The Appropriate Return on Equity for the Transco and Disco Business Operations of the Ontario Hydro Services Company

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The Ontario Energy Board Staff

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Section I. <u>Introduction</u>

Reed Consulting Group ("REED") and Dr. William T. Cannon (jointly referred to as the "Consultants") were retained by the Ontario Energy Board Staff ("Staff") to assist in the evaluation of the rate applications submitted by the Ontario Hydro Services Company ("OHSC"). Jointly, REED and Dr. Cannon have extensive backgrounds in electric utility industry issues in general and the development of the appropriate cost of equity for regulated entities specifically.

OHSC submitted a separate Transmission and Distribution Rate Order Application for its transmission ("Transco") and distribution ("Disco") business operations, respectively. As part of its assistance to the Staff, the Consultants were asked to review and comment on the cost of equity proposal contained in both rate applications. Upon review of the limited information provided by OHSC, the Staff requested that the Consultants prepare a cost of equity study based on first principles. The objective of the study was to provide an appropriate information base to make an informed assessment of OHSC's return on equity ("ROE") proposal.

The study was to accept, as its assumptions, OHSC's proposed 60:40 debt/equity capital structure and OHSC's goal of achieving an "A" credit rating for issuing future debentures and to maintain its financial integrity on a stand-alone basis. Further, as part of their analysis and recommendations, the Consultants were to consider the formulaic approach to ROE developed by the Ontario Energy Board ("OEB") for gas utilities in light of its expanded jurisdiction over hundreds of municipal electric utilities and private electric utilities ("electric utilities"). The Consultants were also to consider the need for regulatory symmetry between Ontario's gas and electric utilities. This report details the Consultants' findings with respect to the proposed cost of equity contained in both applications.

This report contains eight sections including this Introduction. Section II provides an Executive Summary of the Consultants' findings. Section III discusses foundational, theoretical-empirical and regulatory issues that underly cost of equity analyses. Section IV outlines the specific business and financial risk considerations that must be addressed as part of the evaluation to determine the appropriate cost of equity for Transco and Disco. Section V discusses the Equity Risk Premium

("ERP") analytical approach adopted to estimate the cost of equity for Transco and Disco and reports the findings. Section VI discusses the Capital Asset Pricing Model ("CAPM") analytical approach used to corroborate the findings in Section V. Section VII compares the cost of equity findings using the two analytical approaches with recent allowed returns for gas utilities in Ontario. Finally, Section VIII provides a commentary on the report submitted by OHSC's financial advisor in support of its equity return proposal.

Section II. Executive Summary

In sections 10.4 and 9.3.4 of its distribution and transmission applications, respectively, OHSC has put forth its proposed ROE. OHSC is requesting a 10.0% return for both its Transco and Disco business operations based on a 60:40 debt/equity capital structure. In support of its request, OHSC included an opinion letter from its financial advisor. The opinion letter is contained in Appendices 7 and U of its distribution and transmission applications, respectively. In addition, subsequent to the rate filing, OHSC's financial advisor submitted a report, "Capital Structure and Fair Rate of Return on Common Equity for Ontario Hydro Services Company," which provides the evidence in support of the overall recommendations.

At the request of the Staff, the Consultants conducted their own evaluation of the appropriate ROE for Transco and Disco. The Consultants' analysis was guided by economic principles that dictate that the appropriate ROE for a regulated firm is that which is sufficient to attract investors on reasonable terms without impairing the financial integrity of the regulated firm. The return must be commensurate with the returns on investments with comparable risk in the market. In their analysis, the Consultants evaluated the feasibility and desirability of employing four analytical methods to determine Transco and Disco's cost of equity. These methods included the comparable earnings test ("CET"), the discounted cash flow test ("DCF"), the CAPM, and the ERP test.

As part of the analysis, the Consultants also evaluated the business and financial risk of Transco and Disco. Such evaluation is key to the determination of the appropriate cost of equity and must be conducted. To this end, a commentary on the business and financial risk of the electric utility industry in general is provided and used as a backdrop for a discussion of the business and financial risk of Transco and Disco.

Investors must be compensated for long-run and short-run risks. In the long run, an electric utility is subject to risk related to a sustained decline in energy consumption brought on by deteriorating economic conditions and/or demographics. In the short run, an investor is subject to volatility in earnings brought on by numerous sources of business risk. In general, business risk for an electric utility arises because of differences between a firm's actual cost of service and its allowed revenue requirement. For example, actual operations and maintenance ("O&M") expenses can differ from those included in the revenue requirement. A second source of business risk arises because a regulated firm's actual revenues can differ from the revenue requirement. This is due primarily to plant utilization forecasting errors. For example, the forecasted energy sales underlying the revenue requirement may deviate from actual energy sales.

With respect to long-run risk, it is not expected that either Transco or Disco will experience a sustained decline in electric throughput. This finding is based on the anticipated economic growth and inability of customers to effectively switch to alternative energy sources. Indeed, the open access initiatives will enhance the competitive position of electricity as such initiatives are designed to reduce the cost of electricity.

With respect to short-run risk, and specifically the potential for Transco's and Disco's actual cost of service to differ from their revenue requirement, the report notes three sources of risk. Of the three, Transco and Disco are exposed to only one. Specifically, the actual cost of service can differ from the revenue requirement due to energy cost/price risk, variations in capital costs, and variations in O&M expenses. It is shown that only the latter is relevant for Transco and Disco. While OHSC has indicated that its assets are somewhat physically deteriorated, it has also provided evidence that its O&M expenses are in the lower quartile of a sample of 20 comparable utilities. This fact, combined with Transco's and Disco's aggressive prospective asset sustainment program for which they are requesting an average of $264 million annually over 1999-2000 which represents an 29.0% increase over the corresponding figure for 1998. This will serve to dampen O&M expense variability and, thus, both entities' risk.

With regard to Transco's and Disco's actual revenues deviating from their revenue requirements, the report distinguishes two periods. In the pre-2001 period, Transco and Disco will be *guaranteed* their revenue requirement. Absent future rate reviews, this fact would be less important. However, future rate reviews will occur, thus Transco's and Disco's revenue guarantee is relevant. In the post-2001 period, the report highlights the reasons why a utility's actual revenues can deviate from the established revenue requirement. Among the potential forecast errors that can give rise to such deviations are fluctuating economic conditions and changes in customer additions and customer mix. The report explains that, by virtue of the entities' sizes and the diversity of their customer bases, forecasting errors in these areas are less consequential to Transco and Disco. In all, the allowed ROE recommended by the consultants is somewhat high in the short term given the revenue requirement guarantee through 2000, but reflects actual risk levels in the post-2000 period.

For the reasons cited above and discussed in the body of the report, Transco and Disco are subject to less business risk relative to other financially comparable electric utilities. In addition, as discussed in Section VI, at this time, there is no reason to conclude that any appreciable risk differences exist between Transco and Disco.

To determine the appropriate cost of equity for Transco and Disco, two complementary methodological approaches were employed: the ERP test and the CAPM. Two versions of the ERP test were employed. The first ERP test focuses on estimating gas and electric utility equity risk premiums based on historical utility return and utility cost of equity data. The second gauges gas and electric utility equity risk premiums by risk adjusting the prospective Canadian market risk premium. The CET approach was not adopted as it is inconsistent with the OEB's formulaic rate objectives. Specifically, it does not lend itself to a formulaic return methodology and is inconsistent with the objective of regulatory symmetry between gas and electric utilities. The DCF approach was not employed for similar reasons.

Both the ERP tests and the CAPM focus on the rate of return premium required to attract common equity capital in competition with other investment opportunities available to investors in the marketplace. Results of the first version of the ERP indicate an appropriate range for cost of equity of 7.52%-8.26% based on long Canada bond rates in the range of 5.0-6.0%. Results of the second version of the ERP indicate an appropriate cost of equity range of 7.6%-8.10% based on "all-in" equity risk premium of 2.10%. Finally, the CAPM results reveal an appropriate cost of equity of 7.62%. Based on these results, the consultants conclude that an appropriate allowed equity return range for Transco and Disco should be 8.00%-8.25%, considering the financial market conditions expected for the 1999-2000 time period and the desire to see the financial integrity and financing flexibility of Transco and Disco preserved.

We have recommended an allowed return at the high end of the range of returns indicated by our analysis to reflect the fact that OHSC is a new entity from the perspective of investors, although this consideration will really only be relevant when and if the Ontario government begins to reduce its stake in OHSC, by which time OHSC will have a "track record" which investors can judge.

The above cost of equity results were further validated by comparing them to similar results for a broader group of electric utilities. In addition, the results were compared to the allowed equity returns of two of Ontario's largest gas utilities. Given differences in financial and business risk between Transco/Disco and the gas distribution utilities (which are fully documented throughout the report and in Appendix C), the cost of equity results are comparable and, thus, appropriate.

Finally, given the large size and low business risk of Transco and Disco, and their ample 40% common equity ratios, the desired "A" bond rating for OHSC is reasonably assured with an equity return in the range of 8.0%-8.25%. This conclusion has been confirmed by a major Canadian institutional bond investor. Using 1999 balance sheet and income information for OHSC and assuming an equity ratio of 40% and equity return of 8.0%, the institutional investor's own assessment technique, which is geared toward S&P ratings, concluded an A rating would be forthcoming.

Section III. Theoretical-Empirical/Regulatory Issues

Guiding Principles-Theoretical

Any cost of equity analysis is guided by fairly straightforward principles. To begin, one must keep in mind what is meant by "appropriate ROE." As a regulated firm, OHSC will undertake certain obligations and accept various restrictions on how it operates. In exchange, it is provided the opportunity to set prices such that it can recoup its operating costs and generate a profit. In particular, it is allowed a return on capital sufficient to attract new capital. This is key to determining what the appropriate ROE should be.

The appropriate, (or what is sometimes referred to as the "fair"), ROE is the minimum rate necessary to attract capital on favorable terms. Many concepts are subsumed in this definition. First, the appropriate ROE is a forward-looking concept. It is the return expected by investors in the future, not the return that actually may prevail in some future period. Second, it is an opportunity cost. To attract investors' funds, a firm must provide a return commensurate with other investments in the market of comparable risk. Thus, the return must be sufficient to compensate investors for their foregone opportunities. Third, it is a return established in the capital markets where all investments compete against each other for investors' funds. Finally, and related to the third point, the appropriate return is predicated on the perceived risk of the investment. The higher the perceived risk, the higher the return. Conversely, the lower the risk, the lower the return. The guiding principle just highlighted for determining the appropriate cost of equity for a regulated firm should also be placed in the context of broader cost of capital concepts. Two such concepts are the relationship between capital structure and bond ratings and the relationship between capital structure and the cost of equity itself.

Capital structure analysis using a static trade-off model suggests a high debt ratio and low common equity ratio ("CER") for "taxable" rate-regulated distribution utilities within the restructured Ontario electricity market. This is because these utilities have a very high probability of being profitable and, therefore, of being able to realize the beneficial tax-shielding effects of interest payments. In addition, local electricity distributors have a very low probability of experiencing "financial distress" and, even if they did, the real "costs" of this financial distress would be relatively small as compared with firms in many other industries.

Nevertheless, the static trade-off model does not address all the factors that utility owners and managers consider when setting the target capital structure proportions for their utilities. The most important of these other factors is the reaction of the debt rating agencies to the utility's capital structure choice and the implications of these rating agency reactions for the utility's subsequent financing flexibility.

The extent to which a company can push its CER lower by increasing its use of debt and preferred share financing is limited by its perceived need to preserve some degree of financing flexibility, which, in turn, usually requires that it preserve its bond ratings at their present level or, at least, above some critical level. The company's ability to continue borrowing may also be limited by the provisions attached to its current bond indentures or bank loan agreements.

In order to ensure that new capital projects can be funded and maturing debt can be refinanced, utility managers feel they need to preserve particular bond ratings. Conventional wisdom suggests that BBB-rated debt can be sold on reasonable terms under normal debt market conditions, but either cannot be successfully issued, or can be issued only at exorbitant rates, under adverse financial market conditions. A-rated debt, on the other hand, can be issued on reasonable terms under almost all financial market conditions. Consequently, those utilities, which can, try to preserve A ratings or better on their bonds. This "A" rating is what OHSC has targeted as the goal of its capital structure policy.

A utility's credit strength and associated bond rating may be improved by increasing its CER and/or by increasing the return it is allowed to achieve on its equity base. Because the regulatory setting of allowed CERs is seen as likely to be subject to less year-to-year adjustment or refinement by the regulators (as opposed to the setting of allowed equity returns), and because higher CERs mean less debt on the utility's balance sheet and higher interest and fixed-charges coverage ratios, and because the achievement of any given level of equity returns is subject to a wide variety of risks, both the rating agencies and the utilities themselves have a preference for targeting the CER and other capital structure proportions to achieve particular bond rating objectives. Consequently, the rating criteria employed by the various bond rating agencies play a significant role in limiting the extent to which a local gas or electricity distributor or gas and electric transmission company can increase the use of debt financing and lower its CER, even if there are favorable tax consequences associated with adopting a more leveraged capital structure.

In general, the expert witnesses appearing for utility applicants in rate hearings frequently stress the need to establish or maintain relatively healthy CERs in order to protect the utility's bond rating and preserve its access to financial markets on reasonable terms to meet its continuing service obligations. Witnesses for those intervenors representing some classes of ratepayers, on the other hand, tend to point to the utility's inherently low level of business risk and, by implication, the low present-expected-value of its financial distress costs, and call for lower deemed CERs and higher preferred-share and debt ratios to take advantage of the tax shielding effects and lower costs of these non-equity forms of financing, with their concomitant savings for current ratepayers.

As just discussed, the choice of capital structure bears on the bond rating of a company. It also bears on the cost of equity of a firm. For non-regulated companies, even if there is absolutely no chance that an increase in debt ratios will cause a firm to go bankrupt or experience any financial distress costs, greater use of financial leverage will still increase the riskiness of the firm's shares, and hence increase its cost of equity capital, by making achieved equity returns more sensitive to fluctuations (from whatever source) in its operating earnings. The market interprets this increased sensitivity as increased volatility and heightened uncertainty about future equity return levels, causing investors to raise their required rates of return for the affected shares. Add to this the fact that, in reality, a firm's bankruptcy riskiness rises, if only marginally, as its debt ratio increases, and one can readily see why the risk-compensating return requirements of common shareholders rise as debt ratios rise and CERs shrink. This is generally referred to as the "financial risk" of a company. In this connection, the prospective risk of the regulated activities of OHSC, at a CER of 40%, will be significantly less than those of Enbridge Consumers Gas and Union Gas Limited—each of which currently operates on the basis of a deemed 35% CER.

The shape and slope of the inverse relationship between CERs and costs of equity capital for *non-regulated industrial* firms is a matter of ongoing debate. Most academics and practitioners agree that it is not a static relationship, but one that changes over time with the state of financial markets and the mood (more formally, the degree of risk aversion) of investors. They would also agree that, in the longer run (encompassing a number of swings in investor enthusiasm and pessimism), it is the level of the corporate and personal income tax rates that primarily determines how costs of equity capital change in response to permanent changes in firms' CERs, at least in the range of CERs over which bankruptcy risk fears are negligible.

Whatever the sensitivity of equity return requirements to changes in CERs for non-regulated companies, the extent of this effect is bound to be muted for *regulated enterprises* by the operation of the regulatory process and by the price inelasticity of demand for the essential services provided by these utilities—especially gas and electricity local distribution companies ("LDCs") or gas and electric transmission companies. When an industrial company experiences a prolonged downturn in the demand for its products, it must generally respond with some combination of price and production cuts that undermine its profitability for the entire period of the downturn. For a rate-regulated LDC or transmitter that experiences the effects of the same economic downturn, however, if it has successfully forecasted this downturn and persuaded the regulator to adjust the user rates for its products accordingly, its earnings may be completely sheltered from the effects of the economic downturn. And even if the downturn is not foreseen, at the next rate review subsequent to the onset of the downturn, the regulated LDC has the opportunity to have its rates adjusted to restore its profitability to the level allowed by the regulator. In other words, the earnings-variability-risk-magnifying effects of increased financial leverage will impact the typical industrial company over the entire downturn, while it will affect the regulated LDC, at most, only until the next adjustment in its user rates.

The key distinction between industrial companies and rate-regulated utilities is that the competitive marketplace sets the total revenues available to the former, while the utility regulator sets the latter's "total revenue requirement," and establishes user rates to achieve this revenue requirement, based on a "bottom up" approach that is designed to enable the utility to achieve an agreed-upon equity return that is largely, itself, independent of market demand conditions.

Reinforcing the above explanation for expecting a more muted response of equity return requirements to changes in utility CERs is the fact that, as compared to industrial firms, utilities are generally exposed to much lower levels of business risk because of their monopoly right franchises and the greater inherent stability in the demands for their services. Financial leverage has the effect of *magnifying* the underlying business risks of an organization. If these business risks are smaller—as in the case of utilities—then the absolute magnitude of the increased risk associated with the use of a particular debt ratio will also be smaller.

The relationship between debt ratios and CERs, on the one hand, and equity return requirements, on the other, for National Energy Board (NEB)-regulated gas transmission pipeline companies was examined in considerable detail during the NEB's Multi-Pipeline Rate Hearing (RH-2-94) in 1994. In its March 1995 decision in RH-2-94, the NEB declined to express an opinion on the sensitivity of pipeline costs of equity to changes in their CERs. During the hearing, however, estimates from expert witnesses ranged from two basis points to 25 basis points for the change in required equity returns for every two-percentage-point change in the allowed CER. In recent Enbridge Consumers Gas and Union Gas Limited rate hearings, expert witnesses have suggested corresponding equity-return sensitivity ranges for gas LDCs of between 15 and 24 basis points for every 2% adjustment in a gas LDC's CER, when such adjustments take place in the neighborhood of CERs of 33% to 40%.

Analytical Models and Empirical Considerations

The following four alternative methods for determining the appropriate cost of equity for a regulated firm are principally used:

- Comparable Earnings Test;
- Discounted Cash Flow Test;
- Capital Asset Pricing Model ; and
- Equity Risk Premium Test.

The CE test compares the rate of return on book equity earned by regulated and unregulated firms of similar risk to the regulated firm under study. The DCF test postulates that the value of a share of stock is the discounted value of all dividends that will accrue to that share of stock. Starting with a "share value" equation, the DCF equation is derived algebraically and is a representation of the rate of return required by the market. In the simple DCF formulation, the cost of equity is represented by a dividend yield and anticipated long-run growth rate for dividends.

The CAPM postulates that investors will only rationally undertake investments in which the prospective return is at least proportional to its systematic risk. In particular, investors will seek a premium return above the prevailing risk-free rate in the economy for those investments that are not free of risk. The premium for any particular investment will be a function of its individual risk profile, which is captured by its "beta coefficient." The ERP is closely related to the CAPM. The ERP test recommends that the cost of equity be found by adding an explicit risk premium to a current risk-free interest rate, usually to the interest rate on government bonds. In many cases, the risk premium is calculated with reference to the premium earned on common stock relative to risk-free assets.

A great deal has been written on the desirability, or lack thereof, of employing the above methods to determine a regulated firm's cost of equity.[1] Generally, all the above models have been evaluated against three general criteria: theoretical, empirical, and practical. The theoretical criterion seeks to determine if a particular method is both logically consistent and consistent with theory. The empirical criterion seeks to evaluate the model's or test's inferred accuracy and

[1] For a thorough discussion see *The Cost of Capital: Estimating the Rate of Return for Public Utilities,* A. Lawrence Kolbe, James A. Read, and George R. Hall, The MIT Press, 1984.

regulatory use, while the practical criterion evaluates an approach relative to the availability and robustness of data and the needs of the regulator. As a practical matter, the practical criterion has often dictated the choice of analytical model or test.

Regardless of which model or test is chosen to determine the appropriate cost of equity for a regulated firm, all approaches rely to some extent on data that is not specific to the regulated firm under study. That is, the cost of equity is determined with reference to broader capital markets and/or data drawn from representative industry samples of firms with comparable business and financial risk. In the latter, the data are culled from publicly available sources and reflect the operational characteristics of similarly situated regulated utilities. In deriving a firm's cost of equity with reference to data for other firms, it is important to ensure that comparability is achieved. Instead, if the analyst is employing an industry average beta in the CAPM, it is important to make sure the business and financial risk inherent in the industry group is comparable with the utility under study. For example, if the business and financial risk of the utility under question vastly exceeds that for the industry proxy group, the resultant cost of equity estimate will be underestimated. The converse is true if the business and financial risk of subject utility is far less than the industry proxy group.

As was discussed, the choice of test or model should be evaluated on theoretical, empirical, and practical grounds. The latter criterion includes an evaluation of the availability and robustness of the data employed in the model. In the present case, the ERP model was chosen as the primary analytical tool, while the CAPM was used to corroborate the ERP results. Conceptually, both approaches are quite similar and, in fact, complement each other. Both approaches estimate the appropriate cost of equity by adding a risk premium to the yield on the risk-free asset. Despite these similarities, there are significant differences in the empirical implementation of these approaches. An overview of each approach and the path taken to implement each is described in detail in Sections V and VI.

The Consultants have not employed the CE approach for estimating an appropriate equity return for OHSC. First, it is widely accepted that the CE approach does not provide a cost of attracting equity capital. More importantly, the OEB has discounted the usefulness of the CE method in recent years for non-publicly traded investor owned utilities, and moved away from reliance on its results, as the OEB has moved to adopt a formulaic approach—based on the ERP test—to establish and adjust gas LDC allowed returns as a precursor to, and input component of, its government-supported, performance-based regulation ("PBR") system. As it is the policy of the OEB and the Ontario Government to promote symmetry of regulatory treatment between the gas and electricity distribution industries, the Consultants believe that it is counter-productive to introduce CE-based evidence for establishing the equity return for OHSC, when the OEB and the major Ontario gas LDCs (with which OHSC competes) will expect consistency and symmetry between the process of establishing OHSC's allowed returns and that applied to the gas distributors. Similar reasoning had dissuaded the Consultants from using the DCF method to estimate the cost of equity for OHSC's regulated operations.

Regulatory Issues

Two regulatory issues need to be addressed before proceeding into the next section, which discusses the business risk of Transco and Disco. The first issue is the OEB's objective of employing a formulaic approach to determine cost of equity for utilities under its jurisdiction. The second is the trade-off between bond ratings and ROE and the overall impact on a utility's revenue requirement.

Both the ERP and CAPM approaches complement each other and the OEB's objective of employing a formulaic return methodology in determining ROE for a forward test-year. In draft guidelines issued in March 1997, the OEB set forth its reasons and objectives for adopting a formulaic ROE approach for gas utilities ("Guidelines on a Formula Based Return on Common Equity for Regulated Utilities").

The OEB identified three reasons for adopting a formulaic approach. The first is the benefit to the hearing process and attendant regulatory costs due to reduced time in the hearing and the elimination of the need for expert consultants. The second is the weight of experience from other Canadian jurisdictions that have reviewed the issue and adopted a formula-based ERP as the method for setting equity returns. The third reason was that a formulaic approach was a first step towards formulaic rate making within the context of performance-based or incentive ratemaking.

Both the ERP and CAPM can be implemented in a formulaic framework and are thus consistent with the OEB's stated goals. The need for a formulaic approach to ROE has certainly been heightened as a result of the OEB's expanded jurisdiction over the electric utilities. Absent a formulaic approach for determining the ROE for the electric utilities, it is the Consultants' opinion that the OEB's resources would simply be overwhelmed if individual hearings were held for each of the hundreds of electric utilities. It would simply not be cost effective.

The second regulatory issue that needs to be addressed here is the trade-off between a regulated utility's bond rating and its ROE and the overall impact on the utility's revenue requirement. Thus far, this report has discussed the need to determine the appropriate cost of equity in light of financial market conditions and the unique business and financial risk of the regulated utility. Clearly, one of the regulator's goals is to maintain the financial integrity of the utility and indeed that is an objective of the OEB Act. However, the regulator must also recognize the impacts on customers of its decision with respect to allowed equity returns.

As was discussed previously, there is a trade-off between the bond rating of a regulated firm and its allowed ROE. For example, in order to support a premium bond rating, the regulator may need to allow a generous ROE. The premium bond rating, of course, allows the utility access to funds at favorable terms. Thus, a premium bond rating serves to lower the prospective borrowing costs of the regulated utility to some extent. However, while future borrowing costs may be reduced, the utility's cost of equity will be higher than otherwise. This results in an overall net increase in the requested weighted average cost of capital and a correspondingly higher revenue requirement for the regulated company. Hence, there is a trade-off that the *regulator* must recognize since it may be beneficial to maintain a slightly lower bond rating if it means the corresponding decrease in the cost of equity serves to lower the overall revenue requirement of the utility. This trade-off is considered in the context of maintaining the financial integrity of the regulated company and facilitating reasonable financial flexibility.

At the beginning of this section, general theoretical guidelines and analytical models were discussed. In both discussions, the need for an evaluation of a regulated firm's business and financial risk was highlighted as an important component in a cost of equity assessment. In the next section, the link between business and financial risk and the appropriate cost of equity for Transco and Disco are discussed.

Section IV. Evaluating the Business and Financial Risk of Transco and Disco

The Role of Business and Financial Risk in Cost of Equity Determinations

Before discussing the business and financial risk inherent both in the electric industry and, specifically, in the operations of Transco and Disco, it is important to understand the role of risk in a cost of equity determination in a more general context. The appropriate ROE of any company regulated or not is predicated on the risk of the enterprise. As described previously, the equity return must be viewed as an opportunity cost. When investors direct their funds to a company, they are foregoing the opportunity to invest those funds elsewhere. If investors are to make their funds available to a particular company, the return they earn on their funds must be commensurate with those earned in other enterprises with comparable risk characteristics. The latter point is key. The return earned on any investment is determined by the risk of that investment relative to other investments. The more/less risky an investment, the higher/lower the return demanded by investors. Thus, an evaluation of Transco's and Disco's risk profiles is a precursor to an analysis of the appropriate ROE.

Risk can be characterized according to type and time horizon. With respect to the latter time dimension , when supplying capital to a firm, an investor assumes short- and long-run risk. The latter risk is related to enterprise viability and the former is related to volatility of returns. Long-run enterprise viability risks are associated with those events or trends that may permanently undermine the capacity of the firm to generate the cash flows necessary to permit the firm's owners to recover their investment and earn a fair return. Hence, long-run risk are characterized as "return of capital risks."

With respect to the *type* of risk, investors are exposed to two types of risks when they purchase a share of common stock. Investors must be concerned with both the financial and business risk of the enterprise. If a firm has no outstanding debt, investors are exposed only to business risk. If a firm finances its operations with both debt and equity, the financial leverage of the firm increases and with it financial risk for investors. The more debt a firm has relative to equity, the higher the financial risk. This results because debt has a prior claim on the firm's earnings and higher debt ratios impart greater volatility to the earnings flowing to the firm's shareholders.

Business risk describes the inherent risk in the operations of the firm and, thus, the uncertainty of future earnings. It is, however, important to distinguish between the mere level of earnings and the volatility of those earnings. It is the latter that is important and critical to an assessment of a firm's business risk. To say that a firm's earnings are expected to become increasingly uncertain is to say the firm's earnings are expected to be volatile. A firm may have little opportunity to achieve extraordinary earnings, but at the same time have little prospect for large unexpected losses. Such a firm's earnings profile would be relatively stable and, thus, its business risk less than that for a firm with an erratic earnings profile.

Business Risk Characteristics of the Electric Industry

Defining business risk by relating it to long-run enterprise viability and uncertainty in earnings is a rather broad definition. Defining business risk of a particular industry can be done with far more specificity. For the electric utility industry, long-run risk is related to the possibility of a sustained decline in the energy commodity flowing through the wires. If this were to happen, the industry would be faced with substantial excess capacity, some of which may be in the form of stranded assets. In an attempt to recover the costs of excess capacity, the industry may attempt to spread these costs across remaining customers. However, this will only serve to weaken the competitive position of the industry and exacerbate the problem of excess capacity.

In the regulated electric utility industry short-run risk (i.e., uncertainty or volatility in earnings) stems primarily from deviations between a firm's allowed revenue requirement and its actual recovered revenues, and from deviations between the revenue requirement and the actual cost of service.

A firm's allowed revenue requirement is based on "test-year" data and consists of a firm's anticipated expenses and recovery (or return on rate base) and of its capital (depreciation). However, the prospective revenue requirement can differ from a regulated utility's actual cost of service. This can result because some of the individual cost elements used to calculate the utility's revenue requirement may change after the revenue requirement has been established, thus creating a difference between the actual cost of service and its *recoverable* revenue requirement.

There can also be differences between the revenue a firm actually earns and its allowed revenue requirement. Normally, when a utility establishes a new revenue requirement, it also establishes a rate structure that will allow it to recover the revenue requirement. The rate structure is predicated on an assumed number of customers and utilization levels for each customer class. As the actual number of customers or utilization levels for those customers diverges from that forecasted, the utility's actual revenues will differ from the revenue requirement.

Differences between a firm's actual revenues and its revenue requirement are caused primarily by forecasting errors associated with the utilization (i.e., overall customer usage). That is, it is difficult to accurately predict a utility's number of customers or the usage of those customers. The consequences are quite straightforward. If, for example, the actual utilization of a utility's assets exceeds that forecasted (e.g., more customers or higher usage for the same number), actual revenue will exceed the revenue requirement (hence, the firm's actual ROE will exceed that allowed). Conversely, if utilization of the assets falls short of that forecasted (fewer customers or lower usage for the same number), actual revenue will be less than the revenue requirement (hence, the firm's actual ROE will be less than that allowed).

Differences between a utility's revenue requirement and its cost of service and deviations between a utility's actual earned revenues and its revenue requirement can compound or offset each other. For example, it may be the case that a firm's actual O&M expenses exceed those reflected in the revenue requirement. This may occur in spite of actual utilization (overall customer usage) being less than, equivalent to, or greater than that forecasted. In the first case, the rise in O&M expense increases the utility's actual cost of service above its revenue requirement. Thus, the utility's actual ROE would be less than its allowed return. However, this would be compounded by the fact that actual utilization was lower than predicted. This is the case because actual sales revenues would fall short of the revenue requirement. Here again, the causal effect would be to reduce the utility's actual ROE below that allowed.

Conversely, if utilization increased above that forecast, the increase in O&M would still increase the utility's cost of service, but this would be offset by the increase in revenues collected by the utility. Thus, overall, the two effects counter-balance each other and might produce a net income equivalent to that commensurate with the utility's allowed ROE.

As the preceding discussion highlights, the principal source of uncertainty in earnings faced by regulated utilities is forecast error. More specifically, for an electric utility (transmitter or distributor), forecast error arises because of variable weather conditions, variable economic conditions, changes in number of customers or customer mix, and changes in energy usage. All of these contribute, in part, to differences between forecast and realized utilization and thus lead to *differences between the allowed revenue requirement and the revenue actually collected*. Unexpected changes in O&M expenses or other cost elements included in the revenue requirement will give rise to *deviations between the revenue requirement and the actual cost of service.*

The inability to forecast weather conditions is by far the greatest source of forecast error and the principal reason why forecast utilization differs from actual, and, hence, why actual collected revenues differ from the allowed revenue requirement.

Fluctuating economic conditions can also give rise to changes in utilization. This is of particular importance for a utility's commercial and industrial load. Declining economic conditions can slow business activity, which leads to lower usage of existing customers and loss of customers.

Utilization can also differ because of changes in the pace of customer additions, changes in the relative energy usage across customer classes, changes in demand-side management ("DSM") and conservation, changes in the conversion of customers from oil and electricity to gas, and the economics of fuel-switching among large "dual-fuel" customers.

Turning to the sources for potential deviations between the actual cost of service and the revenue requirement, the principal reasons underlying such deviations include commodity cost/price risk, O&M expense variability, asset impairments leading to revaluations or write-downs, and capital cost variability. Commodity cost/price risk is common among utilities with a merchant responsibility. For example, many gas utilities purchase natural gas at the wellhead on behalf of their customer and then transport and distribute the gas. The utility is allowed dollar-for-dollar recovery of the gas cost, but must forecast usage and price of the commodity. To the extent forecasted usage and cost differs from actual, a true-up must occur. The utility is, however, at risk if the actual incurred costs are later deemed imprudent.

Utilities must also forecast their future O&M expenses in establishing their revenue requirement. Actual O&M expenses can differ from the forecast because of system damage caused, in part, by ice and wind storms, lightening, and over-heated wires. All such events may demand that the utility increase its O&M activities. Finally, a utility may experience a deviation in some capital cost items such as the cost of capital additions, depreciation, income and other taxes.

Business Risk Characteristics of Transco and Disco

The prospective business risk of Transco and Disco can be evaluated in the same manner just described. That is, one can speak to long-run enterprise risk, and one can also address short-run volatility-in-earnings risk.

Long-run risk, as discussed, is present to the extent one can foresee a sustained and significant decline in electricity consumption. In broad terms, this may be brought on by adverse long-run economic and demographic trends. Alternatively, a sustained decline in electricity consumption may stem from a prolonged deterioration in the competitive position of Transco and Disco.

Prospectively, there does not appear to be a long-run economic or demographic trend that would jeopardize long-run electricity consumption. Canadian real economic growth is expected to be in the range of 2.4-2.9% over the long run, according to KPMG's 1998 "Service of Economic Expectations." There is also no indication that demographic trends within the service areas of Transco and Disco will lead to a prolonged downturn in electricity consumption. This would be evidenced by a significant and sustained decline in population and business activity. The former is not anticipated. The latter is not expected given the robust estimates of economic growth. This is not to say that Transco and Disco will not be faced with commercial and industrial customers closing or moving plants or going bankrupt. However, as customers close plants, move or go bankrupt, other new customers will be locating and opening new plants. That is, the large sizes and diversified operations of Transco and Disco serve to dampen the long-run impacts of plant closures and relocations. For small utilities whose customer base consists of a few very large commercial or industrial customers, this is not the case.

In terms of the long-run viability of electricity and the competitive position of Transco and Disco, there is also no evidence pointing to a sustained decline in electricity consumption. In short, there is no current or foreseeable practical substitute for electric power in many uses and many markets. Open access to, and unshackled competition within, the Ontario marketplace with respect to the generation and marketing of electricity are vital to the economic health of the province and are eventually expected to bring down the delivered price of electric power and encourage greater use of electricity—and, hence, greater demands for its delivery—across Ontario and certainly within Transco's and Disco's service territory. Restructuring Ontario's electricity market is expected to reverse the past trend, which has seen energy-intensive businesses avoid investments in Ontario. The industry will not wither for lack of product, as natural gas, hydro power, fossil fuels, nuclear energy, and wind power are all available for the generation of electricity in Ontario. Thus, rather than suggesting a downturn in electricity consumption, the opposite appears more likely. Electricity stills maintains its monopoly status as an energy input in many sectors. Moreover, prospective market developments will likely encourage the consumption of electricity.

OHSC has pointed to the age and impaired physical condition of parts of its transmission and distribution systems as a long-run business risk in the eyes of potential investors. The Company believes that investors will questions its own asset-valuation estimates in the light of the limited oversight of OHSC's past accounting practices and the lingering effects of the January 1998 ice storm. In the Consultants' view, however, it is inappropriate to ask for a higher return on account of risks attributable to the past management and asset-refurbishment practices of OHSC's predecessor company. With respect to the future, OHSC has put in place an aggressive asset-sustainment program to address the concerns about the physical condition of its assets. If these planned expenditures are not sufficient to restore its systems to the state where there are no more susceptible to physical disruption risk than comparable electric utilities, then OHSC should budget for greater capital expenditures-not ask for a higher allowed return which would set an unjustifiably high precedent for future awards.

With respect to year-to-year volatility in earnings risk, one should first speak to the likelihood of Transco's and Disco's actual cost of service differing from their respective revenue requirements. Second, one must address the potential of Transco's and Disco's actual revenues deviating from their revenue requirements due to differences between actual and forecasted utilization.

As was previously discussed, commodity cost/price risk, O&M expense variability, asset impairment, and capital cost variability can all potentially contribute to deviations between a regulated utility's actual cost of service and its revenue requirement.

Of these items, Transco and Disco will not be exposed to commodity cost/price risk. Prospectively, OHSC will operate only the transmission and distribution business operations of the former vertically integrated Ontario Hydro. A monopoly supply function will continue until markets open and a default obligation will exist thereafter, but will not expose Transco or Disco to commodity cost/price risk. The cost incurred to serve the default customers is likely to be a "smoothed" pass-through. That is, the wholesale market spot price of electricity will be passed through to customers and be trued-up on a regular basis.

As indicated, a utility may experience a deviation in some capital cost items such as the cost of capital additions, depreciation, income and other taxes. Prospectively, it is anticipated that OHSC will be subject to a comparable level of risk for these items as other gas and electric utilities. In most instances, forecast errors in these items are not a significant source of business risk. This is often the case where these costs are uncontrollable and exceptional in nature, where deviations from forecast levels are often absorbed through the application of deferral accounts.

Of the items, Transco and Disco will be subject to O&M expense variability. As discussed, actual O&M expenses can differ from the forecast because of system damage caused, in part, by ice and wind storms, lightening, and over-heated wires. It is expected that Transco and Disco will be subject to the same type of O&M expense variability as any other electric utility situated in a similar climate. As such, the level of business risk arising from O&M expense variability for Transco and Disco should be assumed to be equivalent to other similarly-situated electric utilities.

OHSC has indicated, both in its rate filings and technical conferences, that recent asset evaluations have shown some physical deterioration of the system. Also, in technical conferences OHSC has shown, via graphs, that out of 20 peer utilities, its transmission system has the fifth lowest O&M and capital expense per MW hour-km. Thus, at least its transmission system is operating reasonably efficient in spite of its physical condition. Moreover, OHSC has embarked on an aggressive asset sustainment program. This sustainment program averages $73 million for Disco over the 1999-2000 period and $192 million for Transco for the same period-the latter representing a 58.0% increase over the corresponding 1998 expenditures. The aggressive sustainment program, when combined with a relatively efficient existing system, will serve to dampen O&M expense variability for OHSC and, hence, the business risk it faces. This also holds true for asset impairment risk.

The foregoing discussion highlighted the potential reasons for deviations between Transco's and Disco's actual cost of service and revenue requirement. As indicated, of the three potential sources of forecasting error, Transco and Disco will be subject primarily to O&M expense variability.

The second source of forecast error that must be evaluated are deviations between Transco's and Disco's revenue requirement and actual revenues collected. With regard to this source of forecast error, the evaluation is relatively straightforward and simple. As proposed, Transco and Disco will not be subject to the risk of deviations between actual revenues collected and their respective revenue requirements, as both are *guaranteed their revenue requirement as proposed until the market opens.* This fact, of course, would be less consequential in the absence of future rate reviews. That is, if the cost of equity being set for Transco and Disco were being set for an extended time period (e.g., in excess of ten years), the essentially two years for which the revenue requirement is guaranteed would be less significant. However, it is expected that OHSC will file a new rate case application when the market opens, at which time the issue of ROE will be addressed. At such time, the business risk of Transco and Disco would have to take into account any lack of revenue guarantee.

As proposed by OHSC, both Transco and Disco will receive their approved revenue requirement in 1999 and 2000. The current "bundled" rates in effect will continue until the Ontario market opens in the year 2000. The actual revenue collected by OHSC could actually exceed or fall short of Transco's and Disco's revenue requirement. However, both business units are shielded as the residual amounts will flow through to the other OHSC business units and ultimately be used as an offset to the competitive transition surcharge. As such, Transco and Disco will not be faced with any over/under-recovery of their revenue requirements if the MDC's proposal is implemented. While this is true only for the period until markets are opened, it is nonetheless an important consideration. Furthermore, the MDC has proposed that the connection charge component of Transco's rates will be payable based on forecast demand even if actual demand is less than the forecast. In addition, overrun charges will be applied and collected if the demand proves to be more than the forecast. Thus, if this MDC proposal is accepted this will eliminate an appreciable proportion of revenue risk.

Beyond 2000, it is assumed that Transco and Disco will not be guaranteed their respective revenue requirements. Thus, one must address potential over/under-recovery of the revenue requirement. As discussed previously, the primary sources of forecast error include inability to predict weather conditions, fluctuating economic conditions, and changes in customer additions and mix.

Given that it is the widespread regulatory practice to normalize revenue forecasts for weather, it is expected that weather forecasting errors will likely arise and impact Transco and Disco in ways quite similar to other utilities. Depending on the rate design chosen, in many cases the impacts of weather-related forecasting errors can be mitigated. One such rate design involves instituting a rate structure in which the majority of fixed costs are recovered via a demand charge that is invariant to actual energy throughput. Such a rate design is employed in the U.S. interstate natural gas pipeline market and is termed “straight-fixed-variable.” In all, regardless of rate design chosen, it is not expected that either Transco or Disco will be subject to more weather-related risk relative to other electric utilities in the post-2000 period. Of course, prior to 2000, Transco and Disco will bear no weather-related risk on the revenue side.

As just noted, another source of forecast error is fluctuating economic conditions. Economy-related risks impinge primarily on the industrial and commercial customers of a utility. Unexpected plant closures and temporary shutdowns can, of course, reduce energy consumption in the industrial sector. Similarly, businesses can shut down as the economy slows. During an economy-wide recession, which is not anticipated, Transco and Disco can expect to lose a proportion of their industrial and commercial loads as would be the case with any other electric utility. Thus, Transco and Disco are anticipated to be subjected to a similar risk level as other large utilities of the same size and diversity with respect to fluctuating economic conditions. While sharing similar risk exposure with other electric utilities in a general economic slowdown, Transco and Disco actually possess an inherent risk advantage vis-à-vis other electric utilities during fluctuating economic conditions that are not economy-wide.

The term “fluctuating economy conditions” is not meant to encompass only those events where all sectors of the economy are experiencing a recession. In many cases, one sector of the economy could be enduring a slowdown, while other sectors could be experiencing growth. To the extent an electric utility's industrial and commercial customer base are tied primarily to only a few economic sectors, it will be adversely impacted if those sectors experience a recession. In contrast, a utility whose industrial and commercial customer base is diverse will not be as adversely impacted when only a few sectors begin to experience a slowdown. In fact, as those few sectors begin to experience a slowdown, others may be expanded. Thus, for a utility with an economically diverse customer base, the impact of fluctuating economic conditions will be less consequential. This is precisely the case for Transco and Disco. Both enjoy an extremely large and diverse customer bases. As the economy begins to fluctuate and some sectors experience recession while others experience growth (or at least no recession), both entities will be relatively less adversely affected than smaller, less diverse utilities. It is here that Transco's and Disco's size and diversity provide tangible benefits and a reduction in risk.

Transco's and Disco's size and diversity also serve to minimize forecast error and risk related to changes in utilization that arise due to changes in the pace of customer additions and changes in customer mix. In addition, forecast error can arise because of DSM and conservation efforts. The competitiveness of electricity vis-à-vis other energy sources was previously discussed as an issue related to the long-term viability of OHSC. It also has a bearing here in that some industrial customers have "dual-fuel" capabilities.

Again, due to Transco's and Disco's size and customer base diversity, the impact of changes in the pace of customer additions and changes in the mix of volumes demanded across customer classes is less consequential relative to smaller, less diverse utilities. For example, a utility with a predominately residential customer base will be more adversely impacted with a slowdown in housing construction and the advent of more efficient appliances. In contrast, a large utility with a geographically large residential customer base and an equally large and diverse commercial and industrial base will be less affected. That is, it may be the case that while housing construction is slowing in one region, it may be booming in others. Alternatively, any negative impact felt in the residential sector might be outweighed by robust growth in the number and usage of commercial and industrial customers.

With respect to DSM and conservation and the impact on forecasting error, it is expected that Transco and Disco will be subject to similar risk as other utilities. Finally, in the short run, forecast error can arise because of the actions of dual-fired industrial customers who act on changes in relative energy prices. Generally speaking, the issue of dual-fired customers has more relevance for a gas utility in that its customers can switch from gas to oil. For an electric utility, the ability of its industrial customers to switch its fuel source is less clear. In any case, it is expected that the forecasting error that Transco and Disco will be subject to will be comparable to other utilities with similar industrial loads.

OHSC has indicated that it believes that its business risk is higher than otherwise comparable utilities because it is a new entity to investors without an established track record to point to. This is not a serious concern, in the consultants' view however, because there is no indication that the Ontario Government plans to reduce its 100% ownership of OHSC in the near-future. By the time the Government decides to sell some or all of its stake, OHSC will *have* a track record for investors to examine. Consequently, a premium allowed equity return to compensate for this putative risk factor is not warranted. Nor do the Consultants believe that this will have a material impact on the Company's ability to raise debt financing on reasonable terms in the interim, as the rating agencies will recognize that the organization essentially consists of the same, albeit somewhat reorganized, management and labor force.

In sum, Transco's and Disco's business risk is largely limited to O&M expense variability, which will be mitigated by an aggressive proposed asset sustainment program. Importantly, unlike most electric utilities, Transco and Disco are not expected to be exposed to the business risk that arises when actual collected revenues deviate from the revenue requirement, at least until the market opens. This serves to provide both business units with significant insulation from the business risk exposure of most of North America's electric utilities. Following open access, Transco and Disco will no longer enjoy the revenue guarantee. However, the size and diversity of Transco's and Disco's customer base will shield both entities to a great extent from the forecast error that arises due to fluctuating economic conditions and changes in customer additions and customer mix.

Section V. Estimating the Appropriate Cost of Equity for Transco and Disco: The ERP Approach and Results

The foregoing discussion of business risk provides the proper backdrop for analytically determining the cost of equity for Transco and Disco In this section of the report, the ERP model, comparative measures of overall investment risk, and empirical results are discussed.

The purpose of this section is to determine a just and reasonable ROE in the regulator's consideration for OHSC in 1999 and beyond that is both: (1) based on the ERP test methodology; and (2) consistent with the OEB's recently promulgated formulaic approach to regulating gas utility allowed rates of return. Furthermore, the ERP tests employed here will be specified using comparative Canadian risk, return, and market valuation data. This will promote the consistency of OHSC's regulatory treatment, as compared with Ontario's major gas distribution utilities and other gas and electric utilities across Canada.

The ERP test is designed to implement the *capital attraction standard* of regulatory rate-setting. It is commonly used to estimate the cost of equity capital for utilities and pipeline companies. It focuses on the rate-of-return premium required to attract common equity capital in competition with other investment opportunities available to investors in the marketplace.

Two versions of the ERP test have been used here: one focuses on estimating gas and electric utility ERPs based on historical utility-return and utility-cost-of-equity-capital data; the other gauges gas and electric utility ERPs by risk-adjusting the prospective Canadian market risk premium. The nature, implementation, and results of these two versions of the ERP test are discussed, in turn, in the following two sub-sections of the report.

A. ESTIMATING GAS AND ELECTRIC UTILITY EQUITY RISK PREMIUMS USING HISTORICAL UTILITY-RETURN AND UTILITY-COST-OF-EQUITY-CAPITAL DATA

To implement this version of the ERP test, a sample of six Canadian gas and electric utility companies was selected. These companies are all now publicly-traded, with non-regulated activities that have represented no more than a relatively small part of their overall corporate operations throughout the 1983-1998 period. These firms are:

BC Gas	Nova Scotia Power
Canadian Utilities	Pacific Northern Gas (PNG)
Fortis	TransAlta Corporation

This sample of companies was considered to be the most appropriate, reasonably-sized comparative group of publicly-traded Canadian utilities for the purpose of affording a historical foundation from which OHSC's ERP could be estimated.

For this ERP test based on a sample of gas and electric utilities, the annual ERP values reflect the differences between: (1) the estimated sample-average costs of equity capital, on the one hand; and (2) long-term Government of Canada bond yields, on the other, over approximately the past two business cycles. The design of the structural framework of this test relies on the fundamental relationship among five variables to estimate utility costs of equity capital:

(1) A gas/electric utility's allowed return on common equity ("ROCE");
(2) Its actually-achieved ROCE;
(3) Its cost of equity capital (K_e);
(4) Its investor-determined market-value-to-book-value ("MV/BV") ratio; and
(5) Average industrial MV/BV ratios.

Annual, historical, sample-average data was collected for all of these variables except the inherently-unobservable costs of equity. However, the data that are available can be used to estimate these unobservable sample-average equity capital costs. The model and estimation procedures employed to do this are described in detail in Appendix B. The supporting input data and statistical results are set out there as well.

In general terms, it is postulated that the typical gas/electric utility's MV/BV ratio will deviate, from year to year, above or below its long-run average value in response to some combination of three influences. Specifically, we believe that the typical utility's MV/BV will usually rise above its long-run average value: (a) if and to the extent that its actually-achieved ROCE exceeds its regulatory-allowed ROCE; (b) if and to the extent that its regulatory-allowed ROCE exceeds its bare-bones cost of equity capital; and (c) if and to the extent that general investor enthusiasm or lower interest rates and inflation drive the MV/BV ratios for all stocks (as proxied by a sample of industrial companies) above their long-run average values, or as result of any combination of these factors. Conversely, one would generally expect the typical gas/electric utility's MV/BV ratio to be deflated and to fall below its long-run average level if it under-earns its allowed return, or its allowed return falls short of its true cost of equity capital, or the market prices and MV/BV ratios for stocks in general fall to cyclically-depressed levels, or if any combination of these events occurs.

As described in Appendix B, the relationship outlined above for publicly-traded gas and electric utilities was modeled and used to find the extent to which: (1) over-or-under-earning allowed returns; and (2) the "market effect," as proxied by the average level of industrial MV/BV ratios, has influenced average gas/electric MV/BV ratios over the 1983-1997 period. As one might expect, the "market effect" turns out to be the more dominant of the two factors. Using these results, we then found, for the gas/electric sample, for each year, the portion of the level of the sample-average MV/BV ratio that was left to be accounted for by a combination of: (1) the extent to which the utility-average allowed ROCE differed from the average "bare-bones" cost of equity in each year; and (2) other miscellaneous influences not considered in the model. In technical terms, an "instrumental variable" was created to account for the impact on utility MV/BV ratios attributable to the systematic effect of differences between regulator-determined allowed returns and market-determined, required costs of equity capital. The resulting MV/BV figures—the instrumental variable—can be expected to differ from unity in the same direction as, and to the extent that, allowed gas/electric returns, respectively, exceed or fall short of contemporaneous equity capital costs.

For the final step, the reconstituted annual sample-average MV/BV ratios were used to estimate the corresponding annual costs of equity with the aid of the familiar DCF-based formula for translating market-required equity costs into allowed accounting ROCEs, and vice versa. The sample-average earnings retention ratios required for this DCF formula were also available from the historical data. The estimated, annual, sample-average, gas/electric utility costs of equity capital covering the 1983-1998 period are set out in column 1 on Schedule 11 of Appendix B. These, in turn, are taken from the results reported in the table on page 89 (B-4) of the same appendix.

The intermediate objective of the analysis was to examine whether broad, observable economic data could be used to explain a significant proportion of the historical variation in gas/electric equity costs. Based on the experience of earlier studies, we postulated that: (1) the level of long-term interest rates in the Canadian economy; (2) the level of Canadian inflation; and (3) the relative investment riskiness of the typical gas/electric utility would all likely have some influence on the movements in utility capital costs. Time-series regression analyses were used to test these propositions. The results of this testing for the 1983-1998 period are set out in Schedule 11 of Appendix B. The input data for these analyses are found in Schedule 10 of the same appendix.

The 1983-1998 period was chosen for testing because the post-1982 period was characterized by a lower-risk environment for Canadian gas/electric utilities than the preceding three to five-year period, on account of two reasons. First, the post-1982 period saw lower and less volatile inflation rates than the period from 1980 through 1982. Second, the movement by Canadian regulatory boards in the early 1980s to: (a) more frequent rate reviews; and (b) the use of forward test years had the effect of reducing the risk of regulatory lag and earnings attrition for utility shareholders in the post-1982 era. Consequently, regression tests using data confined to the post-

1982 period will more likely reflect the kind of business risk environment that OHSC can expect to face prospectively than tests based on data that begin at an earlier date.

Overall, the results of the regression testing on gas/electric costs of equity were exceedingly good and encouraging. The top two regression equations shown in Schedules 12 of Appendix B are highly significant, as indicated by their logical signs, high R^2 values, very high F-ratios, and by the highly significant t-statistics associated with the estimated parameter coefficients. Moreover, the Durbin-Watson statistics for these regression equations indicate the absence of any serial correlation in the residual terms, which suggests that there are no important explanatory variables missing from the regression specifications. Unfortunately, the third (bottom) equation on Schedule 12 is unsatisfactory because of the illogical sign associated with the beta risk variable.

The first conclusion to be drawn from these Schedule 12 regression results is that, as one would expect, there is a strong positive relationship between the cost of equity capital for gas and electric utilities and the level of long Canada yields. It appears that the annual sensitivity of their equity costs (up and down) to changing Canada bond yields has been in the range of 66% to 81% over the 1983-1998 period. This finding strongly supports the OEB's move to use a 75% annual change sensitivity factor with its automatic, formula-based, ROE adjustment mechanism (for gas LDC returns) based on long-term Canada bond yields.

A second observation from the results of this time-series study of gas/electric equity costs is that utility risk, as measured by the average standard deviation of investment returns ("STD" or "SD(r)") for the sample of gas/electric utilities, appears to be positively related—as one would expect—to utility equity costs, once the cyclical impact of changing long-term interest rates is accounted for. The statistical significance of this relationship is relatively strong as the coefficient on the STD variable is significant at the 3% level of significance.

A third finding of the regression study is that when the sample-average *beta* variable is used to represent utility risk, the regression-estimated relationship between risk and costs of equity capital is characterized by a counter-intuitive negative sign (as shown in equation 3 on Schedule

12 of Appendix B). This result corresponds with the author's findings in previous years' tests. One would normally expect higher average levels of beta risk to lead to higher average equity costs, and vice versa. The explanation for the disappointing result embodied in equation 3 may lie with the data input values for the beta variable itself. The five-year beta values for the years 1987 through 1991 appear to have been distorted by the effects of the October 1987 stock market crash, which magnified the monthly return volatility of most non-utility shares while impacting the return volatility of gas/electric utility shares very little. On the other hand, the 1987 crash does not appear to have created any noticeable distortion in the time series of SD(r) risk figures, since the latter is an absolute measure of risk, while beta is a relative (to the market) risk measure.

A fourth observation with respect to the regression studies concerns the inflation variable. There are good theoretical reasons to expect a positive relationship between utility equity costs and Consumer Price Index ("CPI") inflation rates over time, and single-variable regression equations (with annual inflation used to explain contemporaneous annual equity costs) strongly confirm such a relationship. Unfortunately, however, the inflation rate is also a major determinant of long Canada bond yields. Consequently, when Canada bond yields and CPI inflation are used together in these regression equations, the very high degree of collinearity between these two variables undermines the reliability and usefulness of the resulting regression models. Consequently, an inflation variable has not been included in the regressions used for estimating OHSC's prospective cost of equity capital.

Overall, then, the Appendix B regression results strongly support the conclusion that: (1) long Canada bond yields; and (2) utility investment-return-volatility risk are the two most important and useful variables for explaining gas/electric utility costs of equity capital over the past 16 years. Logically, then, these same two factors are bound to be good candidates for explaining gas/electric ERPs over the 1983-1998 period.

There are good reasons to expect a cyclical pattern in gas/electric and other utility ERPs. In particular, one would expect to observe an inverse relationship between utility ERPs and the general level of interest rates (as proxied by long Canada yields). In other words, ERPs should tend to be high when rates in general are cyclically low, and tend to be low (and occasionally negative) when rates are cyclically high. Income tax effects are generally considered to play an important role with respect to this inverse relationship in the Canadian context. While bond interest is fully taxable for most investors, portions of the returns to investors in industrial and utility common shares have been sheltered from the full effects of income taxation (e.g., via dividend tax credits and former capital gains exemptions). In addition, an environment of rising interest rates in a time of tight money and rising inflation expectations may also alter investors' perceptions of the relative riskiness of common stocks versus fixed-income securities in a way that contributes to the cyclical pattern of ERPs.

There are other variables, as well, that might be expected to help explain the time path of gas/electric ERPs in Canada. In theory at least, market-determined ERPs are generally interpreted to be the extra investment rate of return required by investors as compensation for the riskiness of their investments. Consequently, one would expect the time path of average gas/electric utility risk to have some impact on the levels of utility-average ERPs over time. To examine this possibility, two possible market-based utility risk proxies—SD(r) and beta—were tested within the framework of the Appendix B regression analyses. In each case, one would expect, a priori, that higher levels of risk would be associated with higher gas/electric ERPs, and vice versa.

The ERP regressions based on data covering the 1983-1998 period are set out in Schedule 13 of Appendix B. The equations in Schedule 13 reveal a strong inverse relationship between gas and electric ERPs and long-term Canada bond yields—as expected based on theoretical reasoning and the experience of past studies. Each of the regression equations is significant in terms of its R^2 ("goodness of fit") and F-ratio values, as well as having a significant t-statistic on the coefficient of the Canada-bond-yield variable. All the Durbin-Watson statistics are also favorable, in the sense of rejecting the possibility of serial correlation in the regression's residual error terms.

For the second (middle) equation in Schedule 13 of Appendix B, the SD(r) risk variable was added to the specification along with long Canada yields. The resulting regression model reveals a statistically significant positive relationship between gas/utility ERPs and average SD(r) risk over time. The one possible shortcoming with the regression that contains the SD(r) risk variable is the high degree of collinearity between the SD(r) variable and the Canada bond yield variable. This collinearity undoubtedly "fuzzies" the estimation of the test statistics to some extent. However, the presence of collinearity does *not* reduce the predictive power of the equation. Furthermore, in this particular situation, where we have no strong theoretical or practical reason to expect a time-series relationship between government bond yields and gas/electric utility riskiness, the presence of collinearity between these two variables does not seriously hamper the interpretation of the regression result. On balance, then, both the top and the middle equations on Schedule 13 are judged to be fully satisfactory for the purposes of the first ERP test, and they have been accorded equal weights in the analysis.

The third (bottom) regression equation in Schedule 13 was constructed to employ sample-average beta values to represent gas/electric utility riskiness in place of the SD(r) measure. The resulting regression model turned out to be unsatisfactory, however, because the estimated coefficient on the beta variable has a counter-intuitive negative sign—indicating that utility ERPs will go down as beta riskiness goes up. (As explained earlier, the 1987 crash-related distortions to utility beta estimates over the 1987-1991 period may be to blame for the poor showing of the beta variable throughout these regression studies.) Because of the counter-intuitive results when the beta variable is incorporated in the regression specification, the third regression on Schedule 13 was not used in the ERP test for determining OHSC's prospective cost of equity.

Based on the just-described analysis of the historical gas/electric risk premium evidence, a number of conclusions can be drawn with respect to the appropriate ERP for the typical Canadian gas/electric utility for the 1999 test year. Based on the evidence in Schedule 5 of Appendix B and an assessment of the prospective overall riskiness of the typical Canadian gas and electric utility company, the Consultants have projected that the average value for the gas/electric SD(r) risk variable will be about 4.375% for the test year. Incorporating this SD(r) risk value, the ERP results for each of the useful Appendix B, Schedule 13 regressions are set out below for a range of possible 1999 average Canada bond yields.

Equity Risk Premiums Derived From Equations In Sch.12 of Appendix B:	Weight	ERP Value At Forecasted 1999 Average Canada Bond Yield of: 5.00%	5.50%	6.00%
Regression (1)	50%	2.48%	2.39%	2.30%
Regression (2)	50%	3.05%	2.88%	2.72%
Weighted Average		2.77%	2.64%	2.51%

The figures in the last row of the table above are the "bare-bones" ERPs appropriate for the typical Canadian gas/electric utility for the range of long Canada bond yields shown. However, the investment riskiness of OHSC's monopoly transmission and distribution operations is judged to be much less than the average riskiness of the six firms in the gas/electric utility sample used to arrive at the above ERP estimates for two reasons.

First, as discussed in an earlier section, the business riskiness of the wires businesses of OHSC is less than that of all the companies in the sample for a variety of reasons. All the sample utilities face the risks associated with their competitive, unregulated affiliated supply and marketing activities—risks that the regulated transmission and local distribution activities of OHSC are shielded from. Three of the four electric utilities in the sample own significant electric generating assets, which present a range of risks in the evolving North American electricity market that OHSC does not have to face. Several of the sample companies operate primarily in geographically isolated and economically disadvantaged areas, which makes theses companies face relatively greater long-run and stranded-asset risks than OHSC. All in all, the author's judgment is that OHSC's lesser business risk exposure relative to that of the firms in the gas/electric sample is such as to warrant a 25-30 basis point downward adjustment from the sample-average ERPs for the purpose of establishing an equitable, risk-adjusted ERP for OHSC.

Second, OHSC proposes that its rates be established on the basis of a 40% deemed CER. This 40% CER is six percentage points greater than the average CER employed by the six utilities in the gas/electric sample and greater than that found at the consolidated corporate level for any of the sample firms (see Schedule 4 in Appendix A). In other words, OHSC's prospective financial risk is much less than that of the comparative group used to establish the initial gas/electric ERP estimates. As a general rule in recent Canadian regulatory proceedings, expert witnesses have estimated that there is a lowering of utility equity capital costs in the range of six to ten basis points for every one percentage point increase in the utility's CER, when such adjustments take place in the neighborhood of CERs of 33% to 40%. This, in turn, means that OHSC's prospectively elevated CER of 40%—relative to the sample-average of 34%—calls for a further downward bare-bones ERP adjustment of 36 to 60 basis points, to recognize OHSC's lower financial risk relative to the sample from which the initial ERP estimates are determined.

Combining the two adjustments described above indicates that OHSC's risk-adjusted, bare-bones ERP—at each prospective long-Canada yield—should be 60 to 90 basis points lower than the sample-average ERP values estimated from the regression study in Schedule 13 of Appendix B. Counter-balancing this to a considerable extent, however, is the fact that the OEB's formula-based ROE methodology calls for an "all-in" ERP figure. In the Consultants' opinion, this requires the addition of a flotation-cost-and-financing-flexibility adjustment in the neighborhood of 50 basis points to the risk-adjusted, "bare-bones" ERP for OHSC. The magnitude of this adjustment is consistent with that recommended by Dr. Cannon and Ms. McShane in the recent Union Gas rates case in E.B.R.O.499.

Therefore, incorporating these relative business and financial risk adjustments as well as the financing-flexibility adjustment, the conclusion, on the basis of this first version of the ERP test, is that OHSC's 1999 test year allowed common equity return should be set to reflect an "all-in" ERP of: 2.37%-2.67% if the Canada bond yield forecast employed is 5.00%; 2.24%-2.54% if the Canada yield forecast is 5.50%; and 2.11%-2.41% if the yield forecast is 6.00%. This pattern of "all-in" ERPs is consistent with the OEB's view that there is an inverse relationship between

ERPs and long Canada yields. **Furthermore, these ERP recommendations imply that OHSC's allowed equity return, at a 40% CER, should be centered around 7.52% if the forecast for long-Canada yields in 1999 is 5.00%; around 7.89% if the forecast is for a 5.50% long Canada yield; and 8.26% if the forecast is for a 6.00% long Canada yield during 1999.**[1]

Readers should not confuse (a) the sensitivity of the OHSC return recommendation to different long-Canada rate assumptions (in this case, reflecting a 74 basis point increase in recommended return for each 100 basis point increase in rate forecast) with (b) the 75% adjustment factor adopted by the OEB for its formulaic ROE-setting mechanism. The former is the sensitivity indicated by the author's ERP regression equations for the purpose of establishing the initial ROE for OHSC; the latter is the sensitivity of allowed ROEs to changes in the forecasted Canada rate from year to year, for the purpose of the OEB's automatic adjustment mechanism.

C. ESTIMATING GAS/ELECTRIC UTILITY EQUITY RISK PREMIUMS BY RISK-ADJUSTING THE MARKET RISK PREMIUM

The second approach used here for gauging an appropriate ERP for OHSC's regulated transmission and distribution operations is based on experienced market risk premiums and on an assessment of the typical, non-diversified gas and electric utilities' investment riskiness relative to the typical TSE 300 stock. Developing the inputs for this approach requires a numerical assessment of three factors, namely:

> (1) The required market risk premium ("MRP"), relative to the long-term Canada rate, expected for the test year;
>
> (2) The investment riskiness of the typical Canadian gas/electric utility relative to the typical firm in the TSE 300 Index; and
>
> (3) The appropriate adjustments to reflect OHSC's relative business and financial riskiness, as well as flotation costs and financing flexibility considerations.

In theory, the "market risk premium" in the Canadian context represents the long-run average rate-of-return compensation that investors require to accept the investment risks associated with the typical TSE 300 share as opposed to investing in a truly risk-free long-term financial asset. At the present time and for the remainder of 1999, the author believes that this theoretical MRP lies in the range of 4.75% to 5.25%, as will be discussed presently. However, when, instead of being based on a truly risk-free asset, the MRP is based on the return on long-term Canada bonds, which are *not* risk-free but rather subject to considerable price-volatility risk (or capital-value risk) over time, then the theoretical MRP range must be reduced by the estimated maturity risk premium imbedded in long Canada yields (discussed below) to arrive at the relevant MRP for use with the OEB's formula-based ROE approach to establishing allowed returns. Making this adjustment, the basis for our estimate of OHSC's test year ERP is the MRP range from 4.0% to 4.4%.

A consideration of the "maturity risk premium" is the basis for the adjustment of the MRP. While long-term Canada bonds are free of default risk, they are subject to a great deal of price-volatility risk as interest rates fluctuate over time. Consequently, long-term Canada yields incorporate a "maturity risk premium," or "capital value risk premium," or "term premium," to compensate investors for this element of investment risk. Over the period from 1926 to 1993, the maturity risk premium in the United States averaged 130 basis points. The corresponding experienced maturity risk premiums for long Canada bonds over various historical periods are set out in the table below:

	Average Return On Long-Term Canada Bonds	Average Return On Canadian 91-Day Treasury Bills	Average Experienced Maturity Risk Premium
	%	%	%
1958-97 (40 years)	7.99	7.43	0.56
1963-97 (35 years)	8.91	8.00	0.91
1968-97 (30 years)	10.05	8.65	1.40
1973-97 (25 years)	10.84	9.29	1.55

For an unbiased estimate of the historical maturity risk premium, the time period chosen should be one where the average level of long-term interest rates is approximately the same at the beginning and end of the period. Long-term Canada bond yields averaged 5.50% during 1998 and are about ten basis points lower than this presently. We have to go back to the 1965-66 period (with an average yield of 5.47%) to find long Canada yields as low as this. Consequently, the most appropriate of the above time periods to use for estimating the historical maturity risk premium is the average of the 30-year (1968-to-1997), and 35-year (1963-1997) periods, which indicates an average risk premium of about 115 basis points (midway between 91 and 140 bps)—somewhat lower than the corresponding long-run U.S. value.

The underlying maturity risk premium tends to vary over the interest rate cycle. It tends to be lowest when rates in general are at their cyclical peaks and expected to fall, or when buying long-term bonds is perceived to be least risky. It is highest when interest rates are near their cyclical lows and expected to spike upwards, or when long-term bonds are perceived to embody the greatest amount of investment risk. Consequently, keeping in mind the historical evidence and considering the present stage in the Canadian interest rate cycle and the dormancy of inflation fears—where investing in long-term bonds is not currently perceived to be particularly risky—it is judged that the maturity risk premium for long-term Canada bonds is likely to be about 75 to 85 basis points.

Many empirical studies have used a time-series of short-term treasury bill returns as a proxy for the risk-free rate. Schedule 3 in Appendix A shows the year-by-year rates of investment return experienced by investors who invested in: (1) Canadian treasury bills; and (2) the typical TSE 300 stock in the period since 1957 (as compiled by ScotiaMcLeod Inc.), as well as the experienced market-average equity risk premium for each year gauged relative to treasury bill returns (i.e., the "theoretical" MRP). The average experienced rates of return and MRPs for various time periods are set out at the bottom of Schedule 3. For the longest period (40 years), the compound average MRP was 3.52% per annum (or 4.54% on an arithmetic average basis), while the average MRPs were generally smaller for shorter averaging periods.

To translate these theoretical MRPs into MRPs based on long-term Canada bonds, it is necessary, as explained above, to subtract the prospective maturity risk premium, which is estimated to be in the neighborhood of 80 basis points. The resulting 40-year-average MRPs relative to long Canada rates are 2.7% and 3.7%, respectively. (Note that if we had simply taken the difference between historical TSE 300 returns and experienced long-term Canada bond returns, the geometric average and arithmetic average historical MRPs would have been 2.12% and 3.46%, respectively.)

While some previous Canadian and U.S. studies would indicate that the ERP for the average Canadian stock must be somewhat above the 3.7%-and-lower range indicated by the historical data in Schedule 3 (once this data is adjusted for the maturity risk premium), there are several factors, in addition to the direct Canadian evidence, that suggest that the prospective MRP may not be much above 3.7%.

First, it is important to note that periods when average stock market valuations are "high" (e.g., relative to prospective earnings), such as in the current market environment, these periods are generally characterized by investor optimism and lower-than-average market risk premiums, while periods of “low” stock valuations are often associated with investor pessimism and higher market risk premiums.

Second, a number of studies and commentaries have pointed to the fact that the volatilities in the returns on Canadian and U.S. government debt securities have risen in recent years (relative to earlier periods) in comparison with the return volatility on the typical competing stock market investment. This development has been especially pronounced in Canada. As the riskiness of investing in long-term government bonds rises relative to the riskiness of investing in common stocks and, hence, the risk differential between these two markets narrows, the MRP—representing the expected compensation for this risk differential—declines. The figures in the table below show that the volatility in the returns in the long Canada bond market have been growing relative to the TSE 300 return volatility over the past 15 years.

Time Period	Standard Deviation of Annual TSE 300 Returns	Standard Deviation of Annual Long Canada Bond Returns	Relative Volatility of Long Canada Bond Returns Versus TSE 300 Stock Returns
(column)	(1)	(2)	(3 = 2 ÷ 1)
	%	%	%
1983-1992	13.89	7.78	56.0
1984-1993	13.37	8.08	60.5
1985-1994	13.18	11.69	88.7
1986-1995	12.33	12.31	99.8
1987-1996	13.63	12.23	89.7
1988-1997	13.57	11.75	86.6

Having considered of all the above-noted evidence and our own views regarding current market conditions, we concluded that the prospective MRP (relative to long Canada yields) would best be reflected by the range of 4.0% to 4.4%.

We now turn to an assessment of the overall investment riskiness of the typical Canadian gas/electric utility, as reflected in our six-firm sample, as compared with the typical firm in the TSE 300 Index. Considering all aspects of investment risk, we believe that the typical Canadian gas/electric utility company is no more than 50% as risky as the typical TSE 300 company. To arrive at this figure, we examined the recent investment risk data for our sample of publicly-traded, Canadian gas and electric utilities, as set out in Schedule 4 of Appendix B and summarized below.

	Common Share Beta Value 1994-1998	Standard Deviation of Investment Return 1994-1998
Typical TSE 300 Stock (As represented by the average of all firms in the TSE 300 Index)	1.00	12.35%
Gas/Electric Utility Sample	.528	4.37%
(As a % of Typical TSE 300 Share)	(53%)	(35%)

These quantitative risk measures show clearly that the typical Canadian gas/electric utility is only 35% to 53% as risky as the typical TSE 300 company. Consequently, based on the numerical findings and conclusions to this point—namely, the judgments that the prospective MRP lies in the range of 4.0% to 4.4% and that the required risk compensation for the typical gas/electric utility is bound to be no more than 50% of the market average—we conclude that the required "bare-bones" ERP—relative to the long-term Canada rate—for the typical gas/electric utility lies between 2.00% and 2.20%.

As with our first ERP test, it is necessary to make adjustments to this sample-average ERP finding to reflect OHSC's relatively lower business and financial risks, which we earlier estimated to total between 60 and 90 basis points in a downward direction, and to recognize flotation-cost and financing-flexibility considerations, a 50-basis point upward adjustment. Consequently, the prospective "all-in" ERP range for OHSC indicated using the MRP-based approach to ERP estimation is 1.60% to 2.10%. **This, in turn, points to an allowed equity return for OHSC no greater than 7.60% at a forecast long-Canada yield of 5.50%, or 8.10% at a forecasted average Canada yield of 6.00% for 1999.**

D. PRESERVATION OF OHSC'S FINANCIAL INTEGRITY ON A STAND-ALONE BASIS

The question arises as to whether an allowed ROE in the range of 8.00% to 8.25% will be sufficient to preserve OHSC's "financial integrity" over the 1999-2000 period. The OHSC has associated the preservation of its financial integrity with the maintenance of an A rating on its outstanding and newly-issued debt, were it to be operating on a stand-alone basis and competing for financing in the capital markets.

As shown in Schedule 5 of Appendix A, if the debt/equity proportions financing OHSC's rate base are 60%/40%, then the prospective before-tax interest coverage ratios ("ICRs") for both its regulated transmission and distribution components will be 2.235 times and 2.274 times, respectively, if its allowed and achieved equity returns are 8.00% and 8.25%. These ICR figures are based on assumptions consistent with those in OHSC's rate application, namely an average cost of debt of 7.8% over the 1999-2000 period and a marginal income tax rate of 44.62%.

The Consultants have recently had extensive discussions with the two major Canadian bond rating agencies and with the credit rating/evaluation department of a major, institutional, fixed-income investor. All of these sources assured the Consultants that an Ontario-based, regulated, monopoly electricity distribution company with no generating assets, but possessing the following characteristics, would be accorded an A to A(high) bond rating. The electricity distributor characteristics on which their assessments were based are as follows:

Rate base assets in excess of $1,000 million;

Common equity in excess of $350 million;

A deemed common equity ratio of 35%;

A deemed debt ratio of 65%; and

A pro forma ICR of 2.28 times.

For both the transmission and distribution components of OHSC, the projected rate base assets for 1999-2000 are at least 2.5 times as great as the corresponding parameter considered by the bond raters, and their equity capital amounts are both at least 3.0 times as large. The proposed deemed common ratios, at 40%, are higher than those considered by the bond raters, and the debt ratios, at 60%, are lower than those considered in the raters' evaluations. Finally, the pro forma ICRs for each of OHSC's regulated components, with allowed ROEs in the 8.00%-8.25% range, are very similar to those considered by the bond raters. It is clear, as a consequence, that both of the regulated components of OHSC possess an overall credit strength that is superior to that which those responsible for setting and evaluating utility bond ratings considered sufficient to warrant an A to A(high) bond rating.

OHSC has indicated that it may eventually want to issue debt in the United States, and, therefore, the ratings accorded to its debt by the S&P rating agency are important to it from the perspective of ensuring its access to U.S. debt markets. Ms. McShane, OHSC's financial advisor has indicated that the S&P rating criteria are "more stringent than the CBRS guidelines." To investigate whether OHSC would likely receive an "A" rating from the S&P organization with equity returns in the 8.00%-8.25% range, the Consultants requested the credit assessment department of a major Canadian institutional bond investor to apply its assessment techniques (which are specifically geared to the S&P ratings to OHSC's prospective situation). The technique was applied to OHSC's Disco and Transco operations using the projected 1999 balance sheet and revenue/income statement figures set out in the respective applications of Disco and Transco, adjusting the projections, as appropriate, to reflect an 8.00% equity return. At a 40% CER and an 8.00% equity return, the credit assessment model employed by this major institutional investor showed that Disco would likely receive an "A" S&P rating (the same rating as CBRS accords to Enbridge Consumers Gas), and its equity would achieve a market to book ("MV/BV") ratio of 1.80 times. Transco would achieve an "A-" rating on the S&P scale, and its equity would be valued in the marketplace at 1.38 times its book value.

It is important to recognize that this assessment model assumed that Disco's and Transco's business riskiness was comparable to that of a typical, equally-large, vertically integrated North American electric utility with the latter's riskier generation component. Consequently, given that Disco and Transco face no generation-asset risk, the S&P rating for Transco's debt (with Transco allowed an 8.00% equity return) would likely be higher than "A-". In any case, an "A-" or "A(low)" rating, which is the same as the rating which CBRS attaches to

Union Gas' debentures, is sufficient to assure Transco's access to both Canadian and U.S. debt markets under almost all financial market conditions. In the Consultants' opinion, it is unnecessary and perhaps inimical to the best interests of OHSC's ratepayers and the Ontario economy for either Disco or Transco to target a bond rating above "A-" or "A(low)" *unless* that rating can be achieved with an allowed equity return that is commensurate with the business and financial risk exposure of these regulated entities.

On the basis of these investigations, then, it is the Consultants' strong opinion, considering OHSC's large size, its low business risk, and its more-than-ample 40% common equity ratio, that: (1) OHSC's financial integrity on a stand-alone basis, as well as (2) an A rating or better for its debt will be assured if the OEB allows OHSC's regulated transmission and distribution businesses to earn equity returns in the 8.00%-8.25% range.

Section VI. Estimating the Appropriate Cost of Equity for Transco and Disco: The CAPM Approach and Results

In this section of the report, the CAPM and empirical results are discussed. The results presented here are then compared with the equity returns for a broader group of utilities.

The CAPM Approach and Results

For the current study, the CAPM was chosen as a means to corroborate the results in the preceding section. The CAPM presented here is a variant of the model employed in subsection C of the previous section. The model in this section employs a slightly different set of data and relies on business risk comparisons with a broad set of U.S. electric utilities. Consequently, the results presented here are meant to broaden the analysis of the appropriate equity return for Transco and Disco and, thus, are meant to corroborate the findings in the preceding section.

The CAPM is based on the principles discussed earlier. The principles highlight the need to compare the rate of return a regulated utility is allowed against those rates being earned by business in general. In particular, it is not necessary (and can be, in fact, circular) to confine the comparison to other regulated utilities. Going beyond regulated utilities to unregulated businesses to form a comparison group is accepted because regulated utilities must compete with these unregulated firms for access to capital.

The CAPM postulates that investors will only rationally undertake investments in which the expected return is at least proportional to the risk. In particular, investors will seek a premium above the prevailing risk-free rate in the economy for those investments that are not free of risk. The premium for any particular investment will be a function of its individual risk profile, which is captured by its beta coefficient. This CAPM principle is captured by the following mathematical equation:

$$R = R_f + \beta*(\text{equity risk premium})$$

where:

R	=return to equity;
R_f	=risk-free rate; and
b	=beta coefficient.

The beta coefficient is an indicator of the relative risk of a particular stock (investment) to the market as a whole. For example, a stock with a beta coefficient of one can be expected to "move" with the market and thus mimic the risk inherent in the stock market as a whole. Stocks with betas above (below) one are more (less) risky relative to market risk.

The risk-free rate of return is simply that return which can be achieved without accepting any risk. Government bond yields, for example, can serve as a proxy for the risk-free rate of return for investors with long-term holding periods. As investors are exposed to risk above that inherent in government bonds (zero risk) they demand a premium to compensate them for such risk.

The equity risk premium is the premium above the risk-free rate that investors require to hold common stocks. It is a forward-looking premium that represents the additional return investors require over that for risk-free investments.

The risk premium, however, is not directly observable because the actual return expected on common stocks is not observable. The usual method used to calculate the equity risk premium is to calculate the rates of return actually realized by investors and to subtract that earned on safe investments. The justification of this method stems from the assumption that over the long run, rates of return actually realized will be equivalent to expected returns.

General Results: Both Transco and Disco

As was discussed, for the CAPM three pieces of information are needed to estimate an equity return. These include the current return on a "risk-free" security, a company-specific beta, and an equity risk premium.

For the risk-free return, the average yield earned on 10- and 30-year Canadian bonds for the latest 12 months was employed. The beta for the equation was selected with reference to those of U.S. electric utilities. Finally, the Canadian equity risk premium was calculated as the difference between the total return to common stocks and the investment return on long-term government bonds over the last 40 years.

With respect to the Canadian risk premium, the premium was calculated by subtracting the long-term arithmetic average of the yield on the riskless asset from the long-term arithmetic average total stock market return. The riskless asset was represented by the investment return on a long-term government bond. For the 1957-1997 period, such data was derived from the International Monetary Fund International Financial Statistics.

The total return to common stock was calculated with reference to the Toronto Stock Exchange 300 for the period 1957-1997.

As indicated, the beta employed in the CAPM equation was derived with reference to the betas for U.S. electric utilities. The sample chosen and betas for each of the utilities are included on Table 1 (page 51). The sample included 20 electric utilities with different sizes, capitalizations, and operating environments. The sample was not selected as a means to precisely select a group of utilities with identical business and financial risk. Rather, the sample provides a useful benchmark that represents utilities with more, and in some cases less, business risk than either Transco or Disco. Thus, the sample more or less "bounds" the measure of risk for both Transco and Disco. That is, absent sufficient information indicating otherwise, it can be assumed that the business risk profile of Transco and Disco falls somewhere in the middle of the sample.

Indeed, there is ample evidence that the beta for Transco and Disco does not lie above the betas shown in Table 1. This is so because some (perhaps most) of the utilities included in Table 1 have electric generation business units. Thus, the betas reported for these companies reflect not only the business risk of transmission and distribution, but also the risk of generation. There is general agreement that the business risk of the latter activity exceeds that of distribution and transmission. Therefore, if the risk component associated with generation were removed from the betas reported, the reported betas for the sample would decrease. Accordingly, the beta applied to Transco and Disco would be less.[2]

With regard to capital structure, OHSC has proposed a 40%(equity)/60%(debt) structure for determining its overall cost of capital. A review of Table 1 reveals that the proposed capital structure is comparable to the average for the sample group of utilities, although it is slightly more leveraged. As shown, the average capital structure of the sample is approximately 50%. Generally, this would justify an upwards adjustment to the beta applied to Transco and Disco. However, as cited earlier, the betas reported for the sample reflect the risk of all business units of the sample, including electric generation, which is normally considered higher risk. Thus, whatever adjustment is made to reflect differences in financial leverage would be offset by a corresponding adjustment to exclude the effect of risk in electric generation on the reported betas. As such, no adjustment was made, and instead the average beta for the sample was applied directly to Transco and Disco.

The general results for both Transco and Disco are provided on Table 2 immediately following Table 1. Table 2 provides the data for the current return on a “risk-free” security, the beta, and equity risk premium.

[2] See the article of David Wagener referenced in the discussion of differences in risk between Transco and Disco for a discussion of beta differentials between various utility business segments.

[insert Table 1

[insert Table 2]

As shown in Table 2, application of the CAPM results in a cost of equity of 7.62%.

The results here were termed "general" in that they applied both to Transco and Disco. The natural question is whether such dual application is appropriate. More specifically, the question that must be addressed is whether the business risk of Transco differs measurably from Disco. To the extent that the business risk of the two business units is comparable, the CAPM estimate of 7.62% is applicable to both.

At this point, it is difficult to say anything definitive about differences in business risk between Transco and Disco. The Ontario market is not yet open, and, thus, it is difficult to conjecture about the relative risks of electric transmission and distribution. Until the market opens, Transco and Disco will operate in a somewhat integrated fashion with both business units experiencing similar levels of business risk. As the market opens, this could indeed change. Unfortunately, at this point, it is difficult to tell.

While it is difficult to speak to specific differences in business risk between Transco and Disco, it is possible to say something generally about differences in risk between electric transmission and distribution. Indeed, differences in business risk between electric distribution and transmission have been addressed before. For example, in a February 15, 1995 article in *Public Utilities Fortnightly,* "Letting Go of Electric Generation," David Wagener sought to determine whether generation, as opposed to distribution and transmission, operations should carry a higher ROE. The goal of his analysis was to measure the riskiness of the three business operations of a vertically integrated electric utility. As a proxy for risk of each segment, he compared betas for independent power, gas transmission, and gas distribution. The betas for each of these business enterprises were meant to measure the business risk for electric generation, transmission, and distribution, respectively. Analogies to the gas industry and independent power industries were employed because at the time (and, by and large, still true), betas were not reported for "pure" generation, transmission, and distribution companies.

A similar approach as that above was employed to speak to the issue of differences in business risk between transmission and distribution generally and, thus, to the need to provide specific cost of equity estimates for Transco and Disco. Included in Table 3 (page 55) are the betas for a group of 22 U.S. gas utilities whose primary business is gas distribution. As shown in the table, the average beta for the group was .65. This average beta is quite close to the average beta of .61 calculated for the group of U.S. electric utilities shown in Table 1. The data in Table 3 indicates little difference in business risk for the gas distribution companies relative to the electric utilities included in Table 1. While not a definitive statement regarding precise differences in business risk between electric transmission and distribution, the data at least point to a lack of clear evidence that such a distinction must be drawn. As such, there is no compelling evidence to suggest the CAPM point estimate of 7.62% is not appropriate for both Transco and Disco.

In comparison with the ERP results presented in the previous section, it is clear that the CAPM results here are generally consistent with the earlier ERP findings. To the extent that there are differences in the results, these can be traced primarily to: (1) the differences in the comparative samples used for risk estimation (U.S. companies for the CAPM test and Canadian gas/electrics for the earlier ERP work); (2) differences in the construction or source of the beta estimates themselves (Value Line "adjusted" price betas, in the case of the CAPM analysis, and directly-calculated, rate-of-return-based betas, in the case of the ERP studies); and (3) the interpretation of the "risk-free asset" for purposes of estimating the "market risk premium" (long-term government bonds for the CAPM and long-term bonds stripped of the "maturity risk premium" for the ERP tests). The choice between the alternate approaches to implementing these tests is a matter of professional judgment.

[Insert Table 3]

Validity of the CAPM estimate

In any exercise such as this, it is useful to compare or benchmark an analytical result with some other objective standard. In this section, the CAPM estimate for Transco and Disco is compared with CAPM estimates for U.S. electric utilities.

As a basis of comparison, 50 firms engaged in the generation, transmission, and/or distribution of electric energy for sale were sampled. The firms included in the sample and overview data on sales and capital structure are included in Table 4 (page 57). Also included in Table 4 are the CAPM results for various segments of the sample. As shown in Table 4, the CAPM results for the sample range from 7.40% (25^{th} percentile) to 8.97% (75^{th} percentile). The industry composite cost of equity is 7.89% and the large company composite is 7.65%. These values coincide quite closely with the estimate of 7.62% provided here for Transco and Disco.

In the previous discussion of the application of the CAPM to Transco and Disco, comparisons were made between the proposed capital structure of these two entities and that of the sample. Another comparison can be made between the bond ratings of the comparative group above and that desired for Transco and Disco. OHSC's financial advisor has indicated in her letter that "the financial structure that is proposed is intended to allow the company to attract capital on a stand alone basis, with financial parameters that would permit an investor-owned utility to achieve a debt rating of single A." A distribution of the bond ratings for the comparative group is also provided in Table 4. As shown on page 3 of Table 4, almost half of the utilities have S&P debt ratings of A,AA or AAA.

[INSERT TABLE 4-page1]

[INSERT TABLE 4-page2]

[INSERT TABLE 4-page3]

Section VII. Comparison of Recommended Cost of Equity With Allowed Returns for Ontario Gas Utilities

Additional evidence regarding the appropriateness of the Consultant's recommended return allowance for Tranco and Disco can be found by referencing the allowed returns for the major gas distribution companies in Ontario. Currently, gas utilities subject to the OEB's jurisdiction are allowed a return on common equity of approximately 9.5% to 9.6% (specifically, Enbridge Consumers Gas, 9.51% effective October 1, 1998; Union Gas, 9.61% effective January 1, 1999). Moreover, these two large gas utilities have regulatory capital structures with 35% common equity and 65% fixed-income senior securities (the vast majority of which are debt). Thus, if adjusted to reflect the debt and equity levels proposed by OHSC and the inherently lower business risk of OHSC's regulated operations, the resulting cost of equity would be considerably lower for these two companies, as discussed in the principles section of this report and in connection with the ERP test.

Additional evidence regarding the relative risk of gas and electric utilities is discussed in Section V, where the ERP approach and results are documented. The conclusion of that section is clearly that a high degree of comparability does, in fact, exist between similar-sized electric and gas utilities in Ontario. For a more detailed discussion of the relative business risk of these two industries, see Appendix C. In sum, the conclusions drawn in the body of this report and those contained in Appendix C are that comparability exists. This finding, along with the recognition that Transco and Disco face much less business risk than the average electric utility in Ontario, support the recommendation of this report in comparison with recent allowed returns for gas utilities in Ontario.

Section VIII. A Commentary on the Report Issued by OHSC's Financial Advisor

Subsequent to filing both rate applications, OHSC submitted a report by its financial advisor, Ms. Kathleen McShane, which presented and discussed the rationale and data underlying the advisor's recommendations. In this section of the report, the Consultants provide a brief commentary on the advisor's report. Specifically, this section comments on Ms. McShane's discussion of business and regulatory risk and her use of the use of various analytical models to determine the cost of equity for Transco and Disco.

Business and Regulatory Risk

In her report, Ms. McShane starts by identifying short- and long-run risks generally and then subsequently identifying specific business risks faced by OHSC. Among the long-term risks she identifies are economic and demographic trends and competitive trends. Among the short-term risks are regulatory framework, rate design, weather, competition, economic conditions and conservation. Thus, to substantial degree, the general risks identified by Ms. McShane correspond to those identified in this report. With respect to specific business risks she cites: rate structure, PBR, high capital needs, asset condition, and proposals put forth by the Market Design Committee ("MDC") as contributors to business risk.

With respect to long-run trends, Ms. McShane begins by citing "robust" economic growth forecasts generated in 1997 ranging from 2.5%-3.0%. She then cites November 1998 consensus "mean" forecasts for GDP growth of 2.0% for 1999 and 2.3% for 2000. She then recites a number of reasons why these forecasts may be off the mark and concludes by saying "there is significant risk that economic growth in both countries may fall short of projections in 1999/2000." Presumably, the forecasting sources she relies on have already factored in some of the alleged impediments to growth she recites. Aside from the fact that forecasters have already factored these reasons into their projections (and, based on their forecasts, down played the risk), it is not clear why Ms. McShane concentrated on the 1999/2000 time horizon. She has made it clear that from the "perspective of an investor with a long-term horizon, the risks specific to 1999/2000 are over-shadowed by the operating/regulatory environment that will accompany open access (post-2000) when the consensus forecast calls for real economic growth in the range of 2.4% to 2.9% in the long run.

Ms. McShane does not discuss any adverse demographic or competitive trends. Thus, it must be assumed that there are no material developments on the horizon to negatively impact the long-run risk of OHSC.

Turning to short-run business risk, Ms. McShane, as noted above, discusses rate structure, capital needs and condition, PBR, and MDC proposals. She notes that OHSC's rates will be demand-based. It is not clear why that this rate structure would expose OHSC to more risk relative to comparable utilities. In addition, as discussed in this report, to the extent those demand charges recover the majority of fixed costs and are invariant to throughput, this is actually advantageous. In that part of her discussion, she also briefly notes that a 3.0% swing in revenues due to a combination of weather and economic factors reduces earned ROE by 1.0%. However, she does not provide any discussion as to the means whereby changes in weather and economic conditions translate into a revenue swing. Assuming that such a swing is possible, presumably Ms. McShane would not disagree that such a swing can just as easily give rise to a 1.0% *increase* in ROE. Nor does Ms. McShane discuss how this is different from peer utilities.

Ms. McShane has suggested that PBR programs subject a utility to greater risk than cost-of-service regulation. In addition, she has indicated that the IMO will be given significant control over system reliability. Thus, OHSC's control over transmission O&M expenditures and capital expenditures and additions is reduced, which creates a risk that the company will not achieve the proposed productivity factors that lie at the heart of the PBR program. Ms. McShane's findings here are perplexing on a number of counts. First, while PBR programs, and all other types of incentive ratemaking, expose a utility to additional risk, they also expose the utility to *more reward*. It is disingenuous for a utility to argue for the implementation of a incentive mechanism on the one hand while arguing for an increase in its cost of equity on the other because of the increased risk it faces as a result of the PBR. The Consultants know of no regulatory commission that has increased a utility's cost of equity due to the implementation of an incentive ratemaking program. Second, Ms. McShane's comments regarding OHSC's reduced control over transmission O&M expenditures and capital expenditures and additions contradict entirely the rationale underlying incentive ratemaking. Incentive ratemaking, including PBRs, is premised on the recognition that incentives should be placed on items *under the control* of the utility. Absent control of costs, incentive ratemaking is entirely *inappropriate*. Moreover, the PBR recognizes the IMO control and provides incentives based on what is/is not under OHSC control.

Ms. McShane has also noted the physical condition of the company's assets as a source of risk. In this report this issue is also discussed. As discussed, the company itself has signalled its relatively efficient operations as evidenced by a relatively low O&M expense ratio as compared to other utilities. In addition, as discussed, but ignored by Ms. McShane, the company is about to undertake an aggressive asset sustainment program. The company has proposed to increase its capital sustainment investment in 1999-2000 by 29.0%-to $265 million per year-as compared to the corresponding expenditures during 1998.

Finally, Ms. McShane attempts to predict the demise of certain MDC proposals, which she believes will adversely impact the company if not accepted by the government. Specifically, she does not believe the MDC's proposal regarding transmission charges for self-generation and postage stamp rates will be upheld. It is simply not possible to predict the outcome of the various proposals. Notwithstanding the Board's final judgment with respect to these proposals, Ms. McShane has not shown the nexus between these proposals and a definitive increase in OHSC's business risk.

With respect to regulatory risk, Ms. McShane's comments are equally troubling. Ms. McShane argues, on behalf of OHSC, that OHSC's business risk is elevated in part because "the proposed institutional/regulatory setting is untested," i.e., the OEB will be regulating OHSC in the post-2000 period. However, OHSC's sole owner—the Ontario Government—is the body that legislated that the OEB should regulate the monopoly "wires" businesses of OHSC. Recognizing this, it is both specious and self-serving for OHSC, on behalf of its shareholder, to turn around and suggest that OHSC should have a "thicker" equity base *and* a higher allowed equity return than inherently-riskier gas utilities like Enbridge Consumers Gas and Union Gas, which face the same regulatory risks as OHSC anticipates for itself. Moreover, the request is flagrantly counter-productive to the Ontario Government's goal to reduce the delivered cost of electricity in the province and encourage job growth.

Ms. McShane's Comparable Earnings Test

The reliability and usefulness of the CET evidence provided by Ms. McShane is seriously undermined by the obvious bias associated with her sample selection procedures. She uses the coefficient of variation as a prominent component of her sample selection technique. Once she has pared her universe of industrials down to 40 companies (as described on page B-3 of her evidence), she uses the coefficient of variation of book-equity returns (i.e., CV(ROCE)) and the coefficient of variation of EBIT as two of her final four risk-ranking, <u>sample-selection</u> <u>criteria</u>. In doing so, Ms. McShane imparts a significant upward bias to her CET results, since legitimately low-risk industrials which nevertheless experience a significant decline in earnings for whatever reason, will tend to be weeded out of her sample as it is revised from year to year. This happens because, even if the absolute volatility of their profit streams remains unchanged, as the average earnings of these low-risk firms decline, their CV(ROCE) values automatically rise. As a consequence, the selection procedure Ms. McShane employs tends to exclude highly volatile firms (as it should) <u>and also</u> low-earning, low-risk firms (which, we submit, it should not exclude in the context of the "fairness-based" Comparable Earnings test).

Another area of dispute is Ms. McShane's use of a sample of 7 Canadian industrial firms on page B-5 of her report. Ms. McShane relies on Value Line earnings projections for these 7 Canadian firms to support her conclusion that prospective equity returns for low-risk Canadian industrials will be as high as 11.75%. The sample of only 7 firms is suspect since the reason(s) for <u>Value Line's</u> focus on these firms is unclear and may introduce an unwarranted bias into the sample.

Ms. McShane's use of return data for U.S. industrials must also be questioned. There is certainly a concern about sample-selection bias. However, aside from potential bias, Ms. McShane's apparent increase of 50 basis points to Canadian utilities is problematic in that its justification is questionable. More importantly, however, is the problem inherent in making such an adjustment. That is, once we go beyond Canadian industrial returns, there is little realistic hope that analysts and the Board will be able to understand and effectively make the numerous adjustments necessary to translate corporate accounting returns in foreign countries into something that could legitimately be considered a "comparable" to Canadian utility returns. Undoubtedly, such adjustments would be required to account for such factors such as: systematic risk differences; different corporate tax rates and structures; different accounting rules; foreign currency translation effects; differences in environmental regulations and labour laws; withholding taxes; differences in the tax treatments of personal dividend income and inter-corporate dividends, differences in the ease with which corporations can repurchase their own common shares (thus effectively pushing up their ROCES); and differences in the degrees of corporate concentration and effective competition with the Canadian economy versus the U.S. or other foreign market. It is not likely that the Board is prepared to undertake this task, especially when perfectly good and appropriate industrial samples can be constructed from among publicly-traded Canadian companies and when the Board has already indicated that its return awards will not necessarily be consistent with the returns being earned by comparably risky nonregulated enterprises whether they are Canadian-based or not. (Draft Guidelines On a Formula-Based Return," page 26).

Ms. McShane's Equity Risk Premium Test

Ms. McShanes's conclusions on page A-19 reveal the results of three separate market risk premium tests. The data was as follows:

DCF-Based Risk Premium for U.S. Distributors	4.3%
Risk Adjusted Market Risk Premium Test	4.5%
Achieved Canadian/U.S. Electric Utility Risk Premiums	5.2%

Ms. McShane concludes that the above estimates indicate a risk premium of no less than 4.5%, which when added to a long Canadian bond yield of 5.5%-5.75% yields a cost of equity in the range of 10.0%-10.25%. This estimate is then adjusted to account for financing flexibility.

There are significant problems with all three of Ms. McShane's risk premium estimates above.

<u>DCF-Based Risk Premium for U.S. Distributors</u>.

Ms. McShane attempts to estimate a forward looking risk premium for U.S. gas distributors. She relies on U.S. gas distributors because she was unable to gather similar data on investor growth expectations for Canadian gas and electric utilities. She calculates the risk premium as the difference between a DCF estimate of cost of equity and a corresponding long government yield. She notes that "the reliability of this type of test is dependent on the ability to consistently capture investor expectations in the growth component of the individual DCF cost of equity estimates." The DCF estimates are calculated as the sum of the month-end dividend yield and the corresponding Institutional Brokers Estimate System ("IBES") five-year earnings growth expectations. She notes on page A-19 of her report that the IBES "can be used as a proxy for investors' expectations of long-term growth." **In fact, they cannot.** First, the IBES forecasts are for earnings not dividends as required by the DCF methodology. Second, and far more important, is the fact that the estimates are for only a five-year horizon. They are not long-term growth estimates. Finally, IBES earnings growth estimates have historically incorporated an upward (optimistic) bias in relation to subsequently-achieved actual result.

IBES five-year growth estimates are just that, five-year growth estimates and not long-term forecasts. Numerous regulatory bodies including the U.S. Federal Energy Regulatory Commission ("FERC") have specifically declared that the five-year forecasts are inappropriate as a measure of long-term growth. Specifically, in a July 7, 1994 order, the FERC reversed the Initial Decision of the Administrative Law Judge (ALJ) regarding the appropriate rate of return authorized for Ozark Gas Transmission. With respect to relying solely on a five-year growth factor in the constant growth DCF model, the FERC stated:

> We need not address most of the specific arguments advanced by the staff on exception because both Ozark's methodology and that employed by the ALJ contain a <u>critical</u> flaw. Both approaches are limited to five-year growth projections, and neither Ozark nor the ALJ attempted to develop projections beyond that horizon.

And,

> In the constant growth DCF model used by both parties in this proceeding, dividends are expected to grow indefinitely at the rate (g). The indefinite future used by the DCF model is 50 years or more. By using analysts' projections of growth for the next five years as an estimate of (g), Ozark's witness implicitly assumes that dividends will continue to grow at that rate for the following 45 or more years. The witness made no effort to justify this assumption. However, as we stated in Opinion No. 180, <u>in estimating growth, 'we cannot simply adopt, without further consideration, calculations of past dividend growth or projections by</u>

investment advisory services of growth for relatively short periods of years into the future.'[3] [emphasis added]

The FERC subsequently issued rulings indicating that longer-term growth expectations must be employed. Among such long-term growth rates is the long-term (20-25 years) growth rate for Gross National Product. In short, the five year IBES earnings estimates employed by Ms. McShane are entirely inappropriate and thus her conclusions regarding risk premiums for U.S. gas distributors are similarly invalid.

Risk Adjusted Market Risk Premium Test

Ms. McShane's risk adjusted market risk premium test result of 4.5% is really a composite of a number of things. She starts by calculating a historical market risk premium for Canadian and U.S. stocks for the period 1947-1997. Based on a weighting of 80/20 for Canadian versus U.S. she determines an appropriate historical market risk premium of 5.8% but concludes a range of 5.0%-6.0% is appropriate.

Ms. McShane's second step is to calculate a "forward looking" market risk premium and does so using the same IBES five-year growth rates as were employed in her U.S. gas distributor risk premium analysis above which we have already shown to be inappropriate. She determines that the market risk premium using this method is 8.2%. For a U.S. sample she finds the result to be 9.2% and concludes a "forward looking" premium is 8.4%.

[3] Ozark Gas Transmission System, 68 FERC ¶ 61,032 (1994).

Moving from the historical risk premium of 5.0%-6.0% to the "forward looking" premium of 8.4%, Ms. McShane concludes a "reasonable" (albeit subjective) risk premium is in the range of 6.5-6.75%. She then notes that this range must be adjusted to reflect risk of electric utilities. However, she claims utility betas, which are measures of utility risk relative to the broader market, are flawed for a number of reasons. She concludes by saying that an adjustment of .65-.70 to the market risk premium of 6.5-6.75% is appropriate and thus concludes with a market risk premium of 4.5% is appropriate.

Ms. McShane's result can be disregarded on a number of grounds including the veracity of the regression results she uses to support her conclusions along the way. On page A-13, she constructs a regression equation (but does not provide the underlying data or other regression statistics). The equation is supposed to show that a beta of .43 is inappropriate in spite of the fact that the average beta for reported Canadian gas and electric utilities has been .45-.50, as shown in her Schedule 16. She dismissed the regression results because the equation estimate for the intercept, 2.0, is greater than zero indicating something else besides market risk premiums drive utility risk premiums. More likely, the positive constant indicates that utilities have earned more than their cost of equity capital and in no way besmirches the use of beta as a measure of investment risk. Moreover, Ms. McShane's use of adjusted betas in the Canadian context is inappropriate because the historical evidence shows that Canadian gas/electric utility betas have not tended "to regress toward the mean" (i.e., toward 1.0) over time, as can be seen from Schedule 4 in Appendix B.

Ms. McShane's results can also be disregarded for the very same reason cited previously. Her "forward-looking" risk premiums are fatally flawed in that they are based on the same five-years earnings forecasts used in her gas distributor risk premium analysis. These are not long-run growth expectations.

Given that her attempt to measure "forward-looking" premiums is fatally flawed, one can focus only on her Canadian historical risk premiums of 4.8-5.9%. Ms. McShane herself notes that the choice of historical time significantly alters the results. She shows that the Canadian risk premium if one modifies the time horizon to 1956-1997 is 3.4%. Aside from historical time horizon, if one applies the betas for Canadian gas and electric distributors as shown on Schedule 16 (.45-.50), Ms. McShane's utility specific risk premium is 2.4-2.95. This risk premium when added to her long Canadian bond yield of 5.5-5.75% reveals OHSC's cost of equity is 7.9%-8.7%, which is in line with the findings in this report.

<u>Achieved Canadian/U.S. Electric Utility Risk Premiums</u>

In the referenced analysis on pages A-17/18 and Schedule 19 of her report, Ms. McShane attempts to infer the relative required risk compensation for (1) the TSE Utility Index (less BCE) and the TSE Gas/Electric Utility Index versus (2) the TSE 300 Index by comparing historically-achieved rates of investment return. From this comparative-achieved-returns evidence, she apparently concludes that TSE utility shares in general require about the same risk compensation as the TSE 300 Index or perhaps the typical TSE 300 stock, while TSE gas/electric utilities require risk compensation in excess of that historically afforded to the typical TSE 300 company. One simply cannot accept the logic of her argument or the resulting unreasonable conclusions.

Ms. McShane appears to want us to believe that just because Canadian utility shares have provided investors with relatively high returns over the years - by achieving returns in excess of their cost of equity capital - the risk premium investors now require to continue to invest in utility share must necessarily also be high. The “leap of faith” involved in this reasoning is simply not acceptable for, and is counter-productive for, responsible regulatory rate-making.

Appendix A
Schedule 1

THE CANADIAN CONSUMER PRICE INDEX (CPI)
Expected or Forecasted

Period	Average Level of CPI For the Period	Year-to-Year CPI Inflation Rate	CPI Inflation Rate*
	(1992=100)	%	%
1977	40.0	8.0	5.9
1978	43.6	9.0	9.1
1979	47.6	9.1	8.6
1980	52.5	10.2	9.5
1981	58.9	12.4	11.1
1982	65.3	10.9	12.3
1983	69.1	5.7	9.7
1984	72.1	4.4	4.6
1985	75.0	3.9	5.0
1986	78.1	4.2	4.45
1987	81.5	4.4	4.2
1988	84.8	4.0	4.85
1989	89.0	5.0	4.8
1990	93.3	4.8	4.6
1991	98.5	5.6	6.1
1992	100.0	1.5	3.4
1993	101.8	1.8	2.5
1994	102.0	0.2	2.0
1995	104.2	2.2	1.8
1996	105.9	1.6	2.0
1997	107.6	1.6	1.8
1998:December	108.7	1.0	1.8
<u>Averages For</u>:			
1982-1997 (16 years)	-	3.9	4.6
1989-1997 (9 years)	-	2.7	3.2

* Based on "Central Consensus" forecasts for 1985-1992 and on the actual year-over-year CPI inflation rate prevailing during the fourth quarter of the previous year, for years prior to 1985; the 1991 value is based on the Conference Board of Canada's Autumn 1990 forecast for 1991, the 1993 value is taken from <u>The Financial Post's</u> quarterly forecast on page 4 of its November 14th, 1992 issue, and the 1994 figure is taken from the consensus forecast published by <u>The Financial Post</u> on page 6 of its October 16th, 1993 issue. The 1995 figure is taken from the consensus forecast published by <u>The Financial Post</u> on page 6 of its October 1st, 1994 issue, while the 1996, 1997, and 1998 values are taken from KPMG's "Survey of Economic Expectations" for 1996, 1997, and 1998.

<u>Source</u>: <u>Bank of Canada Review</u>

Appendix A
Schedule 2

HISTORICAL CANADIAN INTEREST RATES AND PREFERRED SHARE YIELDS--AVERAGES FOR ANNUAL AND QUARTERLY PERIODS

Year and Quarter	Government of Canada 91-Day Treasury Bills	Chartered Bank Prime	Government of Canada Long-Term Bonds	ScotiaMcLeod Weighted Long-Term Corporate Bonds
	%	%	%	%
1970	6.10	8.17	7.97	9.18
1971	3.60	6.48	6.95	8.35
1972	3.55	6.00	7.23	8.30
1973	5.39	7.65	7.55	8.47
1974	7.80	10.66	8.87	10.10
1975	7.37	9.48	9.00	10.75
1976	8.90	10.00	9.22	10.54
1977	7.35	8.53	8.69	9.72
1978	8.59	9.66	9.24	10.02
1979	11.55	12.72	10.17	10.88
1980	12.75	14.20	12.33	13.22
1981	17.77	19.21	15.03	16.11
1982	13.81	16.07	14.36	16.03
1983	9.32	11.19	11.77	12.73
1984	11.11	12.05	12.74	13.53
1985	9.44	10.64	11.11	11.82
1986	8.99	10.52	9.54	10.29
1987	8.19	9.52	9.95	10.68
1988	9.42	10.75	10.23	10.94
1989	12.02	13.26	9.92	10.83
1990	12.80	14.11	10.81	11.85
1991	8.85	10.08	9.82	10.84
1992	6.50	7.56	8.77	9.90
1993	4.91	6.00	7.86	8.89
1994	5.42	6.77	8.60	9.33
1995	6.98	8.60	8.35	9.09
1996	4.30	6.17	7.54	8.11
1997	3.13	4.96	6.46	6.98
1998:1	4.40	6.32	5.61	6.26
2	4.71	6.50	5.49	6.06
3	4.99	6.84	5.55	6.22
4	4.72	6.95	5.35	6.25

<u>Sources</u>: <u>Bank of Canada Review</u> and Bank of Canada Weekly Financial Statistics.

Appendix A
Schedule 3

COMPARATIVE RATES OF TOTAL INVESTMENT RETURN* AND EXPERIENCED MARKET EQUITY RISK PREMIUMS
(Percentage Rates of Return from December to December)

	T.S.E. "300" Composite Stock Index %	Canadian 91-day Treasury Bills %	Experienced Market-Average Equity Risk Premiums[a] %		ScotiaMcLeod Long-Term Bond Value Index $
1957	-20.58	3.83	-24.41		7.94
1958	31.25	2.51	28.74		1.92
1959	4.59	4.62	-0.03		-5.07
1960	1.78	3.31	-1.53		12.19
1961	32.75	2.89	29.86		9.16
1962	-7.09	4.22	-11.31		5.03
1963	15.60	3.63	11.97		4.58
1964	25.43	3.79	21.64		6.16
1965	6.68	3.92	2.76		0.05
1966	-7.07	5.03	-12.10		-1.05
1967	18.09	4.59	13.50		-0.48
1968	22.45	6.44	16.01		2.14
1969	-0.81	7.09	-7.90		- 2.86
1970	-3.57	6.70	-10.27		16.39
1971	8.01	3.81	4.20		14.84
1972	27.38	3.55	23.83		8.11
1973	0.27	5.11	-4.84		1.97
1974	-25.93	7.85	-33.78		-4.53
1975	18.48	7.41	11.07		8.02
1976	11.02	9.27	1.75		23.64
1977	10.71	7.66	3.05		9.04
1978	29.72	8.34	21.38		4.10
1979	44.77	11.41	33.36		-2.83
1980	30.13	14.97	15.16		2.18
1981	-10.25	18.41	-28.66		-2.09
1982	5.54	15.42	-9.88		45.82
1983	35.49	9.62	25.87		9.61
1984	-2.39	11.59	-13.98		16.90
1985	25.07	9.88	15.19		26.68
1986	8.95	9.33	-0.38		17.21
1987	5.88	8.48	-2.60		1.78
1988	11.08	9.41	1.67		11.30
1989	21.37	12.36	9.01		15.17
1990	-14.80	13.48	-28.28		4.32
1991	12.02	9.83	2.19		25.30
1992	-1.43	7.08	-8.51		11.57
1993	32.55	5.51	27.04		22.09
1994	-0.18	5.35	-5.53		-7.39
1995	14.53	7.57	6.96		26.34
1996	28.35	5.02	23.33		14.18
1997	14.98	3.20	11.78		18.46
Average For:				Arith. Mean	
1958-97 (40yrs)	10.95	7.43	3.52	4.54	8.74
1963-97 (35yrs)	10.87	8.00	2.87	3.89	9.37
1968-97 (30yrs)	10.83	8.65	2.18	3.28	10.68
1973-97 (25yrs)	10.99	9.29	1.70	2.90	11.33

* Total investment rate of return incorporates both capital gains (or losses) and income (dividends or coupon interest) received during the period.

[a] Column 1 minus column 2.

Source: ScotiaMcLeod Inc., Economics Department, various annual "Investment Returns" publications

Appendix A
Schedule 4

COMMON EQUITY RATIOS FOR A SAMPLE OF SIX CANADIAN,

PUBLICLY-TRADED, GAS AND ELECTRIC UTILITIES

Gas/Electric Utility Company	Common Equity Ratio* As At Dec.31, 1997
	%
BC Gas Inc.	29.3
Canadian Utilities Ltd.	33.9
Fortis Inc.	37.4
Nova Scotia Power Inc.	32.6
Pacific Northern Gas Ltd.	32.0
TransAlta Corporation	38.9
Sample Mean	34.0

* Calculated as the ratio of common shareholders' equity to the sum of all debt plus preferred share equity plus common share equity; deferred taxes are excluded from the calculation.

Appendix A
Schedule 5

CALCULATION OF PRO FORMA, BEFORE-TAX INTEREST COVERAGE RATIOS FOR OHSC'S REGULATED TRANSMISSION AND DISTRIBUTION BUSINESSES, ON A STAND-ALONE BASIS, FOR ASSUMED ALLOWED EQUITY RETURNS IN THE RANGE OF 8.00% TO 8.50%

(Figures in the table are expressed as percentages of rate base)

		Assumed Allowed Equity Return		
Row		8.00%	8.25%	8.50%
1	After-Tax Equity Return Component[a]	3.20	3.30	3.40
2	Income Tax Component[b]	2.58	2.66	2.74
3	Before-Tax Equity Return Component	5.78	5.96	6.14
4	Interest Expense Component[c]	4.68	4.68	4.68
5	Income Before Interest and Taxes Component[d]	10.46	10.64	10.82
	Pro Forma Interest Coverage Ratio[e]	2.235	2.274	2.312

[a] 40% CER multiplied by the allowed ROE.

[b] Assumed to be 44.62% of the before-tax equity return component.

[c] 60% debt ratio multiplied by assumed 7.8% average cost of debt.

[d] Row 5 is the sum of rows 3 and 4.

[e] Row 5 divided by row 4.

Appendix B
Schedule 1

THE DETERMINANTS OF GAS AND ELECTRIC UTILITY MARKET-TO-BOOK-VALUE RATIOS AND THE DERIVATION OF UTILITY COST-OF-EQUITY-CAPITAL AND ERP ESTIMATES

The model described below is based on the proposition that gas and electric utility market-to-book-value (MV/BV) ratios are positively related over time to (1) the corresponding MV/BV ratio for industrial stocks in general (representing the "market effect") and to (2) the extent to which achieved utility returns on book equity (ROCE) exceed the "bare-bones" costs of equity capital for these utilities. The latter variable can itself be decomposed into two parts - namely, (a) the extent to which achieved utility ROCEs exceed the equity returns allowed by their regulatory boards and (b) the amount by which regulatory allowed returns exceed the corresponding utility's cost of equity capital.

For ease of exposition, we define the following symbolic notation.

MU_t ≡ the gas/electric utility-average MV/BV ratio for year t;

MUAVG ≡ the average value of MU_t over the time period of the study;

$[MU_t\text{-}MUAVG]$ ≡ the difference between the utility-average MV/BV ratio in year t and its average value over the period of the study;

MI_t ≡ the industrial-average MV/BV ratio for year t;

MIAVG ≡ the average value of MI_t over the time period of the study;

$[MI_t\text{-}MIAVG]$ ≡ the difference between the industrial-average MV/BV ratio in year t and its mean value over the period of the study;

$BETAU_t$ ≡ the gas/electric utility-average beta value for year t;

BETAI ≡ the industrial-average beta value, assumed to be a constant over the time period of the study;

$BETAU/I_t$ ≡ the ratio of the utility-average beta to the industrial-average beta for year t;

R_t ≡ the gas/electric utility-average achieved return on common equity (ROCE) for year t;

A_t ≡ the gas/electric utility-average regulatory-allowed return on the book value of common equity for year t;

K_t ≡ the gas/electric utility-average "bare-bones" cost of equity capital for year t;

RET_t ≡ the gas/electric utility-average earnings retention ratio for year t;

a ≡ the constant term in the regression equation;

b, b_1, b_2, c ≡ coefficients on the variables within the regression model; and

e_t ≡ the residual or error term in the estimated regression equation for year t.

The model explaining gas-and-electric-utility-average MV/BV ratios postulates the following relationship among the above variables.

(1) $[MU_t\text{-}MUAVG] = a + b(R_t\text{-}K_t) + c(BETAU/I_t \times [MI_t\text{-}MIAVG]) + e_t$

(2) Since $(R_t\text{-}K_t) = (R_t\text{-}A_t) + (A_t\text{-}K_t)$, we can substitute the right hand side of equation (2) into equation (1) to get ...

(3) $[MU_t\text{-}MUAVG] = a + b_1(R_t\text{-}A_t) + b_2(A_t\text{-}K_t) + c(BETAU/I_t \times [MI_t\text{-}MIAVG]) + e_t$

We would expect, a priori, that the coefficients b, b_1, b_2, and c would all be positive.

(4) Now let $a^* + e_t^* \equiv a + b_2(A_t\text{-}K_t) + e_t$, and substitute the left-hand side of (4) into (3) to get ...

(5) $[MU_t\text{-}MUAVG] = a^* + b_1(R_t\text{-}A_t) + c(BETAU/I_t \times [MI_t\text{-}MIAVG]) + e_t^*$

Equation (5) is the one whose parameter values are specified through time-series regression analysis in this study - the results of which are shown later.

Once regression equation (5) has been estimated using the data in Schedules 1 to 4 of this appendix, the values of $(R_t\text{-}A_t) = 0$ and $[MI_t\text{-}MIAVG] = 0$ are
substituted into the numerically-specified regression equation (5) to get ...

(6) $[MU_t^*\text{-}MUAVG] = a^* + e_t^*$

or, by adding MUAVG to both sides of (6), to get

(7) $MU_t^* = MUAVG + a^* + e_t^*$

By setting $(R_t\text{-}A_t) = 0$, we remove from our regression model the impact that differences between utility-average achieved returns and allowed returns have on utility MV/BV ratios. Similarly, by setting $[MI_t\text{-}MIAVG] = 0$, we remove from our model the impact that general stock market movements (as represented by changes in the industrial-average MV/BV ratio) have on utility MV/BV ratios.

The resulting instrumental variable, MU_t^*, therefore represents the value for the utility-average MV/BV ratio in each year that can be ascribed to the impact of differences between utility-average allowed returns and costs of equity capital, on the one hand, and, on the other, all remaining miscellaneous effects which might explain utility MV/BV ratios over time (but which have been omitted from the model described above).

The DCF valuation formula provides a means for estimating utility costs of equity capital if the utility's allowed equity return, earnings retention ratio, and MV/BV ratio (reconstituted as above to remove the market-enthusiasm and over/under-earning effects) are available as input values. The DCF-derived formula for expressing the relationship between the cost of equity capital (K_t), on the one hand, and allowed returns (A_t), retention ratios (RET_t), and adjusted MV/BV ratios (MU_t^*), on the other hand, is ....

(8) $$K_t = \frac{A_t(1-RET_t)}{MU_t^*} + A_t(RET_t)$$

A sample of 6 publicly-traded, essentially-non-diversified Canadian gas and electric utilities was assembled in order to provide the input data to estimate regression equation (5) and compute annual average utility equity costs (K_t) from equation (8). The companies in the sample are BC Gas, Canadian Utilities, Fortis (Newfoundland Power), Pacific Northern Gas, Nova Scotia Power, and TransAlta Corporation. The input data for each firm and the sample-average values covering the 1983-1997 period, are found in Schedules 1 through 4 of this appendix. The MV/BV and beta values are all expressed in decimal fraction form, while the rates of return and retention ratios are expressed as percentages. The input data for industrial-average MV/BV ratios is drawn from a sample of 24 low-risk Canadian industrials, as set out in Schedules 7 and 8 of this appendix. The figures for MI_t are found in column 1 of Schedule 7, as well as Schedule 2, of this appendix. The constant value for BETAI was chosen to be 0.70 - a value that reflects the typical average beta for low-risk industrial samples over the past decade.

Using this 6-utility sample data, regression equation (5) was estimated for the 1983-1997 time period. The result is set out below.

<u>Based on 1983-1997 input data</u>: "market-effect"

$$[Mu_t\text{-}MUAVG] = 0.00505 + 0.0\overline{058(R_t\text{-}A_t)} + 0.69204(BETAU/I_t \times [MI_t\text{-}MIAVG])$$

(t) (0.5) (0.6) (10.4)

$R^2 = 90.2\%$; F-ratio(2,13) = 55.4; D-W statistic = 2.03

This result indicates that the "market effect" has been the major determinant of changing Canadian gas and electric utility MV/BV ratios over time. This is not surprising for while the market effect may reflect ephemeral factors such as "investor enthusiasm" and changing investor expectations and risk aversion, the market effect also captures such concrete economic influences as changing interest rates, which can be expected to affect both utility and industrial stock prices and MV/BV ratios quite significantly and in the same direction.

Nor is the negligible impact of over-earning and/or under-earning allowed returns on the pattern of utility-average MV/BV ratios over time a surprise. While over-or-under-earning allowed returns may be important for explaining the movement in individual-company MV/BV ratios over time, the true significance is likely to be masked at the level of the sample average, where the over-earning firms will tend to cancel out the under-earning firms, in each year, and blunt the variation in the data used to capture this relationship. Furthermore, to the extent that systematic deviations from allowed returns are related to unexpected changes in the interest rate environment for the test year, the effect may already have been picked up in the "market effect" variable. Moreover, for some utilities, much of the over-earning or under-earning from year to year may be weather-related. In the parlance of capital market theory, weather-related variances are considered to be "unsystematic risk elements" and, as such, do not influence share values under efficient market conditions.

The small constant term in the estimated regression indicates that there is very little difference between how the <u>average deviation</u> between accounting ROCEs and market-determined, equity capital costs affects utility and industrial MV/BV ratios over time. This is not unexpected either.

The R^2 correlation statistic for the regression is very good, and the equation is highly significant as indicated by the elevated F-ratio (which is significant at the 0.1% significance level). The Durbin-Watson statis-tic of 2.03 indicates that there is no serial correlation in the residuals.

The estimated annual utility-average costs of equity capital over the 1983-1998 period are found by plugging the adjusted MV/BV output from the regression discussed above into equation (8). The resulting gas/electric utility-average cost-of-equity estimates are set out in the table below.

Year	Gas and Electric Utility-Average Cost of Equity Capital Based on 1983-1997 Data	Year	Gas and Electric Utility-Average Cost of Equity Capital Based on 1983-1997 Data
	%	%	
1983	13.49	1991	11.48
1984	13.46	1992	10.53
1985	12.87	1993	9.84
1986	12.19	1994	9.16
1987	11.86	1995	10.14
1988	11.39	1996	9.50
1989	11.53	1997	8.79
1990	11.44	1998*	8.07

* The 1998 values are derived from the regression relationship (equation 5) estimated over the 1983-1997 time period. The input data used to estimate the MV/BV instrumental variable and cost-of-equity values for 1998 were determined as follows. For each of the 24 industrials and 6 gas and electric utilities in the respective samples, 1998 MV/BV ratios were estimated using the ratio of (a) the average of their 1998 high and low share prices and (b) their estimated June 30th, 1998 book values per common share. The details of these estimates are set out in Schedule 5 of this appendix. The average MV/BV values for each sample (2.322 for low-risk industrials and 1.841 for the gas/electric utilities) were then inputted into the regression equation. The allowed utility equity returns were taken from Schedule 1 of this appendix. I assumed that my sample utilities would just earn their allowed returns in 1998. The 1998 utility beta and SD(r) values are set out in Schedule 4 of this appendix. The utility-average retention ratio was taken to be 33.55%, based on the DPS rates for 1998 and the average of analysts' 1998 EPS estimates for each gas/electric utility, as set out in Schedule 6 of this appendix.

ALLOWED RETURNS ON COMMON EQUITY FOR SAMPLE OF 6 NON-DIVERSIFIED GAS AND ELECTRIC
(expressed as percentages)

Utility Companies	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1
BC Gas	15.75	15.75	15.75	14.00	13.50	13.50	13.50	13.50	13.50	12.25	11.87	10.65	12.00	11
Canadian Utilities	15.88	14.56	14.69	14.25	13.69	13.69	13.44	13.37	13.56	13.13	11.97	11.97	11.97	11
Pacific Northern Gas	15.63	15.87	15.00	15.00	15.00	15.00	15.00	15.00	14.00	13.25	13.25	11.50	12.75	11
Fortis (Nfld L&P)	15.75	15.75	15.25	14.00	13.50	13.75	13.75	13.95	13.25	13.25	12.25	12.00	12.25	11
TransAlta Utilities	15.00	15.00	14.75	14.75	14.75	13.50	13.50	13.50	13.50	13.25	11.87	11.87	12.25	11
NS Power	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	11.75	11.75	11.75	10
Total	78.01	76.93	75.44	72.00	70.44	69.44	69.19	69.32	67.81	65.13	72.96	69.74	72.97	67
Number of Firms	5	5	5	5	5	5	5	5	5	5	6	6	6	
Mean	15.601	15.387	15.088	14.400	14.088	13.888	13.838	13.864	13.563	13.025	12.159	11.623	12.161	11.
Canadian Western Nat	14.75	14.75	15.25	15.50	15.50	15.50	13.50	13.25	13.50	12.25	12.25	12.25	12.25	12
Northwestern Utiliti	14.75	13.50	14.00	14.00	13.25	13.25	13.25	13.25	13.75	13.75	11.87	11.87	11.87	11
Alberta Power	17.00	15.00	14.75	13.75	13.00	13.00	13.50	13.50	13.50	13.25	11.87	11.87	11.87	11

Canadian Utilities: 1/4 Can. Western + 1/4 Northwestern U. + 1/2 Alberta Power

ACHIEVED RETURNS ON COMMON EQUITY FOR SAMPLE OF 6 NON-DIVERSIFIED GAS AND ELECTRIC UT
(expressed as percentages)

Utility Companies	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1
BC Gas	13.6	16.8	20.0	12.9	12.2	23.1	18.9	16.5	11.3	2.6	7.8	7.2	8.6	1
Canadian Utilities	15.9	17.1	16.0	17.3	13.6	13.7	10.9	11.8	12.5	13.5	13.4	13.7	14.0	1
Pacific Northern Gas	17.4	16.2	15.8	13.3	14.9	14.7	15.1	15.1	14.9	12.5	13.0	13.4	11.8	1
Fortis (Nfld L&P)	17.0	15.6	15.2	14.0	13.6	13.9	13.9	13.5	12.7	12.4	11.8	10.7	10.7	
TransAlta Utilities	16.8	15.9	15.2	13.9	13.7	13.4	11.2	3.0	13.0	13.1	12.6	12.5	11.9	1
NS Power	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	12.0	11.9	11.5	1
TOTAL	80.7	81.6	82.2	71.4	68.0	78.8	70.0	59.9	64.4	54.1	70.6	69.4	68.5	7
MEAN	16.14	16.32	16.44	14.28	13.60	15.76	14.00	11.98	12.88	10.82	11.77	11.57	11.42	11

AVERAGE ANNUAL MARKET-TO-BOOK-VALUE RATIOS (UNADJUSTED) FOR SAMPLE OF 6 NON-DIVERSIFIED GAS AND
(expressed as decimal fractions)

Utility Companies	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1
BC Gas	1.03	1.05	1.28	1.49	1.60	1.44	1.45	1.41	1.33	1.25	1.21	1.15	1.07	1
Canadian Utilities	1.37	1.38	1.55	1.51	1.40	1.38	1.42	1.40	1.40	1.41	1.52	1.51	1.41	1
Pacific Northern Gas	1.04	1.02	1.21	1.12	1.28	1.17	1.16	1.12	1.13	1.24	1.45	1.56	1.38	1
Fortis (Nfld L&P)	1.20	1.18	1.31	1.27	1.26	1.18	1.23	1.15	1.16	1.14	1.22	1.18	1.10	1
TransAlta Utilities	1.32	1.24	1.32	1.43	1.45	1.48	1.59	1.46	1.50	1.49	1.53	1.56	1.45	1
NS Power	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1.31	1.3	1.20	1
TOTAL	5.96	5.87	6.67	6.82	6.99	6.65	6.85	6.54	6.52	6.53	8.24	8.26	7.61	8
MEAN	1.19	1.17	1.33	1.36	1.40	1.33	1.37	1.31	1.30	1.31	1.37	1.38	1.27	1
Avg Industrial MV/BV*	1.56	1.54	1.77	2.09	2.08	1.87	1.99	1.78	1.88	1.81	1.84	1.81	1.82	2

* From Column 1 of Schedule 7 of this appendix.

BOUNDED RETENTION RATIOS* FOR SAMPLE OF 6 NON-DIVERSIFIED GAS AND ELECTRIC UTILIT
(expressed as percentages)

Utility Companies	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1
BC Gas	37.5	52.0	60.2	49.6	46.9	20.9	60.2	54.2	53.6	0.0	37.1	3.2	22.4	6
Canadian Utilities	46.8	42.3	34.8	40.4	26.8	30.1	14.5	21.5	22.7	29.9	31.5	35.3	38.9	4
Pacific Northern Gas	56.7	53.4	46.7	35.8	44.4	44.0	48.1	53.3	52.3	46.0	46.0	51.1	43.7	5
Fortis (Nfld L&P)	52.2	48.2	48.3	40.5	39.9	41.3	40.9	41.7	38.6	41.6	39.8	34.1	33.2	2
TransAlta Utilities	49.6	48.6	41.7	0.0	30.8	0.0	4.5	0.0	12.5	16.9	15.5	17.0	14.0	1
Quebec Telephone	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	30.2	31.1	29.6	2
TOTAL	242.8	244.5	231.7	166.3	188.8	136.3	168.2	170.7	179.7	134.4	200.1	171.8	181.8	22
MEAN	48.56	48.90	46.34	33.26	37.76	27.26	33.64	34.14	35.94	26.88	33.35	28.63	30.30	37

* The minimum earnings retention ratio for any company in any year is set at zero percent.

DIVIDEND PAYOUT RATIOS FOR A SAMPLE OF 6 NON-DIVERSIFIED GAS AND ELECTRIC UTILIT
(expressed as percentages)

Utility Companies	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1
BC Gas	62.5	48.0	39.8	50.4	53.1	79.1	39.8	45.8	46.4	100.0	62.9	96.8	77.6	3
Canadian Utilities	53.2	57.7	65.2	59.6	73.2	69.9	85.5	78.5	77.3	70.1	68.5	64.7	61.1	5
Pacific Northern Gas	43.3	46.6	53.3	64.2	55.6	56.0	51.9	46.7	47.7	54.0	54.0	48.9	56.3	4
Fortis (Nfld L&P)	47.8	51.8	51.7	59.5	60.1	58.7	59.1	58.3	61.4	58.4	60.2	65.9	66.8	7
TransAlta Utilities	50.4	51.4	58.3	100.0	69.2	100.0	95.5	100.0	87.5	83.1	84.5	83.0	86.0	8
NS Power	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	69.8	68.9	70.4	7
TOTAL	257.2	255.5	268.3	333.7	311.2	363.7	331.8	329.3	320.3	365.6	399.9	428.2	418.2	37
MEAN	51.44	51.10	53.66	66.74	62.24	72.74	66.36	65.86	64.06	73.12	66.65	71.37	69.70	62

BOUNDED DIVIDEND PAYOUT RATIOS* FOR A SAMPLE OF 6 NON-DIVERSIFIED GAS AND ELECTRIC UT
(expressed as percentages)

Utility Companies	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1
BC Gas	62.5	48.0	39.8	50.4	53.1	79.1	39.8	45.8	46.4	100.0	62.9	96.8	77.6	3
Canadian Utilities	53.2	57.7	65.2	59.6	73.2	69.9	85.5	78.5	77.3	70.1	68.5	64.7	61.1	5
Pacific Northern Gas	43.3	46.6	53.3	64.2	55.6	56.0	51.9	46.7	47.7	54.0	54.0	48.9	56.3	4
Fortis (Nfld L&P)	47.8	51.8	51.7	59.5	60.1	58.7	59.1	58.3	61.4	58.4	60.2	65.9	66.8	7
TransAlta Utilities	50.4	51.4	58.3	100.0	69.2	100.0	95.5	100.0	87.5	83.1	84.5	83.0	86.0	8
NS Power	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	69.8	68.9	70.4	7
TOTAL	257.2	255.5	268.3	333.7	311.2	363.7	331.8	329.3	320.3	365.6	399.9	428.2	418.2	37
MEAN	51.44	51.10	53.66	66.74	62.24	72.74	66.36	65.86	64.06	73.12	66.65	71.37	69.70	62

* The maxmium payout ratio for any company in any year is set at 100 percent.

BETA ESTIMATES FOR SAMPLE OF 6 NON-DIVERSIFIED GAS AND ELECTRIC UTILITIES
(expressed as decimal fractions)

Utility Companies	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
BC Gas	0.33	0.23	0.13	0.08	0.49	0.52	0.54	0.52	0.49	0.41	0.41	0.53	0.59	0.56
Canadian Utilities	0.53	0.52	0.47	0.47	0.26	0.39	0.42	0.41	0.38	0.45	0.45	0.54	0.48	0.42
Pacific Northern Gas	0.34	0.23	0.23	0.10	0.38	0.35	0.30	0.38	0.44	0.40	0.53	0.58	0.44	0.29
Fortis (Nfld L&P)	0.69	0.67	0.60	0.52	0.28	0.36	0.32	0.26	0.29	0.41	0.36	0.44	0.51	0.33
TransAlta Utilities	0.63	0.56	0.61	0.55	0.25	0.20	0.22	0.27	0.26	0.36	0.44	0.55	0.59	0.59
NS Power	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0.47	0.52	0.53	0.49
MEAN	0.504	0.442	0.408	0.344	0.332	0.364	0.360	0.368	0.372	0.406	0.443	0.527	0.523	0.447

STANDARD DEVIATION OF INVESTMENT RETURNS (STD) ESTIMATES FOR SAMPLE OF 6 NON-DIVERSIFIED GAS AND EI
(expressed as decimal fractions)

Utility Companies	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
BC Gas	8.25	7.84	7.61	6.97	5.14	5.42	5.31	4.78	4.22	3.81	3.35	3.69	3.53	3.51
Canadian Utilities	7.24	7.37	6.83	6.55	5.03	4.25	3.80	3.53	3.58	3.76	3.61	3.62	3.36	3.79
Pacific Northern Gas	8.93	6.84	5.34	5.31	4.60	4.45	4.44	4.95	4.69	4.19	4.66	4.72	3.94	4.16
Fortis (Nfld L&P)	7.17	6.81	5.79	4.88	4.41	4.28	3.82	3.28	3.28	3.12	2.88	3.24	3.19	3.43
TransAlta Utilities	6.49	6.34	5.52	5.03	4.21	3.32	2.98	3.71	3.83	3.92	4.01	4.14	3.44	3.45
NS Power	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	2.02	2.92	2.97	3.10
MEAN	7.616	7.040	6.218	5.748	4.678	4.344	4.070	4.050	3.920	3.760	3.422	3.722	3.405	3.573

Appendix B
Schedule 6

ESTIMATING AVERAGE MARKET-TO-BOOK-VALUE RATIOS FOR 1998

Low-Risk Industrial Companies	Fiscal Year-end	BV/Share @June 30/98	Est'd 1998 Share Prices High	Low	1998 Average	MV/BV
Bombardier Inc. "B"	Jan-98	7.46	22.55	13.25	17.9	2.4
Cara Operations "A"	Mar-98	2.69	7.6	4.6	6.1	2.27
Celanese Canada	Dec-97	11.63	29	19.3	24.15	2.08
Chum Ltd. "B"	Aug-97	17.88	60	31	45.5	2.54
Du Pont Canada	Dec-97	11.87	47.5	31.5	39.5	3.33
Empire Company "A"	Apr-98	14.515	32.55	18.25	25.4	1.75
Imasco Ltd.	Dec-97	16.75	33.1	22	27.55	1.64
Imperial Oil "A"	Dec-97	9.72	30.5	20.8	25.65	2.64
Jannock Ltd.	Dec-97	11.79	22.4	12	17.2	1.46
Loblaw Companies	Dec-97	6.39	38	24	31	4.85
MDS Health Group "B"	Oct-97	9.62	34.5	24	29.25	3.04
Molson Co. "A"	Mar-98	16.7	28	19.75	23.875	1.43
Moore Corporation*	Dec-97	12.7	17.69	9.44	13.563	1.07
Northern Telecom*	Dec-97	8.85	69.25	26.81	48.032	5.43
Oshawa Group "A"	Jan-98	22.75	36.9	22.85	29.875	1.31
Quebecor Inc. "B"	Dec-97	19.36	33	23.6	28.3	1.46
Rothmans Inc.	Mar-98	37.61	222	172	197	5.24
Seagram Company*	Jan-98	27.16	46.69	25.13	35.907	1.32
Shaw Industries "A"	Dec-97	12.93	19.33	10	14.665	1.13
Shell Canada	Dec-97	11.5	27.2	20.5	23.85	2.07
Toromont Industries	Dec-97	5.86	23	14.25	18.625	3.18
Torstar Corp.	Dec-97	14.94	27.05	14	20.525	1.37
UAP Inc.	Dec-97	15.02	28.5	16	22.25	1.48
Weston (George)	Dec-97	40.08	60	37.33	48.665	1.21
Mean						2.32

Non-Diversified
Gas and Electric
Utility Companies

BC Gas	Dec-97	15.82	34	25.5	29.75	1.88
Canadian Utilities	Dec-97	20.55	48.85	38	43.425	2.11
Fortis Inc.(Nfld Power)	Dec-97	25.83	48.1	35	41.55	1.61
Nova Scotia Power	Dec-97	10.5	20.1	14.75	17.425	1.66
Pacific Northern Gas	Dec-97	17.46	32.75	24.75	28.75	1.65
TransAlta Utilities	Dec-97	10.19	25.4	18.2	21.8	2.14
Mean						1.84

* US $ share prices and book values per share.

Appendix B
Schedule 7

ESTIMATION OF GAS AND ELECTRIC UTILITY

AVERAGE 1998 PAYOUT AND RETENTION RATIOS

Non-Diversified Gas and Electric Utilities	Analysts' DPS For 1998	Average of 1998 EPS Estimates[a]	Indicated Dividend Payout Ratio	Indicated Earnings Retention Ratio
	$	$	%	%
BC Gas	1.09	1.83	59.6	40.4
Canadian Utilities	1.64	2.94	55.8	44.2
Fortis (Nfld Power)	1.80	2.27	79.3	20.7
NS Power	0.82	1.108	74.0	26.0
Pacific Northern Gas	1.10	2.087	52.7	47.3
TransAlta Utilities	0.98	1.267	77.3	22.7
Mean			66.45	33.55

[a] Average of 1998 EPS estimates as provided by Nesbitt Burns, RBC Dominion Securities, ScotiaMcLeod, and Wood Gundy.

Appendix B
Schedule 8

SAMPLE OF 24 INDUSTRIAL COMPANIES - YEAR-BY-YEAR SAMPLE-AVERAGE MV/BV RATIO VALUES*

Market-to-Book Value Ratio (MV/BV)

Year	Sample Mean	Sample Median	1/3 Mean Plus 2/3 Median
(column)	(1)	(2)	(3)
	%	%	%
1983	1.56	1.34	1.41
1984	1.54	1.44	1.47
1985	1.77	1.61	1.66
1986	2.09	1.99	2.03
1987	2.08	2.02	2.04
1988	1.87	1.81	1.83
1989	1.99	1.88	1.91
1990	1.78	1.66	1.70
1991	1.88	1.63	1.71
1992	1.81	1.69	1.73
1993	1.83	1.76	1.78
1994	1.81	1.57	1.65
1995	1.82	1.51	1.61
1996	2.08	1.85	1.93
1997	2.55	2.43	2.47
1998e	2.32	1.91	2.05

* Based on data set out in Schedule 8 of this appendix.

e Estimated from figures in Schedule 5 of this appendix.

INDUSTRIAL COMPANIES MV/BV DATA

	Bombardier	Cara	Celanese	Chum	Du Pont	Empire	Imasco	Imperial	Jannock	Loblaw
1983	0.66	3.38	1.11	1.48	0.89	1.42	1.96	1.29	1.46	1.5
1984	0.71	2.7	0.99	1.72	1	1.44	1.9	1.44	1.32	1.73
1985	1.03	3.61	0.91	2.06	1.18	2.68	2.06	1.6	1.54	1.84
1986	1.77	4.85	1.48	2.58	1.73	3.33	2.15	1.4	2.08	2
1987	2.11	3.84	1.74	2.6	2.26	2.41	1.86	1.99	2.45	1.88
1988	1.93	4.07	2.01	2.06	1.89	1.95	1.55	1.57	1.91	1.67
1989	2.25	4.32	2.39	2.31	1.6	2.02	1.89	1.55	1.8	1.86
1990	2.05	3.2	2.04	2.19	1.4	1.48	1.64	1.58	1.4	2.15
1991	2.42	3.06	2.23	2.01	1.66	1.7	1.56	1.41	1.53	2.22
1992	2.34	2.31	2.48	1.91	2.09	1.65	1.68	1.24	1.68	1.84
1993	2.22	1.93	2.75	1.73	2.01	1.74	1.6	1.33	1.76	1.94
1994	2.4	1.53	3.28	1.44	2.07	1.42	1.46	1.37	1.88	1.88
1995	3.23	1.55	3.09	1.12	2.12	1.33	1.71	1.59	1.54	2.03
1996	4.02	1.57	2.72	1.19	2.67	1.25	2.1	1.88	1.53	2.46
1997	4.47	2.3	2.52	1.43	2.92	1.7	2.79	2.63	1.74	3.59

	Moore	Nortel	Oshawa	Quebecor	Rothmans	Seagram	Shaw	Shell	Toromont	Torstar
1983	1.89	3.95	1.19	1.34	1.15	1.33	1.04	1.27	1.04	1.34
1984	1.55	3.53	1.49	1.43	0.98	1.46	1.13	1.17	0.91	1.42
1985	1.92	2.79	1.9	2.36	0.81	1.23	1.2	1.26	1.2	1.73
1986	2.2	2.83	2.4	2.84	0.97	1.49	1.33	1.1	1.22	2.65
1987	1.82	2.85	2.04	2.6	1.42	1.49	1.52	1.76	1.24	2.54
1988	1.72	2.19	1.94	1.72	2.06	1.24	1.37	1.58	1.41	2.21
1989	2.01	2.1	2.07	1.71	2.2	1.5	1.5	1.63	1.65	2.33
1990	1.66	2.47	1.9	1.01	2.09	1.35	2.01	1.36	1.47	1.83
1991	1.47	2.57	1.61	1.23	3.18	1.51	2.46	1.43	1.5	1.6
1992	1.17	2.58	1.17	1.55	3.05	1.85	2.22	1.51	1.66	1.57
1993	1.29	2.41	1.25	1.78	3.63	2.09	1.96	1.45	2.25	1.61
1994	1.38	2.52	1.09	1.57	3.4	2.11	1.76	1.56	2.75	1.75
1995	1.43	2.69	1.05	1.38	3.93	1.64	1.37	1.47	2.84	1.47
1996	1.29	3.35	1	1.44	4.71	1.41	2.08	1.82	3.35	1.98

1997	1.26	4.86	1.02	1.56	5.23	1.46	3.81	1.63	3.56	2.35

Appendix B
Schedule 10

SAMPLE OF 24 INDUSTRIAL COMPANIES--INDIVIDUAL COMPANY EQUITY RISKINESS DATA

Industrial Company Name	Common Share Beta Value			Standard Deviation of Investment Return		
	92-96[a]	93-97[b]	94-98[c]	92-96[a]	93-97[b]	94-98[c]
Bombardier Inc. “B”	1.21	0.81	0.86	8.29	7.23	7.06
Cara Operations “A”	0.63	0.42	0.49	7	7.13	6.98
Celanese Canada	0.52	0.43	0.49	4.96	4.98	5.46
Chum Ltd. “B”	0.29	0.16	0.42	5.08	8.51	9.38
Du Pont Canada	1.04	0.86	0.93	6.28	6.27	6.9
Empire Company “A”	0.06	0.47	0.58	6.05	6.34	7.18
Imasco Ltd.	0.74	0.6	0.55	4.86	5.16	5.39
Imperial Oil “A”	0.54	0.32	0.37	4.85	4.9	5.36
Jannock Ltd.	1.16	1.04	0.85	6.63	6.74	7.1
Loblaw Companies	0.75	0.75	0.57	4.88	5.91	6.6
MDS Health Group “B”	0.73	0.76	0.66	7.47	7.22	6.84
Molson Co. “A”	0.9	0.85	0.73	5.68	5.97	6
Moore Corporation	1.3	1.25	0.84	7.13	6.9	6.52
Northern Telecom	1.22	1.34	1.37	8.65	8.9	10.42
Oshawa Group “A”	0.54	0.45	0.62	5.21	4.47	6.17
Quebecor Inc. “B”	0.86	0.73	0.61	6.45	6.3	6.19
Rothmans Inc.	0.13	0.18	0.13	5.71	5.79	5.98
Seagram Company	0.94	0.83	0.75	6.36	6.25	6.71
Shaw Industries “A”	0.78	0.76	0.95	8.06	8	8.64
Shell Canada	0.61	0.6	0.48	4.94	5.54	5.19
Toromont Industries	0.76	0.68	0.84	7.44	7.84	8.94
Torstar Corp.	0.73	0.82	0.89	5.25	5.5	6.33
UAP Inc.	-0.11	-0.14	0.42	5.09	5.37	8.45
Weston (George)	0.75	0.91	0.69	4.86	6.2	6.83
24 Industrials:						
Mean	0.71	0.66	0.67	6.13	6.39	6.94
Median	0.74	0.74	0.64	5.88	6.26	6.77
2/3 Med + 1/3 Mean	0.73	0.71	0.65	5.96	6.3	6.83

Sources: Company annual reports; The Financial Post Corporation Service cards; Datastream.

[a] For the 60 months ending December 1996.

[b] For the 60 months ending December 1997.

[c] For the 60 months ending December 1998.

Appendix B
Schedule 11

TIME-SERIES REGRESSION ANALYSIS OF GAS AND ELECTRIC UTILITY CAPITAL COSTS AND EQUITY RISK PREMIUMS

A. DATA FOR REGRESSION ANALYSES COVERING THE 1983-1998 PERIOD

	Cost of Equity Capital For The Typical Non-Diversified Gas/Electric Utility[a]	Average Long-Term Gov't of Canada Bond Yield[b]	Utility Equity Risk Premium[c]	CPI Inflation Rate[d]	Averages For A Sample of Gas/Electric Utilities[e]		Time Trend Variable
Name	Ke	LTGOVT	ERP	INFL	BETA	STD	TIME
(column)	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Year	%	%	%	%			
1983	13.49	11.77	1.73	5.7	0.504	7.616	1
1984	13.46	12.74	0.39	4.4	0.442	7.04	2
1985	12.87	11.11	1.5	3.9	0.408	6.218	3
1986	12.19	9.54	2.8	4.2	0.344	5.748	4
1987	11.86	9.95	2.12	4.4	0.332	4.678	5
1988	11.39	10.23	1.35	4	0.364	4.344	6
1989	11.53	9.92	1.66	5	0.36	4.07	7
1990	11.44	10.81	0.42	4.8	0.368	4.05	8
1991	11.48	9.82	1.42	5.6	0.372	3.92	9
1992	10.53	8.77	1.74	1.5	0.406	3.76	10
1993	9.84	7.86	2.1	1.8	0.443	3.422	11
1994	9.16	8.6	0.51	0.2	0.527	3.722	12
1995	10.14	8.35	1.33	2.2	0.523	3.405	13
1996	9.5	7.54	2.06	1.6	0.447	3.573	14
1997	8.79	6.46	2.37	1.6	0.42	3.67	15
1998	8.07	5.5	2.57	1.1	0.528	4.375	16

[a] Taken from page C4 of this appendix.

[b] Taken from the Bank of Canada Review, and the Bank of Canada's "Weekly Financial Statistics." The figures reflect the average yield on all Government of Canada bonds with terms to maturity exceeding 10 years.

[c] Column 3 equals column 1 minus column 2.

[d] Data taken from Bank of Canada Review.

[e] Based on data set out on Schedule 4 of this appendix.

Correlation Matrix For 1983-1998 Data:

(Column):	(1) Ke	(2) LTGOVT	(3) ERP	(4) INFL	(5) BETA	(6) STD
(2) LTGOVT	0.949					
(3) ERP	-0.282	-0.571				
(4) INFL	0.844	0.775	-0.160			
(5) BETA	-0.416	-0.344	-0.035	-0.565		
(6) STD	0.789	0.698	-0.069	0.558	0.012	

(7) TIME	-0.972	-0.921	0.270	-0.785	0.418	-0.818

Appendix B
Schedule 12

B. REGRESSION MODELS TO EXPLAIN THE LEVEL OF GAS AND ELECTRIC UTILITY COSTS OF EQUITY CAPITAL OVER THE 1983-1998 PERIOD

The definitions of the variables and the data used to specify the regressions below are found in Schedule 10 of this appendix.

(1) Ke = 3.42 + 0.812(LTGOVT)
(t) (11.2)

R^2 = 90.0%; F-ratio(1,14) = 126.0; D-W statistic = 1.77

(2) Ke = 3.40 + 0.664(LTGOVT) + 0.306(STD)
(t) (7.7) (2.4)

R^2 = 93.1%; F-ratio(2,13) = 88.3; D-W statistic = 2.15

(3) Ke = 4.75 + 0.782(LTGOVT) - 2.462(BETA)
(t) (10.3) (1.1)

R^2 = 90.9%; F-ratio(2,13) = 65.0; D-W statistic = 1.71

Appendix B
Schedule 13

C. TIME-SERIES REGRESSION ANALYSES OF GAS AND ELECTRIC UTILITY EQUITY RISK PREMIUMS OVER THE 1983-1998 PERIOD

The following regressions quantify the historical relationship between gas and electric utility equity risk premiums (ERPs) and the independent economic variables that are believed to affect their costs of equity capital and, hence, their ERPs. This relationship contains a cyclical element which the interest rate variable is intended to pick up. The SD(r) and beta risk variables may also help to explain the movements in gas/ electric ERPs over time. The definitions of the variables and the data used to specify these regressions are found in Schedule 10 of this appendix.

(1) ERP = 3.42 - 0.188(LTGOVT)
(t) (2.6)

R^2 = 32.6%; F-ratio(1,14) = 6.8; D-W statistic = 1.77

(2) ERP = 3.40 - 0.336(LTGOVT) + 0.306(STD)
(t) (3.8) (2.4)

R^2 = 53.8%; F-ratio(2,13) = 7.6; D-W statistic = 2.15

(3) ERP = 4.75 - 0.218(LTGOVT) - 2.462(BETA)
(t) (2.9) (1.1)

R^2 = 38.7%; F-ratio(2,13) = 4.1; D-W statistic = 1.71

Implied Average Gas and Electric ERP For 1999:	Forecasted 1999 Average Canada Bond Yield		
	5.00%	5.50%	6.00%
Regression (1)	2.48%	2.39%	2.30%
Regression (2)*	3.05%	2.88%	2.72%

* Assuming that the SD(r) value for the typical non-diversified Canadian gas and electric utility is 4.375% (i.e.,the value found for the 1994-1998 period).

A Comparison of the Business Risks Facing Local Gas and Electric Distribution Utilities in Ontario

1. Categorization of Business Risks

Business owners who supply capital to an enterprise generally expect to receive compensation for two kinds of investment risks - namely, (1) longer-run, enterprise viability (or recovery-of-owners'-investment) risks and (2) short-run, volatility-of-return-related risks.

Long-run enterprise-viability risks are associated with those events and trends which may permanently undermine the capacity of the utility to generate, on an on-going basis, the cash flows necessary to permit the utility's owners to recover their investment and earn a fair rate of return on the funds they have committed to the business. As a consequence, these risks are often labelled "return of capital risks" or "capital recovery risks", and "bankruptcy risk" is perhaps the most severe manifestation of this category of risks. It is the perception of the level of these long-run capital recovery risks that is primarily reflected in the debt ratings assigned by bond and credit rating agencies.

Short-run volatility-of-return or earnings-variability risks are those occurrences which cause either the utility's actual cost-of-service-based revenue requirement or its actually-achieved revenues and net earnings to deviate from the forecasted or budgeted levels used for planning and rate-setting purposes. These year-to-year forecasting-related uncertainties may be associated with variable weather conditions, economy-driven fluctuations in the usage of the utility's services, changes in customer mix and usage patterns, variations in the cost of the commodity being distributed, unexpected operating and maintenance costs, and the effects of regulatory lag (which may cause the utility to earn less than its allowed return). In many areas, these short-run risks are mitigated or eliminated through the use of insurance, deferral or variance accounts, mechanisms to pass costs directly through to end-users, and other rate design adaptations.

In this section, we undertake a brief comparison of the business risk profiles of the regulated monopoly operations of local gas distribution companies and electric distribution utilities, as they have evolved or are expected to evolve over the next few years in Ontario. For the gas utilities, the regulated monopoly activities are essentially the gas delivery services provided through their systems of "pipes," as well as the provision of some Board-mandated load balancing, backstopping, and supplier-of-last-resort services. For electric utilities, the regulated monopoly activities are those directly related to the transmission and distribution of electric power through their systems of "wires" to end-users, as well as the provision of a default-customer electricity supply option.

2. Long-Run, Enterprise-Viability or Recovery-of-Capital Risks

In an equitable, cost-of-service-based, rate regulatory environment, it is not unreasonable to conclude that the long-run, enterprise-viability risk for either an electric utility or a gas LDC will "come home to roost" only if, in the future, there is a significant and sustained decline in the volume of the energy commodity flowing through its "wires" or "pipes", as the case may be. If this were to happen, the distribution utility would find itself carrying substantial excess capacity (some of which might be in the form of stranded assets), which would, in turn, jeopardize its ability to recover its fixed costs each year, as rate increases would gradually drive more of its customers to alternate energy sources or alternate delivery systems and away from the electric utility's or gas LDC's distribution infrastructure. Such "death spiral" scenarios are the ultimate manifestation of long-run, enterprise viability concerns.

At a conceptual level, there is the question of whether stranded assets necessarily imply a non-recovery of shareholders' investment capital even if the LDC, on an overall basis, remains economically viable and is not caught in some “death spiral”. Our view is that it does <u>not</u> imply a non-recovery of capital as long as the allowed equity return for the LDC incorporates an

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appropriate premium to compensate for stranded asset risk and the LDC continues to exist and to operate in a manner which affords it a reasonable opportunity to achieve its allow returns over time.

At a macro level, it is hard to imagine that there is any credible threat to the long-run viability of either the electricity distribution industry or the natural gas distribution industry in Ontario. The same conclusion holds at the micro level for the <u>typical</u> electric utility and the <u>typical</u> gas LDC in Ontario. Starting with electricity, there is no current or foreseeable practical substitute for electric power in many uses and many markets. Open access to, and unshackled competition within, the Ontario marketplace with respect to the generation and marketing of electricity is seen as vital to the economic health of the province and is eventually expected to bring down the delivered price of electric power and encourage greater use of electricity - and, hence, greater demands for its delivery - across Ontario. Restructuring Ontario’s electricity market is expected to reverse the past trend which has seen energy-intensive businesses avoid investments in Ontario. Nor will the industry wither for lack of product, as natural gas, hydro power, fossil fuels, nuclear energy, and wind power are all available for the generation of electricity in Ontario. With the exception of science fiction authors, it is hard for us to imagine a future world that does not include electricity delivered to the homes, offices, farms, and industrial plants in Ontario over an infrastructure of wires.

The case for the long-run survival of the <u>typical</u> gas LDC is almost as compelling. Where it is made available, natural gas is the “fuel of choice” for space heating, water heating, small-scale electric power generation, and for an increasing number of other applications. Gas presently enjoys, and for the foreseeable future will likely continue to enjoy, substantial cost, availability, security-of-supply, and environmental advantages vis-a-vis alternate fuels in most locations in Ontario. The availability of adequate gas supplies deliverable to the Ontario market also appears secure into the foreseeable future, as the pipeline infrastructure to operationalize an effective, integrated, North-America-wide gas market is nearing completion and gas reserves - whose abundant discovery, development, and delivery appear to be limited only by price

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considerations - are now available to the west, east, south, and even north of Ontario (in addition to a very small supply located in Ontario). However, in contrast to the indispensability of electricity, it is barely possible to imagine an Ontario in the future that is not primarily heated by natural gas. Nevertheless, the probability of the combination of circumstances arising that would result in this future is, in the Consultants' view, very very small over the next 30-40 years.

While the continued existence and vitality of the electricity and natural gas distribution industries is, thus, assured, the long-run economic viability and survival of every individual electric utility and gas LDC is not guaranteed. For either type of LDC, there is the risk that a portion of its existing rate-base assets will become "stranded" - that is, no longer used and useful for rate-base determination purposes - if a major customer, or a significant group of smaller customers, leave (fail to use) the distributor's system. Generally speaking, this can happen in only three ways: (1) the (former) customer(s) can bypass the LDC's system; (2) the technology employed by the customer(s) can change, making its/their continued use of gas or electricity unnecessary; or (3) the customer(s) can cease its/their operations as result of bankruptcy or a move to a new location. LDCs serving one-industry/one-plant towns or primarily economically-sensitive businesses are most exposed to this third source of stranded asset risk. If a substantial portion of a LDC's rate base were to become stranded, the survival of the affected LDC itself could be jeopardized.[2]

Bypass risk is, conceptually at least, a source of stranded asset risk and, hence, if severe enough, a risk to capital recovery for individual electric and gas LDCs. For Ontario gas LDCs, the practical significance of bypass risk rests squarely in the hands of the Board. Several provisions inscribed in the Ontario Energy Board Act, 1998, ("OEB Act") confirm the Board's exclusive jurisdiction over bypass[3]. Furthermore, history has repeatedly shown that the Board will employ rate-making solutions to accommodate legitimate bypass candidates in a manner that does not raise the stranded asset risk exposure of, or otherwise disadvantage, the shareholders of Ontario gas LDCs. Similar provisions in the OEB Act are expected to confer on the Board equal jurisdictional authority over bypass within the electricity distribution sphere.[4] Moreover, the Market Design Committee ("MDC") in its Third Interim Report recommends that steps be taken

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to discourage "uneconomic bypass" of transmission and distribution systems through the creation of embedded generation for the purpose of avoiding payments to recover the sunk costs of existing transmission and distribution systems.

While the MDC expresses the view that "it is unclear whether [the] OEB will have the authority to review [electricity] bypass proposals, and if so, what criteria and procedures it would apply" (Third Interim Report of the Market Design Committee, Chapter 2, page 9), it is reasonable to think that the Ontario Government intends the Board to exercise jurisdiction in this area and that the Board will apply similar rules, procedures, and economic remedies to legitimate electric distribution bypass candidates as it already does to those in the gas distribution industry. In conclusion, bypass risk presently appears to be no more than a very small risk to individual gas or electric LDCs in Ontario.

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2 At this point the discussion of the stranded asset risk to LDC survival is conceptual only, for as the size and geographic diversity of a LDC increases, the significance of the stranded asset risk <u>to enterprise survival</u> quickly shrinks to nothing, although the effects of this risk on short-run, forecasting-related, earnings variability risk, though diminished, do not disappear. For example, the continued existence of Consumers Gas and Union Gas are not threatened by the possibility of stranded assets, although their annual industrial volume forecasts retain some level of uncertainty in this regard because of the possible failure or relocation of major industrial customers.

3 These provisions are contained in sections 90, 36, and 43 of the OEB Act, 1998.

[4] These provision are contained in sections 57, 92, 78, 80, and 81 of the OEB Act, 1998.

The risk that technological change at the customer's facilities will eliminate its prior need for electric power and/or gas supplies - thereby creating stranded assets for the LDC - appears similarly small and perhaps non-existent in the case of electricity distributors.

The risk of stranded assets arising as a result of customer/plant relocation or bankruptcy is not negligible for some smaller and isolated LDCs.[5] However, it is not obvious that similar-size and similarly-located electric and gas LDCs would be exposed to any different degree of risk of customer bankruptcy or relocation-related stranded asset risk.

Overall, then, the risk of stranding existing rate base assets and thereby undermining the long-run economic viability of individual electric and gas LDCs appears to be about the same for enterprises of comparable size and geographic and customer diversity, while the capital-recovery aspects of this risk decline rapidly for both gas and electric LDCs as their size and geographic/customer diversity increase.

Finally, we must consider the future stranded asset risk that might be imposed upon a LDC if it is required to make new rate base investments to provide service to new customers or upgrades/additions to its infrastructure dedicated to major existing customers. In this respect, a number of people have noted a difference between the historical legislative/regulatory treatment of electric and gas distributors and wondered whether this would continue in the future. The Electricity Act, 1998, imposes an obligation on electic utility's, apparently unqualified by any economic considerations, to connect customers to its distribution system and to backstop these customers' electricity supplies (sections 26, 28 and 29). The corresponding obligation imposed on gas distributors (section 42 of the OEB Act) is not quite so unequivocal as it appears that significant investments in facilities to serve a new customer or community must first receive Board approval.

However, the Electric Act may provide for a similar Board role with respect to the ELECTRIC UTILITYs as section 26(1) of the Act indicates that an electric utility's connection

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of a customer to its distribution system must be done "in accordance with its licence." Arguably, this provision will give the Board as much discretion in establishing the rules for electric utility system expansion in the future as it currently has with respect to gas LDCs. Traditionally a gas distributor's obligation to connect a customer or community to its system and deliver gas to this customer or community has been conditional on the economic feasibility of the investment, and those proposals not meeting certain prospective economic/financial criteria have not been proceeded with in the absence of a compensating customer contribution in aid of construction. It is the author's view that there is unlikely to be any enduring distinction in the legal obligations of electric and gas LDCs to make rate base investments to serve (primarily industrial) customers and hence there will be no meaningful difference in the exposure of electric versus gas LDCs to the risk of stranding newly-created assets at some time in the future.

In conclusion, there appears to be very little difference between the <u>long-run enterprise viability risks</u> of smaller and more isolated electricity and gas distributor utilities, although the case can be made that the risk for electric utilities is marginally smaller than that of gas LDCs of similar size and geographic diversity if only because there are no substitutes for electric power in some of its uses and markets.

[5] For example, if Imperial Tobacco were to close its plant in Aylmer, Ontario, then Natural Resource Gas Ltd (NRG) would be left with sizeable stranded pipe-line assets, possibly jeopardizing this small gas utility's on-going viability.

3. Short-Run, Volatility-of-Return-Related Risks

A. Risks Related to Revenue Forecasts

Unpredictable weather conditions are the single greatest source of revenue forecasting errors for both electric utilities and gas LDCs. Nevertheless, since a higher proportion of the load/throughput of gas LDCs, as opposed to electric utility, is heating related, weather variations are a greater risk to gas LDC revenue forecasts than they are to the corresponding electric utility forecasts. The differences here are narrowing over time, however, as more gas load is directed toward cogeneration facilities while the use of electric-powered air conditioners has increased. In Ontario, neither the electric utilities' nor the gas LDCs currently have deferral/variance accounts to absorb the impact of mis-forecast volumes. (In contrast, BC Gas Utility and Gaz Métropolitain are allowed extensive deferral accounts to shelter their earnings from volume fluctuations.)

Fluctuating economic conditions are also a major source of uncertainty for electric utilities and gas LDCs as they make their revenue forecasts - particularly with respect to their industrial volumes. Unexpected plant closures and temporary shutdowns will cause both electric power consumption and the consumption of natural gas as a fuel or a feedstock to be lower than forecasted, resulting in revenue forecasting errors. In the commercial sector, the economy is also a source of revenue-forecasting errors as a higher proportion of businesses shut down and/or default on their bills during recessions. Even in the residential sector, the frequency with which consumers fail to pay their bills increases during difficult economic times. Those that we spoke to who had experience with the economy-related demand forecasting risks in both the gas and electricity distribution industries did not see a significant difference between these two businesses with respect to these economy-related risks.

Demand forecasting errors for both the electric utilities and gas LDCs are also created by unexpected outcomes in the areas of (1) the pace of customer additions; (2) the mix of volumes demanded across customer and rate classes; (3) the effects of demand-side management and conservation efforts; (4) the pace of (permanent) customer conversions from oil and electricity to natural gas; and (5) the fuel-supply choices of those industrial customers with "dual-fuel" capabilities. Within some of these latter five categories, (e.g., the pace of electricity-to-gas conversions), the risk to the local electric utility is the mirror image of that to the local gas utility (that is, one industry's gain is the other's loss), so, unless the forecasting accuracy is better in one industry than the other, the risk exposures in these areas are the same for the electric utilities and gas LDCs. In most of the other areas, however, the forecasting risk, though it may be relatively small, is probably greater for gas LDCs than electric utilities, since, for example, "fuel-switching" is primarily a gas-versus-oil phenomenum.

Severe physical risks, if they come to pass, may also cause actual throughput volumes to fall short of forecasts. This risk is a marginally more serious one for electric utilities than for gas LDCs because, if electric power is physically disrupted to a electric utility customer it is usually instantaneous (hence offering no time to plan to avoid/mitigate the risk) and, as electric power cannot usually be stored by the customer, there is often little the customer can do to replace the lost power. With respect to natural gas, however, the existence of "line pack" gas and possibly some gas in storage between the industrial plant and the break in the line may give large gas users some time and capability to adjust to the disruption. This "breathing room" may also allow gas LDCs time to make alternate gas sourcing arrangements to prevent isolated line breaks from disrupting its service to its customers.

Finally, there are revenue risks to both electric utility and gas LDCs resulting from the failure of end-use customers and/or aggregators, brokers, and marketers (i.e., "ABMs") to meet their contractual payment obligations to their local gas or electric distributors. In the past when electric utilities and gas LDCs were the principal marketers of electricity and gas, respectively, the credit risk involved in supplying these products was primarily the risk that end-use customers (large or small) would not pay their utility bills. As electric utilities and gas LDCs are now being

asked to exit the competitive supply and marketing aspects of electricity and gas distribution (to a large extent) under the restructuring contemplated in the Electricity Act and the OEB Act, much of this end-user credit risk will be shifted to the ABMs, and the regulated monopoly electric utilities and gas LDCs will be exposed, instead, to the credit risk of the ABMs. The level of the uncertainty associated with ABM credit risk will be controlled to a large degree through the application of the ABM licensing process and the regulations that the Board imposes as conditions for granting ABMs access to the LDC's system. Prospective ABMs lacking the administrative systems and financial backing to ensure their solvency will simply not be granted licences and/or access to the system (see sections 44(d), 48, 51, 57, 58, and 76 of the OEB Act, 1998). For those ABMs granted licences, the Board and/or the LDCs are likely to seek guarantees, in one form or another, to insure that the ABMs meet their financial obligations.

Despite these precautions and depending on the regulatory requirements the Board establishes, a monopoly LDC may possibly still be exposed to risks associated with the failure of an ABM in the form of the unforeseen revenue shortfalls and/or costs the LDC may have to absorb in carrying out the role(s) it is required to play if the ABM cannot meet its end-user supply obligations. We shall address these risks under the following sub-section where we compare the uncertainties associated with the cost estimates used to determine the revenue requirements of the electric utilities and gas LDCs.

While electric utilities and gas LDCs will generally be expected to exit the marketing function in future years, in each case it is expected that the monopoly local distributor will continue to serve as the commodity provider and marketer for one class of customers. With respect to the gas LDCs, the Board's "Advisory Report to the Minister of Energy, Science and Technology on Legislative Change Requirements For Natural Gas Deregulation," dated December 16, 1997, makes it clear that until the deregulated Ontario gas marketing environment envisioned by the Board/Ontario Government meets certain conditions with respect to consumer awareness, effective retail competition, non-discriminatory access to the monopoly distribution systems, competent/reliable industry self-management, and the assurance that system integrity and safety will be maintained, the Board will require the gas LDCs to make available to

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customers in their service areas a regulated, cost-based, standard gas sales/supply option to serve the needs that are currently met largely through system gas supplies. With respect to those of its customers that choose the regulated standard gas sales/supply option, the gas LDCs will continue to bear the revenue forecasting risks associated with customer non-payments.

Within the restructured electricity market, it is also envisioned that the regulated electric utilities will be required to make available a regulated supply of electricity to those customers who do not choose to arrange for their own electricity supplies through a competitive supplier. These customers are known as “default customers” and they will receive the default supply of electricity. In its Second and Third Interim Reports, the Market Design Committee (MDC) described and evaluated a number of fixed gas price and smoothed spot price pass-through pricing options for the regulated default supply offering and, in both cases, recommended that the Board mandate a default electricity supply priced at a “smoothed” pass-through of the wholesale market spot price of electricity, with quarterly “true-ups” and including a regulated recovery of administrative costs.

For the regulated electric utility, the revenue-forecasting and cost-forecasting implications depend on which pricing approach is chosen for the default supply option and what regulatory requirements are established with respect to whether it is the ABM or the electric utility, itself, that collects from the end-use customer the costs for the utility’s delivery services. With the fixed price options where the unregulated electricity retailer/supplier (ABM) collects the payments from end users, the ABM will bear the risk of end-user defaults, while the risk which arises if the retailer/supplier fails when spot electricity prices are high would be borne by the regulated electric utility or the end-use customers. (This latter risk is having to pay a higher-than-expected price to obtain a replacement supply of electricity.) To mitigate this risk, the regulated electric utility would require potential suppliers to meet certain prudential requirements such as an appropriate level of capitalization and the payment of a security deposit or the posting of a surety bond. With the smoothed spot pass-through option where the electric utility bills end users directly, there would be no risk for the utility from a supplier's failure, but the utility would

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be subject to the risk of payment defaults by end users or, more precisely, to mis-forecasts of the level of end-user non-payments.

The electric utility would also be responsible, under the smoothed spot option, for carrying the extra working capital "float" required to make timely payments for spot electricity supplies between periodic "true-up" dates in situations where the end-use customers will eventually be required to make positive "true-ups" through their subsequent electricity bills. Forecasting the carrying costs of this extra float is another, through relatively minor, source of risk for the electric utility. This latter risk is similar to the minor forecasting risk associated with the interest rate used for accruing balances under gas LDC purchased gas variation accounts (PGVAs).

All in all, there does not seem to be any fundamental difference between the typical electric utility and the typical gas LDC with respect to the revenue forecasting risks associated with the possibilities of non-payment by the end-use customers and by the commodity retailer-suppliers - in other words, with respect to "retail market risk".

Considering all related sources of uncertainty, it appears that the year-to-year revenue forecasting risks are somewhat greater for gas LDCs than they are for electric utilities, although there is a great deal of similarity between the nature and pattern of the short-run risk exposures in these two industries.

B. Risks Associated With Forecasting the Revenue Requirement

Commodity cost/price risk is potentially a source of risk for a gas or electricity distribution company which performs the merchant function as well as the delivery function. As the LDC exits the merchant function, this risk is transferred to the competitive retailer who arranges for the supply of the commodity on behalf of the end-use customer.

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For Ontario's gas distributors, currently, their delivered gas costs are included in their customers' rates based on Board-approved forecasts. The differences between the Board-approved weighted-average cost of gas and what turns out to be the actual delivered cost of gas purchased, including the impact of both indexed purchase prices and any hedging activities, is deferred into a Purchased Gas Variation Account (PGVA) and brought forward for disposition at a subsequent rate or gas cost hearings. While it is normally the case that these gas distributors will be able to recover fully any excess gas costs in future rates (and be required to refund unanticipated gas cost savings to ratepayers), the Ontario gas utilities and their shareholders have always been at some risk for the disallowance of imprudently-incurred costs. In the future, when the monopoly gas LDCs are confined to providing a regulated standard gas supply only, their gas cost risks will undoubtedly continue to be mitigated by the operation of Board-approved PGVAs.

Similarly, under the proposed restructuring of Ontario's electricity market, electric utilities, under normal circumstances and in the absence of third party supplier default, be at no risk for fluctuations in electricity prices. This risk will be born by the electricity retailer-suppliers, in the case of fixed-price options for the default-customer supply, and by the end-use customers themselves under a smoothed spot-price pass-through regime.

Consequently, as regards those customers for whom the regulated distributor will continue to perform the merchant function as well as the delivery function, the commodity cost variation risk appears to be equally small for electric utilities and gas LDCs. However, the provisions of the Electricity Act and the OEB Act, and the Board's Advisory Report on Legislative Change Requirements For Natural Gas Deregulation, make it clear that the regulated LDC - whether gas or electric - will be required to supply end-use customers itself in emergency situations where the retailer fails to meet its supply obligations. This prospect raises the risk that the LDC - acting in its capacity as “supplier of last resort” - will not be able to recover in its rates the commodity purchase costs it incurs to fulfil this supplier-of-last-resort role.

For electric utilities, the MDC's proposals imply that either the electric utilities or the end-use customers will absorb the extra costs to access spot electricity supplies subsequent to a supplier's failure to deliver. The extreme electricity spot price spikes experienced in the U.S. during June 1998 suggest that this risk might be quite high. On the other hand, if the Ontario Government accepts the MDC's recommendation for a price cap on 90% of the domestic energy sales from Ontario Hydro's generating company for the first four years after the opening of the restructured Ontario electricity market, then this supplier-of-last-resort electricity cost risk will be greatly mitigated for the electric utilities, even if they are asked to bear all the risk. Furthermore, those electric utilities with some self-generation capability will have greater flexibility in dealing with either supplier failure or outages than those electric utilities without, and hence face less commodity cost/price risk. Nevertheless, as the key decisions have yet to be taken, we can only speculate that the rules and regulations designed to address this risk will not allocate an undue portion of it to the regulated electric utility sector.

For the gas LDCs, the commodity cost risk associated with their performance of the supplier-of-last-resort role is inherently less risky, since the availability of stored gas supplies makes spot gas prices less volatile than spot electricity prices. Nevertheless, the gas LDCs have claimed that, as their system gas portfolios have shrunk, they have found themselves with less gas supply management flexibility to play the role of market facilitator by providing load balancing and backstopping services to their customers, by accommodating the movement of customers to and from the direct purchase market, and by acting as the supplier of last resort. This, in turn, they feel, has raised the risk of their under-recovery of TCPL transportation capacity costs. In our view, however, the expanded order-making and rule-making capacity granted the Board under the OEB Act, 1998 will enable the Board to effectively relieve Ontario's gas LDCs of the risk of stranded transportation contracts if they are asked to maintain a portfolio of gas supplies to ensure system integrity or if they are required to exit the merchant function altogether and hand over their sales customers to independent gas marketers.

Overall, then, it is possible that electric utilities will experience more commodity cost risk acting as suppliers of last resort than will gas LDCs in the future, but this will depend on electricity pricing decisions and market structure choices that have yet to be made.

Gas and electric LDCs must also forecast their future operating and maintenance (O&M) expenses in the process of establishing their revenue requirements and user rates. Year-to-year, the greatest source of uncertainty with respect to these O&M expenditures is what we could call "physical disruption risks." For the gas distributors, these risks are usually associated with events which cause line breaks and outages, which may be caused by corrosion, stress fractures, or floods (PNG, WCE), by sabotage, or by construction accidents. These outages may lead to unabsorbed demand charges for the LDCs as well as increased repair costs. For the electric utilities, these physical disruption risks are usually unplanned outages/blackouts caused by the collateral damage from ice and wind storms, lightening, and possibly floods, as well as by over-heated wires at times of peak demand, and by sabotage. On balance, it appears that the exposure of electric utilities to physical disruption risks - and, in particular, the uncertainties with respect to forecasting the associated repair expenditures year to year - are greater than those of gas LDCs. In most cases, however, this forecasting risk is small relative to the major revenue forecasting risks.

For the forecasting risks associated with the other O&M expenditure items, there would appear to be no reason for these risks to be materially different between gas and electric LDCs of similar size and organizational diversity.

Capital costs - including the cost of capital additions, depreciation, income and other taxes, payments in lieu of taxes, and the servicing costs of embedded and new debt and preferred share financings - are also components of a utility's overall revenue requirement which must be projected for the rate-setting purposes. Generally speaking, forecast errors in these items are not seen as expanding the business riskiness of either gas or electric LDCs in any material way. In instances where the LDCs are subject to significant prediction error, the financial impact of

deviations from forecasted or budgeted levels is usually absorbed through the application of deferral accounts.

Ontario's gas and electric LDCs are also going to be subject to various "regulatory risks" in the future; however, as each of these sets of LDCs will be regulated by the Board under a similar set of rules and regulations, and the Ontario Government and the Board have expressed their intentions to provide treatment that is as equal as possible to the LDCs in these competing industries, there is no reason to believe that the regulatory risks (including earnings attraction from tardy rate decisions, management prudence requirements, etc.) facing electric utilitys and gas LDCs will be any different. Both industries, for example, will also benefit from the Board's move to develop and employ a performance-based or incentive-based system of regulation in the near future.

C. Overall Evaluation of Short-Run Forecasting/Volatility Risks

The above evaluation and comparison of the short-run volatility-of-return-related business risks of electric utilities versus gas LDCs in Ontario concludes that (1) the revenue forecasting risks of gas LDCs are somewhat greater than those of the electric utilitys, while (2) forecasting the cost components of the distributors' revenue requirements is likely to involve slightly greater risk in the future for electric utilities than it will be for the regulated gas LDCs. As the revenue forecasting risks have historically dominated the cost forecasting uncertainties,
we are drawn to the conclusion that the inherent return-volatility riskiness of Ontario's gas LDCs - both currently and in the future - is marginally greater than that which Ontario's electric utilitys are likely to experience in the future.

4. Overall Evaluation of the Comparative Business Riskiness of Ontario's Gas and Electricity Distribution Companies

In Section 2 of this Appendix, we conclude that there appears to be very little difference between the long-run, enterprise viability riskiness of electricity and gas distributors in general, and smaller and more-isolated electricity and gas LDCs in particular, although we felt that the risk for gas LDCs might be marginally greater than that for electric utilities when enterprises of similar size and geographic diversity are compared. In Section 5, we conclude that, with respect to short-run, volatility-of-return-related risks, gas distributors might also be marginally more risky than electric utilities of similar size and diversity. These two conclusions reinforce each other and lead us to conclude that, controlling for organizational size and diversity, Ontario's electric utilities are marginally less risky, in terms of overall business risk exposure, than gas LDCs. It is doubtful, however, that the small magnitude of this overall difference in business riskiness would, by itself, justify different deemed capital structure proportions, or different degrees of acceptable financial leverage risk, or significantly different allowed equity returns, between similarly-sized and similarly-diversified electric utilities and gas LDCs.

The analysis throughout this Appendix also reveals, perhaps not surprisingly, that there is a remarkable similarity in the nature and pattern (if not always the intensity) of the business risks facing individual enterprises in the Ontario gas and electricity distribution industries. The similarity in their risk profiles also suggests that it may be reasonable to infer appropriate financial structures and allowed returns for electric utilities by looking at the deemed financial structures and allowed returns adopted for, and considered optimal for, similarly-sized gas distribution utilities.