A DISCUSSION PAPER ON

THE DETERMINATION OF RETURN ON EQUITY

AND RETURN ON RATE BASE FOR

ELECTRICITY DISTRIBUTION UTILITIES

IN ONTARIO

Prepared for
The Ontario Energy Board
By

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1.1 The Purpose and Scope of the Paper

The purpose of this discussion paper is to assist the Ontario Energy Board ("the Board") in addressing its recently-acquired responsibilities for regulating the monopoly "wires" businesses of the 270-plus municipal electric utilities ("MEUs") in Ontario. In particular, under section 78(3) of the Ontario Energy Board Act, 1998, the Board is charged with the responsibility for making "orders approving or fixing just and reasonable rates for the transmitting or distributing of electricity ..." It is the Board's intention to use a performance-based framework for regulating the MEUs' rates of return.

As a component of this performance-based regulation ("PBR"), the Board requires a methodology for determining the allowed return on common equity ("ROE") and the allowed overall rate of return on rate base for the regulated MEUs. The Board already employs a formula-based approach for determining, and making year-to-year adjustments to, the allowed equity returns for the natural gas distributors under its regulatory jurisdiction. One of the broad purposes of this paper, then, is to assess whether these existing equity-return-setting guidelines for the Ontario gas local distribution companies ("LDCs") can and should be applied - in their current or some amended form - to the regulation of MEU allowed returns.

The focus of the research effort behind this paper is on the applicability of the gas LDC return-setting procedures to the 270 or more MEUs in Ontario. The paper and its recommendations are not intended to deal with the regulation of the transmission and distribution businesses of Ontario Hydro Retail under the Ontario Hydro Services Company.

In addition, readers should be aware that the numerical results reported in this paper with respect to Ontario MEUs are all based on 1996 yearend figures. The Board and the author recognize that some significant amalgamations among MEUs have taken place over the past two years which will impact the tabulations reported in this paper. There is no reason to believe, however, that the paper's major conclusions or recommendations have in any way been compromised by the process of consolidation that has already begun within the industry.

In order to address the appropriateness and practical applicability of the gas LDC formula-based return-setting methodology to Ontario's network of MEUs, the scope of the author's investigations, conclusions, and recommendations have, by necessity, also included the following topics and issues:

(1) An assessment of the degree to which the rate of return regulation of Ontario's MEUs can be made to be symmetric with the Board's regulatory treatment of the gas distributors;

(2) An assessment of the feasibility and appropriateness of grouping MEUs into a limited number of business risk classes, so that initial uniform equity risk premiums ("ERPs") can be established for MEUs in each group to simplify the administrative processing of rate applications;

(3) If grouping MEUs into risk classes is feasible and appropriate, the criterion or criteria for making these MEU risk-class designations must be chosen;

(4) An assessment of whether it is feasible and appropriate to employ hypothetical or deemed capital structures - either individually or by risk class - in the process of regulating MEU rates of return;

(5) If employing hypothetical capital structures is judged to be appropriate, an assessment of reasonable, risk-class-differentiated, deemed capital structure proportions for the network of MEUs is required;

(6) A determination of how the regulatory process should translate allowed returns on equity and hypothetical capital structure proportions into the overall rates of return on rate base for the MEUs; in particular, a policy choice is required with respect to whether the differentiation between MEU risk classes and overall rate-of-return requirements should be accomplished (a) entirely through the choice of risk-differentiated deemed capital structures, (b) entirely through the setting of risk-differentiated allowed equity rates of return, or (c) by partial adjustments to both the deemed capital structures and the allowed equity returns.

The following section of the paper sets out the Board's goals with respect to regulating MEU rates of return. The goals provide the basis for evaluating the author's recommendations with respect to the above-noted regulatory issues, in the context of the Ontario MEU industry.

1.2 The Board's Goals With Respect to Regulating MEU Equity Returns and Rate Base Returns

The conclusions and recommendations developed in this discussion paper are based on the assumption that the following list reflects the goals of the Ontario Government and the Board with respect to the roles and effects of the allowed returns on equity, the allowed returns on total capital, and the deemed capital structure ratios that will be employed by the Board in establishing and revising the user rates for the regulated "wires" businesses of Ontario's MEUs. These goals are:

(1) The allowed returns on equity and total capital for MEUs should be fair and reasonable from the perspectives of both the MEU's ratepayers and its owners.

(2) The allowed equity returns should provide fair compensation for the owners of the MEU in comparison with the returns that could be earned on comparable, equally risky, alternate Canadian investments. When establishing this fair compensation, unless the deemed capital structure proportions for the MEUs are set so as to fully compensate for the differences in the business risks among the MEUs, the allowed returns on equity must be adjustable to recognize the variations in the capital structure ratios that may be appropriate across the spectrum of MEUs.

(3) The allowed returns on equity and total capital should be sufficient to enable a prudently-managed MEU to attract new debt and equity capital on reasonable terms under normal market conditions and without impairing the financial integrity of the MEU's existing securities. Furthermore, the deemed MEU capital structure ratios for rate-setting purposes, in conjunction with the allowed returns on debt and equity capital, should not unreasonably impair a MEU's ability to access loan and capital markets for new debt and equity on reasonable terms under normal financial market conditions.

(4) The determination of allowed returns on equity and total capital should be as symmetric as possible with the process applied to the regulated operations of the Ontario natural gas LDCs and, in any case, not confer any unwarranted advantage or disadvantage on MEUs, as compared to gas LDCs, that might unfairly distort the relative competitive positions of the electric power suppliers and marketers versus the natural gas suppliers and marketers in Ontario.

(5) The transition process from the current levels of MEU returns to those which reflect and foster the standards of fairness, capital attraction, and maintenance of financial integrity should be managed in such a way that it gives due consideration to the potential impacts on ratepayers and on the process of consolidation (including mergers and acquisitions) envisioned for the MEU industry.

There are a number of additional considerations which may, from time to time, play a role in helping the Board interpret the above goals in specific circumstances. First, the Board may wish to consider whether its MEU return awards, expressed as percentages of the book values of the MEUs' deemed equity and total capital, will be high enough to provide sufficient funds for the normal refurbishment and replacement of existing rate base assets when, and to the extent that, the funds set aside through the MEUs' depreciation accounts (which are based on historical costs) are not alone adequate for maintaining the integrity of the MEUs' distribution systems.

Second, the deemed MEU capital structure ratios for rate-setting purposes, in conjunction with the allowed returns on debt and equity capital, should ideally be such as to minimize the overall, weighted-average cost of capital for the MEUs - and thus minimize the contribution of capital costs to the MEUs' revenue requirements - to extent that this is possible without undermining the achievement of the Board's above-noted goals with respect to setting MEU rates of return.

Third, it would be desirable if pursuing the regulatory goal of preserving user-rate stability were not subverted, or made unnecessarily difficult, by the MEU return-setting process adopted by the Board. In other words, the operation of the year-by-year adjustment mechanism for the MEU allowed returns, either on its own or in conjunction with the adjustment of other components of the delivered cost of electricity service, should, to the extent possible considering the Board's return-setting goals, not contribute unduly to user-rate instability from year to year.

Fourth, in order to preserve the financial integrity of those owners or investors who have committed their financial capital to an MEU in past years, and in order not to impede the process of consolidation within the electricity distribution industry by unduly disincenting mergers among MEUs or the sale of MEUs to private interests, it would be desirable if the returns allowed by the Board were sufficient to provide the existing municipal owners of the MEUs the opportunity to transfer the ownership of the shares and/or assets of their MEUs at a market value which is not less than the book value of the municipality's existing equity in the MEU. This would be a desirable outcome, however, only to the extent that its pursuit is congruent with achieving the five above-noted goals for the MEU-return-setting process.

Finally, in connection with the Board's transition-process-related goal for MEU returns, it is necessary to recognize that a major goal of the Ontario Government is to allow the forces of competition within a restructured electricity market to lower the user prices for electricity in Ontario in the medium and longer-term future. It is not possible to address this goal directly through the allowed-return-setting process, however, since the returns allowed to MEUs in a rate-regulatory environment are eventually bound to exceed the 3%-4% returns that Ontario MEUs have typically earned in recent years. If significant cost economies cannot be achieved in other areas of the restructured electricity marketplace, then the goal of stabilizing and eventually reducing the delivered prices for electricity in Ontario may limit the degree to which, and the speed with which, the Board's first four goals with respect to its regulation of MEU returns can be achieved.

1.3 Summary of Conclusions and Recommendations

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

In Section 3, I consider various criteria for classifying MEUs according to their business risks and come to the conclusion that regulated rate-base asset size, alone, is the most appropriate basis for forming MEU business risk groupings. I further recommend that MEUs with total rate base assets in excess of $1.0 billion be designated "low-risk" MEUs, while MEUs with rate bases in the $300 million to $999 million range should be designated "medium-low-risk"; those with rate bases of between $100 and $299 million should be "medium risk"; those with rate bases between $40 and $99 million should be "medium-high risk"; and those with rates bases of less than $40 million should be described as "high-risk" MEUs.

Section 4 is devoted to examining the determinants of industrial and utility capital structure policies and the relationship between capital structure policies and required rates of return on equity for organizations employing financial leverage. Section 4.2, in particular, focuses on the considerations influencing the choice of capital structure proportions for rate-regulated utilities, while Section 4.4 compares the range of regulatory capital structures presently employed for private gas and electricity utilities across Canada. Based on the theoretical and empirical evidence considered in Sections 4.1 through 4.4, I make the following recommendations (shown in the table below) for the appropriate deemed MEU capital structures, conditional on the Board's adoption of another of my recommendations - namely that the Board's entire adjustment for differences in business risk across MEUs be reflected in its choice of each MEU's deemed common equity and debt ratios for regulatory rate-setting purposes.

MEU Business Risk Class	**Deemed CER %**	**Deemed Debt Ratio %**
Low Risk	35	65
Medium-Low Risk	40	60
Medium-Risk	42.5	57.5
Medium-High Risk	45	55
High Risk	50	50

In Section 4.6, I conclude that MEUs adopting a "conservative" financing policy should opt for a high proportion of long-term, fixed-rate issues in their organization's debt mix, although MEUs may provide some incremental stability to their achieved interest coverage ratios ("ICRs") if they employ more than the minimum amount of short-term and/or floating-rate debt financing.

In Section 5, I describe the Board's current formula-based approach to setting and revising gas LDC equity rates of return, and I provide an evaluation of the strengths and weaknesses of this approach in the context of Ontario's gas LDC and MEU industries. In Section 5.4, I conclude that there is no serious impediment standing in the way of applying the Board's current formula-based approach for setting gas LDC allowed returns to the MEU industry and thus insuring consistency of regulatory treatment between firms in these two, frequently-competing industries. Indeed, the analysis in this section indicates that the volatility-related drawbacks of the formula-based return-setting approach are likely to be less detrimental to electricity ratepayers than to gas ratepayers. However, for reasons outlined in Section 5.5, I also recommend that for the formula's future application in regulating both gas and electricity distributor returns, the 30-year Canada yield forecast should be replaced by the 10-year forecast in the mechanism employed by the Board to adjust LDC allowed equity returns on an annual basis.

My recommendation for how the Board should establish the allowed, overall rates of return on rate base for MEUs in each risk class is described and illustrated in Section 6. The approach that I suggest is one where all MEUs are awarded the same allowed return on common equity, but their deemed debt and common equity ratios are set to reflect the business risk classes in which each resides. The debt-cost requirements associated with each MEU's deemed debt ratio are, in the first instance, set equal to the actual embedded rate on any MEU borrowings. Then, to the portion of the debt ratio for which there is no corresponding actual debt outstanding, a Board-set, debt-cost requirement is applied, which reflects the prospective borrowing rates for organizations within the MEU's risk class. This debt rate would be determined annually by the Board on the basis of expert advice.

Again, to summarize the three main conclusions from Section 6:

(1) MEU deemed capital structures are to be adjusted to fully reflect MEU business riskiness which, in turn, is based on asset-size risk classes;

(2) MEU allowed equity return are to be set using an amended Board formula with annual adjustments; and

(3) for deemed MEU debt that is not embedded, a market-related prospective cost rate is to be prescribed to reflect the MEU's risk class.

Finally, in Section 7, I evaluate the major recommendations of this paper by examining whether or not they are consistent with achieving the Board's goals for MEU regulatory rate-setting, as set out in Section 1.2. Using the Board's formula-based return-setting methodology (with or without my suggested amendment) as the basis for the rate regulation of Ontario's MEUs is found to be consistent with, and likely supportive of, the Board's rate-regulation goals.

2. A Comparison of the Electricity Distribution Utilities and the Natural Gas Distributors in Ontario

2.1 Comparative Profile of Gas LDCs and MEUs in Terms of Number, Size, and Geographic Diversity of Operations

There are presently three privately owned, local natural gas distribution companies ("gas LDCs") in Ontario whose operations and user rates are regulated by the Board. These companies are Enbridge Consumers Gas (formerly The Consumers' Gas Company Ltd. and hereafter referred to as "Consumers" or "Consumers Gas"), Union Gas Limited ("Union" or "Union Gas") and Natural Resource Gas Limited ("NRG"). Gas service is also provided in various Ontario localities by municipal public utilities commissions ("PUCs") whose operations are not regulated by the Board.

Two of these gas LDCs - Consumers and Union - are very large, geographically-diversified utilities operating under the corporate umbrellas of even larger corporate organizations; the third gas LDC - NRG - is a small organization headquartered in Aylmer, Ontario, with limited operations concentrated in the vicinity of Aylmer. The following table compares these three gas LDCs in terms of various measures of size and financial strength.

(e = estimated; n.a.= not available)	Consumers	Union	NRG
Total assets (1997 FYE, in $MM)	3,542	3,967	9[e]
Rate base (for 1999, as per most recent OEB hearing, in $MM)*	3,283	2,709	9.0
Total revenues (1997 FY, in $MM)	1,987	1,894	6
Number of customers (1997 FYE, in 000s)	1,342	1,041	4.5[e]
Total common shareholders' equity (1997 FYE, in $MM)	1,022	1,077	4
Total gas distribution volumes (1997 FY, in $10^6 m^3$)	12,137	14,476	n.a.

* The values for the approved or requested average rate bases for 1999 are used because these now exclude the competitive retailing assets for Consumers and Union.

In terms of geographic diversity, Consumers serves customers in the areas of central and eastern Ontario, including: Metropolitan Toronto and the greater Toronto areas of Peel, York, and Durham regions, as well as the Niagara Peninsula, Ottawa, Brockville, Peterborough, Barrie and many other Ontario communities. Union serves over 400 communities in northern, southwestern, and eastern Ontario, in a region that extends throughout northern Ontario from the Manitoba border to the North Bay/Muskoka area, through southern Ontario from Windsor to just west of Toronto, and across eastern Ontario from Port Hope to Cornwall. NRG serves the town of Aylmer and some or all of 14 rural townships mostly east Aylmer.

There are currently some 270 or more municipally owned electric utilities ("MEUs") in Ontario, including those which operate under the umbrella of municipal public utilities commissions. At the end of 1996 - the date corresponding to the MEU data used in this paper - there were 306 MEUs. There are also four privately-owned electricity distributors in Ontario - namely, Great Lakes Power Limited, Canadian Niagara Power Company, Granite Power Corporation, and Cornwall Street Railway Light and Power Ltd. ("Cornwall Electric").

Based on 1996 figures, the MEUs range in size from Toronto Hydro[1] - with total assets of $808 million, total equity of $621 million, annual revenues of $738 million, and 221,148 customers - down to Apple Hill Hydro - with total assets of $80,804, total equity of $61,534, annual revenues of $131,616, and 114 customers. The table below shows the numbers of MEUs in each of the indicated ranges for 1996 total assets and 1996 total revenues.

[1] Toronto Hydro has now amalgamated with most of the other Toronto-area MEUs to form a much larger organization.

Total Assets Size Range (in $millions)	Number of MEUs
200 - 1,000	8
100 - 199.9	8
50 - 99.9	18
20 - 49.9	17
10 - 19.9	22
5 - 9.9	29
less than 5	204

Total Revenues Size Range (in $millions)	Number of MEUs
200 - 1,000	8
100 - 199.9	8
50 - 99.9	18
20 - 49.9	18
10 - 19.9	24
5 - 9.9	28
less than 5	202

Virtually all the MEUs have concentrated operations from a geographic perspective. The larger MEUs, of course, have considerably greater diversification across customers - especially large-volume industrial customers - than their smaller cousins. Only 15 of the 306 MEUs used any locally-generated electric power during 1996, and local generation as a whole accounted for only 0.11% of overall MEU power supplies across Ontario.

2.2 A Comparison of the Ownership Structures and the Goals and Incentives of Gas LDC and MEU Owners in Ontario

The three Board-regulated gas LDCs in Ontario are privately owned. Consumers Gas is 100%-owned by Enbridge Inc. (formerly IPL Energy Inc.), which is itself a widely-held Canadian pipeline and energy services corporation. Union Gas is a 100%-owned subsidiary of Westcoast Energy Inc., which is also a widely-held Canadian pipeline and energy services company. NRG is owned by a single individual shareholder who also manages the Company's affairs. While all of these gas LDCs are undoubtedly operated in a manner to serve and promote the long-run interests of the gas customers within their respective service areas, as private, shareholder-owned and shareholder-controlled corporations, the primary goal of these organizations is to maximize the wealth and welfare of their shareholders. Subject to the regulatory oversight of the Board, the major investment and financing decisions of these private gas LDCs are motivated by this pursuit of shareholder wealth maximization in the long run.

Within the present rate-of-return regulatory environment, as a consequence, there is an incentive for managers of these gas LDCs to seek the highest reasonable allowed equity return and the highest reasonable deemed common equity ratio ("CER*") during their periodic rate hearings. Furthermore, recognizing that there are real shareholder opportunity costs association with the provision of equity capital to these private gas utilities, there is an incentive for the owners/shareholders to invest no more equity capital in these regulated entities than the Board is willing to attach an allowed equity rate of return to (unless bond rating and financing-flexibility considerations dictate otherwise). Indeed, the common shareholders of these gas LDCs would stand to benefit if the Board would permit a utility to retain in the regulated enterprise less actual equity than that implied by its deemed CER for regulatory purposes.

With the exception of the four, privately-owned, local electricity utilities mentioned at the beginning of this section, all of the MEUs in Ontario are municipally-owned, not-for-profit organizations. These MEUs do not have any publicly-held or publicly-traded shares. As a consequence, managers of MEUs are not driven by return-maximization or share-value-maximization objectives. Instead, these managers generally conceive of their customers and their owners as one and the same constituencies - namely, the municipal government and the residents of the municipality - and strive to set rates and provide electricity services in the manner that best fosters the prosperity, growth, and financial health and welfare of the communities they serve. MEU managers recognize that lower user rates will reduce the burdens on ratepayers within the municipality and possibly help to attract new businesses and industry to their communities (or retain existing ones), while lowering the utility net earnings that can be passed on to the municipal government to ease its budgetary strains and possibly lower municipal property taxes. Higher user rates, conversely, may fatten a MEU's net returns and distributions to the municipality, thus serving to lower local property taxes, but this will come at the expense of higher burdens on electricity ratepayers and a reduced community appeal to electric-power-intensive businesses or plants.

The municipal ownership of MEUs and the fact that they have, in the past, been exempt from income taxation has meant that MEUs have not had the same incentives to employ debt financing as otherwise-similar private utilities. Unnecessary debt financing charges have usually been seen as a diversion of some portion of the MEU cash flows which could otherwise be directed to support the municipal budget. Consequently, MEUs have generally taken on debt only when they have undertaken major fixed-asset investments for which sufficient capital funds have not previously been accumulated. Once the debt was on the MEU balance sheets, it was not viewed as a permanent fixture (as it might be by a private, taxable utility corporation), but as an obligation to be paid down over a prescribed time horizon.

While some of the financial constraints and incentives facing MEUs will change under the electricity market restructuring envisioned in the Electricity Act, 1998, as long as MEUs are municipally owned the managers of these organizations are bound to conceive of their organizational goals, and the motivations behind their major investment and financing decisions, in a different light than those of their colleagues managing shareholder-owned gas and electricity LDCs.

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

2.3.1 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, I undertake a brief comparison of the business risk profiles of the regulated monopoly operations of local gas distribution companies and municipal electric utilities (MEUs), 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 MEUs, 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.

2.3.2 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 a MEU 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 MEU'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". My view is that it does not imply a non-recovery of capital as long as the allowed equity return for the LDC incorporates an 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 typical MEU and the typical 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 typical 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 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 author's 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 MEU 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 happened 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

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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 to enterprise survival 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.

sphere.[4] Moreover, the Market Design Committee ("MDC") in its Third Interim Report recommends that steps be taken 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.

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 <u>individual</u> 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 MEUs, apparently <u>un</u>qualified 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 MEUs as section 26(1) of the Act indicates that a MEU's connection 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 MEU 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

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

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.

and more isolated electricity and gas distributor utilities, although the case can be made that the risk for MEUs 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.

2.3.3 **Short-Run, Volatility-of-Return-Related Risks**

2.3.3.1 **Risks Related to Revenue Forecasts**

Unpredictable weather conditions are the single greatest source of revenue forecasting errors for both MEUs and gas LDCs. Nevertheless, since a higher proportion of the load/throughput of gas LDCs, as opposed to MEUs, is heating related, weather variations are a greater risk to gas LDC revenue forecasts than they are to the corresponding MEU 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 MEUs 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 MEUs 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 I 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 MEUs 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 MEU 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 MEUs 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 MEUs, since, for example, "fuel-switching" is primarily a gas-versus-oil phenomenon.

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 MEUs than for gas LDCs because, if electric power is physically disrupted to a MEU 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 MEUs 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 MEUs 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 MEUs 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 MEUs 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 "market rules" 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. I shall address these risks under the following sub-section where I compare the uncertainties associated with the cost estimates used to determine the revenue requirements of the MEUs and gas LDCs.

While MEUs 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 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 MEUs 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 MEU, the revenue-forecasting and cost-forecasting implications depend on which pricing approach is chosen for the default supply option and what "market rules" are established with respect to whether it is the ABM or the MEU, itself, that collects from the end-use customer the costs for the MEU'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 MEU 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 MEUs 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 MEU bills end users directly, there would be no risk for the MEU from a supplier's failure, but the MEU would 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 MEUs 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 MEU. 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 MEU 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 MEUs, although there is a great deal of similarity between the nature and pattern of the short-run risk exposures in these two industries.

2.3.3.2 **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.

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, MEUs will, 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 MEUs 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 MEUs, the MDC's proposals imply that either the MEUs 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 MEUs, even if they are asked to bear all the risk. Furthermore, those MEUs with some self-generation capability will have greater flexibility in dealing with either supplier failure or outages than those MEUs without, and hence face less commodity cost/price risk. Nevertheless, as the key decisions have yet to be taken, I can only speculate that the rules and regulations designed to address this risk will not allocate an undue portion of it to the regulated MEU 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 my 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 MEUs 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 MEUs, 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 MEUs 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 MEUs and gas LDCs will be any different. For example, it is one of the purposes of the author's present investigations to seek to establish, to the extent that it appears possible, a common approach to setting and adjusting the allowed equity returns for individual enterprises within Ontario's regulated gas and electricity distribution industries. Both industries 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.

2.3.3.3 **Overall Evaluation of Short-Run Forecasting/Volatility Risks**

The above evaluation and comparison of the short-run volatility-of-return-related business risks of MEUs versus gas LDCs in Ontario concludes that (1) the revenue forecasting risks of gas LDCs are somewhat greater than those of the MEUs, while (2) forecasting the cost components of the distributors' revenue requirements is likely to involve slightly greater risk in the future for MEUs than it will be for the regulated gas LDCs. As the <u>revenue</u> forecasting risks have historically dominated the <u>cost</u> forecasting uncertainties, I am 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 MEUs are likely to experience in the future.

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

In Section 2.3.2, I concluded 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 I felt that the risk for gas LDCs might be marginally greater than that for MEUs when enterprises of similar size and geographic diversity are compared. In Section 2.3.3.3, I concluded that, with respect to short-run, volatility-of-return-related risks, gas distributors might also be marginally more risky than MEUs of similar size and diversity. These two conclusions reinforce each other and lead me to conclude that, controlling for organizational size and diversity, Ontario's MEUs are marginally less risky, in terms of overall business risk exposure, than gas LDCs. It is doubtful, however, that the small magnitude of this overall difference in business riskiness would, by itself, justify different deemed capital structure proportions, or different degrees of acceptable financial leverage risk, between similarly sized and similarly diversified MEUs and gas LDCs.

My analysis throughout Section 2.3 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 for MEUs by looking at the financial structures adopted by, and considered optimal for, similarly sized gas distribution utilities.

3 Grouping Ontario's MEUs on the Basis of Their Business Risk Exposures

3.1 Using Business Risk Profiles to Group Ontario's MEUs

Conceptually, MEU deemed capital structure ratios for rate-regulation purposes and/or their allowed returns on equity should vary to reflect the extent of the business risks to which each MEU is exposed. Higher relative business risks will imply less debt-carrying capacity and hence call for higher deemed common equity ratios (CERs). Furthermore, if the higher CER does not fully compensate for a MEU's relatively higher business risk, then the allowed return on equity (ROE) should also be adjusted upward to compensate MEU owners for the relatively higher total investment risk that their ownership stakes are exposed to.

Whatever its theoretical merits, assessing an individual MEU's relative business risk and determining the appropriate adjustments to its deemed CER and its allowed ROE is a potentially costly and time-consuming process involving subtle judgments and likely modifications over time - possibly requiring public hearings and the assistance of outside experts. It is impractical to imagine the Board managing this process, and making separate judgments and decisions, for all of Ontario's 270 or so individual MEUs. The "costs" involved would simply not justify the incremental benefits in the vast majority of cases. Moreover, the complexity of the process and the sheer number of decisions would, for most MEU managers and advisors, obscure many of the important signals that the Board would like its Decisions to convey. For example, signals with respect to (1) the inter-relationships between MEU business risks, deemed CERs, and allowed ROEs, as well as (2) the impact of debt-servicing constraints and bond rating guidelines on deemed CERs and allowed ROEs, would be in danger of being buried by an avalanche of individual-MEU-specific considerations. Consequently, it is quite reasonable for the Board to seek to sort all of Ontario's MEUs into a limited number of groupings based on their relative business risk profiles, with the intention of providing distinctive regulatory treatment with respect to deemed CERs and allowed ROEs across these risk groupings or risk classes, but uniform treatment with respect to these variables for MEUs within any particular grouping. The purpose of this section of the paper is to seek out an appropriate basis for making the risk-grouping or risk-class distinctions and allocating individual MEUs to particular risk classes.

It would be desirable if one of the outcomes of this risk-class grouping scheme were a set of one or more categorization criteria that would enable MEUs which are contemplating a business combination (merger, takeover) to predict, with some assurance, the impact of their proposed combinations on their risk-class categorizations. It would also be desirable to have a risk-class categorization system which is congruent with the risk categorization approach used by the debt-rating agencies to rate MEU debt issues. While there are some theoretical distinctions with respect to how the business or asset risk of an organization gets transferred across to the investment risk exposures of its debtholders and its owners, these distinctions, which surface primarily during times of "financial distress", are not of practical significance to municipally-owned MEUs and not likely very relevant to privately-owned MEUs either. Consequently, the time-tested risk criteria employed by the bond rating agencies to rate MEU debt securities may provide a useful guide for establishing the criteria for assessing the risk to the equity stakes of the MEU owners.

Discussions with a number of people within, or familiar with, the electricity distribution industry revealed a sizeable number of potential factors for categorizing MEUs into different business risk classes. I have listed some of these below, accompanied by brief examples of the connection(s) between the structural or environmental factor, on the one hand, and the MEU risk exposure, on the other.

(1) The size of the MEU's operations, assets, and revenue base

- generally, the smaller the MEU, the less well diversified it will be geographically and across individual customers and customer classes; for example, small MEUs serving one-industry, one-plant towns are at considerable risk to the temporary or permanent shutdown of this plant; this risk gradually disappears as the MEU, and the customer base it serves, grows larger and larger.

- generally, the smaller the MEU, the less access it has to financial markets and the more difficulty it has arranging loans - both of which reduce its financing flexibility.

- generally, smaller MEUs cannot afford sophisticated managerial resources and operating systems which might otherwise mitigate some risks.

(2) The nature and stability of the MEU's customer mix

- different customer classes have different load factor characteristics and are exposed to different risks to different degrees. For example, the demand from residential customers is weather-sensitive and they represent a source of uncertain bad debt expense. Deliveries to commercial customers are sensitive to both weather and economic conditions. Industrial throughput is also sensitive to both weather and economy risks, and these customers may also pose a stranded asset risk. The degree to which uncertain levels of consumption impact a particular MEU's business risk depends not only on the mix of its customers by customer/rate class and these customers' inherent sensitivity to weather and economic conditions, but also on the rate design characteristics the MEU is required to use (especially with respect to the proportion of the MEU's fixed distribution costs that are covered in monthly demand charges which do not themselves vary with the power usage by the customer).

- different customer classes, in different parts of Ontario, also pose different degrees of bad debt risk.

(3) Degree of competition from other fuels

- where a MEU serves a community which does not have a competing natural gas service, then the MEU is, of course, at less risk to its industrial customers switching to alternate fuels, and at less risk to mis-fore-casting the pace of customer additions and customer conversions to gas.

(4) The age and condition of the physical distribution system

- the older the MEU's distribution system and the less assiduously it has been maintained, the greater the chance the MEU and its customers will experience physical disruptions to their power supplies. This, in turn, may cause an unanticipated increase in the MEU's current O&M expenses and in its capital refurbishment requirements for future years.

- MEUs in newer, urban communities are more likely to have a higher proportion of their wires underground, which makes these wires, and hence the MEU's O&M expenses, less susceptible to weather-related and other physical disruption risks.

(5) Local climate peculiarities

- MEUs situated in those localities which are more frequently subject to severe weather conditions (e.g., tornados in the Windsor area) are also at greater risk with respect to forecasting their annual O&M expenses.

(6) The geographic size and isolation of the MEU's service area

- MEUs serving rural areas with low customer load densities are more exposed to line losses and have more distribution assets per dollar of revenues exposed to weather and sabotage-related physical disruption risks and, hence, unanticipated O&M expenses.

- MEUs serving isolated communities are likely to be more exposed, than those in larger urban areas, to the risk of lost load from the closure of the community's sole or main source of employment and power demand - with its concomitant risk to the continuing economic viability of the MEU.

(7) The availability of back-up self-generation capacity

- MEUs with their own generation capability (or those with connections to alternate sources of electricity generation in emergencies) are better able to respond to physical disruption risks and their cost consequences. Furthermore, depending on the pricing option chosen for default supply customers, a MEU will be less exposed to the incremental cost consequences of an electricity supplier's failure to deliver if it has access to its own, or alternative, electricity generation.

While the above list of MEU risk factors is not exhaustive, it is sufficient to illustrate some of the practical problems with attempting to separate MEUs into risk classes based on these factors, either individually or in combination. First, the net risk impact of many of these factors is difficult to measure or otherwise assess. For example, with the second factor, there are pros and cons with respect to the business riskiness of each customer class, and their relative riskiness is likely to vary over the business cycle and from one MEU to another. Getting a consensus among industry participants on how Ontario's MEUs would rank relative to each other in terms of this customer-mix risk dimension is bound to be difficult, and any ranking is bound to lead some MEU managers to question the fairness of the regulatory system.

Another example of the difficulty in using some of these factors as risk-discriminant criteria flows from the recognition that those MEUs which face the least competition from other fuels (a risk-lowering factor) are also likely to be those MEUs which are most isolated and subject to the "one-major-industry-town" risk (a risk-magnifying factor). How then can the Board trade-off these conflicting risk influences in an objective or subjective way without leaving some MEUs feeling unfairly treated.

A third problem with employing most of these risk factors is that their use as risk-class categorization criteria may have a detrimental influence with respect to promoting consolidation within the Ontario MEU sector. Some otherwise worthwhile mergers (say from a cost-efficiency point of view) may be discouraged because they will be perceived as moving one of the participating MEUs into a higher risk class - thus reducing the maximum level of debt financing available to the merged entity. Or, conceivably, mergers among MEUs may be initiated, not for the laudable purposes of realizing cost economies or diversifying customer bases, but rather to move the combined entities into a higher risk class, providing them with a higher allowed equity return and saddling their customers with higher user rates. Nor, in my view, should we contaminate the investment decisions of MEUs with respect to adding or abandoning generation capacity by the consideration of the possible impact of these decisions on the MEU's risk categorization and, hence, its allow equity return and/or deemed CER.

Another concern I have with several of these risk factors as risk-categorization criteria is their relative insignificance in terms of the typical MEU's overall business risk exposure. Recognizing that the risk to the MEU lies in their forecasting errors and not in the variability of the underlying condition itself, the forecasting risks attributable to local weather peculiarities (#5), competition with alternate fuels (#3), the absence of local back-up electricity generation (#7), and varying ages and conditions of the MEUs' distribution assets (#4) are likely to be relatively small in comparison with the size, diversification, and customer-mix variables as overall business risk discriminants. The MEU exceptions to this rule likely represent too small a share of the overall Ontario MEU industry to warrant constructing an industry-wide risk-categorization system around. Furthermore, these four, largely short-run-forecasting-risk factors - numbers 3, 4, 5, and 7 - are all "unsystematic" or "diversifiable" risk factors from the perspective of investors (though not from the viewpoint of the individual MEUs and their employees). In the context of institutional investors or of companies with an eye to the future consolidation of MEUs across Ontario, these "diversifiable" risks are ones for which no incremental return compensation is warranted.

The foregoing comments disqualify factors (3), (4), (5) and (7) from consideration, in my view, and suggest that customer mix - factor (2) - is too clouded a barometer to be useful alone as a risk-categorization criterion. When I add to these observations the recognition that factors (1) and (6) are highly positively correlated with one another - that is, large MEUs are bound not to be characterized by a wide geographic spread, low density, and/or geographic isolation - I am driven to the conclusion that the categorization of Ontario MEUs into risk classes should be done solely on the basis of MEU size.

The arguments supporting the use of some measure of organizational size (such as total assets or total revenues) as the sole discriminating factor in assigning Ontario MEUs to particular risk classes are as follows:

(1) A size-based classification process would be simple and straight-forward to implement, and the least contentious of all the options.

(2) Since the short-run business forecasting risks in the MEU industry are relatively small, manageable, and largely diversifiable, the segmentation of MEUs into risk classes should focus on long-run, enterprise-viability risks (e.g., stranded asset risk) and the "access-to-financing (to meet customer needs)" risks of the MEUs - each of which is inversely related to size.

(3) Categorization by size will, in effect, account for the effects of some of the other possible criteria as well. For example, the larger the size of a MEU, the more diversified its customer base is likely to be and the less likely it is to be exposed to the risks of geographic isolation and low load density.

(4) The use of size to gauge the risk to the MEU owner's equity is congruent with the approach taken by bond rating agencies to rate MEU and municipal debt, where size is the over-riding consideration.

(5) Risk classification on the basis of size should also have minimal detrimental effects with respect to promoting consolidation within the Ontario MEU industry. MEUs contemplating business combinations will know confidently ahead of time what effect their planned merger will have on the risk categorization of the resulting entity. Moreover, as combinations will never cause MEUs to be put into a higher-risk category, mergers will not be initiated for the unworthy reason of achieving a higher allowed return or allowed CER, to the detriment of

ratepayers.[6]

Discussion of the specific measure of size to use for MEU risk-categorization purposes, as well as specification of the numerical limits to use to identify each risk class, is covered in the next section.

3.2 Classifying MEU Business Riskiness On the Basis of Size

At the end of Section 3.1 we concluded that some measure of size, alone, should be used to categorize Ontario's MEUs into different risk classes for rate-regulation purposes. In this section, we evaluate various candidates for this size variable and come to the conclusion that "total regulated transmission and distribution rate base assets" is the preferred variable for risk-categorization purposes. We also propose and justify numerical limits that might reasonably be used to classify individual MEUs as either "low risk", "medium-low risk", "medium risk", "medium-high risk", or "high risk."

3.2.1 Choice of the Appropriate Measure to Represent MEU Size

Among the possible candidate variables to represent the size of individual Ontario MEUs, we would have to include: total accounting assets (including or excluding generation-related assets); total rate base assets (which confines the coverage to the regulated transmission and distribution assets of the MEUs and excludes assets associated with competitive generation and retailing activities); total equity (either the consolidated value for the MEU or that amount which is devoted to supporting the MEU's regulated activities); total service revenues (for all services or regulated services only); total power purchased; and total number of customers.

Several of these variables can be discarded on logical grounds. Total equity is an unsuitable measure for two reasons. First, total equity is a direct determinant of financial risk, but only an ambiguous measure of business risk since higher equity levels are often employed to compensate for higher perceived levels of business risk. Second, using total equity would potentially confound the measurement of risk with the determination of risk, as higher levels of equity would call for a lower-risk classification which, in turn, would lead the Board to allow a lower CER for regulatory purposes, possibly steering the MEU to move to a lower level of equity and, counterproductively, to a higher measured level of risk. Including generation or retailing assets or revenues in the size-based risk measure is also counter-intuitive, given the Board's intention to isolate the MEU's regulated transmission and distribution activities in a separate entity and to provide a regulated, risk-compensating allowed return solely for investments in these regulated operations. "Power purchased" may also be a poor barometer of regulated MEU size in the future if a significant portion of the MEU's customers purchase their power directly or through retailers, and the relevant purchased-power data for gauging relative MEU size is not readily available. A similar criticism applies to the "number of customers" variable. Finally, revenue-based size measures will be affected by varying costs to purchase electricity, differences in the extent to which various bundled services are offered, and differences in the split between direct purchase and default customers - all serving to distort inter-MEU relative-size rankings.

In the end, it is the author's view that "total regulated rate-base assets" is the most appropriate measure of MEU size for risk-classification purposes. While rating agencies prefer to look at an organization's consolidated total assets for risk-assessment purposes, omitting local-generation assets and retailing assets from the size calculation will make little difference to the size-ranking of Ontario's MEUs because (1) so few of them own any local generation (only 15 of 307 MEUs used any locally generated power during 1996) and (2) retailing assets, other than working capital, are small in relation to transmission and distribution assets. Moreover, as pointed out earlier, it is the MEU's distribution activities that are the focus of our regulatory risk-classification efforts.

In addition to practical congruence with rating agency procedures, the choice of total rate-base assets as the measure of MEU size will build in a consistency between the risk-classification variable and the variable to which the allowed CER - which will itself be determined by the MEU's risk classification - is applied. It is also a variable whose value should be readily available to the Board and easily understood by all participants.

At first blush, basing a MEU's business risk classification (and, hence, deemed CER) on total rate base assets alone may seem to be unfair to those MEUs which choose to hold an equity proportion significantly above their allowed CERs for regulatory rate-setting purposes. After all, by doing so they have made themselves less risky in the eyes of

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[6] The issue of whether risk-categorization by size might discourage worthwhile mergers by virtue of vaulting the MEUs into a lower-risk category - thus reducing their allowed returns and allowed CERs - is examined in Section 7 of this paper.

both rating agencies and owners. But here, again, we are confounding business risk, financial risk, and total investment risk. A more constructive way of expressing what these MEUs have done is to say that, for whatever reasons, they have moderated their total investment riskiness by adding little or no financial leverage risk on top of their business risk exposures. The existence of MEUs which make this choice in no way invalidates the use of "total rate base assets" as a measure of business risk; nor does it in any way justify using "total equity" as a business risk classification criterion.

In conclusion, then, I recommend that the Board use total regulated rate base assets as the criterion for classifying Ontario's MEUs into different risk classes.

3.2.2 **Specifying the Rate-Base-Asset-Size Ranges For Each Business Risk Class**

Given the high degree of correspondence between the nature and extent of the business risks facing Ontario's gas LDCs and MEUs, and given the Board's wish to provide regulatory treatment that is as consistent as possible between these gas LDCs and the MEUs, a consideration of the rate base size and putative business risk classification of Ontario's three Board-regulated gas LDCs provides a good starting point for our analysis. Consumers Gas and Union Gas each have rate base assets in excess of $2,500 million (excluding retailing assets) and are unequivocally "low risk" from a business risk perspective. In my view, no Ontario MEU, as constituted at the end of 1996, is in the same business-risk league as these highly-diversified, well-managed, favourably-debt-rated giants. Hence, I have chosen to relegate the largest and least risky of Ontario's MEUs to the second tier, "medium-low risk" category.

The third Board-regulated gas LDC is Natural Resource Gas Limited (NRG) based in Aylmer, Ontario. NRG has a $9 million rate base and 15 or so salaried employees; it has one major industrial customer (an Imperial Tobacco plant) and about 4,500 other residential, commercial, and seasonal agricultural customers, all within a fairly concentrated geographic area; and it has trouble accessing financial capital on terms that it considers reasonable. In my view, NRG is a "high risk" gas LDC. However, its business risk profile is not unlike that of the majority of Ontario's MEUs which are small operations serving isolated local areas and often dependent on one or a few customers for a significant portion of their power demand. The majority of MEUs should then, in my view, be classified as "high risk."

Consideration of those of Ontario's privately-owned electricity utilities for which data/estimates are available may also assist us in defining the borders between MEU risk classes. Great Lakes Power's Northern Ontario rate base assets are estimated to be about $236 million, while Canadian Niagara Power's rate base is likely to be in the range of $60 to $70 million. In each case, a large proportion of the total rate base reflects generation assets. Nevertheless, an admittedly subjective assessment of scant evidence suggests that Great Lakes Power's Ontario operations might be considered "medium risk," while those of Canadian Niagara Power would warrant a "medium-high risk" classification. On the other hand, Granite Power Corporation (serving Gananoque, Ontario), with approximately 3000 customers and $1.5 million in "wires-only" rate base assets, is undoubtedly a "high risk" electricity LDC. Cornwall Electric, which is estimated to have total assets in the range of $47-$55 million, would then fall into the "medium-high risk" category, although this might over-state its inherent business riskiness.

Outside of Ontario, a somewhat wider base of evidence would indicate that West Kootenay Power in B.C., with a $245 million rate base, and P.E.I.-based Maritime Electric, with an estimated rate base of about $130 million, are both "medium risk" utilities. The assets of these latter two companies are primarily devoted to electricity transmission and distribution. Newfoundland Power, which is overwhelmingly a transmission and distribution company, provides another tentative rate-base-size marker. Newfoundland Power's rate base is about $477 million and it might fairly be classified as a "medium-low risk" utility if Great Lakes Power, West Kootenay Power, and Maritime Electric are considered to be "medium risk." Finally, TransAlta Utilities, Alberta Power, Edmonton Power, and Nova Scotia Power - all of which have rate base assets in excess of $1,400 million - are, in my judgment, "low risk" utilities, although all of them have significant generation assets which detracts somewhat from their usefulness as markers for distribution-only MEUs.

Using these benchmarks from gas and electricity utilities, both inside and outside Ontario, I have developed the following scheme for classifying the business riskiness of Ontario's MEUs based on their total regulated rate base assets. I recommend this scheme for the Board's consideration. The comments beside each risk class in the table below are based on 1996 yearend data and on the assumption that MEU total assets ("TAs") equal rate base assets (as a figure for each MEU's rate base assets was not available to the author).

MEU Risk Class Designation	Defining Total Rate Base Asset Size Range (in $millions)	Comments (based on 1996 data)
Low Risk	$\geq$ 1,000	no Ontario MEUs, as constituted in 1996, would qualify
Medium-Low Risk	300-999	4 Toronto-area MEUs, with 30.5% of industry TAs, would qualify as of year-end 1996
Medium Risk	100-299	12 MEUs, with 30.9% of industry TAs, would qualify
Medium-High Risk	40-99	23 MEUs, with 21.9% of industry TAs, would qualify
High-Risk	$\leq$ 39	Remaining 240+ MEUs, with 16.7% of industry TAs

One attractive feature of these rate-base ranges is that they allocate, among four of the risk classes, proportions of the total assets of the Ontario MEU industry that are not too dissimilar to one another.

Based on the above suggested risk-categorization scheme, the following table shows how other Canadian gas and electricity utilities in Ontario and across Canada would be classified, as well as how some of Ontario's MEUs would be classified based on their 1996 fiscal yearend total asset figures.

	Private Gas or Electric Utility (estimated rate base assets, in $millions)		Municipal Electric Utility (1996 fiscal yearend total assets, in $millions)	
Low Risk:	TransAlta Utilities	(3,329)		
	Consumers Gas	(3,283)		
	Union/Centra Gas	(2,709)		
	NS Power	(2,774)		
	Alberta Power	(1,804)		
	BC Gas Utility	(1,516)		
	Edmonton Power*	(1,406)		
Medium-Low Risk:			Toronto Hydro	(808)
	Newfoundland Power	(477)	Mississauga Hydro	(473)
			North York Hydro	(445)
			Scarborough Hydro	(352)
Medium Risk:	Great Lakes Power (Ontario ops. only)	(236)	Etobicoke Hydro	(241)
			Ottawa Hydro	(241)
	West Kootenay Power	(243)	Hamilton Hydro	(234)
	Pacific Northern Gas	(164)	... down to ...	
	Maritime Electric	(130[e])	Richmond Hill Hydro	(105)
Medium-High Risk:	Canadian Niagara Power	(64[e])	Barrie Hydro	(89)
	Cornwall Electric	(52[e])	... down to ...	
			Kingston Hydro	(40)
High Risk:	Natural Resource Gas (Aylmer-based gas LDC)	(8)	Stoney Creek Hydro	(34)
			... down to ...	
	Granite Power (Gananoque)	(1.5[e])	Apple Hill Hydro	(0.08)

* Edmonton Power is publicly-owned.

4. The Appropriate Deemed Capital Structure For Regulatory Purposes For the Monopoly "Wires" Businesses of the MEUs, Within the Restructured Ontario Electricity Market

4.1 Capital Structure Theory and the Effect of Taxes, Return Variability, and Financial Distress Costs in Determining Optimal Capital Structures

Capital structure theory has a long and distinguished history in the academic finance literature as well as a prominent place in the tool kits of consultants, commercial bankers, and the corporate finance specialists at the investment dealers. Capital structure theory focuses primarily, though not exclusively, on the relationship between corporate debt-to-capitalization ratios ("debt ratios") - a measure of "financial leverage" - and those variables which impact the firm's "overall cost of capital", its share price, and the overall market value of the firm (including both its long-term debt and equity capital).

The traditional conception of the relationship between the use of financial leverage and the overall corporate cost of capital focused on the so-called "U-shaped cost of capital curve." In other words, as increments of debt were substituted for equity on the balance sheet of an (initially) all-equity firm, the firm's overall cost of capital was expected to fall, as the positive effects of increasing financial leverage on the level and future growth rate of the firm's earnings per share (EPS) - the result of substituting low-cost debt for higher-cost equity financing - were expected to more than compensate for the higher EPS variability and greater bankruptcy risk associated with increased levels of financial leverage.

A decrease in the firm's overall cost of capital would be mirrored by an increase in its common share price. The traditionalists did not view the relationships between the firm's debt ratio and the determinants of its cost of capital and share price as linear, however. Rather, as the firm's debt ratio increased beyond some point, its expected EPS level and growth rate were seen as increasing at a decelerating rate, as the increasing risk premiums charged by bankers and underwriters on its incremental debt issues would moderate these positive impacts of financial leverage. On the other hand, the level of investor risk perceptions associated with the use of debt financing was expected to increase at an accelerating pace - as the firm's debt ratio continued to rise to and beyond "prudent" levels - to the point where these unfavourable influences of financial leverage would completely negate the positive EPS effects. At this point, the firm's overall cost of capital would be minimized and its share price would be maximized.

The particular debt ratio for which the positive and negative influences of financial leverage were equal or balanced - that is, the overall-cost-of-capital-minimizing and share-price-maximizing debt ratio - was considered to be the firm's "optimal debt ratio", and its value was unique although not always easy to identify in practice. If a firm were to increase its debt ratio beyond this optimal value or range, the traditionalists expected that the negative risk effects of financial leverage would begin to overwhelm the positive EPS effects, precipitating a rise in the firm's cost of capital (creating the "U-shaped" cost of capital curve in relation to the firm's debt ratio) and a decline in its share price.

Professors Franco Modigliani and Merton Miller ("M&M") made a quantum leap in the understanding of capital structure theory with a set of publications beginning in 1958. They based their findings on a model which, like the traditionalists, assumed that corporate managers - working on behalf of shareholders - would make their financial decisions with a view to maximizing the market value of the firm, as a whole, and thereby maximizing the market value of the holdings of the firm's shareholders. M&M structured their model on the basis of a number of critical assumptions including: that capital markets were perfectly competitive and frictionless; that there were no corporate or personal taxes affecting investors' decisions; and that firms could not go bankrupt. Working from basic principles and using an arbitrage argument, M&M "proved" that, in a world characterized by their model's assumptions: (1) the overall market value of a firm (including both its debt and equity capital) would be independent of, or invariant with respect to, its debt ratio or degree of financial leverage employed; (2) a firm's overall cost of capital would, as result of (1), also be invariant with respect to different levels of debt financing; and (3) the market price of a firm's common shares would also be independent of the degree of financial leverage used.

A number of implications flowed from M&M's findings. First, in a world of competitively-efficient markets but without taxes and bankruptcy risk, a firm's <u>overall</u> cost of capital would depend solely on the perceived level of its business risk and be unaffected by its debt-versus-equity financing choice. This, in turn, meant that there was no single, optimal debt ratio - all debt ratios would be optimal in the sense that they would all yield the same overall cost of capital and equilibrium share price. Moreover, as M&M did not dispute the existence of the influences of financial leverage on the level, growth rate, and riskiness of a firm's EPS stream, their conclusion regarding the invariance of share prices to changing debt ratios implied that, at every point along the debt-ratio spectrum, the positive influences from using financial leverage must just exactly balance the negative risk effects, such that there would be <u>no net impact</u> on share prices as debt ratios change. Another way of saying the same thing is to say that the firm's cost of equity capital - which reflects both the firm's business risk and its financial leverage risk - can be expected to rise in a linear fashion as its debt ratio rises[7] or, conversely, as its common equity ratio (CER) falls. This M&M conclusion is the foundation for the trade-off between allowed equity returns and deemed CERs that is all-but-universally recognized.

The applicability of the original M&M model was criticized for its assuming away of taxation and bankruptcy risk effects - two of the key factors driving corporate capital structure choices in practice. In 1963, M&M, and in 1977, Merton Miller alone derived extensions to their original model to incorporate the effects of corporate and personal income taxes. They showed that, as interest expenses are tax-deductible at the corporate level, a firm could increase the overall, after-corporate-tax amount of money flowing to its debt and equity holders, in aggregate, by increasing its debt ratio and hence sheltering more of its operating earnings from taxes. This, in turn, meant that the overall market value of the firm and the market price of its equity shares could both be expected to increase (in a linear fashion if tax rates were constant) as its use of debt financing increased. However, the authors also realized that as the firm increases its debt financing proportion, it forces more of its investors (in dollar terms) to receive interest income which, for most of these investors, is taxed in their hands at a higher rate than the dividends and capital gains from holding shares. This second realization tended to moderate, but not completely negate, the favourable-to-debt-financing implications of the corporate tax effect. In other words, in both Canada and the U.S. there are still significant net tax benefits to debt financing for profitable corporations, and this is particularly true from the perspective of non-taxable institutional investors such as pension funds.

If this were the end of the story, then 99.9% debt would be the optimal capital structure for many corporations. What prevents such extreme debt ratios from being optimal or targeted in the real world, however, is the fact that all firms face some business risks, and excessive levels of debt financing might magnify the income-variability effects of these business risks to such an extent that the firm would experience some form of "financial distress" - possibly culminating in bankruptcy and liquidation or reorganization.

What is important here is not so much the possibility of bankruptcy but the brutal fact that value flows out of a firm when it is experiencing financial distress. These "costs of financial distress" - which may include direct costs, such as legal fees and losses on the disposition of assets at "fire sale" prices, as well as the opportunity costs associated with customer, supplier, and creditor reactions to the firm in distress - are disadvantages of debt financing that do not simply represent a shuffling of risks between shareholders and debtholders, but rather a deadweight loss to all of the corporation's investors in aggregate.

So the "static trade-off model" of modern capital structure theory essentially concludes that companies will push their target debt ratios up to the point where the tax advantages of debt financing are just balanced off against the financial distress/bankruptcy disadvantages. At low levels of debt, where the firm's chances of experiencing financial distress costs are small, the tax shield effect increases the value of the firm, and decreases its overall cost of capital, as the debt ratio rises. However, at high levels of debt where the firm's chances of being saddled with financial distress costs are much greater, the favourable effects of the tax shield are less certain and no longer sufficient to offset the expected value of the distress costs. Consequently, any increase in the debt ratio from this already-elevated level will cause the firm's market value to drop and its overall cost of capital to rise. We have thus come "full circle," back to the implications of (if not the explanations of) the traditional model - namely, a corporation will have a unique, and potentially-identifiable, "optimal" capital structure which minimizes its overall cost of capital and maximizes its share price.

The "optimal" capital structure from the perspective of the "static trade-off model" is not necessarily the one which a particular firm should or will target in its financial planning, however. The static model takes no account of a company's potential strategic need for financing flexibility and assured access to capital markets under a range of both favourable and unfavourable market conditions. Firms which require or value such financing flexibility to capitalize on strategic opportunities (e.g., pursuing opportunistic acquisitions and takeovers) or to respond to unexpected environmental changes (e.g., the competitive threat from a rival's introduction of a new production technology) will tend to target debt ratios which are less than those which would be indicated by a simple trade-off of tax advantages and expected financial distress costs. Since a company's access to financial markets on reasonable terms may be affected by its debt and preferred share ratings, firms attaching a premium to financing flexibility may also be constrained in their choice of debt ratios by the judgments of the rating agencies. Finally, shareholder and/or managerial "control"

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7 The firm's cost of equity capital rises as its financial leverage increases because, as its use of financial leverage rises, the relative variability or uncertainty of its future EPS stream increases, the systematic or beta riskiness of its shares increases, and its exposure to bankruptcy risk (from the failure to make debt servicing payments) increases.

considerations, as well as the impact on managerial behaviour from limiting a firm's net discretionary cash inflows, may also argue for debt ratios other than those indicated by the static trade-off model.

4.2 The Relationship Between Business Risk, Capital Structure, Bond Ratings, and Financing Flexibility Requirements For Rate-Regulated Utilities

The capital structure theory described in the previous section was designed to apply to the typical, taxable, non-regulated corporate enterprise. The purpose of this section is to examine whether, and to what extent, the principles uncovered in Section 4.1 do or should apply to rate-regulated utilities and, where these principles do not fully apply, to discuss the modifications to the general theory and prescriptions that are necessary to make them useful guides within the regulatory environment.

Capital structure analysis using the static trade-off model suggests a high debt ratio and low CER for rate-regulated utilities, including the MEUs envision within the restructured Ontario electricity market. This is because utilities have a very high probability of being profitable and therefore being able to realize the beneficial tax-shielding effects of interest payments. Under the Electricity Act, 1998, municipally-owned electricity distributors will have available to them the same taxation-related advantages for debt financing as are presently available to privately-owned utilities, since the "payments in lieu of taxes" for these MEUs will be determined in a manner that mimics the income taxes that they would be liable for if they were privately owned.

Besides being able to realize the tax benefits of debt financing, utilities - including gas LDCs and MEUs - have a very low probability of experiencing severe financial distress and, even if they did, the "costs" of this financial distress would be relatively small as compared with firms in many other industries. To elaborate on these points, the very nature of the rate regulation process, with its use of deferral and variance accounts and its annual resetting of the capital costs to be recovered in rates is designed to shield the owners of utilities from the detrimental impacts of many of the risks over which utility managers have no control. Even without these regulatory measures to stabilize utility returns, the underlying business riskiness of most pipelines and gas and electricity utilities is relatively low (as discussed in Section 2.3) and their year-to-year achieved rates of return on equity are more stable than those in any other industry. Moreover, most gas and electricity LDCs are not expanding rapidly enough to cause the tax shields from their capital consumption allowances to reduce their taxable earnings to zero and, therefore, negate the tax-shielding benefits of interest payments.

On the other side of the equation, the disadvantages associated with debt arising from the potential for experiencing distress costs are relatively low for gas and electricity utilities. Companies with few tangible assets that can be ready resold or continue to be used tend to have large distress costs. For these companies, most of their market value evaporates when they go bankrupt. Many technology firms, where most of their value consists of potential products rather than the value of current operations, are examples of this. In contrast, companies currently achieving a healthy level of net cash inflows from relatively standard and transferable assets - such as gas and electricity LDCs - are seen as having lower potential distress costs and can potentially carry greater debt loads.

To substantiate the position that lower potential distress costs are associated with gas and electricity LDCs, it is useful to distinguish between two types of distress costs. First, there are those financial distress costs which are incurred prior to bankruptcy and liquidation, such as the changes that may take place in the behaviour of the firm's managers, employees, customers, and suppliers as the possibility of the firm's imminent failure rises. Second, there are the bankruptcy and liquidation costs that are experienced when the firm is liquidated, such as the fees of the bankruptcy trustee, the sale of company assets at "fire sale" prices, and the writeoff of any loss carry forwards for tax-sheltering purposes. Recognizing that the delivery services provided by the "pipes" and "wires" of gas and electricity LDCs, respectively, are essential services for which there are, as a practical matter, no alternative providers within their service areas, as long as there remains a significant demand for gas and electricity among end users, a LDC is not going to be wound up simply because it has become saddled with too much debt. Instead, it will be in the interests of all parties involved - owners, debtholders, employees, the municipality, and the ratepayers - to have the ownership and management of the utility reorganized. As a consequence, the bankruptcy/liquidation costs are irrelevant from the perspective of utility capital structure choices.

With respect to the pre-bankruptcy financial distress costs, the exposure of local gas and electricity distributors to these costs is also bound to be limited by the captive nature of many of their customers and the likely intervention of regulatory boards to address the risks that these LDCs may be exposed to. Board-sanctioned deferral accounts and rate-design solutions (such as those to forestall bypass) are some of the means for regulatory authorities to mitigate utility financial distress costs.

In summary, the static trade-off model for capital structure choices would seem to indicate relatively low optimal CERs and relatively high levels of debt for taxable, rate-regulated, local gas and electricity distributors. 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.

There are various points of view on the issue of whether local gas and electricity distributors need to preserve significant financing flexibility. Those who question the gravity of this need point to a number of mitigating factors. First, most LDCs are relatively mature and slow growing. Major investments can almost always be anticipated and planned for well in advance, and either gradually pre-funded or funded at a time of favourable market conditions. Moreover, major technological breakthroughs or serious competitive threats (requiring immediate investment responses on the part of industry players) are unlikely to arise over a short time frame for either gas or electricity distributors. Even if they were to occur, the captive nature of most of these utilities' customers would afford the LDCs the luxury of timing their investment responses to accommodate changing capital market conditions. These considerations make it less likely that the utility will have to engage in a major new financing during unfavourable financial market conditions. Second, the requirement that the Board has to approve major new capital spending projects, where the projected cost of capital is one of the factors considered in the approval process, makes it unlikely that the utility will be <u>forced</u> to proceed with a major investment (requiring external financing) without either some compensating relief from the Board or a customer contribution in aid of construction.

On the other side of the issue, gas and electricity LDCs have a legislated "obligation to serve" - and to build the facilities required to deliver this service - which, depending on the circumstances, may or may not be conditional on the economic feasibility of the associated projects. Utility managers generally feel that this obligation to provide service to customers located within their franchise territories - and to make the concomitant investments and to find the necessary financing - applies no matter what the prevailing financial market conditions. Moreover, utilities will also be required, from time to time, to refinance borrowings that are maturing on their balance sheets, and the financing (of whatever nature) to replace these maturing issues cannot be postponed.

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, while smaller companies, for which A ratings are simply not available, strive to maintain BBB ratings. Aside from operational measures to manage a company's business risk, bond ratings can be maintained or possibly improved by increasing the firm's CER, by increasing its expected return on equity, or both. On the other hand, a company's bond rating can be threatened if its CER is pushed below some critical level, or if its equity-return prospects deteriorate, or both.

Because the regulatory setting of allowed CERs is seen as likely to be subject to less year-to-year tinkering or tampering 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 - which we shall examine in a later section - play a significant role in limiting the extent to which a local gas or electricity distributor can increase the use of debt financing and lower its CER, even if there are favourable tax consequences associated with adopting a more-leveraged capital structure.

In conclusion, then, the 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.

4.3 The Relationship Between Capital Structure and Required Equity Rates of Return For Rate-Regulated Utilities

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.

The shape and slope of the inverse relationship between CERs and costs of equity capital for non-regulated industrial firms is a matter of on-going 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. One model of this relationship can be derived from Merton Miller's 1977 extension of the original M&M model. This model concludes that

$$K^s = K^u + (K^u/(1-T^p) - K^D)(1-T^c)(1-T^s)(DR/CER)$$

where:

K^s = the after-tax cost of equity/share capital for a firm using financial leverage;

K^u = the after-tax, business-risk-based, overall cost of capital for the firm if it were all-equity financed and, thus, unleveraged;

K^D = the current nominal cost of debt financing;

T^p = the marginal personal tax rate on "ordinary" income for investors;

T^s = the marginal tax rate on equity income (i.e., dividends and capital gains) for investors;

T^c = the marginal effective income tax rate levied on firms at the corporate level;

DR = the firm's debt ratio, or debt-to-capitalization ratio; and

CER = the firm's common equity ratio, or the complement of the DR.

To illustrate, suppose that the following figures are reflective of a particular industrial firm and its actual and potential shareholders.

K^u = 10.0% K^D = 7.00%   DR = 60%   CER = 40%

T^p = 50% T^s = 37.5% T^c = 40%

Then the firm's after-tax cost of equity capital would be expected to be 17.3% and, in the vicinity of a 40% CER, it would be expected to change by about 65 basis points for every 2% change in the CER. In the vicinity of a 70% CER - a more normal CER for industrial companies - a 2% change in the CER would be expected to cause a 20 basis point change in shareholder rate-of-return requirements.

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 LDCs. 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 which undermine its profitability for the entire period of the downturn. For a rate-regulated LDC 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 hearing 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 which is designed to enable the utility to achieve an agreed-upon equity return which 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 franchises and the greater inherent stability in the demands for their services. Financial leverage has the effect of <u>magnifying</u> 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 NEB-regulated 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 2 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 Consumers Gas and Union Gas 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 neighbourhood of CERs of 33% to 40%.

In summary, then, the degree to which the equity return requirements of utility investors change in response to changes in the actual and/or deemed CERs of their utilities, is still a matter of considerable debate and wide-ranging estimates. Based on qualitative considerations and quantitative "guestimates" presented in past rate hearings, my own view is that a two-percentage-point change in the allowed CER for an Ontario-based, local gas or electricity distributor would call for a corresponding required equity return adjustment and, hence, allowed-return adjustment of between 12 and 20 basis points. More precise quantification, even if it were possible, would depend on LDC-specific considerations relating to businesses riskiness, tax status, the starting position from which the CER adjustment is made, and possibly other factors.

It is perhaps appropriate to note at this point that quantification of the above relationship for the purpose of establishing the allowed returns for the "wires" business of Ontario's MEUs will only be required if the CERs that the Board deems for the MEUs in each business risk class do not fully account for, and compensate for, the differences in their business risk exposures. If, on the other hand, the deemed CERs do incorporate a full adjustment for differing levels of business risk, then it would be appropriate to award all MEUs in all risk classes the same allowed equity rate of return for a given test year - in the same fashion as the NEB used to award the identical returns to all the pipelines under its jurisdiction, having previously established different, pipeline-specific, allowed CERs for them.

4.4 The Regulatory Capital Structures Presently Employed for Private Gas and Electricity Utilities in Canada

Regulatory boards across Canada have wrestled for years with the question of the optimal regulatory capital structures for local gas and electricity distributors. Examination of the decisions that they have made with respect to allowed CERs in relation to the perceived business risks of their regulated utilities will give us a useful starting point for assessing the appropriate deemed CERs for Ontario MEUs within each risk class.

The table below lists all the privately-owned[8] gas and electricity utilities across Canada for which the author was

[8] Edmonton Power is publicly-owned.

able to find or estimate most of the significant data required for the purposes of the present analysis[9]. The table separates the utilities into risk classes corresponding to those that were suggested for the Ontario MEUs in Section 3.2.2. Classifying these privately-owned utilities on the basis of rate-base size produced a risk ranking that corresponds closely with the overall judgments of the rating agencies (as shown by their respective bond ratings) and various regulatory witnesses. In the table, the bond ratings apply to the consolidated, corporate-wide operations of these companies, and "NR" stands for "not rated", while an asterisk indicates that the rated debt is guaranteed by the parent organization.

For each utility - in addition to its risk class and bond ratings - I have listed its allowed or targetted CER and the amount of total common equity that the utility actually has on its latest balance sheet or the amount of equity that corresponds with its allowed or targeted CER. In the case of electricity utilities which possess significant generation assets, I have indicated their actual regulatory allowed CERs in brackets, and indicated what I would judge to be the relevant corresponding CER if it were applied to their monopoly distribution assets alone. In particular, under the restructured Alberta electricity market, the Alberta Energy and Utilities Board (EUB) has made generation a low-risk activity and distribution (which includes the supply-retailing function in Alberta) a higher-risk activity; for Ontario, I have assumed that generation will be higher risk and the regulated, "wires-only," MEUs will be low risk; therefore, I have adjusted the allowed CERs for the Alberta electric utilities to reflect this difference and recorded the deemed CER that I believe would apply to their "wires-only" distribution businesses; again, their actual, corporate-wide allowed CERs are shown in brackets.

Risk Class	**Company**	**Allowed CER %**	**Total Common Equity ($MM)**	**Actual Bond Rating**	
				CBRS	**DBRS**
Low	TransAlta	32-35(40)	1,219	AA	AA(1)
Low	Consumers Gas	35	1,027	A	A(h)
Low	Union/Centra Gas	34-35	948	A(1)	A
Low	NS Power	35	893	A(1)	A(1)
Low	Alberta Power	35(40[e])	706	AA	AA(1)
Low	BC Gas Utility	33	600	A(1)	A
Low	Edmonton Power	33(35)	630	?	NR
Med-Low	Newfoundland Power	40-45	228	A(1)	A
Medium	Great Lakes Power	40-42(50)	140	NR	BBB(h)*
Medium	West Kootenay Power	40	103	NR	BBB(h)*
Medium	Pacific Northern Gas	36	59	?	BBB(h)
Medium	Maritime Electric	40	71	BBB(h)	NR
Med-High	Cdn Niagara Power	40[e]	31[e]	NR	NR
High	Nat. Resource Gas	50	4	NR	NR
High	Granite Power	50[e]	1	NR	NR

The deemed CERs approved by the various regulatory boards for the above utilities reflect, in some instances and at various times, the influence of factors above and beyond relative business risks, such as the presence of preferred shares and/or deferred tax accumulations in the capital structure, the utility's tax status, and adjustments to accommodate bond rating/financing flexibility concerns. Nevertheless, there is, for the most part, a direct, monotonic relationship between perceived business riskiness and allowed CERs (adjusted to reflect monopoly distribution assets only) evident in the above table. Low-risk LDCs are generally allowed deemed CERs in the range of 32% to 35%, while medium-low-risk LDCs are accorded deemed CERs in the neighbourhood of 40%. (Newfoundland Power's

[9] It would have been useful to include Cornwall Electric in the table, but information about its financing structure was not available to the author. In addition, Cornwall Electric presently has no rated debt, confining itself, apparently, to bank debt.

recently deemed CER of 45% was seen by many - including the Dominion Bond Rating Service - as being set generously, or relatively high, in order to compensate for what was judged by some to be a "low" allowed equity rate of return.)

Those LDCs classed as medium risk have allowed CERs in the range of 36% to 42%. In all of these cases the deemed CERs are below what they would have to be to compensate fully for the business risks of these utilities on a stand-alone basis - for two reasons. First, all four medium-risk-rated utilities benefit from the support of strong, controlling parent corporations which have, in at least a couple of cases, guaranteed the debt of their utility subsidiaries. In the cases of West Kootenay Power and Pacific Northern Gas, presently, and Maritime Electric, up until 1993 (prior to its being switched to price cap regulation), part of their shareholders' compensation for higher business risk exposures is provided by higher-than-benchmark allowed equity returns. Consequently, adjusting for these considerations, I would interpret the allowed CERs for these four utilities as indicating that a deemed CER in the range of 40%-45% would be warranted to afford full risk compensation to a medium-business-risk, independent (or stand-alone) gas or electricity LDC.

The same considerations as above apply to evaluating the estimated 40% CER of Canadian Niagara Power - the only utility available in the medium-high-risk category for which an indication of its targetted financing structure was available. Canadian Niagara benefits from being jointly owned by Fortis Inc. and Niagara Mohawk Power Corporation (a major U.S. power utility). If Canadian Niagara Power were operating as an independently-financed organization, it would likely require a CER closer to 45% to obtain external financing on reasonable terms, considering its relatively small size and higher perceived level of business risk exposure.

Finally, there are two high-risk LDCs to examine. We shall begin with Natural Resource Gas (NRG). In NRG's recently completed E.B.R.O. 496 rate hearing, the Board apparently adopted the approach, suggested by one of NRG's witnesses, that NRG's allowed equity return to set equal to that of Consumers Gas while its deemed CER should be set - at 50% - to fully compensate for the difference in the business riskiness of NRG versus Consumers (see "Decision With Reasons," 20 August 1998, pages 45-48.) Implied in this Decision is the Board's view that, if all of the adjustment for the relative business risks of Ontario's gas LDCs is to be accomplished through differential deemed CERs, while the allowed equity returns are standardized across the industry, then the range from a CER of 35% to a CER of 50% represents the spectrum of adjustments required when moving from low-risk gas LDCs to high-risk gas LDCs. If consistency in regulation between gas LDCs and the MEUs is to be achieved, then a similar range of CERs would seem to have to be chosen to apply across the spectrum of low-risk to high-risk MEUs.

For Granite Power, the Gananoque-based electricity utility with assets of under $2 million, actual balance sheet data were not available. However, company officials indicated to the author that while Granite Power had recently been operating with a CER somewhat under 50% (and a debt ratio in excess of 50%), it was now targetting a 50% CER and a 50% debt ratio for the company as a whole (including some 100-year-old generation assets which are all-but-fully depreciated). A director and senior financial advisor to Granite Power also expressed the view that the firm would want a CER in excess of 50% for the recently-refurbished, "wires only" part of its business to help address the demands of its debt providers for enhanced security. Nevertheless, there was no indication that the firm would be unable to access debt at a 50% CER. Therefore, it is the author's view that Granite Power's past financing choices do not invalidate the conclusion that a 50% CER would adequately reflect the business riskiness of the typical "high-risk" Ontario MEU, which, in this analysis, is considered to be any MEU with rate base assets under $40 million.

4.5 The Recommended Debt Versus Equity Mix For Regulating Ontario Electricity Utilities Based on Sized-Differentiated Business Risk Classes

Based on the evidence and discussion in the foregoing section, as well as on the evidence with respect to the comparability of the business risk profiles between similarly-sized gas and electricity LDCs (as set out in Section 2.3), I have arrived at recommendations, set out below, for the deemed CERs and corresponding debt ratios, for Ontario MEUs based on their risk-class designations. These deemed CER recommendations are appropriate, however, only if the Board adopts the approach of reflecting all the variation in MEU business risk exposures in their respective deemed CERs while simultaneously allowing a single, uniform, equity rate of return for all LDCs across the MEU industry. This overall approach to determining MEU total capital cost requirements is the one I am recommending in this paper, and it is consistent with the approach the Board adopted in the recent NRG Decision and the approach taken by the NEB until recently in its regulation of pipeline rates of return.

The table below sets out my risk-class-differentiated recommendations for the deemed capital structures of the regulated operations of the Ontario MEUs. The right-hand-side column in the table sets out what I believe would be the ratings attached to the public bond issues of the typical MEU in each risk class if its user rates were established on the basis of my recommended CERs and debt ratios for each risk class and if its allowed equity returns and debt costs were "just and reasonable" and the same as those awarded to similarly-sized gas LDCs. (In reality, of course, the debt financing for many MEUs may continue to be done at the level of the municipality, and smaller MEUs, even if they borrow on their own name and credit, will borrow privately from banks, life insurance companies, or other institutional lenders and not need to obtain ratings from the bond rating agencies.)

MEU Business Risk Class	Deemed CER %	Deemed Debt Ratio %	Estimated Bond Rating
Low Risk	35	65	A(l) to A(h)
Medium-Low Risk	40	60	BBB(h) to A
Medium-Risk	42.5	57.5	BBB to BBB(h)
Medium-High Risk	45	55	BBB(l) to BBB(h)
High Risk	50	50	BBB(l) to BBB

It should be noted that the recommended capital structure proportions in the above table are for rate-regulation purposes only. Once the MEUs come under the Board's regulatory supervision and have restructured themselves to conform with the requirements of the Electricity Act, as municipally-owned business corporations (initially) they may quite reasonably choose to operate with actual financing proportions that differ significantly from those in the table above. Owners of many of these MEUs may opt to forego debt financing and choose, instead, to receive an equity rate of return on their MEU's deemed CER and an allowed debt return on the remainder of their MEU's rate-base-supporting capitalization. These will presumably be MEUs with no major capital projects pending and which are associated with those municipal governments which have no pressing need for the cash windfall that would flow from having their MEUs issue debt and remit the proceeds to their municipal owners.

On the other hand, some MEUs, if they are sold to private owners, may attempt to take on debt to an extent that exceeds the level indicated in the above table for deeming purposes for its risk class. This might be feasible for a "privatized" MEU if its parent corporation guaranteed its debt issues. Whether the Board would adjust its deemed CERs in these cases to reflect the actual CERs carried by these "privatized" MEUs is a matter for the Board's future consideration.

4.6 The Optimal Mix of Short-Term and Floating-Rate Debt Versus Long-Term and Fixed-Rate Debt

The fact that the Electricity Act, 1998 contains provisions that will enable MEUs to employ debt financing to shelter some of their future cash flows from "payments in lieu of taxes" suggests that a number of MEUs, even if they remain municipally owned, may choose to add debt to their balance sheets. This raises the question of whether this added debt should be longer-term debt at fixed rates or shorter-term and/or floating-rate debt. Traditional finance wisdom holds that the longevity of a firm's debt should be chosen to match, at least roughly, the longevity of the balance sheet assets it is being asked to support - thereby avoiding a number of risks associated with having to refinance continuing assets at future dates when financial market conditions may or may not be favourable.

The table below shows the condensed aggregate December 31st, 1996 year-end balance sheet for the Ontario MEU industry in the left-hand-side numerical column. The four right-hand-side columns set out the author's "guesstimates" with respect to how this aggregate balance sheet will initially be restructured, and then divided between the regulated "wires" portion of the MEUs' operations and their competitive retailing/services affiliates and/or third party retailers. For the purpose of the initial restructuring, I have assumed that the MEUs' regulated "wires" businesses will not be allowed to count their "capital contributions received" as part of their regulatory capital, and that the net assets supported by these contributions will likewise be removed from the MEUs' rate bases. Furthermore, I have assumed that some of the cash and investments - that portion determined to be surplus to the needs of the MEU in the restructured corporate and retailing environment - will be "dividended" out to the municipal owners. Then, in the three right-hand-side columns, I have assumed that most of the remaining current assets and current liabilities presently on the MEUs' books will be transferred over to their newly-created retail services affiliates or be absorbed by the third party retailers that are expected to vie for the competitive aspects of the MEUs' current operations. The results of these adjustments are shown below, where the "post restructuring" columns show the net effects of all the above-discussed adjustments but do not show the debt-for-equity substitutions that some MEUs may wish to make in the new regulatory and "taxation" environment.

Based on 1996 Yearend Values: (figures in $millions, unless otherwise indicated)	Aggregate MEU Industry	Initial Restruc-turing	Post Restructuring Competitive Retail Services	Monopoly "Wires" Business	As % of "Wires" Assets %
ASSETS:					
Cash and Investments	914.2	(367.0)	247.2	300.0	7.5
Accounts Receivable and Unbilled Revenues	956.3	716.3	240.0	6.0	
Inventory & Other C/As	182.6	22.6	160.0	4.0	
Total Current Assets	2,053.2	(367.0)	986.2	700.0	17.5
Other Assets	98.2	26.2	72.0	1.8	
Net Plant and Equipment	4,657.9	(1,251.3)	178.6	3,228.0	80.7
Total Assets	6,809.3	(1,618.3)	1,191.0	4,000.0	100.0
LIABILITIES & NET WORTH:					
Current Liabilities, excl. Debt Due in <1 year	816.6		600.3	216.2	5.4
Debt Due in <1 year	33.8		-	33.8	0.8
Total Current Liabilities	850.3		600.3	250.0	6.3
Other Liabilities	146.8		26.8	120.0	3.0
Net Long-Term Debt	192.5		-	192.5	4.8
Accumulated Net Income	$4,367.0	(367.0)	563.9	3,436.1	85.9
Capital Contributions Rec'd	$1,251.3	(1,251.3)	-	-	-
Total Equity	$5,618.3	(1,618.3)	563.9	3,437.5*	100.0

* There is a discrepancy of $1.4 million between total assets and total liabilities plus equity; this value is added to "accumulated net income" to get the "total equity" figure for the "wires-only" business.

If the "guesstimates" in the "Monopoly Wires Business" column above represent reasonable expectations, then the regulated portion of Ontario's MEU industry will have, in aggregate, available <u>unused</u> borrowing capacity of approximately $1.9 billion, once the initial restructuring adjustments are completed. To arrive at this estimate, I assumed that the weighted-average MEU (based on total rate-base assets) would be a "medium risk" MEU capable of financing 57.5% of its capitalization ($3,437.5 + $192.5 = $3,630 million, in aggregate) with debt. From the resulting total debt figure of $2,087.3 million (57.5% of $3,630 million), I subtracted the amount of long-term debt already on the aggregate MEU balance sheet (i.e., $2,087.3 - $192.5 = $1,894.8 million) to estimate unused debt capacity as of yearend 1996.

Following traditional practice where a firm might finance the variable or unpredictable portion of its current assets with short-term, easily-expandable-and-repayable debt (such as via a bank operating line of credit), MEUs in aggregate might opt to arrange to have $100 million to $200 million of their total debt in some short-term form, leaving the remaining $1.9 to $2.0 billion to be funded on a medium-to-long-term basis (depending on bond market conditions). In many ways, this would represent a conservative approach, allowing the MEUs to stabilize their interest expenses over time and, by staggering their debt maturities, avoid any major "refunding crises" in future years. Stability in interest payment requirements would also add stability to the MEUs' overall revenue requirements and, in turn, to the user rates for the MEUs' "wires" services.

This conservative, "mostly-long-term-debt-financing" policy has at least one drawback, however. If the allowed equity returns for the MEUs are going to be set according to a formula which is based on long-Canada bond yield expectations which fluctuate over the interest rate cycle, then the MEUs will likely find that their interest coverage ratios (ICRs) will fluctuate in a pro-interest-rate-cycle manner - possibly to the detriment of their financing flexibility, and even their bond ratings, if long-Canada yield expectations drop dramatically or on a sustained basis for two or three years. The reason for this is simply that the numerator of the ICR will fluctuate from year to year in a pro-cyclical way because the equity return and "payments-in-lieu-of-tax" components in the numerator will rise or fall with the level of long-Canada bond rates. The denominator of the ICR, on the other hand, will remain cyclically- stable because the denominator value is simply the MEU's prospective or actual interest expenses, most of which are embedded fixed amounts which change only gradually over time as old bond issues are retired and new bonds are issued to replace them.

One way to address the problem highlighted in the previous paragraph is for the MEU to "swap" some of the fixed interest rate payments on its outstanding long-term debt for floating-rate payments. While this "swap market" transaction is very easy to arrange and would impart some cyclical variation to a MEU's total net interest payments, it might not be interpreted favourably under the MEU's existing bond indenture covenants or by the bond rating agencies. Consequently, the ICR-stabilizing and financing-flexibility-enhancing effects of the swap transaction might not be realized by the MEU. The other way, then, for a MEU to address the problem described in the previous paragraph is for it to increase the proportion of short-term and/or variable-rate financing in its overall debt mix. In this way, the MEU can inject some year-to-year variability in the denominator of its ICR calculation that is likely to be (though not necessarily) positively correlated with the annual changes in the numerator value of the ICR. Whether this benefit is reliable enough and great enough to warrant incurring the risks and other disadvantages associated with fluctuating interest costs is a financing policy question for MEUs to deal with in the future. Securing this potential ICR-stabilizing benefit is, nevertheless, a reason why a MEU might choose to employ more than the minimum level of short-term financing, despite the fixed-asset intensity of its balance sheet.

5 A Formula-Based Approach To Determining the Regulatory Return on Equity For Electricity Distributors

5.1 The Board's Current Approach To Determining Allowed Equity Returns For Ontario Gas LDCs

In a report circulated in the spring of 1997, the Board promulgated draft guidelines explaining how it intended to establish initially, and then revise annually, the fair rate of return on equity (for regulatory purposes) for Ontario's natural gas utilities. This approach has been used to set the allowed equity returns for Consumers Gas, Union Gas, and NRG since that time. Readers who wish to know why the Board decided to change its approach to setting equity returns and/or more detail on the mechanics of the procedure itself (than that which will be set out below), are referred to the Board's document titled "Draft Guidelines On a Formula-Based Return On Common Equity For Regulated Utilities", dated March, 1997.

The Board's new procedure is grounded in its judgment that the equity risk premium (ERP) approach to establishing allowed equity returns is both the most appropriate and the most widely-accepted approach for this purpose, and that long-Canada yields - as proxied by the forecasted average annual yield on 30-year Government of Canada bonds for the test year - are the appropriate base for the ERP technique. The following summary of the approach taken by the Board for the Ontario gas LDCs, both for establishing each LDC's allowed equity return initially and then for revising it on a year-by-year basis thereafter, is quoted directly from the Board's March 1997 Draft Guidelines Report.

The Initial Setup

The initial setup will establish a just and reasonable return on equity ("ROE") for each of the Ontario LDCs, given a test year long Canada forecast, which will be the base against which subsequent adjustments to the formula-based ROE can be made.

Step 1: Establish the forecast of the long Government of Canada yield for the test year

The forecast yield for long-term Government of Canada bonds will be established for the test year by taking the average of the 3 and 12 months forward 10-year Government of Canada bond yield forecasts, as stated in the most recent issue of Consensus Forecasts, and adding the average of the actual observed spreads between 10 and 30-year Government of Canada bond yields, as reported in the Financial Post, for each business day in the month corresponding to the most recent Consensus Forecast issue.

Step 2: Establish implied risk premium

A utility's test year ROE will consist of the projected yield for 30-year long Canada bonds plus an appropriate premium to account for the utility's risk relative to long Canada bonds. The primary methodological approach to be used in evaluating the appropriate risk premium should be the equity risk premium test.

The Adjustment Mechanism

Once the initial ROE has been set for each of the utilities, as per the above-mentioned steps in the initial setup phase, a procedure must be put in place to automatically adjust the allowed ROE for each utility to account for changes in long Canada yield expectations. The timing of the adjustment mechanism process for each utility will be consistent with its fiscal year-end.

Step 1: Establish the forecast long Canada rate

The formula-based equity risk premium approach annually adjusts a utility's allowed ROE based on changes in forecast long-term Government of Canada bond yields. Each year the process outlined in Step 1 of the initial setup phase will be repeated and an updated, consensus-based forecast of 30-year long-Canada bond yields will be obtained. The current test year rate forecast will then be compared to the previous test year forecast.

Step 2: Apply adjustment factor

The Board suggests that the difference between the forecast long Canada rate calculated in Step 1 and the corresponding rate for the immediately preceding year should be multiplied by a factor of 0.75 to determine the adjustment to allowed ROE. This adjustment factor will then be added to the utility's previous test year ROE and the sum should be rounded to two decimal points. An illustration of the adjustment formula is shown below.

Allowed ROE for test year 1		12.25%
Test year 2 long-Canada forecast (30-year)	8.30%	
Test year 1 long-Canada forecast (30-year)	9.25%	
Change in interest rates	-0.95%	
Adjustment factor (0.75 to 1)		-0.7125%
ROE for test year 2		11.5375%
Approved ROE for test year 2 (rounded to nearest 2 decimal points)		11.54%"

In its March 1997 Draft Guidelines Report, the Board indicated that this equity-return formula would be reviewed, at the Board's discretion, whenever it judged that conditions had arisen to call into question the formula's validity. Furthermore, the Board expressed its view that "an adjustment to the utility-specific risk premiums should be done only when there is a clear indication that relative risks have changed. The Board [also] believes that the [deemed utility] capital structures should be reviewed only when there is a significant change in financial, business or corporate fundamentals."

5.2 Strengths and Advantages of the Board's Current Formula-Based Approach For Gas LDCs

In its Draft Guidelines Report, the Board cited a number of the strengths and advantages associated with the formulaic approach to setting allowed returns that had motivated it to adopt this approach for the Ontario gas LDCs. The Board saw simplification of the rate hearing process as one of the major advantages of using a formulaic approach, as opposed to the wider variety of return-assessment models previously used by witnesses from all sides. The length and cost of the hearing process would be reduced, in the Board's view, because considerable duplication of effort from year to year would be eliminated and - with the focus squarely on assessing utility-specific ERPs - the range for conflicting interpretations of the evidence would be sharply narrowed. Despite the narrower focus, the formula-based allowed returns would still reflect major changes in the capital markets through the mechanism of annual long-Canada rate forecast adjustments, and the need for outside expert witnesses would be reduced. Increasing the efficiency and reducing the costliness of the hearing process is, of course, of even greater merit when the Board begins to regulate the monopoly operations of the 270-plus Ontario MEUs.

In addition, the Board expected that formula-based allowed equity returns would be more readily understood by all participants. The new procedure would also help to insure consistency, as well as the perception of consistency, in return awards across rate-regulated utilities and between fiscal periods. This rationale now extends to a consideration of the consistency of treatment, and the perception of fair play, on the part of the Board as between gas LDCs and MEUs.

A third reason for adopting a formulaic approach to equity return setting is to facilitate the Board's move to introduce performance-based rate-setting, or incentive rate-making, for both gas LDCs and MEUs, now that the Ontario Energy Board Act has been changed to permit this. Many incentive or performance-based methods require an allowed equity return (or a range of ROEs) for implementation, and the Board considered that it would be prudent to have some experience with the operation of formula-based allowed returns before incorporating them into a broader alternative framework for utility rate making.

Another benefit of the Board's recently-adopted formulaic approach to LDC return setting is the predictability about future LDC allowed returns that such an approach affords. First, the use of the Board's formula and its automatic annual adjustment mechanism greatly reduces the risk of regulatory lag and earnings attrition from the perspective of the regulated utilities and their owners. In addition, the use of the ERP-based formula and the automatic adjustment of the base Canada rate forecast increases the predictability of the Board's equity return award in the eyes of investors and bond raters. The Dominion Bond Rating Service (DBRS), for one, finds this "predictability" a "positive" from the perspective of assessing a utility's regulatory risk. Furthermore, the formula adjustment mechanism reduces the risk that a particular gas LDC or MEU might, at some future date, be subjected to a harsh Board decision or to a punitive rate of return. The Board seems to have anticipated this last point in its March 1997 report where it admits that "a move to formula-based ROEs may restrict a regulator's ability to make discretionary adjustments to a utility's return for the purpose of creating incentives for particular behaviours or sending signals to the marketplace."

There is also a fourth risk-reducing aspect of setting and adjusting allowed LDC returns on the basis of the forecasted long Canada bond yield. This procedure has the effect of stabilizing the equity market values of the LDCs that are regulated in this manner. It is a well-known valuation principle in the finance literature that if (a) the prospective actual return on an investment and (b) the opportunity-cost-determined, prospective required rate of return on that same investment (in this case represented by the long Canada yield plus some add-on) are highly correlated, than the market value of the investment will be stabilized over time. This effect of the Board's formula-based approach to establishing allowed equity returns may, as a consequence, make it easier for MEUs to attract outside, non-municipal equity capital and promote consolidation within the Ontario MEU industry.[10]

While the Board's experience with its new formulaic approach to gas LDC equity-return setting is not lengthy, it is the author's opinion that the benefits that the Board itself envisioned for adopting this approach have, for the most part, been realized. Whether the other, risk-related benefits of the new approach have been achieved, or will eventually be realized or capitalized upon, is still an open question.

5.3 Limitations and Drawbacks of the Board's Current Formula-Based Approach

The formula-based equity return approach suffers from a number of actual or potential shortcomings, some of which were acknowledged by the Board in its March 1997 Draft Guidelines Report. First, any overstatement or understatement of the fair rate of return for a particular LDC in the initial setup phase will likely have a cumulative or compounding effect over time on the results flowing from the formulaic ROE mechanism, either short-changing or inflating subsequent equity-return determinations. The new approach provides less opportunity than the previous, more-open-form, return-setting procedure for subsequent interventions to compensate for initial errors.

A second limitation of the formulaic return-setting approach is that, by design, it relies primarily on the ERP return-estimation technique to the exclusion of other methods that witnesses have employed in the past. This narrowing of the focus of the return portion of the rate hearing necessarily sacrifices the unique contributions of the other approaches and ignores changes in factors, other than interest rates, that may impact a utility's fair rate of return over time. The Board also acknowledged that by committing itself to use the formulaic approach to equity-return setting, it had given up some flexibility or discretion to make adjustments to utility returns for signalling and/or behaviour-modification purposes.

Beyond these three shortcomings that the Board identified in its March 1997 Report, there are couple of other problems with the formulaic ROE approach that have come to light as the approach has been implemented in particular rate hearings. The most serious of these involves the impact that the automatic equity-return adjustments can have on the projected interest coverage ratios (ICRs) for a utility. When long-term Canada yields decline and are projected to continue to decline, the utility's Board-formula-determined, allowed equity return will decline, as well, to the extent of approximately 75% of the decline in long-Canada yields. The utility's required interest payments, on the other hand, will likely decline only marginally, if at all, as most of these are embedded costs associated with earlier debt financings.

Consequently, the utility's ICR will be squeezed, perhaps down to a level which restricts its ability to issue new debt or which jeopardizes its existing bond ratings. Witnesses for Union Gas in E.B.R.O. 499 have indicated, as an example of the formula effect, that they believe the operation of the Board's return formula may make it impossible for Union to meet the new-issue ICR test in its trust indenture and, thus, force the Company to forego new long-term debt financing during 1999. As an example of the second or latter effect identified at the start of this paragraph, the Canadian Bond Rating Service (CBRS) recently downgraded its rating on the mortgage bonds and preferred shares of Newfoundland Power Inc. Among other reasons offered for the downgrading, the CBRS analyst stated that "the adoption of an automatic adjustment mechanism for setting annual rates of return on common equity in future years (1998-2000) will consistently grant Newfoundland Power a regulated ROE measuring below the industry norms." The analyst also concluded that the "projected decline in revenues, earnings and coverage ratios in 1998 has reduced the margin of protection traditionally provided to the bondholders."

Another shortcoming of the Board's formula approach to equity-return determination, in the eyes of some, is

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[10] If, rather than stabilizing the LDC's market value, prospective MEU investors would prefer stability in the annual accounting earnings (or returns on common equity) from their MEU investments, then the Board's use of a Canada-bond-yield-based formula will facilitate this as well. To accomplish such return hedging under the formulaic ROE-setting regime, MEU equity investors need only (a) enter into long-term interest rate swap arrangements (where they are the floating-rate payers and fixed-rate receivers) or (b) roll over short positions in Montreal-Exchange-traded 10-year Canada bond futures, in sufficient quantities to effect the desired degree of return-volatility dampening with respect to the MEU earnings that are a product, at least in part, of the formula-based return-setting mechanism. This point will be discussed at greater length in Section 5.5.

that it tends to make utility allowed returns more volatile year-to-year than they would have been under the Board's previous "no-holds-barred" approach. This is simply because a change in the allowed return under the new formula-based approach that is occasioned by a change in long-Canada yield expectations might likely have been moderated by the results of other, non-ERP, equity return tests under the former regulatory regime.

Finally, the use of the 30-year Canada bond yield as the base rate within the ERP framework of the Board's formula-based, annual return adjustment mechanism creates a number of problems. First, there is no generally-accepted consensus forecast of the 30-year yield for the Board to rely on. Instead, the Board is forced to employ the Consensus Forecasts based on current rather than expected-future market conditions, to translate the consensus forecast of the 10-year rate into a corresponding forecast of the 30-year Canada rate. If the bond market is passing through an inflection point when this 30-year-versus-10-year yield spread is determined, then the estimated spread may be a poor forecast of the spread likely to prevail during the regulated utility's test year.

Using the 30-year Canada yield forecast as opposed to the 10-year yield forecast also complicates utility earnings management in another way. The Board's formula-based return has the effect of turning the regulated utility's common shares into a floating-rate, bond-type investment. The utility's owners may, instead, wish to stabilize the returns from their investment. The derivative-security products available in Canada to do this hedging of the interest rate risk that has now been built into Ontario gas LDC returns are primarily built around the 10-year Canada bond yield and the 10-year Canada bond futures and options traded on the Montreal Exchange. Over the counter (OTC) interest rate swaps based on 30-year yields are also harder to price and "set off" (hedge) by swap dealers and, as a consequence, are more expensive than their 10-year cousins for which direct dealer hedging opportunities exist. In short, investors wishing to hedge the returns from their Ontario gas LDC share-holdings or their future investments in MEUs would find it considerably easier and cheaper to do so if the year-by-year adjustments to utility allowed returns were equal to 75% of the hearing-to-hearing change in the direct 10-year Canada yield forecasts as opposed to the "two-part-constructed" 30-year forecasts.

5.4 **Implications of Applying the Current Gas LDC Formula-Based Approach to Regulating Electricity Utilities**

To begin with my conclusion for this section, I see no serious impediment to applying the Board's current, formula-based approach for setting allowed equity returns to Ontario's MEUs, once they fall under the Board's regulatory jurisdiction. Applying the procedure used for the gas distributors to the electricity distributors will insure consistency of Board rate-of-return treatment between the firms in these two, frequently-competing industries, with no detrimental impacts on the MEUs above and beyond those already mentioned in the previous section for the gas LDCs.

Indeed, the impact of a cyclically-variable return on equity through the operation of the Board's Canada-yield-based formula may have a less consequential impact on MEUs and their ratepayers than it has on gas LDCs. For Ontario gas consumers, in aggregate, the gas-cost component of the all-in average user rate represents between 60% and 65% of the total delivered cost of gas, while the Ontario distribution function accounts for 35% to 40% of the costs. (These percentages will very from year to year, of course, depending on the level of natural gas prices.) For the customers of Ontario's MEUs, on the other hand, the cost of the electricity purchased by the MEUs represents about 85% of the price of the electricity service delivered to ratepayers, while the MEU distribution costs make up only about 15% on average of the total delivered price of electric power. While this 15% distribution cost proportion may rise in the future as MEU rates begin to incorporate higher-than-historical allowed equity returns and the cost of electricity supplies eventually comes down, it appears unlikely that it will rise to the level that characterizes Ontario's gas distribution industry.

For Ontario's gas LDCs, before-tax profits represent about 25%-30% of total distribution costs (about 27.6% in 1996), depending on the level of allowed returns, while the other costs including: operating, maintenance, and administration; government levies; depreciation; and net interest expenses - which are largely invariant with respect to delivery throughput volumes - make up 70% to 75% of total distribution costs. This implies that the Board-influenced pre-tax equity returns of Ontario's gas LDCs comprise somewhere between 9% and 12% of their customers' all-in delivered price of gas. If we assume that Ontario's MEUs are allowed to earn equity returns similar to those of the gas LDCs, on similar deemed common equity bases (or slightly higher deemed CERs until MEU industry consolidation is further advanced), and that the MEU rates will also include a recovery of interest expenses on debt for the non-deemed-equity proportions of their capitalizations, then the MEU earnings before payments in lieu of taxes can be expected to account for between 25% and 33% of total MEU distribution costs - not too dissimilar to the fraction associated with the gas LDCs. However, what this means is that the future-Board-influenced, pre-payments-in-lieu-of-tax, equity earnings of the typical MEU will comprise only somewhere between 5% and 7% of their customers' total delivered cost of electricity (on the assumption that the MEU's higher debt and equity capital costs will drive the distribution-cost share of total ratepayer costs up to around 20%).

The moral of the above story is that whatever instability the Board's formulaic return-setting mechanism builds into final user rates will be less serious for MEU electricity ratepayers than it will be for gas ratepayers.

There is also an economic cycle effect to consider here as well. In the future Ontario regulatory environment, the equity capital costs of the delivery functions for both gas and electricity supplies will vary directly with actual and forecasted long-term interest rates. While there is no reason to expect any correlation between interest rates and weather conditions over time, there is bound to be some positive or direct correlation between Canadian long-term rates and the pace of North American economic growth. Generally speaking, when all other factors are held constant, faster economic growth leads to increased credit demands and rising inflation expectations, both of which typically put upward pressure on long-term interest rates. Again, all other things being equal, rapid North American growth also tends to put upward pressure on gas commodity prices, as usage rises in the face of limited delivery flexibility. Similarly, strong growth increases electricity demand, which calls out more-costly generation at the margin and raises spot prices for electricity.

In other words, both gas consumers and electricity consumers can often be expected to absorb higher capital costs for their LDCs and higher passed-through commodity costs at the same time. The difference here for Ontario ratepayers, however, is that both historically and for the near-term future, at least, the cyclical variability in the commodity cost of electricity is less, and going to be less, than that associated with gas supplies (the latter being a cost over which Ontarians have little control, in contrast to the control Ontario Hydro exercises over the cost of electricity supplies). Again, the moral is that the "double jeopardy" pain that Ontario's MEU ratepayers may have to endure because of any correlation between purchased electricity costs and MEU capital costs is likely to be less than the corresponding correlation-related pain gas consumers may have to bear.

Finally, we should consider the situation of the MEU owners. If the MEUs become privately owned, there is no reason to think that they will be any less able than the owners of the gas LDCs to handle the year-to-year volatility in equity returns caused by the application of the Board's formula-based approach to return setting. If the MEUs remain municipally owned, the upset that their municipal owners may feel regarding the volatility in their annual MEU dividends (resulting from the Board's new approach to setting allowed returns) will likely depend on the ability of the respective municipalities to accommodate, from a planning/financing perspective, this year-to-year and cyclical dividend volatility. This accommodation might involve the use of a reserve account or having the municipality issue a debenture, to meet municipal budget needs, if MEU equity returns are projected to be low for several years because of low Canadian bond yield expectations. Greater stability in the net distributions that municipal owners receive from their MEU equity holdings might also be achieved in a fairly low-cost fashion through the prudent use of interest rate derivative instruments such as rate swaps and bond futures. Municipal owners of MEUs may also take some comfort that the realizable market values of their MEU equity holdings will tend to be stabilized over time by the operation of an equity-return-setting mechanism such as the one currently used by the Board to regulate the gas utilities.

All in all, I do not anticipate any major detrimental impacts on the Ontario MEU industry from having their allowed equity returns determined and adjusted annually on the same formulaic basis as the Ontario gas LDCs.

5.5 Suggested Amendment to the Current Approach For the Purpose of Its Application to Ontario Municipal Electric Utilities

In Section 5.3, I discussed what I felt was a weakness in the Board's year-to-year adjustment mechanism for revising its formula-based equity return awards for the Ontario gas utilities - namely, the procedure's reliance on a two-part-constructed, 30-year Canada yield forecast found by summing (a) the Consensus Forecasts prediction of 10-year Canada yields for the test year and (b) an estimate of the likely 30-year-versus-10-year yield spread (based on conditions prevailing at the time of the rate hearing as opposed to forecasted future market conditions). I suggested, instead, that the Board should consider substituting the forecasted 10-year Canada bond yield for the forecasted 30-year yield in the mechanism for adjusting allowed MEU returns from year to year. (Note that I am not suggesting any change in how the initial setup phase is implemented.) In order to preserve consistency between the treatment of MEUs and gas LDCs, this change, if adopted, would, of course, have to be made to the annual return revision procedure for the gas LDCs as well.

The amendment I am recommending would offer two distinct advantages over the current formulation. First, adoption of the 10-year forecast would obviate the need to incorporate an adjustment for the estimated spread between 10-year and 30-year Canada yields in each application of the adjustment mechanism. This extra element of estimation has the potential to increase the forecast error whether it is done, as presently, in a simplistic way (i.e., assuming that next year will look like today) or based on prospective information. Furthermore, the present procedure may considerably over-state or under-state the appropriate Canada rate adjustment (and hence equity return adjustment) depending upon the pattern of ex post errors in the consecutive-year spread estimates.

My second reason for promoting the 10-year Canada yield for the Board's consideration is that its use may enable the owners of Ontario's MEUs and the shareholders of the major gas LDCs to hedge the risk associated with year-to-year fluctuations in the returns and earnings from their utility investments. There are no conveniently-available hedging products based on 30-year Canada yields. For 10-year yields, on the other hand, the Montreal Exchange has created, and supports the trading in, bond futures and bond options contracts based on the 10-year Canada yield. The existence of these exchange-traded products, which are relatively liquid in Canadian terms, also means that financial institutions will be more willing to offer 10-year-yield-based interest rate swaps and rate cap and collar products to investors, as the institutions have a market in which to "set off" any unwanted risk exposure that they might accumulate by selling these products.

The ability for potential purchasers of Ontario's MEUs to create effective hedges to counter the earnings variability of their prospective MEU investments will be particularly attractive for purchasers that wish to pre-arrange long-term, fixed rate debt financing to support their bids and eventually consummate their purchases.

It would be unfortunate if the effect of the substitution of 10-year yields for 30-year yields in the Board's adjustment procedure were to exaggerate the year-to-year changes in LDC return awards. To examine the likelihood of this occurring, I compared the magnitude of the year-to-year changes in 10-year Canada yields and 30-year Canada yields for each possible ending month - starting with September 1998 and working my way back in time as far as the available figures from the Datastream data service would permit (i.e., to January 1992). What I found was that the standard deviations of the 81 annual yield changes, in absolute terms, were identical (at 93 basis points) for the recent time series of 10-year Canada yields and 30-year yields. While there may be reasons to believe that 10-year yields will be marginally more volatile over time than 30-year yields, the available historical data themselves offer no supporting evidence.

I briefly considered whether or not it would be preferable to replace the 30-year Canada yield forecast with some consensus forecast of the Scotia Capital Markets index of long-term corporate bond yields. The rationale for considering an index of corporate bond yields is that these corporate yields take account of a wider range of changes in capital market conditions and in the level of investors' credit risk fears (as compared to Government of Canada yields). The same factors that affect the corporate bond market may also influence the required rates of return on equity investments in MEUs and gas LDCs. Further-more, the available historical evidence indicates that year-to-year changes in long-term corporate bond yields are actually somewhat smaller than those for 30-year Canada yields. Nevertheless, the lack of any conveniently available and trusted consensus forecast for long-term corporate yields dissuaded me from pursuing this idea.

6 Determining Regulatory Return on Rate Base Differentiated by MEU Risk Class

As discussed in Section 4.5, I am recommending that the Board, for the purpose of regulating MEU returns, adopt the approach of reflecting all the variation in MEU business risks, across the designated risk classes, through the selection of their deemed common equity and debt ratios. This would then permit, and indeed require, the Board to allow a single uniform, formula-determined equity rate of return for all LDCs across the Ontario MEU industry. This approach has a number of goal-achievement-related advantages (as discussed in Section 7) and is consistent with the approach the Board adopted in its recent NRG Decision (in E.B.R.O. 496) and the approach taken by the NEB until recently in its regulation of pipeline rates of return.

Differences in the rate-of-return-on-rate-base requirements for MEUs in different risk classes would be reflected in the regulatory allowed return on rate base, as set by the Board, via three avenues - namely,

(a) via the Board-determined, deemed CER and deemed debt ratio, with higher allowed CERs and lower debt ratios for higher-risk MEUs;

(b) via the actual interest rates charged by the financial markets on any outstanding MEU debt, with higher risk MEUs being charged higher rates for their debt issues; and

(c) via the Board's awarding a debt cost, calibrated to reflect the MEU's business risk class, on that portion of the MEU's total regulatory capitalization not covered by its deemed CER and any actual accumulated net debt financings. (Note that each MEU's total regulatory capitalization would be set equal to its approved rate base.)

Consequently, the return on rate base for a MEU with no debt on its balance sheet would be determined as

$$\begin{bmatrix} Return\ on \\ Rate\ Base \end{bmatrix} = \begin{bmatrix} Allowed \\ CER\,\% \end{bmatrix} \times \left[100 - Allowed\ CER\,\%\right] \times \begin{bmatrix} Board-set \\ debt\ rate\ to \\ reflect\ risk\ class \end{bmatrix}$$

follows:

The reader should note that this procedure requires the Board to determine and approve debt yield requirements for the test year that are differentiated across MEU risk classes. This is not an arduous task, however, as there is ample evidence continually available from the banks and investment dealers to assist with these credit-spread determinations (relative to Canada bond yields).

For a MEU which already has debt on its balance sheet, the average, prospective test-year, embedded cost of its debt would be used - instead of the Board-set debt rate - for that portion of its total capitalization represented by its existing debt. Any difference remaining between 100% and the sum of the MEU's CER plus its embedded debt ratio would be assigned the Board-set debt rate for the MEU's risk class.

The table below illustrates how MEU overall rate-base returns might be expected to vary across MEU risk classes in a "normal" financial market environment characterized by Canada bond yields not too dissimilar those prevailing in late 1998. The assumptions underlying this illustration are:

- a MEU-industry-wide allowed ROE set at 10.00% for the test year;

- deemed debt-cost rates which very from 7.0% for low-risk MEUs to 7.70% for high-risk MEUs;

- deemed CERs and deemed debt ratios across MEU risk classes, as per the author's recommendations from Section 4.5;

- proforma "before-tax" interest coverage ratios based on a 40% assumed payments-in-lieu-of-taxes rate, the assumption that the MEU just achieves its allowed equity return, and the assumption that the MEU has debt financed itself up to its deemed debt ratio at an average cost equal to the allowed debt ratio; and

- the estimated bond rating ranges are based on bond rating agency criteria and discussions with utilities analysts at DBRS and CBRS and the fixed-income portfolio managers at the Bank of Montreal.

MEU Risk Class	**Deemed CER %**	**Allowed ROE %**	**Deemed Debt Ratio %**	**Allowed Debt Rate %**	**Overall Return On Rate Base %**	**Pro Forma Before-Tax ICR**	**Estimated Bond Rating**
Low Risk	35	10.00	65	7.00	8.05	2.28	A(l) to A(h)
Medium-Low Risk	40	10.00	60	7.10	8.26	2.56	BBB(h) to A
Medium-Risk	42.5	10.00	57.5	7.20	8.39	2.71	BBB to BBB(h)
Medium-High Risk	45	10.00	55	7.40	8.57	2.84	BBB(l) to BBB(h)
High Risk	50	10.00	50	7.70	8.85	3.16	BBB(l) to BBB

7 Are the Recommendations in This Paper Consistent With the Board's Goals For Its Regulation of MEU Equity and Rate Base Returns?

The purpose of this final section of the discussion paper is to evaluate whether the paper's major recommendations are consistent with achieving the Board's goals for MEU regulatory rate-setting, as outlined in Section 1.2.

The first of these goals requires that the allowed returns on equity and total capital for the MEUs should be fair and reasonable from the perspectives of both the MEU's ratepayers and its owners. In this context, it is important to note that the recommendations in this paper have focused on the formulas and procedures used to arrive at allowed equity rates of return and returns on rate base from year to year, and not on the choice of the final levels of these returns. The fairness and reasonableness of the allowed-return levels will depend, in the end, on the equity risk premium (ERP) chosen by the Board for implementing these formulas. The reasonableness of the formulas from the owners' perspective resides in (1) their on-going adjustment of allowed returns to reflect year-to-year changes in financial market conditions and (2) in their differentiation of allowed returns on rate base to compensate for different levels of business risk. From the point of view of ratepayers, the use of the Board's formula-based equity-return procedure will, as discussed in Section 5.4, not unreasonably exacerbated year-to-year fluctuations in electricity user rates. Consequently, this paper's recommendations are judged to be consistent with the Board's first goal.

It is also the Board's goal that the allowed equity returns for MEUs should provide fair compensation for the owners of these MEUs in comparison with the returns that could be earned on comparable, equally-risky, alternate Canadian investments. The approach recommended in this paper is to deem different common equity ratios and debt ratios, for rate-setting purposes, to reflect the different degrees of business risk exposure across Ontario's network of MEUs. The different, risk-class-differentiated degrees of deemed financial leverage have been chosen with the intention of equalizing the overall investment risk exposure (including both business risk and financial risk) of the equity holdings of the MEUs' owners across all the risk classes. Fairness of owner compensation across MEUs depends, therefore, on one's judgment as to whether the range of deemed capital structure ratios adequately reflects differences in business risk, such that the sought-after equalization of the total investment riskiness of MEU equity holdings (at these deemed capital structure ratios) is achieved. Fairness in comparison with equally risky investments in the equity of Ontario's gas LDCs has been attended to by an extensive comparison of the business risks in the gas LDC and MEU industries and by setting the range of deemed MEU common equity ratios in a parallel fashion to that which has recently been approved by the Board for gas distribution utilities. Finally, there is nothing in the paper's recommendations that would prevent the Board from selecting the particular ERP level to incorporate within the equity-return formula that results in MEU equity-return levels which are comparable with the costs of equity capital of equally-risky, alternate Canadian investments.

The recommendations set out in this paper have been aimed at the typical MEU within each risk class. The author recognizes, therefore, that even if the implementation of the recommended approach provides fair compensation for the owners of the typical MEU, the owners of the most risky or disadvantaged MEUs in each risk class may feel that their Board-awarded equity and overall-rate-base returns are too low to fairly compensate for the risks they face. Whether the Board provides for some ad hoc individual MEU return adjustments to address these perceived inequities is a matter for future policy consideration.

The Board's third goal vis-a-vis the regulation of MEU rates of return is to insure that the allowed returns on equity and total capital are sufficient to enable prudently-managed MEUs to attract new debt and equity capital on reasonable terms under normal market conditions and without impairing the financial integrity of their existing securities. Furthermore, the Board-approved deemed MEU capital structure ratios, in conjunction with the allowed returns on debt and equity capital, should not unreasonably impair the ability of MEUs to access loan and capital markets for new debt and equity on reasonable terms under normal financial market conditions. Satisfaction of this "capital attraction goal" depends primarily on the Board's choice of the MEU-network-wide ERP level to incorporate within the equity-return formula, as the risk-class-differentiated, deemed capital structure ratios have already been structured with an eye to the maximum acceptable degrees of financial leverage permitted by the bond rating agencies for attaining an investment-grade bond rating, as discussed in Sections 4.2 and 4.5.

Concerns have recently been raised, however, about whether the application of the formula-based mechanism for adjusting gas LDC and MEU equity returns from year to year might not "squeeze" actual and prospective interest coverage ratios (ICRs) under certain circumstances and, as a consequence, restrict the financing flexibility of either MEUs or gas LDCs. I described the nature of the problem with the formula-based approach to setting allowed equity returns in Section 5.3. The problem has come to light in connection with setting the rates for Ontario's gas LDCs which already have substantial debt financing on their balance sheets at average embedded debt rates which are "high" in relation to today's rates because of the sustained downward course of interest rates since 1982. This "ICR-squeezing phenomenum" of the Board's formula is highly unlikely to impact the MEUs in general, however, because (1) very few of the MEUs currently have any substantial debt on their balance sheets, and (2) if, in conjunction with the restructuring of, and imposition of rate regulation on, the MEU industry, MEUs choose to take on substantial debt loads, then these debts will be arranged in an environment characterized by lower rates.

Only if the MEUs were to go through a prolonged cycle of, first, rising rates and, then, falling rates - such as the one witnessed in Canada between 1965 and 1998 - would the MEUs possibly experience any financing flexibility constraints because of the operation of the Board's equity-return formula. Furthermore, if some years from now the situation arises where the MEUs might be exposed to the possibility of falling interest rates over a sustained period of time, their financial officers - aware of the potential problem - will be able to institute financing policies (e.g., rolling over more short-term financing, swapped into fixed rates) to mitigate the problem of squeezed ICRs before it arises. Adoption of my suggestion that the year-to-year adjustment mechanism, within the Board's formula-based return-setting approach, be based on changes in prospective 10-year Canada bond yields would make it easier for MEUs to successfully address the above financial planning problem.

In summary, then, the formula-based approach to regulating MEU returns meets the capital attraction standard more fully than the approach, as currently employed, does with respect to Ontario's gas LDCs.

The Board's fourth goal is for the determination of MEUs' allowed returns on equity and total capital to be as symmetric as possible with the process applied to the regulated operations of the Ontario natural gas LDCs and, in any case, not confer any unwarranted advantage or disadvantage on MEUs, as compared to gas LDCs, that might unfairly distort the relative competitive positions of the electric power suppliers and marketers versus the natural gas suppliers and marketers in Ontario. My analytical approach throughout this paper has been designed to insure that this consistency of regulatory treatment and results will be achieved. Risk-class-differentiated, deemed capital structure ratios have been proposed for the MEUs based largely on (1) the corresponding ratios used by the Board for the gas LDCs and (2) a thorough consideration of the relative business risks of the organizations in each of these industries. As long as the system-wide, uniform ERP for the MEU industry is set - in relation to the ERPs used for the gas LDCs - to reflect any perceived differences in the business riskiness between similarly-sized and similarly-diverse organizations, then the adoption of the Board's formula approach within the framework of the paper's other recommendations will insure that the Board's "inter-utility-industry consistency goal" is achieved.

Finally, there is the Board's goal to minimize any detrimental impact that its move to regulate the rates and returns on the monopoly "wires" businesses of the MEUs might have on the process of consolidation and rationalization within the Ontario MEU industry in future years. More formally, it is the Board's intention that the transition process from the current levels of MEU returns to those which reflect and foster the standards of fairness, capital attraction, and maintenance of financial integrity should be managed in such a way that it gives due consideration to the potential impacts on ratepayers and on the process of consolidation (including mergers and acquisitions) envisioned for the MEU industry. It is expected that the use of the Board's formula-based approach to return-setting, within the framework of this paper's other recommendations, will support the achievement of this last goal in a number of distinct ways.

First, the predictability of future MEU equity returns (in relation to long-Canada rates) from the perspective of potential investors (including industry consolidators) will significantly reduce the uncertainty of their MEU (market) valuation estimates and, thus, facilitate the negotiation and implementation of mergers and takeovers within the MEU industry (once the preconditions for this process are put in place). Second, not only will the uncertainty surrounding these valuation calculations be reduced, but the market values for these MEUs (in the absence of structural changes) will themselves be stabilized over time. This market value stability should be appealing to potential investors and have the effect of elevating market values from what they might otherwise be. At the same time, the municipal sellers of MEUs (in whole or in part) will not need to feel "panicked" into selling at a particular time because of the prospect that a changed interest rate environment might erode the sale proceeds that the municipality would receive if it waited, for whatever reason, to sell.

The framework for applying the Board's formula approach that I have recommended in this paper can also be expected to minimize any disincentive that smaller MEUs and their municipal owners might otherwise have to participate in size-enhancing and risk-reducing mergers. By adopting a uniform allowed rate of return on equity across all risk classes, the Board would ensure that individual MEU owners would not be disadvantaged through lower equity returns by participating in consolidations that have the effect of improving the participants' business risk classifications. Many such consolidations are likely to require some on-loading of debt to lubricate the process, and the larger, financially-stronger organizations created by these consolidations should find it easier to arrange the debt financing to support the process. This latter point is especially important in situations where privately-owned companies are arranging debt financing to enable them to take over one or more municipally-owned MEUs. In this latter case, the debt-carrying capacity of the acquired MEUs will help determine the speed and pervasiveness of the process of consolidating Ontario's MEU industry.

In conclusion, then, it is my judgment that applying the Board's formula-based approach to regulating gas LDC returns to the regulation of the returns of Ontario's MEUs - within the framework of the other recommendations developed in this discussion paper - will achieve the goals that the Board has set for itself with respect to regulating the rates of return of Ontario's MEUs.