ONTARIO ENERGY BOARD

COST OF CAPITAL GENERIC PROCEEDING

EB-2024-0063

OEB STAFF COMPENDIUM

PANEL 4 – M4 DR. CLEARY

October 9, 2024

ONTARIO ENERGY BOARD

2024 REVIEW OF COST OF CAPITAL PARAMETERS AND DEEMED CAPITAL STRUCTURE

EB-2024-0063

Evidence of Dr. Sean Cleary, CFA Professor of Finance

Sponsored by Industrial Gas Users Association (IGUA) and

Association of Major Power Consumers in Ontario (AMPCO)

July 19, 2024

- The current policy of considering the impact of risk factors on request when there is a perceived significant change in business/financial risks (including regulatory risk) is a reasonable approach, which should be retained.
- Proactive impact assessments should occur following material regulatory changes.

3.4 Short-term debt rate – appropriateness of existing methodology

***Issue 4: Should the short-term debt rate** for electricity transmitters, electricity distributors, natural gas utilities, and OPG **continue to be set using the same approach** as set out in the OEB Report?*

For electricity transmitters and distributors (T&D), the deemed short-term debt rate (DSTDR) is used to set short-term debt rates, while the short-term rates applied for natural gas distributors and OPG are based on these utilities' forecasts of short-term debt rates based on their actual debt portfolio. In addition, for electricity T&D, the DSTDR applies to 4% of their capital structure.

The current OEB policy is to determine the DSTDR based on estimates of the spread of a typical short-term loan for an R1-low utility over the 3-month Bankers Acceptance (BA) rate based on a confidential survey of up to 6 major Canadian banks (after eliminating the high and low estimates). The OEB generally calculates the 3-month BA rate used as the September average rate. As LEI points out, this practice must be changed since the BA rate will no longer be available, and Canadian banks are transitioning (and/or have already transitioned) to short-term debt products that are based on the Canadian Overnight Repo Rate Average (CORRA). My recommendation is similar to that of LEI:

4) The current approach is reasonable in principle; however, the DSTDR methodology will have to be adjusted since the 3-month BA rate is no longer appropriate or available.

3.5 Short-term debt rate – recommended revisions to existing methodology

Issue 5: If no to Issue #4, how should the short-term debt rate be set?

LEI recommends changing the base reference rate for determining the DSTDR from the BA rate to the CORRA. I agree with this recommendation, since the BA rate will no longer be available and because Canadian Financial Institutions are transitioning short-term lending products to this reference rate.

LEI further recommends estimating the spread for an R-1 rated borrower to this rate based on a confidential survey of banks, which they recommend should be extended from the current sample of 6 to a larger sample of 6-10 banks. I am fine with this suggestion, assuming that it does not lead to including less reliable estimates (i.e., from the smaller banks) nor adds unnecessary complexity to the survey process. If either of these issues come to fruition, then the current practice of surveying Canada's large 6 banks is very representative of the Canadian market, since they dominate the Canadian banking industry.

On page 82 of its evidence, LEI further recommends estimating the base CORRA to be used in the DSTDR (to replace the BA rate) based on the "average CRA (3-month CORRA futures) determined over the relevant forward-looking 12-month period." They further suggest that using the futures rates will be "more representative of investor expectations of short-term rates over the next year, in line with potential BoC policy rate reduction expectations." Generally, I am against using interest rate "forecasts" or futures rates versus actual rates (which provide more accurate forecasts), as I will discuss in response to Issue 7, based on evidence provided in Appendix A. However, since the CORRA is linked directly to the Bank of Canada's rate decisions, I am fine with this suggestion; although, I would also be fine with using the existing CORRA rate as of September 30th of each year (as opposed to an average of the rate over the month – which is consistent the OEB's current policy of estimating the base BA as the September average). If the Board decides to continue the practice of using the existing rates rather than futures rates, using the month-end rate should be a better estimate of future rates than using an average for the month. Consider for example if the Bank of Canada unexpectedly cut its policy rate in the middle of a given month. This would lead to a decrease in CORRA, which may continue near the new level for some time, but would not have been reflected in the CORRA rates during the first half of the month (i.e., since it was unexpected). Therefore, in this instance using the rates during the first half of the month in estimating an average CORRA would bias the base rate upwards.

My recommendation is similar to that of LEI, with two minor qualifications:

5) - The CORRA should be used to replace the BA rate in the DSTDR methodology.

- LEI recommends extending the current practice of sampling 6 big banks to estimate the spread to a larger sample of 6-10 banks. I am fine with this suggestion, assuming that it does not lead to including less reliable estimates (i.e., from the smaller banks), nor adds unnecessary complexity to the survey process.

- LEI recommends estimating the base CORRA based on the average of 3-month CORRA futures rates over the next 12 months. Since the CORRA is linked directly to the Bank of Canada's rate decisions, I am fine with this suggestion; although, I would also be fine with using the existing CORRA rate as of September 30th of each year as the base CORRA rate.

3.6 Long-term debt rate – appropriateness of existing methodology

Issue 6: Should the long-term debt rate for electricity distributors, natural gas utilities, and OPG continue to be set using the same approach as set out in the OEB Report and as set out in the Staff Report for electricity transmitters?

The OEB currently applies the weighted average of actual embedded long-term debt costs to natural gas distributors and OPG, as well as to electric T&D, but uses the DLTDR as a proxy or a ceiling for electric T&D utilities. The OEB currently sets the DLTDR equal to the Long Canada Bond Forecast (LCBF) obtained from Consensus forecasts plus the average Canadian A-rated utility yield spread, which is estimated as the average from the September preceding the test year. The LCBF is estimated by using the average of the 3-month and 12-month 10-year Government of Canada bond yield forecasts, and adding to this forecast the average of the actual observed spreads between 10-year and 30-year Government of Canada bond yields for each business day in the month of the Consensus Forecasts that are used (usually September).

The approach is sound, and **my recommendation is similar to that of LEI, with two minor qualifications:**

6) The existing approach is appropriate, but I have some suggestions discussed in response to Issue #7 that will improve its application (i.e., improve the accuracy of the forecasts) and enhance the ease of application (i.e., reduce the estimation requirements and potential issues with using poor estimates).

current estimates are based on samples that include 22 of 28 U.S. utilities, which are riskier than Canadian utilities (as demonstrated in in Appendix B of my evidence), and have historically had higher beta estimates (as demonstrated in in Appendix C of my evidence). Finally, LEI's MRP estimates do not consider current market conditions or investor expectations regarding future market returns (or MRPs) in the U.S. (or Canada), but simply focuses on U.S. historical evidence during relatively short time periods that reflect above average historical MRPs, and which triple weights the most recent period, thus providing a totally inflated and unrealistic MRP estimate that implies expected future long-term stock returns of 11.5%. These estimates are inconsistent with the practice employed by investment professionals (as reflected in the Kroll MRP estimates since 2008 of between 5 and 6%), and of using an MRP within the 4-6% range (which is the norm) in the CAPM, as discussed in Section 5.2 of my evidence.

Transaction Costs and the Cost of Equity:

LEI states on page 122 of its evidence that:

> As with LEI's recommendation for the treatment of transaction costs from debt issuances, LEI recommends considering the transaction costs associated with equity issuances as operating costs for similar reasons. Equity issuances do not happen with predictable regularity, which makes it more suitable to recover such costs as and when the utility incurs expenses.

Similar to my response regarding debt financing transaction costs provided in Section 3.8, I believe the current practice of adding 0.5% to Ke estimates seems reasonable, since it embeds the actual costs of equity financing related to new equity issues into the cost of equity, as they should be. The fact that most companies (utilities and other businesses alike) do not frequently engage in new equity issues does not detract from the fact that such issuing costs have a legitimate impact on their actual long-term equity financing costs when they do occur. As such, I believe the OEB's current practice of adding 0.5% to Ke estimates is a reasonable compromise, contrary to LEI's suggestion that these costs be included in operating costs.

My Base ROE Analysis and Recommendations:

Context:

I would note that my base ROE analysis is built upon my analysis of current and expected macroeconomic and capital market conditions that is presented in Section 4 of my evidence.

for the typical regulated Ontario utility, which are reported in Section 5.2.5 in Table 9 of my evidence, which I replicate below. Based on these calculations my CAPM analysis suggests an ROE of **6.05%**.

Estimate	**RF (%)**	**MRP (%)**	**Beta**	**Spread Adjust. (%)**	**Financial Flex. (%)**	**Ke (%)**
CAPM Best Estimate	3.30	5.0	0.45	-0.001	0.50	**6.05%**

As mentioned above, the CAPM parameters used (i.e., RF of 3.30%, MRP of 5% and a negligible spread adjustment of -0.001%) imply a required return on the entire market of 8.3%, well above the long-term market return expectations of finance professionals of 6.1% provided in Table 8 of my evidence, while it is in line with the long-term real returns on Canadian stocks. It is also marginally above my best estimate of 7.5% for the long-term expected return on the market that I discuss later in my evidence.

DCF Estimates:

I obtain my final DCF approach Ke estimate based on application of the single-stage Dividend Discount Model (DDM) and a multi-stage version of the DDM called the H-Model, both of which are described in detail in Section 5.3 of my evidence. I rely solely on my Canadian utility sample for the reasons discussed above, but I do note that the results for my U.S. sample are virtually the same as those for the Canadian sample.

The Canadian sample Ke estimates obtained using the single-stage DDM lie in a range from 6.30% to 8.00%, and I use as my best estimate the average of four estimates, which is **6.91%** (before adding 0.5% flotation costs). This estimate is obtained using December 31, 2023 average and median dividend yields for the sample, as well as 7-year averages and medians, all of which range from 4.53% to 5.71%. It is also based on sustainable growth rate estimates ranging from 1.46% to 2.17%, and averaging 1.80%, which seems reasonable for mature low-risk, regulated utilities that should be expected to grow slower (but steadier) than average firms and overall GDP growth in the 3.3-4.3% range as discussed previously.

My H-Model Ke estimate for the Canadian sample is 6.88% (before flotation costs), which is virtually identical to my single-stage DDM estimate of 6.91%. Weighting these two DDM estimates equally gives me a final DCF estimate of 6.9%, or **7.4%** after adding 0.5% for flotation costs. I would note that the 6.9% estimate is only 0.5% below my overall DCF estimate for the market of 7.4% (as estimated in Section 5.3.2 of my evidence), so it seems slightly high for well below-average risk utilities relative to overall expected market returns.

Bond Yield plus Risk Premium (BYPRP) Estimates:

My third and final approach that I use to estimate Ke is the BYPRP approach, which adds a risk premium (generally in the 2-5% range) to the yield on a firm's outstanding publicly-traded long-term bonds. This risk premium is not to be confused with the market risk premium (or MRP) used in the CAPM, which represents the premium above government risk-free yields and expected overall stock market returns. The BYPRP approach is depicted below:

Ke = Company's Bond Yield + Company Risk Premium

This approach is more widely used by analysts and CFOs than DCF approaches; albeit not used as much as the CAPM. In particular, evidence suggests this approach is used by 43 percent of financial analysts and by over 50 percent of Canadian CFOs.

The intuition behind the approach is that we are able to use typical relationships between bond and stock markets, along with information that can be readily obtained from observable ***market-determined*** bond yields (which include yield spreads that can be viewed as debt financing *risk premiums*), to estimate the required rate of return on a firm's stock. In other words, since stocks are riskier than bonds, we know that investors will require a higher return to invest in a firm's stocks than its bonds. The riskier the company, the greater the difference between these two required returns (i.e., the greater the company-specific risk premium).

The first step in applying the BYPRP approach is to obtain an estimate of the cost of long-term yields on a typical utility. As of June 5, 2024 the yield on long-term A-rated Canadian utility bonds was 4.68% according to the Bloomberg data provided in Figure 3 of my evidence. This figure is close to the average yield of 4.78% on bonds outstanding for five Canadian utilities as of June 6, 2024, as reported in Section 5.4 of my evidence. This evidence implies that 4.7% is a reasonable starting point for my BYPRP estimate.

We now need to determine the appropriate risk premium to add to this. As mentioned, the usual range is 2-5%, with 3.5% being commonly used for average risk companies, and lower values for less risky companies. Given the low risk nature of Canadian regulated utilities, a low risk premium is appropriate, suggesting the use of a 2-3% range, with a best estimate of 2.5%.[16] Combining this information, I obtain the following estimate for Ke according to this approach:

Ke = 4.7 + 2.5 = 7.2%

If we add 50 bp for flotation costs, we end up with a Ke estimate **7.7%**. This is on the high side given my long-term expected market return estimate of 8% (if we add 0.50% to my raw market estimate of 7.5%). It is also well above my CAPM estimate of 6.1% and 30 bp above my DCF estimate of 7.4%.

Final Ke Estimate:

I weight all three of my Ke estimates equally, as I have done in all my previous evidence, because all three methods are used in practice and provide different perspectives on Ke. As discussed previously, CAPM is more heavily relied upon in practice due to its conceptual advantages. For example, previous studies (referenced in Section 5 of my evidence) indicate with respect to the DCF approaches to estimating Ke, they were used by:

- only 15% of U.S. CFOs - versus over 70% for CAPM;
- about 12% of Canadian CFOs - versus close to 40% for CAPM.
- Not widely used, while CAPM was used by the majority of investors.

CAPM is also very intuitive from the point of view of a utility cost of capital hearing. In particular, it has a direct relationship to financing costs (i.e., RF and MRP). The CAPM also makes a direct adjustment for the risk of utilities relative to the market, unlike DCF models, since it has a direct measure of risk (i.e., beta) included in the model. In addition, there are data uncertainties associated with determining some of DCF input estimates for pure play regulated Canadian industries, since most of them are not publicly listed. The BYPRP approach is much more widely used than DCF approaches due to its intuitive nature, and because it adjusts for market-determined borrowing rates and risk. In fact the BYPRP approach is more widely used than CAPM by Canadian CFOs, as mentioned above. Thus the BYPRP approach accounts for interactions between market-determined company debt costs and equity markets, and as such it is intuitively sound.

[16] For example, Attachment AH provides an example of implementing the BYPRP approach for IBM from the CFA curriculum, where a risk premium of 2.75% is added to cost of IBM's debt. Clearly IBM (at that time) is riskier than an Ontario regulated A-rated operating utility, so 2.5% is very reasonable by comparison.

maintain the status quo, subject to any concerns regarding mitigation of significant resulting rate impacts.

My recommendation is in agreement with that of LEI:

18) I support the status quo.

3.19 Mechanics of implementation – approach for updating cost of capital parameters and/or capital structure for utilities in the middle of an approved rate term

Issue 19: Should changes in the cost of capital parameters and/or capital structure arising out of this proceeding (if any) be implemented for utilities that are in the middle of an approved rate term, and if so, how?

The OEB currently applies any changes to cost of capital parameters and capital structure upon rebasing applications, with the changes not being applied in the middle of an approved rate term. This approach seems reasonable to me. In addition, I also support LEI's recommended addition to this policy, as summarized on page 163 of its evidence: "However, to ensure the FRS continues to be met, the OEB should also introduce an option for parties to request implementation of such changes prior to rebasing, so long as the two-factor test is met – (i) the utility should have more than 60% of its rate term remaining, and (ii) deviations in the cost of capital parameters should be material (100 bps or more)."

My recommendation is in agreement with that of LEI:

19) I support maintaining the current OEB approach, but also incorporating the additional option recommended by LEI.

3.20 Prescribed interest rates – appropriateness of existing methodology

Issue 20: Should the prescribed interest rates applicable to DVAs and the construction work in progress (CWIP) account for electricity transmitters, electricity distributors, natural gas utilities, and OPG continue to be calculated using the current approach?

Currently, the OEB sets the prescribed interest rate for CWIP equal to the FTSE Canada (formerly DEX) Mid Term Bond Index All Corporate yield, which it applies to all projects under construction, regardless of duration of the construction period. I support continuing this policy, as does LEI.

The OEB's existing policy with respect to estimating prescribed interest rates for DVAs is to apply its estimate of the 3-month actual BA rate at the end of the month that is one month prior to the start of the quarter, plus a 25 bps fixed spread. As discussed in response to Issues #4 and #5, the use of the BA rate plus a spread is no longer appropriate since the BA rate will no longer be available, and Canadian banks are transitioning (and/or have already transitioned) to short-term debt products that are based on CORRA.

My recommendation, which is consistent with LEI's, is:

> 20) – Maintain the current approach regarding estimating the prescribed interest rate for CWIP.
>
> - Modify the existing practice for DVAs, as discussed in response to Issue #21.

3.21 Prescribed interest rates – recommended changes to existing methodology

Issue 21: If no to Issue #20, how should the prescribed interest rates applicable to DVAs and the CWIP account be calculated?

As discussed in response to Issue #20, the application of the BA rate plus a spread is no longer appropriate since the BA rate will no longer be available. As a result, similar to LEI's recommendation, I suggest this approach be revised to align with the DSTDR methodology recommended in response to Issue #5.

My recommendation, which is consistent with LEI's, is:

> 21) The prescribed interest rate for DVAs should be revised to align with the recommended DSTDR methodology by using CORRA as the base rate instead of the BA Rate, where the base CORRA rate is estimated as the average of 3-month CORRA futures rates over the next 12 months, and the spread added to it is determined by sampling 6-10 banks to determine the appropriate R1-low rated utility spread.

While I do not focus on the U.S. evidence, it is noteworthy that the average expected market return for U.S. stocks is 6.84% - well below its average of the last few decades. This is important to recognize, as it indicates that expected market return (and related MRP) forecasts that rely heavily on recent U.S. stock returns (such as that done by LEI which uses historical averages from five recent U.S. time periods in estimating potential MRPs), will be overly optimistic. In fact, it is well-known that the U.S. stock market has experienced exceptional returns over the last few decades, producing abnormally high real returns relative to its longer term history, and relative to global equity returns in other markets. I have attached an article as Attachment AD, which expands on this matter. The authors note that: "The real return on U.S. stocks from 1950 through 2023 was 7.63 per cent, and 7.16 per cent for the 20 years ending December 31, 2023. A real return above 7 per cent is exceptional even for the U.S. market. From 1900 through 1950, U.S. stock returned a real annualized 5.57 per cent." They further note that "Global real stock returns from 1900 through 2023 were 5.16 per cent annualized" (based on analysis of 38 developed markets). Putting this in perspective, they note that: "The often cited 10-per-cent return for stocks based on the post-1950 period is roughly equivalent to a 7-per-cent real return in the historical data. That is about 2 per cent higher than unbiased estimates of U.S. expected returns, U.S. equity returns before 1950 and global stock returns spanning 1890 through 2023." Similar to the U.S. stock returns forecast by investment professionals reported in Table 8, the authors expect future real returns for U.S. stocks in the 4.25% range, and combine this with 2.5% expected inflation to arrive at an expected U.S. stock market return of 7.24%, much more in line with the nominal forecasts provided in Table 8.

I believe that both historical returns and current expectations of market professionals represent the <u>best</u> sources of information regarding future long-term market returns. Combining the historical results and market forecasts for Canada that are presented in Table 7 and discussed above suggests a range of estimates in the 4.0% to 9.3% range, and the mid-point between historical averages (when adjusted to nominal terms) of 8.5% and the forecast average of investment professionals which is 6.1%, of 7.3%. This is consistent with my usual recent assumptions that an appropriate range for expected long-term Canadian stock market returns is 6-9%, and that the mid-point of **7.5% represents an appropriate point estimate**.[42] This is

[42] This estimate of 7.5% for future expected Canadian market returns is reflective of my analysis of historical market returns and forecasts for future returns from investment professionals discussed above. Attachment BC

well above the consensus view of financial professionals of 6.1% that is estimated in the bottom portion of Table 7, but below historical averages, so it seems reasonable. It is important to recognize that this expected market return of **7.5%** represents an **upper bound** for the cost of equity to regulated utilities (before adding 0.50% for flotation costs), since they are less risky than the average company in the market. This aligns well with my DCF estimate for the market of 7.40% (in Section 5.2.2), but is below my implied CAPM estimate for the market of 8.3% (discussed later in this section).

Figure 11 shows that the world market MRP, as measured by the return on the market less the long-term government bond yield over the 1900-to-2015 period, provided an arithmetic average of 4.1% (geometric mean of 3.2%). These means are lower than the corresponding U.S. figures (5.8% and 4.4%) and slightly below the Canadian figures (4.2% and 3.3%) over that period. The figures for Canada are in line with the differences between the average (and geometric mean) returns for Canadian stock and bond returns over the 1938 to 2023 period, which were 4.97% (4.16%) as previously reported in Table 6. These numbers are also consistent with expected MRPs according to a recent survey of analysts, companies, and finance professors, which were in the 5 to 6% range for most regions. The results for Canada and the U.S. are reported in Figure 12, with 2024 figures of **5.2%** and 5.5% respectively.

provides a July 3, 2024 article (published after I had made this estimate) discussing the iShare S&P/TSX 60 Index ETF (XIU). The article confirms the reasonableness of my estimate, suggesting that: “The average annual total return since inception for XIU is 7.6 per cent. If you invest in big Canadian companies, that’s your benchmark for measuring returns over periods of 10 years and longer.”

EB-2024-0063 Interrogatory Responses

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO/INDUSTRIAL GAS USERS ASSOCIATION (Dr. Sean Cleary)

Answer to Interrogatory from Ontario Energy Association (OEA)

Reference:

Exhibit M4
Page 43, lines 17-19

Preamble:

Based on an equal weighting of the three approaches, I determine the following best estimate for allowed Ontario utility ROEs:

$$Ke = (1/3)(6.05) + (1/3)(7.4) + (1/3)(7.7) = \mathbf{7.05\%}$$

Questions:

a. How does Dr. Cleary's base ROE recommendation of 7.05% for Ontario's utilities compare to the average authorized ROE for other Canadian electric and gas utilities in 2024?
b. Please confirm that Dr. Cleary's base ROE recommendation of 7.05% for Ontario's utilities is 145 basis points lower than the lowest authorized ROE for any other investor-owned electric or gas utility in Canada (i.e., Newfoundland Power has an authorized ROE of 8.50% on a common equity ratio of 45.0% and currently has a General Rate Application pending before its regulator in which Newfoundland Power is requesting an increase in its authorized ROE to 9.85%).
c. Please explain why Dr. Cleary recommends an equal weighting of the results of the CAPM, DCF and Risk Premium models if his research indicates that the CAPM is more heavily relied upon and the DCF model is not widely used.
d. Has Dr. Cleary performed any analysis of how the credit outlooks, metrics and ratings of Ontario's utilities would be impacted if the OEB were to adopt his recommended base ROE of 7.05% and his proposed reductions in the equity ratio for Hydro One Inc. and Enbridge Gas? If so, please provide that analysis. If not, what is the basis for Dr. Cleary's conclusion that his cost of capital recommendations would satisfy the Fair Return Standard?
e. What is Dr. Cleary's understanding of the concept of gradualism?
f. Please explain how Ontario's utilities can compete for capital with other comparable-risk investments if the authorized ROE and deemed equity ratios for Ontario's utilities are well below the average for their North American peers in Canada and the U.S.

Responses:

a. Dr. Cleary has not conducted such an analysis, but according to Figure 27 (page 80) of Concentric's evidence, the Canadian utility average allowed ROE is 9.16% (electricity) and 9.23% (gas).

b. A base ROE of 7.05% as recommended by Dr. Cleary for Ontario's utilities would be 145 basis points lower than the 8.5% that the question indicates is the authorized ROE for Newfoundland Power (NP). Dr. Cleary has not investigated whether 8.5% is the lowest authorized ROE in Canada, though he is not aware of a lower one.

   The status of NP's GRA and its requests therein is not something that Dr. Cleary can confirm, nor of course what the outcome of that GRA and those requests will be. Dr. Clary does note that, according to Figure 27 (page 80) of Concentric's evidence in this case, the current allowed ROE and ER for NP are 8.5% and 45% respectively.

   Dr. Cleary also notes that Concentric's ROE recommendation in this case of 10.1% is 1.6% higher than 8.5%.

c. Please see response to M4-17-OEB Staff-62(a).

d. Dr. Cleary has not prepared such an analysis, nor is Dr. Cleary aware of any such analysis performed by Concentric or the other experts that have provided evidence in this proceeding to support their allowed ROE and ER recommendations. Credit ratings and outlooks are prepared by credit rating agencies, and Dr. Cleary would not prepare such analyses in his work. Dr. Cleary has not prepared an analysis of how his recommendations, nor those of the other experts providing their recommendations in this proceeding, would impact the credit metrics of each of Ontario's dozens of regulated utilities, though he would agree that such analysis would support, in any particular case, determination of an appropriate allowed ROE and ER that would satisfy, but not exceed, the Fair Return Standard.

e. To change things gradually, as opposed to suddenly or abruptly.

f. The argument that Ontario (and Canadian) utilities need to increase their allowed ROEs and ERs to align with U.S. utilities in order to attract capital has been argued consistently by (exclusively U.S.-based) utilities' experts during every Canadian cost of capital proceeding that Dr. Cleary has been involved in. The fact is that despite these consistent assertions, none of the experts have provided evidence that Canadian utilities have had any issues attracting capital at reasonable terms through the years or currently, and in most cases Canadian utilities have done so at lower rates than their riskier U.S. counterparts (e.g., according to bond yield spreads, etc.).

The approach of simply comparing the allowed ratios for Ontario (and Canadian) utilities to average awarded ratios at various times in the past in the U.S. is simply flawed by design. Such an approach ignores the more relevant current market conditions facing Ontario utilities at a given point in time. Lt also ignores the simple and obvious fact that Ontario (and Canadian) utilities successfully compete for capital now, and have consistently done so in the past, against companies in other industries and jurisdictions with higher ROEs and ERs.

Dr. Cleary's recommendations are based on his expert, market-based and objective analysis, upon which he determined that Ontario utilities would continue to attract capital based on these recommendations and in the circumstances and given the risk profiles relevant to them. In contrast, the utilities' experts do not provide evidence that allowed ROEs and ERs need to be increased substantially so that Ontario utilities can continue to attract capital at attractive terms, as they currently do and have for quite some time.

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO/INDUSTRIAL GAS USERS ASSOCIATION (Dr. Sean Cleary)

Answer to Interrogatory from Ontario Energy Board Staff (OEB Staff)

Reference:

Dr. Cleary Report, pp. 21, 22, 55

Preamble:

Dr. Cleary noted that his recommendation is similar to that of LEI, with two minor qualifications, and agreed that the CORRA should be used to replace the BA rate in the DSTDR methodology.

- LEI recommended extending the current practice of sampling 6 big banks to estimate the spread to a larger sample of 6-10 banks. He is fine with this suggestion, assuming that it does not lead to including less reliable estimates (i.e., from the smaller banks), nor adds unnecessary complexity to the survey process.
- LEI recommended estimating the base CORRA based on the average of 3-month CORRA futures rates over the next 12 months. Since the CORRA is linked directly to the Bank of Canada's rate decisions, he is fine with this suggestion; although, he would also be fine with using the existing CORRA rate as of September 30th of each year as the base CORRA rate.

Dr. Cleary stated that the current annual review process can be supplemented by adding annual reporting requirements for utilities regarding new short-term and long-term debt and equity issued/borrowed during the year.

OEB staff notes that Bloomberg publishes the following ticker each business day, related to Canadian utilities:

BVCAUA3M BVLI Index	CAD Canada Utilities A+ A A- BVAL Yield Curve 3 Month

Questions:

a) Instead of using the average of 3-month CORRA futures rates for the next 12-month period, plus conducting a confidential bank survey, what are Dr. Cleary's views on instead using the Bloomberg BVCAUA3M BVLI Index (3-month) for the DSTDR and the prescribed interest rates for DVAs, which has a spread already built in?

b) Does Dr. Cleary have any alternative views on how to derive an appropriate DSTDR and prescribed interest rate for DVAs (including an appropriate spread), without conducting bank surveys or collecting actual short-term loan data from utilities? If so, please elaborate.

c) What are Dr. Cleary's views as to whether the short-term loan data underlying the calculations should reflect three-month loans or one-year loans?

d) LEI stated on page 80 of its report that "since CORRA is an overnight risk-free rate, it has historically been slightly lower than the 3-month CDOR. Based on a Bloomberg analysis, the official recommendations from CARR suggest adding 32.138 bps to CORRA to be comparable with the 3-month CDOR. Consequently, the spreads associated with CORRA will be different from the spreads over the 3-month BA rate/CDOR."

   Does Dr. Cleary agree that if bank survey spreads over the 3-month CORRA futures rates are obtained, then the 32.138 bps would not need to be added to the rate applied to the DSTDR or prescribed interest rates? If not, please explain what spread would need to be added.

e) To obtain the average of 3-month CORRA futures rates for the next 12-month period, does Dr. Cleary agree that the data would be obtained from the following website, using settlement price data as of September 30, 2024, and derived by selecting "Futures", then "CRA"? If this is not the case, please explain.

   https://www.m-x.ca/en/trading/data/historical

Responses:

(a) Either approach would be acceptable. Given that the Bloomberg BVCAUA3M BVLI Index (3-month) already has a spread built into it that does not require surveys or estimates, it would be administratively easier to implement, so this approach makes the most sense. As discussed in the evidence, Dr. Cleary would recommend the use of the Index "point" estimate as of the end of September, rather than using averages over the previous month or longer periods, in order to provide the most accurate estimate of future rates beyond the end of September.

(b) Dr. Cleary has not considered alternative approaches, and as discussed in response to (a), he supports the use of the Bloomberg 3-month index.

(c) Three-month loans would be more appropriate, as typically the financing arranged by firms has rates that are tied to a shorter-term rate (i.e., such as banks' prime lending rate, in the case of operating lines of credit).

(d) If the survey is based on "3-month" CORRA futures rates, then there would be no need to add a spread.

(e) Agreed.

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO/INDUSTRIAL GAS USERS ASSOCIATION (Dr. Sean Cleary)

Answer to Interrogatory from Ontario Energy Board Staff (OEB Staff)

Reference:

EB-2024-0063, OEB Letter and Accounting Order, July 26, 2024

Preamble:

On July 26, 2024, the OEB issued a letter regarding prescribed DVA interest rates and the DSTDR.

The purpose of this letter was to provide an update regarding the calculations of the above-noted prescribed interest rates for DVAs and the DSTDR, given that the three-month bankers' acceptances that underpin these calculations have been phased-out.

The OEB stated that it will set the prescribed DVA interest rates for 2024 Q4 and 2025 Q1 on a final basis, using the Canada three-month T-bill rates at the time plus a 25 basis point spread. The DVA interest rates are expected to be issued by the OEB in mid-September 2024 and mid-December 2024, respectively. The final rate will be the three- month Canada T-bill rate as at August 30, 2024 (for the 2024 Q4 DVA rate) and November 29, 2024 (for the 2025 Q1 DVA rate), plus a fixed spread of 25 basis points.

The OEB also stated that in October 2024, the DSTDR will be set by the OEB, on an interim basis for those utilities rebasing for 2025 rates, using the average of the three-month Canada T-bill rate for each business day in September 2024.[1] The bank survey from September 2023 (the prior year) will be used as the average annual spread. No bank survey will be conducted in September 2024.

The OEB also approved the establishment of a generic variance account to capture certain revenue requirement impacts related to the DSTDR.

Questions:

a) Please provide Dr. Cleary's views on the OEB's approach outlined in the OEB's July 26, 2024 OEB Letter and Accounting Order, but only related to what could be used going forward, specifically using the three-month Canada T-bill rate to calculate:

[1] The DSTDR will apply to those utilities rebasing for 2025 rates, but with a decision expected in advance of the OEB's decision in the cost of capital generic proceeding.

i. Prescribed DVA interest rates for 2025 Q2 and forward, plus a 25 basis point spread
ii. The DSTDR for 2026 and forward, plus a spread using a bank survey

b) Given the elimination of the bankers' acceptance rates, does Dr. Cleary's viewpoint still remain that the CORRA rate should be used, or alternatively, please elaborate on a different methodology that should be used.

Responses:

(a) Dr. Cleary supports the approach as described above, but as discussed in his evidence, Dr. Cleary would recommend the use of the T-bill rate and "spread" point estimates as of the end of September, rather than using averages over the previous month or longer periods, in order to provide the most accurate estimate of future T-bill rates and spreads beyond the end of September.

(b) As discussed in response to Staff 58, part (a), Dr. Cleary feels that using the CORRA rate (as recommended by LEI), or using the Bloomberg BVCAUA3M BVLI Index (3-month) would be acceptable. But since the Index approach already has a spread built into it that does not require surveys or estimates, it would be administratively easier to implement, the Bloomberg Index approach makes the most sense.

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO/INDUSTRIAL GAS USERS ASSOCIATION (Dr. Sean Cleary)

Answer to Interrogatory from Ontario Energy Board Staff (OEB Staff)

Note this interrogatory has been asked by LEI

Reference:

Dr. Sean Cleary Report, p.33

Preamble:

Dr. Cleary stated the following:

Recognizing that four of the five Canadian utilities included in that sample are holding companies that operate in several jurisdictions that are riskier than Ontario (and Canada in general), and that also hold significant proportions of unregulated assets, it is interesting to note that the sole publicly-listed regulated operating Canadian utility (Hydro One) had a P/B ratio of 2.04 as of the end of 2023. It is further interesting to note that the average P/B ratio for the U.S. sample was greater than the Canadian average every year, ranging from 1.69 to 2.36 and averaging 2.05 over the 2017-2023 period. This is consistent with evidence provided in Section 5.1 of my evidence discussed above that shows that allowed ROEs in the U.S. are even more upward biased than those in Canada… In addition, there are data uncertainties associated with determining some of DCF input estimates for pure play regulated Canadian industries, since most of them are not publicly listed.

Questions:

a) If four of the five publicly traded Canadian utilities in Dr. Cleary's sample are holding companies that operate in several jurisdictions (mainly in the US and Canada), would Dr. Cleary consider it prudent to consider a larger sample size comprising similar US and Canadian utilities, allowing for a more reasonable representation of investor expectations? If Dr. Cleary disagrees, please explain.

b) Please confirm that the P/B ratio for the broader market over the last five years (such as the S&P 500 index) was 4.94 (Source: Bloomberg), and P/B ratios ranging from 1.69 to 2.36 are well within the range of normalcy. If Dr. Cleary disagrees, please explain.

Responses:

(a) It would be preferable to have a larger sample of Canadian utilities. However, it is not helpful to have a larger sample that does not include representative comparators, which is the focus of establishing proxy groups. Comparing applies to more oranges doesn't help. As demonstrated in Appendix B of Der. Cleary's evidence, U.S. utilities possess higher business risk than their Canadian counterparts. This higher risk is further reflected in Appendix C of Dr. Cleary's evidence which shows that over a long period of time (more than 25 years), U.S. utility beta estimate historical averages are much, much higher than (almost double) the comparable Canadian beta estimates, and that this difference is even more pronounced after accounting for the higher leverage of Canadian utilities. This longer-term evidence is further supported by Table 8 of Dr. Cleary's evidence, which shows that both monthly and weekly beta estimates as of December 31, 2023, and estimates based on the 2017-2023 average estimates for U.S. utilities are **higher** than the comparable Canadian utility beta estimates. Similarly, Figure 16 of Concentric's evidence shows that beta estimates for U.S. utilities are higher than the comparable Canadian utility beta estimates.

(b) Dr. Cleary can neither confirm nor dispute the P/B ratio reported for the S&P 500 Index provided above. Note, however, that the appropriate comparator would be the P/B ratio for the Canadian market, which would likely be much lower than for the S&P500 Index. Section 5.1.2 of Dr. Cleary's evidence notes a June 5, 2024 P/E ratio for the S&P 500 Index of 23.5, versus for the S&P/TSX Index of 15.7. Such high relative valuations for the S&P 500 are consistent with the recently abnormally high U.S. stock returns as discussed in Dr. Cleary's evidence, and in response M4-10-OEB Staff-64, part (d).

P/B ratios for broad market indices (which includes all companies in all industries) have traditionally been above 2 for the Canadian market. However, this average is based upon the inclusion of predominantly non-regulated companies operating in numerous industries that do not operate regulated effective monopolies. As such, these companies operate in riskier and more competitive markets, place their invested capital at significantly greater risk than regulated monopolies, and therefore it is expected that the "survivors" in such industries would earn excessive economic rents (at least until competitive pressures kick in). In contrast, regulated operating utilities serve a vital role for society, and as such they are regulated to ensure they earn a fair and adequate (but not excessive) return for serving this function. Regulated with this in mind, a fair but not excessive return should dictate they would have P/B ratios approximately equal to one. P/B ratios well above one indicate they are earning excess economic rent (as discussed in greater detail in Section 5.5 of Dr. Cleary's evidence).

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO/INDUSTRIAL GAS USERS ASSOCIATION (Dr. Sean Cleary)

Answer to Interrogatory from Consumers Council of Canada (CCC)

Reference:

Ex. M4/pp. 35, 46, 76

Preamble:

(Page 35) Allowed ROEs in Canada have not declined in line with reductions in government and utility bond yields, and hence are providing Ontario (and other Canadian and U.S.) utilities "excess compensation" in terms of allowed ROEs relative to their actual market-determined cost of equity.

(Page 46) I recommend an adjustment factor of 0.75 for both factors, which maintains the relationship, is more responsive to changing market conditions, and will still reduce year-to-year fluctuations in allowed ROEs relative to a weighting of 1.0.

(Page 76) A large part of this can be explained by the fact that allowed ROEs "tend to exhibit considerable stickiness around focal 'odometer' points." Consistent with the evidence for Ontario and Alberta discussed above, the authors note that "awarded ROE spreads over risk free treasuries have progressively *widened* significantly since 2005, even though systematic risk in the utilities industry has *fallen continuously* during the same time period."

Questions:

a) Please further discuss why ROEs have not declined in line with government and utility bond yields. Is this related to the fact that, under the current ROE formulaic annual update, only a portion of the change in bond yields are passed through to the allowed ROE? Are there other reasons?

b) Please provide your view on applying no adjustment factor (i.e., passing through the entirety of changes to bond yields) in the ROE annual update formula. Is there a reason that you prefer to reduce the impact of annual changes in bond yields on the allowed ROE (i.e., 0.75 adjustment factor)?

c) Please further comment on the reasons for the cited "stickiness" of ROEs. As part of the response, please discuss whether regulators' general inclination to benchmark against other regulators, is part of the reason for that stickiness

Responses:

a) This is the result of several factors. As discussed in Section 5.1 of Exhibit M4, the downward "stickiness" in awarded ROEs is not unique to Ontario but can be observed in other Canadian jurisdictions, and is even more prevalent in the U.S., which is evidenced in the results of a 2017 study that examines "a dozen years' of gas and electric rate-setting decisions" in the U.S. and Canada over the 2005-2016 period.[1] This study provides evidence "demonstrating empirically that allowed returns on equity diverge significantly and systematically from the predictions of accepted asset pricing methodologies in finance." A large part of this can be explained by the fact that allowed ROEs (bold added for emphasis) "tend to **exhibit considerable stickiness around focal 'odometer' points**." Consistent with the evidence for Ontario and Alberta discussed above, the authors note that "awarded ROE spreads over risk free treasuries have progressively *widened* significantly since 2005." While Section 5.1 of Dr. Cleary's evidence shows that this "widening" of spreads over risk-free rates and utility bond yields would have not been as dramatic if the adjustment factors in the OEB formula were increased from 0.5 to 0.75, the spreads would still have occurred. One reason is the consistent references to awarded ROEs in other jurisdictions, which may not have declined in response to decreases in utility costs of capital. This in turn produces circular reasoning that they have to remain high in order to remain consistent with other jurisdictions, as well as with previous levels.

b) The recommended adjustment factor of 0.75 for both factors maintains the relationship, but is more responsive to changing market conditions than using a 0.5 adjustment. Further an adjustment factor of 0.75 will still reduce year-to-year fluctuations in allowed ROEs relative to a weighting of 1.0.

c) Please see response to part (a).

[1] Source: "The Utility of Finance," S. Azgad-Tromer and E. Talley, Working Paper, Columbia University (https://papers.ssrn.com/sol3/papers.cfm?abstract_id=2994314).

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO/INDUSTRIAL GAS USERS ASSOCIATION (Dr. Sean Cleary)

Answer to Interrogatory from Consumers Council of Canada (CCC)

Reference:

Ex. M4/pp. 117-118

Question:

In the context that regulated electric utilities are allowed to recover prudently incurred costs, please provide your views on whether increased spending in response to climate change/electrification increases or decreases risk. As part of this response, please discuss whether long-term significant growth in approved rate base, which provides for larger returns on an absolute basis, increases or decreases risk for electricity utilities.

Response:

An expected increase in demand represents a growth opportunity for utilities and is a situation that most companies would happily embrace – far preferable to a forecast decrease in demand for their product. This is particularly true when the companies have the opportunity to adequately plan for such increases in demand, and can pass through legitimate costs to consumers (as is the case for regulated operating utilities).

Aside from operational considerations, such an expected growth opportunity (i.e., to earn higher revenues and income), would only be considered a significant risk if Ontario utilities faced issues in attracting capital on reasonable terms to finance this growth. This seems inconsistent with evidence that shows that for example the largest Ontario T&D utility (Hydro One Inc.), which clearly faces such a well-known expected future increase in demand, maintains credit ratings of A (Stable) by S&P, A(High) by DBRS Morningstar and A3 by Moody’s, issues bonds at yields that are at the lower end of those for similar Canadian operating utilities, and while Hydro One Ltd’s stock traded at a price-to-book ratio of 2.04 at the end of 2023 (well above the Canadian utility average of 1.45 at that time).

ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO/INDUSTRIAL GAS USERS ASSOCIATION (Dr. Sean Cleary)

Answer to Interrogatory from Vulnerable Energy Consumers Coalition (VECC)

Reference:

Exhibit M4, pages 36 and 95

Preamble:

The Report states:

"*Similar to my response regarding debt financing transaction costs provided in Section 3.8, I believe the current practice of adding 0.5% to Ke estimates seems reasonable, since it embeds the actual costs of equity financing related to new equity issues into the cost of equity, as they should be*." (page 36)

And

"*Finally, I add 50 bp for financial flexibility (or flotation costs), consistent with previous OEB practice, and consistent with long-term estimates*." (page 95)

Questions:

20.1 Is financial flexibility the same as flotation costs?

20.1.1 If not, please explain the difference and how the 50 bp accounts for both.

Responses:

Yes. Financial flexibility is equivalent to flotation costs.

Expert Report on the Cost of Capital and Certain Accounting Issues EB-2024-0063

Presentation Day Comments

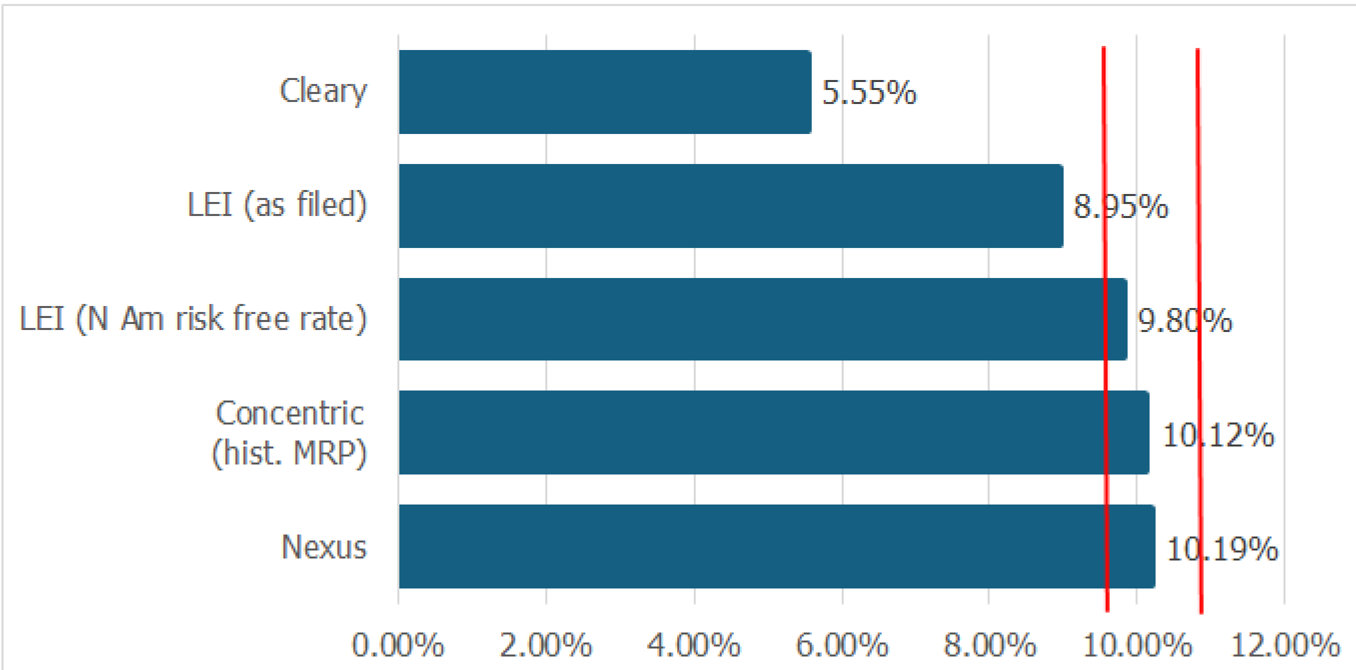
September 5, 2024

Francis X. Pampush, PhD, CFA
Ralph Zarumba, MA

Nexus Economics

Most CAPM Results are Similar
(excludes flotation costs)

- LEI would fit in confidence interval **if** the US risk-free rate of 4.06% were used (producing 9.80%) instead of the 3.19% Canadian rate (producing 8.95%)
- Three CAPM results are within Nexus' 95% confidence interval



For Canadian electric utilities, Dr. Cleary's 5.55% CAPM result (ex. flotation) offers the investor about <u>the same rate as a</u> Moody's Baa bond (5.56% as of 8/30/2024). The unreasonableness is self-evident.

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2024-0063**	**Generic Proceeding - Cost of Capital and Other Matters**

VOLUME:	**Presentation Day**	
DATE:	**September 5, 2024**	
BEFORE:	**Michael Janigan**	**Presiding Commissioner**
	Lynne Anderson	**Commissioner**
	Pankaj Sardana	**Commissioner**

LCBF and utility spread factors, how to estimate them, the adjustment factors, and then a little bit in conclusion on allowed equity ratios.

So, if we could go to the next slide. And I think most people involved in these proceedings would agree that, and certainly every proceeding I've been involved in, that the market as a whole, regulated operating utilities are less risky than the market as a whole. So, I think it's interesting with all the references to me being the outlier and whatnot that none of the other experts make any reference to their expected market return and how their recommendations stack up with real market data. I provide some evidence showing, you know, experts managing tens of trillions of dollars, over 25 of them predict about 6.1 percent over the next 5 to 10 years. Historical evidence suggests about 8.5 percent if you take the real returns and add about 2 percent expected inflation, and I come in somewhere in the middle there about 7.5 percent.

So, if you turn to the next slide, you can see that if we consider that 7.5 percent of mine as the upper bound for what the required return on equity is for regulated operating utilities, my estimate comes in slightly below that, which is what you would expect if they're less risky than market, whereas the estimates of LEI, Concentric and Nexus are considerably higher than that. So, that, to me, suggests that they believe that regulated operating utilities in Ontario should be earning more than what market participants expect on the market going forward over the next 5 to 10 years.

So, if we go to the next slide, please, I'm going to talk a little bit about Concentric's and Nexus' recommendations in particular, and I guess the reason their estimates come in so high is they seem to be gravitating to the allowed ROEs particularly in the U.S. that are much higher than in Canada as I think we're all aware of by now, and, you know, somewhere in the nine-and-a half to 10 percent range. And there's heavy emphasis on that in their models with the various inputs and assumptions they make, which I'll discuss later, and upcoming into support them that they always kind of should be around what the U.S. allowed.

And in particular, if you look at Concentric's ER recommendations of 45 percent, it recommends that's to bring it in line with U.S. utilities when their own evidence even shows it's right in line with the Canadian utilities.

So, if we could actually just go to the next slide and I'll pick up on just a couple other points. Back to that 10 percent recommendation of 45 percent equity ratio recommendation by Concentric, that's higher than what they recommended for Newfoundland Power, you know, just 10 months ago. And even in those proceedings they noted several risks that Newfoundland Power faced due to its small size, due to its weak macro and demographic conditions and potential issues with future demand and slow potential growth, which is in contrast to they're arguing to recognize. Nobody is disputing the reliability of it or the fact that it's a legitimate model. Let's put it that way. You also see the average ROE spread was 4.6 percent. Now, in the bond yield plus risk premium that I use that's used widely by CFOs and financial analysts, it's in the CFA curriculum, that is at the upper end of that typical spread of 2 to 5 percent that you usually use with 3 being for an average risk utility, so that also indicates excess compensation.

Next slide, please. And finally, you know, this point, that means that if you're basing, as the OEB formula does, you're basing the cost of equity on two important factors that affect its cost of equity, government rates and the rates they can borrow at, A-rated utility yields, and those are both declined but the allowed ROE hasn't, then something is going wrong here. And it's not unique to Ontario. It's across Canada. It's even more prevalent in the U.S., and I cite a couple of studies there that note that. Okay?

If we just go to these hearings, and we refer to allowed ROEs in other jurisdictions, then it becomes a circular argument because if they haven't had a hearing and we are having one, they haven't lowered their ROE first. So, I recognize it's difficult to be the first to start to lower it, but the bottom line is that kind of resistance, you know -- what do you call it, inertia, if you will -- has led to the fact that they just gradually, through time, these costs -- these inputs into the cost of equity have declined, but the allowed ROEs have not declined in step.

So, one last point on this. And if you could turn to the next slide, please. Where are we seeing evidence that this is the case? And one of the things -- I look at the price-to-book ratio analysis in my analysis. I don't include the cost of equity estimates in my final estimate, but I look at it as a way to think, what does the market think is going on here?

And the fact that the -- you know, if the allowed ROE is exactly equal to their cost of equity, then the price-to-book ratio should be 1.0. Okay? It means it's allowing -- it's earning enough profit and it's earning zero economic profit, which means it's earning enough in accounting profit to account for its reinvestments and so on and so forth.

With it sitting at 1.45 for Canadian utilities and having averaged 1.65 over the recent seven-year period, that suggests there's some economic excess economic rent going on there.

And if you look at Hydro One, which is, as pointed out earlier, the mostly pure-play regulated operating utility, it was 2.04. And they are subject to the OEB formula and the allowed ROEs here. So it doesn't seem to suggest that the market thinks that they are earning too low an allowed ROE.

In the U.S., of course, we see a little bit higher, which is consistent with the allowed ROEs we see there, and the higher allowed equity ratio. Okay.

that make them less risky than the average company in the market that has to fight for demand, that doesn't get to pass on their costs to the consumers and so on and so forth. Right? But that's a big part and, you know, as to why, I think the betas are a little bit higher because of the holding company nature of them. You see that also in some of the Canadian holding companies. Enbridge Inc., I don't think, is a good one because it's too risky because they have some regulated, you know, operating utilities, low risk, like EGI. Right? But then they also have a lot of pipelines in a lot of U.S., so in some sense I would view that they use some of that stability from their cash cows with the lower risk and then they undertake more risky operations, which is their prerogative. Right? But then that means they're going to get lower debt ratings, you know, than some of their operating companies. I don't know. Sorry, long answer. I don't know if I answered your question or not.

MS. ANDERSON: One of the issues seems to be the inclusion of the flotation costs in the debt and your recommendation is to put it into the actual rate, but you also used the 0.5 and then we did hear that some people thinking that was a bit rich and I don't see that you have commented on the use of 0.5.

DR. CLEARY: Yes. Thanks. That's also a good question, because I thought about it a lot as I read the evidence. And LEI makes a good point that it is a little bit high because companies don't issue equity on a regular basis. They do issue debt on a more regular basis, although I think there was an IR response maybe even for the big ones, one to two times a year, you know, probably not more than that, in some years, none. Right? Now, the flotation costs on debt would be lower probably than 50 basis points. The flotation costs on equity would be higher. Right? You know, 1 to 2 percent depending on, you know, the market. Right?

So, if you recognize that they're going to issue the equity -- and remember the ROE is supposed to be the cost of equity. I think it's appropriate to include a cost in there, but I think if you use 2 percent, that would be kind of assuming they're issuing every year. Right? So, 50 basis points maybe is a reasonable compromise, and maybe also reflecting that you're maybe paying a little bit, maybe 20 bps on debt issues during the year, too. So that was my thinking on that, although I appreciate LEI's approach as well.

MS. ANDERSON: Okay. Thank you.

MR. JANIGAN: Yes, Dr. Cleary, I just have one question and it deals with energy transition. And energy transition has been cited as a possibility hazard in the future in the event that ROEs do not match the ability of utilities to raise the appropriate money to spend in that area. What is your opinion on that?

DR. CLEARY: Yes. Thank you. That's a great question because I did hear it come up this morning, so I kind of thought about it on my drive in here, and actually in

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2024-0063**	**Generic Proceeding - Cost of Capital and Other Matters**

VOLUME:	**3**	
DATE:	**September 27, 2024**	
BEFORE:	**Michael Janigan**	**Presiding Commissioner**
	Lynne Anderson	**Commissioner**
	Pankaj Sardana	**Commissioner**

MR. GARNER: So, there is no decision you are saying on that point? There is a settlement.

MR. COYNE: The settlement was the just and reasonable ROE for Florida Power and Light.

MR. GARNER: Fair enough.

MR. COYNE: 10.6 on a 59.6 percent equity ratio.

MR. GARNER: Well let me ask -- sir.

MR. COYNE: I don't recall that there was a, there was mention of the allowance for flotation costs in that number.

MR. GARNER: Let me ask you something in the common literature of this area, you know, Roger Moran type stuff, Khan, let's go back to the gospel of Bonbright. Is there some sort of thing where it says flotation costs should be integrated into a cost of capital calculation that you're aware of?

MR. COYNE: Yes, I think we cite that in our testimony citing from Dr. Roger Moran's book on utility regulatory finance. It's in our testimony.

MR. GARNER: Of him actually using a flotation cost as an adjustment to an ROE calculation?

MR. COYNE: Yes, yes. Let me just check with Dr. Trogonosky.

MR. GARNER: That's fine. While he is checking -- we can move on while he is checking, and then you can give me that.

MR. DANE: I am sorry, Mr. Garner, I might just --

MR. TROGONOSKI: OEB Staff-16, our response there we quote Dr. Moran on flotation costs.

MR. GARNER: And in that he is telling you that that's part of the adjustment?

MR. COYNE: Yes.

MR. GARNER: All right. Okay, thank you.

MR. DANE: And I was just going to add, Mr. Garner, that the concept of financial flexibility, while it might be reflected differently in certain jurisdictions, I don't think it's unique to Canada and --

MR. GARNER: Well, you are using the term financial flexibility. I am using and I am making a point that the BCUC has distinguished between those two concepts. I am talking about flotation costs. I am not talking about financial flexibility right now. Just so we are on the same page. So go on.

MR. DANE: No, I know. But your question asked about our reflection of flotation costs versus financial flexibility or our consideration of those. And so, I just wanted to elaborate on that. And so, the concept there, which I think is not unique to Canada, is that utilities have an obligation to serve and need to, you know, that incurs costs over time to do so and they don't have the luxury of waiting out a market, necessarily, to access financing. And so, that's the concept of the flexibility that allows them to access capital in all markets.

MR. GARNER: Right. But your talking about flexibility, right?

MR. DANE: That's the financial flexibility.

MR. GARNER: Right. Thank you, Mr. Dane. I am going to hand over the mic to my colleague, I think he wants to ask you a few more questions about flotation costs.

CROSS-EXAMINATION BY MR. HARPER

MR. HARPER: Actually -- sorry, pushing buttons on the mic at the same time. This had to do specifically with a follow-up to a discussion you had with Mr. Rubenstein this morning. And he was talking to you and was walking through you the equity that was on Hydro One's books for transmission and for distribution, and asking whether it was reasonable in your mind that it should all track to transaction cost. And I think you said yes, and what I wrote down here was part of your rationale was it got there somehow; that was the particular expression that I wrote down.

And I am no finance expert by any means; that's why you're here and I am here. But it just struck me that, when they say "the" there, it seems to me there are four ways that equity gets on a balance sheet. And you can correct me if I am wrong, if I go through it.

One is they issue shares, the company issues shares, in which case you can acknowledge there is going to be a transaction cost associated with that.

A second way of making it get on their balance sheet is there is accumulated net income left over every year, after they have paid out their dividends. Now I don't see there being much of a specific transaction cost associated with that part of the equity that's getting built up on a

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2024-0063**	**Generic Proceeding - Cost of Capital and Other Matters**

VOLUME:	**4**	
DATE:	**October 1, 2024**	
BEFORE:	**Michael Janigan**	**Presiding Commissioner**
	Lynne Anderson	**Commissioner**
	Pankaj Sardana	**Commissioner**

have a reasonable opportunity to earn their return. From what we can tell now that's not the case, and that is referencing a graphic in the LEI report.

MR. RUBY: Let's deal with just one last topic which is transaction costs, maybe dealing directly with the equity flotation costs. At a high level, can you just describe briefly what are the flotation costs for equity?

MR. ZARUMBA: Yes. What has generally been associated with transaction costs are the professional fees associated with issuing these equities, lawyers, accountants, rating agencies. However, that is not it, there are some other costs that are not as easily identifiable, such as the dilution effects of introducing these equities. Therefore, if you do account for these costs, essentially just as the professional fees, you would underestimate them.

MR. RUBY: Can you just describe for two seconds what you mean by dilution costs?

MR. ZARUMBA: Dilution costs are essentially when you issue equity, you have the existing shareholders that then have less because of the fact that you have added more shareholders, so you basically have a numerator that is at one level but the denominator has gotten larger so the result has become smaller.

MR. RUBY: So, are flotation costs for equity reimbursed in the ROE for actual costs incurred or something else?

MR. ZARUMBA: No, they are essentially incurred and essentially become a permanent part of the utility capital structure. But it's not that they are amortized over time. Therefore, if we were to have a change in methodology, the Board would need to embark on some process to address the costs that were previously incurred.

MR. RUBY: And how do you recommend the Board address transaction costs for equity in this proceeding?

MR. ZARUMBA: I believe, and so do several other parties, that the 50 basis points approach is reasonable and should be continued.

MR. RUBY: Why?

MR. ZARUMBA: Because it is an approach that recognizes all of the cost, both the professional fees and dilution, it has been adopted by other jurisdictions, and is consistent with the deemed equity approach which the Board uses.

MR. RUBY: And you used, and you mentioned this, 50 basis points as an adder for flotation costs. Why that amount?

MR. ZARUMBA: As I had previously stated, it is, it was previously investigated by the Board in the 2009 report, it was determined to be reasonable, and it has been adopted by other jurisdictions.

MR. RUBY: Okay. Thank you, Commissioners. The witnesses are available to be cross-examined.

MR. JANIGAN: Thank you very much, Mr. Ruby. I believe first up is the Three Fires Group.

MR. DAUBE: I am happy to go, but I think it may be the OEA next.