, including utilities, include:

- a well-defined change-of-control covenant
- financial covenants such as maximum debt to capital, with all debt being reduced pro rata in the event of equity financing
- interest coverage ratios
- restrictions on distributions and dividends
- interest rate step-ups if and as ratings decline

The Enbridge shelf prospective for its medium term notes [issued for up to 30 years] filed in evidence, contain covenants and structures as described by Ms. Zvarich.

- they are issued under a trust indenture
- they contain a negative pledge

- they contain negative covenants, eg. no encumbering of assets to secure any obligation unless it applies rateably to all outstanding rates of the corporation

- earnings coverage ratios.

Ms. Zvarich also noted that in a time of market turmoil and volatility, Canadian utilities maintained good market access in both 2008 and 2009. She noted:

> "Year to date, 2009, we have seen $3.2 billion of issuance and remaining outstanding 2010 maturities are just over a billion, which will bring the total issuance for Canadian utilities to just about $4.2 billion".

And, at p5:

> "several Canadian utilities were able to issue 30 year debt quite nicely though 2008 and 2009."

And finally, at p51:

> "Credit ratings are lower in the US market, average credit rating is a lot more skewed to the BBB credit rating. This is versus an average A level or Single A level credit rating for Canadian utilities".

While these comments are applicable in the first instance to utility bond investors, they also help equity investors since they ensure the company will be financed on a more conservative and predictable fashion. Her comments also address directly the fact that Canadian utilities had continued access to capital markets through the epicenter of the world financial crisis in 2008-09.

<u>Judicial Basis for the Fair Return Standard</u>

Contrary to Enbridge's/Concentric's claim, in BOMA's view, the Board's current approach to establishing equity thickness for Enbridge (and Union) does not violate the "Fair Return

Standard". The principle of a fair return for which the NEB fashioned the Fair Return Standard, is a legal principle, which depends for its legitimacy in law.

What the Board, in its Report, after the fashion of the NEB in RH-2-2004, Phase II, have come to call the Fair Return Standard, is ultimately based on decisions of the Supreme Court of Canada in 1929, Northwest Utilities vs. the City of Edmonton [1929, S.C.R. 186], and the Board of Public Utility Commissioners of Alberta, and to some degree, a second decision of that Court, some thirty years alter, the BC Railways case (see below).

In that case, the Court (Justice Lamont, writing for the majority of the Court [a 5 judge panel], Chief Justice Anglin and Justice Miquaut concurring) stated 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 in the same amount in other securities possessing an attractiveness, stability, and certainty equal to that of the company's enterprise". [p193]

The case ultimately depended on the Court's interpretation of The Public Utilities Act, 1923 Alta. C53, as amended, 1927, C39.

The facts of the case are, briefly, as follows:

The company applied to the Board of Public Utility Commissioners of Alberta (the "Board") for an order continuing its current rates, which had been approved by the Board three years earlier.

The City of Edmonton, which had issued the company a franchise, supported the decision.

In its decision, the Board maintained the earlier rate base (with necessary adjustments) but reduced the rate of return to the company from 10% to 9%. The Board stated its reasons as follows (reproduced at p191 of the Court's decision):

> "In view of the elements that go to make up the rate base, and in view of the altered conditions of the money market, the Board believes it is justified in reducing the rate of return that the Company shall be allowed, to nine percent (and the Board's estimates are on that basis)".

The Board did not hear any evidence at the hearing for the Company or the City of Edmonton of the money market between November 22 (the date the Board first approved the 10%) and July 1927, the date of the hearing in which it reduced the return from 10% to 9%.

Justice Lamont stated the issue (and the only issue) in the appeal to be:

> "Had the Board the jurisdiction to find as a fact how the condition of the money market had altered between November 1922 and July 1927, without any witness testifying at the hearing that an alteration had taken place". [p192]

The judge observed that:

> "As the Board was determining what would be a fair return on the capital invested by the Company in the enterprise and as it reduced the return from 10% to 9%, it can, I think, be taken, that by the 'altered conditions' in the money market, the Board meant that the return for money invested in securities in which moneys were ordinarily invested had decreased during the period in question. In other words, that the rate of interest obtainable for moneys furnished for investment was, generally speaking, lower by a certain percentage in 1927 than it was in 1992. That, in my opinion is all that is involved in the [Board's] finding". [p192]

The judge reviewed the provisions of the Public Utilities Act and concluded that the Board could obtain the evidence by any method it wished, and that therefore it had not exceeded its jurisdiction.

The judge observed that:

> "To properly fix a fair return, the Board must necessarily be informed of the rate of return which money would yield in other fields of investments. Having gone into the matter fully in 1922, and having fixed 10% as a fair return under the conditions then existing, all the Board needed to know, in order to fix a proper return in 1927, was whether or not the condition of the money market had altered, and, if so, in what direction and to what extent". [p193]

While the judgement read narrowly, it was the Board's right to gain information (evidence) as it saw fit, and therefore, it did not make an error of law or exceed its jurisdiction (the only grounds of appeal from the Board's decision to the Court under the Act), Justice Lamont needed to define, and did define, what was meant by a fair return.

He started, interestingly, with the statutory duty of the Board. He stated that the duty of the Board was to fix fair and reasonable rates; rates which under the circumstances, would be fair to the consumer on the one hand, and on the other hand, would seem to the company a fair return for the capital invested (p193). Justice Smith concurred in the decision but noted at page 198, that at the original hearing in 1922:

> "The rate of return to be allowed on the capital was fixed in the award at 10%, not based on the ordinary rate of money on the market at the time, or on an estimated future rate but on consideration of the rate that would induce investors to risk their capital in an extremely hazardous and doubtful venture". [p198]

Several points came out of the Justices' comments:

- the test is comparative, and prospective, in other words, what would the return the investor would obtain in securities possessing an attractiveness, stability, and certainty to that of the company's enterprise; what some economists would call the "opportunity cost"

- the judgements speak of returns to an investor or to the company's investment in its enterprise, which refers to the shareholders of the company investment in the shares of the company, and not to the lender or bondholders

- the judgement does not speak about capital structure; what is at issue is the return on the investment of a similar amount

- Lamont's judgement confuses the issue a little by talking about "the return on the capital invested in its enterprise"; the return is the return to the shareholder; not the return on any particular company project. Different projects or parts of projects may have, in contemporary parlance, different internal rates of return or different Net Present Values

- Lamont's judgement speaks of rates which would be fair to the consumer, on the one hand, and which, on the other hand, would serve to the company [the shareholder] a fair return for the capital invested. So he strikes a balance there

- finally, Smith's comment stated above is helpful, that the original return set in the 1922 hearing was deemed necessary to induce investors to invest in the company's shares. This is the first legal recognition of the capital attraction test.

The second Supreme Court of Canada case, which serves as a legal formulation of the fair return principle, is a more recent one. The British Columbia Electric Railway Company Ltd. and the Public Utilities Commission of British Columbia et al [1960].

The facts of the case are briefly as follows:

BC Railway (the "Company") had the franchise for transportation of customers by railway, bus, and streetcar, and the generation and supply of gas and electricity on the Lower Mainland, and Vancouver Island.

The Company filed in April 1958 to increase its rates for its various services. The applied for rates would have resulted in the Company earning somewhat less than their allowed rate of return of 6.5%.

The Commission did not accept the proposed rates as filed. It directed that the residential rates be reduced by 25% and it directed further that increases in the commercial and industrial rates to compensate for the reduction in residential would not be allowed. The result of the decision was that the Company would earn significantly less than its currently approved return of 6.5%, and the rate it had proposed.

The Company appealed the decision on a matter of law to the BC Court of Appeal. The Company's argument was that, having earlier determined (in 1952), 6.5% as fair and reasonable, the Commission should authorize rates that would yield that return, or whatever lesser return the Company's application requested.

The legal issue was the proper interpretation of sections 16(1)(a) and (b) of the Public Utilities Act.

> "The relevant portions of s. 16(1) of the *Public Utilities Act* provide as follows:
>
> 16.(1) In fixing any rate:-
>
> (a) The Commission shall consider all matters which it deems proper as affecting the rate;"
>
> (b) The Commission shall have due regard, among other things, to the protection of the public from rates that are excessive as being more than a fair and reasonable charge for services of the nature and quality furnished by the public utility; and to giving to the public utility a fair and reasonable return upon the appraised value of the property of the public utility used, or prudently and reasonably acquired, to enable the public utility to furnish the service".

The Commission had interpreted the section to mean that the Commission needed to balance of the two factors referred to in 1.16(b), both protection of the public from more than a fair and reasonable change for the service and giving to the public utility a fair and reasonable return upon the appraised value of the property of the public utility used, or prudently and reasonably acquired to enable the public utility to furnish the service.

The BC Court of Appeal upheld the Commission's decision on the grounds that since the subsection stated that due regard should be given to each of the two factors, it was for the Commission to decide the relative weights.

The Supreme Court of Canada looked at the Public Utilities Act as whole, and interpreted the statute in a broader manner. It reasoned that given the various obligations placed on the utility by the Public Utilities Act, including:

- a duty to maintain its property and equipment in such condition as to enable it to furnish service to the public, and to furnish service, in all respects, adequate, safe, and efficient, just and reasonable (s5).

- an obligation, having been granted a certificate of public convenience and necessity or a franchise not to cease its operations or any part of them, without first obtaining the permission of the Commission (s7).

- upon reasonable notice, to furnish to all persons who may apply therefore, and be reasonably entitled thereto, suitable service without discrimination and without delay (s6).

- to extend its services, in certain circumstances, if ordered by the Commission, and to make capital outlays, for extension of its service (ss 38, 42, and 43).

The Court noted (p853) that a public utility which operates in a rapidly expanding community may be required to make a substantial expenditure in order to keep pace with increasing demands. If it is to fulfill those obligations, it must be able to obtain the necessary capital which is required, which it can only do if it is obtaining a fair return on its rate base.

The Court took special note of section 20 of the Act, which empowers the Commission to set rates. It reads:

> "The Commission may upon its own motion or upon complaint that the existing rates in effect and collected or any rates charged or attempted to be charged by any public utility for any service are unjust, unreasonable, insufficient, or discriminatory, or in anywise in violation of law, after a hearing, determine the just, reasonable, and sufficient rates to be thereafter observed and in force, and shall fix the same by order. The public utility affected shall thereupon amend its schedules in conformity with the order and file amended schedules with the Commission".

The Court noted that in addition to the words "reasonable and unreasonable", also uses the words "insufficient and sufficient" in addition to the setting of rates.

Justice Martland concluded as follows:

> "Clearly, as between these two matters [section 16(b)] there is no priority directed by the Act, but there is a duty imposed upon the Commission to have due regard to both of them. The rate to be imposed shall be neither excessive for the service nor insufficient to provide a fair return on the rate base. There must be a balancing of interests. In my view, however, if a public utility is providing and adequate and efficient service (as it is required to do by s. 5 of the Act), without incurring unnecessary, unreasonable or excessive costs in so doing, I cannot see how a schedule of rates, which, overall, yields less revenue than would be required to provide that rate of return on its rate base which the Commission has determined to be fair and reasonable, can be considered, overall, as being excessive. It may be that within the schedule certain rates may operate unfairly, relatively, as between different classes of service or different classes of consumers. If so, the Commission has the duty to prevent such discrimination. But this can be accomplished by adjustments of the relative impact of the various rates in the schedule without having to reduce the total revenues which the whole schedule of rates is designed to produce".

A key point in his analysis was that the Company was applying for a rate that was less than the amount the Commission had already agreed was just and reasonable.

Justice Martland also relied on Justice Lamont's definition of a fair return in the Northwestern Utilities.

Justice Locke agreed with the result reached by Lamont, but added that under common law, as a common carrier, the utility is entitled to fair compensation.

The "Northwest Utilities" and "BC Railway" are the only cases in which the Supreme Court of Canada has talked about a fair return.

The BC Railway decision confirms the approach of the Court in Northwest Utilities, namely:

- the fair return principle refers to the return on the investment, not the capital structure
- there is no talk of equity thickness in either case
- while the Court in BC Railway speaks of return on rate base, it is more likely that the Commission (in 1952) spoke of return on equity
- in BC Railway, the Court had to deal with a Statute which, like the Alberta statute, on one reading, did not prescribe the fair return to the investor as an overriding factor
- the Court did prescribe a fair return, assisted by the fact that the Commission had already approved a 6.5% return as fair and reasonable, and in a case where the statute defined the Commission's duty to determine rates that are just, reasonable, and sufficient

- the majority judgements in both Northwest Utilities and BC Railway did not rely on precedents, or deal at any length of US law. However, J. Locke, in his concurring judgement, did refer to the Bluefield case in the United States Supreme Court, as evidence of the overriding nature of the fair return principle. But it was mainly his interpretation of the common law, and his analysis of the BC statute, that led him to that conclusion.

The first Canadian regulator's pronouncement on the fair return was from the NEB in March 1995, RH-2-2004 Phase II decision.

In that case, the NEB stated in a case dealing with TransCanada's cost of capital RH-2-2004. It reviewed both the Canadian cases referred to above, plus some others, as well as two US Supreme Court cases. It concluded:

> "…a fair or reasonable return on capital should:
>
> - be comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable investment standard);
> - enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and
> - permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).
>
> In the Board's view, the determination of a fair return in accordance with these enunciated standards will, when combined with other aspects for the Mainline's revenue requirement, result in tolls that are just and reasonable".

In its Letter to Stakeholders, and Issues List, from the EB-2009-0084 proceeding, issued on July 30, 2009, the Board quoted, with approval the formulation of a fair return standard put forward by the NEB in its RH-2-2004 Phase II decision. In that decision, the NEB stated:

These three tests appear to have been gleaned by the NEB from the two Supreme Court of Canada cases cited above, in addition to a more recent (2002) decision of the Federal Court of Appeal (which, inter alia, takes appeals or matters of law and jurisdiction from federal regulatory tribunals, including the NEB).

The NEB, in this case, spoke only about a comparable return available from invested capital. It did not talk at all about equity thickness. It was referring to the return on equity, i.e. invested capital, and not the interest paid on bonds or the amount of debt. When it spoke of investing in enterprises of like risk, it appears to paraphrase the comment of Justice Martland in the Northwest Utilities case discussed above.

The financial integrity and capital attraction criteria also appear to be derived from various comments by the Justices in the two Supreme Court of Canada cases.

The OEB discussed the application of the fair return standard to determining the cost of capital in pages 15 to 20 of its EB-2009-0084 Report. It cited with approval the description of a fair return found in the Northwestern Utilities case, and the 2004 Federal Court of Appeal cases noted above, as well as two United States Supreme Court cases from the first half of the twentieth century, Bluefield Waterworks, and the Federal Power Commission v. Hope Natural Gas (320 US 591 (1944)). The Board made several points which summarized its understanding of how the fair return principle should be used in determining an appropriate cost of capital for a utility, notably:

- the fair return is prospective in nature as it refers to an opportunity cost of capital

- it is not determined by a balancing of the company and the customer interests

- all three tests must be met and no one ranks in priority to the others

- the cost of capital is not an amount in excess of the cost required to attract capital to the utility

- the cost of capital refers to the cost of equity capital

- the capital attraction standard means the utility's ability to attract capital on a long term sustainable basis.

However, the Board does not discuss in any substantial way, the equity thickness of the utility as being part of the principle of a fair return. In fact, the only place the Board discusses capital structure in the Report, and then for only three paragraphs, is a restatement of its existing policy on that subject, as discussed above.

The judicial finding of the principle of a fair return, which the NEB and the Board have restated as the "Fair Return Standard" has been clearly stated by both the Supreme Court of Canada and, for those inclined to, place weight on US jurisprudence, the Supreme Court of the United States, in very similar terms. The Canadian legal principle is quite clear, and it does not include the equity thickness or capital structure of the utility. Enbridge's and Concentric's contention that it does is simply wrong.

The Board may well consider the "fair return standard" as an overarching principle in setting a utility's cost of equity capital, but, in BOMA's view, the legal content of that principle is as set out above.