Calculating the Cost of Capital for LDCs in Ontario

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June 14, 2006

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Objectives

We have been contracted to examine the cost of capital using the benchmark OEB Decision of May 11, 2005 and the 2006 Electricity Distribution Rate Handbook as the points of departure.

Current Methodology for Setting the Cost of Capital for LDCs

In order to establish the weighted average cost of capital (WACC), the LDCs have been grouped according only to the size of the regulated rate base. Four size groupings have been adopted:

- Small – rate base of less than $100 million;
- Medium-small – rate base between $100 and $250 million;
- Medium-large – rate base between $250 million and $1 billion;
- Large – rate base in excess of $1 billion.

The entire adjustment for differences in business risks among the LDCs was to be reflected through a deemed capital structure, which would vary according to the size groupings. The capital structures were based on the size groupings of the LDCs:

- Small – debt/equity split of 50%/50%;
- Medium-small – debt/equity split of 55%/45%;
- Medium-large – debt/equity split of 60%/40%;
- Large – debt/equity split of 65%/35%.

All the LDCs were allowed the same return on equity regardless of their size. The initial after-tax, return on equity (ROE) was set at 9.88%. This rate was derived by adding an equity risk premium of 3.80% for the LDCs to the forecast yield on 30-year Government of Canada bonds as of year-end 1999.[1] The ROE was to be adjusted automatically in subsequent years according to a simple formula. The allowed ROE would change each year by a multiple of 0.75 times the annual change in the 30-year Government of Canada bond yield. Applying this formula to the year-end 2005 bond rates produces a ROE of 8.65%.

The equity risk premium was derived by taking a weighted average of risk premiums derived from three tests:

- the equity risk premium test;
- the discounted cash flow (DCF) test; and
- the comparable earnings test.

[1] It is difficult to determine what value of beta was used to derive this ROE, especially since it is unclear how the three basic tests were combined. But assuming that a beta in the range of 0.5 to 0.75 was used and that CAPM was given a weight of 40%, then the weighted average beta implicit in this ROE would have been in the range 0.8 to 0.9.

It seems as if the multiple of 0.75 for annual adjustments also was derived by taking the same weighted average of the interest rate sensitivities of the risk premiums produced by each test.

Size

Dr. William Cannon presented a number of arguments for using size, based on assets, as the sole criterion for differentiating LDCs. Standard & Poor's has no minimum size criterion for any given rating level. However, size does turn out to be significantly correlated to its ratings. The reason: size often provides a measure of diversification, and/or affects competitive position. Small companies are, almost by definition, more concentrated in terms of product, number of customers, or geography. In effect, they lack some elements of diversification that can benefit larger companies. In addition, lack of financial flexibility is usually an important negative factor in the case of very small companies. Adverse developments that would simply be a setback for companies with greater resources could spell the end for companies with limited access to funds.

Economies of Scale

It is generally accepted that there are economies of scale in electricity distribution. Thus, consolidation, especially among the smaller LDCs, is expected to lead to lower distribution costs. But mergers are not the only means by which the cost savings from economies of scale can be realized. Virtual utilities are an alternative to the outright sale of a LDC. That is, a LDC could outsource some or all of its operations to take advantage of potential economies of scale, without the need for a change in ownership.

Conceptual Discussion re. Cost of Capital

In a regulated environment a regulator aims to set the allowed rate of return in a fair and just way. A prerequisite for estimating and fixing the allowed rate of return is to define and justify a "fair" rate of return.

In financial markets a "fair" or a correct price of an asset, or a financial instrument, is the price that does not induce free lunches in an economy. This notion of a correct price is not only derived from the economic intuition, but is also supported by rigorous arguments and characterizations of no-arbitrage in financial markets. A necessary and sufficient condition for financial markets not to admit arbitrage opportunities is that the prices of assets are actually their present values. The absence of arbitrage opportunities is the cornerstone of modern Financial Economics.

AS we noted, three types of tests have been used to determine the risk premium and the resulting "fair" ROE for companies subject to rate of return and/or performance-based regulation. The equity risk premium includes the Capital Asset Pricing Model (CAPM). The CAPM, while not free of some deficiencies, is widely used in valuing and assessing risk, and the risk premiums of assets.

Since the CAPM is used by other regulatory bodies and for the following reasons as well, we utilize only the CAPM to assess the risk and rate of return:

- The CAPM is a market based approach and hence is an objective approach that relates to actual conditions in financial markets.
- The CAPM has a strong theoretical foundation in the academic finance literature and has been widely adopted in the financial markets. Indeed, the major stock exchanges provide estimates for beta for all companies listed on the exchanges. (Beta measures the risk of the asset relative to a market portfolio.)
- The CAPM is subject to fewer errors relative to the other two methods which require estimates of future cash flows and their likelihoods.
- Finally, implementing the CAPM is relatively simple and requires use of data that are readily available.

Further, the use of the one test, which has the soundest theoretical basis, precludes the need to establish a set of weights. Since there is no theory to assist in calculating the weights, that exercise turns out to be quite arbitrary.

Cost of debt

DBRS has set out the following criteria, both quantitative and qualitative, for rating the credit of electricity and gas distribution companies.

- Debt-equity ratios
- Fixed charge coverage
- Cash flow to debt.
- Proportion of regulated versus non-regulated activity
- Condition of the transmission and distribution grid
- Economic strength of the franchise area – growing or shrinking
- Size of the utilities
- Diversification, and the degree of diversification
- The quality of regulation - is there regulatory lag?
- Growth – long-term growth in electricity demand
- Sales mix between residential/commercial/industrial
- Company sensitivity to temperature (residential and commercial customers) and economic factors (industrial customers)

Standard and Poors uses a similar mix of quantitative and qualitative factors in its analysis of the credit ratings of companies. For industrials in general, the qualitative factors include industry characteristics, each company's competitiveness within its industry and the caliber of management. For water and sewer companies, which tend to be smaller in size and largely regulated at the state level, S&P uses economic considerations (e.g. the stability of a utility's customer base, the potential need for capital spending, the affordability of rates, and the employment opportunities available to its customers), operational characteristics, and an assessment of management.

It is most likely that many of the small LDCs will come up short in any analysis of their management strengths. Of course, one solution is to go the route of a virtual utility and outsource most functions, including management. The other solution is merging to create larger LDCs – a strategy undertaken thus far by Veridian, CNPI and Powerstream.

Setting aside the two smallest size categories – net plant assets of less than $5 million – since the averages are distorted by a few of the LDCs, the earnings before interest and taxes (EBIT) coverage are on average between two and three – safely within the "BBB" rating category for utilities. On the other hand, the ROEs are in the 3% to 7% range – consistent with "B" and "BB" ratings for utilities, but lower than the average ROEs for a number of the largest electricity utilities in Canada. With the exception of the largest LDCs, those with net plant assets in excess of $300 million, total debt represents between 40% and 50% of the total debt and equity of the LDCs. This places the LDCs on average in the "AA" rating level. The five largest LDCs have leverage ratios in the "BBB" rating category. The average returns on capital (total debt plus equity) and the total debt to EBITDA ratios generally run in the range of the "B" rated industrials.

Size does not seem to be a disadvantage in terms of profitability, although there is greater variability among the smaller LDCs in each of the profit measures. Other than the five largest LDCs, the average total debt to total debt and equity ratios tend to be comparable for the LDCs with net plant assets of less than $300 million. Finally, the LDCs with net plant assets of less than $10 million have much higher total debt to earnings before interest, taxes, depreciation and amortization (EBITDA) ratios on average than the larger LDCs. The three smallest LDC groupings also have the most unreliable interest coverage measures.

While it is tempting to conclude that the LDCs should be placed into different rating categories, and that size could be the most appropriate criterion to use to do so, it is important to consider that the credit ratings are intended to provide a proxy for the potential losses that an investor may incur. Consequently, it is important to examine the potential risks for investors in the debt instruments of LDCs.

We agree with Professor Booth's argument that "ROE regulated firms have minimal risk in Canada due to the high degree of regulatory protection." Professor Cannon earlier had reached a similar conclusion. Furthermore, DBRS has stated that it views regulation as a strength in assessing the credit risks of utilities since regulation assures financial stability and performance-based regulation shares future efficiencies. DBRS did add that there could be "bad" regulation, with regulatory lag and unfavourable decisions.

Consequently, we propose that all LDCs be treated similarly for the purpose of determining the capital charge. For those LDCs that currently have outstanding debt, the appropriate rate of interest to use for their cost of debt is the average rate of interest they are paying. To diminish the opportunities for a LDC to game the system, we suggest that the average rate be re-set each year and it should be based on the expected average interest rate to be paid on the outstanding debt in the coming year. Furthermore, since the credit rating agencies include short-term debt in the total debt quantitative analysis, and again to reduce the opportunities for gaming the system, we would set a total (short-term and long-term) debt to equity ratio and separate rates for long-term and short-term debt but limit the percentage of short-term debt in the deemed capital structure.

Cost of Equity

In competitive markets, investors who hold a risky asset must be compensated for the risk they bear, otherwise they would have no incentive to prefer it over the risk free rate. This compensation is usually presented in the form of expected rate of return. The Capital Asset Pricing Model (CAPM) is credited with the contribution of calculating the risk premium and its relation to the "risk" assumed by the investors who hold the asset. This relation, *the security market line*, connects the expected rate of return of a risky asset to its risk, and stipulates the risk premium.

In the CAPM, the risk of an asset is measured by its beta. The beta of an asset measures the sensitivity of the expected rate of return of a risky asset to the expected rate of return of the "market". The "market" is usually represented by an index which captures the market, such as the S&P 500 or the S&P/TSX Index.

The conclusion of the CAPM is that an investor is compensated only for the systematic risk, the non-diversifiable risk, which is implicit in a risky asset. The diversifiable risk can be eliminated by holding the market portfolio which offsets part of the total risk of a risky asset. Hence the risk premium compensates the investor only for the non-diversifiable risk, the systematic risk that must be assumed when holding a risky asset.

In sum, therefore, it seems that given the circumstances, the approach which estimates the beta based on proxy firms is not only the most practical, but also the only feasible method at the current time. We have chosen a few publicly traded (on the TSX) companies that could be used as proxy firms. The after-tax beta recommended for estimation is the average beta (for the 52 weeks or 60 months) for the years 2004 and 2005, which turns out to be 0.357.

The rate of return on the market was estimated based on the rate of return for the S&P/TSX index. We estimated the market return to be 7.17% based on the S&P index for the past five years, and 10.65% based on the S&P index for the past 10 years.

Estimating the risk free rate is usually done using prices of Government of Canada bonds. Practitioners, to simplify matters, use the yields on Government of Canada bonds as they are reported in the financial papers. However, a more appropriate procedure will be to utilize the so called "zero coupon curve" which is derived from prices of coupon bonds.

The conceptual issue is, however, what rate should be used over the next review period. Would it be appropriate to set the risk free rate according to the current spot rates, or based on the forward rate, or perhaps on some average of rates as justified by the mean reverting property of interest rates?

It seems reasonable to assume that the spot rate should not be used for this purpose as it is not a fair representation of the rate to prevail over the next review period. The decision should therefore be between:

- the forward rate as it is an estimate of the spot rate that will prevail in the future; and
- some historical average of spot rates (spanning the review period) or even a longer term rate (e.g., the yield on five years Government of Canada Bonds) since it can be considered as an average of the short term rates.

The forward rate is considered a good estimate for a future spot rate. We estimated the forward rate, based on an average of 5, 10 and 15 year forward rates to be 5.01% for 2007.

Debt-Equity Ratio

While about eight years have passed since the last report prepared by Dr. Cannon for the OEB was published, the academic literature has still not reached a definite answer regarding the issue of the optimal debt equity ratio or its relevance. Some authors suggest that the best way to choose this ratio is to mimic the average in the industry.

SUMMARY AND CONCLUSIONS

Cost of Debt:

For those LDCs with outstanding third-party debt, both short-term and long-term, the cost of long-term debt should be set annually to equal the expected average interest rate on the long-term debt for the next year. The cost of short-term debt should be set equal to the expected average interest rate on the short-term debt for the next year. There should be a maximum component for short-term debt in the capital structure.

For the LDCs with a mix of third-party and associated party debt, the cost of debt for the entire outstanding debt should be set annually to equal the expected average interest rate for the next year on all third party, long-term and short-term debt.

For the LDCs with no debt or only associated party debt, the maximum allowable cost of long-term debt for the outstanding or deemed long-term debt should be set annually to equal the risk free rate based on the average of 5, 10 and 15 year forward rates for 2007 plus the average spread between a sample of “A/BBB” rated corporate bonds of 5, 10 and 20 year maturities and the corresponding Government of Canada bonds. This appears to be approximately 100 basis points. The sample could be selected annually by a panel of experts – academics and capital market professionals. The maximum allowable cost of short-term debt should be set annually to equal the average interest rate on commercial paper issued by the same sample of companies.

These rules should apply to all LDCs regardless of their size, as measured by the rate base.

Return on Equity:

The ROE, starting in 2007, for all LDCs should be based on the CAPM. There are two options. One is to set the initial risk premium and risk free rate for a five-year period, and adjust only the risk free component of the total ROE every year. The other is to calculate both the risk premium and the risk free rate each year.

In either case, the starting points are the risk free rate and risk premiums we have calculated. The risk free rate should be the same as the one used in determining the cost of debt. The risk premium to be added should equal our estimate of after-tax beta – 0.357 – times the market return less the risk free rate. Depending on the time period selected – five years or 10 years in our analysis – the market return can vary between 7.17% and 10.65%. Hence, the overall after-tax ROE for the LDCs can vary between 5.78%[2] and 7.02%. Once again, we suggest that a panel of experts be selected to determine the appropriate time period for calculating the market return, and the sample of companies to be used to determine the beta.

There are two options for the annual updating of the ROE. In option one, the risk premium would remain constant over the five-year period. However, the overall ROE would change in line with the annual changes in the risk free rate. The change in the risk free rate incorporated in the ROE should not change on a one-for-one basis with the actual change in the risk free rate. Instead, we recommend the following annual adjustments in the risk free rate incorporated into the ROE for the years 2008-2011:

2008: $R_{f2008} = R_{f2007} + 0.7(R^*_{f2008} - R^*_{f2007})$
2009: $R_{f2009} = R_{f2008} + 0.7(R^*_{f2009} - R^*_{f2008}) + 0.7*0.3(R^*_{f2008} - R^*_{f2007})$
2010: $R_{f2010} = R_{f2009} + 0.7(R^*_{f2010} - R^*_{f2009}) + 0.7*0.3(R^*_{f2009} - R^*_{f2008}) + 0.7*0.3^2(R^*_{f2008} - R^*_{f2007})$
2011: $R_{f2011} = R_{f2010} + 0.7(R^*_{f2011} - R^*_{f2010}) + 0.7*0.3(R^*_{f2010} - R^*_{f2009}) + 0.7*0.3^2(R^*_{f2009} - R^*_{f2008}) + 0.7*0.33^2(R^*_{f2008} - R^*_{f2007})$

where R^*_f represents the actual risk free rate calculated each year and used in determining the maximum cost of debt.

In option two, both the risk free rate and the risk premium are calculated each year.

Our suggested range for the ROE – 5.78% to 7.02% – represents a very significant reduction from the original 9.88% ROE. There are three reasons for this.

1. The risk free rate that we use is 5.01% compared to the "adjusted" forecast 30-year bond rate in effect in 1999 (approximately 6.08%). Interest rates in general have trended downwards for most of the past eight years.

[2] 5.01% + 0.357(7.17%-5.01%).

2. The original weighted average ERP of 4.22% to 4.75%[3] falls within our MRP range of 2.16% to 5.64%. Our low end estimate, derived for a five-year time period is 206 to 259 basis points lower than the original weighted average ERP.
3. We use one test and a beta of 0.357. We believe that the original ROE was derived as a weighted average of three tests with a resulting implied beta between 0.8 and 0.9 (see note 1).

If we were to use the original, weighted average range of 4.22% to 4.75% for the ERP and apply our estimates of beta and the risk free rate, the resulting ROE today would be 6.52% to 6.71%. The ROE in 1999 using our estimate of beta would have been 7.59% to 7.78%.

On the other hand, if we were to use a beta of 0.8 to 0.9 with our estimates for the MRP and the risk free rate, the resulting range for the ROE today would be 6.74% to 10.09%.

<u>Debt-Equity</u>

Debt should consist of short-term and long-term debt following the practices of the credit rating agencies. We recommend that there be two groupings of LDCs for the purpose of establishing the maximum total debt to total debt plus equity proportions. For all LDCs with a rate base, excluding working capital allowances, of less than $300 million, the maximum debt-equity split should be 50%/50%. For all LDCs with a rate base in excess of $300 million, the maximum debt-equity split should be 60%/40%.

If a LDC chooses a debt-equity split less than these maximums, then the actual proportions should be used in determining the WACC for the LDC and the resulting revenue requirements. Further, we would limit the proportion of short-term debt in the capital structure to the same rate as the working capital allowance since short-term debt should be used to finance short-term assets, primarily working capital requirements.

<u>Rate Base</u>

The rate base should be determined as set out in the OEB Handbook and should be set using the book values of the capital assets. The working capital allowance to be incorporated into the rate base should be the lesser of the existing working capital/rate base ratio or 20% of the rate base. A constant 15% ratio for all LDCs does not seem to be in line with the current practices of the LDCs. Whatever working capital allowance is selected would set the maximum level for short-term debt in the capital structure.

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[3] The range for ERP is derived by dividing the 3.80% value by what we believe was the weighted average value for beta – 0.8 to 0.9 (see note 1).

1. INTRODUCTION
1.1 Objectives

We have been contracted to examine the cost of capital using the benchmark OEB Decision of May 11, 2005 and the 2006 Electricity Distribution Rate Handbook as the points of departure. More specifically, we will address the following issues:

Differentiation among the LDCs: Should there be different costs of debt, costs of equity and/or capital structures (debt/equity ratios) among the LDCs? If so, what criteria should be used to differentiate among or group the LDCs? At present, asset size is the sole criterion. Does it continue to be appropriate?

Return on equity: Following a well-established methodology, the OEB's benchmark approach decomposes the rate of return on equity into two components: a riskless rate, based on the appropriate Government of Canada bonds; and, a risk premium. We will review the current risk premium and risk-free rate of return for LDCs in Ontario as set out in the 2006 Handbook. As well, we will discuss the feasibility of the methodology for updating these rates annually.

Cost of debt: The cost of debt for the LDCs reflects anomalous relations between the LDCs and their municipal owners. We will recommend a preferred approach for the treatment of all debt, affiliated and otherwise, including the term structure. And as in the case of the return on equity, we will consider the feasibility of and the methodology for updating these rates annually.

Capital structure: The existing capital structures of the LDCs reflect the restructuring of the industry initiated by the *Electricity Act, 1998*. We will review the current methodology, which is based on differentiating among the LDCs based solely on their respective sizes. In addition, we will set out our recommendations regarding the capital structures going forward.

Implications of industry sector evolution: The varying objectives and perceived risks of municipal owners may be inconsistent with the long run economic efficiency of electricity distribution. We will review and evaluate the arguments and evidence regarding economies of scale and scope and their applicability to Ontario. In addition, we will evaluate and discuss the incentives that may be created by differing treatments of the cost of capital for the realization of greater economic efficiencies.

1.2 Current Methodology for Setting the Cost of Capital for LDCs

The OEB originally set out the Draft Guidelines for a formula-based Return on Equity for regulated utilities in the province in March 1997. The Draft Guidelines applied only ot the natural gas sector, and were used for rate regulation of Enbridge, Union Gas and NRG. Dr. Cannon's 1998 report adopted the same ROE methodology and also addressed the cost of debt and capital structure for LDCs.

The OEB would establish the revenue requirements for each LDC by multiplying the weighted average cost of capital times the rate base, which would consist of qualifying property, plant and equipment less accumulated depreciation plus a working capital allowance of 15% of the sum of the cost of power and controllable expenses. The weighted average cost of capital (WACC) would be a function of the capital structure, cost of debt and return on equity (ROE) for each LDC. Distribution expenses and taxes would be added to derive the total revenue requirements for each LDC.

Table 1 summarizes the working capital balances in 2004 relative to net plant assets, a proxy for the rate base, for the 95 LDCs in Ontario. The LDCs are listed in ascending order of their net plant assets. Only 34 of the 95 LDCs had a working capital balance of 15% or less of the reported net plant. Most of the 34 had negative working capital balances. Eight of the ten largest had a working capital balance of 15% or less.

The average working capital to net plant ratio declines with increasing size of LDCs. For example, the simple average of these ratios is 109% for all LDCs with net plant assets of less than $1 million. For LDCs with net plant assets between $5 and $10 million, the average ratio is 21%. For LDCs with net plant assets between $40 and $100 million, the average ratio is 12%. And the average for the three LDCs with net plant assets between $300 and $500 million is 9%. Therefore, the OEB may want to reconsider the 15% working capital allowance for establishing the rate base.

In order to establish the WACC for each LDC, the LDCs have been grouped according only to the size of the regulated rate base. Four size groupings have been adopted:

- Small – rate base of less than $100 million;
- Medium-small – rate base between $100 and $250 million;
- Medium-large – rate base between $250 million and $1 billion;
- Large – rate base in excess of $1 billion.

The entire adjustment for differences in business risks among the LDCs was to be reflected through a deemed capital structure, which would vary according to the size groupings. As of 2005, there are only two LDCs in the large category (Hydro One and Toronto Hydro); and four others in the medium-large category (Enersource, Hydro Ottawa, Powerstream, and Horizon Utilities). Eighty-two of the LDCs fall into the small category, and within this category, as well see, there appear to be significant differences between the LDCs with less than $10 million in net plant assets and those with assets between $10 and $100 million. (See Table 1)

All the LDCs were allowed the same return on equity regardless of their size. The initial after-tax ROE was set at 9.88%.[4] This rate was derived by adding an equity risk premium of 3.80% for the LDCs to the forecast yield on 30-year Government of Canada bonds as of year-end 1999. This forecast was derived and continues to be derived by averaging three and 12 months forward, 10-year Government of Canada bond yield forecasts from *Consensus Forecasts* and adding the average of the actual observed spreads between the

[4] See footnote 1.

10 and 30 year Government of Canada bonds. As of December 1999, the average of the three and 12 month Consensus Forecasts for the 10-year bonds was 6.15%. The average spread between the 10-year and 30-year Canada bonds was five basis points.

In setting this ROE for all LDCs, the OEB stated that its "objective in setting the rate of return on rate base is to ensure that the utility is provide with a fair return which enables it to meet its obligations and maintain its capability of attracting capital. This ensures the ongoing viability of the utility to provide service to its customers and helps keep rates as low as possible."

But this rate has not yet been fully realized by the LDCs. They were permitted to implement on April 1, 2005, (subject to OEB approval) the rate increases required to achieve the full 9.88% ROE originally set to be implemented on March 1, 2003. However, all the additional revenues generated during the first year of earning the full 9.88% ROE had to be allocated to spending on conservation and demand-management programs.

The ROE was to be adjusted automatically in subsequent years according to a simple formula. The allowed ROE would change each year by a multiple of 0.75 times the annual change in the 30-year Government of Canada bond yield. Applying this formula to the year-end 2005 bond rates produces a ROE of 8.65%.[5] But in April 2006, the OEB confirmed the maximum allowed ROE would be 9.0% instead – this was based on the bond rates as of April 2005.

Table 2 summarizes the reported net incomes as a percentage of equity for the LDCs in 2004. Only 16 of the LDCs managed a ROE in excess of 9%. Thirteen of the LDCs lost money in 2004. There does not appear to be any relation between the size of a LDC and the actual return on equity. For example, for the smallest size LDCs (net plant assets of less than $1 million), the average return on equity was 14%. For LDCs with net plant assets between $5 and $10 million, the average return was 7%. For LDCs with net plant assets between $40 and $100 million, the average return was 5%. And the average return for the three LDCS with net plant assets between $300 and $500 million was 6%. The two largest LDCs – Toronto Hydro and Hydro One – had returns greater than 6% – 9% and 10% respectively.

Another way of looking at the equity returns of the LDCs is to estimate what a private investor might have paid for the equity of these companies, assuming that an investor would pay some multiple of EBITDA less total debt. Using two possible multiples of EBITDA – 7.0 and 8.5 – produces the market to book equity numbers reported in Table 2.

At a multiple of 7.0, there are 28 LDCs for which an investor might have paid more for the equity than its book value. Six of the 10 largest LDCs are in this group. At a multiple

[5] As of December 2005, the average of the three and 12 month Consensus Forecasts for the 10-year bonds was 4.45%. The average spread between the 10-year and 30-year Canada bonds was 11 basis points.

of 8.5, there are 59 LDCs for which an investor might have paid more for the equity than its book value. Nine of the 10 largest LDCs are in this group. Thus, even though very few LDCs actually earned more than 9% on equity on an after-tax basis, there might be significant capital gains available if the private sector could invest in LDCs.

Dr. William Cannon[6] has suggested that the equity risk premium built into the ROE calculations should now be less than 3.80%. According to Dr. Cannon:

> "Since 1996/1997, there has been a substantial decline in the equity capital costs for the average-risk Canadian gas utility as result of both a significant decrease in equity capital costs for all corporations in general and because of a reduction in the relative riskiness of rate-regulated utilities as compared to the typical firm in the universe of publicly-traded Canadian companies. The post-1996 decline in the formula-determined allowed ROEs for Ontario's major gas utilities has not fully reflected the changes that have taken place in their relative risk environments and in the financial market condition…The benchmark allowed ROE for the average-risk Canada energy utility now lies in the range of 7.5% to 7.8%."

He concluded, based on a review of a number of estimates of the equity risk premium in Canada, "that the forward-looking, long-run (at least 25 years) Canadian MRP relative to long Canada bond yields lies in the range of 2.25 to 3.0%." This would represent a reduction of 40 to 115 basis points from the 3.40% equity risk premium incorporated into the ROE for the gas utilities subject to OEB regulation. He also suggested that "the year-to year sensitivity of allowed ROE adjustments to changes in the forecasted long Canada rate should be reduced to 70% from the current value of 75%" and that the forecasted long rate be the actual 10-year Government of Canada rate at the time of a decision plus a constant 27 basis points spread.

The deemed debt rates were set at premiums of 60 bps, 70 bps, 80 bps and 105 bps above the forecast 30-year Government of Canada bond yields for the large, medium-large, medium-small and small LDC groupings respectively. The deemed rates would be applied only when a LDC did not have any public (third-party) debt outstanding. Otherwise, the actual rate of interest on this debt would be used.

At year-end 1999, the deemed debt rates were 6.80%, 6.90%, 7.00% and 7.25% for the large, medium-large, medium-small and small LDCs respectively. By year-end 2005, the respective deemed rates would have been: 5.16%, 5.26%, 5.36% and 5.61%.

The capital structures, as noted, were based on the size groupings of the LDCs:

- Small – debt/equity split of 50%/50%;
- Medium-small – debt/equity split of 55%/45%;
- Medium-large – debt/equity split of 60%/40%;

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[6] Dr. William Cannon, Prefiled Testimony in Connection with the Application for Review of the Board's Guidelines for Setting ROE, before the OEB, June 2003.

- Large – debt/equity split of 65%/35%.

Table 2 shows that of the 82 "small" LDCs, only 18 had debt ratios in excess of 50%. Most had debt ratios in the 40% range. For LDCs with net plant assets of less than $1 million, the average debt ratio was 44%. For those with net plant assets between $5 and $10 million, the average debt ratio was 35%; and net plant assets between $40 and $100 million, the average rate was 45%. Of the six "medium-small" LDCs, only one had a debt ratio greater than 55%. The average for this group was 50%.

Two of the four in the "medium-large" category had a debt ratio greater than 60% and the average for this group was 59%. Toronto Hydro has a debt ratio of 62% and Hydro One a debt ratio of 59%.

1.3 Perspective of the Credit Rating Agencies

In November 2002, following the announcement by the Ontario Government to freeze rates and cap the distribution and transmission rates levied by distribution and transmission companies at their current levels (Bill 210), DBRS placed all the ratings of Hydro One, Toronto Hydro, Borealis Infrastructure Trust, Electricity Distributors Finance Corporation, Enersource, Hydro Ottawa, and Veridian "under review with negative implications". DBRS commented[7] that:

> "The proposed plan, as it currently stands, could have significant negative implications on the financial profiles of these companies. The potential financial and ratings impact of the proposed plan is viewed to be the greatest on the distribution companies in Ontario.
> In addition to the financial impacts of the proposed plan, the plan highlights the high degree of political intervention that exists in Ontario and distorts the incentives to manage the consumption of electricity, as the retail price is no longer driven by supply and demand…. The cap on the LDCs prevented them from receiving the last one-third rate increase required to earn the previously approved 9.88% ROE."

The reaction by DBRS to Bills 4 and 100 was positive. DBRS[8], in announcing a change in the long-term trend for Toronto Hydro's debt to positive from stable, stated[9]:

> "While regulatory risk and political uncertainty continue to be the biggest challenges for electricity distributors in Ontario, Bill 4 and Bill 100 have together brought a level of certainty to the industry that has not existed since prior to the announcement of Bill 210 in November 2002. Bill 4 entitles local distribution companies (LDC), such as Toronto Hydro-

[7] DBRS, Press Release, November 12, 2002.
[8] DBRS, Press Release, July 8, 2004.
[9] Similar positive comments were made in the DBRS credit upgrades for Powerstream, Electricity Distributors Finance Corporation, Enwin Powerlines, Veridian and Enersource.

> Electric System Ltd., to: (1) raise distribution rates to earn the full 9.88% rate of return on common equity (ROE) that was originally outlined in the *Energy Competition Act, 1998*, but was capped at two-thirds of the allowable ROE with the implementation of Bill 210; and (2) recover deferred regulatory assets through increased rates. The provincial government has also recently indicated that financial disincentives for LDCs as they relate to energy conservation programs would be removed. While Bill 100 is essentially neutral for LDCs, it provides a framework intended to bring stability to the Ontario electricity industry over the medium to long term."

In response to the April 12, 2006 OEB rate decisions for the LDCs, DBRS commented:[10]

> "From a credit perspective, the rate decisions are neutral to mildly positive. In general, the lower ROE and debt rates will lead to lower revenue requirements. However, this is generally offset by rate bases being adjusted upwards. DBRS also notes that LDCs never really received the full benefit of the 9.88% ROE in the past, as it was phased in over several years, and in 2005 (the first year that LDCs received rates fully reflective of the 9.88% ROE) all revenues earned from the final rate increase were to be invested in conservation efforts. On the positive side, the OEB decisions will finally allow LDCs to recover the investment in their distribution systems that they have incurred since 1999."

DBRS has highlighted in several of its rating reports that the are two key challenges facing Ontario LDCs, which limit the credit ratings of these entities:

- "Uncertainty with respect to a framework for rates beyond 2006, as this will be something on which the OEB will be focusing over the next 12 months…
- Political risk, especially in an environment of rising electricity costs. The risk is that the government might interfere with the regulatory process, as was experienced in late 2002."

1.4 Methodologies in Other Jurisdictions

Alberta

The Alberta Energy and Utilities Board (AEUB) has established a deemed capital structure for each regulated utility based on its perception of the risk associated with each utility's regulated operations. The AEUB determined that a common ROE should apply to all regulated electric utilities, and that the differences in the utilities' business risk profile would be reflected in the deemed capital structure. In addition, the allowed ROE for all regulated electric and gas utilities was set at 9.60% for 2004, and being formula-

[10] DBRS, Press Release, April 18, 2006.

based (linked to the forecast long-term Canada bond yield for the year in which the ROE will apply) for subsequent years, was changed to 9.50% for 2005.

The distribution market in Alberta differs significantly from the one in Ontario. The primary electricity distributors in Alberta include: Canadian Utilities Limited, which distributes electricity to 238 communities as well as rural areas in east-central and northern Alberta; Fortis Alberta Inc., which serves the region comprising central and southern Alberta; EPCOR, which serves the City of Edmonton; and ENMAX, which serves the City of Calgary.

Quebec

Transmission and distribution operations are regulated by the Régie de l'énergie. In May 2002, the Hydro-Québec TransÉnergie received the Régie's decision on its first transmission rate case. The Régie approved a deemed capital structure of 70% debt/30% equity, and a ROE of 366 bps above long-term Government of Canada bonds. In May 2003, Hydro-Québec Distribution received the Régie's decision with respect to Phase 1 of its first distribution rate application. The Régie approved a deemed capital structure of 65% debt/35% equity and a ROE of 340 bps above long-term Government of Canada bonds.

Other provinces

Table 3 sets out some ROE awards made in other provinces during the past five years. While they all may seem "generous" in comparison to the OEB guidelines for LDCs (9% as of April 2006 based on April 2005 data), the awarded ROEs seem to be trending downwards over time. This reflects the downward trend in interest rates over this time period, a trend which continued into the second quarter of 2005.

Table 3: Awarded ROEs for Selected Canadian Utilities

	Date	ROE
British Columbia		
Aquila Networks (BC)	Nov./03	9.55%
Pacific Northern Gas	Nov./03	9.90
Terasen Gas	Nov./03	9.15
Terasen Gas	March/06	8.80
Terasen Gas (Vancouver Island)	March/06	9.50
Quebec		
Gaz Metropolitain	Sept./02	9.89
Nova Scotia		
Nova Scotia Power	Oct./02	10.15
PEI		
Maritime Electric	Oct./01	11.00
Newfoundland		

Newfoundland Power	June/03	9.75
NEB	Nov./03	9.56
Alberta		
All natural gas and electric utilities	July/04	9.60
ATCO TFO	Nov./05	8.93

UK

Energy Networks Association (ENA) has stated[11] that the Capital Asset Pricing Model (CAPM) remains the principal method used by UK regulators for determining the cost of equity. According to ENA, this was "confirmed by the Competition Commission inquiry into calls to mobiles, in which it was stated that: the CAPM was used by four of the five main parties to our inquiry and . . . is widely used across the private sector, finance institutions and utility regulators. We therefore adopted the CAPM to estimate the cost of capital."

In its review of BAA's airports, the UK Civil Aviation Authority followed the recommendations of the Competition Commission, including the Commission's conclusions on the cost of equity.

At the time ENA prepared the original report for OFGEM, it was agreed that it would be necessary to update this assessment closer to the time when OFGEM would be making its final decision on this matter. The conclusions reached on each of the components of the weighted average cost of capital, assuming the use of the CAPM to estimate the cost of equity, are as set out in Table 4.

Table 4: ENA Estimates for the Cost of Capital for DNOs in the UK

Parameter	Low Estimate	High Estimate
Risk-free rate	2.25%	2.75%
Equity risk premium (after-tax)	3.0%	5.0%
Equity beta	1.0	1.0
After-tax ROE	5.25%	7.75%
Debt premium	1.25%	2.00%
Cost of debt	3.50%	4.75%
Debt/equity ratio	50/50	50/50
After-tax WACC	4.38%	6.25%

ENA recommended an after-tax WACC for the DNOs of 5.5%. ENA did not recommend any change in the debt-equity ratio citing the conclusion of the UK CAA: "there is no theoretical or normative model that gives an unequivocal prediction as to what the optimal gearing level may be." According to the ENA, "this suggests that empirical regularities may be the most appropriate basis for making any assumption, and, considering a range of utilities, both national and international, and over a sustained

[11] Energy Networks Association, "Cost of Capital Update" (March 2004), prepared for OFGEM.

period of time, the evidence indicates that 50% gearing levels tend to be most frequently observed."

2. KEY ISSUES
2.1 Regarding the Cost of Capital

The following issues need to be addressed by the OEB in developing a process for the determination of the cost of capital:

- What is the appropriate rate of return on equity for each utility?
- What is the appropriate capital structure for each utility?
- Should the same rate of return be awarded to all utilities?
- How often should the cost of capital be reviewed?
- What are the factors that would trigger a subsequent review of the cost of capital for utilities?
- What procedures should be implemented to effect a periodic (annual) adjustment to the rate of return between cost of capital proceedings?
- How does the cost of capital tie-in to performance-based regulation?
- Will the resulting cost of capital determination support or impede the process of consolidation within the industry?
- How should the rate base be determined?
- What should be done if any case arises in which the actual long-term or total debt or equity of a LDC exceeds the deemed level for debt or equity?

2.2 Size

Dr. William Cannon[12] presented a number of arguments for using size, based on assets, as the sole criterion for differentiating LDCs. Smaller LDCs are likely to be less diversified geographically and across individual customers and customer classes. They are likely to have less access to the capital markets. But his decision was based largely on simplicity and objectivity.

Christensen Associates Energy Consulting have pointed out: [13]

> "Systematic grouping on Ontario's distributors is a matter of association, and LDCs can be organized into groups based upon any number of methods, ranging from judgment to formal statistical methods. As an example, LDCs could be organized according to relative size, type of service territory (urban vs. rural), or locale such as Northern Ontario as distinct from Southern Ontario. Alternatively, several business context variables together could be used to group LDCs. While various ad hoc

[12] Dr. William Cannon, "A Discussion Paper on the Determination of the Return on Equity and Return on Rate Base for Electricity Distribution Utilities in Ontario", prepared for the OEB, December 1998.
[13] Christensen Associates Energy Consulting, "Methodology and Study Findings: Comparators and Cohorts Study for 2006 EDR", prepared for OEB, October 2005.

methods can be both sensible and plausible, such approaches are less than fully objective regarding the manner in which the data are managed to obtain the end result, and in choice of characteristic(s) or variables used as the basics to conduct the grouping. Statistical clustering can arguably do a better job."

They presented several alternative clusters based on their empirical work. Table 5 summarizes one of these clusterings.

Table 5: LDC Cohorts for Wire and Interconnection Services

1	Ashphodel-Norwood; Essex Powerlines; Lakefield Distribution; Peterborough Dist'n; Scugog Hydro; Tillsonburg Hydro; Wellington Electric; Whitby Hydro
2	Atitokan Hydro; Chapleau PUC; Espanola Regional Hydro; Front Frances Power; Gravenhurst Hydro; Great Lakes Power; Greater Sudbury Hydro; Hearst Power; Kenora Hydro; Lakeland Power; North Bay Hydro; Sioux Lookout Hydro; Terrace Bay Superior Wires; Thunder Bay Hydro; West Nippissing Hydro
3	Aurora Hydro; Barrie Hydro; Bluewater Power; Brantford Power; Burlington Hydro; Cambridge and North Dumfries; Centre Wellington Hydro; Chatham-Kent Hydro; Clinton Power; Collus Power; Dutton Hydro; Eastern Ontario Power; ELK Energy; Enbrun Hydro; Erie Thames Powerlines; Festival Hydro; Grand Valley Energy; Grimsby Power; Guelph Hydro; Haldimand Country Hydro; Halton Hills Hydro; Hamilton Hydro; Hydro 2000; Hydro Hawkesbury; Hydro One Brampton; Innisfil Hydro; Kingston Electricity; Kitchener-Wilmot Hydro; Lakefront Utilities; London Hydro; Middlesex Power; Midland Power; Milton Hydro; Newmarket Hydro; Niagara Falls Hydro; Niagara-on-the Lake Hydro; Norfolk Power; Oakville Hydro; Orangeville Hydro; Orillia Power; Oshawa PUC; Pen West Utilities; Port Colborne Hydro; Renfrew Hydro; Richmond Hill Hydro; Rideau St. Lawrence; St. Catherines Hydro; St. Thomas Energy; Tay Hydro, Veridian; Waterloo North Hydro; Welland Hydro; Wellington North Power; West Coast Huron; West Perth Power; Woodstock Hydro
4	Enersource; Hydro Ottawa; Powerstream;
5	Northern Ontario Wires; Parry Sound Power; PUC Dist'n
6	Toronto Hydro
7	Wasaga Dist'n

Size does not appear to be the key variable producing these cohorts. Cohort 1 contains LDCs with net plant assets ranging from \$519,000 to \$53.1 million. Cohort 2 contains LDCs ranging from \$927,000 to \$60.5 million. Cohort 3 has LDCs with net plant assets between \$232,000 and \$293.7 million. Cohort 4 contains only the medium-large LDCs. Cohort 5 contains three LDCs with net plant assets ranging between \$3.7 and \$34.9 million. So there does appear to be more than size in grouping the LDCs into cohorts. But is Cannon's argument for simplicity and objectivity stronger? Or does indeed size matter?

Standard & Poor's has no minimum size criterion for any given rating level. However, size does turn out to be significantly correlated to its ratings. The reason: size often provides a measure of diversification, and/or affects competitive position. Small companies are, almost by definition, more concentrated in terms of product, number of customers, or geography. In effect, they lack some elements of diversification that can benefit larger companies. To the extent that markets and regional economies change, a broader scope of business affords protection. In addition, lack of financial flexibility is usually an important negative factor in the case of very small companies. Adverse developments that would simply be a setback for companies with greater resources could spell the end for companies with limited access to funds.

2.2.1 Economies of Scale

It is generally accepted that there are economies of scale in electricity distribution. Thus, consolidation, especially among the smaller LDCs, is expected to lead to lower distribution costs. Christensen Associates Energy Consulting[14] did demonstrate empirically that there appears to be some degree of economies of scale among Ontario LDCs. They estimated a mean cost elasticity of 0.81, indicating that as a LDC increased in size (based on revenues) by 10%, its costs would increase by 8.1%.

Dr. Cannon buttressed his case for using size as the sole separating variable because it would not deter consolidation. As he pointed out, since combinations would never put the new LDC into a higher risk category, "mergers will not be initiated for the unworthy reason of achieving a higher allowed return". But mergers could be discouraged because they might lead to a lower risk category and lower weighted average cost of capital.

But mergers are not the only means by which the cost savings from economies of scale can be realized. Virtual utilities are an alternative to the outright sale of a LDC. That is, a LDC could outsource some or all of its operations to take advantage of potential economies of scale, without the need for a change in ownership.

Table 6 summarizes several cost and profitability measures for the LDCs. Average revenues per employee tend to increase with the size of the LDCs, with size being measured by net plant assets. Customers per employee also increase with size at least up to LDCs with net plant assets between \$20 and \$40million. Customers per employee increase again for LDCs with net plant assets between \$100 and \$500 million. Thereafter the number of customers per employee decline. Expenses per kWh also tend to decline as size increases. So there does appear to be some support for the possibility of cost savings from consolidation as long as the total net plant assets do not exceed \$1 billion. There appear to be some diseconomies of scale beyond this size level.

There does not seem to be any relationship between various measure of profitability (net income to long-term debt + equity; EBITDA to long-term debt + equity; and net income to equity) and size of a LDC. But there is less variability for each measure of profit rates as the LDCs increase in size. So size may not necessarily provide the basis for higher

[14] Ibid.

profit rates, but it does seem to eliminate the extremes in profitability among the LDCs. This suggests that the smaller LDCs, at least to a scale of net plant assets of $40 million, may warrant a lower credit rating.

3. COST OF CAPITAL

3.1 Conceptual Discussion

In a regulated environment a regulator aims to set the allowed rate of return in a fair and just way. A prerequisite for estimating and fixing the allowed rate of return is to define and justify a "fair" rate of return.

In financial markets a "fair" or a correct price of an asset, or a financial instrument, is the price that does not induce free lunches in an economy. This notion of a correct price is not only derived from the economic intuition, but is also supported by rigorous arguments and characterizations of no-arbitrage in financial markets. A necessary and sufficient condition for financial markets not to admit arbitrage opportunities is that the prices of assets are actually their present values. The absence of arbitrage opportunities is the cornerstone of modern Financial Economics. This concept is the reason why a price of a bond is thought of as the present value of its future cash flows, and is the driving force underlying the development[15] of the Black-Scholes option pricing formula.

Consider a risk-free environment, such as the debt market consisting of Government of Canada bonds. In this case the present value of the future cash flow of a bond is calculated by discounting it, at the risk-free rates, to obtain its present value. In fact the situation is reversed. The prices of bonds are readily available and the term structure of interest rates is not. Hence, believing that the price of a bond must be its present value, the term structure of interest rates is estimated by solving for the risk-free rates (as a function of time) that will make the present value of the bonds equal its price. Indeed, the interest rates that we recommend[16] using, is extracted from the prices of the bonds in this way.

The value or the correct price of a risky asset, that promises a risky cash flow, is also the present value of its future cash flows. However, in a risky environment discounting cannot be done at a risk-free rate and a risk adjusted discount factor must be used. Obviously, a future risky dollar is worth less than a sure dollar. Hence, if the discount factor for the sure dollar is

$$\frac{1}{(1+r)}$$

where r is the risk free rate, the discount factor for a risky dollar must be

$$\frac{1}{(1+r+rp)},$$

[15] A more rigorous explanation that is still not too technical can be found in Prisman (2001) for both the equity and the bond markets in a simplified and more realistic model.

[16] The URL for the current estimation is: http://www.bankofcanada.ca/en/rates/yield_curve.html

where rp is a positive constant representing the risk premium.

Three types of tests have been used to determine the risk premium and the resulting "fair" ROE for companies subject to rate of return and/or performance-based regulation. The tests are comparable earnings, discounted cash flow and equity risk premium, with the latter comprising a number of variants, including the CAPM. The Capital Asset Pricing Model is credited with the contribution of calculating a risk premium, and its relation to the "risk" assumed by the investors that hold a risky asset.

An alternative approach to the CAPM for estimating the equity risk premium has been to calculate the spread between returns on equity and a risk-free rate (Treasury Bills or long government of bonds).[17] Dr. Cannon[18] referred to a number of studies that used different time periods between 1900 and 2002, different samples and risk-free rates to produce estimates for Canada. The historical estimates, based on geometric means, ranged between 2.05% and 4.15%. Obviously, the selection of end-points and sample size can affect the estimates.

Regulators in the UK and Australia use the CAPM to establish a risk premium for equity holders. The CAPM, while not free of some deficiencies, is widely used in valuing[19] and assessing risk, and risk premium of assets. Since the CAPM is used by other regulatory bodies and for the following reasons as well, we will utilize CAPM to assess the risk and rate of return:

- The CAPM is a market based approach and hence is an objective approach that relates to actual conditions in financial markets.
- The CAPM is subject to fewer errors relative to the other two methods which require estimates of future cash flows and their likelihoods.
- Finally, implementing the CAPM is relatively simple and requires use of data that are readily available.

First, however, we address the issue of a "correct" price or an "appropriate" rate of return. A correct price, or a fair price, of an asset, as explained above, is its present value calculated based on an appropriate risk adjusted discount factor. There is a difference between an evaluator that tries to estimate the value of a firm via its cost of capital and a regulator that sets an allowed rate of return. Evaluating a firm must be done based on that market value[20] of the debt and the equity.

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[17] In this methodology, beta is implicitly assumed to equal 1.0.

[18] Dr. William Cannon, Prefiled Testimony before the OEB, June 2003.

[19] The CAPM is used in regulated environments as well see for example; Spigher and Daniel Spullber (1994), Breen and Lerner (1972), Litzinberger, Ramaswamy and Sossin (1980), and more recently Oxford Economic Research Associates, March 2004.

[20] This introduces circularity into the process as if the market value of the debt and equity are known so is the value of the firm, but the value of the firm is what we try to estimate. Even in valuing a firm practitioners use book values as a solution to this problem even though it can be solved numerically. A few iterations can obtain a value of equity and debt that is consistent (to a tolerance) with the value of the firm.

A regulator that decides on an allowed rate of return should thus set it in such a way that the book value equals the value of the investment, thereby not allowing for "arbitrage". This is accomplished[21] by choosing a cost of capital which is a weighted average of the cost of equity and the cost of debt, based on their book values. In particular, for recently established LDCs, the appropriate quantity to be used in calculating the average cost of capital to determine an allowed rate of return, is the book value.

3.2 Cost of debt

DBRS[22] has set out the following criteria, both quantitative and qualitative, for rating the credit of electricity and gas distribution companies.

<u>Debt-equity ratios</u>:

- The percentage of debt is defined as short- and long-term debt, divided by short- and long-term debt, plus equity. It is now commonplace to find permanent layers of short term debt, which finance not only seasonal working capital but also an ongoing portion of the asset base.
- For an "A/BBB" rating on long-term debt instruments, a regulated utility can usually carry 60% to 70% debt on its balance sheet. This declines to the 50% to 60% range when the company is involved in more unregulated activities which are subject to greater instability, uncertainty, and business risk.
- Debt levels establish the strength of related ratios such as the fixed charge coverage and cash flow to debt.

<u>Fixed charge coverage:</u>

- The fixed-charges coverage is defined as earnings before interest and taxes (EBIT), divided by interest, plus tax-adjusted preferred share dividends, where a utility has such preferred shares as part of its equity.
- Regulated entities standards for an "A/BBB" rating are 1.5 times, while unregulated entities should have a higher safety margin, with coverage above two times.
- The ratio is measured over a period of time, so a temporary dip outside these standards may not affect the rating.

<u>Cash flow to debt:</u>

- Cash flow is defined as income before extraordinary income, plus depreciation, plus normal deferred taxes, divided by total debt.
- With debt levels above 60%, it is difficult to bring this ratio above 0.10 times. As debt levels approach 50%, this ratio's strength usually improves to the 0.15-0.20 range.

DBRS also considers a number of qualitative factors such as:

- Proportion of regulated versus non-regulated activity

[21] A detailed explanation of this point from a different angle is provided in Dr. Booth's testimony.
[22] DBRS, Approach to Rating Electric and Gas Distribution Companies, April 30, 2002.

- Condition of the transmission and distribution grid
- Economic strength of the franchise area – growing or shrinking
- Size of the utilities
- Diversification, and the degree of diversification
- The quality of regulation - is there regulatory lag?
- Growth – long-term growth in electricity demand
- Sales mix between residential/commercial/industrial
- Company sensitivity to temperature (residential and commercial customers) and economic factors (industrial customers)

Standard and Poors (S&P)[23] uses a similar mix of quantitative and qualitative factors in its analysis of the credit ratings of companies. Among the quantitative variables are the following:

Capital structure/leverage and asset protection:
- Total debt/total debt + equity; traditional measures focusing on long term debt have lost much of their significance, because companies rely increasingly on short-term borrowings.
- A company's asset mix is a critical determinant of the appropriate leverage for a given level of risk. Assets with stable cash flow or market values justify greater use of debt financing than those with clouded marketability.
- Ratios using the market value of a company's equity in calculations of leverage are given limited weight as analytical tools. The stock market emphasizes growth prospects and has a short time horizon; it is influenced by changes in alternative investment opportunities and can be very volatile. A company's ability to service its debt is not affected directly by such factors.

Profitability and coverage:
- Profit potential is a critical determinant of credit protection. A company that generates higher operating margins and returns on capital has a greater ability to generate equity capital internally, attract capital externally, and withstand business adversity.
- The more significant measures of profitability are: pretax, pre-interest return on capital; and operating income as a percentage of sales.
- The primary fixed charge coverage ratio is EBIT coverage of interest.

Cash-flow adequacy
- Analysis of cash flow patterns can reveal a level of debt-servicing capability that is either stronger or weaker than might be apparent from earnings. Cash-flow analysis is the single most critical aspect of all credit rating decisions.
- Some of the specific ratios considered are: funds from operations/total debt (adjusted for off-balance-sheet liabilities); Debt/EBITDA; EBITDA/interest; free operating cash flow + interest/interest; total debt/discretionary cash flow (debt

[23] S&P, Corporate Ratings Criteria 2006, April 2006.

payback period); funds from operations/capital spending requirements, and capital expenditures/capital maintenance.

S&P[24] has summarized the interplay of these variables for different credit ratings for both industrial companies and utilities (Table 7). It is apparent that utilities are considered to be less risky than the typical industrial company.

Table 7: Key Financial Ratios for Industrials and Utilities, Three-Year (2002-2004) Median Values

	AA	A	BBB	BB	B
Industrials					
EBIT interest coverage (X)	19.5	8.0	4.7	2.5	1.2
EBITDA interest coverage (X)	24.6	10.2	6.5	3.5	1.9
FFO/total debt (%)	79.9	48.0	35.9	22.4	11.5
Total debt/EBITDA (X)	0.9	1.6	2.2	3.5	5.3
Return on capital (%)	27.0	17.5	13.4	11.3	8.7
Leverage (%)	28.3	37.5	42.5	53.7	75.9
Utilities					
EBIT coverage (X)	4.4	3.1	2.5	1.5	1.3
FFO/average total debt (%)	30.6	18.2	18.1	11.5	21.6
ROE (%)	11.3	10.8	9.8	4.4	6.0
Leverage (%)	47.4	53.8	58.1	70.6	47.2

S&P also uses a number of qualitative factors in assessing credit risks. For industrials in general, these factors include industry characteristics, each company's competitiveness within its industry and the caliber of management. For water and sewer companies, which tend to be smaller in size and largely regulated at the state level, S&P uses economic considerations (e.g. the stability of a utility's customer base, the potential need for capital spending, the affordability of rates, and the employment opportunities available to its customers), operational characteristics, and an assessment of management.

Management is quite important in the overall credit rating process. S&P's analysis of management employs criteria such as:

- institutionalized planning processes that are revised regularly to reflect changing conditions;
- sound financial and operating policies that are supported, implemented and achieved;
- a deep and experienced executive team;
- a solid grasp of industry issues that extends beyond the local utility;
- extensive knowledge of customers and their needs;
- a proactive and farsighted management approach that has the support of an informed board or council.

[24] Ibid.

It is most likely that many of the small LDCs will come up short in any analysis of their management strengths. These LDCs simply cannot afford to hire the number of management personnel required; nor are they likely to be able to compete for the talented managers. Financial resources are likely to be a serious constraint in this area. Of course, one solution is to go the route of a virtual utility and outsource most functions, including management. The other solution is merging to create larger LDCs – a strategy undertaken thus far by Barrie, CNPI, Horizon Utilities, Powerstream, Veridian, and Westario.

Setting aside the two smallest size categories – net plant assets of less than $5 million – since the averages are distorted by a few of the LDCs, the EBIT coverage are on average between two and three – safely within the "BBB" rating category for utilities.[25] On the other hand, the ROEs are in the 3% to 7% range – consistent with "B" and "BB" ratings for utilities, but lower than the average ROEs for a number of the largest electricity utilities in Canada.[26] With the exception of the largest LDCs, those with net plant assets in excess of $300 million, total debt represents between 40% and 50% of the total debt and equity of the LDCs.[27] This places the LDCs on average in the "AA" rating level. The five largest LDCs have leverage ratios in the "BBB" rating category. The average returns on capital (total debt plus equity) and the total debt to EBITDA ratios generally run in the range of the "B" rated industrials.

Size does not seem to be a disadvantage in terms of profitability, although there is greater variability among the smaller LDCs in each of the profit measures. Other than the five largest LDCs, the average total debt to total debt and equity ratios tend to be comparable for the LDCS with net plant assets of less than $300 million. Finally, the LDCs with net plant assets of less than $10 million have much higher total debt to EBITDA ratios on average than the larger LDCs. The three smallest LDC groupings also have the most unreliable interest coverage measures.

The average cash flows to total debt ratios are greater than 15% for all but the smallest group of LDCs, where the average is 11%.[28] The combination of debt ratios between 40% and 50%, EBIT coverage rates between two and three times, and cash flows to total debt between 15% and 20% are commensurate with the S&P financial requirements for an

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[25] In 2004, the EBIT coverage ratios averaged 1.4 for four integrated government owned and guaranteed electricity utilities in Canada; 2.6 for seven integrated and investor-owned electricity utilities in Canada; and 2.4 for eight transmission and distribution utilities in Canada, excluding Enmax (include in this group are Enersource, Hydro One, Hydro Ottawa, Toronto Hydro and Veridian). DBRS, The Canadian Electricity Industry, 2004.

[26] Ibid, the average ROE for the four government-owned utilities was 8% in 2004; for the seven integrated, investor-owned utilities the ROE averaged 13%; and for the nine transmission and distribution utilities the average ROE was 8%.

[27] Ibid. By comparison, debt comprised, on average, 72% of the total capital of the four government-owned utilities; 53% of the total capital of the seven integrated, investor-owned utilities; and 54% of the total capital of the eight transmission and distribution utilities (excluding Enmax).

[28] Ibid. By comparison, cash flow total debt averaged 10% of the total capital of the four government-owned utilities; 14% of the total capital of the seven integrated, investor-owned utilities; and 17% of the total capital of the eight transmission and distribution utilities (excluding Enmax).

"A/BBB" rating. Indeed, the combinations for many of the LDCs compare quite favorably with the similar combinations for the large electricity utilities in Canada (see footnotes 20 to 23).

We are left with three questions:

1. Should the LDCs be placed into different rating categories, and if so, using what criteria?
2. What spreads should be used over Government of Canada bond yields?
3. Should 10-year Government of Canada bonds be used?

While it is tempting to conclude that the LDCs should be placed into different rating categories, and that size could be the most appropriate criterion to use to do so, it is important to consider that the credit ratings are intended to provide a proxy for the potential losses that an investor may incur. Consequently, it is important to examine the potential risks for investors in the debt instruments of LDCs.

The interest rate paid by a company on its debt is the sum of the risk-free rate for the country in whose currency the debt is denominated plus a capital charge. There are several alternatives for the risk-free rate in Canada. Among them are a one-year Government of Canada treasury bill rate; the rate on a Government of Canada real interest rate bond plus the expected average rate of inflation over some future time period (one year to 10 years); a medium to long-term Government of Canada bond yield; or using the methodology discussed in section 3.3.4 below.

The capital charge depends upon the product of the expected likelihood of default by the issuer and the severity of the default as measured in terms of loss in asset value recovery, and the market's appetite for risk. S&P, in its corporate default study, has estimated the following worst-case default frequencies for long-term risks across rating categories:

- AA: 5.9%
- A: 7.1%
- BBB: 14.8%
- BB: 55.4%

We agree with Professor Booth's argument[29] that "ROE regulated firms have minimal risk in Canada due to the high degree of regulatory protection." [30] Professor Cannon earlier had reached a similar conclusion:

> "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

[29] Professor Laurence Booth, Business Risk and Capital Structure for Union Gas, evidence before the OEB, April 2006.
[30] Dr. William Cannon, Prefiled Testimony in Connection with the Application for Review of the Board's Guidelines for Setting ROE, before the OEB, June 2003.

> the micro level for the typical MEU and the typical gas LDC in Ontario…. 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."

However, he did allow for the possibility that the risks of stranded assets arising as a result of customer/plant relocation or bankruptcy are not negligible for some smaller and isolated LDCs. But we believe that even in these cases, the municipal owner(s), while writing down their equity stake in the LDC, would provide more equity/cash to the LDC so that it could be its outstanding debt obligations.

Dr. Cannon has pointed out:

> "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."

It is also possible that the Government of Ontario could become a lender of last resort to ensure the continuing operations of the LDC. The province could provide the cash with strings attached such as requiring the LDC to be acquired by a larger company or become a virtual utility. Or the LDC could request that the OEB revisit its determination of the WACC for the utility.

DBRS has stated that it views regulation as a strength in assessing the credit risks of utilities since regulation assures financial stability and performance-based regulation shares future efficiencies. DBRS did add that there could be "bad" regulation, with regulatory lag and unfavourable decisions.

Consequently, we propose that all LDCs be treated similarly for the purpose of determining the capital charge. If there were to be a grouping based on size, it appears that two size categories would be adequate: net plant assets of less than $10 million, and net plant assets in excess of $10 million.

If Professor Cannon is right that some of the smaller and isolated LDCs do face higher default risks, the problems they face would be compounded by placing them into a higher risk category and incorporating a higher cost for debt in the calculation of their WACC. If the municipal owners chose to pass on the full cost of capital to the LDC customers, the higher capital costs per customer and/or kWh likely would increase the likelihood of customer/plant relocations or bankruptcies. We suspect that the municipal owners of these LDCs would not pass on the full capital costs.

For those LDCs that currently have outstanding debt, the appropriate rate of interest to use for their cost of debt is the average rate of interest they are paying. We still need to address whether this average rate of interest includes interest charges for short-term debt and whether the average rate should be re-set each year.

To diminish the opportunities for a LDC to game the system, we suggest that the average rate be re-set each year and it should be based on the expected average interest rate for the coming year. Furthermore, since the credit rating agencies include short-term debt in the total debt quantitative analysis, and again to reduce the opportunities for gaming the system, we would set a total (short-term and long-term) debt to equity ratio and separate rates for long-term and short-term debt but limit the percentage of short-term debt in the deemed capital structure.

As for the LDCs that currently have no debt outstanding (see Table 2), or whose debt is held by an associated company, a cost of debt will have to be deemed for the purpose of calculating the weighted average cost of capital for these LDCs. There are three options for setting the interest rate for long-term debt.

The first involves using the rate of a relatively recent third party financing by a LDC other than the two largest. This procedure might result in a more accurate cost of debt than that of using a "synthetic" rating. The second entails setting a deemed or synthetic rate that remains unchanged for a five year period (the time period we assume between hearings to revise the rate base, weighted average cost of capital, and the X-factor in the PBR formula). The third involves setting the formula that would lead to automatic changes annually. In any of these options, it is necessary to select the risk-free rate and the capital charge.

<u>Option 1:</u>
Each year an average of the interest rates on all third party financings by LDCs, other than those with assets in excess of $1 billion, and the average spread between this rate and an average of the yields on a comparable mix (similar average term to maturity) of Government of Canada bonds would be calculated. This spread would be added to the forecast of the average yield on Government bonds (with a similar term to maturity) for the coming year.

<u>Option 2 (constant cost of debt for five years):</u>

The risk-free rate either can be the real yield on the Government of Canada real return bond plus the average annual inflation forecast derived from the nominal yield on five-year Government of Canada bonds. The real yield should be averaged over the preceding five years. Or it can be the risk free rate discussed and estimated in section 3.3.4 below. The capital charge should be the average spread during the preceding five years between "A/BBB" rated 10-year corporate bonds and 10-year Government of Canada bonds.

Option 3 (annual updates):
The risk-free rate either can be the current real yield on the Government of Canada real return bond plus the inflation forecast for the following year. Or it can be the risk free rate discussed below. The capital charge should be the average spread during the year between "A" rated 10-year corporate bonds and 10-year Government of Canada bonds.

There are two options for setting the rate of interest for short-term debt.

Option 1:
Each year an average of the interest rates on all third party financings (variable rate bank loans or commercial paper) by LDCs, other than those with assets in excess of $1 billion would be calculated and used.

Option 2:
Each year an average of the interest rates on 90-180 day commercial paper issued by a sample of companies with A/BBB credit ratings for the long-term debt would be calculated. The rate of interest for short-term debt for LDCs would equal a simple average of this rate, and the prime rate plus the spread between this rate and 90-180 day Government of Canada Treasury Bills.

3.3 COST OF EQUITY
3.3.1 Measuring risk and risk premium

In competitive markets investors who hold a risky asset must be compensated for the risk they bear, otherwise they would have no incentive to prefer it over the risk free rate. This compensation is usually presented in the form of expected rate of return. The expected rate of return on a risky asset, $E(R)$, must be greater[31] than the rate of return offered by the risk free asset, R_f. Hence, $E(R) > R_f$ and the difference $E(R) - R_f$ is termed the risk premium.

The Capital Asset Pricing Model is credited with the contribution of calculating the risk premium and its relation to the "risk" assumed by the investors who hold the asset. This relation, *the security market line*, connects the expected rate of return of a risky asset to its risk, and stipulates the risk premium.

[31] We assume here the common case of a stock that is positively correlated with the market. A negative beta is possibly generating a negative risk premium and an expected rate of return on the stock that is smaller than the risk free rate. In this case the stock serves as a hedging mechanism and the investor "pays" in turm of expected retune for risk elimination.

In the CAPM, the risk of an asset is measured by its beta. The beta of an asset measures the sensitivity of the expected rate of return of a risky asset to the expected rate of return of the "market". The "market" is usually[32] represented by an index which captures the market, such as the S&P 500. The CAPM specifies the risk premium of an asset as a function of the excess rate of return of in the market, $E(R_m)$, over the risk free rate. That is

Risk Premium $= E(R) - R_f = \beta(E(R_m) - R_f)$.

Hence, the security market line is given by

$$E(R) = R_f + \beta(E(R_m) - R_f).$$

The beta, as a sensitivity measure, tells us the change in the risk premium of an asset for each percentage change in the market return, $E(R_m)$.

Given the above relation, the risk premium of an asset for public companies can be estimated by a regression. Having observations on the rate of return of the market and of the risky asset, beta is estimated[33] by trying to fit the observations to the linear relation

$$R = \alpha + \beta R_m.$$

Beta is therefore the slope of the "best line" that fits the observed coordinates (R_{m_t}, R_t), where t denotes the time index of the observation. The estimated beta is the covariance between R_m and R divided by the variance of R_m. That is

$$\beta = \frac{Cov(R_m, R)}{\sigma_m^2}.$$

The conclusion of the CAPM is that one is compensated only for the systematic risk, the non-diversifiable risk, which is implicit in a risky asset. The diversifiable risk can be eliminated by holding the market portfolio which offsets part of the total risk of a risky asset. Hence the risk premium compensates the investor only for the non-diversifiable risk, the systematic risk that must be assumed when holding a risky asset. The systematic risk is implicit in the covariance[34], and thus is represented by beta.

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[32] The model actually solves for a well diversified portfolio which is R_m. In practice, however, a major index is used instead of the formal market portfolio. There are indeed some errors that are introduced by this procedure,(see Ferson and D. Locke (1988)).

[33] Note: α is $R_f(1-\beta)$

[34] A naive diversification of investing equal amounts in each stock, when the number of stocks increases, shows that the risk of the portfolio depends mainly on the average covariance, and not on the variance, showing that the covariance is the main part of the risk.

The valuation literature indeed touches on the question of whether beta, being a measure of only the non-systematic risk, is an appropriate measure of the risk for all circumstances. The common practice is [see Damodaran (2002)] that it depends on the purpose of the valuation. For example, for an IPO or a valuation of a sale of a private firm, the latter may require an adjustment of the beta depending on the buyer. If the buyer has all of his or her wealth invested in the business – adjustments[35] are warranted. In the case of evaluating LDCs where there are shares offered to different individuals, it is appropriate to use a measure of risk that takes into account only the systematic risk.

The beta of a firm thus tells us the risk premium that should be used in evaluating the firm. For simplicity let us assume for now a firm that has no debt outstanding. Hence, the cost of capital of this firm is $E(R) = R_f + \beta(E(R_m) - R_f)$, and in order to discount a future expected cash flow from this firm we will use a discount factor defined by

$$\frac{1}{1+E(R)} = \frac{1}{1+R_f+\beta(R_m - R_f)}.$$

The risk measured by a beta that is estimated from stock prices, β_e, (referred to as equity beta) measures not only business risk but also financial risk. The risk of a company that has no debt (commonly referred to as unlevered beta, β_u) is implicit in β_e. Under some simplifying assumptions[36], β_e and β_u satisfy the equation

$$\beta_e = \beta_u\left(1+\frac{D}{E}\right)$$

where $\frac{D}{E}$ is the debt equity ratio. Thus, β_u can be inferred from β_e.

In a regulated environment in which a regulator aims to set a fair rate of return, the allowed rate of return is set to be $R_f + \beta(E(R_m) - R_f)$, when $\frac{D}{E} = 0$. Fixing the allowed rate of return in such a way compensates for the assumed risk with the appropriate risk premium.

The difficulty we are presented with is that most LDCs are not public companies and market prices of their values are not readily available. Hence, we cannot estimate their beta and consequently their risk premiums.

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[35] An adjustment to beta that measures the total risk is done by writing the Covariance as $\rho \times \sigma_R \times \sigma_{Rm}$ and dividing the beta by ρ (the correlation coefficient) arriving at a measure of the total risk defined as $\frac{\sigma_R}{\sigma_{Rm}}$. Intuitively, sigma measures the total risk and this is a risk measure scaled by the market risk.

[36] Most practitioners assume that beta of debt is equal to zero and the beta of the tax shield is the same as the beta equity.

The valuation literature (e.g., Damodaran (2002), Koller, Goedhart and Wessels (2005), and Fernandez (2002)) offers the following solutions in such cases.

1. Management by comparison – the help of the management is sought in order to identify an industry that is similar to the firm at hand. The beta of the industry is then used (after correcting for the appropriate debt equity ratio).
2. Estimate the beta of a proxy firm that is publicly traded (and correct it for the appropriate debt equity ratio)[37].
3. Accounting beta – utilizes the **E**arnings **B**efore **I**nterest and **T**axes (**EBIT**) and estimates the rate of return per period (monthly or quarterly). Use these rates of return instead of the observations of the stock of a traded company and proceed to estimate the beta as the beta of a publicly traded firm.

Applying the idea implicit in methods 1 and 2 above is feasible for the situation of the LDCs. It is possible to identify a few publicly traded companies that are similar to an LDC[38].

Setting the risk premium in the above manner, using an industry beta or a proxy firm, however, amounts to stating that the business risk faced by each LDC is the same. That is, that the unlevered beta, β_u, is constant across the LDCs. Implicit in this approach is the assumption that LDCs, while they may face a different profile of clients, or are situated in different geographical areas, still face the same business risk. Consequently the risk premium of different LDCs will be the same. The allowed return on equity will be different only for LDCs that have different debt to equity ratios and/or different cost of debt. However, LDCs with the same debt to equity ratio and the same cost of debt will have the same allowed rate of return.

Adopting this approach requires the following steps in order to calculate the allowed return on equity (or equivalently the risk premium):

1. Estimate the industry beta equity, or the beta equity of a proxy public company.
2. Unlever the beta equity β_e, and solve for unlevered beta, β_u, as $\beta_u = \dfrac{\beta_e}{\left(1+\dfrac{D}{E}\right)}$.
3. Calculate $\overline{\beta}_u$, the average of the β_u s.
4. Given an LDC denoted by LDC_i, with a debt to equity ratio[39] of $\dfrac{D_i}{E_i}$, calculate its beta equity β_{ei} as $\beta_{ei} = \overline{\beta}_u\left(1+\dfrac{D_i}{E_i}\right)$.

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[37] A similar method is also possible when multiple lines of business are traded and one of the lines is as of that of the evaluated firm.

[38] For example the shares Emera Inc that owns Nova Scotia Power Inc. are traded on the TSX. Nova Scotia Power Inc. supplies electricity to 95% of Nova Scotia.

5. If LDC_i is not tax exempt and has a corporate tax rate of τ , substitute $D_i(1-\tau)$ for D_i in the above equation.
6. Set the risk premium of LDC_i to be $\beta_{ei}(R_m - R_f)$.

Fixing the allowed return on equity in the above stipulated manner utilizes a relatively simple and unified method that is applied in the same manner to each of the LDCs. This methodology lends itself to an updating mechanism that is easy to implement. The period over which beta is estimated and the choice of the R_f will be dealt with henceforth. However, once this has been decided, if an annual updating is required, the steps above should be followed each year.

The third alternative for estimating beta is the accounting beta which utilizes the Earnings Before Interest and Taxes. This method has the advantage of estimating the betas for each LDC individually and hence capturing the risk profile of each LDC. Thus, if indeed, facing different customers or geographical locations does affect the value of beta (the unlevered beta); this approach has the potential to capture it. The risk premium under this approach may differ among LDCs even when the debt to equity is the same. There are however some warnings that are voiced in the literature with respect to this approach. First, accounting data are usually available only once a year. This would lead to a regression with few observations and limited statistical power. Second, accounting data are often smoothed subject to accounting judgment and thus cause biases in the estimation.

Data on the EBIT of the LDCs are sparse. The data for the years 2001-2003 are available, but an estimation based on few observations is not very (statistically) powerful. Data from the old regime (prior to incorporation of the LDCs) are also available for some periods. However, they may not reflect the current situation and may not be very meaningful given the change in the industry, and they may not correspond to the existing LDCs as of today. If this approach is followed, the EBIT is used instead of market prices of outstanding shares in order to calculate the rates of return and the betas are estimated above. In view of the warning of using accounting data and the bias this might cause, it is recommended to use them and compare the results to the benchmark of the industry or proxy company. In certain cases where it is clear that the EBIT generates an unreasonable result, it is corrected based on the proxy beta.

There is another alternative in the literature that measures the risk premium. This method is based on the Arbitrage Pricing Theory (APT). The APT (or the multiple factor model) can in essence[40] be viewed as a generalization of the CAPM. In the CAPM the risk in the economy is captured by the market portfolio. Under the APT there are different types of risks in the economy. The investor is compensated, by a risk premium, for holding

[39] The debt equity ratio is the deemed ratio.
[40] While the CAPM is an equilibrium model the APT is based only on the assumption of the non-existence of a free lunch in the market. The multifactor model and the APT are different in that the APT does not specify the risk factor in the economy and the multifactor does, see for example French and Fama (1993). The risk premium for each of these factors is available in the US market from some providers.

different types of risks. The APT, hence, estimates a beta for each type of risk (also referred to as factors) and stipulates the expected rate of return of a risky asset as

$$E(R) = R_f + \beta_1(E(F_1) - R_f) + \beta_2(E(F_2) - R_f) + \cdots + \beta_n(E(F_n) - R_f) .$$

The $F_1,...,F_n$ are the risk factors in the economy and the $\beta_1,...,\beta_n$ are the regression coefficients in the multivariable regression

$$R = \alpha + \beta_1 F_1 + \cdots + \beta_n F_n .$$

While this approach also has the capability of identifying the uniqueness of the risk profile of each LDC, it has its own problems. It requires the identification of the factors $F_1,...,F_n$ every time an update of the allowed rate of return is needed. This entails using the principal components methodology and having access to a large set of data. This can be eased somewhat by choosing a set of factors based on some recommendation from the academic literature[41]. The implementation of this method however still requires access to the data set of the factors to be updated each time. It also requires running a regression of the rate of return for each LDC against the factors each time an update of allowed rate of return is to be set. Overcoming all of the above would still present an implementation problem. The LDCs are not publicly traded and thus their accounting beta, based on EBIT should be used. Currently, however, EBITs are only available for the last two or three years.

In sum, therefore, it seems that given the circumstances, the approach which estimates the beta based on proxy firms is not only the most practical, but also the only feasible method at the current time. Requiring the LDCs to file a report every quarter on EBIT will help in generating a reliable database. These reports can be used in the future for a risk premium estimate that will better capture the unique risk profile of each LDC. This, however, is an executive decision that should value the trade-off between the costs of frequent reporting vs. the generation of the database and a risk premium that is individually estimated.

3.3.2 Beta Estimates

In order to implement the conclusions above, we have chosen a few publicly traded (on the TSX) companies that could be used as proxy firms. We gathered information on their financial statements and betas (sources used were Bloomberg, Financial Post Advisor, and www.sedar.com). The raw data and the information gathered are available in the Adobe file entitled **Sources.pdf**. The companies used and a short description of their line of business is listed below in Table 9:

Table 9: TSX Companies Used as a Proxy for Estimating Beta for LDCs

[41] Formally applying this methodology amounts to using a multifactor model, for example Fama and French (1993).

TRANSALTA is an electric generation and marketing company. TransAlta's growth is focusing on developing coal and gas-fired generation in Canada, the U.S., Mexico and Australia. Ticker: TA Stock Exchange: TSX
CANADIAN UTILITIES LIMITED operates in four business segments: regulated natural gas operations; regulated electric operations; technologies; and power generation. These operations provide service to industrial, residential and commercial customers. Other businesses consist of: natural gas gathering, processing, storage and natural gas supply management and technical facilities management. Ticker: CU.NV Stock Exchange: TSX
FORTIS INC. is an international diversified electric utility holding company. Ticker: FTS Stock Exchange: TSX
Emera Incorporated is a holding company in the energy sector whose principal operating subsidiaries are Nova Scotia Power Inc. and Bangor Hydro-Electric Company. Ticker: EMA Stock Exchange: TSX
GREAT LAKES HYDRO INCOME FUND owns Great Lakes Power Trust. Great Lakes Power Trust owns, operates and manages an integrated hydroelectric power generating, transmission and distribution system. Ticker: GLH.UN Stock Exchange: TSX
ATLANTIC POWER CORPORATION has formed Atlantic Holdings, a Delaware limited liability company, to acquire indirect interests in 15 non-utility power generating plants primarily in the U.S. Ticker: ATP.UN Stock Exchange: TSX
ALGONQUIN POWER INCOME FUND is an open-ended investment trust that owns or has interests in a diverse portfolio of power generating and infrastructure assets across North America, including 48 hydroelectric facilities, five natural gas-fired cogeneration facilities, 17 alternative fuels facilities and 15 water reclamation and distribution facilities. Ticker: APF.UN Stock Exchange: TSX
BORALEX POWER INCOME FUND is an open-ended limited purpose trust. The fund owns hydroelectricity, wood residue and natural gas power stations in Quebec and New York. Ticker: BPT.UN Stock Exchange: TSX
Canadian Hydro Developers Inc. is a developer, owner and operator of power generation facilities. Ticker: KHD Stock Exchange: TSX
EPCOR Power L.P. currently owns independent power generating facilities in Ontario,

British Columbia, New York and Colorado. Ticker: EP.UN Stock Exchange: TSX
NORTHLAND POWER INCOME FUND is a trust that indirectly owns interests in five power projects. Ticker: NPI.UN Stock Exchange: TSX

Tables 10 and 11 report the information gathered and calculated. In order to estimate the beta for the LDCs, we first had to unlever the beta reported by the sources and use the debt equity ratios to do so. In Tables 10 and 11 the beta of 52 weeks and 60 months are reported, as well as the average of the betas before and after tax. The beta recommended for estimation is the average after-tax beta (for the 52 weeks or 60 months) for the years 2004 and 2005. Hence for a period of 52 weeks the after-tax beta we recommend is: [(0.3556 + 0.3589)/2] = 0.3572.

Table 10: Beta Estimates for 2004

				Beta - 52 weeks			Beta - 60 months		
Ticker	D/E	Avg. Tax	Equity % 1/(1+D/E)	Beta	Unlevered pre-tax	Unlevered after tax	Beta	Unlevered pre-tax	Unlevered after tax
TA	1.06	0.3604	0.4854	0.03	0.0146	0.0179	0.5	0.2427	0.2980
CU.NV	1.41	0.3604	0.4149	0.34	0.1411	0.1788	0.24	0.0996	0.1262
FTS	2.36	0.3604	0.2976	0.58	0.1726	0.2311	0.27	0.0804	0.1076
EMA	1.17	0.3604	0.4608	-0.12	-0.0553	-0.0686	-0.03	-0.0138	-0.0172
GLH.UN	1.11	0.3604	0.4739	0.29	0.1374	0.1696	0.31	0.1469	0.1813
ATP.UN	6.39	0.3604	0.1353	0.51	0.0690	0.1003	0	0.0000	0.0000
APF.UN	0.42	0.3604	0.7042	0.63	0.4437	0.4966	0.47	0.3310	0.3705
BPT.UN	0.25	0.3604	0.8000	0.8	0.6400	0.6897	0	0.0000	0.0000
KHD	0.79	0.3604	0.5587	0.71	0.3966	0.4717	1.05	0.5866	0.6975
EP.UN	0.54	0.3604	0.6494	0.99	0.6429	0.7358	0.19	0.1234	0.1412
NPI.UN	0.53	0.3604	0.6536	1.19	0.7778	0.8887	0.42	0.2745	0.3137
Average			**0.5122**		**0.3073**	**0.3556**		**0.1701**	**0.2017**

Table 11: Beta Estimates for 2005

				Beta - 52 weeks			Beta - 60 months		
Ticker	D/E	Avg. Tax	Equity % 1/(1+D/E)	Beta	Unlevered pre-tax	Unlevered after tax	Beta	Unlevered pre-tax	Unlevered after tax
TA	0.9	0.3594	0.5263	0.03	0.0158	0.0190	0.5	0.2632	0.3172
CU.NV	1.33	0.3594	0.4292	0.34	0.1459	0.1836	0.24	0.1030	0.1296
FTS	2.04	0.3594	0.3289	0.58	0.1908	0.2514	0.27	0.0888	0.1170
EMA	1.15	0.3594	0.4651	-0.12	-0.0558	-0.0691	-0.03	-0.0140	-0.0173
GLH.UN	1.55	0.3594	0.3922	0.29	0.1137	0.1455	0.31	0.1216	0.1555
ATP.UN	7.12	0.3594	0.1232	0.51	0.0628	0.0917	0	0.0000	0.0000
APF.UN	0.54	0.3594	0.6494	0.63	0.4091	0.4681	0.47	0.3052	0.3492
BPT.UN	0.26	0.3594	0.7937	0.8	0.6349	0.6858	0	0.0000	0.0000

KHD	0.69	0.3594	0.5917	0.71	0.4201	0.4924	1.05	0.6213	0.7281
EP.UN	0.55	0.3594	0.6452	0.99	0.6387	0.7321	0.19	0.1226	0.1405
NPI.UN	0.4	0.3594	0.7143	1.19	0.8500	0.9473	0.42	0.3000	0.3343
Average			**0.5145**		**0.3115**	**0.3589**		**0.1738**	**0.2049**

Our estimates seem to be in line with other estimates for the betas for utilities. Indeed, they seem to be larger on average. In March 2005 S&P[42] presented its estimates of the unlevered, pre-tax betas for a number of selected US electric utility companies. The results tend to support our conclusions. The average beta for the sample of 20 companies (see Table 12), was 0.26, with the betas ranging between -0.44 and 0.69 for the individual companies.

Table 12: S&P Estimates of Beta for Selected US Electricity Utility Companies, March 2005

Company	Beta
American Electric Power	0.42
Ameron	0.17
Cinergy	0.12
Consolidated Edison	-0.07
Constellation Energy	0.43
DTE Energy	0.12
Dominion Resources	0.12
Duke Energy	0.68
Edison International	0.12
Entergy	-0.02
Exelon	0.15
FPL Group	0.28
First Energy	0.07
NiSource	0.69
PPL	0.66
Progress Energy	0.24
Public Services Enterprise	0.32
Sempra Energy	0.27
Southern Company	-0.44
Xcel Energy	0.69
Average	0.26

Table 13 summarizes the findings of the London Business School[43] beta estimates for listed water and electricity companies in the UK for January 2004. The betas range from 0.20 to 0.57, with a simple average of 0.32.

[42] S&P, Stock Reports, March 2005.
[43] London Business School, Risk Measurement Service, 2004.

Table 13: London Business School Estimates of Beta for Water and Electricity Companies in the UK, January 2004

Company	Beta
AWG	0.37
Kelda Group	0.32
National Grid Transco	0.57
Pennon Group	0.22
Scottish and Southern Energy	0.20
Scottish Power	0.42
Severn Trent	0.28
United Utilities	0.25
Average	0.32

It is important to keep in mind that Dr. Cannon probably used a weighted average beta of between 0.8 to 0.9 in deriving his initial estimate for the ROE. If he had used CAPM and an estimate of beta in the range of 0.3 to 0.5, his ROE would have been between 7.35% and 8.46%.

3.3.3 The expected rate of return on the market

The rate of return on the "market" $E(R_m)$ was estimated based on the rate of return for the S&P/TSX index following the steps below:

1. The S&P/TSX composite index's monthly closing value for the last 10 years is available from the Government of Canada's website[44] under key economic indicators.
2. Monthly closing index values from January 2000 to April 2006 (see the excel file **spt_tsx.xls**) were used to estimate the monthly rate of return (monthly percentage change in the index value with respect to the previous month's value).
3. These monthly percentage changes were then used to calculate the average monthly return for S&P/TSX index.
4. Next, the effective annual rate of return (EAR) for the index was calculated using the following formula,

$$\text{EAR} = (1 + \text{Average monthly return})^{12} - 1$$
$$= (1 + 0.5784\%)^{12} - 1 = 7.1662\ \%$$

Similarly, we calculated the expected rate of return of the index return for the next five years as:

$$\text{5-year expected return} = (1 + \text{Average monthly return})^{\{5 * 12\}} - 1$$
$$= (1 + 0.5784\%)^{(5*12)} - 1 = \mathbf{41.348\ \%}$$

44 http://www.canadianeconomy.gc.ca/english/economy/index.cfm#top

We repeated these calculations using the full 10-year time period. The resulting EAR was 10.648%. While we prefer using the five-year time period since it more closely corresponds to the time interval between re-setting the formulas for the cost of capital and the X factor in the incentive-based formula, we recognize that there is likely to be a wide range of opinion on the appropriate time period to use to calculate the EAR.

3.3.4 The risk-free rate

Estimating the risk-free rate is usually done using prices of Government of Canada bonds. Practitioners, to simplify matters, use the yields on Government of Canada bonds as those are reported in the financial papers. However, a more appropriate procedure will be to utilize the so called "zero coupon curve" which is derived[45] from prices of coupon bonds. A description of a methodology to derive the zero coupon curve is provided in Bolder, Johnson, and Metzler (2004). Discrete observations of the zero coupon curve (with increments of 0.5 years) are available from: http://www.bankofcanada.ca/en/rates/yield_curve.html.

The conceptual issue is, however, what rate should be used over the next review period. Would it be appropriate to set the risk-free rate according to the current spot rates, or based on the forward rate, or perhaps on some average of rates as justified by the mean reverting[46] property of interest rates?

It seems reasonable to assume that the spot rate should not be used for this purpose as it is not a fair representation of the rate to prevail over the next review period. The decision should therefore be between:

- the forward rate as it is an estimate of the spot rate that will prevail in the future; and
- some historical average of spot rates (spanning the review period) or even a longer term rate (e.g., the yield on five years Government of Canada Bonds) since it can be considered as an average of the short term rates.

The forward rate is considered a good estimate for a future spot rate. Thus an estimate of the spot interest rate at a future date t (measured in years), spanning the time interval $[t,u]$ is the forward rate $r(t,u)$. Given the discrete observations on the zero coupon curve[47], a continuous function $h(t)$ can be fitted to the observations. The forward rate will thus be $(1+r(t,u))^{u-t} = \dfrac{(1+h(t))^t}{(1+h(u))^u}$. Our methodology was to fit a polynomial of

[45] In a market in which all the bonds are zero coupon bonds the yield curve and the zero coupon bonds coincide.
[46] The mean reverting process occurs when there is some equilibrium level towards which the variable tends, despite random variation. Historical estimates would provide a useful indication of both the mean level to which the variable reverted, and the speed of this reversion.
[47] A simplified version of the above will be just to use the yields on Government of Canada bonds in order to derive forward rates.

degree 6 to discrete observations on the zero coupon curve in order to estimate the function $h(t)$. An excel file **InterestRate.xls** further demonstrates our calculations. The results obtained are summarized in the table below (rates are reported based on an annual continuously compounded basis):

Time span	**1/1/2007-31/12/2007**	**1/1/2007-31/12/2012**
Forward rate	4.65065%	4.6609%
Average of 5, 10 and 15 Forward rates	5.01468%	5.01468%

The issue of the time period will be dealt with henceforth.

3.4 Debt-Equity Ratio

While about eight years have passed since the last report prepared by Dr. Cannon for the OEB was published, the academic literature has still not reached a definite answer regarding the issue of the optimal debt equity ratio or its relevance.

The main points to consider when investigating the optimal debt equity ratio are:

- The primary benefit of debt is the tax benefit.
- A secondary benefit of debt is that it induces mangers to be more careful in their choice of projects as a few bad choices may cause defaulting on interest payments etc.
- A significant cost of borrowing is the expected cost of bankruptcy. Increasing the likelihood of bankruptcy triggers direct costs (legal costs) and indirect costs (lost sales, harder access to capital).
- Borrowing money increases the conflict between bond holders and share holders of the firm and may induce bond holders to insert certain contingent conditions on the loan.
- A loss of flexibility may be realized by a firm that operates in a volatile environment that may induce unexpected investment opportunities.
- With no taxes, transaction costs or agency problems the capital structure is not relevant - the Miller and Modigliani (1968) theorem. Miller (1977) later showed that with both corporate and personal taxes the above results might still hold.

It seems reasonable to assume that in some cases however there will be a trade-off between the cost and benefit of the use of debt. Consequently, an optimal debt equity ratio that maximizes the value of the firm exists. At the same time it is not easy to determine or quantify the cost and benefit of debts. The literature offers the results of surveys of CEOs which rank certain factors in order of importance. There is also academic evidence that the debt-equity mix does not affect the value of the weighted average cost of capital (Graham 2003). As well, Welch (2002) reports that no evidence of optimization in reaching the debt-equity ratio is apparent and that this ratio is mainly driven by the market value of the firm's shares. The conclusion reached by Hovakimian, Opler and Titman (2001) also enforces the picture of the non-existence of an optimal stable ratio from a different angle[48]. The bottom line is that there still is no clear way of choosing[49] a debt-equity ratio.[50]

The literature also questions the way hypotheses are tested in this field. Strebulaev, (2004) states "The results suggest that, in the presence of infrequent adjustment, cross-sectional properties of economic variables in dynamics may be fundamentally different from those derived assuming that they are always at their target levels. Taken together, the results suggest a rethinking of the way capital structure tests are conducted."

As we discussed above, Table 2 shows that of the 82 "small" LDCs, only 18 had debt ratios in excess of 50%. Most had debt ratios in the 40% range. For LDCs with net plant of less than $1 million, the average debt ratio was 44%. For those with net plant between $5 and $10 million, the average debt ratio was 35%; and net plant between $40 and $100 million, the average rate was 45%.[51]

Of the six "medium-small" LDCs, only one had a debt ratio greater than 55%. The average for this group was 50%. Our sample of "similar firms" that we used to estimate the beta also had an average of about 50%.

Two of the four in the "medium-large" category had a debt ratio greater than 60% and the average for this group was 59%. Toronto Hydro has a debt ratio of 62% and Hydro One a debt ratio of 59%.

DBRS has reviewed the financial performance and capital structures of the major electricity utilities across Canada.[52] The debt ratios are presented in Table 14.

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[48] These conclusions cast serious doubts on a methodology suggested by Dr Kold (2006) in which an optimal debt equity ratio is found by optimization, assuming that a stable optimum mix exists, and that the optimal point is not unique but rather attained over a wide range of ratios.

[49] There are a few approaches of trying to determine an optimal mix and they are surveyed in most corporate finance texts.

[50] Recent evidence of this phenomena can be found in "Theory of Capital Structure - A Review:" by Frydenberg, *forthcoming in the Journal of Quantitative and Finance analysis.* " … paper is ended by a summary where the option price paradigm is proposed as a comprehensible model that can augment most partial arguments. The capital structure and corporate finance literature is filled with different models, but few, if any give a complete picture."

[51] Dr. Cannon has explained why the LDCs have not built up their debt ratios to the deemed levels. According to Dr. Cannon: "The municipal ownership of (LDCs) and the fact that they have, in the past, been exempt from income taxation has meant that (LDCs) 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 (LDC) cash flows which could otherwise be directed to support the municipal budget. Consequently, (LDCs) 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 (LDC) 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."

[52] DBRS, The Canadian Electricity Industry 2004.

Table 14: Debt as % of Total Capital, Electricity Companies in Canada, 2004

Integrated Government-Owned	(%)
BC Hydro	80
Hydro-Quebec	67
Manitoba Hydro	86
NB Power	106
Newfoundland and Labrador Hydro	76
SaskPower	57
Churchill Falls	29
Integrated/Investor Owned	
Fortis BC	59
CU	57
Epcor	47
Brascan Power	56
Nova Scotia Power	57
TransAlta Utilities	53
Transmission & Distribution	
AltaLink	54
Fortis Alberta	57
Enersource	57
Enmax	17
Hydro One	54
Hydro Ottawa	50
Newfoundland Power	55
Toronto Hydro	60
Veridian	50
Industry Average	**59**

Other than for the government-owned utilities and Enmax, debt generally comprises 50% to 60% of the capital structure of these utilities. These ratios are within the current guidelines for the small to medium-large LDCs. As well, as shown in Table 7, debt ratios in this range are consistent with credit ratings of "A/BBB" for utilities.

ENA[53] concluded that "it may be useful to consider empirical regularities regarding capital structures, which suggest that, considering a wide range of national and international evidence, gearing of 50% may be close to the norm."

The debt component includes both long-term and short-term debt. Therefore, it is necessary to break up the entire debt component into separate short-term and long-term components. Short-term debt is used primarily to finance short-term assets. It also can be used as a means to speculate on the future course of interest rates. Any rule should

[53] Energy Networks Association, "Cost of Capital Update" (March 2004), prepared for OFGEM.

discourage interest rate speculation. As a result, the short-term debt component should be limited to the proportion of short-term assets in the total rate base. Since working capital should comprise most, if not all of the short-term assets, we believe that the working capital allowance also should set the maximum for short-term debt in the deemed capital structure.

4. SUMMARY AND CONCLUSIONS

Cost of Debt:

For those LDCs with outstanding third-party debt, both short-term and long-term, the cost of long-term debt should be set annually to equal the expected average interest rate on the long-term debt for the next year. The cost of short-term debt should be set equal to the expected average interest rate on the short-term debt for the next year.

For the LDCs with a mix of third-party and associated party debt, the cost of debt for the entire outstanding debt should be set annually to equal the expected average interest rate for the next year on all third party long-term and short-term debt.

For the LDCs with no debt or only associated party debt, the maximum allowable cost of debt for the outstanding or deemed debt should be set annually to equal the risk free rate based on the average of 5, 10 and 15 year forward rates for 2007 (based on our calculations in section 3.3.4, this rate would be 5.01%) plus the average spread between a sample of "A/BBB" rated corporate bonds of 5, 10 and 20 year maturities and the corresponding Government of Canada bonds. This appears to be approximately 100 basis points. The sample could be selected annually by a panel of experts – academics and capital market professionals. The maximum allowable cost of short-term debt should be set annually to equal the average interest rate on commercial paper issued by the same sample of companies.

These rules should apply to all LDCs regardless of their size, as measured by the rate base.

Return on Equity:

The ROE, starting in 2007, for all LDCs should be based on the CAPM. There are two options. One is to set the initial risk premium and risk free rate for a five-year period, and adjust only the risk free component of the total ROE every year. The other is to calculate both the risk premium and risk free rate each year.

In either case, the starting points are the risk free rate and risk premiums we have calculated above in sections 3.3.2 to 3.3.4 above. The risk free rate should be the same as used in determining the cost of debt. The risk premium to be added should equal our estimate of the after-tax beta – 0.357 – times the market return less the risk free rate. Depending on the time period selected – five years or 10 years in our analysis – the market return can vary between 7.17% and 10.65%. Hence, the overall after-tax, ROE for the LDCs can vary between 5.78% and 7.02%. Once again, we suggest that a panel of experts be selected to determine the appropriate time period for calculating the market return, and the sample of companies to be used to determine the beta.

In option one, the risk premium[54] (0.77% to 2.01%) would remain constant over the five-year period. However, the overall ROE would change in line with the annual changes in the risk free rate calculated using the methodology we have used in section 3.3.4. The change in risk free rate incorporated in the ROE should not change on a one-for-one basis with the actual change in the risk free rate. Instead, we recommend the following annual adjustments in the risk free rate incorporated into the ROE for the years 2008-2011:

2008: $R_{f2008} = R_{f2007} + 0.7(R^*_{f2008} - R^*_{f2007})$
2009: $R_{f2009} = R_{f2008} + 0.7(R^*_{f2009} - R^*_{f2008}) + 0.7*0.3(R^*_{f2008} - R^*_{f2007})$
2010: $R_{f2010} = R_{f2009} + 0.7(R^*_{f2010} - R^*_{f2009}) + 0.7*0.3(R^*_{f2009} - R^*_{f2008}) + 0.7*0.3^2(R^*_{f2008} - R^*_{f2007})$
2011: $R_{f2011} = R_{f2010} + 0.7(R^*_{f2011} - R^*_{f2010}) + 0.7*0.3(R^*_{f2010} - R^*_{f2009}) + 0.7*0.3^2(R^*_{f2009} - R^*_{f2008}) + 0.7*0.33^2(R^*_{f2008} - R^*_{f2007})$

where R^*_f represents the actual risk free rate calculated each year and used in determining the maximum cost of debt.

In option two, both the risk free rate and the risk premium are calculated each year. As in the case of the cost of debt, we suggest that a panel of experts be assembled to determine the sample of companies to be used in determining the beta to be used in calculating the risk premium. This panel would be assembled once every five years for option one, and every year for option two.

Our suggested range for the ROE – 5.78% to 7.02% – represents a very significant reduction from the original 9.88% ROE. There are three reasons for this.

1. The risk free rate that we use is 5.01% compared to the “adjusted” forecast 30-year bond rate in effect in 1999 (approximately 6.08%). Interest rates in general have trended downwards for most of the past eight years.
2. The original weighted average ERP of 4.22% to 4.75%[55] falls within our MRP range of 2.16% to 5.64%. Our low end estimate, derived for a five-year time period is 206 to 259 basis points lower than the original weighted average ERP.
3. We use one test and a beta of 0.357. We believe that the original ROE was derived as a weighted average of three tests with a resulting implied beta between 0.8 and 0.9 (see note 1).

If we were to use the original, weighted average range of 4.22% to 4.75% for the ERP and apply our estimates of beta and the risk free rate, the resulting ROE today would be 6.52% to 6.71%. The ROE in 1999 using our estimate of beta would have been 7.59% to 7.78%.

[54] The difference between the market return and the risk free rate.
[55] The range for ERP is derived by dividing the 3.80% value by what we believe was the weighted average value for beta – 0.8 to 0.9 (see note 1).

On the other hand, if we were to use a beta of 0.8 to 0.9 with our estimates for the MRP and the risk free rate, the resulting range for the ROE today would be 6.74% to 10.09%.

Debt-Equity

Debt should consist of short-term and long-term debt following the practices of the credit rating agencies. We recommend that there be two groupings of LDCs for the purpose of establishing the maximum total debt to total debt plus equity proportions. For all LDCs with a rate base, excluding working capital allowances, of less than $300 million, the maximum debt-equity split should be 50%/50%. For all LDCs with a rate base in excess of $300 million, the maximum debt-equity split should be 60%/40%.

If a LDC chooses a debt-equity split less than these maximums, then the actual proportions should be used in determining the WACC for the LDC and the resulting revenue requirements. Further, we would limit the proportion of short-term debt in the capital structure to the same rate as the working capital allowance since short-term debt should be used to finance short-term assets, primarily working capital requirements.

Rate Base

The rate base should be determined as set out in the OEB Handbook and should be set using the book values of the capital assets. We are in agreement with the arguments presented by Professor Booth[56] on this matter.

The working capital allowance to be incorporated into the rate base should be the lesser of the existing working capital/rate base ratio or 20%. A constant 15% ratio for all LDCs does not seem to be in line with the current practices of the LDCs. Whatever working capital allowance is selected would set the maximum level for short-term debt in the capital structure.

[56] Professor Laurence Booth, Business Risk and Capital Structure for Union Gas, April 2006.

5. APPENDIXES
5.1 Disentangling the ROE Discrepancies

Cannon and McShane have each discussed three tests that can be used to derive the ROE for regulated utilities in Ontario:

- the equity risk premium test – essentially the sole test we have proposed;
- the discounted cash flow (DCF) test; and
- the comparable earnings test.

According to Ms. McShane:

> "Historically, Canadian regulators considered three types of tests (with varying weights accorded to the results) in determining allowed returns: comparable earnings, discounted cash flow and equity risk premium, with the latter comprising a number of variants, including the Capital Asset Price Model (CAPM)."[57]

Furthermore, in order to derive the ROE, both have proposed taking a weighted average of the ROEs produced by each test. Of course, they differ with respect to the weights that should be applied.

McShane has proposed the following weights[58]:

- Equity risk premium – 37.5%
- DCF – 37.5%
- Comparable earnings – 25.0%.

Cannon's has recommended the following weights:[59]

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[57] Kathleen McShane, evidence, prepared September 2002 and updated in February 2003 in Union Gas case.
[58] Ibid.
[59] Dr. William Cannon, Prefiled Testimony before the OEB in Connection with the Application for Review of the Board's Guidelines for Setting ROE, June 2003.
"I now believe that significantly less weight should be attached to the findings of the Comparable Earnings test for four reasons:

(1) A much fewer number of Canadian industrial firms qualify as low-risk industrials in 2003 than did in 1996…
(2) The importance of survivor bias in interpreting the results of the Comparable Earnings test has become clearer to me with my studies in preparation for this evidence…It is reasonable to believe that, in general, surviving firms will have brighter prospects and higher returns than non-survivors..
(3) IT has become more evident over the past three years that a wide range of companies…have been "managing" or "fudging" their financial statements in ways which overstate achieved returns….through the exclusion of restructuring costs and losses on discontinued operations in the ROCE calculations…
(4) It is now clear that corporate profit and ROCE have been overstated in past years by most companies' failure to expense compensation-related stock option grants….

For these reasons, I now believe that the weight attached to Comparable Earnings evidence should be reduced to 25% from the 40% that I though was appropriate in 1996. I also believe that the weight

- Equity risk premium – 60%
- DCF – 15%
- Comparable earnings – 25%.

But there is no theoretical reason to use all three tests, and consequently, any weighting scheme is arbitrary. Our preference for a single test precludes the need to determine a set of weights.

McShane did note:[60]

> "the application of the comparable earnings test, to which this Board had historically given significant weight, had become problematic. Two factors were key to regulators discounting the results of the comparable earnings test at that time. (1) The sharp decline in inflation in 1992 (from an average of 4.7% over the period 1983-1991 to an average of 1.5% in 1992-1996) cast considerable doubt on the relevance of pre-1991 returns on equity to a future business cycle. (2) The level of returns on equity for low risk industrial firms between 1990-1994 reflected the impact of a prolonged recession and restructuring period. Similar to the returns achieved during a relatively high inflation environment, the relationship between the "recession and restructuring" period returns and future achievable returns was viewed as dubious…Related factors led Canadian regulators to disregard the discounted cash flow test. The discounted cash flow model requires estimates of investor expectations of future growth in conjunction with prevailing dividend yields. With the protracted decline in earnings, and concurrent lack of growth (or reductions) in dividends, historic growth rates for industrial firms provided no insight into investor expectations for future growth rates…The risk premium test was effectively the only remaining choice for Canadian regulators. As a result, its initial adoption by Canadian regulators as virtually the sole basis for setting a benchmark return and for designing an automatic adjustment mechanism **was not unreasonable. The risk premium test provided an objective (observable) means of not only establishing a point of departure, i.e., the long Canada yield, but also for estimating subsequent changes in the equity return requirement.**" (emphasis added)

We opt for the CAPM version of the equity risk premium test since it has the soundest theoretical underpinnings in the finance literature and it does provide an objective means for estimating the ROE and any subsequent changes in the "equity return requirement".

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associated with DCF-based, cost of equity findings should be reduced from 20% (my 1996 weighting) to 15% (today)…I now have somewhat less confidence in analysts' consensus future earnings and dividend growth rate projections than I once did, although I have always recognized that these projections were biased on the high side because of the analysts' predominant focus on the "if all goes well or as planned" scenario, when forecasting corporate results, with little recognition of possible future pitfalls.."

[60] McShane, op.cit.

We do not agree at all with McShane's claim that "it is difficult to accurately measure changes in the required market risk premium from test period to test period, or measure changes in investors' relative risk perceptions.." It is very straightforward to estimate the CAPM ROE every year, and even to estimate individual utility ROEs.[61]

McShane now believes that all three tests should be used again. But there is no reason to favour the use of one test one day, and then to favour all three tests or perhaps two tests on another day, other than to produce the results that are most favourable for a client. Similarly, there is no basis for changing the weights periodically and arbitrarily.

While there are legitimate areas for disagreement in applying CAPM – the time period for measuring the risk free rate, the time period for measuring the market equity return, and the sample of companies for measuring beta – CAPM (including more sophisticated variants such as Arbitrage Pricing Theory) is the most widely accepted methodology in the finance literature for determining the ERP for individual companies. And the areas of disagreement can be resolved by using a panel of experts.

Interestingly, in her most recent testimony,[62] McShane did apply CAPM and betas less than 1.0 to argue in favour of "an incremental equity risk premium of about 170 basis points (5.25% x .32) for a Micro-Cap company, e.g., NRG."

As a result of our favouring CAPM and the equity premium test alone, we implicitly assign a weight of 100% to this test, and 0% weights to the DCF and comparable earnings tests. And these implicit weights remain unchanged over time. They are not subject to capricious arguments.[63]

Aside from the absence of theoretical support in the literature, the DCF and comparable earnings tests also are flawed.

The comparable earnings test depends upon accounting data for net profits. GAAP is not a science, and there are many accountants (our former colleague at Schulich, Al Rosen, being one of the harshest critics) who claim that it is more of an art. Net earnings can be manipulated legally, as well as fraudulently as Cannon has intimated. But it is the wide scope available for interpreting and applying GAAP that makes net profit numbers as reported to shareholders a weak basis for comparing profitability both across companies and over time for the same company. Cash flows and EBITDA data are more likely to be used in evaluating the financial performance of companies since there is less scope for manipulation. But there is still scope that limits comparability across companies.

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[61] Once the time period and the sample of companies have been selected, it will be a straightforward exercise for the OEB staff to input the required data into the program we have developed to generate the ROE(s).

[62] Opinion of Kathleen McShane on Capital Structure and Equity Risk premium for Natural Resource Gas, March 2006.

[63] Cannon in his most recent filed evidence is moving his weights closer to ours, although he still only assigns a weight of 60% to the equity risk premium test.

DCF largely ignores current market realities. Both McShane and Cannon have indicated that DCF-based ROE estimates show little if any correlation with interest rates, or for that matter with other key macro-economic variables. Dividend yields likely track interest rates. Moreover, the expected growth rates implicit in the DCF calculations for regulated utilities are overly optimistic.

Simple arithmetic suggests that the growth rates in utility earnings per share (EPS) are unlikely to exceed the growth rates in nominal GDP. First, if they did continually exceed nominal GDP growth, then the profits of utilities likely would account for an increasing share of national income – highly unlikely given regulation of these utilities. Second, the volume growth for these utilities likely equals population growth rates on average, which in turn are less than real GDP growth. So even if we add the rate of inflation into the revenue growth estimate, the resulting nominal growth in revenues will fall short of nominal GDP growth. Unless operating margins are growing, largely the result of productivity/efficiency growth, EPS growth also will lag behind nominal GDP growth. With PBR, utilities will have to continually improve their productivity just to maintain their operating margins. So going forward, it is not reasonable to expect EPS growth to exceed nominal GDP growth.

So instead of DCF ROE estimates of 11-12% as McShane has suggested, assuming a dividend yield of 4% and nominal GDP growth of 5% per year, a more reasonable estimate is likely to lie in the 7.5-8.0% range. And even this estimate should vary from year-to-year with changing macro-economic conditions.

In applying CAPM, there are three key variables:

- Risk free rate
- MRP
- Beta.

We do not believe that there is much controversy regarding the methodology we propose for estimating the risk free rate. The same cannot be said for the MRP and beta.

Cannon has stated:[64]

> "Unfortunately, the treasury bill rate tends to be volatile over time, incorporates only short-term inflation expectations, and is subject to central bank manipulation. These deficiencies mean that the prevailing T-bill rate may not always be a true reflection of the underlying risk free rate in the economy…What I have traditionally done in my rate-of-return evidence before this Board is to recognize that existing long-term bond yields can be uncontaminated by removing the "maturity risk premiums" imbedded in them—thus constructing an estimate of the truly riskless rate of return relevant for long-term investors."

[64] Cannon, op. cit.

While the Treasury bill rate is more volatile, our methodology does not depend solely on this rate and tends to correct for this volatility in a clear and generally accepted manner. So we doubt that Cannon would have difficulty with our methodology for estimating the risk free rate.

Further, like Cannon, we argue that the original methodology proposed by the OEB to add the ERP to the forecast rate for 10-year Canada bonds plus the spread between 10 and 30 year Canada bonds was flawed. The risk free rate should not include a premium for price variability caused principally by uncertainties regarding future rates of inflation. With a normal upward sloping yield curve, the use of 10-year bonds and spread provides unnecessary return for equity holders.

In estimating the MRP, we opt for the geometric mean. We do so for one reason in particular – simple arithmetic. Consider the case where the price of a share drops by 50% in one year and then recovers completely in the following year, rising by 100%. Over this two year period, any shareholder who has held on to this share has an aggregate return of 0% (0% per year based on the geometric means). But the arithmetic mean is +50%, which is entirely misleading regarding the actual return for the long-term shareholder, and is the consequence of a $X price decline representing a smaller proportion of the original price than a subsequent $X price increase from the lower base. The use of arithmetic means in volatile markets will overstate the actual annual returns over time (geometric means) for long-term shareholders.

The choice of time periods matters for estimating MRP. We agree with McShane that:

> "It is critical to recognize that the equity risk premium test is a forward looking concept that reflects investor expectations. The magnitude of the differential between the expected return on equities and the yield on bonds is a function of investors' views of such key factors as inflation, productivity, profitability and investors' willingness to take risks. It is precisely because the risk premium is a forward-looking concept that: Historic risk premium data need to be evaluated in light of prevailing economic and capital market conditions; and, direct estimates of the forward-looking risk premium need to supplement measurement of the risk premium by reference to historic data."

But the DCF test is not the appropriate one for estimating the forward-looking risk premium.

Cannon has highlighted the importance of time periods[65] and has suggested a more reasonable approach for determining a forward-looking risk premium. He has cited a number of Canadian studies:

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[65] So too has McShane: "The experience of the first half of the decade squeezed the achieved Canadian risk premiums by over 1.5 percentage points; the historic risk premium declined from a 1947-1989 average of 7.6% (6.8%) to a 1947-1996 average of 6.1% (5.3%), based on arithmetic (geometric) averages."

- Scotia Capital Fixed Income Research: 1957-2002 – MRP relative to T-bills averaged 2.05% (geometric means);
- Ibbotson Associates: 1936-2002 – MRP relative to long Canadas averaged 3.37% (geometric average);
- Mercer Investment Consulting: 1924-2002 – MRP relative to long Canadas averaged 3.64% (geometric means); 1934-2002 – MRP relative to T-bills 5.13% (geometric);
- Dimson, Marsh and Staunton (two professors and a research director at London Business School): 1900-2002 – MRP relative to long Canadas 4.15% (geometric)

Forward-looking MRPs "are often estimated by advisors to pension funds and other institutional investors…" For example,[66]

- Mercer Investment Consulting (forecasts to Queen's University Pension Committee), September 4, 2002: long-run Canadian MRP vs. yield on riskless long-term asset (yield on real return Canada bonds plus expected rate of inflation of 2.0%) 1.75%-2.75%;
- Letko Brosseau, pension asset manager and advisor to Queen's Pension Plan (meeting May 3, 2002): forecast forward-looking MRP vs. long Canadas 3%
- Ontario Teachers Pension Plan Board: 3.5% real return on Canadian equities (proxy for MRP relative to T-bills);
- Watson Wyatt Investment Consulting Practice – consensus economic forecasts: 2.4% MRP relative to 10-year Canadas

Cannon also acknowledged that "the equity risk premium test is a forward-looking concept that reflects investors' expectations about the future" As a result, he assigned a weight (arbitrarily selected) of 60% to the forward-focused MRP estimates and a 40% weight to the historical evidence. This weighting produced a MRP estimate relative to his risk-free, long-term asset of 4.0% to 4.3% -- well within our range of 2.16% to 5.55%.

Cannon also reviewed a number of US studies:

- Ibbotson Associates: 1924-2002 – MRP relative to long US bonds 4.7% (geometric); relative to T-bills 6.4% (geometric);
- Dimson, Marsh and Staunton: 1900-2002 – MRP relative to long US bonds 4.58% (geometric); relative to T-bills 5.42% (geometric);
- Jeremy Siegel: 1802-2001 – MRP relative to long US bonds 3.4% (geometric); relative to T-bills 4.0% (geometric)

Forward-looking for the U.S.:

- Jeremy Siegel: MRP relative to long US bonds 2% to 3%

[66] Cited by Cannon.

- Ibbotson Associates: MRP vs. long bonds 3.41%.

Using Cannon's 60/40 weights, produces a U.S. MRP relative to a risk-free, long-term asset of about 4.0 to 4.5%.

Both sets of estimates and our range for the MRP are below the 6.0% to 6.5% range suggested by McShane. So too are the estimates presented by Energy Networks Associates.[67] ENA concluded:

> "the ERP estimates are also similar to those used in the previous paper, although a further review of the academic evidence that has emerged in the period since the original document was prepared has highlighted the range of uncertainty regarding this parameter. As a result, although a mid-point estimate of 4% is retained in the WACC assessment, the spread has been increased to 3–5%, compared with 3.5– 4.5%. The mid-point of this range remains slightly above the range implied by recent regulator precedence— although, when adjustments made by the Commission are taken into account, it is shown that it has estimated ERP in the region of 3.75%. Empirical work demonstrates that average premia on equities have been above 5% during most of the twentieth century. However, there are a number of reasons to suggest that the use of such values may overstate the true *ex ante* risk premium, in particular due to unanticipated factors (especially inflation and stock returns) and changes in the market including a reduction in transactions costs. However, there continues to be considerable evidence that stock markets are more risky than when Ofgem made its determination of 3-4% at the last review. Interestingly, Dimson, Marsh and Staunton have published an update to their previous analysis... Dimson, Marsh and Staunton's most recent analysis concludes that an appropriate value for the global ERP is between 3%, on a geometric averaging basis, and 5%, on an arithmetic averaging basis, consistent with a wider review of the evidence…"

We favour our methodology for estimating the MRP since it is straightforward to apply. The only issue that is outstanding is the time period to use. An expert panel should be able to address this issue.

Estimating beta is the most contentious issue.

McShane did not like the downward trends in the betas for TSX listed utilities. As a result, she arbitrarily adjusted the betas (taking a weighted average of the actual betas and a beta of 1.0).[68] This produced a "relative risk adjustment of approximately 0.60-0.65 for an average risk LDC." The sole purpose of this exercise is to inflate the value of beta to be used in CAPM.

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[67] Energy Networks Associates, Cost of Capital Update, prepared for Ofgem, March 2004.
[68] The weights were 2/3 and 1/3 respectively.

Focusing on her updated schedules,[69] we find that the "raw" betas for S&P/TSX utilities have been trending downwards since 1992 from 0.72 to -0.06 in 2002. Beta averaged 0.52 between 1992 and 2000 (excluding the two years with negative betas for the S&P/TSX utilities). Beta averaged 0.43 over the same period for the TSE gas/electric index – beta did not exceed 0.55 in any year.

Adjusting the betas by excluding Nortel is reasonable given the grossly overweight position of Nortel in the TSE index during this period. As a result, the S&P/TSX utilities' betas declined from 0.35 in 2000 to 0.16 in 2002, and the TSE gas/electric index betas in 2000 and 2001 was still below the average for the period 1992-2000. The "raw" betas are comparable to our estimated values for the after-tax, unlevered betas.[70]

It is well documented now that beta is not a constant but it varies with time. The ROE therefore also varies with time – since market conditions are by nature volatile. The LDCs should receive the ROE that is appropriate for the period in question. For a non-regulated firm this is done by the competitive market instantly, every instant or trading day. The ROE for a regulated firm is being fixed every updating period. Hence, as opposed to a competitive firm, a regulated firm's ROE is updated and is in line with the market using a discrete (less refined grid) than that of a competitive firm.

If the beta trend is downward or if it is upward there is no reason for the "econometrician" to interfere with this process. Since the beta is estimated over some past period it reflects the market conditions during that period. Thus when an updating period is set and the same mechanism is used, the LDC will indeed lag after the competitive market but will pass through along the same paths. Having a short updating period will keep the LDC very close and lagging less behind the market.

However, very frequent updating is not practical. Updating the ROE say every five years when the beta and the ROE on the market are both estimated over the last five years will fulfil these goals. It will keep the LDCs in line with the market every five years . The estimates, being based on monthly observations over five years, will have enough statistical power, and the updating every five years will provide the LDCs with a reasonable period of planning thus reducing the uncertainty.

Cannon has observed that:[71]

> "Since 1996/1997, there has been a substantial decline in the equity capital costs for the average risk Canadian gas utility – and for Ontario's major gas distributors – as a result of both a significant decrease in equity capital costs for all corporations in general and because of a reduction in the relative riskiness of rate-regulated energy utilities as compared to the typical firm in the universe of publicly traded Canadian companies."

[69] In particular, schedule 11.
[70] We do not believe that McShane adjusted the reported betas for the debt-equity ratios for each company.
[71] Cannon, op. cit.

While acknowledging that the beta for the typical Canadian regulated energy utility has fallen by more than 50% over the post-1996 period, both in absolute terms and relative to the systematic riskiness of the typical S&P/TSX firm, Cannon did not accept that the total investment riskiness for these utilities has changed appreciably during this period of time. He suggested as a result, "Giving equal weight to the beta and SD(r) measures of market risk". Consequently, the "typical utility was 43.9% as risky as the typical S&P/TSX firm just at the time the Board was introducing its formulaic ROE methodology. Since that time, the relative investment riskiness of the typical utility, as compared to the S&P/TSX firm has fallen to 36.8%."

Even his "adjusted" 36.8% does not differ significantly from our estimated beta of 0.357.

Cannon concluded:[72]

> "The ERP is basically the product of the MRP and the risk of the subject company relative to the overall market or, more specifically, relative to the riskiness of the typical firm within the universe of rims contained in the market index…I showed that the riskiness of the average-risk Canadian energy utility to the typical firm in the S&P/TSX Index has fallen from about 44% in 1997 to 37% at the beginning of 2003…I concluded that the MRP relative to the riskless long-term Canadian asset has declined from 5.125% to 4.30% over the same time span. Combining these two developments…
> Estimated ERP for 1997 = (.44)(5.125%) = 2.25%
> Estimated ERP for 2003 = (.37)(4.30%) = 1.59%...
> Consequently, the "bare-bones" cost of equity capital – based on the capital attraction standard and the ERP test – has fallen by 245 bps since 1997, using MRP estimates based on long Canadas, and by 248 bps using MRPs based on the riskless asset."

Cannon's ERPs for the regulated utilities in Ontario relative to his riskless long-term asset has declined from:

- 1997 ROE = 5.82% + 2.25% = 8.07% to
- 2000 ROE = 4.00% + 1.59% = 5.59%.

If we use our estimate of the risk free rate of 5.01%, the resulting ROE using Cannon's estimates for "adjusted" beta and his MRP of 4.30% (2003 value) is 6.60%, within our range. It is important to note the following in Cannon's analysis:

- If only the CAPM test is used (implicit weight of 100%), the ERP for the regulated utilities in Ontario would have been significantly lower than 9.88% in 1997 – 8.07% according to Cannon.

[72] Ibid.

- Since 1997, the risk free rate has declined, beta has declined and so too has the MRP. The combination of these changes has produced a sharp reduction in the ERP for the utilities.

Cannon and McShane have accepted a value for beta of less than 1.0. However, both adjusted the raw betas, and both did not use CAPM exclusively.

ENA favours the use of CAPM exclusively. However, they do not accept that beta should be less than 1.0. They argued “that an equity beta of 1 should be used, on the basis that, although beta estimates for regulated companies demonstrated a significant fall since 1999, often by as much as 50%, this was likely to be the result of the volatility of the markets, and the statistical properties of beta estimates, and that there was no credible reason for believing that the business fundamentals of DNOs had altered.”

We disagree with this conclusion, as it appears would McShane, Cannon and Booth. Thus, this would be another key issue for an expert panel to address.

McShane in her latest evidence (in support of NRG) recommends in favour of “individualized” ROEs. That is, ROEs should vary among companies to reflect their different risks for investors. Our methodology, in particular the APT variant, could produce company-specific ROEs. In a few years’ time when the OEB has more financial data for the LDCs, this could be a straightforward exercise.

But, it is important to consider simplicity and the possible disincentives for consolidation. The simplest regulatory structure would have a single capital structure, ROE and debt cost for all LDCs. This also would not create an artificial regulatory impediment for consolidation. However, consolidation need not involve the acquisition of assets. Rather it could involve the outsourcing of the provision of services – the creation of virtual utilities. Company-specific ROEs would not impede this form of consolidation.

5.2 List of electronic files and their descriptions

The file **InterstRates.xls** is an Excel file that includes the raw data on the zero coupon curves as of May 19 2006 and the estimation of the term structure and implied forward rates

The file **Sources.pdf** is a pdf file that includes all the material gathered on the firms that were used as a proxy firm in order to estimate beta. The file also includes the Bloomberg results as well as financial statements gathered in order to identify the debt equity ratio etc.

The file **spt_tsx.xls** is an Excel file that includes closing prices of the spt and the estimation of the expected rate of return on the index.

The file **Beta Estimates.xls** is an Excel file that includes information and beta on the proxy firms as well the debt equity ratio to calculate the unlevered betas.

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Table 1: Working Capital as a % of Net Plant, LDCS, 2004

Kaschewan Power	23.6%
Fort Albany Power	357.4%
Dutton Hydro	31.7%
Hydro 2000	32.8%
Grand Valley	70.8%
Attawapiskat	273.4%
Asphodel Norwood Distribution	0.7%
Chapleau PUC	82.3%
Average	**109.1%**
Clinton Power	44.9%
Hearst Power Dist'n	366.3%
Terrace Bay Superior Wires	20.4%
Wellington Electric Dist'n	73.8%
Lakefield Dist'n	17.2%
Scgog Hydro Energy (Veridian)	19.7%
West Nipissing Energy Services	30.2%
Atikokan Hydro	17.4%
West Perth Power	52.1%
Hydro Hawkesbury	110.8%
Espanola Regional Hydro Dist'n	61.7%
Cooperative Hydro Embrun	44.0%
Wellington North Power	47.7%
Tay Hydro Electric Dist'n	-48.6%
Fort Frances Power	77.1%
Rideau St. Lawrence Dist'n	-15.1%
Northern Ontario Wires	29.6%
West Coast Huron Energy	21.8%
Renfrew Hydro	-10.1%
Eastern Ontario Power	-29.4%
Kenora Hydro Electricity	43.6%
Parry Sound Power	25.5%
Average	**45.5%**
PortColborne (CNP)	-102.6%
Midland Power Utility	42.4%
Sioux Lookout Hydro	-9.4%
Tillsonburg Hydro	29.0%
Centre Wellington Hydro	68.8%
Gravenhurst Hydro Electric	19.3%
ELK Energy	113.8%
Middlesex Power Dist'n (Chatham Kent Hydro)	-46.8%
Wasaga Dist'n	22.8%
Ottawa River Power	56.3%
Lakefront Utilities	40.9%
Average	**21.3%**
Grimsby Power	17.5%
Collus Power	29.2%
Orangeville Hydro	43.5%
Lakeland Power Dist'n	4.9%
Brant County Power	27.7%
Erie Thames Powerlines	3.7%
Orillia Power Dist'n	56.1%
Niagara on the Lake Hydro	-5.5%
Innisfil Hydro Dist'n	11.5%
Woodstock Hydro Services	32.0%
St. Thomas Energy	-1.2%
Welland Hydro Electric System	48.1%
Penninsula West Utilies	-49.2%
Average	**16.8%**
Kingston Electricity Dist'n	33.8%
Aurora Hydro	5.1%
Westario Power	-11.0%
Halton Hills Hydro	20.6%
Essex Powerlines	8.9%
North Bay Hydro Dist'n	60.4%
Festival Hydro	-23.0%
Haldimand County Hydro	25.5%
Fort Erie (CNP)	-7.3%
Norfolk Power Dist'n	0.0%
PUC Dist'n	20.0%
Bluewater Power Dist'n	15.2%
Milton Hydro Dist'n	23.3%
Average	**13.2%**
Chatham Kent Hydro	29.5%
Peterborough Dist'n	3.6%
Newmarket Hydro	30.3%
Brantford Power	6.5%
Oshawa PUC Networks	49.9%
Great Lakes Power	-68.2%
Whitby Hydro Electric	14.8%
St. Catherines Hydro Utility	20.9%
Thunder Bay Hydro Electricity Dist'n	26.5%
Niagagra Falls Hydro	14.3%
Greater Sudbury Hydro	-55.5%
Cambridge & North Dumfries Hydro	25.7%
Burlington Hydro	26.7%
Guelph Hydro Electric System	35.4%
Waterloo North Hydro	18.4%
Average	**11.9%**
Oakville Hydro Electric Dist'n	28.2%
Barrie Hydro	-10.4%
Veridian	26.6%
Kitchener Wilmot Hydro	27.7%
Enwin Powerlines	-21.0%
London Hydro	12.8%
Hamilton Hydro	21.5%
Hydro One Brampton Networks	-0.7%
Average	**10.6%**
Hydro Ottawa	4.6%
Enersource Hydro Mississauga	13.9%
Powerstream	9.8%
Average	**9.4%**
Toronto Hydro	-37.8%
Hydro One Networks	-4.3%

Table 2: Selected Financial Ratios, LDCS, 2004

	Net Plant	Net as %	Total debt/	Market to book equity	
	($000s)	equity	Debt+ Equi	7X	8.5X
Kaschewan Power	$122	9.9%	0.0%	5.2	6.3
Fort Albany Power	$177	-28.6%	92.6%	-11.1	-10.7
Dutton Hydro	$232	-12.3%	0.0%	-0.3	-0.3
Hydro 2000	$350	14.3%	35.0%	1.3	1.7
Grand Valley	$364	-3.6%	0.0%	0.1	0.2
Attawapiskat	$376	120.8%	92.1%	-1.8	0.3
Asphodel Norwood Distribution	$519	1.3%	0.0%	0.4	0.5
Chapleau PUC	$927	NM	131.5%	NM	NM
Average		**14.5%**	**43.9%**	**-0.9**	**-0.3**
Clinton Power	$1,040	5.0%	47.8%	0.6	0.9
Hearst Power Dist'n	$1,085	1.5%	37.9%	0.0	0.1
Terrace Bay Superior Wires	$1,242	7.5%	51.4%	0.3	0.6
Wellington Electric Dist'n	$1,260	-1.0%	51.2%	-0.2	-0.1
Lakefield Dist'n	$1,514	6.1%	0.0%	1.0	1.2
Scgog Hydro Energy (Veridian)	$1,825	5.4%	56.5%	0.4	0.8
West Nipissing Energy Services	$1,877	30.2%	98.3%	-33.9	-28.6
Atikokan Hydro	$1,910	-10.8%	61.1%	-0.6	-0.4
West Perth Power	$1,912	1.8%	36.9%	0.3	0.5
Hydro Hawkesbury	$2,029	5.4%	44.4%	0.9	1.3
Espanola Regional Hydro Dist'n	$2,041	-66.8%	105.7%	NM	NM
Cooperative Hydro Embrun	$2,083	13.8%	80.9%	-2.2	-1.7
Wellington North Power	$2,548	6.6%	47.0%	1.1	1.5
Tay Hydro Electric Dist'n	$2,900	5.7%	59.5%	0.7	1.1
Fort Frances Power	$3,390	54.6%	0.0%	4.2	5.1
Rideau St. Lawrence Dist'n	$3,427	10.6%	37.5%	0.8	1.1
Northern Ontario Wires	$3,740	-5.0%	43.6%	0.2	0.4
West Coast Huron Energy	$3,904	4.0%	20.3%	0.6	0.7
Renfrew Hydro	$4,028	2.0%	50.2%	0.7	1.1
Eastern Ontario Power	$4,087	16.6%	40.9%	1.8	2.3
Kenora Hydro Electricity	$4,690	-1.2%	31.6%	0.0	0.1
Parry Sound Power	$4,879	2.8%	37.5%	0.6	0.8
Average		**4.3%**	**47.3%**	**-1.1**	**-0.5**
PortColborne (CNP)	$5,006	NM	0.0%		
Midland Power Utility	$5,172	8.7%	19.2%	0.8	1.1
Sioux Lookout Hydro	$5,272	1.7%	29.1%	0.2	0.4
Tillsonburg Hydro	$6,415	-0.5%	29.3%	-0.1	-0.1
Centre Wellington Hydro	$7,082	4.8%	42.2%	0.7	1.0
Gravenhurst Hydro Electric	$7,535	13.7%	58.3%	1.4	2.0
ELK Energy	$7,713	11.3%	31.3%	1.3	1.6
Middlesex Power Dist'n (Chatham Kent Hydro)	$7,832	5.9%	54.4%	0.1	1.1
Wasaga Dist'n	$8,210	5.1%	38.1%	1.0	1.4
Ottawa River Power	$8,897	8.0%	42.8%	-0.6	-0.5
Lakefront Utilities	$9,537	10.5%	43.6%	1.5	2.0
Average		**6.9%**	**35.3%**	**0.6**	**1.0**
Grimsby Power	$10,793	5.6%	45.7%	0.8	1.2
Collus Power	$11,796	2.6%	33.3%	0.8	1.0
Orangeville Hydro	$12,757	6.2%	48.1%	1.0	1.4
Lakeland Power Dist'n	$12,906	8.8%	24.9%	1.3	1.6
Brant County Power	$14,386	5.4%	27.3%	0.6	0.8
Erie Thames Powerlines	$14,878	-1.0%	47.7%	0.4	0.7
Orillia Power Dist'n	$14,918	11.1%	46.1%	1.7	2.3
Niagara on the Lake Hydro	$16,594	-1.3%	56.0%	0.5	0.9
Innisfil Hydro Dist'n	$16,729	3.3%	43.5%	1.1	1.5
Woodstock Hydro Services	$17,376	1.7%	47.5%	0.7	1.0
St. Thomas Energy	$18,187	8.0%	42.5%	1.4	1.9
Welland Hydro Electric System	$18,704	2.2%	48.9%	-0.1	0.0
Penninsula West Utilies	$19,391	2.3%	45.1%	0.7	1.1
Average		**4.2%**	**42.8%**	**0.8**	**1.2**
Kingston Electricity Dist'n	$20,631	4.9%	49.3%	0.6	1.0
Aurora Hydro	$20,757	2.5%	47.0%	0.8	1.1
Westario Power	$23,539	1.7%	42.5%	0.4	0.7
Halton Hills Hydro	$24,159	6.5%	46.7%	0.9	1.3
Essex Powerlines	$26,682	31.3%	97.1%	-10.2	-5.1
North Bay Hydro Dist'n	$27,869	2.2%	48.2%	0.6	0.9
Festival Hydro	$28,690	5.5%	41.0%	0.9	1.3
Haldimand County Hydro	$29,476	0.7%	39.9%	0.8	1.2
Fort Erie (CNP)	$30,703	1.7%	53.5%	0.9	1.3
Norfolk Power Dist'n	$33,739	1.9%	40.5%	0.5	0.8
PUC Dist'n	$34,869	-30.5%	90.2%	-2.7	-1.3
Bluewater Power Dist'n	$35,549	5.7%	41.7%	1.0	1.4
Milton Hydro Dist'n	$38,145	7.0%	41.3%	1.1	1.5
Average		**3.2%**	**52.2%**	**-0.3**	**0.5**
Chatham Kent Hydro	$40,025	5.7%	44.9%	0.9	1.2
Peterborough Dist'n	$40,372	8.3%	45.6%	1.3	1.7
Newmarket Hydro	$41,641	8.4%	45.9%	1.2	1.6
Brantford Power	$41,926	1.7%	54.4%	0.3	0.6
Oshawa PUC Networks	$42,158	10.5%	44.2%	1.7	2.2
Great Lakes Power	$46,903	2.0%	0.0%	2.0	2.4
Whitby Hydro Electric	$53,072	9.7%	44.8%	1.2	1.6
St. Catherines Hydro Utility	$56,620	3.8%	38.5%	0.8	1.1
Thunder Bay Hydro Electricity Dist'n	$59,526	1.0%	47.3%	0.1	0.3
Niagagra Falls Hydro	$60,146	3.4%	49.1%	0.7	1.1
Greater Sudbury Hydro	$60,485	-3.4%	71.1%	0.1	0.7
Cambridge & North Dumfries Hydro	$73,887	3.8%	45.5%	0.8	1.1
Burlington Hydro	$78,123	7.9%	49.1%	1.2	1.7
Guelph Hydro Electric System	$78,418	5.1%	39.7%	0.9	1.2
Waterloo North Hydro	$83,001	2.7%	59.4%	0.8	1.3
Average		**4.7%**	**45.3%**	**0.9**	**1.3**
Oakville Hydro Electric Dist'n	$110,869	2.2%	52.9%	0.8	1.3
Barrie Hydro	$116,113	0.0%	46.1%	0.6	0.9
Veridian	$118,715	4.0%	51.1%	0.9	1.3
Kitchener Wilmot Hydro	$129,693	4.3%	48.4%	0.9	1.3
Enwin Powerlines	$152,874	2.2%	66.0%	0.1	0.5
London Hydro	$166,252	3.8%	36.9%	0.8	1.1
Hamilton Hydro	$207,603	7.3%	48.3%	1.2	1.6
Hydro One Brampton Networks	$293,687	8.4%	52.3%	1.1	1.6
Average		**4.0%**	**50.3%**	**0.8**	**1.2**
Hydro Ottawa	$376,599	5.5%	61.1%	0.8	1.3
Enersource Hydro Mississauga	$393,844	6.1%	63.0%	1.0	1.6
Powerstream	$452,488	7.7%	60.0%	1.3	2.0
Average		**6.4%**	**61.4%**	**1.0**	**1.6**
Toronto Hydro	$1,560,232	8.7%	62.1%	1.6	2.2
Hydro One Networks	$3,298,802	10.1%	59.0%	1.3	1.9

Table 6: Selected Cost and Profit Measures, LDCS, 2004

	Revenue/ Employee $000s	Customers/ Employee	Expenses/ 1000Kwh	of expenses ıin+general	Billing	% of debt+ equity O&M	Net	EBITDA	Net as % equity
Kaschewan Power	$217	91	$83.7	49.2%	13.0%	22.2%	9.9%	74.4%	9.9%
Fort Albany Power	$166	75	$69.6	52.9%	7.2%	33.0%	-2.1%	1.6%	-28.6%
Dutton Hydro	$84	229	$29.5	24.5%	23.6%	41.9%	-12.3%	-3.8%	-12.3%
Hydro 2000	$173	567	$7.9	47.4%	21.8%	3.4%	9.3%	16.8%	14.3%
Grand Valley	$123	453	$22.7	51.3%	22.4%	8.1%	-3.6%	2.0%	-3.6%
Attawapiskat	$205	113	$67.3	41.8%	9.2%	42.6%	9.5%	11.1%	120.8%
Asphodel Norwood Distribution	NM	NM	$13.9	10.5%	30.2%	30.9%	1.3%	5.5%	1.3%
Chapleau PUC	$117	270	$23.0	29.5%	9.3%	28.4%	-5.5%	4.5%	NM
Average	**$155**	**$257**	**$39.7**	**38.4%**	**17.1%**	**26.3%**	**0.8%**	**14.0%**	**14.5%**
Clinton Power	$92	292	$287.2	34.9%	15.3%	20.3%	2.7%	11.6%	5.0%
Hearst Power Dist'n	$167	559	$6.8	25.4%	14.9%	35.6%	0.9%	5.3%	1.5%
Terrace Bay Superior Wires	$186	422	$18.5	29.7%	28.1%	16.0%	3.6%	9.3%	7.5%
Wellington Electric Dist'n	$486	1559	$30.8	41.6%	21.9%	11.3%	-0.5%	5.6%	-1.0%
Lakefield Dist'n	NM	NM	$11.4	12.1%	24.9%	40.6%	6.1%	14.3%	6.1%
Scgog Hydro Energy (Veridian)	NM	NM	$13.0	39.5%	9.5%	22.1%	2.3%	10.8%	5.4%
West Nipissing Energy Services	$122	358	$17.7	35.5%	9.7%	33.2%	-3.7%	5.9%	-222.1%
Atikokan Hydro	$114	233	$26.1	31.6%	14.7%	31.3%	-4.2%	5.3%	-10.8%
West Perth Power	$127	326	$11.7	4.7%	25.8%	38.3%	1.1%	8.2%	1.8%
Hydro Hawkesbury	$169	747	$4.5	25.8%	22.5%	19.3%	3.0%	13.6%	5.4%
Espanola Regional Hydro Dist'n	NM	NM	$17.3	20.3%	20.0%	24.8%	-3.4%	7.5%	-66.8%
Cooperative Hydro Embrun	$197	683	$13.6	46.9%	15.3%	10.3%	2.7%	5.7%	13.8%
Wellington North Power	$163	394	$13.6	23.9%	23.3%	23.9%	3.5%	14.9%	6.6%
Tay Hydro Electric Dist'n	$159	463	$29.2	30.1%	17.1%	16.1%	5.7%	30.8%	5.7%
Fort Frances Power	$556	507	$15.9	45.0%	11.0%	19.1%	54.6%	60.6%	54.6%
Rideau St. Lawrence Dist'n	$122	383	$11.4	35.2%	25.0%	23.5%	8.9%	16.8%	10.6%
Northern Ontario Wires	NM	NM	$18.9	34.3%	26.3%	16.2%	-2.8%	7.8%	-5.0%
West Coast Huron Energy	$116	279	$9.3	29.9%	21.4%	25.6%	3.2%	9.4%	4.0%
Renfrew Hydro	$161	450	$14.5	19.6%	18.3%	19.2%	1.9%	23.3%	2.0%
Eastern Ontario Power	$247	438	$16.5	18.4%	23.9%	30.6%	9.8%	20.9%	16.6%
Kenora Hydro Electricity	$156	530	$16.4	27.4%	21.0%	22.1%	-0.8%	4.8%	-1.2%
Parry Sound Power	NM	NM	$17.2	27.0%	18.4%	17.1%	1.8%	10.4%	2.8%
Average	**$196**	**507**	**$28.2**	**29.0%**	**19.5%**	**23.5%**	**4.4%**	**13.8%**	**3.1%**
PortColborne (CNP)	$509	1436	$18.9	9.3%	19.5%	20.5%	NM	NM	NM
Midland Power Utility	$146	329	$9.4	29.7%	20.5%	27.0%	7.1%	12.6%	8.7%
Sioux Lookout Hydro	$171	344	$13.7	19.5%	21.3%	34.4%	1.7%	9.2%	1.7%
Tillsonburg Hydro	NM	NM	$23.3	28.1%	19.9%	33.5%	-0.3%	2.7%	-0.5%
Centre Wellington Hydro	$168	364	$15.2	23.7%	17.7%	18.9%	2.7%	11.5%	4.8%
Gravenhurst Hydro Electric	$211	437	$24.1	20.2%	26.3%	17.6%	5.9%	17.3%	13.7%
ELK Energy	$219	526	$13.3	24.3%	19.3%	16.9%	7.8%	16.7%	11.3%
Middlesex Power Dist'n (Chatham Kent Hydro)	$114	338	$12.2	21.5%	23.7%	15.0%	5.6%	24.9%	5.9%
Wasaga Dist'n	$114	697	$10.5	19.2%	0.0%	0.5%	3.2%	14.4%	5.1%
Ottawa River Power	$151	396	$14.8	23.5%	15.2%	24.5%	4.6%	14.3%	8.0%
Lakefront Utilities	$317	640	$9.5	21.5%	8.5%	20.7%	5.9%	18.3%	10.5%
Average	**$212**	**551**	**$15.0**	**21.9%**	**17.4%**	**20.9%**	**4.4%**	**14.2%**	**6.9%**
Grimsby Power	$217	645	$16.2	21.1%	15.6%	16.6%	3.1%	13.4%	5.6%
Collus Power	$409	1346	$10.3	20.9%	14.3%	31.8%	1.8%	12.2%	2.6%
Orangeville Hydro	$259	615	$12.9	21.9%	14.0%	18.7%	3.3%	14.5%	6.2%
Lakeland Power Dist'n	$209	406	$13.3	19.6%	20.6%	24.5%	6.6%	17.3%	8.8%
Brant County Power	$187	341	$18.4	19.4%	22.0%	30.4%	3.9%	10.4%	5.4%
Erie Thames Powerlines	$181	427	$13.9	19.5%	19.1%	33.0%	-0.5%	10.0%	-1.0%
Orillia Power Dist'n	$261	454	$15.7	17.0%	17.8%	22.0%	6.0%	19.8%	11.1%
Niagara on the Lake Hydro	$170	372	$18.8	15.9%	9.3%	19.4%	-0.7%	13.2%	-1.3%
Innisfil Hydro Dist'n	$301	682	$23.3	18.2%	15.4%	18.8%	1.9%	15.4%	3.3%
Woodstock Hydro Services	$168	424	$12.9	24.5%	12.3%	18.7%	0.9%	11.7%	1.7%
St. Thomas Energy	$211	515	$11.7	15.9%	23.9%	21.5%	4.7%	18.2%	8.0%
Welland Hydro Electric System	$171	598	$11.6	22.7%	19.4%	33.5%	1.1%	5.9%	2.2%
Penninsula West Utilies	$231	448	$20.5	20.3%	13.1%	27.4%	2.2%	22.3%	2.3%
Average	**$229**	**559**	**$15.3**	**19.8%**	**16.7%**	**24.3%**	**2.6%**	**14.2%**	**4.2%**
Kingston Electricity Dist'n	$195	576	$10.7	22.8%	16.0%	30.0%	2.8%	13.0%	4.9%
Aurora Hydro	$231	587	$13.1	24.8%	14.4%	14.1%	1.3%	12.5%	2.5%
Westario Power	NM	NM	$15.4	34.8%	20.4%	15.9%	1.2%	11.8%	1.7%
Halton Hills Hydro	$208	451	$15.1	28.1%	12.7%	15.4%	3.4%	13.8%	6.5%
Essex Powerlines	NM	NM	$14.6	28.6%	8.8%	34.3%	1.0%	10.9%	31.3%
North Bay Hydro Dist'n	$240	588	$13.6	23.7%	10.9%	27.8%	1.1%	11.3%	2.2%
Festival Hydro	$182	406	$10.0	16.6%	14.3%	18.9%	5.5%	23.2%	5.5%
Haldimand County Hydro	$238	484	$22.7	16.2%	13.3%	32.1%	0.5%	13.3%	0.7%
Fort Erie (CNP)	$114	244	$24.2	19.4%	12.2%	23.8%	0.8%	13.4%	1.7%
Norfolk Power Dist'n	$172	391	$20.8	18.3%	13.3%	20.7%	1.1%	10.4%	1.9%
PUC Dist'n	NM	NM	$17.3	19.6%	7.7%	25.5%	-3.0%	9.1%	-30.5%
Bluewater Power Dist'n	$184	419	$11.6	57.9%	2.0%	5.0%	3.3%	14.4%	5.7%
Milton Hydro Dist'n	$265	506	$11.4	21.2%	13.9%	17.3%	4.1%	15.1%	7.0%
Average	**$203**	**465**	**$15.4**	**25.5%**	**12.3%**	**21.6%**	**1.8%**	**13.2%**	**3.2%**
Chatham Kent Hydro	$328	861	$11.0	19.9%	15.4%	17.8%	3.1%	13.4%	5.7%
Peterborough Dist'n	NM	NM	$12.2	11.6%	21.1%	21.1%	4.5%	16.5%	8.3%
Newmarket Hydro	$295	583	$15.0	19.8%	14.6%	15.6%	4.7%	16.2%	8.4%
Brantford Power	$191	563	$12.0	29.6%	8.2%	22.9%	0.8%	10.3%	1.7%
Oshawa PUC Networks	$213	566	NM	30.1%	9.9%	10.0%	5.9%	19.9%	10.5%
Great Lakes Power	$180	159	$63.6	28.1%	5.6%	26.3%	2.0%	28.5%	2.0%
Whitby Hydro Electric	NM	NM	$16.0	17.9%	13.7%	20.8%	5.4%	16.0%	9.7%
St. Catherines Hydro Utility	$177	530	$10.1	9.3%	19.0%	30.6%	2.3%	12.5%	3.8%
Thunder Bay Hydro Electricity Dist'n	$126	388	$14.3	19.0%	18.1%	33.5%	0.5%	7.5%	1.0%
Niagagra Falls Hydro	$185	414	$16.4	14.1%	15.4%	25.1%	1.8%	12.6%	3.4%
Greater Sudbury Hydro	NM	NM	$19.0	23.2%	11.3%	19.4%	-3.4%	36.9%	-3.4%
Cambridge & North Dumfries Hydro	$235	577	$9.9	22.9%	4.9%	22.9%	2.1%	12.4%	3.8%
Burlington Hydro	$290	655	$12.0	17.4%	10.0%	25.1%	4.0%	15.8%	7.9%
Guelph Hydro Electric System	$222	457	$9.9	27.2%	9.9%	16.0%	3.1%	13.4%	5.1%
Waterloo North Hydro	$193	434	$14.1	9.1%	9.2%	28.7%	1.2%	13.8%	2.7%
Average	**$220**	**516**	**$16.8**	**19.9%**	**12.4%**	**22.4%**	**2.5%**	**16.4%**	**4.7%**
Oakville Hydro Electric Dist'n	$313	585	$15.4	18.4%	6.3%	16.9%	0.0%	13.2%	2.2%
Barrie Hydro	$202	554	$12.9	18.0%	6.2%	21.0%	0.0%	12.9%	0.0%
Veridian	$496	1300	$13.6	19.6%	25.0%	14.0%	2.0%	13.4%	4.0%
Kitchener Wilmot Hydro	$186	463	$12.1	9.9%	10.3%	21.4%	2.2%	13.3%	4.3%
Enwin Powerlines	$369	780	$14.1	50.1%	1.4%	9.6%	1.1%	14.0%	2.2%
London Hydro	$175	535	$11.2	17.5%	9.4%	28.9%	2.4%	12.4%	3.8%
Hamilton Hydro	$250	723	$11.2	21.8%	9.5%	18.7%	3.8%	15.7%	7.3%
Hydro One Brampton Networks	$307	619	$10.3	10.9%	9.8%	15.1%	4.0%	15.2%	8.4%
Average	**$287**	**695**	**$12.6**	**20.8%**	**9.7%**	**18.2%**	**1.9%**	**13.8%**	**4.0%**
Hydro Ottawa	$187	572	$10.3	5.0%	12.3%	24.0%	2.2%	13.8%	5.5%
Enersource Hydro Mississauga	$552	946	$11.2	25.9%	0.9%	15.8%	2.3%	14.4%	6.1%
Powerstream	$285	548	$12.9	22.2%	7.0%	15.1%	3.1%	16.4%	7.7%
Average	**$341**	**689**	**$11.5**	**17.7%**	**6.7%**	**18.3%**	**2.5%**	**14.9%**	**6.4%**
Toronto Hydro	$393	558	$13.9	14.5%	9.2%	18.0%	6.9%	36.4%	8.7%
Hydro One Networks	$360	470	$29.7	2.2%	15.3%	32.5%	4.3%	17.2%	10.1%

Table 8: Key Financial Ratios for LDCS, 2004

	% of debt+ equity		Net as %	Total debt/	Cash flow/	EBIT/	EBITDA/	total debt/
	Net	EBITDA	equity	Debt+ Equi	debt	interest	interest	EBITDA
Kaschewan Power	9.9%	74.4%	9.9%	0.0%	NM	1.2	1.6	0.0
Fort Albany Power	-2.1%	1.6%	-28.6%	92.6%	1.2%	-3.6	3.3	60.4
Dutton Hydro	-12.3%	-3.8%	-12.3%	0.0%	NM	NM	NM	0.0
Hydro 2000	9.3%	16.8%	14.3%	35.0%	36.0%	6.8	8.4	2.1
Grand Valley	-3.6%	2.0%	-3.6%	0.0%	NM	-24.0	12.0	0.0
Attawapiskat	9.5%	11.1%	120.8%	92.1%	12.0%	104.6	121.2	8.3
Asphodel Norwood Distribution	1.3%	5.5%	1.3%	0.0%	NM	19.0	43.0	0.0
Chapleau PUC	-5.5%	4.5%	NM	131.5%	-4.5%	0.4	0.6	19.2
Average	**0.8%**	**14.0%**	**14.5%**	**43.9%**	**11.2%**	**14.9**	**27.2**	**22.5**
Clinton Power	2.7%	11.6%	5.0%	47.8%	18.9%	2.2	5.0	4.2
Hearst Power Dist'n	0.9%	5.3%	1.5%	37.9%	10.1%	1.9	4.1	7.1
Terrace Bay Superior Wires	3.6%	9.3%	7.5%	51.4%	18.1%			5.5
Wellington Electric Dist'n	-0.5%	5.6%	-1.0%	51.2%	5.9%	0.8	2.2	9.1
Lakefield Dist'n	6.1%	14.3%	6.1%	0.0%	NM	NM	NM	0.0
Scgog Hydro Energy (Veridian)	2.3%	10.8%	5.4%	56.5%	13.0%	1.7	3.2	5.2
West Nipissing Energy Services	-3.7%	5.9%	-222.1%	98.3%	5.4%	-31.5	60.2	16.6
Atikokan Hydro	-4.2%	5.3%	-10.8%	61.1%	3.7%	-0.4	1.7	11.5
West Perth Power	1.1%	8.2%	1.8%	36.9%	16.6%	1.6	4.0	4.5
Hydro Hawkesbury	3.0%	13.6%	5.4%	44.4%	15.4%	3.0	4.2	3.3
Espanola Regional Hydro Dist'n	-3.4%	7.5%	-66.8%	105.7%	2.7%	0.3	1.6	12.7
Cooperative Hydro Embrun	2.7%	5.7%	13.8%	80.9%	6.9%	97.0	202.0	14.3
Wellington North Power	3.5%	14.9%	6.6%	47.0%	20.9%	2.3	3.9	3.2
Tay Hydro Electric Dist'n	5.7%	30.8%	5.7%	59.5%	12.9%	1.7	2.9	4.8
Fort Frances Power	54.6%	60.6%	54.6%	0.0%	NM	NM	NM	0.0
Rideau St. Lawrence Dist'n	8.9%	16.8%	10.6%	37.5%	25.5%	5.4	7.0	3.0
Northern Ontario Wires	-2.8%	7.8%	-5.0%	43.6%	8.5%	0.3	2.0	5.6
West Coast Huron Energy	3.2%	9.4%	4.0%	20.3%	36.0%	2.8	5.1	2.2
Renfrew Hydro	1.9%	23.3%	2.0%	50.2%	14.5%	1,4	3.0	4.2
Eastern Ontario Power	9.8%	20.9%	16.6%	40.9%	34.9%	5.6	7.1	2.0
Kenora Hydro Electricity	-0.8%	4.8%	-1.2%	31.6%	9.0%	0.7	2.8	6.6
Parry Sound Power	1.8%	10.4%	2.8%	37.5%	18.6%	1.8	3.5	3.6
Average	**4.4%**	**13.8%**	**3.1%**	**47.3%**	**14.9%**	**5.1**	**17.1**	**6.4**
PortColborne (CNP)	NM	NM	NM	0.0%	NM	NM	NM	0.0
Midland Power Utility	7.1%	12.6%	8.7%	19.2%	60.2%	17.2	26.9	1.5
Sioux Lookout Hydro	1.7%	9.2%	1.7%	29.1%	15.8%	2.3	4.9	4.4
Tillsonburg Hydro	-0.3%	2.7%	-0.5%	29.3%	8.2%	-0.2	13.1	10.9
Centre Wellington Hydro	2.7%	11.5%	4.8%	42.2%	16.4%	2.3	3.7	3.7
Gravenhurst Hydro Electric	5.9%	17.3%	13.7%	58.3%	19.7%	3.1	4.7	3.5
ELK Energy	7.8%	16.7%	11.3%	31.3%	36.5%	5.1	6.5	1.9
Middlesex Power Dist'n (Chatham Kent Hydro)	5.6%	24.9%	5.9%	54.4%	15.1%	2.2	4.1	4.5
Wasaga Dist'n	3.2%	14.4%	5.1%	38.1%	23.3%	3.3	5.6	2.7
Ottawa River Power	4.6%	14.3%	8.0%	42.8%	21.2%	2.7		30.6
Lakefront Utilities	5.9%	18.3%	10.5%	43.6%	23.9%	4.0	5.3	2.4
Average	**4.4%**	**14.2%**	**6.9%**	**35.3%**	**24.0%**	**4.7**	**7.5**	**6.6**
Grimsby Power	3.1%	13.4%	5.6%	45.7%	18.7%	2.3	4.0	3.5
Collus Power	1.8%	12.2%	2.6%	33.3%	25.5%	2.0	4.6	2.8
Orangeville Hydro	3.3%	14.5%	6.2%	48.1%	16.9%	3.5	5.4	3.4
Lakeland Power Dist'n	6.6%	17.3%	8.8%	24.9%	46.4%	7.9	11.0	1.4
Brant County Power	3.9%	10.4%	5.4%	27.3%	29.6%	3.5	5.9	2.6
Erie Thames Powerlines	-0.5%	10.0%	-1.0%	47.7%	11.0%	1.2	2.8	4.8
Orillia Power Dist'n	6.0%	19.8%	11.1%	46.1%	25.9%	3.3	4.8	2.3
Niagara on the Lake Hydro	-0.7%	13.2%	-1.3%	56.0%	10.2%	1.2	2.8	5.0
Innisfil Hydro Dist'n	1.9%	15.4%	3.3%	43.5%	19.2%	2.0	3.5	2.9
Woodstock Hydro Services	0.9%	11.7%	1.7%	47.5%	15.4%	1.5	3.4	4.1
St. Thomas Energy	4.7%	18.2%	8.0%	42.5%	23.7%	4.0	5.8	2.4
Welland Hydro Electric System	1.1%	5.9%	2.2%	48.9%	11.4%	13.6	54.6	8.2
Penninsula West Utiles	2.2%	22.3%	2.3%	45.1%	20.0%	1.6	4.4	3.7
Average	**2.6%**	**14.2%**	**4.2%**	**42.8%**	**21.1%**	**3.7**	**8.7**	**3.6**
Kingston Electricity Dist'n	2.8%	13.0%	4.9%	49.3%	14.5%	2.4	3.9	4.2
Aurora Hydro	1.3%	12.5%	2.5%	47.0%	15.1%	1.9	3.6	3.8
Westario Power	1.2%	11.8%	1.7%	42.5%	12.6%	2.3	4.2	4.4
Halton Hills Hydro	3.4%	13.8%	6.5%	46.7%	18.6%	2.5	4.0	3.4
Essex Powerlines	1.0%	10.9%	31.3%	97.1%	5.9%	1.7	3.3	10.0
North Bay Hydro Dist'n	1.1%	11.3%	2.2%	48.2%	12.6%	2.5	4.5	4.3
Festival Hydro	5.5%	23.2%	5.5%	41.0%	20.8%	2.8	4.5	3.0
Haldimand County Hydro	0.5%	13.3%	0.7%	39.9%	15.2%	2.7	4.8	3.1
Fort Erie (CNP)	0.8%	13.4%	1.7%	53.5%	16.2%	1.4	3.4	4.0
Norfolk Power Dist'n	1.1%	10.4%	1.9%	40.5%	18.6%	1.7	4.5	4.0
PUC Dist'n	-3.0%	9.1%	-30.5%	90.2%	2.8%	0.6	1.5	9.9
Bluewater Power Dist'n	3.3%	14.4%	5.7%	41.7%	23.9%	2.3	4.3	2.9
Milton Hydro Dist'n	4.1%	15.1%	7.0%	41.3%	23.6%	2.9	4.7	2.7
Average	**1.8%**	**13.2%**	**3.2%**	**52.2%**	**15.4%**	**2.1**	**3.9**	**4.6**
Chatham Kent Hydro	3.1%	13.4%	5.7%	44.9%	18.7%	2.5	4.1	3.4
Peterborough Dist'n	4.5%	16.5%	8.3%	45.6%	20.8%	3.5	5.0	2.8
Newmarket Hydro	4.7%	16.2%	8.4%	45.9%	24.0%	2.9	4.9	2.9
Brantford Power	0.8%	10.3%	1.7%	54.4%	9.0%	1.3	2.2	5.7
Oshawa PUC Networks	5.9%	19.9%	10.5%	44.2%	27.8%	4.4	6.5	2.2
Great Lakes Power	2.0%	28.5%	2.0%	0.0%	NM	NM	NM	0.0
Whitby Hydro Electric	5.4%	16.0%	9.7%	44.8%	24.2%	2.6	3.9	2.8
St. Catherines Hydro Utility	2.3%	12.5%	3.8%	38.5%	20.0%	3.6	6.4	3.1
Thunder Bay Hydro Electricity Dist'n	0.5%	7.5%	1.0%	47.3%	13.0%	7.9	31.8	6.3
Niagagra Falls Hydro	1.8%	12.6%	3.4%	49.1%	15.0%	0.2	3.9	3.9
Greater Sudbury Hydro	-3.4%	36.9%	-3.4%	71.1%	6.9%	0.8	1.8	6.7
Cambridge & North Dumfries Hydro	2.1%	12.4%	3.8%	45.5%	17.5%	2.5	4.7	3.7
Burlington Hydro	4.0%	15.8%	7.9%	49.1%	20.0%	2.7	4.3	3.1
Guelph Hydro Electric System	3.1%	13.4%	5.1%	39.7%	20.8%	3.5	5.8	3.0
Waterloo North Hydro	1.2%	13.8%	2.7%	59.4%	11.7%	1.9	3.4	4.5
Average	**2.5%**	**16.4%**	**4.7%**	**45.3%**	**17.8%**	**2.9**	**6.3**	**3.9**
Oakville Hydro Electric Dist'n	0.0%	13.2%	2.2%	52.9%	15.0%	1.5	3.2	4.0
Barrie Hydro	0.0%	12.9%	0.0%	46.1%	10.9%	2.5	4.5	4.1
Veridian	2.0%	13.4%	4.0%	51.1%	15.8%	2.0	3.7	3.8
Kitchener Wilmot Hydro	2.2%	13.3%	4.3%	48.4%	15.0%	2.3	3.8	3.6
Enwin Powerlines	1.1%	14.0%	2.2%	66.0%	9.2%	1.4	2.9	6.7
London Hydro	2.4%	12.4%	3.8%	36.9%	23.8%	2.5	5.2	3.0
Hamilton Hydro	3.8%	15.7%	7.3%	48.3%	20.6%	2.7	4.5	3.1
Hydro One Brampton Networks	4.0%	15.2%	8.4%	52.3%	16.5%	2.9	4.1	3.5
Average	**1.9%**	**13.8%**	**4.0%**	**50.3%**	**15.9%**	**2.2**	**4.0**	**4.0**
Hydro Ottawa	2.2%	13.8%	5.5%	61.1%	13.9%	1.8	3.5	4.6
Enersource Hydro Mississauga	2.3%	14.4%	6.1%	63.0%	15.5%	2.2	4.5	4.4
Powerstream	3.1%	16.4%	7.7%	60.0%	15.0%	2.4	3.8	3.7
Average	**2.5%**	**14.9%**	**6.4%**	**61.4%**	**14.8%**	**2.1**	**3.9**	**4.2**
Toronto Hydro	6.9%	36.4%	8.7%	62.1%	15.8%	2.5	4.0	3.6
Hydro One Networks	4.3%	17.2%	10.1%	59.0%	18.4%	2.4	4.2	3.6