Enbridge Gas Compendium Panel 7, 8 and 9

Ontario Energy Board

EB-2009-0084

Report of the Board

on the Cost of Capital for Ontario's Regulated Utilities

December 11, 2009

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Executive Summary

Earlier this year, the Board initiated a consultative process to assist the Board in reviewing its cost of capital policies. The consultative process began in February 2009 and has culminated in this policy report of the Board. All materials in relation to this consultation are available on the Board's web site.

The Board affirms its view that the Fair Return Standard frames the discretion of a regulator, by setting out three requirements that must be satisfied by the cost of capital determinations of the tribunal. Meeting the standard is not optional; it is a legal requirement. Notwithstanding this obligation, the Board notes that the Fair Return Standard is sufficiently broad that the regulator that applies it must still use informed judgment and apply its discretion in the determination of a rate regulated entity's cost of capital. The Board also confirms other key principles with respect to its cost of capital policy.

The Board has analyzed submissions, discussions at the consultation and the final written comments of participants to the consultation with these general principles in mind. In light of the information and supporting empirical analysis provided in consultation with stakeholders, the following refinements to the Board's policies with regard to the cost of capital are set out in this report.

1. <u>Need to Reset and Refine Existing Return on Equity Formula:</u> The Board will continue to use a formula-based equity risk premium approach. Also, the Board is of the view that the Long Canada Bond Forecast (the "LCBF") continues to be an appropriate base upon which to begin the return on equity calculation. However, in order to ensure that on an ongoing basis changing economic and financial conditions are adequately and appropriately accommodated in the Board's formulaic approach for determining a utility's equity cost of capital, the Board has determined that its current formula-based return on equity approach needs to be reset and refined.

- Reset the Formula: The formula needs to be reset to address the difference between the allowed return on equity arising from the application of the formula and the return on equity for a low-risk proxy group that cannot be reconciled based on differences in risk alone. Based on the equity risk premium recommendations derived from multiple approaches that were provided by all participants in this consultation, the Board has determined that an initial equity risk premium of 550 basis points is appropriate for the purposes of deriving the initial return on equity to be embedded in the Board's reset and refined return on equity formula. This includes an implicit 50 basis points for transactional costs. Consequently, assuming a forecast long term government of Canada bond yield of 4.25%, the initial return on equity to be embedded in the Board's reset and refined return on equity formula will be 9.75% (i.e., 4.25% + 550 basis points = 9.75%).

- Refine the Formula: The formula also needs to be refined to reduce its sensitivity to changes in government bond yields due to monetary and fiscal conditions that do not reflect changes in the utility cost of equity. First, the Board views the determination of the LCBF adjustment factor to be an empirical exercise, and as such, based on the empirical analysis provided by participants in conjunction with the consultation, the Board is of the view that the LCBF adjustment factor should be set at 0.5. Second, based on the analysis provided by participants to the consultation, the Board concludes that there is a statistically significant relationship between corporate bond yields and the cost of equity, and that a corporate bond yield variable should be incorporated in the return on equity formula. The Board has determined that it will use a utility bond spread based on the difference between the Bloomberg Fair Value Canada 30-Year A-rated Utility Bond index yield and the long Canada bond yield and that the utility bond spread reflected will be subject to a 0.50 adjustment factor, consistent with the empirical analyses provided by participants to the consultation.

2. Refine Long-term Debt Guidelines and Approach to Determine Rate: The determination of the cost of long-term debt 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 policies and practices. However, in the report the Board formalizes certain approaches to reflect recent determinations regarding long-term debt costs. Further, the deemed long-term debt rate will be estimated including the A-rated utility bond index yield consistent with refinement to the return on equity formula.

3. Refine Approach to Determine Deemed Short-term Debt Rate: The determination of the cost of short-term debt also was not a primary focus of the consultation. However, to better reflect utility short-term debt costs, the Board has determined that the spread over the Bankers' Acceptance rate used to derive the deemed short-term debt rate should be based on real market quotes for issuing spreads over Bankers' Acceptance rates for the cost of short-term debt.

The Board will apply the methods set out in this report annually to derive the values for the return on equity and the deemed long-term and short-term debt rates for use in cost of service applications. If the application of these methods produces numerical results that, in the view of the Board, raise doubt that the Fair Return Standard is met, the Board may then use its discretion to begin a consultative process. Also, the Board has determined that a review period of five years provides an appropriate balance between the need to ensure that the formula-generated return on equity continues to meet the Fair Return Standard and the objective of maintaining regulatory efficiency and transparency. Accordingly, the Board intends to conduct its first regular review in 2014.

The remainder of this Report sets out in greater detail the Board's policy as summarized above, as well as the considerations underlying the different elements of the Board's approach.

1 Introduction

The Ontario Energy Board (the "Board") adopted a formula-based approach using the Equity Risk Premium ("ERP") method for determining the fair rate of return on common equity for Ontario natural gas utilities in March, 1997. Application of the approach was extended to the electric utilities when the Board's regulatory oversight expanded to include the electricity sector in 1999. The Board's current approach for determining the cost of capital is set out in the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, dated December 20, 2006 (the "December 20, 2006 Report").

Earlier this year, the Board initiated a consultative process to assist the Board in reviewing its cost of capital policies. The consultative process, detailed below, began in February 2009 and has culminated in this policy report of the Board. All materials in relation to this consultation are available on the Board's web site.

This report sets out the Board's updated approach to cost of capital and the methods that the Board will use to annually update the cost of capital parameters for all rate-regulated utilities. Specifically, this report refines the Board's policies regarding the cost of capital in the following five ways: (i) resetting and refining the return on equity ("ROE") formula; (ii) refining long-term debt guidelines and the approach to determining the deemed long-term debt rate; (iii) refining the approach to determining the deemed short-term debt rate; and (iv) setting out an annual review process to be used by the Board in conjunction with each application of the methodology to ensure that the results meet the Fair Return Standard ("FRS"); and (v) developing a framework within which to conduct a periodic review of the Board's cost of capital policies.

Organization of this Report

This report is organized as follows: The consultative process is detailed in Chapter 2. Important principles in the regulation of cost of capital are discussed in Chapter 3. The Board's policy for and analysis of cost of capital are outlined in Chapter 4. Certain implementation considerations are identified in Chapter 5, and the annual update process and provision for periodic review of the cost of capital policies are addressed in Chapter 6. A summary of the formula-based ROE guidelines in effect in the 2009 rate year is provided in Appendix A. The new methods that the Board will use to annually update the cost of capital parameters as set out in this report are contained in the Appendices.

2 Consultative Process

On February 24, 2009, the Board issued a letter which set out its determination on the values for the ROE and the deemed long-term and short-term debt rates for use in the 2009 rate year cost of service applications. These cost of capital parameter values were calculated based on the methodologies and formulae set out in the December 20, 2006 Report. In that letter, the Board advised participants that it would be initiating a review of its current policy regarding the cost of capital.

2.1 Overview

Initial Consultation

On March 16, 2009, the Board initiated a consultation process to help it to determine whether current economic and financial market conditions warrant an adjustment to any of the cost of capital parameter values (i.e., the ROE, long-term debt rate, and/or short-term debt rate) set out in the Board's February 24, 2009 letter. The consultation was initiated, in part, by (i) the fact that the difference between the cost of equity and the cost of long-term debt values determined by the Board for the 2009 Cost of Service Applications was only 39 basis points (8.01% and 7.62%), versus a difference of 247 basis points in 2008; and (ii) concern that the Board did not have a sufficiently robust approach within which to exercise its discretion to adjust any or all of the values produced by the application of the methodology. The Board indicated that the objective of the consultation was to test whether the values produced, and the relationships among them, are reasonable in the current economic and financial market conditions, and to allow the Board to determine if, when and how to make any appropriate adjustments to any of the values.

Cost of Capital Review

In light of stakeholders' comments, the Board determined not to vary the 2009 parameter values for 2009 rates. In its June 18, 2009 letter setting out this determination, the Board explained that it was not persuaded that there was a sufficient basis to do so, in a timely manner. Nevertheless, the Board determined that further examination of its policy regarding the cost of capital was warranted to ensure that, on a going forward basis, changing economic and financial conditions are accommodated if required. Therefore, the Board advised that it would proceed with a review of its policy regarding the cost of capital. The Board indicated that any changes to the policy made as a result of this review would apply to the setting of rates for the 2010 rate year.

The Board set an issues list to form the basis of its review which took into account the stakeholder comments received in response to the Board's March 16, 2009 letter and other information that the Board considered relevant (the "Issues List"). This Issues List was posted to the Board's web site on July 30, 2009. Appended to the Issues List were: a summary of stakeholder options in response to the Board's March 16, 2009 letter; and a list of references to documents germane to the consultation.

The Issues List

In the cover letter to the Issues List, the Board affirmed its view that the FRS constitutes the over-arching principle for setting the cost of capital, which is one input into the setting of rates. The Board also set the scope for the consultation as follows. First, that the consultation would deal only with the means by which the Board determines the cost of capital. The actual effect, if any, on specific utilities' revenue requirements as a result of any updated policies arising from this consultation and the determination of just and reasonable rates would not be addressed in this process, but in future rate proceedings. Second, that historically, the Board has found the ERP approach to be pragmatic and efficient given the Ontario market structure and the number of utilities that the Board regulates. The Board concluded that an ERP approach remains the most appropriate in the current circumstances. However, the Board decided to review the application and the derivation of the current ERP approach to determine if it is sufficiently robust to guide the

Board's discretion in applying the FRS. And third, the Board stated that the application of the FRS would be central to the consultation.

The Board identified three areas where further information was needed:

- Potential adjustment to the established cost of capital methodology (i.e., based on the ERP approach) to adapt to changes in financial market and economic conditions;
- Determination of reasonableness of the results based on a formulaic approach for setting cost of capital parameter values; and
- Board discretion to adjust those results, if appropriate.

The Board received written comments from stakeholders identifying their views and positions on the listed issues and held a Stakeholder Conference to provide a forum for discussion of the substantive matters contained in the Board's Issues List.

The Stakeholder Conference

The Stakeholder Conference was held over a three day period, September 21, 22 and October 6, 2009.

The Board identified the objectives of the stakeholder conference as follows:

- To allow participants and their respective experts to clarify and elaborate on their written comments;
- To provide participants with an opportunity to explore in some depth the rationale and merits of alternatives supported by other participants and their respective experts; and
- To help the Board gain, through the presentations and an interactive exchange with participants and their respective experts, a clearer understanding of the positions of participants and of significant issues and areas of concern.

At the start of the Stakeholder Conference, a Capital Markets Panel provided participants with a comprehensive overview of capital markets conditions. The Panel was comprised of practicing capital markets individuals, representing investor, equity analyst, and bond market perspectives. Representatives from Sun Life Financial, TD Securities Inc., Scotia Capital, and Macquarie Capital Markets participated on the Capital Markets Panel. Panel members addressed matters such as:

- What the capital markets have been through, where they are today, and set out key indicators or variables that are of interest prospectively;
- Overall availability of capital and the cost of that capital (both debt and equity);
- Access to bank credit/debt/equity, the absolute cost of debt, spread, term availability, and covenants;
- Spreads that have been and are being observed and under what conditions; and
- Activity that has been and/or is evident in the market in terms of funds flow into the market and between asset classes.

Following the Capital Markets Panel discussion, the following individuals provided presentations to participants and the Board at the Stakeholder Conference:

- Dr Laurence D. Booth, Professor, University of Toronto (consultant for the Building Owners and Managers Association of the Greater Toronto Area, the Consumers Council of Canada, Canadian Manufacturers and Exporters, Industrial Gas Users Association, London Property Management Association, and the Vulnerable Energy Consumer's Coalition);
- Mr. Donald A. Carmichael, Independent Consultant (consultant for Enbridge, Fortis Ontario Inc., and Toronto Hydro-Electric System Limited);
- Mr. James M. Coyne, Senior Vice President, Concentric Energy Advisors (consultant for Enbridge, Hydro One Networks, Inc. and the Coalition of Large Distributors [Enersource Hydro Missisauga Inc., Horizon Utilities Corporation, Hydro Ottawa Limited, PowerStream Inc., Toronto Hydro-Electric System Limited and Veridian Connections Inc.]);

- Mr. John Dalton, Power Advisory LLC (consultant for Great Lakes Power Transmission);
- Ms Kathleen McShane, President, Foster Associates (consultant for Electricity Distributors Association);
- Dr Lawrence P. Schwartz, Consulting Economist (consultant for Energy Probe Research Foundation); and
- Dr. James Vander Weide, Research Professor of Finance and Economics, Duke University, The Fuqua School of Business (consultant for Union Gas).

Subsequent to the Stakeholder Conference and in light of the presentations made by participants and discussions at the conference, the Board received final written comments from participants. The Board indicated in its October 5, 2009 letter to participants that following the receipt of final written comments, it would review all of the materials, including Stakeholder Conference transcripts and all of the written comments in making its determination, and that the Board aimed to issue its report in December.

2.2 Approach to Developing Regulatory Policy

In their final comments to the Board, several participants expressed concern regarding the potential scope of outcomes arising from this consultation. In a joint submission, the Consumers Council of Canada, the Vulnerable Energy Consumer's Coalition and the Canadian Manufacturers and Exporters describe their understanding that the consultation was intended to have a limited scope, and pointed to several statements made by the Board regarding the scope of the consultation. In summary, the submission states: “[i]n these circumstances, we suggest that the possible outcomes of this consultation are limited to a Board report which evaluates whether any of the information presented during the course of the consultative is sufficient to call into question the continued appropriateness of any element of the Board’s current cost of capital methodology.”[1] The School Energy Coalition filed a similar submission, stating: “[t]he primary purpose of this part of the consultation, as

[1] Final Comments on behalf of the Consumers Council of Canada, the Vulnerable Energy Consumer's Coalition and the Canadian Manufacturers and Exporters. October 30, 2009. p. 3.

noted by the Board in a number of communications, and reiterated at the stakeholder conference, is to help understand whether the current approach to cost of capital has sufficient robustness to be relied on by the Board in all circumstances."[2]

Although the Board appreciates the perspectives of these participants about their expectations, it does not agree that the scope of the consultation was limited in the fashion that they suggest. The Issues List set out a comprehensive set of issues that set the scope for this consultation. Amongst the issues are the following: How should the Board establish the initial ROE for the purpose of resetting the methodology? Does the current approach used by the Board to calculate the ERP remain appropriate? If not, how should the ERP be calculated?[3]

In response to a letter it received on August 13, 2009 from Mr. Robert Warren, sent on behalf of the Consumers Council of Canada, the Vulnerable Energy Consumers Coalition and the London Property Management Association, the Board again invited participants to provide any information they felt appropriate in responding to the questions on the Issues List:

> Stakeholders are asked to provide in their written comments answers to the questions identified in the Board's Issues List. To help the Board in its review, the Board invites stakeholders to include in their written comments some analytical support and detailed information to identify their views and support their positions in response to the Board's questions.[4]

It is the Board's view, therefore, that the policies determined by the Board in this report are within the scope of the consultation. The Board has benefitted from the materials and submissions received from the participants. This information contributes to the substantive foundation upon which the Board will base its policies. The Board does not believe that the

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[2] Final Comments on behalf of the School Energy Coalition, p. 2.
[3] Ontario Energy Board. Letter to Participants re: Consultation on Cost of Capital – Issues List, Attachment B: Issues for Discussion at Stakeholder Conference. July 30, 2009. Questions 10 and 13.
[4] Ontario Energy Board. Letter to Mr. Robert B. Warren re: Consultation on Cost of Capital (Board File No.: EB-2009-0084). August 20, 2009.

extensive body of information before it would be materially improved by a hearing process, as was suggested by some participants.

Courts have long recognized that duties of procedural fairness such as the requirement of a hearing apply to adjudicative decisions and decisions affecting specific rights, interests and privileges. Where a board is engaged, as here, in the development of a policy guideline, courts have held that it falls to the board to decide on the method of consultation to be employed - as long as the legislative requirements, if any, are met. There also is abundant precedent for this approach within the Board's practice, and it is neither unusual nor improper to develop a guideline through a consultative process.[5]

The final "product" of this process, of course, is a Board policy. This was not a hearing process, and it does not - indeed cannot - set rates. The Board's refreshed cost of capital policies will be considered through rate hearings for the individual utilities, at which it is possible that specific evidence may be proffered and tested before the Board. Board panels assigned to these cases will look to the report for guidance in how the cost of capital should be determined. Board panels considering individual rate applications, however, are not bound by the Board's policy, and where justified by specific circumstances, may choose not to apply the policy (or a part of the policy).

[5] The Board's current methodology for setting electricity rates through the incentive regulation mechanism, for example, was established through a consultative/guideline process.

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3 Context, Background and the Role of the Board

In competitive markets, the outputs of the goods and services of the economy and the prices for these outputs are determined in the market place, in accordance with consumers' preferences and incomes, as well as producers' minimization of cost for a given output. In such a market, the outcome is the efficient allocation of resources, including capital, and social welfare is maximized.

However, in some situations, markets fail to achieve such efficient outcomes. Market failure refers to situations in which the conditions required to achieve the market-efficient outcome are not present. Common examples of market failure are the existence of significant externalities, the exercise of market power by a small number of producers or buyers, natural monopolies, and information asymmetry between producers and their customers.

Electric transmission and distribution companies and natural gas distribution utilities are natural monopolies and are subject to rate regulation in Ontario by the Ontario Energy Board. In this context, the purpose of rate regulation, among other things, is to create or emulate an efficient market solution that cannot otherwise be achieved due to the presence of one or more market failures. As it relates to a rate regulated entity's cost of capital, the role of the regulator is to determine, as accurately as possible, the opportunity cost of capital to ensure that an efficient amount of investment occurs in the public interest for the purpose of setting utility rates.

3.1 Fair Return Standard

On July 30, 2009 the Board issued a letter and its Issues List for the then planned stakeholder consultation. In that letter, the Board communicated its view that the FRS constitutes the over-arching principle for setting the cost of capital, which is one input into the setting of rates. There are a number of key messages in this statement.

First, as set out by the Federal Court of Appeal, the cost of capital to a utility "is equivalent to the aggregate return on investment investors require in order to keep their capital invested in the utility and to invest new capital in the utility."[6]

Second, the Federal Court of Appeal also stated:

> … even though cost of capital may be more difficult to estimate than some other costs, it is a real cost that the utility must be able to recover through its revenues. If the… [Board] does not permit the utility to recover its cost of capital, the utility will be unable to raise new capital or engage in refinancing as it will be unable to offer investors the same rate of return as other investments of similar risk. As well, existing shareholders will insist that retained earnings not be reinvested in the utility.[7]

Thirdly, the Board is of the view that the process to determine the cost of capital aligns the private interest of the utility and its shareholders with the public interest, and notes that the Federal Court of Appeal said:

> … in the long run, unless a regulated enterprise is allowed to earn its cost of capital, both debt and equity, it will be unable to expand its operations or even maintain its existing ones…This will harm not only its shareholders, but also the customers it will no longer be able to service. The impact on customers and ultimately consumers will be even more significant where there is insufficient competition in the market to provide adequate alternative service.[8]

The determination of a utility's cost of capital must meet the FRS. The FRS is a legal concept, and has been articulated in three seminal court determinations as set out below:

1. In *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia* et. al. 262 U.S. 679 (1923), the FRS is expressed to include concepts of comparability, financial soundness and adequacy:

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[6] TransCanada PipeLines Limited v. National Energy Board et al. [2004] F.C.A 149. Para. 6.
[7] Ibid. Para. 12.
[8] Ibid. Para. 13.

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding, risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

2. In *Northwestern Utilities Limited v. City of Edmonton*, [1929] S.C.R. 186, the FRS concept was described as follows:

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

3. In *Federal Power Commission v. Hope Natural Gas* 320 U.S. 591 (1944), the Court expresses that "balance" is achieved in the ratemaking process, and outlines three elements of a fair return:

> The rate-making process under the act, i.e., the fixing of "just and reasonable" rates, involves a balancing of the investor and the consumer interests…the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock…By that standard, the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

The FRS was further articulated by the National Energy Board in its RH-2-2004 Phase II Decision as:

> A fair or reasonable return on capital should:
>
> - be comparable to the return available from the application of 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).[9]

In its letter of July 30, 2009, the Board noted that the National Energy Board's articulation of the FRS is consistent with the principled approach described on page 2 of the Compendium to the Board's March 1997 *Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities* (the "1997 Draft Guidelines") and the policies set out in the Board's December 20, 2006 Report.

The Board is of the view that the FRS frames the discretion of a regulator, by setting out three requirements that must be satisfied by the cost of capital determinations of the tribunal. Meeting the standard is not optional; it is a legal requirement. As set out by Enbridge in their final comments, the Supreme Court of Canada has "described this requirement that approved rates must produce a fair return as an 'absolute' obligation."[10] Notwithstanding this mandatory obligation, the Board notes that the FRS is sufficiently broad that the regulator that applies it must still use informed judgment and apply its discretion in the determination of a rate regulated entity's cost of capital.

Informed by the comments made by stakeholders in the context of this consultation and the relevant jurisprudence, the Board offers the following observations about the application of the FRS.

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[9] National Energy Board. RH-2-2004, Phase II Reasons for Decision, TransCanada PipeLines Limited Cost of Capital. April 2005. p. 17

[10] *British Columbia Electric Railway Co. Ltd. v. Public Utilities Commission of British Columbia et al [1960] S.C.R. 837*, at p. 848.

First, the Board notes that the FRS expressly refers to an opportunity cost of capital concept, one that is prospective rather than retrospective.

Second, the Board agrees with the National Energy Board which stated that "[i]t does not mean that in determining the cost of capital that investor and consumer interests are balanced."[11] Further, the Board notes that the Federal Court of Appeal was clear that the overall ROE must be determined solely on the basis of a company's cost of equity capital and that "the impact of any resulting toll increase is an irrelevant consideration in that determination. This does not mean however, that any resulting increase in tolls cannot be considered by a tribunal in determining the way in which a utility should recover its costs."[12] The Federal Court of Appeal also stated that:

> It may be that an increase is so significant that it would lead to "rate shock" if implemented all at once and therefore should be phased in over time. It is quite proper for the Board to take such considerations into account, provided that there is, over a reasonable period of time, no economic loss to the utility in the process. In other words, the phased in tolls would have to compensate the utility for deterring the recovery of its cost of capital.[13]

Third, all three standards or requirements (comparable investment, financial integrity and capital attraction) must be met and none ranks in priority to the others. The Board agrees with the comments made to the effect that the cost of capital must satisfy all three requirements which can be measured through specific tests and that focusing on meeting the financial integrity and capital attraction tests without giving adequate consideration to comparability test is not sufficient to meet the FRS.

Fourth, a cost of capital determination made by a regulator that meets the FRS does not result in economic rent being earned by a utility; that is, it does not represent a reward or payment in excess of the opportunity cost required to attract capital for the purpose of

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[11] National Energy Board. Reasons for Decision. Trans Quebec & Maritimes Pipelines Inc. RH-1-2008. March 19, 2009. p. 6.
[12] *TransCanada PipeLines Ltd. v. National Energy Board, 2004 FCA 149*, para. 35-36.
[13] *TransCanada PipeLines Ltd. v. National Energy Board, 2004 FCA 149*, para. 43.

investing in utility works for the public interest. Further, the Board reiterates that an allowed ROE is a cost and is not the same concept as a profit, which is an accounting term for what is left from earnings after all expenses have been provided for. The Board notes that while cost of capital and profit are often used interchangeably from a managerial or operational perspective, the concepts are not interchangeable from a regulatory perspective.

Fifth, there was considerable discussion in the consultation about utility bond ratings. The ability of a utility to issue debt capital and maintain a credit rating were generally put forth by stakeholders in the consultation as a sufficient basis upon which to demonstrate that a particular equity cost of capital and deemed utility capital structure meet the capital attraction and financial integrity requirements of the FRS. The Board is of the view that utility bond metrics do not speak to the issue of whether a ROE determination meets the requirements of the FRS. The Board acknowledges that equity investors have, as the residual, net claimants of an enterprise, different requirements, and that bond ratings and bond credit metrics serve the explicit needs of bond investors and not necessarily those of equity investors.

Finally, the Board questions whether the FRS has been met, and in particular, the capital attraction standard, by the mere fact that a utility invests sufficient capital to meet service quality and reliability obligations. Rather, the Board is of the view that the capital attraction standard, indeed the FRS in totality, will be met if the cost of capital determined by the Board is sufficient to attract capital on a long-term sustainable basis given the opportunity costs of capital. As the Coalition of Large Distributors commented:

> [t]he fact that a utility continues to meet its regulatory obligations and is not driven to bankruptcy is not evidence that the capital attraction standard has been met. To the contrary, maintaining rates at a level that continues operation but is inadequate to attract new capital investment can be considered confiscatory. The capital attraction standard is universally held to be higher than a rate that is merely non-confiscatory. As the United States Supreme Court put it, 'The mere fact that a rate is non-confiscatory does not indicate that it must be deemed just and reasonable'.[14]

[14] Final Comments of the Coalition of Large Distributors. October 26, 2009. pp. 5-6.

The Role of the Comparable Investment Standard

Continued investment in network utilities does not, in itself, demonstrate that the FRS has been met by a regulator's cost of capital determination, and in particular, whether the determination of the equity cost of capital meets the requirements of the FRS. This is a particular challenge – how does the regulator determine when investment capital is <u>not</u> allocated to a rate regulated enterprise? These decisions are typically made within the utility/corporate capital budgeting process and rarely, if ever, broadly communicated to stakeholders. The Board notes that acquisition and divestiture activities of regulated utilities are not definitive in this regard, one way or the other, and notes that there are many reasons why investors are willing to acquire or desirous of selling utility assets, notwithstanding their view of whether an allowed ROE meets the FRS.

The primary tool available to the regulator to rectify this lack of transparency is the comparable investment standard. By establishing a cost of capital, and an ROE in particular, that is comparable to the return available from the application of invested capital to other enterprises of like risk, the regulator removes a significant barrier that impedes the flow of capital into or out of, a rate regulated entity. The net result is that the regulator is able, as accurately as possible, to determine the opportunity cost of capital for monies invested in utility works, with the ultimate objective being to facilitate efficient investment in the sector.

There are a number of specific issues relating to the comparable investment standard that the Board considers are relevant in the context of this cost of capital policy.

First, "like" does not mean the "same". The comparable investment standard requires empirical analysis to determine the similarities and differences between rate-regulated entities. It does not require that those entities be "the same".

Second, there was a general presumption held by participants representing ratepayer groups in the consultation that Canadian and U.S. utilities are not comparators, due to differences in the "time value of money, the risk value of money and the tax value of money."[15] In other words, because of these differences, Canadian and U.S. utilities cannot be comparators. The Board disagrees and is of the view that they are indeed comparable, and that only an analytical framework in which to apply judgment and a system of weighting are needed. The analyses of Concentric Energy Advisors and Kathy McShane of Foster Associates Inc. are particularly relevant in this regard, and substantially advance the issue of establishing comparability to meet the requirements of the FRS. Further, the Board notes that in the consultation session on October 6, 2009, Dr. Booth stated that it is "absolutely possible" to form a sample from a risky universe that is low risk and compare it to the universe or the population of Canadian utilities.[16] All participants agreed.

The Board notes that Concentric did not rely on the entire universe of U.S. utilities for its comparative analysis. Rather, Concentric carefully selected comparable companies based on a series of transparent financial metrics, and the Board is of the view that this approach has considerable merit. Commenting on Concentric's analysis, Union Gas noted that no one else in the consultation performed this kind of detailed analysis of U.S. comparators.[17] The use of a principled, analytical, and transparent approach to determine a low risk comparator group from a riskier universe for the purpose of informing the Board's judgment was supported by various participants in the consultation.

The PWU commented that the position taken by Dr. Booth on the question of the comparability of US utility returns is not based on an appropriate empirical foundation.[18] The PWU further commented that:

> On the other hand, it is the view of the PWU that the analysis produced by Concentric, as summarized in one of their charts presented at the conference, represents a far more comprehensive analysis of the key characteristics of distribution utilities in Ontario vs. a North American

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[15] Professor L.D. Booth. Written Comments on behalf of Consumers Council of Canada, the Vulnerable Energy Consumer's Coalition, the Industrial Gas Users Association, the Canadian Manufacturers & Exporters (CME), the London Property Management Association and the Building Managers and Owners Association of the Greater Toronto Area. September 8, 2009. p. 25.
[16] Ontario Energy Board. Transcript of Consultation Process on Cost of Capital Review. October 6, 2009. Comments of Dr. Booth at p. 60. Lines 24-26.
[17] Written Comments of Union Gas Limited. October 30, 2009. p. 14.
[18] Final Comments of the Power Workers' Union. October 30, 2009. p. 3.

> proxy group. Differences and similarities were thoroughly considered before arriving at the conclusions that based on a careful selection of like companies, a proxy group which includes US distribution utilities adheres to the Comparable Investment Standard. Moreover, Concentric was better suited to complete such as an analysis, having recognized expertise in the risks faced by both Ontario and US electricity distributors.[19]

Dr. Vander Weide indicated that since Canadian utility bonds tend to have more covenants than US utility bonds, they would receive a slightly higher credit rating. The PWU observed that it the slight variance in ratings can be attributed to specific features of debt instruments, rather than fundamental differences in the underlying business or regulatory risks faced by the utilities. This observation was also made by Ms. Zvarich of Sun Life Financial, who presented evidence that Canadian utility bonds generally have more restrictive covenants than U.S. utility bonds.[20]

The Board is of the view that the U.S. is a relevant source for comparable data. The Board often looks to the regulatory policies of State and Federal agencies in the United States for guidance on regulatory issues in the province of Ontario. For example, in recent consultations, the Board has been informed by U.S. regulatory policies relating to low income customer concerns, transmission cost connection responsibility for renewable generation, and productivity factors for 3rd generation incentive ratemaking.

Finally, the Board agrees with Enbridge that, while it is possible to conduct DCF and CAPM analyses on publicly-traded Canadian utility holding companies of comparable risk, there are relatively few of these companies. As a result, the Board concludes that North American gas and electric utilities provide a relevant and objective source of data for comparison.

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[19] Final Comments of the Power Workers' Union. October 30, 2009. p. 6.
[20] Ontario Energy Board. Transcript of Consultation Process on Cost of Capital Review. September 21, 2009. Comments of Ms. Zvarich at pp. 24 -25.

3.2 The Cost of Capital in Theory and Practice

The Cost of Capital

The Ontario Energy Board has been engaged in the rate regulation of utilities for many years. Over this extended period, the Board notes that there continues to be any of a number of misconceptions about the cost of capital concept, particularly what the cost of capital is and why it is an important consideration.

The Board is of the view that the following points articulated by Dr. Bill Cannon in his presentation at CAMPUT's 2009 Energy Regulation Conference on July 3, 2009, are principally relevant to defining and understanding the cost of capital concept.

> At its simplest, the cost of capital is the minimum expected rate of return necessary to attract capital to an investment. The rate of return includes the income received during the time the investment is held plus any capital gain or loss, realized or accruing during this period, all as a percentage of the initial investment outlay.
>
> The cost of capital can be viewed from both: (a) a company or utility perspective; and (b) from the investor's or capital provider's perspective. From the company's perspective, the cost of capital is the minimum rate of return the company must promise to achieve for investors on its debt and equity securities in order to preserve their market values and, thereby, retain the allegiance of these investors.
>
> [There is interest] in the cost of capital…because all utilities – private or public – at some time… must raise financial capital to pay for investments, and both fairness and practical considerations dictate that the private and/or government investors who provide these capital funds must be adequately compensated. Raising capital is a competitive process. Private investors are under no obligation to buy a particular utility's securities, and government-owned utilities must compete with other government spending priorities. A utility will be able to secure new capital and replace maturing securities only if investors believe that they will be adequately rewarded for providing new capital funds. That required reward, in turn, must compensate the investors for a least two things: (1) for postponing the consumption of the goods and services that they might otherwise have enjoyed had they not made the investment; and (2) for exposing their funds to the risk that they may not

> get all their money back or not get it back as promptly as they anticipated. The reward demanded by investors is therefore a necessary cost of doing business from the utility's point of view, just as much as the cost of labour or fuel.
>
> From the viewpoint of investors as a group, however, the cost of capital can be defined more clearly and operationalized as "the expected rate of return prevailing in the capital markets on alternative investments of equivalent risk and attractiveness." There are four concepts embedded in this operational definition:
>
> First, it is *forward-looking*. Investment returns are inherently uncertain and the ex post, actual returns experienced by investors may differ from those that were expected ahead of time. The cost of capital is therefore an *expected* rate of return.[21]
>
> Second, it reflects the *opportunity cost* of investment. Investors have the opportunity to invest in a wide range of investments, so the expected rate of return from a given utility-company investment must be sufficient to compensate investors for the returns they might otherwise have received on foregone investments.
>
> Third, it is *market-determined*. This market price - expressed as the expected return per dollar of invested capital - serves to balance the supply of, and demand for, capital for the firm.
>
> And, fourth, it reflects the *risk* of the investment. It reflects the expected returns on investments in the marketplace that are exposed to equivalent risks. Another way of expressing this principle is to say that the cost of capital depends on the *use* of the capital – or, more precisely, the risk associated with the use of the funds – and not on the *source* of the funds.

In Ontario, utilities regulated by the Board in the gas and electricity sectors are structured to operate as commercial entities. As such, the rate setting methodologies used by the Board apply uniformly to all rate-regulated entities regardless of ownership. The determination of rate-regulated entities' cost of capital is no exception. It follows that the opportunity cost of capital should be determined by the Board based on a systematic and empirical approach that applies to all rate-regulated utilities regardless of ownership. The Board sees no

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[21] The word "expected" is used in the statistical sense (i.e., the probability-weighted rate of return). It does not refer to a "hoped for" or "most likely" rate of return.

compelling reason to adopt different methods of determining the cost of capital based on ownership.

The Equity Risk Premium Approach

As previously indicated, the Board has determined that the ERP approach remains the most appropriate approach in the current circumstances. The ERP approach is one of four main approaches that are traditionally used by experts during regulatory cost of capital reviews to establish a fair ROE: (1) the comparable earnings approach; (2) discounted cash flow approach; (3) the capital asset pricing model; and (4) ERP approach. These methods are all used in varying degrees to formulate and/or test an opinion regarding a fair return to investors.[22] The Board's current formulaic approach is a modified Capital Asset Pricing Model methodology and ERP approach.

Each of these four main approaches has well documented strengths and weaknesses. Notwithstanding the known weaknesses of these differing approaches, the Board agrees with Ms. McShane when she states: "each of the various types of tests brings a different perspective to the estimation of a fair return. No single test is, by itself, sufficient to ensure that all three requirements of the fair return standard are met."[23]

Through the consultative process which began in February 2009 and has culminated in this report, the Board has been informed by a number of ex-post analytical approaches, including analysis of experienced ERPs on investments in Canadian utility stocks. The Board observes from these analyses that the ROE produced by various approaches can be expressed as an absolute ROE number or as an ERP over a risk-free rate. Also, the Board agrees that expressing the ROE in terms of a premium above the long-term Canada bond yield does not mean that the initial ROE needs to be estimated by using a single test or a number of tests that might be defined as ERP tests.

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[22] Ontario Energy Board. Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities. March 1997. p. 2.
[23] McShane, K., Foster Associates, Inc. Written comments on behalf of the Electricity Distributors Association. September 8, 2009. p. 2.

A Formulaic Approach

The Board has used a formula-based methodology to determine the rate of ROE since 1998. The advantages identified in the 1997 Draft Guidelines remain appropriate today and include:

- Simplification of the hearing process;
- Is relatively free from conflicting interpretation and is readily understood by all participants;
- Reduces the need for complex, annual risk assessments, while still reflecting major changes in the capital markets; and
- Is capable of producing a rate of return that approximates the result which would have been produced through the traditional process.[24]

The Board also notes that a formula-based approach:

- Is transparent, resulting in predictable and consistent outcomes, and meets the needs of stakeholders broadly, particularly those in the capital market; and
- Is a practical necessity in Ontario, given the large number of rate regulated entities.

The Board also acknowledges that a formula-based ROE methodology and mechanical approaches in general, have a number of disadvantages, as identified in the 1997 Draft Guidelines:

- Establishing the initial parameters of the generic formula will have a profound influence on the potential success or failure of the process. Over time, these parameters and adjustment factors will have a cumulative or compounding effect on the

[24] Ontario Energy Board. Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities. March 1997. p. 7.

results of the formulaic ROE mechanism. The use of an inappropriate initial ROE will either inflate or understate subsequent rate determinations;

- The present formulaic ROE generally relies predominantly on the ERP method to the exclusion of other methods;

- Adjustment for the impact of timing differences for utilities with different year-ends is a challenge; and

- The Board's ability to make discretionary adjustments to a utility's return for the purpose of creating incentives for particular behaviours or sending signals to the marketplace may be restricted. [25]

Notwithstanding these concerns, the Board is of the view that it is appropriate to continue to use a formulaic approach to determine the equity cost of capital and that the overall advantages of the approach outweigh potential disadvantages.

An Empirical Foundation

The essential elements of a formulaic approach must be empirically derived – the initial ROE, implied ERP and the adjustment factor are determined by the Board based on empirical analysis. It is essential that sufficient empirical analysis be provided periodically to ensure that assumed relationships are not misspecified. This includes the construction and application of a framework to evaluate the degree of comparability between rate regulated natural gas distribution and electricity distribution and transmission utilities in Canada and the United States.

To be clear, the approach to be used by the Board in setting the essential elements of a formula-based rate of ROE (i.e., base ROE, formula terms and adjustment factors) will be based on "economic theory and empirically derived from objective, data-based analysis."[26] As such, it is not sufficient for a formulaic approach for determining ROE to produce a

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[25] Ibid. p. 7.
[26] Ontario Energy Board. Report of the Board on 3rd Generation Incentive Regulation. July 14, 2008. p. 19

numerical result that satisfies the FRS on average, over time. The Board is of the view that each time a formulaic approach is used to calculate an allowed ROE it must generate a result that meets the FRS, as determined by the Board using its experience and informed judgment.

This principle is supported by the *Hope* decision, which states: "Under the statutory standard of 'just and reasonable' it is the result reached not the method which is controlling…"[27]

[27] Federal Power Commission v. Hope Natural Gas 320 U.S. 591 (1944). p. 602

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

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.

BEFORE: Cynthia Chaplin
Presiding Member and Vice Chair

Paula Conboy
Member

Ellen Fry
Member

DECISION ON EQUITY RATIO AND ORDER

February 7, 2013

Background

Enbridge Gas Distribution Inc. ("Enbridge") filed an application on January 31, 2012 with the Ontario Energy Board (the "Board") under section 36 of the *Ontario Energy Board Act, 1998*, S.O. c.15, Schedule B (the "Act") 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.

The Board issued a Notice of Application dated March 2, 2012. Details on the various procedural steps which followed are available on the Board's website.

A Settlement Agreement, dated October 3, 2012, was filed which addressed all issues except the common equity ratio, a related aspect of long term debt and a matter related to the “open bill” issue. This Settlement Agreement was subsequently revised in response to concerns raised by the Board. The Board accepted the revised Settlement Agreement in its Decision on Revised Settlement Agreement and Procedural Order No. 6 dated November 2, 2012. On November 26, the Board accepted a Supplementary Settlement Agreement which addressed further matters on the “open bill” issue.

On November 19 and 20, 2012, the Board held an oral hearing concerning Issue E2: “Is the proposed change in capital structure increasing Enbridge’s deemed common equity component from 36% to 42% appropriate?” After the hearing, the Board received written submissions from Enbridge, the Building Owners and Managers Association (“BOMA”), the Consumers Council of Canada (“CCC”), Canadian Manufacturers and Exporters (“CME”), Energy Probe, School Energy Coalition (“SEC”), Vulnerable Energy Consumers Coalition (“VECC”) and Board staff.

This is the Board’s decision on Issue E2. In this decision, the proportion of capital structure comprised of deemed common equity will be referred to as the “equity ratio”.

The Board’s Cost of Capital Policy

In December 2009, after a consultative process, the Board issued its *Report of the Board on the Cost of Capital for Ontario’s Regulated Utilities* (the “Cost of Capital Report”).[1]

In the Cost of Capital Report, the Board stated that in making determinations on the cost of capital, it is governed by the legal standard commonly referred to as the fair return standard (“FRS”). The Board adopted the following articulation of the FRS by the National Energy Board:

> A fair or reasonable return on capital should:
>
> - be comparable to the return available from the application of invested capital to other enterprises of like risk (the comparable investment standard);

[1] Report of the Board on the Cost of Capital for Ontario’s Regulated Utilities, December 11, 2009, EB-2009-0084

- 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).

The Board noted that "the FRS is sufficiently broad that the regulator that applies it must still use informed judgment and apply its discretion in the determination of a rate regulated entity's cost of capital."[2]

The Cost of Capital Report indicates that the Board makes determinations on two elements in establishing the equity component of the cost of capital:

1) The deemed return on equity ("ROE"). This is a single rate of return set by the Board periodically for all utilities, considering overall market conditions; and
2) The deemed equity ratio, which is set by the Board for each utility individually, considering the circumstances of that particular utility.

The Board outlined its policy on the proportions of debt and equity in a utility's deemed capital structure as follows:

> **The Board's current policy with regard to capital structure for all regulated utilities continues to be appropriate.** As noted in the Board's draft guidelines, capital structure should be reviewed only when there is significant change in financial, business or corporate fundamentals. The Board's current policy is as follows:
>
> - 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 relatively constant over time and that a full reassessment of a gas utility's capital

[2] Cost of Capital Report, p. 18

> structure will only be undertaken in the event of significant changes in the company's business and/or financial risk.[3]

All the parties agree that the Board should apply its existing policy in this proceeding. All parties take the position that the Board's policy establishes a threshold test for considering the equity ratio of gas utilities, and that this threshold test is whether there have been significant changes in the company's business and/or financial risk. They submit that the Board should conduct a full analysis of Enbridge's equity ratio only if it concludes that the threshold test has been met.

Board Findings

The Board notes that one of Enbridge's expert witnesses, Mr. Coyne of Concentric Energy Advisors ("Concentric"), has expressed a view that differs from Enbridge's position. Mr. Coyne expressed the view that the Board's analysis, even at the threshold stage, should be a comprehensive FRS analysis, even if there has been no significant change in risk. Concentric conducted a comprehensive quantitative analysis of Enbridge's cost of capital against the FRS, including comparability to other utilities. Mr. Coyne expressed his view as follows:

> Concentric believes that it is consistent with Board policy that a reassessment of a utility's capital structure should be undertaken whenever there is a reasonable doubt that its capital structure, in conjunction with its allowed return, fails to meet the fair return standard.[4]

He further stated that in his view capital structure is an "unfinished element" of the Board's cost of capital policy.

> We felt as though the Board laid out its overarching framework and its adherence to the fair return standard, rendered a decision on ROE, and left the equity ratio as an element of its policy to be decided down the road…that is one of the reasons we're sitting here is that there is an element of unfinished business associated with that work.[5]

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[3] Cost of Capital Report, pp. 49-50
[4] Tr2, p 10
[5] Tr2, p91

This interpretation of the Board's policy is incorrect. The Board states explicitly in the Cost of Capital Report that the current policy on capital structure continues to be appropriate and that capital structure will only be reviewed if there is a significant change in risk for the specific company. This does not entail a full cost of capital analysis and assessment against the FRS unless there has been a significant change in risk. The Board has structured its policy in a way that applies the FRS while promoting regulatory efficiency and predictability. The Board's policy does not require a full FRS analysis in each rate case. However, it ensures that the Board will perform a full review of capital structure in instances where a significant change in risk indicates that a change may be needed in order to continue to meet the FRS. The Board considers that where there has not been a significant change in risk, the FRS continues to be met. The Board notes that another Enbridge witness, Mr. Lister, expressed this as Enbridge's understanding as well: "It is our position that if the Board found that there was no change in business risk, then by definition the Board would be saying that the fair return standard has been met."[6]

In applying the threshold test in this proceeding, the Board will therefore consider the evidence and argument concerning risk, and will not conduct a broader FRS analysis. If the Board concludes that the threshold test has been met (i.e. that there has been a significant change in Enbridge's business and/or financial risk), it will perform a full analysis based on the principles of the FRS to determine the appropriate equity ratio for Enbridge. If the Board concludes that there has not been a significant change in risk, it will not need to perform any further analysis.

Time Parameters

The Board considered what past point of reference it should use in determining whether there have been significant changes in Enbridge's business and/or financial risk. It also considered what prospective timeframe it should use in assessing risks of future events. Enbridge took the position that the Board should be taking a long term view, both historically and prospectively. Enbridge submitted that even though the Board made a decision on Enbridge's equity ratio in 2007 (EB-2006-0034), it should be considering changes in risk since 1993. Enbridge did not propose a specific timeframe for considering long term prospective risk.

[6] Tr1, p. 92

Enbridge submitted that

> It is important that changes in Enbridge's business and financial risk be viewed over the long term. Enbridge's equity ratio should be commensurate with its long-term business risk, which can only be assessed through a long-term view. That is why Enbridge has presented business risk evidence showing changes over the past 20 years. While it is true that Enbridge's equity ratio was considered in a 2006 proceeding, the fact is that there is now additional information available that was not considered at that time. This additional information adds to the conclusion that Enbridge's business and financial risks have increased, over both the long term and the more immediate term. To confine the examination of changes in Enbridge's business risks to consider only changes since 2006 would result in an incomplete examination and evaluation.[7]

The intervenors that made submissions on the past point of reference took the position that the Board should only consider changes in risk since EB-2006-0034. Concerning future risks, CCC submitted that

> ...the change in business and/or financial risk must be within some proximate timeframe. If evidence of a change in business and/or financial risk is of circumstances that may or may not occur at some indeterminate time in the future, then the evidence doesn't satisfy the Board's test. In the case of [Enbridge], the Board must be satisfied not only that there is evidence of a significant change in business and/or financial risk, but that the change will affect [Enbridge] in 2013 or in the near term beyond that.[8]

Board Findings

In 2007 the Board made a decision in EB-2006-0034 concerning the appropriate level for Enbridge's equity ratio. In that proceeding, Enbridge had a full opportunity to present evidence and argument in support of its position.

In arguing that the Board should now consider evidence for a period starting in 1993, as indicated in the extracts of its argument reproduced above, Enbridge is in effect arguing

[7] Enbridge Argument in Chief, p. 5
[8] CCC Argument, p. 3

that the Board should reconsider the basis for its decision in EB-2006-0034. Enbridge had the right to seek a review of that decision, but did not do so. Parties and ratepayers are entitled to rely on the results of Board proceedings, subject to the established legal review mechanisms.

In EB-2006-0034, the Board performed an assessment of the change in Enbridge's risk and determined the appropriate equity ratio for Enbridge at that time. In this proceeding, the Board's task in assessing the change in risk is to examine how risk has changed from the time the issue was previously decided in EB-2006-0034. To extend the analysis to a date before the Board's last consideration of the issue would inappropriately revisit the basis for the Board's risk assessment in EB-2006-0034, which was embodied in the approved equity ratio at that time. If there is now information available which was not known when the equity ratio was previously set, this will inform the analysis of change in risk only to the extent it is relevant to the change in risk since the equity ratio was last set.

Accordingly, the Board will determine whether there has been a significant change in Enbridge's risk since the Board rendered its decision in EB-2006-0034 in 2007.

Regarding the risk of future events, the Board agrees with CCC that the relevant future risks are those that are likely to affect Enbridge in the near term. Any risks that may materialize over the longer term can be taken into account in subsequent proceedings. In considering the risk of future events, the Board will take into account the fact that, generally, the more distant the potential event, the more speculative is any conclusion on the likelihood that the risk will materialize.

Assessment of Change in Risk

Although Enbridge has presented evidence and argument concerning changes in its risk since 1993, its position is also that it has experienced a significant increase in its business and financial risk since 2007. Intervenors take the position that this is not the case. Although the intervenors' expert witness, Dr. Booth, expressed the view that risk has decreased since 2007, the intervenors do not focus on arguing this position. No party argued that the risk had declined sufficiently to warrant a decrease in the common equity ratio. The Board has therefore focused only on the question of whether the risk has increased significantly.

Business Risk

Enbridge submits that its business risk has increased since 2007 in three ways:

1) Volumetric demand profile;
2) System size and complexity; and
3) Environmental and technological advancement.

In assessing the change in risk associated with each of these three factors, the Board will consider both the impact of each factor on Enbridge's business operations and the extent to which regulatory mechanisms mitigate this impact.

Volumetric Demand Profile

Enbridge submits that average use of natural gas by its customers has declined, causing upward pressure on distribution rates as distribution costs are apportioned over lower volumes. It submits that ultimately this can cause customers to fuel-switch or further decrease consumption. Enbridge points out that the decline in average use has occurred despite low gas prices. It submits that gas prices are likely to increase, thereby increasing the risk. Enbridge submits that an increase in its number of customers does not mitigate this risk. In its view, this is because most new customers are customers who are subject to volatility in consumption due to weather conditions.

Intervenors submit that there is no evidence that gas prices will increase in the near term. They also submit that demand for gas is likely to increase in the near term because of increased use of gas for power generation. They submit that the competitive position for gas remains strong.

Intervenors also submit that an increase in the number of Enbridge customers mitigates the impact of declining average use. They point out that any customers considering fuel-switching from gas to electricity would need to be prepared to pay higher prices. Intervenors submit that demand side management ("DSM") initiatives have been a cause of decreased average use, but that Enbridge is protected against this decrease by the Lost Revenue Adjustment Mechanism ("LRAM") account. Intervenors submit that since 2007 Enbridge's risk has also been decreased by its increased proportion of fixed charges and the creation of the Average Use True-Up Variance Account ("AUTUVA").

Enbridge responds that in its view available regulatory tools do not fully manage the impact of declining average use, because deferral and variance accounts do not cover all customer groups and do not ameliorate all short-term volume risk. Enbridge submits that the AUTUVA only remedies in-year forecast error for consumption. Enbridge also responds that its increased proportion of fixed charges does not ameliorate its volumetric risk.

Board Findings

There is no dispute that average use has declined and continues to do so. Enbridge data and forecasts show a decline of 1.2% per year in average weather normalized residential consumption from 2006 to 2013. The Board notes that average use was also declining in 2007. However, the issue in this proceeding is not whether average use has declined; it is whether the declining average use presents a larger risk than in 2007.

As submitted by the intervenors, one cause of declining average use is the explicit regulatory policy goal of greater conservation and energy efficiency. As part of its normal business, embedded in the rate setting process, Enbridge operates Board approved DSM programs to further this policy through reduced gas consumption. An important component of the DSM programs is the Board approved incentive paid to Enbridge for achievement of specific goals. Declining average use may require the spreading of fixed distribution costs over a smaller volume, but it also reduces a customer’s exposure to commodity costs. Hence, DSM can serve to enhance the competitive position of gas, and the impact of DSM on Enbridge’s revenues has been explicitly addressed.

Enbridge has added customers each year since 2007, an overall increase of 11% from 2007 to its forecast for 2013. The Board notes that although Enbridge has expressed concern about the fact that most new customers are weather-sensitive, its evidence indicates that weather risk has not increased since 2007.

The evidence also shows that in terms of price the competitive position of natural gas compared to oil and electricity is stronger than it was in 2007. Shale gas is a significant new development since the last risk assessment. This, among other factors, has led to lower prices. An Enbridge witness expressed the view that environmental issues make shale gas supply uncertain, but the evidence does not demonstrate that this uncertainly is likely to have a detrimental effect over the near term.

Currently, gas maintains a significant price advantage over oil and electricity. The evidence does not indicate whether gas prices are likely to increase over the near term, or how the price of gas is likely to compare to that of other fuel sources in that timeframe. Enbridge's expert, Mr. Coyne, did not express the view that prices are likely to increase. Mr. Coyne testified that gas prices are volatile and uncertain, and that his considerable experience in forecasting gas prices leads him to conclude that gas is a very difficult commodity to forecast.

Historical experience also indicates that higher gas prices would not necessarily eliminate the significant differentials between the prices of gas and other fuels. For example, in 2006, when gas prices were significantly higher, they were still significantly lower than alternative energy sources other than heavy fuel oil for industrial use. This means that any increase in gas prices in the near term would not necessarily be likely to cause significant fuel-switching.

The volatility of gas prices has been a risk factor in the past and continues to be a risk factor currently. The question is whether price volatility is a greater risk when prices are low, as they are currently, than when prices are higher, as they were in 2007. The evidence does not demonstrate that this is the case.

Regulatory mechanisms, including rate design and special accounts, also operate to protect Enbridge's revenues.

Enbridge now collects a greater portion of its revenues from fixed charges than in 2007. Enbridge does not consider that this reduces risk. An Enbridge witness indicated that this change was made for purposes of reflecting cost causality more accurately. However, the Board agrees with the intervenors that this change also helps to mitigate risk. Distribution costs are largely fixed. If more of the costs are recovered through fixed charges, there is less revenue volatility related to volume changes, and less uncertainty that the fixed costs will be recovered. This mitigation is greater now than it was in 2007, since Enbridge's forecast for 2013 shows 51% of revenues collected through fixed charges, a significant increase over 33% in 2007. In addition, Enbridge has benefited from a growing customer base over which to recover its fixed costs. This means that Enbridge's revenues are now less dependent on volume than in 2007.

Mr. Coyne expressed the view, however, that increasing the proportion of fixed costs "sets the stage for the so-called, quote-unquote death spiral"[9] by decreasing customers' opportunity to economize by decreasing consumption. In his view, this could cause significant fuel-switching. The Board considers that this does not take account of the fact that if average use declines, the customer's commodity costs will decline. Given that 49% of distribution revenues are still collected through variable charges, this means that the customer's overall bill will also decline. The evidence does not indicate that a "death spiral" situation will likely arise in the near term.

Other regulatory mechanisms also operate to help mitigate the impact of Enbridge's volumetric risk. Forecast average use is a factor that the Board takes into account in its rate setting framework. As pointed out by the intervenors, the AUTUVA compensates for variance between forecast and actual volume and the LRAM compensates for volume reductions due to DSM programs.

Enbridge is correct in stating that the available regulatory mechanisms do not fully protect Enbridge from the potential impact of volumetric risks. However, the Board notes that current regulatory mechanisms address Enbridge's potential volumetric risks more comprehensively than the mechanisms that were in place in 2007. For example, since 2007 the AUTUVA has been put into place and as indicated above, Enbridge's approved proportion of fixed costs has increased.

In addition, the Board notes that Enbridge has not provided quantitative evidence concerning the potential financial impact of the aspects of its risk not covered by regulatory mechanisms, or of how this has changed since 2007. Given the comprehensive extent of the regulatory mechanisms and the limited extent of Enbridge's likely volumetric risk as discussed above, the Board considers that the financial impact of the amount of risk not covered by the regulatory mechanisms is likely to be small.

[9] Tr2, p.206

Accordingly, as discussed above, the Board concludes that Enbridge has not experienced a significant increase in risk since 2007 relating to its volumetric demand profile.

System Size and Complexity

Enbridge submits that there has been a significant increase in the complexity of managing its gas distribution system due to increased system size, increasing peak demands and higher pipeline integrity standards. It submits that its first Asset Plan, prepared in 2012 and filed in this proceeding, demonstrates a need for higher and growing capital expenditures and that asset condition is an area of considerable uncertainty. Enbridge also identified a number of specific risk factors, relating to system size and complexity, which it considers have increased since 2007.

Enbridge has provided quantitative data on the increase since 1993 in its system size, number of employees, capital budget and operations & maintenance ("O&M") budget and on the increase since 1995 in its major projects. It has not provided data to indicate what part of this increase has occurred since 2007. Enbridge has also provided information on pipeline integrity rules introduced in 2001 and 2006. Enbridge submits that pipeline safety regulatory requirements are becoming more prescriptive as a result of events such as the San Bruno explosion in 2010.

BOMA submits that the size of Enbridge's system has not increased appreciably since 2007. It reaches this conclusion based on its calculation of Enbridge's average annual increase in employees and capital and O&M budgets since 2003. CCC submits that Enbridge's capital expenditure requirements are dealt with adequately in its rate applications. Several intervenors submit that higher safety standards decrease Enbridge's risk rather than increasing it. Board staff submits that many of the specific risk factors listed by Enbridge are simply routine matters of utility business operations rather than risks.

Board Findings

The Board accepts Enbridge's position that system size and complexity have increased since 2007, although as pointed out by BOMA, Enbridge has not provided quantitative information on the magnitude of these increases. The Board also accepts that there has been heightened attention to safety standards since 2007, as a result of incidents in North America that have raised safety concerns. However, the issue the Board must consider is not whether system size and complexity, including related safety standards, has increased; it is whether the increase in size and complexity results in higher risk.

As Enbridge's system grows and becomes more complex, Enbridge adds more assets and employees and does more work. The result may be a higher number of adverse events. However, system growth also brings benefits such as greater economies of scale, greater customer and geographical diversity, more advanced systems and greater employee expertise. As a result, increased size and complexity does not necessarily mean that Enbridge's risk will increase. Its risk will increase only if the increase in adverse events (or probability or severity of adverse events) is greater than the rate of system growth. The evidence does not indicate that this is the situation for Enbridge.

The Board agrees with the intervenor submissions that higher safety standards are more likely to reduce, rather than increase risk. Higher safety standards are designed to decrease the risk of safety-related incidents, which can involve a high financial and reputational cost.

Similarly, the Board considers that Enbridge's Asset Plan reduces risk, rather than increases it, because it provides better information concerning the uncertainties and required expenditures for capital assets.

The Board also considered the specific risk elements listed by Enbridge as being related to system size and complexity. Enbridge has not made specific submissions on a number of the elements on the list: price of materials, interest rates or utility credit spreads, cost of labour, insurance costs, cost of litigation, cost of bad debts, ability to generate other revenues as forecast, aging workforce, technical safety or compliance standards, operational risks associated with underground facilities, third party damages and employee health and safety. Most of these elements are direct costs to the utility which are forecast and addressed directly through rate setting. The evidence does not demonstrate that these elements have resulted in a significant increase in business risk.

Accordingly, the Board concludes that Enbridge has not experienced a significant increase in risk since 2007 relating to its system size and complexity.

Environmental and Technological Advancement

Enbridge submits that changes in policy and laws to further environmental objectives create uncertainty for the gas distribution business. Enbridge provides examples of such changes that include the Ontario *Green Energy Act, 2009,* proposed amendments to the Ontario *Environmental Protection Act* and several policy reports prepared by the National Round Table on the Environment and the Economy (NRTEE).[10]

Enbridge submits that

> There is a clear long-term risk that demand for natural gas will decline, as new technologies and energy saving practices take further hold. The current impact of items such as replacement of less efficient appliances and new *Building Code* standards is described in Enbridge's Gas Volume Budget evidence. These impacts will cumulate over time. Even if the magnitude of impacts cannot be known with certainty, it is a fair concern that these items will negatively impact natural gas demand in the future.[11]

In Enbridge's list of specific risk elements, it categorizes two elements as "Environment and Technology" risks: "price of fuel oil or other energy alternatives"; and "advancement of other technologies".[12] It assesses the risk since 2007 relating to "advancement of other technologies" as "neutral" rather than increasing. The risk element "price of fuel oil or other energy alternatives" covers the possibility that gas prices will increase, which is addressed above under Volumetric Demand Profile.

Several intervenors submit that gas distributors such as Enbridge benefit from the movement from coal fired to natural gas fired electricity generation.

CCC and BOMA submit that Enbridge's position on the risks due to environmental policies and laws is largely speculative. CCC submits that the *Green Energy Act* is the one such initiative with tangible results to date and that Enbridge has not provided evidence to substantiate the impact on its business.

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[10] The NRTEE is a body established by federal statute to identify, promote and explain practices and principles of sustainable development.
[11] Enbridge Reply, p. 13
[12] Exhibit J1.3 p.2

Board Findings

The evidence does not indicate that since 2007 environmental policy and laws which have been implemented have had the effect of making the price of gas less attractive than that of other fuels. Gas prices have decreased since 2007 and the differential between the price of gas and other fuels has increased. As discussed above, the evidence also does not demonstrate that this pricing situation is likely to change significantly over the near term. In addition, as indicated above, to the extent that there is an increase in gas prices in this timeframe, this is not necessarily likely to cause significant fuel-switching.

The evidence does not demonstrate a tangible risk that new environmental policy and laws in relation to gas distribution will be implemented over the near term, or if implemented, will be likely to have a detrimental effect on Enbridge in terms of volume over the near term. The Board agrees with intervenors that, to the contrary, the policy commitment to cease all coal-fired electricity generation in Ontario is likely to result in more gas-fired electricity generation, which is a benefit to Enbridge. In addition, as discussed under Volumetric Demand Profile, to the extent that DSM initiatives decrease Enbridge's volume, this risk is addressed by the LRAM account. Also, as discussed above, increasing energy efficiency has the effect of strengthening the ongoing competitive position of gas compared to other fuels.

Accordingly, the Board concludes that Enbridge has not experienced a significant increase in risk since 2007 relating to environmental and technological advancement.

Financial Risk

Enbridge submits that although it is not inhibited in accessing debt markets, it has greater financial risk than other Canadian and American regulated natural gas distribution businesses with comparable profiles. It submits that this is because it has a lower equity ratio than comparable utilities, which causes unfair competition for investment capital. Enbridge submits that the view taken by the markets in relation to debt issuance is evidence that Enbridge's financial risk has increased since 2007.

CME submits that the capital markets perceive Enbridge's financial risk to be if anything lower than in 2006, considering Enbridge's consistent earnings in excess of allowed returns, its improved interest coverage ratios, its financing costs in comparison to utilities with higher equity ratios, its ability to obtain loans with terms as long as 40 years and its consistent A credit rating. CME submits that Enbridge's lower equity ratio in relation to other comparable utilities would only be relevant if it adversely affected Enbridge's ability to obtain capital on reasonable terms. VECC put forward a similar position.

Board Findings

In assessing whether Enbridge has experienced an increase in financial risk since 2007, the essential question to consider is how the market would view Enbridge as a potential investment.

Enbridge argues that its financial risk has increased since 2007 because other comparable utilities have increased their equity ratios, whereas Enbridge's equity ratio has remained constant. An Enbridge witness characterized a comparison of equity ratios among comparable utilities as an indicator of Enbridge's relative risk. The Board agrees with the submissions of intervenors that the equity ratios of other utilities, including Ontario gas and electricity distributors, and the changes in those equity ratios relative to Enbridge, are not necessarily an indicator of a change in Enbridge's financial risk. The Board considers that in assessing whether Enbridge's financial risk has increased since 2007, the appropriate indicators are the key elements of Enbridge's market circumstances: access to capital, interest coverage ratios, credit ratings, debt terms, and financial results.

<u>Access to Capital</u>

Enbridge states that it is not currently inhibited in accessing debt markets. Enbridge's most recent debt financing was a bond issued in 2011 that was a reopening of a bond issued in 2010. The fact that this bond has a 40 year term confirms that Enbridge has not been inhibited in its access to capital. The evidence also does not lead to the conclusion that Enbridge's access to capital is more difficult currently than in 2007.

<u>Interest Coverage Ratios</u>

Enbridge's trust indenture requires it to have an interest coverage ratio of 2.0. Enbridge's interest coverage ratio was 2.5 for 2011, the same ratio as in 2007. The forecast interest coverage ratios for 2012 and 2013 are lower than the actual ratio for 2011 but still exceed the required ratio of 2.0.

Accordingly, the Board does not consider that Enbridge has experienced a significant decrease in its interest coverage ratio since 2007.

Credit Ratings

Given that debt investors rely on credit ratings, changes in credit ratings would normally indicate a change in financial risk. Enbridge is currently rated by Standard & Poor's as A-/Stable and by DBRS as R-1 low. One of Enbridge's witnesses, Mr. Yaworsky, confirmed that Enbridge's rating has remained the same since 2007, except for a period when there was an issue concerning Enbridge's parent company.

Mr. Yaworsky testified that Standard & Poor's and DBRS are currently reviewing Enbridge's ratings. He expressed the view that there is an increasing risk of lower ratings as a result of an increased spread between Enbridge's bonds and government bonds (as discussed below). However, Dr. Booth testified that the availability of capital to invest in government debt has recently increased the spread between government and corporate bonds generally. It is not clear to what extent the ratings agencies would take this factor into account. Furthermore, Mr. Yaworksy testified that he cannot predict the outcome of the credit ratings review, because "most of the agencies' risk identification is qualitative."[13]

Accordingly, the evidence does not lead to the conclusion that any decrease in Enbridge's credit rating is likely over the near term.

Debt Terms

Mr. Yaworksy testified that in comparing the terms of Enbridge's debt instruments over time, it is important to consider the spread between the yields of Enbridge's and comparable Government of Canada bonds. In his view, a larger spread indicates greater financial risk. Dr. Booth testified that another factor to take into account is that recently an influx of capital seeking to invest in Canadian and American government debt has increased the spread in the market generally. Dr. Booth also pointed out that overall changes in the spread between government and corporate bonds are addressed through the operation of the Board's return on equity formula.

[13] Tr1, p. 169

Enbridge provided listings of the bonds it has issued since 2007 and its estimated bond pricing for a hypothetical 10-year Enbridge bond issued in 2013. The estimated spread for the hypothetical 2013 10-year bond is 110 basis points. This the same as the spread for the 10-year Enbridge bond issued in 2007. This comparison does not indicate an increase in financial risk since 2007.

Enbridge also provided a listing of the spreads for bonds issued by several potentially comparable utilities. However, none of these utilities issued bonds with terms and timeframes comparable to Enbridge's 10-year bonds.[14]

Financial Results

The Board also examined Enbridge's financial performance since 2007. From 2007 to 2011, Enbridge exceeded its Board allowed return on equity. The financial information provided by Enbridge shows a net revenue sufficiency in the range of $21 to $40 million each year in relation to total revenue of approximately $1 billion. Enbridge's forecast for 2012 shows that it does not expect to reach its Board allowed return; however the amount of the forecasted shortfall is only $4 million in relation to forecast total revenue of approximately $1 billion.[15] Therefore Enbridge has not experienced a significant deterioration in financial results since 2007.

Accordingly, as discussed above, the Board concludes that Enbridge's market circumstances have not deteriorated significantly since 2007 in terms of access to capital, interest coverage ratio, credit ratings, debt terms or financial results, and that consequently Enbridge has not experienced a significant increase in financial risk since 2007.

Decision of the Board on Equity Ratio

The Board concludes that there has been no significant increase in Enbridge's business and/or financial risk since 2007. Accordingly, the Board finds that Enbridge's equity ratio shall remain at 36% and that a full FRS analysis is not required.

Settlement on Cost of Debt

Issue E1 in this proceeding is as follows:

[14] Accordingly it was not necessary for the Board to consider the extent to which these utilities are comparable to Enbridge.
[15] Figures in this paragraph have been rounded.

> Is the forecast of the cost of debt for the Test Year, including the mix of short and long term debt and preference shares, and the rates and calculation methodologies for each, appropriate?

In the Settlement Agreement for this proceeding, the parties agreed on how Issue E1 would be settled if Enbridge's equity ratio remains at 36%. Since the Board has now determined that Enbridge's equity ratio remains at 36%, this provision of the Settlement Agreement finalizes Issue E1.

Rate Implementation

The rates currently approved by the Board for Enbridge are interim rates. A Rate Order is required to incorporate the return on equity that was published by the Board on November 15, 2012 in accordance with the Board's policy.

Cost Awards

In determining the amount of cost awards in this proceeding, the Board will apply the principles in section 5 of the Board's *Practice Direction on Cost Awards* and the maximum hourly rates in the Board's Cost Awards Tariff.

THE BOARD ORDERS THAT:

1. Enbridge shall file with the Board and serve on the intervenors a draft Rate Order within 7 days of the date of this Decision.

2. Intervenors shall file with the Board and serve on Enbridge, within 7 days of the date of the draft Rate Order, any comments on the draft Rate Order.

3. Enbridge shall file with the Board and serve on the intervenors any reply to intervenor comments within 7 days of the receipt of the intervenor comments.

4. Parties eligible for cost awards shall file their cost claims with the Board, and serve them on Enbridge, by February 28, 2013. Cost claims must be prepared in accordance with the Board's *Practice Direction on Cost Awards*.

5. Enbridge shall file with the Board any objection to a cost claim, and serve it on the party that made the claim, by March 7, 2013.

6. Any party whose cost claim was objected to shall file any reply submission with the Board, and serve it on Enbridge, by March 14, 2013.

All filings with the Board must quote file number **EB-2011-0354**, be made through the Board's web portal at www.pes.ontarioenergyboard.ca/eservice/, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address, telephone number, fax number and e-mail address.

All filings shall use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available the document may be emailed to BoardSec@ontarioenergyboard.ca. Persons who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Persons who do not have computer access are required to file seven paper copies. If a document has been submitted through the Board's web portal an e-mail is not required. For all electronic correspondence and materials related to this proceeding, parties must include in their distribution the Case Manager, Colin Schuch at colin.schuch@ontarioenergyboard.ca and Senior Legal Counsel, Kristi Sebalj at kristi.sebalj@ontarioenergyboard.ca.

All communications should be directed to the attention of the Board Secretary and be received no later than 4:45 p.m. on the required date.

DATED at Toronto, February 7, 2013

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Ontario Energy Board | Commission de l'Énergie de l'Ontario

EB-2011-0210

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 Union Gas Limited 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.

BEFORE: Marika Hare
Presiding Member

Karen Taylor
Board Member

DECISION AND ORDER

Union Gas Limited ("Union") filed an application on November 10, 2011 with the Ontario Energy Board (the "Board") under section 36 of the *Ontario Energy Board Act, 1998* for an order of the Board approving or fixing rates for the distribution, transmission and storage of natural gas, effective January 1, 2013 (the "Application"). The Board assigned file number EB-2011-0210 to the Application and issued a Notice of Application on December 1, 2011. This is the first cost-of-service application for setting rates since 2007. From 2008 to 2012 rates were set under an Incentive Regulation Mechanism ("IRM") which adjusted rates through a mechanistic formula.

The Board issued its Procedural Order No. 1 on January 11, 2012, which established the approved list of intervenors for this proceeding. The list included:

The results of the review are to be subject to a stakeholder information process and then be submitted in conjunction with Union's next rates proceeding (cost of service or incentive regulation regime).

COST OF CAPITAL

Union's investment in rate base is financed by a combination of short-term and long-term debt, preferred shares and common equity. The current Board approved capital structure is based on a 36% common equity component. The remaining 64% is financed by a mix of short-term debt, long-term debt and preferred shares.

Union has proposed a capital structure which includes a common equity ratio of 40% for 2013 as compared to the 36% currently included in rates. The 36% equity ratio was set as a result of a Settlement Agreement in the 2007 Cost of Service Proceeding (EB-2005-0520).

Union has proposed a long-term debt ratio of 60.17% and a debt rate of 6.53%. The short-term debt ratio is -2.92% with a rate of 1.31%. The average embedded cost of preferred share capital for 2013 is 3.05%. This is a decrease from the 2007 Board approved cost of 4.74%.

Common Equity Ratio

Most intervenors and Board staff submitted that Union's proposal to raise the common equity ratio from 36% to 40% should be rejected. IGUA did not take any position on this issue.

In support of its proposal, Union retained two experts: Mr. Steven M. Fetter and Dr. Vander Weide. In response, intervenors presented the expert evidence of Dr. Lawrence D. Booth.

Intervenors and Board staff cited the Report of the Board on Cost of Capital for Ontario's Regulated Utilities[17] that provided guidelines with respect to a gas utility's capital structure. The report on page 50 states:

[17]Report of the Board on Cost of Capital for Ontario's Regulated Utilities, dated December 11, 2009 (EB-2009-0084),pp. 49, 51.

> 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 relatively 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.

Intervenors and Board staff submitted that Union had made no attempt to comply with the guideline in requesting a change in the equity thickness and Union's evidence indicated that it had not analyzed its financial and business risk as part of this proceeding. Board staff and intervenors further noted that Union's argument was that its current equity structure is not commensurate with its risk. However, Union agreed that its business or financial risk had not changed materially since 2006. In fact, Union witnesses confirmed several times during the oral hearing that there had been no material increase to its business or financial risk.[18] Union agreed in reply that its risk profile had not changed but it noted that in the 2007 rates case, Dr. Carpenter and the Brattle Group stated that Union's business risk warranted an equity ratio between 40 and 56%, depending on the allowed rate of return.[19] Union therefore believed that an equity ratio of 40% was appropriate based on its current risk profile.

Mr. Fetter was of the opinion that an equity thickness of 40%-42% would improve Union Gas' financial profile benefitting its customers through Union's enhanced ability to attract capital from investors when needed and upon reasonable terms. Mr. Fetter, in his report, also indicated that equity ratios of utilities were rarely set below 40% in the United States. Mr. Fetter further noted that a review of other Canadian gas utilities showed that the deemed equity ratios were in the range of 39% to 43%. In its Argument-in-Chief, Union submitted that it had to compete for capital with other utilities across the United States and Canada and a 36% equity ratio puts Union at a disadvantage.[20]

In reply, Union submitted that none of the intervenors had challenged Union's position that other comparable utilities had higher equity ratios than 36% and that Union was lower relative to its peers. Union further submitted that no party challenged the comparability of Union to ATCO Gas or Terasen. Union disputed intervenors' argument that comparability has no value and noted that Dr. Booth, the expert consultant of the

[18]Oral Hearing Transcripts, EB-2011-0210, Volume 4 at p. 128 and Volume 5 at pp. 15 and 31.
[19] Oral Hearing Transcripts, EB-2011-0210, Volume 16 at p. 105.
[20] Oral Hearing Transcripts, EB-2011-0210, Volume 13 at p. 53.

intervenors, in his testimony confirmed that the regulator should give weight to the deemed equity ratios of comparable utilities.[21]

CCC submitted that the Board consistent with its own policy must examine the individual circumstances of Union and in particular, the business and financial risk faced by Union to determine whether a change in capital structure is required. CCC further submitted that the use of comparators may supplement, but cannot replace that analysis. CCC also disputed Mr. Fetter's opinion that a higher equity ratio would allow Union to withstand future unforeseen events. CCC argued that Mr. Fetter's opinion was hypothetical.

Intervenors and Board staff submitted that Union had provided no evidence that it has not been able to compete for capital on favourable terms with other utilities. Intervenors and Board staff submitted that throughout the IRM period which coincided with a severe global financial crisis, Union had maintained a high credit rating. Union has been able to attract capital on reasonable terms under its current capital structure. Intervenors and Board staff referred to an interrogatory response[22] where Union confirmed that an equity ratio of 40% would not lead to a higher credit rating or a lower cost of debt. This view was also stated in the Standard and Poor's report which notes that Union would not get a higher rating than Spectra, its parent. In Reply, Union submitted that DBRS in its report noted that Union had requested a 40% deemed equity ratio. Union submitted that in that report DBRS expected Union to manage its balance sheet in line with the new regulatory capital structure and maintain greater financial flexibility commensurate with the current rating category. Union argued that this meant that Union would fit more appropriately with the current rating if it had a 40% common equity.[23]

Dr. Booth in his testimony expressed the view that one major aspect of risk was whether a utility was able to earn its allowed return on equity. Dr. Booth noted that since 2000, Union's average over-earning was about 2%. Intervenors and Board staff in their submission noted that Union had over-earned by approximately $278.7 million from 2007 to 2012. Intervenors and Board staff submitted that Union had provided no evidence to demonstrate a change in its risk profile. In reply, Union submitted that there

[21] Oral Hearing Transcripts, EB-2011-0210, Volume 6 at p. 61.
[22]Exhibit J.E-1-1-2.
[23] Oral Hearing Transcripts, EB-2011-0210, Volume 16 at p. 102.

is a surplus of supply east of Union's Dawn to Parkway system and that posed a significant risk to Union. Union noted that there was further risk of turnback and this was reflected in lower revenues on Dawn to Kirkwall and M12.[24]

BOMA, in its submission, submitted that Union's interest coverage ratio was 2.74 which was higher than the 2% minimum interest coverage ratio set out in Union's trust indenture. This was higher than the ratios in 2008, 2009 and 2010 when it was 2.4%and 2.24% in 2007. However, the interest coverage ratio was lower than the threshold when the unregulated business was excluded from the calculation. BOMA further submitted that with respect to the interest coverage ratio, the common practice was to look at the entire company and not just the regulated portion of the business.[25] Union, in reply, disagreed with BOMA and submitted that this view was at odds with the general focus of intervenors that pursue to ensure that there is no cross-subsidy of the unregulated business by the regulated business. Union submitted that the intervenors wanted the Board to agree that it was appropriate to cross-subsidize the regulated business in order to meet the interest coverage ratio.

CCC in its argument cited the Ontario Court of Appeal in its decision (Toronto Hydro-Electric System Limited v. Ontario Energy Board, 2010) where the court stated that regulated utilities must balance the needs of shareholders and ratepayers. CCC submitted that if the proposed change in capital structure is approved, Union's shareholders will benefit by approximately $17 million while there would be no corresponding benefit within the test year to Union's ratepayers. CCC submitted that the Board should conclude that Union had not balanced the interests of its ratepayers and shareholders and accordingly disallow the change in the common equity ratio.

LPMA submitted that if the Board does approve Union's proposal or approves an equity ratio greater than the current 36%, then in that case, the Board would have to deal with how to treat preferred shares in the deemed capital structure. LPMA submitted that according to USGAAP, Union's preference shares were classified as equity by their auditors. LPMA submitted that there was no reason for the Board to deviate from the USGAAP treatment. SEC disagreed with LPMA and submitted that when the Board reviewed Union's capital structure in 2004, it did not consider preference shares to be equity and the Board should therefore refrain from doing so in this case. SEC submitted

[24] Oral Hearing Transcripts, EB-2011-0210,Volume 16 at p. 107.
[25] Oral Hearing Transcripts, EB-2011-0210,Volume 14 at p. 88.

that the preference shares should be treated as long-term debt. Union agreed with SEC and noted that the Board had never considered Union's preference shares in any assessment of Union's common equity ratio. In addition, Union noted that they were not even considered relevant by Dr. Booth in his analysis.

SEC, in its submission, agreed with Union that the Board's Report on Cost of Capital is a guideline. However, it noted that the Board had thoroughly reviewed the business risk of Union in 2004 and unless there was a change in the business risk, there was no need for a utility to come before the Board with a different proposal. SEC submitted that Union was merely rearguing the 2004 case and there was no new evidence to show a change in risk.

SEC further submitted that Union had not articulated any benefits to ratepayers such as better access to market or lower borrowing costs, which Union already enjoys. In reply, Union submitted that the expectation that a higher equity ratio must be accompanied by lower borrowing costs or a ratings upgrade is unrealistic. Union therefore submitted that the Board should reject the submissions of intervenors.

Unlike other intervenors, LPMA and SEC submitted that Union's common equity ratio should be reduced from 36% to 35% consistent with what the Board had determined when it last reviewed the business risk and equity thickness of the company in 2004.

Cost of Debt

None of the intervenors raised any issues with the rates for short-term and long-term debt or preferred shares. LPMA however made a submission on the mix of short-term and long-term debt.

LPMA submitted that Union's proposal of a long-term debt ratio of 60.17% and a short-term debt ratio of -2.92% meant that ratepayers were being asked to pay a long-term debt rate on $108.5 million of borrowings and receive a credit at the short-term debt rate. LPMA submitted that this was not appropriate and was an indication that Union was over capitalized for rate base purposes.

LPMA noted that Union attributed the negative short-term debt to items outside of rate base that the utility has to invest in, such as construction work-in-progress and the contribution in excess of expenses for pension.

Union's average short-term borrowing for 2013 is predicted by LPMA to be $136 million[26] which represents approximately 3.66% of Union's rate base.

LPMA and SEC submitted that Union has more long-term debt than needed to finance rate base. This is under the scenario of a 36% and a 40% common equity ratio. At the same time, these scenarios have not included any short-term debt according to LPMA.

LPMA and SEC submitted that the Board should direct Union to include $136 million in short-term debt in the cost of capital calculation. Both parties further submitted that the balancing figure would be the long-term debt component. LPMA considered this to be an appropriate approach since in its view it was obvious that some of the long-term debt is being used to finance items outside of rate base.

In reply, Union noted that its cash position varied significantly due to the seasonal nature of its business. It further stated that long-term debt changes do not occur quickly and that the cash position would slowly return to short-term debt as the long-term debt level adjusted through maturities and reduced issues. Union submitted that issuing debt in small amounts was administratively burdensome and lumpy. Union indicated that it obtains long-term financing when prudent and tries to take advantage of favourable market conditions.

Union further submitted that having a negative short-term balance was not a new issue and the Board had addressed this before in the RP-2003-0063 proceeding. In the RP-2003-0063 Decision with Reasons dated March 18, 2004, the Board, on page112, determined that Union was in compliance with its deemed capital structure even though its long-term debt had marginally exceeded the 65% debt component of its approved capital structure. This excess was offset by a negative short-term debt balance.

Union emphasized that in the RP-2003-0063 Decision, the Board had used the word "marginal" to describe the level of excess in the long-term debt component. The actual

[26] Oral Hearing Transcripts, EB-2011-0210,Volume 5 at p. 40.

unfunded short-term debt was approximately $130 million in 2004 which is higher than the current unfunded short-term debt component of $115 million. Union submitted that the Board should reach a similar conclusion in this proceeding and not make any adjustments to the short-term or long-term debt component.

Board Findings

Deemed Common Equity Thickness

The Board finds that a deemed common equity ratio of 36% is appropriate for the 2013 test year, consistent with the deemed common equity ratio that was in place over the 2007 to 2012 period, inclusively.

The 2009 Cost of Capital Policy of the Board at page 43 sets out that for natural gas distributors such as Union, deemed capital structure is determined on a case-by-case basis and that 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 risks.

Union filed no evidence in this proceeding that demonstrates its business and/or financial risks have changed over the period that the IRM Settlement Agreement was in place. In fact, Union stated many times during the proceeding that its business and financial risks have not changed and that it accepts that its overall risk profile has not materially changed since 2006.

Union put forth two arguments to support its application for a 40% deemed common equity ratio. The first is that the current deemed common equity ratio of 36% is too low and has never appropriately reflected its business and financial risk. Second, that the deemed common equity ratio should be increased solely on the basis of comparability; i.e., because other Canadian utilities now have higher deemed common equity ratios, the Board should also approve a higher deemed common equity ratio for Union.

The Board will address each of these two arguments in turn.

The Board does not accept the proposition that the deemed common equity thickness of 35% as determined by the Board in 2004 and subsequently increased to 36% as a result of a Settlement Agreement was incorrect and that it did not adequately reflect Union's financial and business risk profile. Union has filed no evidence to support this position that the deemed equity ratio was not correct and the Board therefore gives this argument little or no weight.

The Fair Return Standard ("FRS") requires that a fair or reasonable return on capital should:

- Be comparable to the return available from the application of 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).

Union's second argument focuses on the first part of the comparable investment standard – that the return on invested capital must be comparable. However, Union's argument fails to address the second part of the comparable investment standard, that being the issue of "enterprises of like risk". Union would have the Board increase (and potentially reduce) its deemed common equity ratio in lock-step with the decisions of other regulators, without an analysis of whether the utilities to which it is compared are enterprises of like risk.

The Board acknowledges that there was a general consensus on the Canadian utilities that intervenors and Union asserted were comparable. The Board notes, however, that neither Union nor the intervenors filed analytical evidence that demonstrated that these utilities are of like risk to Union. Rather, what evidence was presented was anecdotal, ad hoc, and incomplete.

The Board is aware that since the 2008 financial crisis, the deemed common equity ratios of certain Canadian rate regulated entities have been increased. However, no evidence was filed in this proceeding that set out the risks that resulted in findings supporting higher deemed common equity for these utilities and no evidence was filed that demonstrates Union faces similar risks.

Union reiterated throughout the proceeding that its business and/or financial risks have not changed since 2006.

Accordingly, there is no reasonable basis for the Board to increase Union's deemed common equity ratio above the 36% level presently reflected in rates.

The Board does not agree with the submission of SEC that a higher deemed equity ratio must be supported by benefits to ratepayers. The Board's obligation to determine the quantum of common equity (at issue in this proceeding) and the cost of that equity (subject to the Settlement Agreement) is governed by the FRS, which is a non-optional, legal standard.

The Board also does not agree with the submission of CCC that the Board must balance the interests of ratepayers and shareholders in determining the deemed common equity ratio. Consistent with the jurisprudence discussed in the 2009 Cost of Capital Policy, the Board remains of the view that it is not in the determination of the cost of capital that investor and consumer interests are balanced. This balance is achieved in the setting of rates.

Finally, the Board is of the view that there is no evidentiary basis to support a reduction in deemed common equity from the existing 36% to 35%.

Cost of Debt and Preferred Shares

The Board approves the cost of short-term, long-term debt, and preferred shares as per Appendix B, Schedule 3 of the Settlement Agreement. The Board notes that no issues were raised by intervenors or Board staff regarding the appropriateness of these costs during the proceeding.

Debt and Preferred Share Capitalization

The Board approves the amount of long-term debt, short-term debt, and preferred share equity as set out by Union in Exhibit J5.4, page 2, lines 7 through 12, which reflects the Settlement Agreement relating to this proceeding and deemed common equity of 36%.

The Board’s findings on the amount of short-term and long-term debt are consistent with previous decisions of the Board and are consistent with Union’s evidence that items outside of rate base are funded by short-term debt.

The Board has not undertaken a comprehensive review of whether it is appropriate for a gas utility to have preferred shares in its capital structure. The Board is generally aware that preferred shares are often referred to as “mezzanine capital”, having characteristics of both debt and equity. There was no assessment of the characteristics of Union’s issued and outstanding preferred shares in this proceeding. Similarly, there was no assessment of whether Union’s issued and outstanding preferred shares should be considered to be common equity or debt for the purpose of determining Union’s capital structure in order to set utility rates.

The Board will thus continue its current practice of approving the amount and cost of Union's preferred shares as a separate part of total utility capitalization. The Board notes, however, that the presence of preferred shares has the effect of reducing the amount of total debt capitalization in Union's capital structure.

COST ALLOCATION

General Cost Allocation Issues

Union provided a summary description of the methodology used to complete the cost allocation study, which supports the 2013 rate proposals. Union submitted that subject to the removal of the unregulated storage operations and certain proposals in Exhibit G1, Tab 1 (which are discussed below), the cost allocation study is consistent with the studies that were approved by the Board and used in the past, including in EB-2005-0520.

Union noted that the objective of the cost allocation study is to allocate the utility test year cost of service to customer rate classes for the purpose of acting as a guide to the rate design process. To allocate costs, the test year cost of service is analyzed to determine the appropriate functionalization and classification of costs. Union noted that the allocation of costs to individual rate classes is based upon these determinations.[27]

Union stated that the cost allocation study consists of three steps. These steps are:

Functionalization of costs to utility service functions: The first step of the cost allocation process is to associate asset and operating costs with the various utility service functions. There are four functions generally accepted as necessary to obtain and move gas to market: purchase and production of gas, storage, transmission, and distribution.

Classification of costs to cost incurrence (demand, commodity, customer): The second step categorizes functionalized asset and operating costs into classifications according to cost incurrence. The three main classifications are demand-related, commodity-related, and customer-related. Demand-related costs, also known as capacity-related costs are costs that vary with peak day usage of the system. Commodity-related costs are costs that are typically variable in nature and vary with the

[27] Exhibit G3, Tab 1, Schedule 1 at p. 1 (Updated).

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2022

or

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ______________ to ______________

Commission File No.	Exact Name of Registrants as Specified in their Charters, Address and Telephone Number	State of Incorporation	I.R.S. Employer Identification Nos.
1-14201	SEMPRA ENERGY 488 8th Avenue San Diego, California 92101 (619) 696-2000	California	33-0732627
1-03779	SAN DIEGO GAS & ELECTRIC COMPANY 8330 Century Park Court San Diego, California 92123 (619) 696-2000	California	95-1184800
1-01402	SOUTHERN CALIFORNIA GAS COMPANY 555 West 5th Street Los Angeles, California 90013 (213) 244-1200	California	95-1240705

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of Each Class	Trading Symbol	Name of Each Exchange on Which Registered
SEMPRA ENERGY:		
Common Stock, without par value	SRE	New York Stock Exchange
5.75% Junior Subordinated Notes Due 2079, $25 par value	SREA	New York Stock Exchange
SAN DIEGO GAS & ELECTRIC COMPANY:		
None		
SOUTHERN CALIFORNIA GAS COMPANY:		
None		

which can be subject to volatility. The cost of purchases of natural gas for SDG&E's and SoCalGas' core customers is billed to those customers without markup.

To support the delivery of natural gas supplies to its distribution system and to meet the needs of customers, SoCalGas has firm and variable interstate pipeline capacity contracts that require the payment of fixed and variable tariffed and negotiated reservation charges to reserve firm transportation rights. Energy companies, primarily El Paso Natural Gas Company, Transwestern Pipeline Company and Kern River Gas Transmission Company, provide transportation services into SoCalGas' intrastate transmission system for supplies purchased by SoCalGas.

Natural Gas Storage

SoCalGas owns four natural gas storage facilities with a combined working gas capacity of 137 Bcf and 126 injection, withdrawal and observation wells that provide natural gas storage service. SoCalGas' and SDG&E's core customers, along with certain third-party market participants, are allocated a portion of SoCalGas' storage capacity. SoCalGas uses the remaining storage capacity for load balancing services for all customers. Natural gas withdrawn from storage is important to help maintain service reliability during peak demand periods, including consumer heating needs in the winter, as well as peak electric generation needs in the summer. The Aliso Canyon natural gas storage facility has a storage capacity of 86 Bcf and, subject to the CPUC limitations described below, represents 63% of SoCalGas' natural gas storage capacity. SoCalGas discovered a natural gas leak at one of its wells at the Aliso Canyon natural gas storage facility in October 2015 and permanently sealed the well in February 2016. SoCalGas was subsequently authorized to make limited withdrawals and injections of natural gas at the Aliso Canyon natural gas storage facility and, on an interim basis, has been directed by the CPUC to maintain up to 41.16 Bcf of working gas at the facility to help achieve reliability for the region as determined by the CPUC. To help maintain system reliability, the CPUC issued a protocol authorizing withdrawals of natural gas from the facility if available gas supply reaches defined thresholds for SoCalGas' system, or public health and safety is at risk, as determined by the protocol. We discuss the Leak in Note 16 of the Notes to Consolidated Financial Statements, in "Part I – Item 1A. Risk Factors" and in "Part II – Item 7. MD&A – Capital Resources and Liquidity – SoCalGas."

Customers and Demand

SoCalGas and SDG&E sell, distribute and transport natural gas. SoCalGas purchases and stores natural gas for its core customers in its territory and SDG&E's territory on a combined portfolio basis. SoCalGas also offers natural gas transportation and storage services for others.

SEMPRA CALIFORNIA – NATURAL GAS CUSTOMER METERS AND VOLUMES

	Customer meter count	Volumes (Bcf)[1]		
	December 31,	Years ended December 31,		
	2022	2022	2021	2020
SDG&E:				
Residential	878,220			
Commercial	29,180			
Electric generation and transportation	2,540			
Natural gas sales		45	46	43
Transportation		39	38	40
Total	909,940	84	84	83
SoCalGas:				
Residential	5,857,280			
Commercial	248,800			
Industrial	24,390			
Electric generation and wholesale	40			
Natural gas sales		304	314	312
Transportation		586	568	572
Total	6,130,510	890	882	884

(1) *Includes intercompany sales.*

For regulatory purposes, end-use customers are classified as either core or noncore customers. Core customers are primarily residential and small commercial and industrial customers.

SCHEDULE 3 - COMPARISON OF ENBRIDGE GAS INC AND PROXY GROUP COMPANIES
RISK ASSESSMENT

Company	Operating Subsidiary	Jurisdiction	[1] Regulatory Framework	[2] Test Year	[3] Decoupling?	[4] Conservation Program Expenses	[5] Capital Cost Tracker
Canadian OpCo Proxy Group							
Apex Utilities Inc.	N/A	Alberta	Multi-year rate plans	Historical	No		Yes
ATCO Gas	N/A	Alberta	Multi-year rate plans	Historical	Partial		Yes
Energir	N/A	Quebec	Multi-year rate plans	Fully Forecast	Full	Yes	
FortisBC Energy	N/A	British Columbia	Multi-year rate plans	Fully Forecast	Full	Yes	Yes
Gazifere Inc.	N/A	Quebec					
Heritage Gas Limited	N/A	Nova Scotia	Cost of service	Fully forecast	Full		Yes
Liberty Gas New Brunswick	N/A	New Brunswick	Cost of service	Fully Forecast	No		Yes
Pacific Northern Gas Ltd	N/A	British Columbia	Cost of service	Fully Forecast			
Pacific Northern Gas Ltd (FSJ/DC)	N/A	British Columbia	Cost of service	Fully Forecast			
Pacific Northern Gas Ltd (TR)	N/A	British Columbia	Cost of service	Fully Forecast			
			Multi-Year Rate Plans: 4 (44.4%)	Fully Forecast: 6 (66.7%)	Full: 3 (50.0%)	Yes: 3 (30.0%)	Yes: 5 (50.0%)
			Formula-based ratemaking: 0 (0.0%)	Partially Forecast: 0 (0.0%)	Partial: 1 (16.7%)		
			Cost of service: 5 (55.6%)	Historical: 2 (22.2%)	No: 2 (33.3%)		
			Fair Value: 0 (0.0%)				
Canadian HoldCo Proxy Group							
Algonquin Power & Utilities Corp.	Liberty Utilities (Peach State Nat. Gas) Corp.	Georgia	Multi-Year rate plans	Partially Forecast	Full		
	Liberty Utilities (Midstates Natural Gas) Corp.	Illinois	Cost of service	Fully Forecast	Partial	Yes	
	Liberty Utilities (NE Nat Gas)	Massachusetts	Multi-Year rate plans	Historical	Full	Yes	Yes
	Empire District Gas Co.	Missouri	Original Cost/Fair Value	Partially Forecast	No		
	Liberty Utilities (Midstates)	Missouri	Original Cost/Fair Value	Partially Forecast	Partial		Yes
	Liberty Utilities EnergyNorth	New Hampshire	Multi-year rate plans	Historical	Full		Yes
	Liberty Gas New Brunswick	New Brunswick	Cost of service	Fully Forecast	No		Yes
AltaGas Ltd.	Enstar Natural Gas Co.	Alaska	Cost of service	Historical	No		
	SEMCO Energy Inc.	Michigan	Cost of service	Partially Forecast	No	Yes	Yes
	Washington Gas Light Co.	District of Columbia	Multi-year rate plans	Historical	No	Yes	Yes
	Washington Gas Light Co.	Maryland	Multi-year rate plans	Partially Forecast	Partial		Yes
	Washington Gas Light Co.	Virginia	Cost of service	Historical	Partial		Yes
Canadian Utilities Limited	ATCO Gas	Alberta	Multi-year rate plans	Historical	Partial		Yes
Emera Inc.	New Mexico Gas Co.	New Mexico	Multi-year rate plans	Fully Forecast	No	Yes	
	Peoples Gas System	Florida	Multi-year rate plans	Fully Forecast	No	Yes	Yes
Fortis Inc.	Central Hudson Gas & Electric	New York	Multi-year rate plans	Fully Forecast	Full		Yes
	UNS Gas Inc.	Arizona	Fair Value	Historical	Partial		
	FortisBC Energy	British Columbia	Multi-year rate plans	Fully Forecast	Full	Yes	Yes
			Multi-Year Rate Plans: 10 (55.6%)	Fully Forecast: 6 (33.3%)	Full: 5 (27.8%)	Yes: 7 (38.9%)	Yes: 12 (66.7%)
			Formula-based ratemaking: 0 (0.0%)	Partially Forecast: 5 (27.8%)	Partial: 6 (33.3%)		
			Cost of service: 5 (27.8%)	Historical: 7 (38.9%)	No: 7 (38.9%)		
			Fair Value: 3 (16.7%)				
US OpCo Proxy Group							
Southern California Gas Company	N/A	California	Multi-year rate plans	Fully Forecast	Full		
Consumers Energy Company	N/A	Michigan	Cost of service	Partially Forecast	Partial	Yes	
Northern Illinois Gas Company	N/A	Illinois	Cost of service	Fully Forecast	Partial	Yes	Yes
DTE Gas Company	N/A	Michigan	Cost of service	Partially Forecast	Partial	Yes	Yes
Consolidated Edison Company of NY	N/A	New York	Multi-year rate plans	Fully Forecast	Full	Yes	Yes
East Ohio Gas	N/A	Ohio	Cost of service	Historical	Full	Yes	Yes
Brooklyn Union Gas Company	N/A	New York	Multi-year rate plans	Fully Forecast	Full	Yes	Yes
Atlanta Gas Light	N/A	Georgia	Multi-year rate plans	Partially Forecast	Full		Yes
Columbia Gas of Ohio	N/A	Ohio	Cost of service	Historical	Full	Yes	Yes
Peoples Gas Light and Coke	N/A	Illinois	Cost of service	Fully Forecast	Partial	Yes	Yes
			Multi-Year Rate Plans: 4 (40.0%)	Fully Forecast: 5 (50.0%)	Full: 6 (60.0%)	Yes: 8 (80.0%)	Yes: 9 (90.0%)
			Formula-based ratemaking: 0 (0.0%)	Partially Forecast: 3 (30.0%)	Partial: 4 (40.0%)		
			Cost of service: 6 (60.0%)	Historical: 2 (20.0%)	No: 0 (0.0%)		
			Fair Value: 0 (0.0%)				

Regulatory Focus Topical Special Report

Topical Report

July 18, 2022

Adjustment clauses: A state by state overview

Russell Ernst, Principal Analyst, Brian Collins, Senior Research Analyst, and Monica Hlinka, Research Analyst

Contributors: Jim Davis, Lillian Federico, Lisa Fontanella, Jason Lehmann and Dan Lowrey

This report covers the key adjustment clauses used by the largest electric and gas utilities in the 53 jurisdictions covered by Regulatory Research Associates, a group within S&P Global Commodity Insights.

S&P Global
Market Intelligence

Use of adjustment clauses, as of June 2022

State/Company	Ultimate parent ticker	Type of service	Type of adjustment clause: Electric fuel/gas commodity/ purch. power	Conserv. program expense	Decoupling: Full	Decoupling: Partial	New capital: Traditional generation	New capital: Renewables/ Non-traditional generation	New capital: Delivery infrastructure	Environmental compliance	Transmission costs
ALABAMA											
Alabama Power Co.	SO	Elec.	✓ *	--	--	--	✓ *	✓	--	✓ *	--
Spire Alabama Inc.	SR	Gas	✓ *	--	--	✓ *	--	--	--	--	--
Spire Gulf Inc.	SR	Gas	✓ *	--	--	✓ *	--	--	--	--	--
ALASKA											
Alaska Electric Light & Power Co.	AVA	Elec.	✓	--	--	--	--	--	--	--	--
Enstar Natural Gas Co.	ALA	Gas	✓	--	--	--	--	--	--	--	--
ARIZONA											
Arizona Public Service Co.	PNW	Elec.	✓	✓	--	✓ *	--	✓	--	✓	✓
Southwest Gas Corp.	SWX	Gas	✓	✓	✓	-- *	--	--	✓ *	--	--
Tucson Electric Power Co.	FTS	Elec.	✓	✓	--	✓ *	--	✓	--	✓	✓
UNS Electric Inc.	FTS	Elec.	✓	✓	--	✓ *	--	✓	--	--	✓
UNS Gas Inc.	FTS	Gas	✓	✓	--	✓ *	--	--	--	--	--
ARKANSAS											
Arkansas Oklahoma Gas Corp.	--	Gas	✓	✓	✓ *	--	--	--	✓ *	--	--
Summit Utilities Arkansas Inc.	--	Gas	✓	✓	✓ *	--	--	--	✓ *	--	--
Entergy Arkansas LLC	ETR	Elec.	✓	✓	--	✓ *	✓ *	✓ *	✓ *	--	✓
Oklahoma Gas & Electric Co.	OGE	Elec.	✓	✓	--	✓ *	✓	✓	✓	✓	✓
Black Hills Energy Arkansas Inc.	BKH	Gas	✓	✓	✓ *	--	--	--	✓ *	--	--
Southwestern Electric Power Co.	AEP	Elec.	✓	✓	--	✓ *	✓	--	--	✓	✓
CALIFORNIA											
Pacific Gas & Electric Co.	PCG	Elec.	✓	--	✓	--	--	--	--	--	--
Pacific Gas & Electric Co.	PCG	Gas	✓	--	✓	--	--	--	--	--	--
San Diego Gas & Electric Co.	SRE	Elec.	✓	--	✓	--	--	--	--	--	--
San Diego Gas & Electric Co.	SRE	Gas	✓	--	✓	--	--	--	--	--	--
Southern California Edison Co.	EIX	Elec.	✓	--	✓	--	--	--	--	--	--
Southern California Gas Co.	SRE	Gas	✓	--	✓	--	--	--	--	--	--
Southwest Gas Corp.	SWX	Gas	✓	--	✓	--	--	--	--	--	--
COLORADO											
Black Hills Colorado Electric Inc.	BKH	Elec.	✓	✓	--	--	✓ *	✓	--	--	✓
Public Service Co. of Colorado	XEL	Elec.	✓	✓	--	✓ *	--	✓	--	--	✓
Public Service Co. of Colorado	XEL	Gas	✓	✓	--	✓ *	--	--	✓ *	--	--
Black Hills Gas Distribution LLC	BKH	Gas	✓	✓	--	--	--	--	✓ *	--	--
CONNECTICUT											
Connecticut Light and Power Co.	ES	Elec.	-- *	✓	✓ *	--	--	-- *	✓ *	--	✓
Connecticut Natural Gas Co.	IBE	Gas	✓	✓	✓ *	--	--	--	✓ *	--	--
Southern Connecticut Gas Co.	IBE	Gas	✓	✓	✓ *	--	--	--	✓ *	--	--
United Illuminating Co.	IBE	Elec.	-- *	✓	✓ *	--	--	-- *	--	--	✓
Yankee Gas Services Co.	ES	Gas	✓	✓	✓ *	--	--	--	✓ *	--	--

S&P Global
Ratings

RatingsDirect®

Research Update:

Southern California Gas Co. Outlook Revised To Negative From Stable Reflecting Energy Transition Risk; Ratings Affirmed

May 12, 2023

Rating Action Overview

- We expect Southern California Gas Co. (SoCalGas) to face ongoing energy transition risk as California transitions away from natural gas-fueled technologies to meet decarbonization goals.
- We revised our downgrade threshold for SoCalGas to 20% from 18%, reflecting higher business risk.
- We revised our outlook on the company to negative from stable and affirmed our ratings on Southern California Gas Co., including our 'A' issuer-credit rating, our 'A+' first-mortgage bond ratings, and 'A-1' commercial paper ratings.
- The negative rating outlook on Southern California Gas Co. reflects a gradual increase in business risk, reflecting ongoing energy transition risks in California, and our expectations that stand-alone financial measures may not be consistently above our downgrade threshold. We expect the company's stand-alone financial measures to reflect funds from operations (FFO) to debt of 19%-20% over our forecast period.

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Rating Action Rationale

The negative outlook revision reflects our view that SoCalGas is likely to face a gradual increase in business risk given California's ongoing energy transition away from natural gas-fueled technologies Key factors in our analysis include the California Air Resources Board (CARB) approval of the final 2022 Scoping Plan to address climate change that cuts greenhouse gas emissions by 85% from 1990 levels and achieves carbon neutrality in 2045, the California Public Utilities Commission's (CPUC) adoption of General Order 177, which prescribes new rules relating to the planning and construction of gas infrastructure located in California, and the CPUC's recent move to eliminate rate-payer funded natural gas line subsidies for new natural gas hookups. Overall, we think these developments suggest gradual increase in business risk for

SoCalGas. While the company is proactively taking steps to reduce these risks through initiatives such as its investments in renewable natural gas, proposals for hydrogen blending pilot projects, and related hydrogen infrastructure projects, we expect that the risks of energy transition in California will increase business risk over the longer term.

We revised our downgrade threshold upward to 20% from 18%. Historically, because of SoCalGas' size and generally supportive regulation, we assessed its business risk as being in the upper half of the range for its excellent business risk profile category, compared to peers. However, because of California's ongoing energy transition that we view as a gradually increasing risk over the long-term, we now assess SoCalGas' business risk as more towards the middle of the range for its business risk profile category, compared to peers. We reflect this higher business risk by raising SoCalGas' downgrade threshold.

We revised our group status for SoCalGas to highly strategic from core. This reflects our view that SoCalGas is highly unlikely to be sold, constitutes a significant proportion of Sempra's cash flows (approximately 30% of EBITDA) and is closely linked to the group's reputation, and risk management. Furthermore, SoCalGas is important to the group's long-term strategy, has the strong long-term commitment from the group, and is reasonably successful at what it does. That said, in our opinion, because of ongoing energy transition in California, there may be situations where extraordinary support from the group may be limited, supporting our decision to revise group status for SoCalGas.

We rate SoCalGas two notches higher than our 'bbb+' group credit profile of the parent. This reflects the strength of its stand-alone credit profile (SACP) and the cumulative value of the structural and regulatory protections in place that insulate it from its parent.

The key insulating measures include the following:

- SoCalGas is a separate stand-alone legal entity that functions independently--both financially and operationally--files its own rate cases, and is independently regulated by the CPUC.
- SoCalGas has its own records and books, including stand-alone audited financial statements.
- SoCalGas has its own funding arrangements, issues its own long-term debt, and has a separate committed credit facility to cover its short-term funding needs.
- SoCalGas does not commingle funds, assets, or cash flows with Sempra or its other subsidiaries.
- SoCalGas does not have any cross-default obligations and a default by its parent or its parent's other subsidiaries would not directly lead to a default at SoCalGas.
- We believe there is a strong economic basis for Sempra to preserve SoCalGas' credit strength because the company contributes a significant portion of Sempra's consolidated operations.
- Active regulatory oversight, including a CPUC requirement for the company to maintain a minimum equity ratio and that its capital needs be given first priority by its parent.
- The California state law that restricts intercompany debt or guarantees and requires the CPUC's approval for security issuances.
- A nonconsolidation opinion.

Our business risk assessment for SoCalGas remains excellent. Our assessment of SoCalGas' business risk profile as excellent reflects its lower-risk, rate-regulated natural gas transmission, distribution, and storage operations. The company services a very large customer base of about six million while effectively managing its regulatory risk in a manner consistent with that of its peers. Additionally, the majority of the company's customer base (about 95%) is residential, which provides stability to its cash flow and mitigates its exposure to the economic cyclicality that tends to be more pronounced with a higher concentration of industrial customers. In May 2022, SoCalGas filed a general rate case (GRC) with the CPUC for the 2024-2027 period, requesting a revenue requirement of approximately $4.4 billion effective January 1, 2024, which effectively indicates a total rate increase of about $1.7 billion over this period. A CPUC decision is still pending. As such we continue to monitor subsequent developments related to this GRC.

Our financial risk assessment for SoCalGas remains significant. We assess SoCalGas' financial risk profile using our medial volatility table. This reflects the company's lower-risk regulated gas distribution operations and its effective management of regulatory risk, which we assess as in line with that of its peers. Under our base-case scenario, we assume capital expenditures averaging about $2 billion annually, dividend payments to the parent company over our forecast period, constructive regulatory outcomes on the company's pending rate case, and the continued use of credit-supportive regulatory mechanisms. Furthermore, because of its robust capital spending, we expect SoCalGas to generate negative discretionary cash flow, indicative of external funding needs. Overall, we anticipate the company's FFO to debt will be in the 19%-20% range, consistent with the significant financial risk profile category.

Outlook

The negative outlook for Southern California Gas Co. reflects the company's minimal financial cushion from our downgrade threshold and expectations that its stand-alone FFO to debt will not be consistently greater than 20%. Under our base case, we expect the company's stand-alone financial measures to reflect FFO to debt of 19%-20% over our forecast period.

Downside scenario

We could lower our ratings on Southern California Gas Co. within the next 12-18 months if:

- We lower our ratings on parent Sempra; or
- SoCalGas' stand-alone FFO to debt consistently weakens to below 20%; or
- SoCalGas' business risk increases either due to adverse regulatory developments or elevated risk concerning its gas utility business.

Upside scenario

We could revise our outlook on Southern California Gas Co. to stable over the next 12-18 months if the company maintains strong stand-alone financial measures such that FFO to debt is consistently greater than 20%, the company maintains its track record of effective regulatory risk management, business risk does not increase, and parent Sempra is not downgraded.

Company Description

SoCalGas is a regulated public utility that owns and operates a natural gas distribution, transmission, and storage system and supplies natural gas to approximately six million customer meters over a 24,000-square-mile service territory in Southern California and portions of Central California.

Liquidity

We assess SoCalGas' liquidity as adequate to cover its needs for the next 12 months even if its consolidated EBITDA declines by 10%. Specifically, we expect the company's liquidity sources to be more than 1.1x its uses over the next 12 months as of March 31, 2023. Our assessment also reflects its sound relationships with its banks, its satisfactory standing in the credit markets, and its generally prudent risk management.

Liquidity sources:

- Estimated cash FFO of about $1.55 billion;
- Credit facility of $1.2 billion; and
- Minimal cash and cash equivalents.

Liquidity Uses:

- Assumed maintenance capital of $1.245 billion;
- Long-term debt maturities of $300 million;
- Commercial paper outstanding of $223 million; and
- Dividends to the parent company.

Covenants

SoCalGas must maintain a debt to capitalization ratio of no more than 65% at the end of each quarter. As of March 31, 2023, the company was in compliance with this ratio, and we expect the company to remain in compliance with sufficient headroom.

Environmental, Social, And Governance

ESG credit indicators:E3, S3, G2

Environmental factors are a moderately negative consideration in our credit rating analysis of Southern California Gas Co. SoCalGas has an expansive pipeline network and multiple storage facilities to support its transmission and distribution operations, which are susceptible to a variety of environmental risk factors. Natural gas leakages can stem from aging gas infrastructure or changes in soil integrity. Social factors are a moderately negative consideration in our credit ratings analysis of SoCalGas, reflecting legacy safety issues tied to the Aliso Canyon gas leaks from October 2015 to February 2016. Furthermore, we view the recent CARB approval of the final

2022 Scoping Plan to address climate change, the CPUC's adoption of General Order 177, and move to eliminate rate-payer funded natural gas line subsidies for new natural gas hookups as raising energy transition risk for the company.

Issue Ratings - Subordination Risk Analysis

Capital structure

SoCalGas has approximately $6.1 billion of long-term debt, about $5.1 billion of which was first-mortgage bonds (FMBs) as of March 31, 2023.

Analytical conclusions

- We rate SoCalGas' senior unsecured debt at the same level as our long-term issuer credit rating (ICR) because it is debt issued by a qualifying investment-grade utility under our criteria.
- We rate the company's preferred stock two notches below our long-term ICR based on the instrument's deferability and subordination features.
- We rate the company's short-term debt and commercial paper program 'A-1' based on our long-term ICR.

Issue Ratings - Recovery Analysis

Key analytical factors

We rate SoCalGas' first-mortgage bonds (FMBs) 'A+', which is one notch above our long-term ICR. SoCalGas' FMBs benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of over 1.5x supports a recovery rating of '1+' and an issue-level rating one notch above the ICR.

Ratings Score Snapshot

Issuer credit rating: A/Negative/A-1

Business risk: Excellent

- Country risk: Very Low
- Industry risk: Very Low
- Competitive position: Strong

Financial risk Significant

- Cash flow/leverage Significant

Anchor: a-

Modifiers

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Satisfactory (no impact)
- Comparable rating analysis: Positive (+1 notch)

Stand-alone credit profile: a

Group credit profile: bbb+

Entity status within group: Insulated

Environmental, social, and governance (ESG) credit factors for this change in credit rating/outlook and/or CreditWatch status:

- Climate transition risks

Related Criteria

- General Criteria: Hybrid Capital: Methodology And Assumptions , March 2, 2022
- Criteria | Corporates | Industrials: Key Credit Factors For The Midstream Energy Industry , Nov. 15, 2021
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings , Oct. 10, 2021
- General Criteria: Group Rating Methodology , July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments , April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings , March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings , April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers , Dec. 16, 2014
- General Criteria: Methodology: Industry Risk , Nov. 19, 2013

- Criteria | Corporates | General: Corporate Methodology , Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions , Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry , Nov. 19, 2013
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property , Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities , Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings , Feb. 16, 2011

Ratings List

Ratings Affirmed; Outlook Action

	To	From
Southern California Gas Co.		
Issuer Credit Rating	A/Negative/A-1	A/Stable/A-1
Pacific Enterprises		
Issuer Credit Rating	A/Negative/--	A/Stable/--
Issue-Level Ratings Affirmed		
Southern California Gas Co.		
Senior Unsecured	A	
Preferred Stock	BBB+	
Commercial Paper	A-1	
Issue-Level Ratings Affirmed; Recovery Ratings Unchanged		
Southern California Gas Co.		
Senior Secured	**A+**	
Recovery Rating	1+	

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.standardandpoors.com for further information. Complete ratings information is available to subscribers of RatingsDirect at www.capitaliq.com. All ratings affected by this rating action can be found on S&P Global Ratings' public website at www.standardandpoors.com. Use the Ratings search box located in the left column.

Proxy Group Two: Canadian Holding Companies

Company	Gas Subsidiaries Currently Authorized Equity Ratio	Gas Subsidiaries 2-Year Avg. Book Equity Ratio	Holding Company 2-Year Avg. Equity Ratio
Algonquin Power & Utilities	49.00%	71.98%	49.27%
AltaGas Inc.	52.54%	54.30%	39.23%
Canadian Utilities Ltd.	37.00%	37.78%	32.27%
Emera Inc.	53.35%	63.56%	42.17%
Fortis Inc.	45.77%	50.21%	40.65%
Hydro One, Ltd.	N/A	N/A	44.10%
Average	**47.53%**	**55.57%**	**41.28%**

Proxy Group Three: US Operating Companies

Company	Gas Subsidiaries Currently Authorized Equity Ratio	Gas Subsidiaries 2-Year Avg. Book Equity Ratio	Holding Company 2-Year Avg. Equity Ratio
Southern California Gas Company	52.00%	52.60%	N/A
Consumers Energy Company	NA	51.83%	N/A
Northern Illinois Gas Company	54.46%	54.81%	N/A
DTE Gas Company	51.00%	51.72%	N/A
Consolidated Edison Company of New	48.00%	46.78%	N/A
The East Ohio Gas Company	NA	60.90%	N/A
Brooklyn Union Gas Company	48.00%	52.22%	N/A
Atlanta Gas Light Company	56.00%	59.23%	N/A
Columbia Gas of Ohio, Inc.	NA	50.62%	N/A
The Peoples Gas Light and Coke Com	50.33%	53.12%	N/A
Average	**51.40%**	**53.38%**	**N/A**

Proxy Group Four: US Holding Companies

Company	Gas Subsidiaries Currently Authorized Equity Ratio	Gas Subsidiaries 2-Year Avg. Book Equity Ratio	Holding Company 2-Year Avg. Equity Ratio
Atmos Energy Corporation	56.68%	58.31%	60.80%
New Jersey Resources Corporation	54.00%	55.45%	43.95%
NiSource Inc.	51.40%	55.03%	33.20%
Northwest Natural Gas Company	49.50%	49.34%	49.00%
ONE Gas, Inc.	58.78%	60.04%	48.75%
South Jersey Industries, Inc.	53.00%	54.73%	37.90%
Southwest Gas Corporation	50.79%	49.18%	45.65%
Spire, Inc.	54.16%	57.24%	47.10%
Average	**53.54%**	**54.92%**	**45.79%**

SEMPRA ENERGY NYSE-SRE

RECENT PRICE 155.29 | P/E RATIO 17.4 (Trailing: 16.9; Median: 20.0) | RELATIVE P/E RATIO 1.01 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS 3 Lowered 4/21/23
SAFETY 2 Raised 7/29/16
TECHNICAL 3 Lowered 4/21/23
BETA .95 (1.00 = Market)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
High:	72.9	93.0	116.3	116.2	114.7	123.0	127.2	154.5	161.9	144.9	176.5	163.6
Low:	54.7	70.6	86.7	89.4	86.7	99.7	100.5	106.1	88.0	114.7	129.7	138.6

LEGENDS
—— 33.3 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession

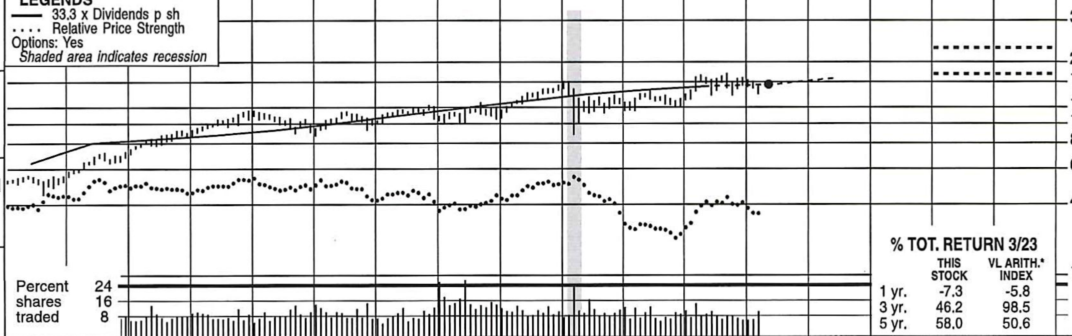
18-Month Target Price Range

Low-High $126-$197 | Midpoint (% to Mid) $162 (5%)

Target Price Range 2026 | 2027 | 2028

2026-28 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	235	(+50%)	13%
Low	175	(+15%)	6%



% TOT. RETURN 3/23

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-7.3	-5.8
3 yr.	46.2	98.5
5 yr.	58.0	50.6

Institutional Decisions

	2Q2022	3Q2022	4Q2022
to Buy	441	476	518
to Sell	376	332	364
Hld's(000)	268609	267683	273687

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
43.79	44.21	32.88	37.44	41.83	39.80	43.18	44.80	41.20	40.71	44.59	42.69	37.12	39.41	40.57	45.94	**49.20**	**52.45**	Revenues per sh	**61.65**
6.93	7.40	7.94	7.76	8.58	8.92	8.87	9.41	10.32	9.50	10.57	11.07	11.14	13.22	14.17	15.70	**16.25**	**17.30**	"Cash Flow" per sh	**21.65**
4.26	4.43	4.78	4.02	4.47	4.35	4.22	4.63	5.23	4.24	4.63	5.48	5.97	7.38	8.43	9.21	**9.00**	**9.60**	Earnings per sh A	**12.00**
1.24	1.37	1.56	1.56	1.92	2.40	2.52	2.64	2.80	3.02	3.29	3.58	3.87	4.18	4.40	4.58	**4.76**	**5.00**	Div'd Decl'd per sh B ■	**6.10**
7.70	8.47	7.76	8.58	11.85	12.20	10.52	12.68	12.71	16.85	15.71	13.82	12.71	16.21	15.82	17.04	**17.00**	**17.00**	Cap'l Spending per sh	**17.00**
31.87	32.75	36.54	37.54	41.00	42.42	45.03	45.98	47.56	51.77	50.41	54.35	60.58	70.11	79.17	83.43	**85.55**	**90.20**	Book Value per sh C	**105.55**
261.21	243.32	246.51	240.45	239.93	242.37	244.46	246.33	248.30	250.15	251.36	273.77	291.71	288.47	316.92	314.33	**305.00**	**305.00**	Common Shs Outst'g D	**300.00**
14.0	11.8	10.1	12.6	11.8	14.9	19.7	21.9	19.7	24.4	24.3	20.4	22.5	17.5	15.4	16.8	*Bold figures are*		Avg Ann'l P/E Ratio	**17.0**
.74	.71	.67	.80	.74	.95	1.11	1.15	.99	1.28	1.22	1.10	1.20	.90	.83	.98	*Value Line*		Relative P/E Ratio	**.95**
2.1%	2.6%	3.2%	3.1%	3.6%	3.7%	3.0%	2.6%	2.7%	2.9%	2.9%	3.2%	2.9%	3.2%	3.4%	3.0%	*estimates*		Avg Ann'l Div'd Yield	**3.0%**

CAPITAL STRUCTURE as of 12/31/22
Total Debt $28919 mill. **Due in 5 Yrs** $6475 mill.
LT Debt $24548 mill. **LT Interest** $1155 mill.
Incl. $1343 mill. finance leases.
(Total Interest Coverage: 3.6x)

Leases, Uncapitalized Annual rentals $53 mill.
Pension Assets-12/22 $2390 mill.
Oblig $2806 mill.
Pfd Stock $889 mill. **Pfd Div'd** $45 mill.
900,000 shs. 4.875%, cumulative.
Common Stock 314,569,519 shs.
as of 2/21/23
MARKET CAP: $48.8 billion (Large Cap)

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	© VALUE LINE PUB. LLC	26-28
10557	11035	10231	10183	11207	11687	10829	11370	12857	14439	**15000**	**16000**	Revenues ($mill)	**18500**
1060.0	1162.0	1314.0	1065.0	1169.0	1607.0	1825.0	2316.0	2701.0	2960.0	**2840**	**2985**	Net Profit ($mill)	**3655**
26.5%	19.7%	19.2%	14.4%	24.5%	20.1%	17.9%	18.0%	25.5%	20.1%	**19.0%**	**19.0%**	Income Tax Rate	**19.0%**
11.2%	14.4%	15.3%	22.2%	21.9%	12.6%	10.0%	8.7%	8.0%	8.6%	**9.0%**	**8.0%**	AFUDC % to Net Profit	**8.0%**
50.5%	51.7%	52.6%	52.7%	56.4%	55.7%	51.0%	48.2%	44.8%	47.5%	**50.5%**	**50.5%**	Long-Term Debt Ratio	**49.0%**
49.4%	48.2%	47.3%	47.3%	43.5%	38.4%	43.4%	44.8%	53.3%	50.7%	**48.0%**	**48.0%**	Common Equity Ratio	**49.5%**
22281	23513	24963	27400	29135	38769	40734	45174	47069	51683	**54700**	**57550**	Total Capital ($mill)	**63800**
25460	25902	28039	32931	36503	36796	36452	40003	43894	47782	**50800**	**53650**	Net Plant ($mill)	**60700**
6.0%	6.1%	6.4%	5.0%	5.1%	5.1%	5.5%	6.1%	6.6%	6.8%	**6.0%**	**6.0%**	Return on Total Cap'l	**7.0%**
9.6%	10.2%	11.1%	8.2%	9.2%	9.4%	9.1%	9.9%	10.4%	10.9%	**10.5%**	**10.5%**	Return on Shr. Equity	**11.0%**
9.6%	10.3%	11.1%	8.2%	9.2%	10.0%	9.5%	10.6%	10.5%	11.1%	**10.5%**	**10.5%**	Return on Com Equity E	**11.5%**
4.1%	5.0%	5.8%	2.9%	3.3%	4.1%	3.9%	4.8%	5.2%	5.7%	**5.0%**	**5.0%**	Retained to Com Eq	**5.5%**
58%	52%	48%	65%	65%	62%	62%	58%	52%	50%	**53%**	**53%**	All Div'ds to Net Prof	**51%**

ELECTRIC OPERATING STATISTICS

	2020	2021	2022
% Change Retail Sales (KWH)	-.4	-3.7	+2.8
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	NMF	NMF	NMF
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+.8	+.9	+.5
Fixed Charge Cov. (%)	178	201	232

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '20-'22 to '26-'28
Revenues	0.5%	--	6.5%
"Cash Flow"	5.5%	7.0%	6.5%
Earnings	7.0%	12.0%	6.0%
Dividends	8.5%	7.5%	5.5%
Book Value	7.0%	9.0%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	3029	2526	2644	3171	11370
2021	3259	2741	3013	3844	12857
2022	3820	3547	3617	3455	14439
2023	**3925**	**3575**	**3650**	**3850**	**15000**
2024	**4175**	**3825**	**3900**	**4100**	**16000**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	2.53	1.58	1.31	1.88	7.38
2021	2.95	1.63	1.70	2.16	8.43
2022	2.91	1.98	1.97	2.35	9.21
2023	**2.90**	**1.80**	**1.90**	**2.40**	**9.00**
2024	**3.10**	**1.90**	**2.05**	**2.55**	**9.60**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.895	.9675	.9675	.9675	3.80
2020	.9675	1.045	1.045	1.045	4.10
2021	1.045	1.10	1.10	1.10	4.35
2022	1.10	1.145	1.145	1.145	4.54
2023	1.145	1.19			

BUSINESS: Sempra Energy is a holding company for San Diego Gas & Electric (SDG&E), which sells electricity & gas mainly in San Diego County, & Southern California Gas (SoCalGas), which distributes gas to most of Southern California. Owns 80% of Oncor (acq'd 3/18), which distributes electricity in Texas. Customers: 5.2 million electric, 7.0 million gas. Electric revenue breakdown not available. Purchases 76% of its power; the rest is gas. Has non-utility subsidiaries, incl. IEnova in Mexico. Sold South American utilities in 2020. Power costs: 24.5% of revenues. '22 reported deprec. rates: 2.6%-7.0%. Has 15,785 employees. Chairman, President & CEO: Jeffrey W. Martin. Inc.: CA. Address: 488 8th Ave., San Diego, CA 92101. Tel.: 619-696-2000. Internet: www.sempra.com.

Sempra Energy will likely post flat to down earnings in 2023. Leadership's projected earnings range for this year is $8.60 to $9.20 per share. Sempra is up against a difficult 2022 comparison. The final bottom-line tally for the year was a 9% gain versus 2021, and $0.51 per share above the high end of Sempra's targeted range at the start of 2022. A heat wave in southern California was a key factor, driving electricity usage up 2.8% last year. Further, the company has been making significant investments in its infrastructure and there is a degree of regulatory lag taking place. This is par for the course in this industry, but with inflation and interest rates up, delays in the recoupment of invested capital are a more onerous issue.

We expect growth will resume next year. Sempra has general rate cases filed with its regulators in Texas and California. A decision is due prior to the close of the second quarter for Oncor, the company's 80%-owned transmission and distribution subsidiary in Texas. The higher delivery rates expected for Oncor should benefit the back half of 2023, with further incremental improvement coming in 2024. Meantime, a regulatory decision is expected in the second quarter of next year for San Diego Gas & Electric and SoCalGas. Higher rates in California should be retroactive to the beginning of 2024.

The economics of the liquefied natural gas (LNG) export operation looks very attractive. Sempra Infrastructure Partners, a 70%-owned subsidiary, has done the legwork necessary to put together a project that will export 13 million tonnes per annum of LNG to Europe and Asia starting in 2027. Long-term contracts are already more than 80% subscribed to. ConocoPhillips has come on board as a partner, and KKR will also help finance the $13 billion endeavor. Sempra is expected to retain about a 20% stake, but will only have to put up a half-share of the capital. We estimate a bump in annual earnings power of $0.50-$0.75 per share, plus an opportunity to replicate the gains through additional project phases.

At the recent quote, this issue's total return prospects do not stand out relative to industry peers. We advise utility investors enter on a pullback.

Anthony J. Glennon *April 21, 2023*

(A) Dil. egs. Excl. nonrec. gain/(loss): '09, (26¢); '10, ($1.04); '11, $1.15; '12, (87¢); '13, (21¢); '15, 14¢; '16, $1.22; '17, ($3.62); '18, ($2.06); '19, 16¢; '20, (80¢); '21, ($4.42); '22, ($1.64); disc. ops.: '07, (10¢); '19, $1.16; '20, $6.30. EPS may not sum due to chg. in shs. Next egs. report due early May. (B) Div'ds paid mid-Jan., Apr., July, Oct. ■ Div'd reinv. avail. (C) Incl. intang. In '22: $14.42/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq.: SDG&E in '22: 9.95%; SoCalGas in '22: 9.8%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	55
Earnings Predictability	90

Decision **27084-D01-2022**

AUC
Alberta Utilities Commission

2023 Generic Cost of Capital

March 31, 2022

impossible to forecast relevant economic conditions for 2022 with any reasonable degree of accuracy."[56] Overall, the Commission finds market volatility remains elevated, making it difficult to forecast relevant economic conditions for 2023. This lends further support to a rollover of GCOC parameters into 2023.

3.2.4 Business risk and earning above awarded ROE

37. Parties submitted conflicting assessments of changes to business risk since the 2018 GCOC decision. The ATCO Utilities/Apex/Fortis[57] submitted that there have been significant transformations occurring in the utility industry since 2018, including emphasis on decarbonization; a focus on environmental, social and governance standards; the need for grid modernization; and changes in the way in which customers are receiving utility service. These utilities stated that they are directly affected by these transformations, and these changes engender risk and uncertainty for utilities at a level seldom witnessed in the past.[58]

38. J. Coyne, on behalf of ENMAX, pointed to renewable energy investments and high capital expenditure plans in an increasing interest rate environment as contributors to the observed elevated utility risk.[59] Fortis engaged Dr. Toby Brown of the Brattle Group to assess the business risk of utilities in Alberta. Dr. Brown concluded that the business risk of the utilities in Alberta in 2023 remains elevated and may have increased since the 2021 GCOC proceeding.[60]

39. The UCA submitted that there has been no change in business risk since the 2018 GCOC decision was issued. It stated that the COVID-19 pandemic appeared to have little effect on the utilities' ability to provide safe and reliable service, and submitted that this confirms the utilities continue to have low business risk and operate within a supportive regulatory environment.[61] The CCA submitted that financial risk and regulatory risk are lower now than they were at the time of the 2018 GCOC proceeding. It noted the reduction in regulatory lag and stated that utility asset disposition risk has been largely eliminated.[62]

40. Some customer groups pointed to the utilities achieving actual ROEs in excess of the Commission-approved ROEs. For example, Calgary noted that ATCO Gas has been remarkably consistent in earning in excess of its approved ROE over the last four years, even when the economy at large has been decimated. It submitted that this indicates minimal business risk for ATCO Gas.[63] The Industrial Power Consumers Association of Alberta (IPCAA) submitted that over the last 10 years, most of the utilities in Alberta have been earning an ROE above the Commission-approved ROE.[64]

41. The Commission considers that historical earnings above or below the approved ROEs do not help it to determine what the ROE for a future test period should be. The Commission agrees with the following submissions made by AltaLink/EPCOR:

56 Decision 26212-D01-2021, paragraph 13.
57 The ATCO utilities, Apex and Fortis filed a joint submission on the record, which is in Exhibit 27084-X0028.
58 Exhibit 27084-X0028, ATCO/Apex/Fortis, page 2.
59 Exhibit 27084-X0025, ENMAX, PDF page 18.
60 Exhibit 27084-X0032, Fortis, PDF pages 6-7.
61 Exhibit 27084-X0031, UCA, paragraphs 33-36.
62 Exhibit 27084-X0026, CCA, paragraph 53.
63 Exhibit 27084-X0021, Calgary, paragraph 38.
64 Exhibit 27084-X0024, IPCAA, paragraphs 7-9.

> Invariably, whether or not a utility earns its approved ROE in a given year will depend on utility specific matters, such as the utility's O&M [operating and maintenance] and capital cost performance in that year. Although these matters may be relevant to the regulation of a utility's revenue requirement (whether under cost of service regulation or performance-based regulation), they are not relevant in the context of establishing fair return within a GCOC proceeding.[65]

42. The Commission notes the conflicting evidence and positions of parties with respect to indicators of business risk and whether business risk is increasing or decreasing. The Commission is not persuaded that there is a quantifiable shift in business risk that would require either an increase or decrease in the deemed equity ratios for 2023.[66]

3.3 Comparable returns on equity

43. Some interveners referenced approved ROEs and ongoing GCOC proceedings from other jurisdictions. Calgary, for example, highlighted[67] two recent determinations of the Newfoundland and Labrador Board of Commissioners of Public Utilities and the New Brunswick Energy and Utilities Board. Both cases resulted in an approved ROE of 8.5 per cent through either a negotiated settlement or an award by a board. In Calgary's view, this is another circumstance accentuating that "the roll-over of 2022 GCOC parameters into 2023 should assure Customers with the comfort that distribution rates will not rise once again due to any parameter adjustments in 2023."[68]

44. The UCA used the Ontario Energy Board's (OEB) formula and, using the Commission's last approved ROE of 8.5 per cent as the base, along with certain market data values as recent as of January 18, 2022, arrived at a calculated ROE of 8.37 per cent. Alternatively, it noted that using a formula proposed by Dr. S. Cleary in the 2021 GCOC proceeding, updated with more current data, would produce an ROE of 8.3 per cent.[69] In the UCA's view, if the Commission was to set the ROE on a final basis without conducting further process, at a minimum, the approved ROE should be 0.27 per cent below the currently approved ROE of 8.5 per cent (i.e., 8.23 per cent).[70] The UCA also pointed to the ongoing GCOC proceeding at the British Columbia Utilities Commission (BCUC) notwithstanding "uncertainties in economic conditions, volatility in financial markets and changes in government policies."[71]

45. While all utilities supported keeping the ROE at 8.5 per cent, some utilities submitted evidence that current economic indicators would actually lead to a higher ROE for 2023 (as well as higher deemed equity ratios), if the Commission was to carry out a full GCOC proceeding.

46. AltaLink and EPCOR identified a number of relevant data points indicating that investor return expectations for utilities have increased, for example: (i) high inflation puts an upward pressure on interest rates and, as a result, investor-required returns on utility investments;

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65 Exhibit 27084-X0023, AltaLink/EPCOR, paragraph 27.

66 Since the 2009 GCOC decision, it has been the Commission's practice to establish an ROE that uniformly applies to all of the affected utilities and account for particular business risks faced by the affected utilities by incorporating any required adjustments into their respective approved deemed equity ratios, either collectively or on an individual basis.

67 Exhibit 27084-X0022, Calgary, paragraph 31.

68 Exhibit 27084-X0022, Calgary, paragraph 46.

69 Exhibit 27084-X0031, UCA, paragraphs 28-31.

70 Exhibit 27084-X0031, UCA, paragraph 27.

71 Exhibit 27084-X0031, UCA, paragraph 6.