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The Island Regulatory and Appeals Commission

December 16, 2020

Ms. Cheryl Mosher
Island Regulatory & Appeals Commission
PO Box 577
Charlottetown PE C1A 7L1

Dear Ms. Mosher:

General Rate Application - Docket UE20944
Response to Interrogatory IR-97 from Commission Staff

Please find attached the Company's response to Interrogatory IR-97 from Commission Staff with respect to Docket UE20944 – General Rate Application and the Application submitted by the Company for electric rates effective March 1, 2020 and March 1, 2021.

Yours truly,

MARITIME ELECTRIC

Gloria Crockett

Gloria Crockett, CPA, CA
Manager, Regulatory & Financial Planning

GCC24
Enclosure
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RESPONSE TO INTERROGATORIES IR-97 FROM COMMISSION STAFF

Docket UE20944
General Rate Application and the Application Submitted by the Company for electric rates effective March 1, 2020 and March 1, 2021

Submitted December 16, 2020

Other Considerations in Response to Commission IR-97

It is of fundamental importance to Maritime Electric that an order on rates, including approval of a revenue shortfall, be issued prior to the end of December 2020. Without a regulatory order, the Company will be unable to record the 2020 revenue shortfall associated with the delayed rate increase from March 1, 2020 resulting in a material decline in profitability for the 2020 year.

The Company would like to take this final opportunity to offer some consideration points to help the Commission reach a timely decision.

<u>Revenue Shortfall</u>
The revenue shortfall in all scenarios presented to the Commission was calculated to recover the lost revenue due to the delayed implementation of customer rates that should have been effective March 1, 2020. The Company does not seek to recover net revenues lost due to the pandemic.

As noted in response to IR-92, the COVID-19 pandemic had a significant impact on revenue due to lower energy sales but had a much smaller impact on net revenue due to the corresponding reduction in energy purchases. Of the $1.1 million reduction in marginal net revenue, the Company reduced or deferred operating expenses in the amount of $750,000 leaving only $350,000 as the net impact of COVID-19. Response to IR-97 shows the calculation of approximately $350,000, as directly or indirectly related to the impact of COVID-19. The remainder of the revenue shortfall is directly related to the delay in setting customer rates.

The most material item driving the remainder of the revenue shortfall is an increase to depreciation rates as ordered by the Commission in UE19-08. The increase in depreciation rates due to the complete adoption of the Gannett Fleming 2017 Depreciation Study effective January 1, 2020 resulted in an increase in depreciation expense of $3.9 million[1]. Without recognizing the revenue shortfall, this increase in expense had no corresponding increase in revenue. In effect, the Commission will have imposed an incremental cost but not provided a related increase in rates to recover the cost from customers.

Customer rates in effect for 2020 were the carryover of rates set in 2018 based on the forecast revenue requirement for 2018. During the last two years, the Company's expenses have increased by inflation, at a minimum[2]. In addition, expenses have increased as circumstances and other economic factors have changed. For example, 2018 customer rates reflected the amortization of an actuarial gain related to the Company's post-employment health benefit plan, which was fully amortized in 2019. Therefore, the 2020 annual actuarial cost associated with the plan increased by approximately $1.3 million. Another example is the Commission's costs, which have been passed onto the Company. In 2018, those costs were forecast to be $459,000. In 2020 those costs will be $690,000, an increase of $231,000 for which there has been no corresponding increase in revenue.

The above examples of cost increases have been marginally mitigated by other changes; however, it highlights the need to ensure the annual revenue requirement reflected in customer

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1 Forecast 2020 depreciation based on depreciation rates approved in UE19-08 from the 2017 Depreciation Study is $28,386,200. Forecast 2020 depreciation based on depreciation rates approved for 2019 in UE16-04 from the 2014 Depreciation Study is $24,511,100. This is an increase of $3,875,100 in depreciation and revenue requirement for 2020.

2 The Commission's consultant, Grant Thornton, has reviewed all proposed expenses for 2020 and concluded that the types and amounts are not unreasonable.

rates is set at an appropriate level to allow the Company a fair and reasonable opportunity to recover prudently incurred costs, including its allowed return on average common equity.

Fair Return Standard

In IR-96 and 97, the Commission requested rates based on five scenarios, three of which did not approve the revenue shortfall. The Company would like to reiterate that not only is it entitled under the Electric Power Act to earn the return as set by the Commission[3], but established legal principals often referred to as the Fair Return Standard require the Commission to provide the utility with a fair and reasonable opportunity to earn that return.

The Fair Return Standard has been put forward by the National Energy Board and the Ontario Energy Board, and established through Canadian and U.S. common law. Such evidence is documented by Concentric's Cost of Capital Report, which was submitted to the Commission as part of the Company's General Rate Application filed on November 30, 2018 (Docket UE20944). This report is provided again in Appendix 1 for ease of reference.

During the summer of 2019, the evidence presented by Maritime Electric in support of its General Rate Application was subject to a rate hearing, which included numerous interrogatories and financial updates. This process resulted in Order UE19-08 and in paragraph 122, the Commission set the Company's maximum return on average equity of 9.35 percent based on 40 percent common equity in each of 2019, 2020 and 2021. In response to IR-96, scenario 2, the Company indicated that the failure to approve the revenue shortfall will result in an achieved return of approximately 7.88 percent in 2020, which is well below the maximum allowed return of 9.35 percent. In addition, the pending decision from the Commission will be received, at the earliest, in the second half of December. The lateness of this decision will not allow the Company a fair and reasonable opportunity to initiate any measures to mitigate the results of an order that does not approve the revenue shortfall. Thereby, guaranteeing that the Company will not earn the set return.

Use of Forecast

In response to IR-95, the Company calculated the revenue shortfall based on the forecast revenue requirement presented to the Commission in the Application for an Order Approving Changes to the Schedule of Rates Effective March 1, 2020 and March 1, 2021 ("January Filing"). The use of forecast data, also referred to as a future test year, in determining a utility's revenue requirement and, therefore, customer rates is a widely accepted utility practice. Many jurisdictions, Prince Edward Island included, seek to approve general rate applications that cover multiple years, thereby acknowledging that the risk of forecast error is acceptable in order to achieve the regulatory efficiency associated with a multi-year decision.

The Commission engaged an external consultant, Grant Thornton, to review the January Filing and their findings were that the Company's methodology was acceptable and nothing came to their attention to indicate that the Company's procedures and forecasts were unreasonable.

In Grant Thornton's report, it was noted that the revenue shortfall calculation was based on forecasts when actuals for the period March to August 2020 were available. It also recommended that "the final revenue shortfall is reviewed in the final determination of customer rates". The Company infers this to mean that Grant Thornton recommended actuals be used in the calculation

[3] Section 24, paragraph 1 of the Electric Power Act states: *"Every public utility shall be entitled to earn annually such return as the Commission considers just and reasonable, … and the return shall be in addition to the expenses as the Commission may allow as reasonable and prudent and properly charged to operating account …"*

for those periods that are available. The Company does not believe that Grant Thornton was recommending that the Commission wait until actuals were available for 12 months within the revenue shortfall period. Grant Thornton's conclusions with respect to the Company's forecast methodology indicated they found the use of forecast information acceptable.

The Company's sales forecast is based upon statistical regression analysis and Grant Thornton agrees that the methodology is not unreasonable. Their conclusions are the same for the forecast of expenses included in the 2020 annual revenue requirement. However, forecasting is not an exact science and actual results will inevitably be different from forecast. With only two months of forecast data to consider, the risk of a material variance is considered minimal. Ultimately, the Rate of Return Adjustment ("RORA") account serves to protect customers by capturing any over-collection of revenue that occurs when actuals are significantly different from forecast.

<u>Retroactive Ratemaking</u>
John Browne published a paper on retroactive ratemaking, which is attached in Appendix 2. Retroactive ratemaking generally refers to adjusting rates for past service: either adjusting past rates or future rates as a result of an under or over recovery of past costs[4], resulting in a retroactive change to the terms on which past rates were based. The Company would like to point out that the requested approval of the revenue shortfall is different from the concept of retroactive ratemaking.

The issue facing the Commission is the fact that customer rates for 2020 were not set to allow the Company a fair and reasonable opportunity to recover its forecast revenue requirement for 2020, including the allowed return. Instead, customer rates in effect for all of 2020 were set based on the Company's 2018 forecast revenue requirement. True retroactive ratemaking would be if customer rates for 2020 had been set based on the Company's forecast 2020 revenue requirement yet the Company failed to earn its maximum return and then requested the shortfall be approved.

In John Browne's paper on retroactive ratemaking, he points to a number of cases were regulators revisit the past, acknowledging that, while limited, this practice is valid. One such case is interim rates[5], which can be directly compared to the current situation.

John Browne notes that regulators can set interim rates, or just a continuation of existing rates, to deal with regulatory lag. Then "once final rates are approved, an adjustment is made for differences with the final rates. In many cases, the difference between the interim and final rates is reflected through an adjustment to future rates".

This is precisely the current situation. Regulatory lag has delayed the setting of new rates and resulted in the continuation of 2019 rates throughout 2020. Final rates for 2020 can only be effective, at the earliest, on January 1, 2021, requiring the Commission to revisit a past period. However, under the current circumstances, it is acceptable for future rates to correct for a shortfall in past rates.

<u>Other Jurisdictions</u>
As illustrated by John Browne's Comments on Retroactive Rate Making, adjusting future rates to correct for regulatory lag is an acceptable practice. It has been used in many jurisdictions over

[4] JT Browne Consulting, Comments on Retroactive Ratemaking, December 2014, page 4
[5] IBID, page 5

the years. At this time, the Company's search was limited to utilities within the Fortis group and the following examples were found.

In August 2020, the Utility Regulation and Competition Office approved the postponement of Caribbean Utilities' scheduled annual rate increase to January 1, 2021 from June 1, 2020. The revenue shortfall associated with the delay was approved to be collected over the two-year period beginning January 2021.

In June 2020, the New York Public Service Commission approved Central Hudson's request to postpone electric and gas delivery rate increases that were scheduled to be effective July 1, 2020. The rate increase went into effect on October 1, 2020 and the revenue shortfall associated with the delay was approved and is being collected from customers over the nine-month period to June 30, 2021.

In March 2015, the Alberta Utilities Commission issued Decision 3220-D01-2015 related to the approval of FortisAlberta's 2013, 2014 and 2015 capital expenditures. Interim customer rates had been set in 2013 and 2014. The March 2015 decision approved FortisAlberta's actual capital expenditures for 2013 and 2014 and forecast capital expenditures for 2015. The resulting change to customer rates, effective January 1, 2015, included the collection of $10.3 million to address the revenue shortfall that resulted from rates in 2013 and 2014 being insufficient to recover the costs associated with the capital expenditures.

In October 2014, the British Columbia Utilities Commission issued decision G-164-14 approving FortisBC Energy's revenue shortfall of $2.3 million that resulted from a delay in establishing final customer rates effective November 1, 2014 instead of January 1, 2014.

Finally, in Grant Thornton's report it was noted that the Company's methodology with respect to its revenue shortfall calculation and proposal is similar to Newfoundland Power's revenue shortfall deferral account that was approved in a number of regulatory orders (Order No. P.U. 13 (2013), Order No. P.U. 25 (2016), Order No. P.U. 2 (2019)).

<u>Alternatives</u>
If, after considering the information provided herein, the Commission is still uncomfortable approving a revenue shortfall that includes any forecast data, the Company offers two alternatives.

1. <u>Interim rates for January 1, 2021</u>
   Under this alternative, the Commission would approve the revenue shortfall based on actuals to October and forecast for November and December 2020, along with directions for the treatment of the other issues discussed in IR-95, 96 and 97. The resulting customer rates would be set on an interim basis for January 1, 2021. The Company would be ordered to provide an updated calculation of the revenue shortfall based on 12 months of actuals ending December 31, 2020 as soon as possible in January. If the revenue shortfall is lower, the Company could be ordered to change customer rates, effective March 1, 2021, to reflect the lower amount. If the revenue shortfall is higher, the Company would assume that shortfall. If the revenue shortfall is higher or the reduction is immaterial, the Commission should order the interim rates to be considered final rates for 2021.

2. <u>Final rates for February 1, 2021</u>
   Under this alternative, the Commission would approve the revenue shortfall as at December 31, 2020, reflecting 12 months of actuals, along with directions for the treatment

of the other issues discussed in IR-95, 96 and 97, with customer rates to be effective February 1, 2021. The resulting customer rates would be presented to the Commission as soon as possible in January, but no later than January 13, 2021. Final confirmation from the Commission would be required no later than January 22, 2021 in order for system changes to be made that are necessary to implement new customer rates for February 1, 2021. This alternative results in a single change in customer rates but will result in a higher overall increase due to the loss of energy sales during a high consumption month.

The Island Regulatory and Appeals Commission (the "Commission"), in assessing the application submitted by Maritime Electric Company, Limited ("Maritime Electric" or "MECL") for electric rates effective March 1, 2020 and March 1, 2021, requests a response to the following interrogatory:

IR-97 Please provide the rates and the rate impact that arise from the following scenario:

SCENARIO 6:
Please assume as follows:

- The Commission does not approve any revenue shortfall account.
- The CTGS accumulated reserve is deferred to the next rate setting period.
- The Commission determines that MECL collected in base rates DSM costs in the amount of $573,000 per year in each of 2019 and 2020. MECL is required to remit to PEIEC, on or before December 31, 2020, the sum of $861,355 as contribution to the outstanding EE&C costs.
- The EE&C rate rider effective January 1, 2021 is reduced accordingly.
- The re-payment of the debt owing to the Province for Point Lepreau and Dalhousie is fixed at approximately $425,000 per month and recovered through a rate rider of $0.0036 per kilowatt hour, effective January 1, 2021.
- The Hurricane Dorian costs ($3,002,900) are recovered using the 2019 RORA balance.
- The remaining balance of the RORA account (including accrued interest calculated at the Company's short term borrowing rate) and the balance of the WNR account at December 31, 2019, are used to offset the ECAM balance.-2-
- The ECAM base rate and collection rate are adjusted accordingly as of January 1, 2021.
- Any remaining RORA balance is refunded to ratepayers over a fourteen (14) month period beginning January 1, 2021.
- The cable contingency fund over-collections for 2019 and 2020 are returned to ratepayers through the ECAM.
- Electric rates are implemented effective January 1, 2021 and the rate setting period will end on February 28, 2022.
- All other requests made by MECL in the application are approved as filed.

Please ensure to include the follow revised schedules:

- Revised Energy Charges per kWh Other Amounts;
- Revised calculation of the costs recoverable from ratepayers on behalf of the Province;
- Revised PEIEC EE&C Plan rate rider as of January 1, 2021;
- Revised calculation of the ECAM base rate and collection rate as of January 1, 2021;
- Revised calculation of the RORA balance, with interest accrued to December 31, 2020, and the proposed RORA refund rate as of January 1, 2021. The refund rate shall include the refund of interest earned on the RORA balance to December 31, 2020, calculated using the Company's short term borrowing rate.

The Commission may approve electric rates based on the above scenario. With this in mind, please provide any comments that MECL may have with respect to the scenario, including any details or information that may be pertinent to the Commission's decision.

Response:

IR-97 - Attachment 1 provides the rates and the rate impacts that arise from Scenario 6 including changes to the proposed revenue requirement for 2020 and 2021, annual cost for a typical customer in each rate class, the energy charges per kWh, and rate base and return on rate base from those proposed in our January Filing.

In addition, supporting calculations of the various balances and rate riders or refunds are provided in IR-97 - Attachment 2 – Supporting Calculations of Scenario 6.

The Company also offers the following additional commentary on the assumptions provided in this scenario.

- The revenue shortfall in this scenario will increase the amount proposed in the response to IR-95 to $3,547,379. This is an increase of $29,408 from the scenarios presented in IR-96 to reflect the Commission's request to accrue forecast interest for November and December on the RORA balance.

  Net of tax, this would result in an earnings shortfall of approximately $2.4 million and the Company's ROE would be 7.88 per cent, well below the maximum ROE of 9.35 per cent based on 40 per cent common equity approved in Order UE19-08. This would also be well below returns in comparable jurisdictions. Further, a decision resulting in an impaired level of return has the potential to negatively impact the Company's business risk and financial risk profile which could, in turn, erode the Company's credit rating. Such outcomes ultimately lead to higher costs for customers in the long run.

  The Company's 2020 average common equity will have a corresponding reduction of $1.2 million and the equity ratio will fall to 39.5 per cent compared to 40 per cent maximum legislated amount.

  Section 24, paragraph 1 of the Electric Power Act (the "Act") states:

  > *"Every public utility shall be entitled to earn annually such return as the Commission considers just and reasonable, computed by using the rate base as fixed and determined by the Commission for each type of service furnished, rendered or supplied by such public utility, and the return shall be in addition to the expenses as the Commission may allow as reasonable and prudent and properly chargeable to operating account, and to all just allowances made by the Commission according to this Act and the rules and regulations made by the Commission hereunder."*

  The revenue shortfall methodology and calculation has been reviewed by Grant Thornton. In their conclusion, Grant Thornton states in Section 4.4 Conclusion:

  > *"…nothing has come to our attention that the proposed revenue shortfall...appears unreasonable. We did not note any discrepancies in the calculation of the proposed revenue shortfall and the components of the revenue shortfall are internally consistent with the Company's January 2020 filing…the Company's methodology does not appear unreasonable*

and is comparable to the methodology used by utilities in Newfoundland and Labrador."

The Company respectfully submits that not approving the revenue shortfall effectively denies the Company any reasonable opportunity to earn the allowable return entitled under the Act.

- Deferral of the CTGS accumulated reserve recovery until the next rate setting period is as proposed in the January Filing and the response to IR-95.

- Recovering Hurricane Dorian costs using the 2019 RORA is as proposed in the January Filing and the response to IR-95.

- The current rates approved by the Commission do not include a rate rider for the PEIEC's EE&C plan. The confusion may be the result of an error in Section 7.1.2.2 of Grant Thornton's report identified in our letter to the Commission dated November 23, 2020 Application for an Order Approving Changes to the Schedule of Rates effective March 1, 2020 and March 1, 2021 – *Comments on Grant Thornton Report.*

  Although the Company has provided its position on the EE&C funding, if the Commission were to alternatively conclude that the Company is collecting DSM costs of $573,000 in base rates, this effectively increases the Company's 2020 Revenue Requirement from that originally proposed in the January Filing by $445,553[1]. This flows through to the revenue shortfall amount calculated in the first bullet in this scenario.

  Similar treatment applied to the 2019 EE&C Plan would require a reduction to the RORA account of $415,802[2] as explained in our comments on the Grant Thornton Report.

  Without these correcting adjustments to the revenue shortfall account and the RORA account, the Commission will be denying the Company a fair and reasonable opportunity to recover these costs.

- Similar to our response to IR-96, in light of the Commission's request to not assume a rate increase on March 1, 2020, we consider that to also mean there is no change to the ECAM base rate on March 1, 2020 and it will remain at $0.09161 until December 31, 2020.

  For the scenario requested in IR-97, the Company assumed an ECAM base rate effective January 1, 2021 of $0.09244 to match the effective date of revised customer rates. This effectively matches the Energy Costs to be recovered from customers in 2021, Net of ECAM, to forecast Gross Energy Costs as the proposed ECAM base rate of $0.09244 is based on the proposed Energy Supply Cost by Source (Appendix 5, Schedule 5-3 of the January Filing) for 2021 and the proposed Net Purchased and Produced Energy (Appendix 5, Schedule 5-2 of the January Filing) in 2021 as outlined the following table.

[1] $573,000 less DSM amortization costs of $127,447 incurred by the Company in 2020.
[2] $573,000 less DSM amortization costs of $157,198 incurred by the Company in 2019.

Calculation of Annual ECAM Base Rate			
Description	**January Filing Reference**		**2021 Forecast**
Energy Supply by Source ($)	SCHEDULE 5-3	A	$ 138,373,900
Net Purchased and Produced Energy X 1000 (GWh converted to kWh)	SCHEDULE 5-2	B	1,496,869,680
ECAM Base Rate effective January 1, 2021		C = A / B	**$ 0.09244**

- Applying the forecast RORA on December 31, 2020 and WNRA balances on December 31, 2019 to the ECAM balance will reduce the forecast ECAM balance to nil on December 31, 2020. Hence there will be no ECAM Collection included in the proposed rates for January 1, 2021. There will be a forecast balance of $1,214,907 in the RORA to be refunded to customers beginning January 1, 2021. This balance includes the requested forecast interest for November and December 2020.

  In this scenario, the Company has calculated the refund rate based on the forecast December 31, 2020 RORA balance being refunded over a 14 month period effective January 1, 2021.

  In the January Filing and in our response to IR-95, the Company had proposed amortizing the balance of the WNRA on December 31, 2019 against the 2020 revenue requirement thereby reducing the revenue required to be collected from customers through basic rates.

  Applying the WNRA balance to ECAM, as proposed in this scenario, increases the amount of 2020 revenue requirement to be collected from customers in 2021 as part of the revenue shortfall calculated in the first bullet in this scenario.

- See references below to the requested revised schedules:

  - Revised Energy Charges per kWh Other Amounts are found in IR-97 - Attachment 1, page 3;
  - Revised calculation of the ECAM base rate and collection rate as of January 1, 2021 have been provided in the body to this response;

  Supporting calculations for the following are provided in IR-97 - Attachment 2, page 1:

  - Revised calculation of the costs recoverable from ratepayers on behalf of the Province;
  - Revised PEIEC EE&C Plan rate rider as of January 1, 2021;
  - Revised calculation of the RORA balance, with interest accrued to December 31, 2020, and the proposed RORA refund rate as of January 1, 2021. The refund rate shall include the refund of interest earned on the RORA balance to December 31, 2020, calculated using the Company's short term borrowing rate.

Revenue Shortfall:

Denial of a revenue shortfall by the Commission does not preclude the shortfall from occurring.

Commission Staff and Counsel have suggested that the Commission is hesitant to approve the revenue shortfall proposed in IR-95 as it is based on forecast sales for the year. Further, Commission is equally concerned that the scenarios presented in IR-96 introduce not only the Sales Price Variance[3] from the delay in rates but also the Sales Volume Variance[4] due to the COVID-19 pandemic. To address these concerns, the Company has broken out these two amounts of the revenue shortfall as presented on page 2 of IR-97 - Attachment 2. The supporting calculations of these two variances are provided in IR-97 - Attachment 3.

As discussed in our response to IR-92, reduced sales due to COVID has reduced revenue by $4.6 million. This has been offset by lower energy purchases of $3.4 million resulting in a forecast marginal revenue of $1.2 million[5]. Further, other revenues[6] and WNRA adjustments are forecast to increase the shortfall by $296 thousand. The Company made efforts to mitigate the impact of the reduced sales resulting in net reductions in operating and other expenses of approximately $850 thousand and thereby reducing the forecast impact of lower than expected sales volume on 2020 earnings to $347 thousand before tax.

The Company's request for a revenue shortfall deferral account has always been in the context of recovering the shortfall due to the delay in the approval of the proposed March 1, 2020 rate adjustments (i.e. the Sales Price Variance). As shown on page 2 of IR-97 - Attachment 2, the price variance for 2020 based on actual year to date sales to October 31, 2020 and forecasts for November and December 2020 is $2,451,544.

As indicated above, we assume there is no change to the ECAM base rate on March 1, 2020 and it will remain at $0.09161 until December 31, 2020. This reduces the energy costs included in the revenue requirement by $753,655 and, as such, this amount is reduced from the proposed revenue shortfall.

The first step in forecasting a proposed rate adjustment is to determine the forecast revenue requirement that needs to be collected through rates. The proposed rate increase on March 1, 2020 was designed to recover the proposed 2020 revenue requirement as set out in the January Filing. Two of the Commission's proposals in this scenario increase the Company's revenue requirement to be collected through rates from that proposed in the January Filing:

- The $455,553 payment to the PEI Energy Corporation to fund the EE&C plan was not included in the revenue requirement in the January Filing. Should the Commission order the Company to pay this amount, the Company should be allowed to increase its proposed revenue requirement and adjust proposed rates accordingly.
- In the January Filing, the Company proposed to offset the December 31, 2019 WNRA balance to the revenue requirement thereby reducing the revenue required to be collected

[3] The Sales Price Variance equals the difference between actual sales at the market price (current approved rates) and actual sales at the budgeted price (the proposed rates for March 1, 2020).
[4] The Sales Volume Variance is the measure of change in profit or contribution as a result of the difference between actual and budgeted sales quantity (kWh sales).
[5] In the Company's response to IR-92, the marginal net revenue was rounded to $1.1 million.
[6] Reduction in forecast other revenue is primarily the result of lower forecast transmission revenue from OATT.

through customer rates. In this scenario the Commission is proposing instead to apply the December 31, 2019 WNRA balance to the RORA balance and refund the amount to customers through the RORA refund rate. This treatment thereby increases the revenue requirement to be collected through customer rates in 2020 from that proposed in the January Filing.

Based on the assumptions presented by the Commission in this scenario, these two items increase the revenue requirement to be collected from customers in 2020 from that proposed in the January Filing and should be included in revenue shortfall for 2020.

The revised revenue shortfall having considered all these items is $3,200,770 as shown in IR-97 - Attachment 2, page 2. Based on this revised revenue shortfall, the Company respectively submits an additional Scenario 7 for consideration.

SCENARIO 7:
Please assume as follows:

- The Commission approves a revenue shortfall account of $3,200,770 reflecting the following items:

Description	Total
Reduction in Electric Revenue due to Delay in Rates	$2,451,544
Reduction in Net Energy Costs due to No Change to ECAM Base Rate	(753,655)
2020 EE&C Plan not included in Revenue Requirement	445,553
December 31, 2019 WNRA Balance Not Applied to Revenue Requirement	1,057,328
Total Revenue Shortfall	**$3,200,770**

The remaining assumptions are consistent with Scenario 6:

- The CTGS accumulated reserve is deferred to the next rate setting period.
- The Commission determines that Maritime Electric collected in base rates DSM costs in the amount of $573,000 per year in each of 2019 and 2020. Maritime Electric is required to remit to PEIEC, on or before December 31, 2020, the sum of $861,355 as contribution to the outstanding EE&C costs.
- The EE&C rate rider effective January 1, 2021 is reduced accordingly.
- The re-payment of the debt owing to the Province for Point Lepreau and Dalhousie is fixed at approximately $425,000 per month and recovered through a rate rider of $0.0036 per kilowatt hour, effective January 1, 2021.
- The Hurricane Dorian costs ($3,002,900) are recovered using the 2019 RORA balance.
- The remaining balance of the RORA account (including accrued interest calculated at the Company's short term borrowing rate) and the balance of the WNR account at December 31, 2019, are used to offset the ECAM balance.
- The ECAM base rate and collection rate are adjusted accordingly as of January 1, 2021.
- Any remaining RORA balance is refunded to ratepayers over a fourteen (14) month period

beginning January 1, 2021.

- The cable contingency fund over-collections for 2019 and 2020 are returned to ratepayers through the ECAM.
- Electric rates are implemented effective January 1, 2021 and the rate setting period will end on February 28, 2022.
- All other requests made by Maritime Electric in the application are approved as filed.

IR-97 - Attachment 4 provides the rates and the rate impacts that arise from Scenario 7 including changes to the proposed revenue requirement for 2020 and 2021, annual cost for a typical customer in each rate class, the energy charges per kWh, and rate base and return on rate base from those proposed in our January Filing.

In addition, supporting calculations of the various balances and rate riders or refunds are provided in IR-97 - Attachment 5 – Supporting Calculations of Scenario 7.

The total revenue shortfall in this scenario will increase from the amount proposed in the response to IR-95 to $3,547,379. However, the shortfall excludes the reduced sales volume due to COVID of $346,703.

Net of tax, this would result in an earnings shortfall of approximately $225 thousand and the Company's forecast ROE would be 9.21 per cent, below the maximum ROE of 9.35 per cent based on 40 per cent common equity approved in Order UE19-08.

The Company's 2020 average common equity will have a corresponding reduction of $112 thousand and the equity ratio will be to 39.9 per cent compared to 40 per cent maximum legislated amount.

RESPONSE TO INTERROGATORIES FROM COMMISSION STAFF

Section IR-97

ATTACHMENTS

Scenario 6 Impact

Revenue Requirement ($)						
	Original Application Proposed		IR 97 Scenario 6		Difference from Proposed	
	2020 Forecast	2021 Forecast	2020 Forecast	2021 Forecast	2020 Forecast	2021 Forecast
Operating Expenses (Net of ECAM)*	$ 162,897,200	$ 169,336,300	$ 158,227,200	$ 169,389,200	$ (4,670,000)	$ 52,900
Interest Expense (including amortization of Debt Issue Costs)	12,844,400	12,854,300	12,794,700	13,070,900	(49,700)	216,600
Amortization - Fixed Assets	28,572,100	26,202,300	28,386,200	26,200,600	(185,900)	(1,700)
Amortization - DSM Costs	127,400	166,600	127,400	166,600	-	-
Amortization - Lepreau Write-down	93,400	93,400	93,400	93,400	-	-
Amortization - Storm Deferral	3,002,900	-	3,002,900		-	-
Amortization - Rate Delay Deferral	-	-	-	-	-	-
Income Tax Expense	6,742,200	6,978,200	5,645,600	6,937,700	(1,096,600)	(40,500)
Return on Equity**	14,842,900	15,371,400	12,411,700	15,281,000	(2,431,200)	(90,400)
Total Gross Electric Revenue	**229,122,500**	**231,002,500**	**220,689,100**	**231,139,400**	**(8,433,400)**	**136,900**
Rate of Return Adjustment	(3,002,900)	-	(3,002,900)	-	-	-
Weather Normalization Adjustment	(1,057,300)	-	102,300	-	1,159,600	-
Other Revenue	(13,425,300)	(13,217,400)	(13,231,300)	(13,258,600)	194,000	(41,200)
Revenue Requirement to be Collected Through Customer Rates	**$ 211,637,000**	**$ 217,785,100**	**$ 204,557,200**	**$ 217,880,800**	**$ (7,079,800)**	**$ 95,700**

* *Excluding Fortis Inc. Costs*

** *Before Disallowable Costs*

Scenario 6 Impact

Impact on Annual Cost March 1 - February 28						
	IR 97 Scenario 6			Original Application Proposed Rates		
March 1 - February 28	**2019/20**	**2020/21**	**2021/22**	**2019/20**	**2020/21**	**2021/22**
Rural Residential Customer (650kWh per Month/7,800 kWh per Year)						
Before Tax Cost	$ 1,443.60	$ 1,448.19	$ 1,471.23	$ 1,443.60	$ 1,459.18	$ 1,476.45
	0.0%	0.3%	1.6%	0.0%	1.1%	1.2%
Total Cost	**$ 1,548.08**	**$ 1,552.90**	**$ 1,577.09**	**$ 1,548.08**	**$ 1,564.45**	**$ 1,582.58**
	-2.4%	0.3%	1.6%	-2.4%	1.1%	1.2%
Urban Residential Customer (650kWh per Month/7,800 kWh per Year)						
Before Tax Cost	$ 1,415.40	$ 1,419.99	$ 1,443.02	$ 1,415.40	$ 1,430.98	$ 1,448.25
	0.0%	0.3%	1.6%	0.0%	1.1%	1.2%
Total Cost	**$ 1,515.65**	**$ 1,520.48**	**$ 1,544.65**	**$ 1,515.65**	**$ 1,532.02**	**$ 1,550.15**
	-2.4%	0.3%	1.6%	-2.4%	1.1%	1.2%
Annual Cost for General Service Customer (10,000kWh/50KW per Month / 120,000 kWh/600KW per Year)						
Before Tax Cost	$ 22,650.82	$ 22,725.67	$ 23,099.95	$ 22,650.82	$ 22,908.71	$ 23,174.45
	0.0%	0.3%	1.6%	0.0%	1.1%	1.2%
Total Cost	**$ 26,048.45**	**$ 26,134.53**	**$ 26,564.94**	**$ 26,048.45**	**$ 26,345.02**	**$ 26,650.62**
	0.0%	0.3%	1.6%	0.0%	1.1%	1.2%

Scenario 6 Impact

Composition of Total Energy Charge per kWh by Rate Class - IR 97 Scenario 6	2016*	2017*	2018*	2019	2020	January 1 2021	Cumulative Change over 2018 Rates
Energy Charge per kWh - Revenue Requirement (A)							
Residential - First Block	$ 0.1320	$ 0.1375	$ 0.1409	$ 0.1409	$ 0.1409	$ 0.1430	1.5%
Residential - Second Block	$ 0.1043	$ 0.1087	$ 0.1114	$ 0.1114	$ 0.1114	$ 0.1131	1.5%
General Service - First Block	$ 0.1628	$ 0.1696	$ 0.1739	$ 0.1739	$ 0.1739	$ 0.1767	1.6%
General Service - Second Block	$ 0.1054	$ 0.1098	$ 0.1126	$ 0.1126	$ 0.1126	$ 0.1144	1.6%
Small Industrial - First Block	$ 0.1594	$ 0.1661	$ 0.1703	$ 0.1703	$ 0.1703	$ 0.1730	1.6%
Small Industrial - Second Block	$ 0.7900	$ 0.0823	$ 0.0844	$ 0.0844	$ 0.0844	$ 0.0858	1.7%
Large Industrial	$ 0.0639	$ 0.0673	$ 0.0686	$ 0.0686	$ 0.0686	$ 0.0689	0.4%
Energy Charges per kWh - Other Amounts (B)							
ECAM Charge per kWh	$ 0.0021	$ 0.0012	$ 0.0006	$ 0.0006	$ 0.0006	$ -	-100.0%
Provincial Costs Recoverable per kWh	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0036	-33.1%
Provincial Energy Efficiency Program per kWh	$ -	$ -	$ -	$ -	$ -	$ 0.0013	100.0%
Cable Contingency Fund per kWh	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003	$ -	-100.0%
RORA per kWh	$ (0.0041)	$ (0.0047)	$ (0.0034)	$ (0.0034)	$ (0.0034)	$ (0.0007)	-78.7%
Total Energy Charge per kWh Excluding Basic Revenue	$ 0.0036	$ 0.0021	$ 0.0028	$ 0.0028	$ 0.0028	$ 0.0042	50.0%
Total Energy Charge per kWh (A+B) - Option - Proposed 2020 Revenue Shortfall Deferral							
Residential - First Block	$ 0.1356	$ 0.1396	$ 0.1437	$ 0.1437	$ 0.1437	$ 0.1472	2.4%
Residential - Second Block	$ 0.1079	$ 0.1108	$ 0.1142	$ 0.1142	$ 0.1142	$ 0.1173	2.7%
General Service - First Block	$ 0.1664	$ 0.1717	$ 0.1767	$ 0.1767	$ 0.1767	$ 0.1809	2.4%
General Service - Second Block	$ 0.1090	$ 0.1119	$ 0.1154	$ 0.1154	$ 0.1154	$ 0.1186	2.8%
Small Industrial - First Block	$ 0.1630	$ 0.1682	$ 0.1731	$ 0.1731	$ 0.1731	$ 0.1772	2.4%
Small Industrial - Second Block	$ 0.7936	$ 0.0844	$ 0.0872	$ 0.0872	$ 0.0872	$ 0.0900	3.2%
Large Industrial	$ 0.0675	$ 0.0694	$ 0.0714	$ 0.0714	$ 0.0714	$ 0.0731	2.4%

* Rate changes effective March 1.

January 2020 Rate Application
Supplemental Information - 2019, 2020 and 2021 Inputs

Calculation of Rate Base ($)								
			Proposed in Original Application		IR 97 Scenario 6		Difference from Proposed	
Components	**2018 Actual**	**2019 Actual**	**2020 Forecast**	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**
Fixed Assets	$ 654,053,538	$ 679,767,856	$ 712,215,800	$ 693,668,900	$ 705,485,600	$ 693,668,900	(6,730,200)	-
Less: Capital Work in Progress	(1,688,342)	(3,750,888)	-	-	(2,950,000)	-	(2,950,000)	-
Less: Accumulated Amortization	(236,162,822)	(245,078,293)	(269,903,600)	(231,933,900)	(269,717,700)	(231,746,300)	185,900	187,600
Less: Contributions in Aid of Construction (net of amortization)	(24,185,307)	(23,691,857)	(24,598,000)	(25,496,000)	(23,476,600)	(24,411,500)	1,121,400	1,084,500
Less (Add): Future Income Tax Liability (Asset) - net of Long Term Receivable	(7,496,013)	(13,522,753)	(19,754,200)	(26,214,600)	(22,819,600)	(29,521,500)	(3,065,400)	(3,306,900)
Less (Add): Costs Payable to (Recoverable from) Customers Post 2003	3,976,693	2,772,690	72,200	(478,100)	-	3,500	(72,200)	481,600
Less (Add): Regulatory Liability (Asset) - As Established by Commission Order WNRA	(290,982)	(1,057,328)	-	-	-	-	-	-
Add: Deferred Financing Costs	859,810	961,283	947,500	933,000	947,500	933,000	-	-
Add: Intangible Assets	3,915,322	4,002,494	4,150,000	4,300,000	4,150,000	4,300,000	-	-
Add: Deferred Demand Side Management Costs	156,998	127,446	166,600	-	166,600	-	-	-
Add: Deferred Charge (Section 47(4)(a)(ii) of the EPA)	1,586,343	1,492,744	1,399,400	1,305,900	1,399,400	1,305,900	-	-
Add: Regulatory Asset - Storm Deferral	-	3,002,882	-	-	-	-	-	-
Add: Regulatory Asset - Revenue Shortfall Deferral	-	-					-	-
Less: Employee Future Benefits Liability	(7,837,014)	(7,631,568)	(7,711,700)	(7,961,700)	(7,711,700)	(7,961,700)	-	-
Less (Add): Regulatory Liability OPEB	1,168,904	2,536,000	2,986,600	2,813,800	2,986,600	2,813,800	-	-
Less: Regulatory Liability - Rebates Payable to Customers	(15,725,025)	(15,453,528)	(5,847,300)	(4,648,100)	(1,317,200)	(303,500)	4,530,100	4,344,600
Add: Reg Asset - CTGS Accumulated Reserve Variance	-	-	9,654,500	9,654,500	9,654,500	9,654,500	-	-
Plus: Working Capital Allowance Comprised of:							-	-
- Inventory	2,793,911	3,240,398	3,000,000	3,000,000	3,000,000	3,000,000	-	-
- Gross Operating Expenses X 3.6% (net of disallowed costs)	5,376,947	5,508,778	5,852,400	6,098,100	5,750,800	6,098,100	(101,600)	-
Income Taxes Paid X 3.6%	126,000	21,000	(21,000)	-	(21,000)	-	-	-
Total Rate Base	**$ 380,628,962**	**$ 393,247,356**	**$ 412,609,200**	**$ 425,041,800**	**$ 405,527,200**	**$ 427,833,200**	**$ (7,082,000)**	**$ 2,791,400**
Average Rate Base		**$ 386,938,159**	**$ 402,928,278**	**$ 418,825,500**	**$ 399,387,278**	**$ 416,680,200**	**$ (3,541,000)**	**$ (2,145,300)**

Calculation of Return on Average Rate Base ($) & (%)							
		As Proposed		IR 97 Scenario 6		Difference from Proposed	
	2019 Actual	**2020 Forecast**	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**	**2020 Forecast**	**2021 Forecast**
Total Revenue	$ 210,720,773	$ 229,122,500	$ 231,002,500	$ 220,689,100	$ 231,139,400	$ (8,433,400)	$ 136,900
Less: Operating Expenses (net of ECAM)	(153,485,663)	(162,897,200)	(169,336,300)	(158,227,200)	(169,389,200)	4,670,000	(52,900)
Less: Amortization of debt issue costs	(13,004)	(13,800)	(14,500)	(13,800)	(14,500)	-	-
	57,222,106	66,211,500	61,651,700	62,448,100	61,735,700	(3,763,400)	84,000
Less: Amortization Fixed Assets	(23,337,238)	(28,572,100)	(26,202,300)	(28,386,200)	(26,200,600)	185,900	1,700
Less: Amortization Deferred Charges	(250,598)	(3,223,700)	(260,000)	(3,223,700)	(260,000)	-	-
	(23,587,836)	(31,795,800)	(26,462,300)	(31,609,900)	(26,460,600)	185,900	1,700
Earnings Before Income Taxes and Financing Costs	33,634,270	34,415,700	35,189,400	30,838,200	35,275,100	(3,577,500)	85,700
Income Taxes	(6,483,242)	(6,742,200)	(6,978,200)	(5,645,600)	(6,937,700)	1,096,600	40,500
Earnings on Average Rate Base (interest expense excluded)	$ 27,151,028	$ 27,673,500	$ 28,211,200	$ 25,192,600	$ 28,337,400	(2,480,900)	126,200
Rate Base - Year End Average	$ 386,938,159	$ 402,928,278	$ 418,825,500	$ 399,387,278	$ 416,680,200	(3,541,000)	(2,145,300)
Actual/Forecast Return on Average Rate Base	**7.02%**	**6.87%**	**6.74%**	**6.31%**	**6.80%**	**-0.56%**	**0.06%**

Supporting Calculations for Scenario 6

Revised Revenue Shortfall		**2020**
Reduction in Electric Revenue due to Lower Sales and Delay in Rates		$ 7,079,900
Reduction in Other Revenue Forecast		193,543
Reduction In Operating Expenses:		
Reduction in Net Energy Costs due to lower NPP (Note 1)	$ (3,436,118)	
Reduction in Net Energy Costs due to No Change to ECAM Base Rate (Note 2)	(753,655)	
Reductions in Other Operating Expenses	(925,780)	
2020 EE&C Plan not included in Revenue Requirement	445,553	(4,670,000)
Reduction in Depreciation & Interest Expense		(245,100)
November & December Interest on RORA		**29,408**
October 2020 YTD Adjustment to WNRA		102,300
December 31, 2019 WNRA Balance Not Applied to Revenue Requirement		1,057,328
Not Approved		(3,547,379)
Approved Revenue Shortfall		**$ (0)**

* Net marginal revenue impact = $1,192,332

	Per Month	**2021**	**2022**
Amortized over 14 months	$ -		

Note 1 - Reduction in Net Energy Costs due to lower NPP		**Jan 1 - Dec 31, 2020**
January Filing, Net Purchased & Produced Energy in kWh	1,450,198,653	
October 2020 YTD Forecast, Net Purchased & Produced Energy in kWh	1,412,690,542	
Lower Forecast NPP from January Filing in kWh	37,508,111	
Existing ECAM Base Rate	$ 91.61	
Reduction in Net Energy Costs due to lower NPP		**$ (3,436,118)**

Note 2 - Reduction in Net Energy Costs due to No Change to ECAM Base Rate		**Mar 1 - Dec 31, 2020**
Net Purchased & Produced Energy in kWh		1,177,585,726
Proposed March 1, 2020 ECAM Base Rate - not approved	92.25	
Existing ECAM Base Rate	91.61	$ (0.64)
Reduction in Proposed Net Energy Costs due to Lower ECAM Base Rate		**$ (753,655)**

CTGS Reserve Deferred		**Per Month**	**2021-2025**
CTGS Reserve	**$ -**	**$ -**	**$ -**

RORA Adjustments & Refund Rate	
RORA Balance 10/31/2020	$ 7,864,663
Forecast Refund for November & December 2020	(779,139)
Forecast Interest on RORA for November & December 2020	**29,408**
2019 Hurricane Dorian Deferral Applied to RORA*	(3,002,882)
WNRA @ 12/31/2019, 2020 YTD Adjustment Deferred	**1,057,328**
ECAM	(3,538,669)
2019 EE&C Adjustment	(415,802)
Balance to be refunded	1,214,907
Refund 14 mos (Jan/21-Feb/22)	1,659,431,460
Refund Rate	**$ 0.0007**

PEIEC EE&C Plan	
Proposed	$ 3,100,000
Adjustments:	
2019 Component	(415,802)
2020 Component ($573,000-127,447)	(445,553)
Balance to be recovered thru rider	$ 2,238,645
Total kWh (14 months)	1,659,431,460
PEIEC EE&C Plan Rate Rider per kWh	**$ 0.0013**

Provincial Costs Recoverable		
Lepreau/Dal Debt Repayments	$ 425,000	
	14 Months	$ 5,950,000
Total kWh (14 months)		1,659,431,460
Provincial Costs Recoverable Rate Rider per kWh		**$ 0.0036**

Scenario Supporting Calculations

Supporting Calculations for Scenario 6			Breakdown of Revenue Shortfall	
Revised Revenue Shortfall		**2020**	**Sales Volume Variance Due to COVID-19**	**Sales Price Variance Due to Delay in Approving Rates and Changes in Revenue Requirement**
Reduction in Electric Revenue due to Lower Sales and Delay in Rates		$7,079,900	$ 4,628,450 *	$ 2,451,544
October 2020 YTD Adjustment to WNRA		102,300	102,300	
Reduction in Other Revenue Forecast		193,543	193,543	-
Reduction In Operating Expenses:				
Reduction in Net Energy Costs due to lower NPP (Note 1)	$ (3,436,118)		(3,436,118) *	-
Reduction in Net Energy Costs due to No Change to ECAM Base Rate	(753,655)			(753,655)
Reductions in Other Operating Expenses	(925,780)		(925,780)	-
2020 EE&C Plan not included in Revenue Requirement	445,553	(4,670,000)		445,553
Reduction in Depreciation & Interest Expense		(245,100)	(245,100)	
November & December Interest on RORA		29,408	29,408	
December 31, 2019 WNRA Balance Not Applied to Revenue Requirement		1,057,328		1,057,328
Total Revenue Shortfall		**$ 3,547,379**	**$ 346,703**	**$ 3,200,770**

* Net Marginal Revenue Impact = $1,192,332

2020 Forecast Revenue Shortfall due to Delay in Approving Rates

		Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total-20
		ACTUAL										FORECAST		
kWh Sales														
Residential	1st Block	59,834,389	60,105,607	54,118,013	52,304,105	48,895,035	39,985,935	40,346,615	44,956,900	39,819,601	39,715,783	46,694,815	56,028,445	582,805,243
	2nd Block	14,559,134	16,748,241	10,914,374	8,367,914	6,342,931	3,974,423	4,260,698	4,687,343	3,565,830	4,058,092	6,649,693	11,005,000	95,133,673
GS	1st Block	13,074,174	13,445,220	12,682,962	11,809,210	11,461,659	10,855,507	11,831,726	12,899,290	12,126,512	11,136,174	11,664,124	12,615,375	145,601,933
	2nd Block	22,171,379	23,341,438	20,973,467	18,025,754	15,126,768	15,479,239	17,566,171	19,841,447	18,782,444	17,685,076	19,766,785	20,665,337	229,425,306
LI		12,883,401	12,370,449	13,011,666	12,078,072	13,062,423	12,463,746	14,086,206	13,958,809	12,710,740	12,664,906	13,504,017	14,705,565	157,500,000
SI	1st Block	2,335,689	2,285,828	2,267,402	2,196,299	2,315,062	2,760,779	2,888,689	2,831,885	2,778,704	2,726,327	1,991,057	1,926,552	29,304,273
	2nd Block	4,919,002	5,046,532	4,476,249	4,514,845	4,048,261	5,378,035	5,608,908	5,654,527	5,642,154	5,616,880	3,934,234	3,539,343	58,378,970
Street Lights*		383,339	381,781	379,504	376,638	373,848	372,491	371,898	371,293	370,502	371,022	513,322	524,662	4,790,299
Unmetered		222,353	205,880	205,982	205,996	206,522	206,778	207,303	207,331	207,331	207,669	211,813	214,929	2,509,888
		130,382,860	133,930,976	119,029,619	109,878,833	101,832,509	91,476,933	97,168,214	105,408,825	96,003,818	94,181,929	104,929,860	121,225,209	1,305,449,585
Rate Differential														
Residential	1st Block	-	-	(0.0025)	(0.0025)	(0.0025)	(0.0025)	(0.0025)	(0.0025)	(0.0025)	(0.0025)	(0.0025)	(0.0025)	
	2nd Block	-	-	(0.0020)	(0.0020)	(0.0020)	(0.0020)	(0.0020)	(0.0020)	(0.0020)	(0.0020)	(0.0020)	(0.0020)	
GS	1st Block	-	-	(0.0032)	(0.0032)	(0.0032)	(0.0032)	(0.0032)	(0.0032)	(0.0032)	(0.0032)	(0.0032)	(0.0032)	
	2nd Block	-	-	(0.0021)	(0.0021)	(0.0021)	(0.0021)	(0.0021)	(0.0021)	(0.0021)	(0.0021)	(0.0021)	(0.0021)	
LI		-	-	(0.0015)	(0.0015)	(0.0015)	(0.0015)	(0.0015)	(0.0015)	(0.0015)	(0.0015)	(0.0015)	(0.0015)	
SI	1st Block	-	-	(0.0032)	(0.0032)	(0.0032)	(0.0032)	(0.0032)	(0.0032)	(0.0032)	(0.0032)	(0.0032)	(0.0032)	
	2nd Block	-	-	(0.0016)	(0.0016)	(0.0016)	(0.0016)	(0.0016)	(0.0016)	(0.0016)	(0.0016)	(0.0016)	(0.0016)	
Street Lights*	1.95% increase	-	-	-	-	-	-	-	-	-	-	-	-	
Unmetered		-	-	(0.0031)	(0.0031)	(0.0031)	(0.0031)	(0.0031)	(0.0031)	(0.0031)	(0.0031)	(0.0031)	(0.0031)	
Revenue Adjustment														
Residential	1st Block	-	-	-135,295	-130,760	-122,238	-99,965	-100,867	-112,392	-99,549	-99,289	-116,737	-140,071	-1,157,163
	2nd Block	-	-	-21,829	-16,736	-12,686	-7,949	-8,521	-9,375	-7,132	-8,116	-13,299	-22,010	-127,653
GS	1st Block	-	-	-40,585	-37,789	-36,677	-34,738	-37,862	-41,278	-38,805	-35,636	-37,325	-40,369	-381,064
	2nd Block	-	-	-44,044	-37,854	-31,766	-32,506	-36,889	-41,667	-39,443	-37,139	-41,510	-43,397	-386,216
LI		-	-	-19,517	-18,117	-19,594	-18,696	-21,129	-20,938	-19,066	-18,997	-20,256	-22,058	-198,369
SI	1st Block	-	-	-7,256	-7,028	-7,408	-8,834	-9,244	-9,062	-8,892	-8,724	-6,371	-6,165	-78,985
	2nd Block	-	-	-7,162	-7,224	-6,477	-8,605	-8,974	-9,047	-9,027	-8,987	-6,295	-5,663	-77,461
Street Lights*		-	-	-3,838	-3,831	-3,827	-3,824	-3,813	-3,815	-3,821	-3,811	-3,804	-3,796	-38,179
Unmetered		-	-	-639	-639	-640	-641	-643	-643	-643	-644	-657	-666	-6,453
TOTAL		**-**	**-**	**-280,166**	**-259,978**	**-241,313**	**-215,758**	**-227,941**	**-248,217**	**-226,377**	**-221,343**	**-246,255**	**-284,196**	**-2,451,544**

2020 Forecast Revenue Shortfall due to Reduced Sales Volume

		Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total-20
Update to October Actuals		ACTUAL										FORECAST		
kWh Sales														
Residential	1st Block	59,834,389	60,105,607	54,118,013	52,304,105	48,895,035	39,985,935	40,346,615	44,956,900	39,819,601	39,715,783	46,694,815	56,028,445	582,805,243
	2nd Block	14,559,134	16,748,241	10,914,374	8,367,914	6,342,931	3,974,423	4,260,698	4,687,343	3,565,830	4,058,092	6,649,693	11,005,000	95,133,673
GS	1st Block	13,074,174	13,445,220	12,682,962	11,809,210	11,461,659	10,855,507	11,831,726	12,899,290	12,126,512	11,136,174	11,664,124	12,615,375	145,601,933
	2nd Block	22,171,379	23,341,438	20,973,467	18,025,754	15,126,768	15,479,239	17,566,171	19,841,447	18,782,444	17,685,076	19,766,785	20,665,337	229,425,306
LI		12,883,401	12,370,449	13,011,666	12,078,072	13,062,423	12,463,746	14,086,206	13,958,809	12,710,740	12,664,906	13,504,017	14,705,565	157,500,000
SI	1st Block	2,335,689	2,285,828	2,267,402	2,196,299	2,315,062	2,760,779	2,888,689	2,831,885	2,778,704	2,726,327	1,991,057	1,926,552	29,304,273
	2nd Block	4,919,002	5,046,532	4,476,249	4,514,845	4,048,261	5,378,035	5,608,908	5,654,527	5,642,154	5,616,880	3,934,234	3,539,343	58,378,970
Street Lights*		383,339	381,781	379,504	376,638	373,848	372,491	371,898	371,293	370,502	371,022	513,322	524,662	4,790,299
Unmetered		222,353	205,880	205,982	205,996	206,522	206,778	207,303	207,331	207,331	207,669	211,813	214,929	2,509,888
		130,382,860	133,930,976	119,029,619	109,878,833	101,832,509	91,476,933	97,168,214	105,408,825	96,003,818	94,181,929	104,929,860	121,225,209	1,305,449,585
January Sales Forecast														
kWh Sales														
Residential	1st Block	59,306,304	57,387,443	53,412,530	53,848,976	46,688,247	42,726,216	41,843,845	44,969,066	44,677,265	42,792,645	48,536,720	59,229,901	595,419,158
	2nd Block	14,533,732	12,540,506	8,883,473	8,125,638	4,449,783	3,551,478	3,577,211	3,317,447	3,196,390	3,369,149	6,024,347	9,722,586	81,291,739
GS	1st Block	12,814,200	12,886,400	12,182,234	12,515,038	12,252,535	12,436,934	13,266,379	13,722,304	13,398,540	11,864,352	11,601,377	12,571,330	151,511,623
	2nd Block	22,390,924	23,136,150	20,261,671	21,169,459	19,212,104	19,615,169	20,360,424	23,167,822	22,490,111	19,651,933	19,853,613	20,419,131	251,728,511
LI		13,146,834	11,245,644	11,614,360	13,355,447	13,786,795	14,006,224	13,853,772	14,985,500	13,376,575	13,504,786	13,504,017	13,120,044	159,500,000
SI	1st Block	2,317,434	2,210,014	2,105,783	2,196,920	2,552,042	2,761,049	2,790,425	2,939,891	2,972,212	2,823,637	2,623,786	2,572,533	30,865,725
	2nd Block	4,724,250	4,991,155	4,339,231	4,653,729	4,727,588	5,971,225	5,780,120	6,307,475	6,414,340	5,596,777	5,259,236	4,648,829	63,413,954
Street Lights*		411,678	408,410	404,723	401,134	398,830	397,250	396,312	395,925	395,214	394,003	393,712	393,461	4,790,651
Unmetered		220,038	206,042	206,590	206,952	206,969	207,505	206,069	205,736	207,912	207,941	207,941	220,195	2,509,888
Sales Volume Variance														
Residential	1st Block	528,085	2,718,164	705,483	(1,544,871)	2,206,788	(2,740,281)	(1,497,230)	(12,166)	(4,857,664)	(3,076,862)	(1,841,904)	(3,201,457)	(12,613,915)
	2nd Block	25,402	4,207,735	2,030,901	242,276	1,893,148	422,945	683,487	1,369,896	369,440	688,943	625,346	1,282,415	13,841,934
GS	1st Block	259,974	558,820	500,728	(705,828)	(790,876)	(1,581,427)	(1,434,653)	(823,014)	(1,272,028)	(728,178)	62,747	44,045	(5,909,690)
	2nd Block	(219,545)	205,288	711,796	(3,143,705)	(4,085,336)	(4,135,930)	(2,794,253)	(3,326,375)	(3,707,667)	(1,966,857)	(86,828)	246,207	(22,303,205)
LI		(263,433)	1,124,805	1,397,306	(1,277,375)	(724,372)	(1,542,478)	232,434	(1,026,691)	(665,835)	(839,880)	-	1,585,521	(2,000,000)
SI	1st Block	18,255	75,814	161,619	(621)	(236,980)	(270)	98,264	(108,006)	(193,508)	(97,310)	(632,729)	(645,980)	(1,561,452)
	2nd Block	194,752	55,377	137,018	(138,884)	(679,327)	(593,190)	(171,212)	(652,948)	(772,186)	20,103	(1,325,002)	(1,109,486)	(5,034,984)
Street Lights*		(28,339)	(26,629)	(25,219)	(24,496)	(24,982)	(24,759)	(24,414)	(24,632)	(24,712)	(22,981)	119,610	131,201	(352)
Unmetered		2,315	(162)	(608)	(956)	(447)	(727)	1,234	1,595	(581)	(272)	3,873	(5,266)	(1)
Residential	1st Block	0.1434	0.1434	0.1434	0.1434	0.1434	0.1434	0.1434	0.1434	0.1434	0.1434	0.1434	0.1434	
	2nd Block	0.1134	0.1134	0.1134	0.1134	0.1134	0.1134	0.1134	0.1134	0.1134	0.1134	0.1134	0.1134	
GS	1st Block	0.1739	0.1739	0.1739	0.1739	0.1739	0.1739	0.1739	0.1739	0.1739	0.1739	0.1739	0.1739	
	2nd Block	0.1126	0.1126	0.1126	0.1126	0.1126	0.1126	0.1126	0.1126	0.1126	0.1126	0.1126	0.1126	
LI		0.0686	0.0686	0.0686	0.0686	0.0686	0.0686	0.0686	0.0686	0.0686	0.0686	0.0686	0.0686	
SI	1st Block	0.1703	0.1703	0.1703	0.1703	0.1703	0.1703	0.1703	0.1703	0.1703	0.1703	0.1703	0.1703	
	2nd Block	0.0844	0.0844	0.0844	0.0844	0.0844	0.0844	0.0844	0.0844	0.0844	0.0844	0.0844	0.0844	
Street Lights*		0.4740	0.4740	0.4740	0.4740	0.4740	0.4740	0.4740	0.4740	0.4740	0.4740	0.4740	0.4740	
Unmetered		0.1678	0.1678	0.1678	0.1678	0.1678	0.1678	0.1678	0.1678	0.1678	0.1678	0.1678	0.1678	
Revenue Adjustment														
Residential	1st Block	75,727	389,785	101,166	-221,534	316,453	-392,956	-214,703	-1,745	-696,589	-441,222	-264,129	-459,089	-1,808,835
	2nd Block	2,881	477,157	230,304	27,474	214,683	47,962	77,507	155,346	41,894	78,126	70,914	145,426	1,569,675
GS	1st Block	45,210	97,179	87,077	-122,744	-137,533	-275,010	-249,486	-143,122	-221,206	-126,630	10,912	7,659	-1,027,695
	2nd Block	-24,721	23,115	80,148	-353,981	-460,009	-465,706	-314,633	-374,550	-417,483	-221,468	-9,777	27,723	-2,511,341
LI		-18,072	77,162	95,855	-87,628	-49,692	-105,814	15,945	-70,431	-45,676	-57,616	0	108,767	-137,200
SI	1st Block	3,109	12,911	27,524	-106	-40,358	-46	16,734	-18,393	-32,954	-16,572	-107,754	-110,010	-265,915
	2nd Block	16,437	4,674	11,564	-11,722	-57,335	-50,065	-14,450	-55,109	-65,172	1,697	-111,830	-93,641	-424,953
Street Lights*		-13,432	-12,622	-11,953	-11,611	-11,841	-11,735	-11,572	-11,675	-11,713	-10,893	56,693	62,186	-167
Unmetered		389	-27	-102	-160	-75	-122	207	268	-97	-46	650	-884	(0)
Subtotal - kWh Sales Variance		**87,528**	**1,069,334**	**621,583**	**-782,012**	**-225,707**	**-1,253,492**	**-694,450**	**-519,411**	**-1,448,997**	**-794,623**	**-354,321**	**-311,862**	**(4,606,431)**
Other Volume Variances & Adjustments*		25,075	15,375	78,376	-22,602	-132,821	-85,093	-47,379	-48,126	-45,245	3,804	110,901	125,716	(22,019)
Total Sales Volume Variance		**$ 112,603**	**$ 1,084,709**	**$ 699,959**	**$ (804,614)**	**$ (358,528)**	**$ (1,338,586)**	**$ (741,829)**	**$ (567,537)**	**$ (1,494,242)**	**$ (790,819)**	**$ (243,420)**	**$ (186,147)**	**$ (4,628,450)**

*Included in other are variances in service charges, demand charges, interruptable credits and billing adjustments.

Scenario 7 Impact

Revenue Requirement ($)						
	Original Application Proposed		IR 97 Scenario 7		Difference from Proposed	
	2020 Forecast	2021 Forecast	2020 Forecast	2021 Forecast	2020 Forecast	2021 Forecast
Operating Expenses (Net of ECAM)*	$ 162,897,200	$ 169,336,300	$ 158,227,200	$ 169,389,200	$ (4,670,000)	$ 52,900
Interest Expense (including amortization of Debt Issue Costs)	12,844,400	12,854,300	12,794,700	12,968,100	(49,700)	113,800
Amortization - Fixed Assets	28,572,100	26,202,300	28,386,200	26,200,600	(185,900)	(1,700)
Amortization - DSM Costs	127,400	166,600	127,400	166,600	-	-
Amortization - Lepreau Write-down	93,400	93,400	93,400	93,400	-	-
Amortization - Storm Deferral	3,002,900	-	3,002,900		-	-
Amortization - Rate Delay Deferral**	-	-	-	2,743,500	-	2,743,500
Income Tax Expense	6,742,200	6,978,200	6,640,300	6,969,000	(101,900)	(9,200)
Return on Equity***	14,842,900	15,371,400	14,617,800	15,350,700	(225,100)	(20,700)
Total Gross Electric Revenue	**229,122,500**	**231,002,500**	**223,889,900**	**233,881,100**	**(5,232,600)**	**2,878,600**
Rate of Return Adjustment	(3,002,900)	-	(3,002,900)	-	-	-
Weather Normalization Adjustment	(1,057,300)	-	102,300	-	1,159,600	-
Other Revenue	(13,425,300)	(13,217,400)	(16,432,100)	(13,277,500)	(3,006,800)	(60,100)
Revenue Requirement to be Collected Through Customer Rates	**$ 211,637,000**	**$ 217,785,100**	**$ 204,557,200**	**$ 220,603,600**	**$ (7,079,800)**	**$ 2,818,500**

* *Excluding Fortis Inc. Costs*

*** Remaining balance of $457,300 will be collected in January & February 2022.*

**** Before Disallowable Costs*

Scenario 7 Impact

Impact on Annual Cost March 1 - February 28						
	IR 97 Scenario 7			Original Application Proposed Rates		
March 1 - February 28	**2019/20**	**2020/21**	**2021/22**	**2019/20**	**2020/21**	**2021/22**
Rural Residential Customer (650kWh per Month/7,800 kWh per Year)						
Before Tax Cost	$ 1,443.60	$ 1,451.05	$ 1,488.39	$ 1,443.60	$ 1,459.18	$ 1,476.45
	0.0%	0.5%	2.6%	0.0%	1.1%	1.2%
Total Cost	**$ 1,548.08**	**$ 1,555.91**	**$ 1,595.12**	**$ 1,548.08**	**$ 1,564.45**	**$ 1,582.58**
	-2.4%	0.5%	2.5%	-2.4%	1.1%	1.2%
Urban Residential Customer (650kWh per Month/7,800 kWh per Year)						
Before Tax Cost	$ 1,415.40	$ 1,422.85	$ 1,460.18	$ 1,415.40	$ 1,430.98	$ 1,448.25
	0.0%	0.5%	2.6%	0.0%	1.1%	1.2%
Total Cost	**$ 1,515.65**	**$ 1,523.49**	**$ 1,562.68**	**$ 1,515.65**	**$ 1,532.02**	**$ 1,550.15**
	-2.4%	0.5%	2.6%	-2.4%	1.1%	1.2%
Annual Cost for General Service Customer (10,000kWh/50KW per Month / 120,000 kWh/600KW per Year)						
Before Tax Cost	$ 22,650.82	$ 22,769.67	$ 23,363.95	$ 22,650.82	$ 22,908.71	$ 23,174.45
	0.0%	0.5%	2.6%	0.0%	1.1%	1.2%
Total Cost	**$ 26,048.45**	**$ 26,185.13**	**$ 26,868.54**	**$ 26,048.45**	**$ 26,345.02**	**$ 26,650.62**
	0.0%	0.5%	2.6%	0.0%	1.1%	1.2%

Scenario 7 Impact

Composition of Total Energy Charge per kWh by Rate Class - IR 97 Scenario 7	2016*	2017*	2018*	2019	2020	January 1 2021	Cumulative Change over 2018 Rates
Energy Charge per kWh - Revenue Requirement (A)							
Residential - First Block	$ 0.1320	$ 0.1375	$ 0.1409	$ 0.1409	$ 0.1409	$ 0.1452	3.1%
Residential - Second Block	$ 0.1043	$ 0.1087	$ 0.1114	$ 0.1114	$ 0.1114	$ 0.1148	3.1%
General Service - First Block	$ 0.1628	$ 0.1696	$ 0.1739	$ 0.1739	$ 0.1739	$ 0.1795	3.2%
General Service - Second Block	$ 0.1054	$ 0.1098	$ 0.1126	$ 0.1126	$ 0.1126	$ 0.1162	3.2%
Small Industrial - First Block	$ 0.1594	$ 0.1661	$ 0.1703	$ 0.1703	$ 0.1703	$ 0.1757	3.2%
Small Industrial - Second Block	$ 0.7900	$ 0.0823	$ 0.0844	$ 0.0844	$ 0.0844	$ 0.0871	3.2%
Large Industrial	$ 0.0639	$ 0.0673	$ 0.0686	$ 0.0686	$ 0.0686	$ 0.0699	1.9%

Energy Charges per kWh - Other Amounts (B)							
ECAM Charge per kWh	$ 0.0021	$ 0.0012	$ 0.0006	$ 0.0006	$ 0.0006	$ -	-100.0%
Provincial Costs Recoverable per kWh	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0036	-33.1%
Provincial Energy Efficiency Program per kWh	$ -	$ -	$ -	$ -	$ -	$ 0.0013	100.0%
Cable Contingency Fund per kWh	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003	$ -	-100.0%
RORA per kWh	$ (0.0041)	$ (0.0047)	$ (0.0034)	$ (0.0034)	$ (0.0034)	$ (0.0007)	-78.7%
Total Energy Charge per kWh Excluding Basic Revenue	$ 0.0036	$ 0.0021	$ 0.0028	$ 0.0028	$ 0.0028	$ 0.0042	50.0%

Total Energy Charge per kWh (A+B) - Option - Proposed 2020 Revenue Shortfall Deferral							
Residential - First Block	$ 0.1356	$ 0.1396	$ 0.1437	$ 0.1437	$ 0.1437	$ 0.1494	4.0%
Residential - Second Block	$ 0.1079	$ 0.1108	$ 0.1142	$ 0.1142	$ 0.1142	$ 0.1190	4.2%
General Service - First Block	$ 0.1664	$ 0.1717	$ 0.1767	$ 0.1767	$ 0.1767	$ 0.1837	4.0%
General Service - Second Block	$ 0.1090	$ 0.1119	$ 0.1154	$ 0.1154	$ 0.1154	$ 0.1204	4.3%
Small Industrial - First Block	$ 0.1630	$ 0.1682	$ 0.1731	$ 0.1731	$ 0.1731	$ 0.1799	3.9%
Small Industrial - Second Block	$ 0.7936	$ 0.0844	$ 0.0872	$ 0.0872	$ 0.0872	$ 0.0913	4.7%
Large Industrial	$ 0.0675	$ 0.0694	$ 0.0714	$ 0.0714	$ 0.0714	$ 0.0741	3.8%

* Rate changes effective March 1.

Scenario 7 Impact

January 2020 Rate Application
Supplemental Information - 2019, 2020 and 2021 Inputs

Calculation of Rate Base ($)								
			Proposed in Original Application		IR 97 Scenario 7		Difference from Proposed	
Components	2018 Actual	2019 Actual	2020 Forecast	2021 Forecast	2020 Forecast	2021 Forecast	2020 Forecast	2021 Forecast
Fixed Assets	$ 654,053,538	$ 679,767,856	$ 712,215,800	$ 693,668,900	$ 705,485,600	$ 693,668,900	(6,730,200)	-
Less: Capital Work in Progress	(1,688,342)	(3,750,888)	-	-	(2,950,000)	-	(2,950,000)	-
Less: Accumulated Amortization	(236,162,822)	(245,078,293)	(269,903,600)	(231,933,900)	(269,717,700)	(231,746,300)	185,900	187,600
Less: Contributions in Aid of Construction (net of amortization)	(24,185,307)	(23,691,857)	(24,598,000)	(25,496,000)	(23,476,600)	(24,411,500)	1,121,400	1,084,500
Less (Add): Future Income Tax Liability (Asset) - net of Long Term Receivable	(7,496,013)	(13,522,753)	(19,754,200)	(26,214,600)	(23,814,200)	(30,547,300)	(4,060,000)	(4,332,700)
Less (Add): Costs Payable to (Recoverable from) Customers Post 2003	3,976,693	2,772,690	72,200	(478,100)	-	3,500	(72,200)	481,600
Less (Add): Regulatory Liability (Asset) - As Established by Commission Order WNRA	(290,982)	(1,057,328)	-	-	-	-	-	-
Add: Deferred Financing Costs	859,810	961,283	947,500	933,000	947,500	933,000	-	-
Add: Intangible Assets	3,915,322	4,002,494	4,150,000	4,300,000	4,150,000	4,300,000	-	-
Add: Deferred Demand Side Management Costs	156,998	127,446	166,600	-	166,600	-	-	-
Add: Deferred Charge (Section 47(4)(a)(ii) of the EPA)	1,586,343	1,492,744	1,399,400	1,305,900	1,399,400	1,305,900	-	-
Add: Regulatory Asset - Storm Deferral	-	3,002,882	-	-	-	-	-	-
Add: Regulatory Asset - Revenue Shortfall Deferral	-	-			3,200,800	457,300	3,200,800	457,300
Less: Employee Future Benefits Liability	(7,837,014)	(7,631,568)	(7,711,700)	(7,961,700)	(7,711,700)	(7,961,700)	-	-
Less (Add): Regulatory Liability OPEB	1,168,904	2,536,000	2,986,600	2,813,800	2,986,600	2,813,800	-	-
Less: Regulatory Liability - Rebates Payable to Customers	(15,725,025)	(15,453,528)	(5,847,300)	(4,648,100)	(1,317,200)	(303,500)	4,530,100	4,344,600
Add: Reg Asset - CTGS Accumulated Reserve Variance	-	-	9,654,500	9,654,500	9,654,500	9,654,500	-	-
Plus: Working Capital Allowance Comprised of:							-	-
- Inventory	2,793,911	3,240,398	3,000,000	3,000,000	3,000,000	3,000,000	-	-
- Gross Operating Expenses X 3.6% (net of disallowed costs)	5,376,947	5,508,778	5,852,400	6,098,100	5,750,800	6,098,100	(101,600)	-
Income Taxes Paid X 3.6%	126,000	21,000	(21,000)	-	(21,000)	-	-	-
Total Rate Base	**$ 380,628,962**	**$ 393,247,356**	**$ 412,609,200**	**$ 425,041,800**	**$ 407,733,400**	**$ 427,264,700**	**$ (4,875,800)**	**$ 2,222,900**
Average Rate Base		**$ 386,938,159**	**$ 402,928,278**	**$ 418,825,500**	**$ 400,490,378**	**$ 417,499,100**	**$ (2,437,900)**	**$ (1,326,400)**

Calculation of Return on Average Rate Base ($) & (%)							
		As Proposed		IR 97 Scenario 7		Difference from Proposed	
	2019 Actual	2020 Forecast	2021 Forecast	2020 Forecast	2021 Forecast	2020 Forecast	2021 Forecast
Total Revenue	$ 210,720,773	$ 229,122,500	$ 231,002,500	$ 223,889,900	$ 233,881,100	$ (5,232,600)	$ 2,878,600
Less: Operating Expenses (net of ECAM)	(153,485,663)	(162,897,200)	(169,336,300)	(158,227,200)	(169,389,200)	4,670,000	(52,900)
Less: Amortization of debt issue costs	(13,004)	(13,800)	(14,500)	(13,800)	(14,500)	-	-
	57,222,106	66,211,500	61,651,700	65,648,900	64,477,400	(562,600)	2,825,700
Less: Amortization Fixed Assets	(23,337,238)	(28,572,100)	(26,202,300)	(28,386,200)	(26,200,600)	185,900	1,700
Less: Amortization Deferred Charges	(250,598)	(3,223,700)	(260,000)	(3,223,700)	(3,003,500)	-	(2,743,500)
	(23,587,836)	(31,795,800)	(26,462,300)	(31,609,900)	(29,204,100)	185,900	(2,741,800)
Earnings Before Income Taxes and Financing Costs	33,634,270	34,415,700	35,189,400	34,039,000	35,273,300	(376,700)	83,900
Income Taxes	(6,483,242)	(6,742,200)	(6,978,200)	(6,640,300)	(6,969,000)	101,900	9,200
Earnings on Average Rate Base (interest expense excluded)	$ 27,151,028	$ 27,673,500	$ 28,211,200	$ 27,398,700	$ 28,304,300	(274,800)	93,100
Rate Base - Year End Average	$ 386,938,159	$ 402,928,278	$ 418,825,500	$ 400,490,378	$ 417,499,100	(2,437,900)	(1,326,400)
Actual/Forecast Return on Average Rate Base	**7.02%**	**6.87%**	**6.74%**	**6.84%**	**6.78%**	**-0.03%**	**0.04%**

Supporting Calculations for Scenario 7

Revised Revenue Shortfall		**2020**	
Reduction in Electric Revenue due to Lower Sales and Delay in Rates		$ 7,079,900	
Reduction in Other Revenue Forecast		193,543	
Reduction In Operating Expenses:			
Reduction in Net Energy Costs due to lower NPP (Note 1)	$ (3,436,118)		
Reduction in Net Energy Costs due to No Change to ECAM Base Rate (Note 2)	(753,655)		
Reductions in Other Operating Expenses	(925,780)		
2020 EE&C Plan not included in Revenue Requirement	445,553	(4,670,000)	
Reduction in Depreciation & Interest Expense		(245,100)	
November & December Interest on RORA		**29,408**	
October 2020 YTD Adjustment to WNRA		102,300	
December 31, 2019 WNRA Balance Not Applied to Revenue Requirement		1,057,328	
Not Approved		(346,703)	
Approved Revenue Shortfall		**$ 3,200,676**	
	Per Month	**2021**	**2022**
Amortized over 14 months	$ -		

Note 1 - Reduction in Net Energy Costs due to lower NPP		**Jan 1 - Dec 31, 2020**
January Filing, Net Purchased & Produced Energy in kWh	1,450,198,653	
October 2020 YTD Forecast, Net Purchased & Produced Energy in kWh	1,412,690,542	
Lower Forecast NPP from January Filing in kWh	37,508,111	
Existing ECAM Base Rate	$ 91.61	
Reduction in Net Energy Costs due to lower NPP		**$ (3,436,118)**

Note 2 - Reduction in Net Energy Costs due to No Change to ECAM Base Rate		**Mar 1 - Dec 31, 2020**
Net Purchased & Produced Energy in kWh		1,177,585,726
Proposed March 1, 2020 ECAM Base Rate - not approved	92.25	
Existing ECAM Base Rate	91.61	$ (0.64)
Reduction in Proposed Net Energy Costs due to Lower ECAM Base Rate		**$ (753,655)**

CTGS Reserve Deferred

		Per Month	**2021-2025**
CTGS Reserve	**$ -**	**$ -**	**$ -**

RORA Adjustments & Refund Rate	
RORA Balance 10/31/2020	$ 7,864,663
Forecast Refund for November & December 2020	(779,139)
Forecast Interest on RORA for November & December 2020	**29,408**
2019 Hurricane Dorian Deferral Applied to RORA*	(3,002,882)
WNRA @ 12/31/2019, 2020 YTD Adjustment Deferred	**1,057,328**
ECAM	(3,538,669)
2019 EE&C Adjustment	(415,802)
Balance to be refunded	1,214,907
Refund 14 mos (Jan/21-Feb/22)	1,659,431,460
Refund Rate	**$ 0.0007**

PEIEC EE&C Plan	
Proposed	$ 3,100,000
Adjustments:	
2019 Component	(415,802)
2020 Component ($573,000-127,447)	(445,553)
Balance to be recovered thru rider	$ 2,238,645
Total kWh (14 months)	1,659,431,460
PEIEC EE&C Plan Rate Rider per kWh	**$ 0.0013**

Provincial Costs Recoverable		
Lepreau/Dal Debt Repayments	$ 425,000	
	14 Months	$ 5,950,000
Total kWh (14 months)		1,659,431,460
Provincial Costs Recoverable Rate Rider per kWh		**$ 0.0036**

Supporting Calculations for Scenario 7			Breakdown of Revenue Shortfall	
Revised Revenue Shortfall		**2020**	**Sales Volume Variance Due to COVID-19**	**Sales Price Variance Due to Delay in Approving Rates and Changes in Revenue Requirement**
Reduction in Electric Revenue due to Lower Sales and Delay in Rates		$ 7,079,900	$ 4,628,450 *	$ 2,451,544
October 2020 YTD Adjustment to WNRA		102,300	102,300	
Reduction in Other Revenue Forecast		193,543	193,543	-
Reduction In Operating Expenses:				
Reduction in Net Energy Costs due to lower NPP (Note 1)	$ (3,436,118)		(3,436,118) *	-
Reduction in Net Energy Costs due to No Change to ECAM Base Rate	(753,655)			(753,655)
Reductions in Other Operating Expenses	(925,780)		(925,780)	-
2020 EE&C Plan not included in Revenue Requirement	445,553	(4,670,000)		445,553
Reduction in Depreciation & Interest Expense		(245,100)	(245,100)	
November & December Interest on RORA		29,408	29,408	
December 31, 2019 WNRA Balance Not Applied to Revenue Requirement		1,057,328		1,057,328
Total Revenue Shortfall		**$ 3,547,379**	**$ 346,703**	**$ 3,200,770**

* Net Marginal Revenue Impact = $1,192,332

RESPONSE TO INTERROGATORIES FROM COMMISSION STAFF

Section IR-97

APPENDIX 1

REPORT:
COST OF CAPITAL

PREPARED FOR:
MARITIME ELECTRIC COMPANY, LIMITED

BEFORE THE:
ISLAND REGULATORY AND APPEALS COMMISSION

NOVEMBER 27, 2018

www.ceadvisors.com

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I. INTRODUCTION

A. Qualifications

My name is John P. Trogonoski, and I am employed by Concentric Energy Advisors, Inc. ("Concentric") as a Senior Project Manager. My business address is 293 Boston Post Road West, Suite 500, Marlborough, MA 01752. I am testifying on behalf of the Maritime Electric Company, Limited ("Maritime Electric"), an indirect subsidiary of Fortis Inc.

I am among Concentric's professionals who provide expert testimony before U.S. state and Canadian provincial regulatory agencies on matters pertaining to finance, economics and public policy in the utility industry. Concentric provides financial, economic and regulatory advisory services to clients across North America, including utility companies, regulatory and public agencies, and utility sector investors. I advise public utilities, energy companies, public agencies and private equity investors on financial and economic issues pertaining to the utilities industry. This work includes estimating the cost of capital for the purposes of ratemaking and valuation and assessing business and financial risk. I have testified or provided expert evidence in state and provincial jurisdictions including Quebec, New York, and Colorado. This evidence has been provided on behalf of both utilities and regulatory commission staff.

For the past five years, I have co-authored an annual newsletter published by Concentric summarizing allowed ROEs and capital structures for gas and electric utilities in Canada and the U.S., and I also co-authored an article in Public Utilities Fortnightly regarding the use of automatic adjustment mechanisms for setting the cost of equity in Canada. I have also attended industry events and conferences, including the 2016 CAMPUT conference in Montreal.

Prior to joining Concentric, I was a member of the Staff of the Colorado Public Utilities Commission from 1999-2008, where I supervised the financial analysts in the energy and telecommunications sections, provided advisory services to the Commissioners on financial and economic matters, and filed expert testimony on rate of return, revenue requirement, cost allocation, rate design, incentive regulation, and public policy matters. I have a Master's degree in Business Administration and an undergraduate degree in Marketing from the University of Colorado at Denver. My qualifications are detailed more fully in Attachment 1.

B. Executive Summary

I have been asked to provide an estimate of the cost of capital for Maritime Electric for the purpose of establishing the return on equity ("ROE") and capital structure for the proposed three year rate setting period from March 1, 2019 through February 28, 2022. In order to estimate the cost of capital, I have relied upon analytical tools and data sources normally used for such purposes before regulators in Canada and the U.S. I have also reviewed past decisions of the Island Regulatory and Appeals Commission ("Commission") in consideration of such matters. The analysis provided in this report supports my overall recommendation on the cost of equity and capital structure. That analysis includes the following:

1) Examination of the legal and regulatory requirements for determination of a fair rate of return;
2) An overview of economic and capital market conditions in Canada and the U.S. and the degree of integration between the economies of the two countries;
3) Selection of Canadian, U.S. and North American proxy groups comprised of companies that are risk comparable to Maritime Electric;
4) Estimation of the cost of common equity for the proxy group companies using the Discounted Cash Flow ("DCF") method and the Capital Asset Pricing Model ("CAPM");
5) Examination of authorized and earned returns on equity for other investor-owned electric utilities in Canada and the U.S.;
6) Development of a range of results for the Canadian, U.S. and North American proxy groups; and
7) An assessment of the appropriateness of Maritime Electric's proposed capital structure based on an examination of the Company's business and financial risks relative to the respective proxy groups.

As shown in Figure 1, the various ROE estimation models produce a range of results for the proxy group companies from 8.86 percent to 10.13 percent. The average of all methods is 9.46 percent.

Figure 1: Summary of Results (including flotation costs)[1]

	Canadian Regulated Utilities	US Electric	North American Electric	Average
CAPM	10.13%	9.47%	9.56%	9.72%
Constant Growth DCF	9.41%	9.26%	9.26%	9.31%
Multi-Stage DCF	10.13%	8.86%	9.03%	9.34%
Average	9.89%	9.20%	9.28%	9.46%

The average results of the Constant Growth and Multi-Stage DCF analyses for the three proxy groups are within a range from 9.31 percent to 9.34 percent, while the average CAPM results are 9.72 percent. The average results for the Canadian, U.S. Electric and North American Electric proxy groups range from 9.20 percent to 9.89 percent. Based on this analysis, I believe a reasonable estimate of Maritime Electric's required cost of equity is within a range from 9.20 percent to 9.90 percent (bounded by the U.S. electric average for all methods of 9.20 percent on the low end, and the Canadian average of all methods of 9.89 percent on the high end). Within this range, the Company's proposed ROE of 9.35 percent is reasonable, if not conservative. In addition, the Company's proposed common equity ratio of 40.00 percent is lower than that justified by its risk profile and well below the average equity thickness for the U.S. electric and North American electric proxy groups. Maritime Electric is small relative to the companies in the Canadian and U.S. electric proxy groups; the long-term economic and demographic trends on Prince Edward Island are weaker than Canada overall; and Maritime Electric does not have many of the variance and deferral accounts that are common among other regulated electric utilities across Canada.

C. Report Organization

The remainder of the report is organized as follows:

- Section II discusses the legal requirements and regulatory precedents for the determination of a fair rate of return;

[1] DCF results are based on 90-day average stock prices for proxy group companies.

- Section III provides an overview of economic and capital market conditions and their impact on the allowed ROE and capital structure for Maritime Electric;
- Section IV describes the selection of proxy group companies to estimate the cost of equity for Maritime Electric and discusses the precedent in Canada for considering the use of U.S. data;
- Section V discusses the methods used to estimate the cost of equity and summarizes the results of the DCF and CAPM analyses, as well as allowed and earned ROEs for other investor-owned electric utilities;
- Section VI provides an assessment of Maritime Electric's business and financial risks relative to the Canadian and U.S. proxy group companies and recommends an appropriate equity ratio for the Company;
- Section VII describes the proposed earnings sharing mechanism; and
- Finally, Section VIII summarizes my overall conclusions and recommendations.

II. LEGAL REQUIREMENTS AND KEY REGULATORY PRECEDENTS FOR THE DETERMINATION OF A FAIR RETURN

A. The Fair Return Standard

The principles surrounding the concept of a "fair return" for a regulated company were first established by the Supreme Court of Canada in *Northwestern Utilities v. City of Edmonton (1929)* S.C.R. 186 ("Northwestern"), where the Supreme Court found:

> By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.[2]

[2] *Northwestern*, at 193.

U.S. common law regarding fair return for utility cost of capital has evolved similarly. In *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia* (262 U.S. 679, 693 (1923)), the U.S. Supreme Court stated:

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

The U.S. Supreme Court further elaborated on this requirement in its decision in *Federal Power Commission v. Hope Natural Gas Company* (320 U.S. 591, 603 (1944)), when it described the relevant criteria as follows:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock.... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

Over time, the Fair Return Standard has been interpreted many times in both Canada and the U.S. For example, the National Energy Board ("NEB") summarized its interpretation of the "fair return standard" in its RH-2-2004 Phase II Decision and reiterated that interpretation in its *Trans Québec & Maritimes Pipelines Inc.* RH-1-2008 Decision.

> The Board is of the view that the fair return standard can be articulated by having reference to three particular requirements. Specifically, a fair or reasonable return on capital should:
>
> - be comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable investment standard);
> - enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and

> - permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).
>
> In the Board's view, the determination of a fair return in accordance with these enunciated standards will, when combined with other aspects for the Mainline's revenue requirement, result in tolls that are just and reasonable.[3]

All three standards must be met, and none ranks in priority to the others. To that point, the Ontario Energy Board ("OEB") articulated the legal requirements for satisfying the Fair Return Standard in Canada in its 2009 Generic Cost of Capital Order as follows:

> The Board affirms its view that the Fair Return Standard frames the discretion of a regulator, by setting out the three requirements that must be satisfied by the cost of capital determinations of the tribunal. Meeting the standard is not optional; it is a legal requirement. Notwithstanding this obligation, the Board notes that the Fair Return Standard is sufficiently broad that the regulator that applies it must still use informed judgment and apply its discretion in the determination of a rate regulated entity's cost of capital.[4]
>
> ***
>
> … all three standards or requirements (comparable investment, financial integrity, and capital attraction) must be met and none ranks in priority to the others. The Board agrees with the comments made to the effect that the cost of capital must satisfy all three requirements which can be measured through specific tests and that focusing on meeting the financial integrity and capital attraction tests without giving adequate consideration of the comparability test is not sufficient to meet the [Fair Return Standard].[5]

This Commission embraces the same standards for the application of the Fair Return Standard as those put forth by the NEB, the OEB and those established through Canadian and U.S. common law. In that regard, the Commission has stated:

> [59] The Commission in determining a fair return must try to assess the risk associated with the capital invested and the comments provided in the Northwestern Utilities case. Those comments make reference to the fact that the company will be allowed as large a return on the capital invested in

[3] National Energy Board RH-2-2004 Reasons for Decision, TransCanada PipeLines Ltd, Phase II, April 2005, at 17.

[4] Ontario Energy Board, EB-2009-084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, at i.

[5] *Id.*, at 19.

> its enterprise as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.
>
> [60] Regulators and courts have evolved a "fair return standard" in which returns have been set to help utilities provide safe and adequate services to the public at reasonable prices, while ensuring that the utilities involved remain a going concern with sufficient credit worthiness to attract capital needed to maintain and expand their facilities. A utility's duty to serve and the acceptance of the risk associated with this obligation cannot be discounted.[6]

The assessment of whether the Fair Return Standard has been met requires an examination of the returns required by investors in comparable risk enterprises. Investors consider whether there are alternative investment opportunities that would provide a better return for the same risk. This weighing of alternatives and the highly competitive nature of capital markets causes stocks and bonds to settle on a price that provides investors with a return that is adequate for the risks involved. Thus, for any given level of risk, there is a corresponding return that investors expect in order to take on that risk and not invest their money elsewhere. That return is referred to as the "opportunity cost" of capital or "investor required" return.

In addition to setting the fair return at the "opportunity cost" of capital, a fair return must also be adequate to maintain the financial integrity of the utility, which requires a return sufficient to maintain credit metrics such that the utility can maintain a favorable credit rating in order to minimize debt costs and provide lenders assurance that the company's earnings are adequate to meet its fixed obligations. Finally, a fair return must be sufficient to attract incremental capital on reasonable terms and conditions, to the benefit of both investors and customers.

B. The Stand-Alone Principle

The Stand-Alone Principle is a finance principle that advocates for investors and companies selecting investments based on comparisons to other investments of similar risks. In utility regulation, this principle considers a utility as if it were a stand-alone entity, raising capital on the merits of its own business and financial characteristics. In this way, capital may be efficiently

6 The Island Regulatory and Appeals Commission, Docket UE20938, Order UE09-02, May 5, 2009, at 15.

allocated, with each business segment earning a return based on its own unique set of risks and business characteristics regardless of affiliations within a holding company structure. In order to establish a fair return and satisfy the Stand-Alone Principle, the utility must be allowed a return sufficient to meet all three requirements of the Fair Return Standard on the basis of the utility's individual merits and risk profile.

C. The Relationship between Capital Structure and ROE

The cost of common equity depends in part on the company's capital structure. The equity ratio and equity rate of return must therefore be considered together to determine whether the Fair Return Standard has been met. Other factors being equal, firms with lower common equity ratios require higher rates of return to compensate shareholders for the risks associated with higher financial leverage. Consequently, when a regulator approves a capital structure, that decision impacts the required rate of return on common equity.

The risk to the earnings stream of the company is a function of both its business and financial risk. Business risk refers to the political and regulatory environment that the company operates within and the operational and competitive forces that could potentially exert pressure on earnings and cash flows. Financial risk refers to the amount of debt in the utility's capital structure and the extent to which fixed debt obligations must be met before utility shareholders receive their returns. Both business and financial risk should be considered when setting the capital structure.

III. ECONOMIC AND CAPITAL MARKET CONDITIONS

A. Summary of Current Economic and Capital Market Conditions

1. Canada

The global economy is comprised of a complex set of interdependent relationships between countries. It is nearly impossible for a disruption in one major economy not to ripple throughout the global economy. Beginning with the Canadian outlook, the Bank of Canada (the "Bank" or the "BOC") noted in its June 2018 Financial System Review that the global economic expansion has strengthened and broadened across countries. According to the BOC, the Canadian economy is operating close to its potential. Labour income growth is solid, supporting households' ability to service their outstanding debt, albeit in an environment of rising global interest rates.[7] The Bank also notes that solid economic growth has led interest rates in Canada and some other advanced economies to rise from historically low levels. Over the past year, yields on U.S. five-year sovereign bonds have risen by as much as 119 basis points and are currently about 95 basis points higher than a year ago. Sovereign yields in Canada have risen a similar amount, contributing to higher bank funding costs.[8]

The Conference Board of Canada ("Conference Board") reports that the Canadian economy is gradually transitioning to more moderate economic growth, as real GDP growth decelerated markedly in the later part of 2017 to a pace of less than 2.00 percent. Economic growth is not expected to improve in Canada over the long term and will average just 1.70 percent from 2017 through 2040. The weakness in business investment over the past few years will continue to weigh on the economy's growth potential. But the main factor slowing the Canadian economy's potential is the country's aging population, which is limiting growth in the labor force and is heavily influencing income and spending patterns.[9]

Bond yields have risen across all maturities and are reflected in higher borrowing rates for businesses and households. The BOC has increased its overnight rate target by 25 basis points four times since July 2017 to 1.50 percent. The BOC observes that while core inflation remains below the 2.00 percent target, it has evolved largely as expected, with a slight increase in both CPI and the Bank's core measures of inflation, consistent with the dissipating negative impact of temporary price shocks and the absorption of economic slack.[10] The BOC is gradually normalizing monetary policy from its accommodative stance of recent years, while continuing to monitor the excess capacity in labor markets and the impact of rising interest rates on household indebtedness in the midst of the Canadian economic recovery.[11]

In the June 2018 Financial System Review, the Bank of Canada identified three financial system vulnerabilities that may pose risks for the Canadian economy:

---

7 Bank of Canada, Financial System Review, June 2018, at 1.

8 *Ibid.*

9 The Conference Board of Canada, "Provincial Outlook Long-Term Economic Forecast 2018," January 19, 2018, at ii.

10 *Ibid.*

11 *Ibid.*

a) Elevated level of household indebtedness: Strong income gains, a significant slowing in household credit growth and improvements in credit quality have begun to ease the vulnerability associated with high household indebtedness. But even as conditions slowly improve, the sheer size of the outstanding debt means that the vulnerability will likely persist at an elevated level for some time.[12]

b) Imbalances in the housing market: Housing prices have increased significantly, especially in Toronto and Vancouver, as employment gains, increased immigration and low interest rates have boosted demand, while geographic constraints and land use regulations have limited housing supply. However, the Bank notes that since last year, declining affordability, tighter mortgage underwriting standards and higher interest rates have weighed on housing demand and price growth, especially for more expensive homes.[13]

c) Cyber threats, operational risks and financial interconnections: According to the BOC, a successful cyber-attack or other operational incident at a financial institution or market infrastructure that propagates across the financial system could interrupt the delivery of crucial financial services. Ongoing collaboration among public and private stakeholders is therefore crucial to addressing evolving cyber and operational vulnerabilities.[14]

The Bank also identified three key risks to the Canadian financial system: 1) the potential for a severe nationwide recession leading to a rise in financial stress (this risk is considered "elevated, but decreasing"); 2) a housing price correction in overheated markets (this risk is considered "moderate"); and 3) a sharp increase in long-term interest rates driven by higher global risk premiums (this risk is considered "moderate, but increasing").[15]

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12 Bank of Canada, Financial System Review, June 2018, at 3.
13 *Id.*, at 9.
14 *Id.*, at 13.
15 *Id.,* at 16.

2. United States

The U.S. economy continues to grow at a moderate pace. At its June 2018 Federal Open Market Committee ("FOMC") meeting, the Federal Reserve raised the federal funds target rate to a range from 2.00 to 2.25 percent, marking the eighth increase in this short-term rate since December 2015.[16] In October 2017, the FOMC also started reducing the size of the Federal Reserve's $4.5 trillion bond portfolio by no longer reinvesting the proceeds of the bonds it holds. In response to the Great Recession, the U.S. Federal Reserve pursued a policy known as "Quantitative Easing," in which it systematically purchased mortgage-backed securities and long-term Treasury bonds to provide liquidity in financial markets and drive down yields on long-term government bonds. Although the Federal Reserve discontinued the Quantitative Easing program in October 2014, it continued to reinvest the proceeds from the bonds it holds. Under the new policy, the FOMC has been gradually reducing the Federal Reserve's securities holdings starting at $10 billion per month in October 2017 and ramping up to $50 billion per month by the end of the first twelve months.[17]

In the minutes released after the August 2018 FOMC meeting, participants noted a number of economic fundamentals were supporting continued above-trend economic growth; these included a strong labor market, stimulative federal tax and spending policies, accommodative financial conditions, and continued high levels of household and business confidence.[18] Participants generally expected that further gradual increases in the target range for the federal funds rate would be consistent with a sustained expansion of economic activity, strong labor market conditions, and inflation near the Committee's symmetric 2.00 percent objective over the medium term.[19] FOMC participants project real GDP growth in the U.S. of 3.10 percent in 2018 and 2.50 percent in 2019, an unemployment rate of 3.70 percent in 2018 and 3.50 percent in 2019, and core inflation of 2.00 percent in 2018 and 2.10 percent in 2019.[20]

16 Federal Reserve Board, press release, March 2018.

17 Federal Reserve press release, Addendum to the Policy Normalization Principles and Plans, June 14, 2017, implemented at FOMC meeting September 20, 2017.

18 Minutes of the Federal Open Market Committee meeting, July 31-August 1, 2018, released August 22, 2018, at 8.

19 *Id.*, at 8.

20 Economic projections of Federal Reserve Board members and Federal Reserve Bank presidents under their individual assessments of projected appropriate monetary policy, September 26, 2018.

B. Projected Bond Yields

According to Consensus Economics' Long-Term Financial Forecast, shown in Figure 2, Canadian and U.S. 10-year government bond yields are expected to rise gradually to reflect movement towards more normalized monetary policy in the respective economies.

Figure 2: Long-Term Forecast for 10-Year Government Bond Yields[21]

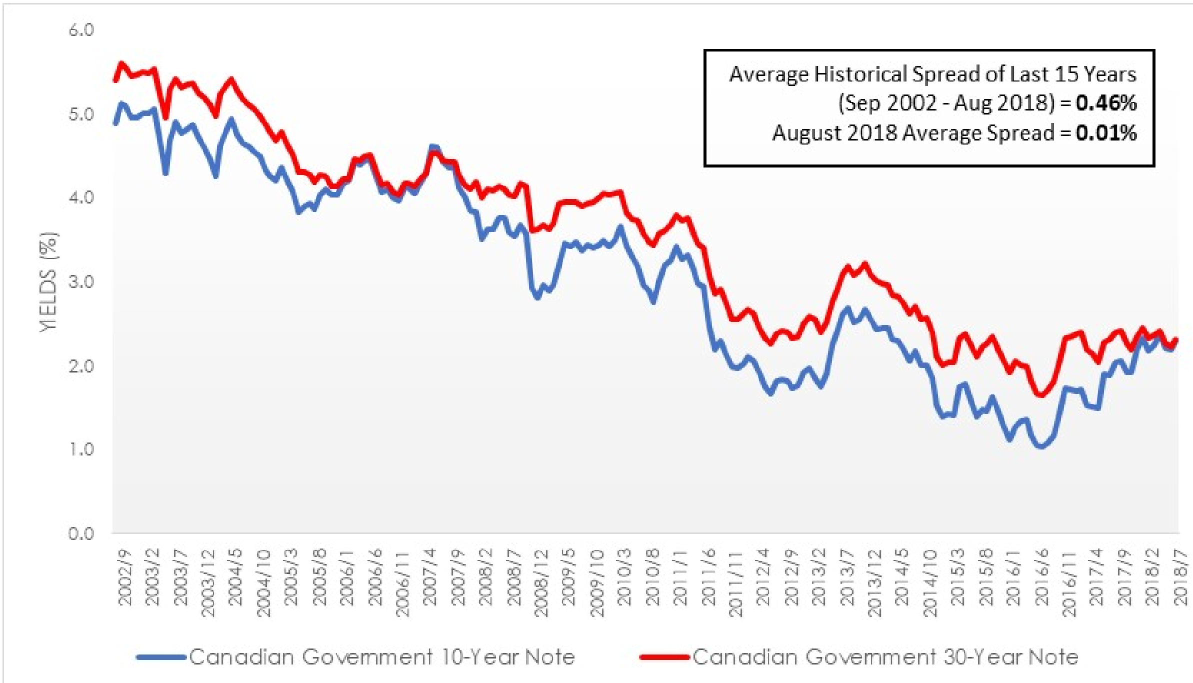
	2019	2020	2021	2022	2023	2024-2028
Canada	2.7%	3.2%	3.3%	3.4%	3.6%	3.6%
U.S.	3.2%	3.5%	3.5%	3.6%	3.6%	3.7%

C. Changes in Capital Markets since 2015

Since Maritime Electric filed its last General Rate Application ("GRA") in October 2015, monetary policy in both Canada and the U.S. has become more restrictive. Increases in both short-term and long-term interest rates on government bonds have resulted in both countries. As shown in Figure 3, the yield on 10-year Canadian government bonds increased from 1.47 percent in October 2015 to 2.30 percent in August 2018, while the yield on longer-term 30-year Canadian government bonds increased from 2.26 percent to 2.31 percent over this same period. Spreads between 10-yr and 30-yr Canadian government bonds decreased from 80 bps in October 2015 to 1 bp in August 2018, well below the historical average of 46 bps from 2002-2018 as the yield curve has flattened. Figure 3 also shows that government bond yields are beginning a transition to more normal levels from all-time lows that reflected the prolonged Quantitative Easing that occurred in both Canada and the U.S. following the global financial and economic crisis.

21 Consensus Forecasts by Consensus Economics Inc., Survey Date April 12, 2018, at 3 and 28.

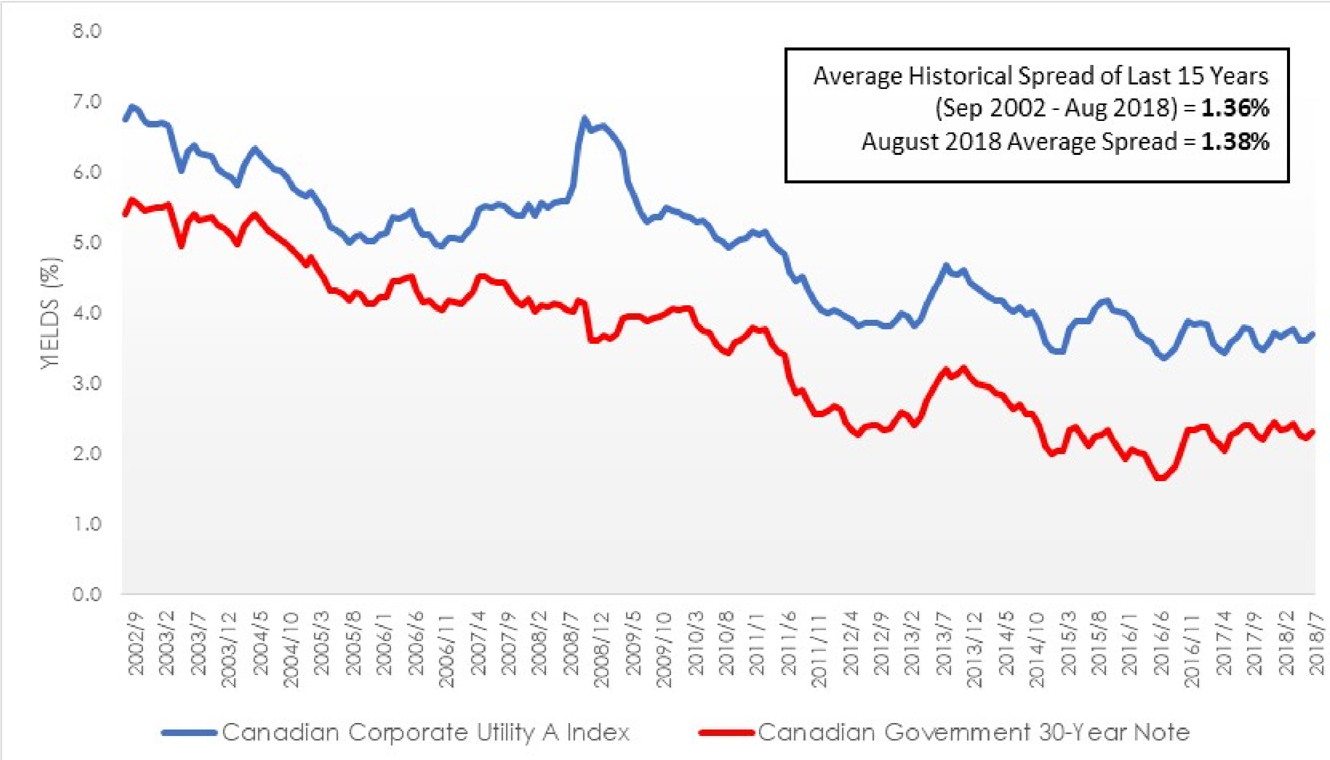
Figure 3: Canadian Government Bond Yields - 10-Year and 30-Year[22]



Yields on corporate bonds have declined since October 2015, despite the increase in long-term government bond yields. As Figure 4 illustrates, the Canadian Utility "A" rated bond yield index was 4.14 percent in October 2015 compared to 3.70 percent in August 2018, a decrease of 44 basis points.

22 Source: Bloomberg series GCAN10YR and GCAN30YR as of August 31, 2018.

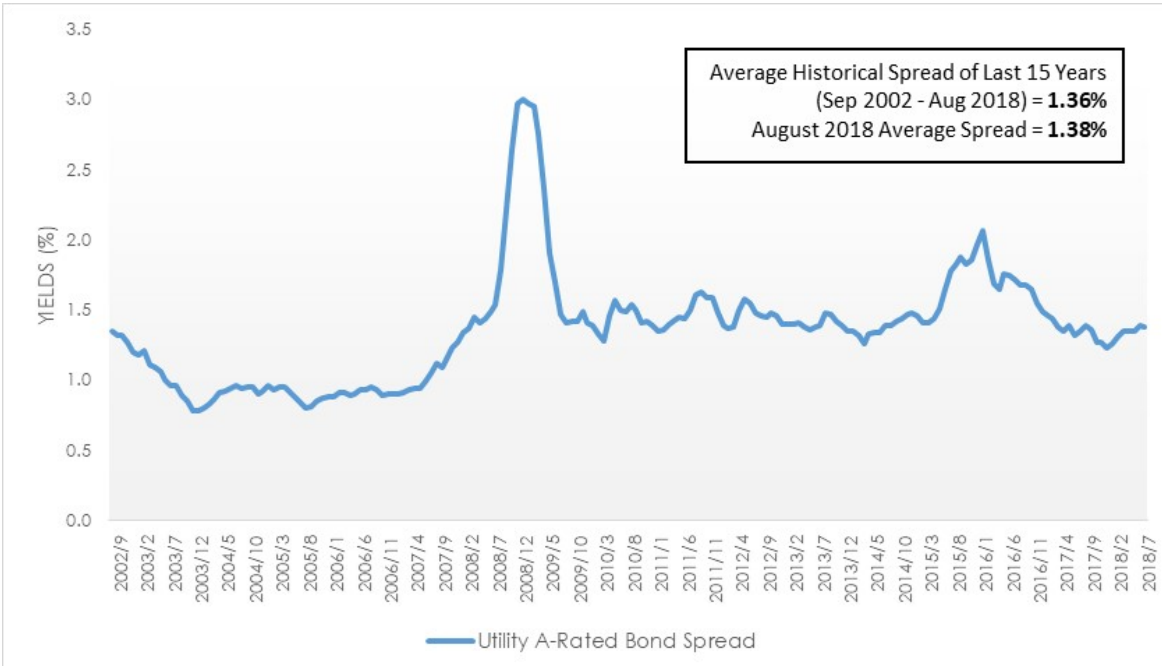
Figure 4: Canadian Utility "A" Rated Bond vs. 30-Year Canada Long Bond[23]



Credit spreads are a measure of the difference between the yields of different securities. These are typically expressed as a spread between bonds of the same maturity, but different quality in terms of risk. As shown in Figure 5, the Canadian Utility "A" rated spread over 30-year government bonds was 1.88 percent in October 2015 versus 1.38 percent in August 2018, a decrease of 50 basis points, indicating a return of the credit spread to average historical levels (1.36 percent from September 2002 through August 2018).

[23] Source: Bloomberg series C29530Y and GCAN30YR as of August 31, 2018.

Figure 5: Canadian Utility "A" Rated Bond Spread vs 30-Year Canada Long Bond[24]



Accompanying the increase in government bond yields, capital market conditions have generally improved in Canada and the U.S. since October 2015. Capital markets continue to recover from the global economic crisis of 2008-2009, but the pace of economic recovery has been slow and a number of unknowns, particularly with respect to U.S. trade policy, still loom on the horizon. Figure 6 provides a snapshot of key market indicators for the S&P/TSX Composite Index,[25] the S&P/TSX Utilities Index,[26] and the S&P/TSX 60 Index.[27] The S&P/TSX Composite, the S&P/TSX Utilities Index and the S&P/TSX 60 price indices have all increased since October 2015; trailing price-to-earnings ratios have decreased for the TSX Composite Index and TSX 60, but have increased for the TSX Utilities Index; dividend yields for all three indices are approximately the same in August 2018 as in October 2015. Over this same period, the 10-year median government bond yield increased from 1.46 percent to 2.30 percent. With the increase in

[24] Source: Bloomberg series C29530Y and GCAN30YR as of August 31, 2018.

[25] The S&P/TSX Composite is a broad market index, comprised of the largest companies on the Toronto Stock Exchange (measured by market capitalization). The companies listed in this index comprise approximately 70 percent of the market capitalization for all Canadian companies listed on the TSX.

[26] The S&P/TSX Utilities Index is comprised of 16 companies with concentration in the Canadian utilities sector.

[27] The S&P/TSX 60 is a stock market index of 60 large companies on the Toronto Stock Exchange, which exposes investors to ten industry sectors.

government bond yields and the generally steady level of equity dividend yields, the ratio of dividend yields to government bonds (D/Y ratio) has decreased from 2.2X to 1.3X for the S&P/TSX; from 3.2 to 2.2X for the S&P/TSX Utilities; and from 2.1X to 1.3X for the S&P/TSX60. This shows that investors now have alternative options for low risk investments, as government bond yields compete more effectively with utility dividend yields.

Figure 6: TSX Market Indicators[28]

	October 2015 Median	August 2018 Median
S&P/ TSX Composite Index		
Price Index	13,829.0	16,330.9
Earnings per Share	$788.0	$1,037.1
Trailing P/E	22.7	17.8
Dividend Yield	3.1%	2.9%
Long Term Growth Rate	9.2%	7.3%
D/Y Ratio	2.2	1.3
S&P/ TSX Utilities Index		
Price Index	1,879.8	1,989.4
Earnings per Share	$82.9	$100.9
Trailing P/E	25.7	31.8
Dividend Yield	4.7%	5.1%
Long Term Growth Rate	N/A	N/A
D/Y Ratio	3.2	2.2
S&P/ TSX 60 Index		
Price Index	$811.9	971.7
Earnings per Share	$49.3	$64.2
Trailing P/E	20.1	16.5
Dividend Yield	3.1%	3.0%
Long Term Growth Rate	8.9%	7.1%
D/Y Ratio	2.1	1.3
10-Year Canada Bond Yield	1.46%	2.30%

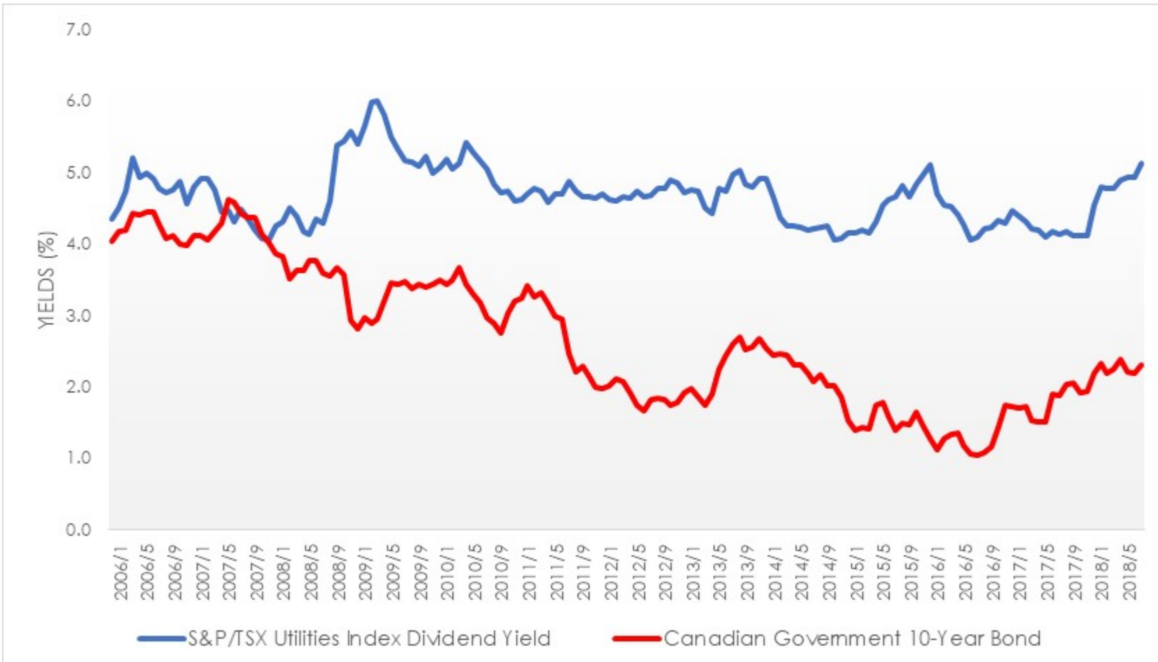
Source: Data from Bloomberg

Historically, utility dividend yields and government bond yields have enjoyed a relatively high degree of correlation. Since the global recession in 2008-2009, however, these yields have separated, as shown in Figure 7. One interpretation is that investors are expecting higher

[28] A long-term growth rate for the TSX Utilities Index is not available from Bloomberg.

government bond yields in the future, so rather than take the risk of rising rates diminishing the value of government bonds, they have favored a low-risk substitute—utility stocks. That trend has begun to turn, although the pre-Great Recession parity in yields has not been restored.

Figure 7: S&P/TSX Utilities Index Dividend Yield vs. 10-Year GOC Bond Yields[29]



In summary, the global economy is stronger today than it was in October 2015, and this strength is reflected in higher stock prices and rising interest rates. Expectations for GDP growth and inflation are both increasing over the near to medium term. Equity valuations have increased, reflecting greater investor confidence in earnings growth as the broader economy continues to recover. As indicated previously, the expectation is that tighter monetary policy and stronger economic growth in the next several years will lead to higher interest rates in both Canada and the U.S. Financial markets reflect earnings growth optimism through higher valuations, but rising interest rates could jeopardize these valuations, especially for interest rate sensitive sectors such as utilities. The cost of capital is a prospective construct and requires a forward-looking analysis as I present in the following sections. There is little doubt that interest rates and bond

29 Source: Bloomberg Series STUTILX and GCAN10YR as of August 31, 2018.

yields have reached a low and now are on an upward trajectory; this must be accounted for in the required equity return.

D. Integration of Canadian and U.S. Capital Markets

In a world of increasingly linked economies and capital markets, investors seek returns from a global basket of investment options. Investors distinguish between risks on a country-to-country basis, factoring in the comparability of the economic and business environments.

Country-specific economic and business conditions that affect investment risk can be measured through a variety of qualitative and quantitative metrics. One such measure, produced by the Economist Intelligence Unit (affiliated with the *Economist* magazine), ranks the world's largest economies based on a range of factors impacting the business environment. According to the report:

> The business rankings model measures the quality or attractiveness of the business environment in the 82 countries covered by *The Economist Intelligence Unit's Country Forecast* reports. It is designed to reflect the main criteria used by companies to formulate their global business strategies, and is based not only on historical conditions but also on expectations about conditions prevailing over the next five years…
>
> … The business rankings model examines ten separate criteria or categories, covering the political environment, the macroeconomic environment, market opportunities, policy towards free enterprise and competition, policy towards foreign investment, foreign trade and exchange controls, taxes, financing, the labor market and infrastructure. Each category contains a number of indicators that are assessed by the Economist Intelligence Unit for the last five years and the next five years. The number of indicators in each category varies from five (foreign trade and exchange regimes) to 16 (infrastructure), and there are 91 indicators in total. Each of the 91 indicators is scored on a scale from 1 (very bad for business) to 5 (very good for business).[30]

The business environment ranks are updated annually in individual country forecasts. Based on the most recent update, which provides the projected 2017-2021 rank for 82 countries, the business environments of Canada and the U.S. are ranked third and fourth, respectively, over the

[30] The Economist Intelligence Unit "Business Environment Rankings; Which country is best to do business in?" Economist Intelligence Unit Limited 2014, at 8.

projected five years.[31] This suggests that from a business investment perspective, Canada and the U.S. are highly comparable in a global context.

The magnitude and significance of trade between the two countries reflects the high degree of integration between the two economies. For example, in 2017, 74.70 percent of Canada's total exports went to the U.S., and imports from the U.S. accounted for 64.60 percent of Canada's total imports.[32]

Exhibit JPT-1 presents several measures that reflect the overall economic and investment environment in Canada and the U.S. The first measure compares the returns to investors from the S&P/TSX and S&P 500 stock indices. From 1993 through 2017, the average annual total return on the S&P/TSX for was 9.99 percent compared to 10.97 percent for the S&P 500. Returns for the period have been highly correlated[33] at 0.68, moving together for the most part. Turning to utility stock indices, U.S. utility returns have typically shown a close historical relationship to Canadian utility returns over the last 25 years, with U.S. utility returns exceeding the Canadian returns by approximately 61 bps for the entire period. In the most recent five years, however, the difference has grown to 574 bps, primarily due to one extraordinary year in the U.S. These returns are also positively correlated at a coefficient of 0.58 for the 25-year period.

Exhibit JPT-1 also shows that the correlation between real GDP growth rates in the two countries is strong, as is the correlation between the consumer price indices, indicating that these metrics tend to move together over time. Over the 25-year period, real GDP growth has averaged 2.56 percent in Canada and 2.49 percent in the U.S., while consumer inflation has

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31 *See:* http://country.eiu.com/article.aspx?articleid=965872080&Country=Canada&topic=Business&subtopic=Business+environment&subsubtopic=Rankings+overview and http://country.eiu.com/article.aspx?articleid=75451591&Country=United%20States&topic=Business&subtopic=Business+environment&subsubtopic=Rankings+overview.

32 Source: Statistics Canada, Imports, exports and trade balance of goods on a balance-of-payments basis, by country or country grouping, updated 5.3.2018 at http://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/gblec02a-eng.htm.

33 Correlation measures the strength of the linear relationship. Two variables moving along identical paths in the same direction will have a correlation of 1.0; if the two variables move in perfectly opposite directions, they will have a correlation coefficient of -1.0; and if they exhibit no signs of a linear relationship, the two variables will have a correlation coefficient of 0.

averaged 1.78 percent in Canada and 2.26 percent in the U.S. Unemployment rates over the 25-year period have been higher in Canada (7.72 percent vs. 5.91 percent in the U.S.), as correlation in employment rates between the two countries is lower than other macroeconomic indicators at 0.31.

Average yields on 10-year government bonds have been similar in Canada and the U.S. Over the past decade, the yield on the 10-year Canadian government bond averaged 2.38 percent, while the yield on the 10-year U.S. Treasury bond averaged 2.58 percent. The 5-year averages for the Canadian and U.S. 10-year government bonds are 1.81 percent for Canada and 2.23 percent for the U.S. The average yield on 10-year government bonds for 2017 was 1.80 percent in Canada and 2.30 percent in the U.S. The correlation between average yields on 10-year government bonds in Canada and the U.S. since 1990 has been strong at 0.98. Correlations of this degree are reflective of closely-integrated financial markets. As shown on Exhibit JPT-1, 30-year government bond yields are also highly correlated between Canada and the U.S., at 0.99.

On balance, the economic and business environments of Canada and the U.S. are highly-integrated and exhibit strong correlation across a variety of metrics, including GDP growth and government bond yields. From a business risk perspective, including overall business environment and competitiveness, Canada and the U.S. are ranked closely when compared against other developed and developing countries. Based on these macroeconomic indicators, there are no fundamental dissimilarities between Canada and the U.S. (in terms of economic growth, inflation, or government bond yields) that would cause a reasonable investor to have a materially different return expectation for a group of comparable risk utilities in the two countries. My cost of capital analysis is framed by the conclusion that Canada and the U.S. have comparable macroeconomic and investment environments. I therefore consider both Canadian and U.S. proxy companies for my analysis.

IV. SELECTION OF PROXY COMPANIES

Since the ROE is a market-based concept and given the fact that Maritime Electric is not publicly-traded, it is necessary to establish a group of companies that is both publicly-traded and comparable to Maritime Electric's business and financial risk characteristics to serve as its "proxy" for purposes of estimating the cost of equity. Even if Maritime Electric's regulated electric utility operations made up the entirety of a publicly-traded entity, transitory events could bias that entity's market value in one way or another over a given period. A significant benefit of using a proxy group is that it mitigates the effects of company-specific events that may be transitory in nature. The proxy companies used in my ROE analyses each possess business and financial risk profiles similar to Maritime Electric's regulated electric utility operations, and thus provide a reasonable basis for the derivation and assessment of ROE and capital structure estimates.

I developed three proxy groups for the ROE analysis. The first proxy group is comprised of publicly-traded, regulated Canadian electric and natural gas utility companies. Recognizing there are very few publicly-traded companies in the utility sector in Canada, the only screening criterion was an investment grade credit rating, which all companies in the sector have. Fortis, Inc. was excluded from the Canadian proxy group because it is the parent company of Maritime Electric. TransCanada was excluded due to the risk profile of the TransCanada Mainline, which arguably presents more risk than regulated electric utility operations. AltaGas was excluded because it recently completed the acquisition of WGL Holdings. The following four companies comprise the Canadian proxy group:

Figure 8: Canadian Proxy Group

Company	Ticker
Canadian Utilities Limited	CU
Emera, Inc.	EMA
Enbridge, Inc.	ENB
Valener	VNR

The second proxy group is comprised of U.S. electric utility companies that investors would consider as generally comparable in risk to Maritime Electric. To obtain companies of comparable risk, I applied a number of screens to develop a group of companies that is primarily engaged in the provision of regulated electric utility service. Starting with the 40 companies that Value Line classifies as Electric Utilities, I screened for companies that meet the following criteria:

a) Credit ratings of at least BBB+ from S&P or Baa1 from Moody's;

b) Consistently pay quarterly cash dividends, with no recent reductions or omissions of the dividend payment;

c) Positive earnings growth rate forecasts from at least two sources;

d) At least 70.00 percent of operating income derived from regulated operations in the period from 2015-2017;

e) At least 90.00 percent of regulated operating income derived from electric utility service in the period from 2015-2017; and

f) Not involved in a merger or other significant transformative transaction during the evaluation period.

The following U.S. electric utility companies met these screening criteria:

Figure 9: U.S. Electric Proxy Group

Company	Ticker
ALLETE, Inc.	ALE
Alliant Energy Corp.	LNT
American Electric Power Company	AEP
Duke Energy Corporation	DUK
Edison International, Inc.	EIX
Eversource Energy	ES
OGE Energy Corporation	OGE
Pinnacle West Capital Corp.	PNW
PNM Resources, Inc.	PNM

The third proxy group is comprised of all nine U.S. electric utilities in Figure 9 plus the two Canadian investor-owned utilities that are primarily engaged in the provision of electricity (Canadian Utilities Limited and Emera). This group is referred to as the North American Electric proxy group shown in Figure 10.

Figure 10: North American Electric Proxy Group

Company	Ticker
ALLETE, Inc.	ALE
Alliant Energy Corp.	LNT
American Electric Power Company	AEP
Canadian Utilities Limited	CU
Duke Energy Corporation	DUK
Edison International, Inc.	EIX
Emera, Inc.	EMA
Eversource Energy	ES
OGE Energy Corporation	OGE
Pinnacle West Capital Corp.	PNW
PNM Resources, Inc.	PNM

Exhibit JPT-2 provides additional details on the proxy group screening process.

The development of a proxy group comprised entirely of Canadian electric utilities is compromised by the small number of publicly-traded utilities in Canada and by the fact that many of those Canadian companies derive a significant percentage of revenues and net income from operations other than regulated electric utility service. This problem has been exacerbated by the continuing trend toward mergers and acquisitions in the utility industry, both within Canada and across the border with U.S. utility holding companies. For these reasons, many utility regulators across Canada have accepted the use of U.S. data and proxy groups to estimate the allowed ROE for Canadian regulated utilities primarily due to the lack of sufficient Canadian data, and in recognition of the need for Canadian utilities to compete for capital in a global marketplace. The NEB, the BCUC, the OEB, the Alberta Utilities Commission and the Régie de L'Energie (Quebec) have all placed some weight on U.S. data and proxy groups for purposes of establishing the allowed ROE and common equity ratio for Canadian electric and gas utilities.[34] In summary, multiple regulatory authorities in Canada have recognized that Canadian utility companies are competing for capital in global financial markets and that Canadian data are limited by the small number of publicly-traded utilities. Canadian regulators have also recognized the integrated nature of Canadian and U.S. financial markets, and the similarity of the utility regulatory regimes.

V. METHODS FOR ESTIMATING THE COST OF EQUITY

A. Financial Models to Estimate the Cost of Equity

Multiple approaches have been developed to estimate the cost of common equity. These financial models rely on market-based data to quantify investor expectations regarding required equity returns, adjusted for certain incremental costs and risks. Quantitative models produce a range of results from which the market-required cost of equity is determined. The methodologies used to estimate the cost of common equity should reflect investors' forward-looking views of financial markets in general, and the risk profile of the subject company relative to the proxy group in particular.

No financial model can exactly pinpoint the correct return on equity. Rather, each model brings its own perspective and set of inputs and assumptions that inform the estimate of the ROE. Consistent with the *Hope* standard, it is "the result reached, not the method employed, which is controlling."[35] Although each model brings a different perspective and adds depth to the analysis, each model also has its own inherent weaknesses and should not be relied upon individually without corroboration from other approaches. Regardless of which analyses are used to estimate the investor's required cost of equity, the analyst must apply informed judgment to assess the reasonableness of results and to determine the appropriate weight to apply to results under current and prospective capital market conditions.

[34] National Energy Board, Reasons for Decision, TQM RH-1-2008 (March 2009), at 66-72; British Columbia Utilities Commission, In the Matter of FortisBC Energy Inc. Application for its Common Equity Component and Return on Equity for 2016, Decision and Order G-129-16, August 10, 2016, at 52-53; Ontario Energy Board, EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, at 23; Alberta Utilities Commission 2018 Generic Cost of Capital August 2, 2018, at paragraph [275], and English translation of Régie de l'Energie, Decision 2009-156 (R-3690-2009), Gaz Metro, December 7, 2009, at paragraph [249].

[35] *See* Hope Natural Gas v. Federal Power Commission.

1. Discounted Cash Flow ("DCF") Model

The premise underlying the DCF model is that investors value a given investment according to the present value of its expected future cash flows over time. The standard DCF model is shown in Formula [1]:

$$P = \frac{D_0(1+g)^1}{(1+r)^1} + \frac{D_1(1+g)^2}{(1+r)^2} + \cdots + \frac{D_{n-1}(1+g)^n}{(1+r)^n} \qquad [1]$$

where:

P = the current stock price
g = the dividend growth rate
D_n = the dividend in year n
r = the cost of common equity.

Assuming a constant growth rate in dividends, the model may be rearranged to compute the ROE, as shown in Formula [2]:

$$r = \frac{D}{P} + g \quad [2]$$

Stated otherwise, the cost of common equity is equal to the dividend yield plus the expected dividend growth rate.

a. Constant Growth DCF Model Assumptions

The Constant Growth DCF model requires the following assumptions: (1) a constant average growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings multiple; and (4) a discount rate greater than the expected growth rate. The assumptions of the Constant Growth DCF model are generally reasonable for regulated utility companies, which operate in a mature industry and are characterized by a relatively steady state of earnings and dividend growth.

b. Dividend Yield

As shown in equation [3], the dividend yield component of the DCF model is calculated as follows:

$$[3] \qquad Y = \frac{D_0(1+0.5g)^1}{P_0}$$

One half year's growth rate is applied to the annual dividend rate to account for increases in quarterly dividends at different times throughout the year. It is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. This adjustment ensures that the expected dividend yield is, on average, representative of the coming twelve-month period and does not overstate the aggregated dividends to be paid during that time.

The dividend yields were calculated for each company in the respective proxy groups by dividing the current annualized dividend by the average stock price for each company for the 30- and 90-trading days ended August 31, 2018. Those dividend yields are multiplied by one-half the growth rate to reflect expected future dividend increases.

c. Growth Rate Estimates

In considering the appropriate growth rate for the DCF model, the projected earnings per share growth rate from equity analysts is the most reliable indicator of investors' expectations. I have relied on consensus earnings growth rate estimates from Zacks Investment Research, Thomson First Call and SNL Financial as of August 31, 2018 for the companies in the respective proxy groups.

Investors typically rely on projected earnings growth rates rather than dividend growth rates for several reasons. First, although the DCF model is based on the expected growth rate for dividends, a company's dividend growth is derived from and can only be sustained by earnings growth. Second, in order to reduce the long-term growth rate to a single measure, as required in the Constant Growth DCF model, it is necessary to assume a constant payout ratio, and that earnings per share, dividends per share and book value per share grow at a constant rate. Third, earnings growth rates are less influenced by dividend decisions that companies may make in response to near-term changes in the business environment. Finally, analysts' earnings growth forecasts are widely available, whereas dividend and book value growth rates are generally available only from Value Line.[36]

d. Constant Growth DCF Results

The Constant Growth DCF results are summarized in Figure 11 (also see Exhibit JPT-3). As shown in that Figure, the Constant Growth DCF analysis produces an average cost of common equity using 90-day average stock prices of 9.41 percent for the Canadian proxy group, 9.26 percent for the U.S. Electric proxy group, and 9.26 percent of the North American Electric proxy group, including an adjustment for flotation costs and financial flexibility.

Figure 11: Constant Growth DCF Results (including flotation costs)

Averaging Period	Mean Low	Mean	Mean High
Canadian Proxy Group			
30-day	7.95%	9.32%	10.75%
90-day	8.03%	9.41%	10.84%
U.S. Electric Proxy Group			
30-day	8.82%	9.15%	9.59%
90-day	8.92%	9.26%	9.69%
North American Electric Proxy Group			
30-day	8.81%	9.17%	9.62%
90-day	8.90%	9.26%	9.70%

The Constant Growth DCF results for the U.S. Electric proxy group and the North American Electric proxy group are both lower than the DCF results for the Canadian proxy group. I do not believe that an adjustment to the U.S. DCF results is required because, as discussed in more detail in Section VI, the U.S. Electric proxy group is more comparable to Maritime Electric than the Canadian proxy group companies, many of which have significant non-electric operations and unregulated operations. Conversely, the U.S. Electric proxy group is comprised of

[36] Value Line is the only publication of which I am aware that projects dividend and book value growth rates. Those estimates represent the Value Line analyst's perspective on dividend and book value growth. In contrast, many of the earnings growth rates that are publicly available are consensus estimates with contributions provided by several analysts.

companies that derive almost 100.00 percent of net operating income and operating revenues from electric utility operations and dedicate almost 100.00 percent of assets to regulated electric utility service. In addition, a September 2013 report published by Moody's Investors Service ("Moody's") indicated that the rating agency views the regulatory environment for utilities in the U.S. as more favorable than it previously believed, primarily due to the increased use of cost recovery mechanisms and reduced regulatory lag in the U.S. Moody's stated:

> Based on our observations of trends and events, we propose to adopt a generally more favorable view of the relative credit supportiveness of the US utility regulatory environment. Our updated view considers improving regulatory trends that include the increased prevalence of automatic cost recovery provisions, reduced regulatory lag, and generally fair and open relationships between utilities and regulators.[37]

On that basis, in February 2014 Moody's upgraded the credit ratings of many U.S. utilities. For these reasons, I have not adjusted the DCF results for the U.S. Electric proxy group or the North American Electric proxy group, and do not believe that such an adjustment is warranted.

2. <u>Multi-Stage DCF Model</u>

In order to address some of the limiting assumptions of the Constant Growth DCF model, some analysts also consider the results of a Multi-Stage DCF Model. The Multi-Stage DCF model tempers the assumption of constant growth in perpetuity with a three-stage approach based on near-term, transitional and long-term growth rates. While I present the results of the Multi-Stage DCF model for the three proxy groups, I place less weight on these results because my view is that the underlying assumptions of the Constant Growth DCF model are reasonable and appropriate for companies that are in a period of steady state growth, such as regulated electric utilities. The Multi-Stage DCF model is more appropriately applied in circumstances where a company is in a rapid growth stage that cannot be sustained at that same high rate for an extended time period. In those circumstances, it may be appropriate to apply the Multi-Stage DCF model using a terminal growth rate based on long-term nominal GDP growth.

[37] Moody's Investors Service, "Proposed Refinements to the Regulated Utilities Rating Methodology and Our Evolving View of U.S. Utility Regulation," September 23, 2013, at 1.

The Multi-Stage DCF model transitions from near-term growth (i.e. the average of Zacks, Thomson First Call, and SNL Financial forecasts used in the Constant Growth model) for the first stage (years 1-5) to the long-term forecast of nominal GDP growth for the third stage (years 11-200). The second, or transitional, stage connects near-term growth with long-term growth by changing the growth rate each year on a geometric average basis. In the terminal stage, the dividend cash flow grows in perpetuity at the same rate as nominal GDP. The return on equity is the internal rate of return based on the current stock price and this stream of projected dividend payments.

Nominal GDP growth rates for Canada and the U.S. were developed using data for each country as reported by Consensus Economics, Inc. for the period from 2021-2025. These forecasts are based on real (constant dollar) growth rates and estimates for projected inflation. The inflation estimate was applied to the estimate of real GDP growth to develop the nominal (post-inflation) GDP growth rate. The estimates of nominal GDP growth are summarized in Figure 12.

Figure 12: Estimates of Nominal GDP Growth [38]

	Canada	U.S.
Real GDP Growth	1.7%	2.1%
Inflation	2.0%	2.2%
Nominal GDP Growth	3.73%	4.35%

The Multi-Stage DCF results are summarized in Figure 13 (also see Exhibit JPT-4). As shown in that Figure, the Multi-Stage DCF analysis produces an average cost of common equity using 90-day average stock prices of 10.13 percent for the Canadian proxy group, 8.86 percent for the U.S. Electric proxy group, and 9.03 percent for the North American Electric proxy group, including an adjustment for flotation costs and financial flexibility.[39]

[38] Consensus Forecasts, for 2021-2025, April 13, 2018, at 3 (U.S.) and 28 (Canada).
[39] Based on 90-day average stock prices.

Figure 13: Multi-Stage DCF Results (including flotation costs)

Proxy Group	30-Day	90-Day
Canadian	10.03%	10.13%
U.S. Electric	8.74%	8.86%
North American Electric	8.93%	9.03%

As previously noted, I place less weight on the results of the Multi-Stage DCF analysis.

3. Capital Asset Pricing Model ("CAPM")

The CAPM approach is based on the relationship between the required return of a security and the systematic risk of that security. As shown in Equation [4], the CAPM is defined by four components, each of which must be a forward-looking estimate:

[4] $$Ke = rf + \beta(rm - rf)$$

where:

Ke = the required ROE for a given security;
β = Beta of an individual security;
rf = the risk-free rate of return; and
rm = the required return for the market as a whole.

The term (rm – rf) represents the Market Risk Premium ("MRP").

According to the theory underlying the CAPM, since unsystematic risk can be diversified away, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by Beta, which is defined as:

[5] $$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)}$$

where:

re = the rate of return for the individual security or portfolio.

The variance of the market return, noted in Equation [5], is a measure of the variability in the general market, and the covariance between the return on a specific security and the market reflects the extent to which the return on that security will respond to a given change in the market return. Thus, Beta represents the risk of the security relative to the market.

a. Risk Free Rate

Although government bond yields have increased in recent months as central banks in both Canada and the U.S. have tightened monetary policy, these yields remain well below the historical average. At the same time, investors expect that interest rates will continue to increase over the near to intermediate term. As such, adjustments are necessary to better reflect forward-looking investor expectations about government bond yields. The use of forecast bond yields, as opposed to the current risk-free rate, reflects the current market reality that while bond yields remain lower than the long-term average, investors are factoring higher interest rates into their longer-term expectations and required returns.

My CAPM analysis relies on the 2019 through 2021 average *Consensus Economics* forecast yield of Canadian and U.S. 10-year government bonds (shown in Figure 14) plus the historical spread between 10-year and 30-year government debt. The use of a forecast is appropriate because it provides a forward-looking view of the cost of equity and accounts for expectations of rising interest rates.

Figure 14: Long-term Forecast for 10-Year Government Bond Yields 2019-2021[40]

	2019	2020	2021	Average
Canada	2.7%	3.2%	3.3%	**3.07%**
U.S.	3.2%	3.5%	3.5%	**3.40%**

With an average spread between 10-year and 30-year government bond yields of 1 basis point in Canada and 15 basis points in the U.S.,[41] the corresponding longer-term yield on 30-year government bonds over the period 2019 – 2021 is shown in Figure 15.

40 Consensus Forecasts by Consensus Economics Inc., Survey Date April 12, 2018, at 28 and 3.

Figure 15: Risk Free Rate

30-Year Risk Free Yield	Canada	U.S.
April 2018 Consensus Forecast Average 2019-2021 Forecasts for 10-year government bonds	3.07%	3.40%
Average Daily Spread between 10-year and 30-year government bonds (August 2018)	0.01%	0.15%
Sum	**3.08%**	**3.55%**

b. Beta

The Beta coefficient for the companies in the proxy groups are based on estimates from Value Line and Bloomberg. [42] Value Line publishes Beta estimates for each company based on five years of weekly stock returns and uses the New York Stock Exchange as the market index. Bloomberg produces Beta estimates based on parameters entered by the user. I computed Bloomberg Betas based on five years of weekly stock returns and used the S&P 500 (in the U.S) or the S&P/TSX Composite (in Canada) as the market index. Both Value Line and Bloomberg report adjusted Betas to compensate for the tendency of Beta to revert toward the market average of 1.0 over time. The Betas used in my CAPM analyses are shown in Figure 16.

Figure 16: Value Line and Bloomberg Betas

	Value Line	Bloomberg
Canadian Group	N/A	0.76
U.S. Electric Group	0.69	0.57
North American Electric Group	0.69	0.60

There are two primary reasons to adjust raw Betas. First, numerous empirical studies have demonstrated that an individual company Beta is more likely than not to move toward the market average of 1.0 over time. Second, adjusting Beta serves a statistical purpose. Because Betas are statistically estimated and have associated error terms, Betas greater than 1.0 tend to have positive estimated errors and thus tend to overestimate future returns. Conversely, Betas below the market average of 1.0 tend to have negative error terms and underestimate future

[41] Historical spreads were calculated using daily bond yields for the 30 days ending August 31, 2018.

[42] I have used Bloomberg betas for the Canadian proxy group and both Value Line and Bloomberg betas for the U.S. proxy group.

returns. Consequently, it is necessary to adjust forecasted Betas toward 1.0 in an effort to improve forecasts.[43] A raw Beta reflects only where the stock price has been relative to the market historically and is an inferior proxy for the expected returns when compared to the adjusted beta.

The Betas in my analysis are also supported by a study conducted for the BCUC by the Brattle Group on cost of capital methodologies, in which Brattle observed:

> Beta estimates are provided by many data services for Canadian, American and other traded companies. The most common methodology to estimate betas is to use the most recent five years of weekly or monthly return data. These betas may then be adjusted towards one as an adjustment for sampling reversion that was first identified by Professor Marshall Blume (1971, 1975).[44]

Dr. Blume specifically studied four groups of betas, ranging from a very low Beta group (averaging 0.50, and similar to the utility industry) to a very high Beta group. Dr. Blume found that his adjustment best predicted future Betas for each of the four risk groups over the next seven years. Dr. Blume found that a low Beta portfolio that averaged 0.50 migrated towards the grand mean of all Betas of 1.0 approximately in accordance with the Blume formula. The study makes obvious that Betas migrate towards 1.0 and do indeed exceed their long-term unadjusted averages. Given that the purpose of estimating the CAPM relying on these Beta coefficients is to estimate the forward-looking cost of capital, it is important to reflect a forward view of Beta and its tendency to revert toward the market mean over time.

c. <u>Market Risk Premium</u>

Estimates of the MRP generally fall into two categories, *ex-post* (historical average) and *ex-ante* (forward looking). The historical MRP is based on the arithmetic mean of historical equity market returns over the income only return on long-term government bonds. While the historical MRP is generally reasonable when interest rates on long-term government bonds are near historical average levels, the historical MRP does not accurately reflect the required equity

43 Roger A. Morin, *New Regulatory Finance*, at 74.
44 The Brattle Group (May 31, 2012) – Survey of Cost of Capital Practices in Canada, at 15.

risk premium when government bond yields are substantially higher or lower than the historical average. This is because there is an inverse relationship between interest rates and the equity risk premium; that is, as interest rates increase (decrease), the equity risk premium decreases (increases).[45] Given the current low level of interest rates in Canada and the U.S., I have relied on an average of the historical MRP and the forward-looking MRP in my CAPM analysis.

The historical MRP is based on long-horizon equity risk premia data averaged over the longest period for which data were available from Duff & Phelps for both the U.S. and Canada. In the U.S., Duff & Phelps reports premia data from 1926-2016, which results in a market risk premium of 6.94 percent,[46] the arithmetic mean of the premium of the S&P 500 total returns for large company common stocks over long-term government bond income returns. In Canada, the longest period for which risk premia data are available from Duff & Phelps is from 1919 – 2016 in Canadian currency, which yielded an equity risk premium of 5.60 percent.[47]

The forward-looking MRP is calculated by subtracting the projected risk-free rate for each country from the estimated total return for the overall market, as calculated using the Constant Growth DCF method for the companies in the S&P/TSX Composite Index in Canada and the S&P 500 Index in the U.S. For purposes of this calculation, I excluded companies that do not pay dividends, companies for which consensus growth rates are not available from Bloomberg, and companies with negative earnings growth rates. As shown in Exhibits JPT-5 and JPT-6, the forward-looking MRP is 11.59 percent for Canada and 10.28 percent for the U.S. In my view, these MRP estimates are reasonable and better reflect the current capital market environment than the long-term historical average MRP.

As shown in Figure 17, the market risk premium I have utilized in my CAPM is 8.60 percent for Canadian companies and 8.61 percent for U.S. companies. Given the integration of the

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45 *See* e.g., S. Keith Berry, Interest Rate Risk and Utility Risk Premia during 1982-93, Managerial and Decision Economics, Vol. 19, No. 2 (March 1998), in which the author used a methodology similar to the regression approach described below, including using allowed ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates.

46 Duff and Phelps, 2017 International Valuation Handbook: Guide to Cost of Capital, Market Results through December 2016 and March 2017; United States Long-Horizon Equity Risk Premia in U.S. Dollars, Data Exhibit 1-52.

47 *Ibid.*, Canada Long-Horizon Equity Risk Premia in Canadian Dollars, Data Exhibit 1-9.

Canadian and U.S. economies and financial markets, these market risk premiums are reasonable and there is no reason to expect a divergence in market risk premiums going forward.

Figure 17: Market Risk Premium Values

	Canadian MRP	U.S. MRP
Historical MRP	5.60%	6.94%
Forward-looking MRP	11.59%	10.28%
Average	**8.60%**	**8.61%**

d. CAPM Results

The results of the CAPM analysis, including flotation costs, are shown in Figure 18 and in Exhibit JPT-7.

Figure 18: CAPM Results (including flotation costs)

	Mean Result
Canadian	10.13%
U.S. Electric Utilities	9.47%
North American Electric	9.56%

4. Flotation Costs and Financing Flexibility

It is common practice for Canadian regulators to allow an adjustment for flotation costs and financing flexibility in order to compensate the equity holder for the costs associated with the sale of new issues of common equity. These costs include out-of-pocket expenditures for the preparation, filing, underwriting and other costs of issuance of common equity including the costs of financial flexibility such that there is adequate cushion to raise equity in a variety of capital market conditions. Because the purpose of the allowed rate of return in a regulatory proceeding is to estimate the cost of capital the regulated company would incur to raise money in the "primary" markets, an estimate of the returns required by investors in the "secondary" markets must be adjusted for flotation costs in order to provide an estimate of the cost of capital that the regulated company requires. I have adjusted the DCF and CAPM results upwards by 50 basis points for flotation costs and financing flexibility.

B. Comparison to Other Authorized ROEs and Earned ROEs

Investors consider authorized ROEs for other investor-owned electric utilities in Canada and the U.S. as a relevant benchmark for purposes of establishing their return expectations. Given the "opportunity cost" concept underlying a fair return, this is reasonable and appropriate because an investor would allocate capital to a higher return for the same level of risk, if available. As shown in Figure 19, the average allowed ROE for Canadian investor-owned electric utilities was 8.74 percent (2017) and 8.78 percent (2018), while in the U.S., the average allowed ROE for electric utilities in 2017 and 2018 was 9.80 percent and 9.70 percent, respectively. Furthermore, Figure 19 shows that the actual earned ROE for the investor-owned electric utilities in Canada in 2017 was 10.12 percent. This variation between the allowed and earned ROE is due to the fact that other investor-owned electric utility companies in Canada do not have a hard cap on the authorized ROE (as Maritime Electric does), but rather are allowed to earn above the authorized ROE either within a specified band or without any specific limitations. Several of these companies also operate under incentive rate programs specifically allowing for both upside and downside earnings risk.

Figure 19: Allowed ROEs and Earned ROEs

	2017 Allowed ROE	2017 Earned ROE	2018 Allowed ROE
Maritime Electric	9.35%	9.35%	9.35%
Canadian Electric Utilities			
Nova Scotia Power	9.00%	9.25%	9.00%
Newfoundland Power Inc.	8.50%	8.93%	8.50%
FortisOntario Inc.	8.78%	10.70%	9.00%
ATCO Electric Distribution	8.50%	13.21%	8.50%
FortisAlberta Inc.	8.50%	9.32%	8.50%
FortisBC Inc.	9.15%	9.31%	9.15%
Average	**8.74%**	**10.12%**	**8.78%**
U.S. Utilities[48]			
Electric Utilities	9.80%	N/A	9.70%

Turning to electric utilities in the Atlantic region, the current allowed ROE for Nova Scotia Power is 9.00 percent on 37.50 percent common equity, and for Newfoundland Power is 8.50 percent on 45.00 percent common equity. The Commission has previously considered this information relevant in setting the allowed ROE and equity ratio for Maritime Electric.[49]

In terms of relative generation risk, Maritime Electric has somewhat more generation risk than Newfoundland Power, which purchases approximately 93.00 percent of its electricity supply from Newfoundland and Labrador Hydro while generating the remaining 7.00 percent from company-owned hydro-electric plants, primarily for peaking purposes. Nova Scotia Power owns substantial generation assets and has higher generation risk than Maritime Electric. Maritime Electric is more risky than electric utilities in Ontario and Alberta because Maritime Electric owns generation assets, while electric utilities in those provinces do not. The generation function is generally regarded by investors as having greater risk than electric transmission or distribution. The Commission has previously accepted that Maritime Electric, with its

48 Source: SNL Financial. Figures are from January 1, 2017 through August 31, 2018.

49 The Island Regulatory and Appeals Commission, Docket UE20940, Order UE10-03, July 12, 2010, at paragraph [101].

responsibilities for electricity supply, is different than Ontario's electric distribution utilities, and the Commission has stated that it "views this difference as significant."[50] Furthermore, the Commission has stated that it "views Maritime Electric as higher risk than the benchmark BC utility and FortisBC due to a variety of factors such as utility size, nature of operations, economic climate within which it operates, and regulatory risk factors."[51]

VI. RISK ASSESSMENT

Concentric examines risk from two primary perspectives: (1) business risk; and (2) financial risk. Business risk for a regulated utility encompasses both operational risk (e.g., economy of service territory, weather conditions, geographical diversity and size of service territory, etc.) and regulatory risk (e.g., opportunity for timely recovery of prudently-incurred costs). Financial risk primarily relates to the risk associated with the way in which a company finances its business, as evidenced by the relative percentages of debt and equity in the capital structure. To the extent a company is more highly leveraged, it requires higher net income to cover its fixed interest obligations, which must be paid before there is any net income for shareholders. Taken together, business and financial risk are the primary elements of investment risk that investors consider when establishing their return requirements.

In each risk category, Concentric further considers three perspectives:

a) Assessment of the business risk profile of Maritime Electric based on the macroeconomic and business environment of its service area;

b) Comparison of the business risk profile of Maritime Electric against both the Canadian and U.S. peer groups; and

c) Comparison of the financial risk profile of Maritime Electric against these same comparators.

[50] *Id.*, at paragraph [99].
[51] *Id.*, at paragraph [104].

A. Business Risk of Maritime Electric

In order to assess the business risk of Maritime Electric, I considered the following factors: 1) the small size of Maritime Electric relative to other electric utilities in Canada and the U.S.; 2) macroeconomic and demographic trends on Prince Edward Island, as well as Canada generally; 3) operating risks within the Company's service territory, including power supply risks and the prevalence of severe weather conditions; 4) the existence of deferral and variance accounts that protect the Company against risks from events that are material in nature and beyond the control of utility management; and 5) risks related to competition from alternative fuel sources.

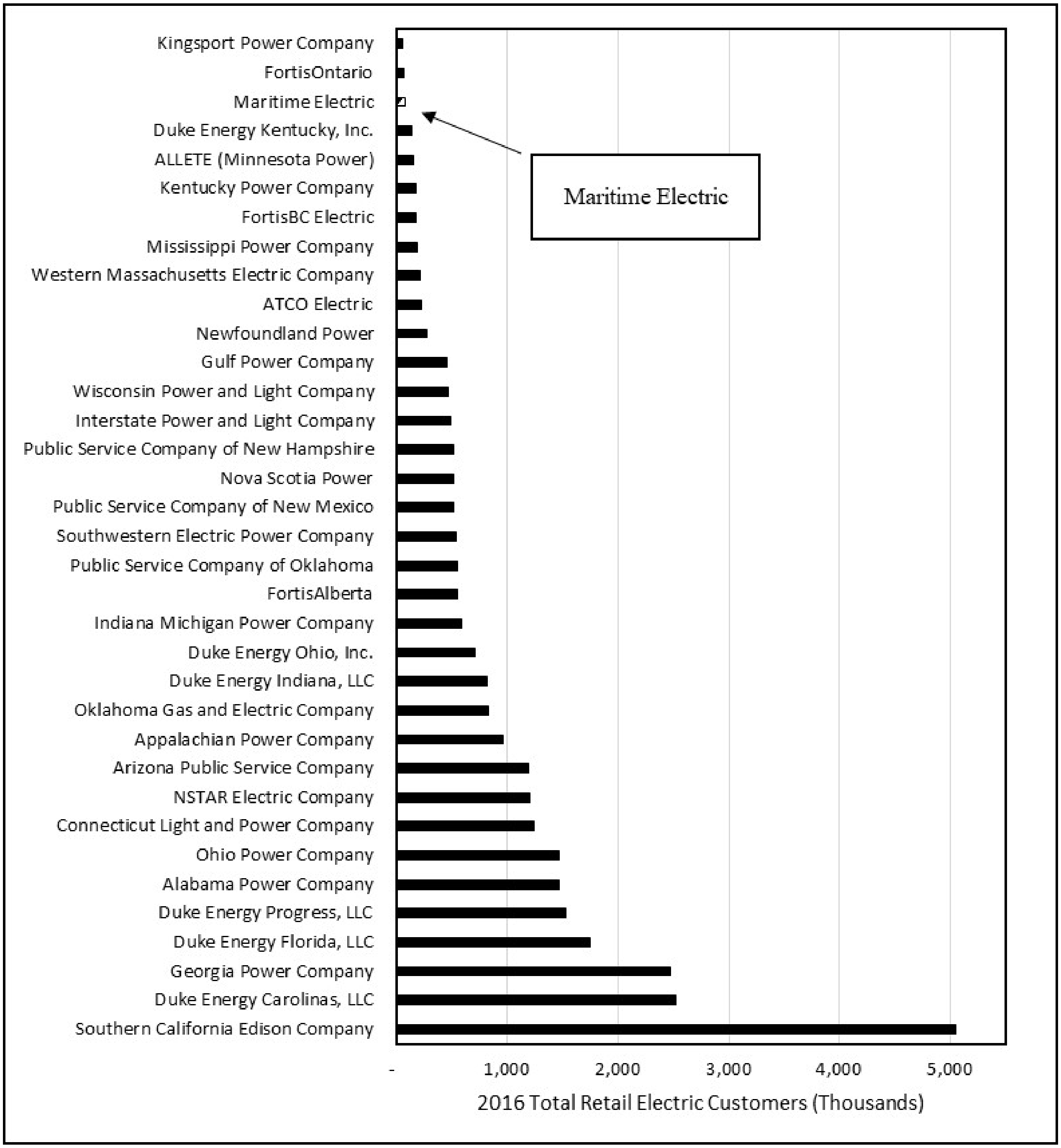
1. Small Size

Maritime Electric is significantly smaller than other electric utilities in the Canadian and U.S. proxy groups, both in terms of retail electric customers and net property, plant and equipment, as shown in Figures 20 and 21 which measure these metrics at the operating company level. The Commission has previously recognized that the small size of Maritime Electric makes it more risky than other electric utilities in Canada.[52] This finding has been used to support an above average ROE. Nothing has changed in this regard since the Company's 2015 GRA filing. Further, recent changes to the Electric Power Act require Maritime Electric to maintain a lower common equity ratio of at least 35.00 percent but not to exceed 40.00 percent, which contributes to greater financial risk. The small size of Maritime Electric could support an equity ratio higher than the upper limit of 40.00 percent allowed by the statute and/or an allowed ROE above the mean for the proxy groups.

[52] Island and Regulatory Appeals Commission, Docket UE 20934, Order UE06-03, at paragraph [28].

1 **Figure 20: Small Size of Maritime Electric**

2 **2016 Retail Electric Customers[53]**



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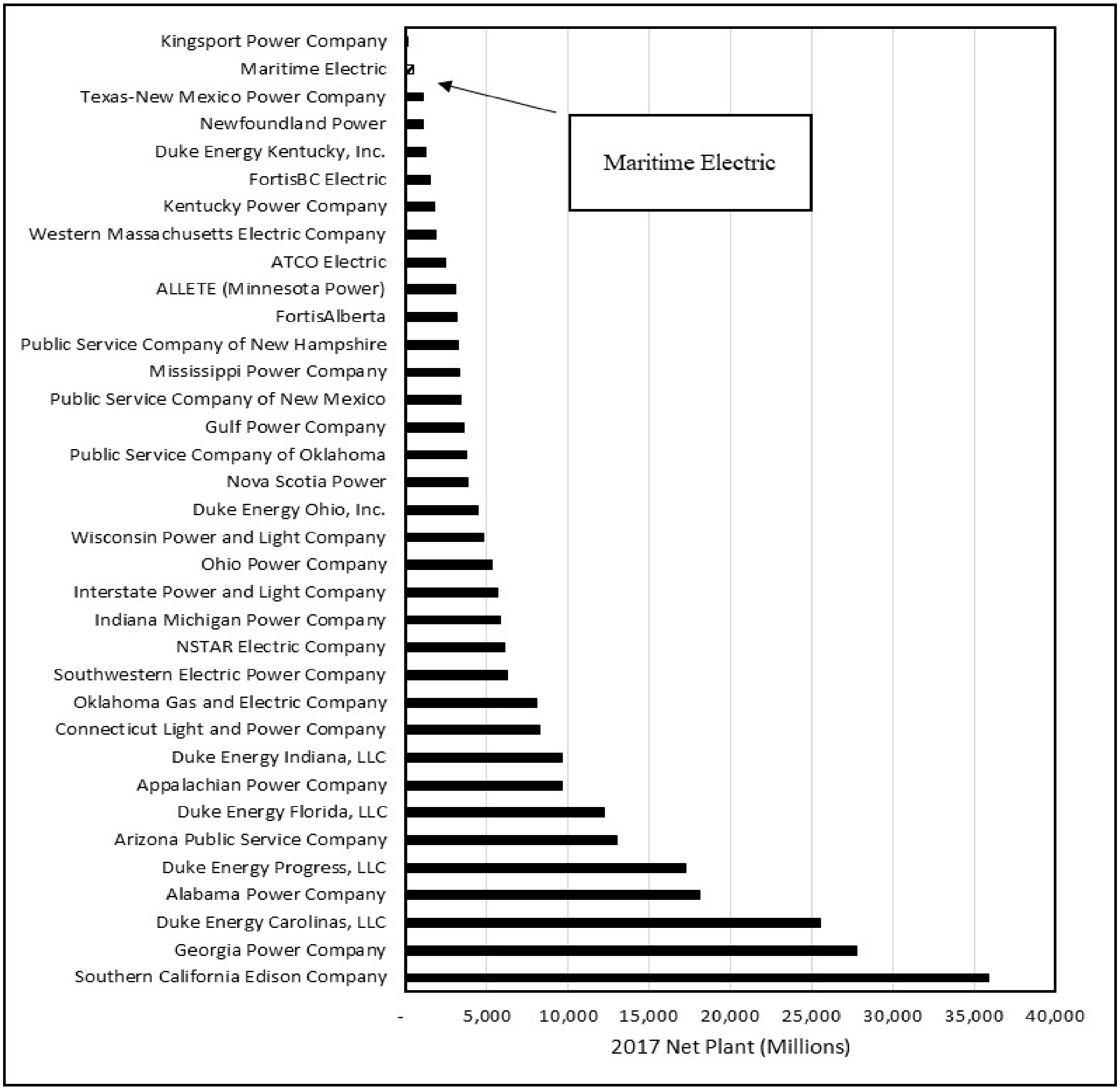
53 Source: SNL Financial. Data taken from EIA Form 861, released October 2017.

Figure 21: Small Size of Maritime Electric

2017 Net Property, Plant and Equipment



Due to its small size, Maritime Electric has greater risk associated with adverse economic conditions, as well as greater risk that customer demand could decrease significantly due to a major employer or industry experiencing a downturn or deciding to relocate. A small utility cannot diversify its risks to the same extent as larger utilities whose assets, geography and economic bases are less concentrated. Negative events are likely to have greater impact on the earnings and cash flows of a smaller utility. Credit rating agencies consider small size as a risk factor for regulated utilities. For example, Moody's considers the size and diversity of utility operations to be a distinguishing factor that makes some utilities riskier than others. In discussing its rating methodology for regulated electric and gas utilities, Moody's states:

> We also consider the diversity of utility operations (e.g., regulated electric, gas, water, steam) when there are material operations in more than one area. Economic diversity is typically a function of the population, size and breadth of the territory and the businesses that drive its GDP and employment. For the size of the territory, we typically consider the number of customers and the volumes of generation and/or throughput. For breadth, we consider the number of sizeable metropolitan areas served, the economic diversity and vitality in those metropolitan areas, and any concentration in a particular area or industry.[54]

Maritime Electric's service territory is characterized by the small size and lack of geographic and economic diversity that Moody's describes as an increased risk factor for regulated utilities.

2. <u>Macroeconomic and Demographic Trends</u>

Maritime Electric's service territory is largely rural; Charlottetown is the only major population center. The economy on Prince Edward Island ("PEI") is concentrated in the following industries: agriculture, fishing, tourism, aerospace and government. According to the Conference Board's Long-Term Economic Forecast, PEI is expected to lead the Atlantic Provinces (i.e., Nova Scotia, New Brunswick, and Newfoundland and Labrador) in economic growth over the long-term, with GDP advancing at a compound annual growth rate of 1.00 percent between 2017 and 2040.[55] However, this long-term GDP growth rate is lower than the overall Canadian compound annual growth rate of 1.70 percent.

The Conference Board projects that PEI will post the highest rate of population growth in the Atlantic region and will be the only province in the region where population growth will remain positive over the long-term due to strong immigration growth.[56] If not for immigration, average

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54 Moody's Investors Service, "Rating Methodology: Regulated Electric and Gas Utilities," December 23, 2013, at 19.

55 The Conference Board of Canada, Provincial Outlook 2018, Long-Term Economic Forecast, January 19, 2018, at 25.

56 *Ibid.*

annual population growth over the next two decades would be negative, as will be the case in Nova Scotia, New Brunswick, and Newfoundland and Labrador. Among the highlights for PEI, the Conference Board notes:

- PEI will outpace its Atlantic neighbors in economic growth, but lag behind the national average;
- Limiting potential output growth is the aging of the population, which will be more pronounced on the Island than elsewhere in Canada;
- The greying of the population will lead to high demand for health care and social services, presenting a significant challenge for island finances; and
- The province has begun to attract more immigrants, which could help mitigate impacts of population aging on the Island's economy.[57]

Figure 22 compares PEI to Canada as a whole and other Canadian provinces on a number of key macroeconomic indicators over the period from 2017-2040. It is notable that over the long-term all of PEI's key economic indicators are projected to be weaker than Canada overall.

[57] *Id.*, at 24.

Figure 22: Key Economic Indicators – 2017-2040[58]

	GDP Growth	Labor Force	Population	Employment	Disposable Income	Retail Sales	Housing Starts
PEI	1.0%	(0.1%)	0.0%	0.0%	2.6%	1.4%	(2.9%)
Canada	1.7%	0.4%	0.8%	1.0%	3.5%	2.6%	(2.4%)
NS	0.8%	(0.3%)	0.0%	(0.2%)	2.5%	1.7%	(8.8%)
NL	0.0%	(1.0%)	(0.5%)	(0.7%)	1.7%	1.2%	(6.8%)
NB	0.8%	(0.2%)	(0.1%)	(0.1%)	2.4%	1.5%	(5.9%)
ALB	1.9%	1.0%	1.3%	1.2%	4.2%	2.6%	(0.1%)
BC	1.7%	0.6%	0.7%	0.6%	3.5%	2.2%	(4.9%)
ONT	1.9%	0.9%	0.9%	0.9%	3.7%	2.3%	(1.9%)
QC	1.5%	0.5%	0.5%	0.5%	2.9%	1.9%	(5.0%)

As a result of these economic and demographic trends, it is likely that Maritime Electric's electric sales growth over the long-term will be weaker even as the Company needs to continue investing capital to maintain and modernize its aging infrastructure so that service quality and reliability are maintained.

3. Operating Risks

Maritime Electric serves approximately 80,000 residential, commercial and industrial customers on PEI. Figure 23 presents the sources of the Company's electricity supply in 2017.

[58] The Conference Board of Canada, Provincial Outlook 2018, Long-Term Economic Forecast, forecast completed January 19, 2018.

Figure 23: Maritime Electric Electricity Supply in 2017[59]

	MWh	%
On-Island oil-fired generation	1,794	0.14%
On-island wind generation (contracted)	292,713	22.54%
Point Lepreau participation (nuclear)	228,990	17.64%
System purchases from NB Power	774,991	59.68%

Due to its island location, Maritime Electric is exposed to relatively high supply and operating risks. In 2017, Maritime Electric depended on New Brunswick Power for more than 77.00 percent of its energy requirements. The off-island energy supply is delivered from the mainland grid via four provincially-owned submarine cables, two of which were activated in August 2017. Based on conversations with the Company, my understanding is that Maritime Electric acted as Construction Agent to install the two new 180 MW submarine cables between New Brunswick and PEI and is responsible for operating and maintaining these cables after they were placed into service. These new submarine cables are expected to enhance the reliability of electricity supply on PEI and will contribute to ongoing efforts to reduce the use of fossil fuels; however, this does not resolve the transmission constraints that are associated with off-island generation in New Brunswick.

Maritime Electric's dependence on mainland power supplies means that, for reliability purposes, the Company owns on-island generation capacity (145 MW) to serve as back-up in case of supply interruption. While this generation capacity is not intended to be operated on a regular basis, as it is relatively high cost compared to off-island production, Maritime Electric has an obligation to ensure that back-up capability is maintained and available. In 2015, Maritime Electric filed an application with the Commission for approval to spend $68 million to construct

59 Provided by Maritime Electric in response to data request. Source: December 2017 Management Report for energy supply as of December 31, 2017.

a new 50 MW combustion turbine at the Charlottetown Generation Station ("CTGS") location that would serve as necessary generation capacity in the event of energy supply disruptions and would eventually replace the generation units at CTGS which are near the end of their useful lives. Rather than refurbishing the existing CTGS units, Maritime Electric determined that it would be more cost effective to design and construct a new combustion turbine. The Company plans to retire and decommission the existing CTGS units after 2021. Generation assets, which inherently face higher operating and capital cost recovery risks than T&D assets, comprise approximately 14.00 percent of Maritime Electric's net utility property, plant and equipment.[60]

Weather-related service disruptions represent another important operating risk for Maritime Electric. The Company's service territory is subject to severe ice and wind storms. The need to address supply disruptions caused by severe weather conditions involves unpredictable and potentially volatile capital and operating costs. Maritime Electric's capital structure and allowed ROE must provide the Company with the financial flexibility necessary to respond to unforeseen capital and operating costs in order to restore electric distribution service promptly to customers. Unlike many electric utilities in Canada and the U.S., Maritime Electric does not have a cost recovery mechanism for storm-related costs to mitigate this risk.

Lastly, my understanding is that all of Maritime Electric's renewable energy supply is generated by on-island wind generation facilities. Future renewable energy supply sources are also expected to be largely from wind generation facilities. Given the intermittent nature of wind as a source of generation, there are additional operational and contractual complexities for Maritime Electric which distribution utilities in other provinces do not face to the same degree. In addition, the wind generation facilities are owned by the Province, and Maritime Electric purchases supply through a Power Purchase Agreement. As a result, Maritime Electric has no control over the reliability of the wind facilities, which could be an additional risk associated with renewable energy.

60 Maritime Electric 2017 Financial Results, at 10.

4. Deferral and Variance Accounts

Maritime Electric has very limited protection against costs that tend to fluctuate significantly from year to year, are material in nature, and over which utility management has no control. While several utilities in Canada have deferral and variance accounts to mitigate the risk associated with operating and capital costs, Maritime Electric has relatively few. The only accounts that Maritime Electric has implemented are 1) the Energy Cost Adjustment Mechanism ("ECAM"), which allows the Company to recover the actual cost of fuel and purchased power compared to the forecasted amount, 2) a variance account for the recovery of costs related to demand side management and energy efficiency,[61] which are recovered through the ECAM, 3) a weather normalization reserve account that represents the cumulative change in the contribution margin (average selling price less average cost of energy purchased) resulting from variations in heating degree days from normal; and 4) a variance account for OPEB costs.

In order to mitigate volume/demand risk, the Commission approved Maritime Electric's weather normalization reserve account in 2016. That account normalizes sales based on fluctuations in heating degree days as compared to the rolling ten-year average for the most recent ten years. Among Canadian investor-owned electric utilities, Newfoundland Power has a weather-related variance account that allows it to recover in a future period the difference between projected and actual revenues due to abnormal weather conditions in the test year. Nova Scotia Power has a Fixed Cost Recovery deferral account that provides for recovery of lost revenues associated with two large industrial customers. FortisBC Electric operates under a revenue stabilization plan that includes full protection against volumetric risk. ATCO Electric Distribution and FortisAlberta both are subject to a performance-based regulation ("PBR") plan that adjusts revenues annually based on inflation less a productivity factor; however, the PBR plan does not include protection against changes in volume/demand. In summary, Maritime Electric has greater volumetric risk than FortisBC Electric, comparable volume/demand risk as Newfoundland Power and Nova Scotia Power, and lower volume/demand risk than the Alberta electric utilities.

[61] This variance account covers community outreach and education costs, which is the only aspect of the DSM and energy efficiency program for which Maritime Electric is responsible. The Province is responsible for the other aspects of the DSM and energy efficiency program, which is scheduled to end in 2021.

5. Alternative Fuel Risk

Maritime Electric faces competition from alternative fuel sources such as fuel oil for space heating needs, but this competition is not significant. The majority of the Company's residential customers are oil-based heating customers. However, Maritime Electric has experienced higher than normal sales growth due to an increase in the use of electric-based space heating (primarily heat pumps), as customers are switching from oil-based heating. Maritime Electric estimates that approximately 30.00 percent of its customers are currently using electricity for space heating. This trend is expected to continue in the near term with the recent announcement of incentives from the Government (efficiencyPEI) for energy efficient equipment for heating/cooling and the 10.00 percent rebate applied on the first block (2000 kwh) for residential customers, but is not expected to be sustained over the longer term.

6. Political and Regulatory Uncertainty

With respect to the political environment and regulatory framework, a change in provincial legislation in the mid-1990s greatly altered the regulatory model for Maritime Electric. The legislation replaced rate of return/rate base regulation with price cap regulation that limited the Company's regulated prices to those of NB Power plus 10.00 percent, thereby exposing Maritime Electric to significant financial pressures. Pursuant to the 2004 Electric Power Act, Maritime Electric was returned to rate of return/rate base regulation and allowed to recover approximately $21 million of costs that had been incurred and deferred pursuant to the prior regulatory framework.

Maritime Electric and the Provincial Government entered into a five-year PEI Energy Accord Agreement for the March 1, 2011 to February 29, 2016 period which, among other things, fixed customer rates and the Company's ROE during this period. As part of the Energy Accord, the government appointed the PEI Energy Commission to undertake a review of PEI's electricity sector. The PEI Energy Commission made several recommendations, including: 1) government ownership of Maritime Electric's existing and future generation assets; 2) a legislatively set reduction in the Company's allowed equity ratio; and 3) government responsibility for demand side management and energy efficiency programs. These recommendations introduced material political risk to the Company. The government acted on the recommendation regarding ownership of Maritime Electric's future generation assets by announcing a policy which gives them the option to own and finance future generation on PEI. The government also established a target range for Maritime Electric's common equity ratio of at least 35.00 percent but not to exceed 40.00 percent. The active role of government, as demonstrated by past changes in legislation as well as by the broad mandate of the PEI Energy Commission, contributes to a higher degree of political/regulatory risk for the Company and its investors.

7. Summary

My assessment is that, while the Company's volumetric risk has been reduced due to the implementation of weather normalization, Maritime Electric's business risk remains relatively high compared to other companies in the Canadian and U.S. proxy groups. The Company is very small compared to other investor-owned electric utilities in Canada and the U.S. Furthermore, the risk related to macroeconomic and demographic trends remains above average as the Provincial economy is projected to experience weaker economic growth and an aging population over the next 20 years. Maritime Electric does not have many of the variance and deferral accounts that are common among other regulated electric utilities across Canada. In particular, Maritime Electric does not have the relative certainty of a deferral account for storm-related costs that might be incurred as the result of severe wind and ice storms. Moreover, the level of government involvement and political uncertainty with regard to ownership of generation assets have increased the business and regulatory risk for Maritime Electric. For all of these reasons, my view is that the business risk of Maritime Electric remains above average.

B. Comparison to other Canadian Electric and Gas Utilities

Maritime Electric derives 100.00 percent of its operating income and revenues from electric utility service. By contrast, the companies in the Canadian proxy group are engaged in diverse businesses, including natural gas distribution, oil and natural gas transmission, merchant generation, development of renewable assets, commodity marketing, and various other unregulated activities.

Emera (the parent of Nova Scotia Power) owns regulated natural gas distribution utilities in Florida and New Mexico, as well as regulated electric utilities in Nova Scotia, Maine, Florida and the Caribbean. Emera also owns a portfolio of competitive electric generating facilities and engages in a physical energy marketing and trading business through its subsidiary, Emera Energy. Emera also owns an equity interest in electricity transmission assets such as Maritime Link and Labrador Link, and owns the Brunswick Pipeline, which transports natural gas from Saint John, New Brunswick to markets in the northeastern U.S. In 2017, Emera derived approximately 94.00 percent of its operating income from regulated operations. The information in Emera's annual report does not make it possible to determine the percentage of operating income from electric utility operations.

Canadian Utilities Ltd. ("CU Ltd.") provides gas distribution service, electric distribution and transmission service, and gas transmission service in Alberta through its ATCO Gas, ATCO Electric, and ATCO Pipeline subsidiaries. CU Ltd. derived approximately 50.00 percent of its operating income in 2017 from regulated electric utility services. CU Ltd. also owns unregulated electric generation plants in western Canada and Ontario, operates unregulated natural gas gathering, processing, storage and transmission businesses, and has regulated and unregulated operations in Australia and Mexico.

Enbridge, Inc. is primarily engaged in the oil and gas pipeline business in both Canada and the U.S. and the gas distribution business in Ontario (Enbridge Gas Distribution and Union Gas) and in New Brunswick. Enbridge also owns renewable energy assets and transmission facilities through its Green Power and Transmission segment in Canada and the U.S., and engages in physical commodity marketing and logistical services, oversees refinery supply services, and manages its volume commitments on various pipeline segments through its Energy Services unit. Enbridge derived approximately 28.00 percent of its operating income from regulated gas distribution service in 2017.

Valener, Inc. owns Gaz Metro, the natural gas distribution company in Quebec, as well as several natural gas distribution and integrated electric utilities in Vermont, including Green Mountain Power and Vermont Gas Systems. Valener derived approximately 91.00 percent of its net income from regulated utility service. The annual report for Valener does not break out the portion of net income that is attributable to electric utility service.

1. Macro-economic Conditions

Macro-economic conditions on PEI are projected by the Conference Board to be generally weaker than other Canadian provinces for the period from 2017-2040. **Error! Reference source not found.** compares the key economic indicators for PEI to those in the provinces where the other five investor-owned electric utilities are located, as well as Ontario, Quebec and New Brunswick. As shown in **Error! Reference source not found.**, PEI's key economic indicators over this period are generally stronger than Newfoundland and Labrador and Nova Scotia, but weaker than the other Canadian provinces.

2. Capital Cost Recovery

Maritime Electric files a capital budget with the Commission on an annual basis, which includes the Company's capital budget for the upcoming year, as well as a ten-year comparative history. The Commission reviews Maritime Electric's capital plan and either provides an Order approving the capital budget or modifying it. Similarly, Nova Scotia Power, Newfoundland Power and FortisBC Electric also file for pre-approval of capital expenditures. In Alberta, the Alberta Utilities Commission ("AUC") approved a new PBR plan for distribution utilities for the period 2018-2022.[62] The new PBR plan incorporates significant changes related to the recovery of capital-related costs. The AUC has established two types of capital. Costs associated with Type 1 capital are subject to a true up, but the Type 1 capital criteria are restrictive (*i.e.*, must be extraordinary, not previously in rate base, and required by a third-party, *e.g.*, regulatory or legislative authority).[63]

Electric utilities in Canada are not allowed to earn a cash return on Construction Work in Progress, but all utilities are permitted AFUDC. In summary, Maritime Electric has similar capital cost recovery risk as other investor-owned electric utilities in Canada except for those in Alberta, which have higher risk on certain capital costs.

[62] AUC Decision 20414-D01-2016 (December 16, 2016).
[63] AUC Decision 20414-D01-2016 (Errata) (February 6, 2017) at para 198.

3. Operating Cost Recovery

Concentric has evaluated Maritime Electric's ability to recover operating costs that (1) tend to fluctuate substantially from year to year, (2) are significant in magnitude, and (3) are generally beyond the control of utility management. Regulators in Canada often use variance and deferral accounts to mitigate the risks associated with these types of costs. Maritime Electric has deferral/variance accounts for employee future benefits expenses and energy efficiency and conservation costs[64], while other Canadian investor-owned electric utilities have varying levels of protection against these operating costs, with the exception of FortisAlberta, which does not have any deferral/variance accounts related to these costs. Importantly, while Maritime Electric has protection against pension and OPEB expenses, the Company does not have a storm-related deferral account like ATCO Electric and FortisBC Electric, despite operating in a service territory characterized by severe ice and wind storms.

4. Conclusions on Business Risk

Based on the information in this section, I conclude that Maritime Electric generally has greater business risk than other Canadian investor-owned electric utilities. Factors contributing to this higher risk profile include Maritime Electric's small size, dependence on one supplier, weak macro-economic and demographic trends in the Province as compared to the remainder of Canada, and weather and storm related risk. While the regulatory framework on PEI is generally supportive of maintaining credit quality, there are certain aspects of the economic and operating environment where Maritime Electric has higher business risk than other Canadian investor-owned electric utilities.

C. Comparison to U.S. Electric Proxy Group

In this section, I compare Maritime Electric to the companies in the U.S. Electric proxy group on the following factors: (1) percentage of regulated electric utility operations; (2) credit rating agency comments on the supportiveness of the U.S. regulatory environment for regulated utilities; (3) assessment of regulatory mechanisms used to mitigate cost recovery risk for U.S

64 As noted previously, Maritime Electric is only responsible for the customer education component of the energy efficiency and conservation program, and the program is scheduled to end in 2021.

electric utilities as compared with Maritime Electric; and (4) investment risk as measured by the business and financial risk rankings from S&P.

1. Comparison of Regulated Electric Utility Operations

Maritime Electric derives 100.00 percent of its operating income and revenues from regulated electric utility service. As shown in Exhibit JPT-8, the U.S. Electric proxy group companies derive approximately 98.00 percent of regulated income and 96.00 percent of regulated revenues from electric utility service, and approximately 96.00 percent of regulated assets are dedicated to electric utility operations. For this reason, I conclude that the U.S. Electric proxy group is more representative of Maritime Electric than the Canadian proxy group, which as noted previously is engaged in other regulated utility businesses, as well as non-regulated activities.

2. Credit Rating Agency Comments on U.S. Regulatory Environment

Some observers have previously argued before Canadian regulators that the U.S. regulatory environment for utilities is higher risk than the regulatory environment in Canada. As previously discussed, Moody's issued a September 2013 report in which the rating agency indicated that its view of U.S. utility regulation was more favorable than it had previously been. In that report, Moody's stated: "Our revised view that the regulatory environment and timely recovery of costs is in most cases more reliable than we previously believed is expected to lead to a one notch upgrade of most regulated utilities in the U.S., with some exceptions."[65]

My business risk comparison is consistent with Moody's conclusion that regulated utilities in the U.S. operate in a regulatory environment similar to those in Canada, including the generally supportive regulatory framework of this Commission.

3. Comparison of Business and Regulatory Risk

Exhibit JPT-9 compares the regulatory mechanisms for Maritime Electric to those for the U.S. Electric proxy group. As shown in that Exhibit, and summarized below, Maritime Electric generally has comparable business and regulatory risk as the U.S. Electric proxy group. On that

[65] "Proposed Refinements to the Regulated Utilities Rating Methodology and our Evolving View of US Utility Regulation," Moody's Investors Service, September 23, 2013, at 1.

basis, I believe it is reasonable and appropriate to consider the DCF and CAPM results for the U.S. proxy group without adjusting those results for differences in regulatory risk between Canada and the U.S.

a) Regulated generation risk: Maritime Electric owns limited regulated generation assets and therefore has lower generation risk than the U.S. Electric proxy group operating companies, the majority of which own regulated generation assets.

b) Fuel and purchased power cost risk: Maritime Electric purchases approximately 77.00 percent of its power supply from New Brunswick Power; the remaining 23.00 percent is derived from the Company-owned combustion gas turbine and on-island wind generation. Maritime Electric is allowed to recover variations in energy supply costs through the Energy Cost Adjustment Mechanism. All of the electric utility companies in the U.S. proxy group have fuel adjustment clauses that allow them to pass through fuel and purchased power costs to customers. As such, the U.S. electric utilities are not at risk for differences between the projected and actual cost of fuel and purchased power. In addition, Maritime Electric's predominant reliance on a single source of power (New Brunswick Power Corp.) places it at greater risk of supply disruptions than the electric utilities in the U.S. proxy group.

c) Regulatory lag: Maritime Electric files rate applications based on a forecasted test year, while 38.00 percent of operating companies in the U.S. Electric proxy group also use fully or partially forecasted test years.

d) Volume/demand risk: Maritime Electric has a weather normalization adjustment clause that provides regulatory protection against changes in volume/demand caused by abnormal weather conditions. Approximately 44.00 percent of the operating companies in the U.S. Electric proxy group have either full or partial revenue decoupling mechanisms, which provides more protection against volumetric risk than a weather normalization clause.

e) Capital cost recovery risk: Maritime Electric annually files a capital investment plan with the Commission, which approves a specified amount that will be recoverable in future rates. Approximately 79.00 percent of the operating companies in the U.S.

electric utility proxy group either receive pre-approval for capital expenditures and/or are allowed to earn a cash return on Construction Work in Progress. In addition, approximately 88.00 percent have one or more cost tracking mechanisms that allow them to recover capital costs between rate cases. Maritime Electric does not have any capital tracking mechanisms and earns AFUDC on capital costs rather than a cash return on CWIP.

f) <u>Operating cost recovery mechanisms</u>: Maritime Electric has been allowed to implement several deferral and variance accounts; likewise, the operating companies in the U.S. Electric proxy group employ similar regulatory protection against specific categories of costs that tend to fluctuate significantly from year to year, are material in nature, and are beyond the control of utility management. For example, Maritime Electric has an account for recovery of demand side management and energy efficiency costs, and 79.00 percent of operating companies in the U.S. Electric proxy group also have an account for this purpose. A notable exception is that Maritime Electric has no deferral or variance account or other regulatory protection against storm-related costs (both operating and capital costs), which tend to be a significant risk factor in any given year due to harsh climate in the Province. Of the U.S. Electric proxy group companies, 35.00 percent of the operating companies have a storm-cost recovery account.

In addition to these short-term risks, as discussed previously, Maritime Electric has higher long-term business risk than the U.S. proxy group companies due to (1) unfavorable demographic trends (e.g., Maritime Electric serves an island where the population is aging and is expected to decline in absolute terms over the next 20 years), (2) the fact that macroeconomic growth is projected to be weak in the Province over the next 20 years relative to Canada, and (3) the small size of Maritime Electric in terms of customer base and net utility plant, which heightens the effect of other business risks on the Company. In addition, Maritime Electric's service territory is exposed to severe weather conditions, especially wind and ice storms that create significant risk that the Company will incur substantial capital and operating costs to restore service in any given year. On a more favorable note, Maritime Electric has lower business risk than operating companies in the U.S. Electric proxy group as it relates to competition from alternative fuel sources such as natural gas.

4. Credit Ratings as Measure of Investment Risk

Maritime Electric is rated BBB+ by S&P, while the average S&P credit rating for the U.S. proxy group of electric utility companies is A-. The credit rating screen used to select the U.S. proxy group is based on both business risk (including an assessment of the regulatory environment in which the utility operates) and financial risk. Companies with similar credit ratings have been determined by the rating agency to have similar levels of business and financial risk. Various regulatory agencies have used credit ratings to assess overall investment risk. For example, in the U.S., the Federal Energy Regulatory Commission ("FERC") has found that "it is reasonable to use the proxy companies' corporate credit rating as a good measure of investment risk, since this rating considers both financial and business risk."[66]

Concentric compared the investment risk of Maritime Electric to that of the U.S. Electric proxy group by analyzing the business and financial risk rankings reported by S&P. As shown in **Error! Reference source not found.**, Maritime Electric's business risk ranking is "Excellent" and its financial risk ranking is "Significant." On that basis, Maritime Electric's business risk is comparable to most companies in the U.S. Electric proxy group, but the Company has higher financial risk due to its more leveraged capital structure.

[66] *See*, for example, *Potomac-Appalachian Transmission Highline, LLC*, 122 FERC ¶ 61,188 at paragraph 97 (2008).

Figure 24: U.S. Electric Proxy Group – S&P Rankings

Company	S&P Rating	Business Risk	Financial Risk
ALLETE, Inc.	BBB+	Strong	Significant
Alliant Energy Corp.	A-	Excellent	Significant
American Electric Power Co.	A-	Excellent	Significant
Duke Energy Corporation	A-	Excellent	Significant
Edison International	BBB+	Excellent	Significant
Eversource Energy	A+	Excellent	Intermediate
OGE Energy Corporation	BBB+	Strong	Significant
Pinnacle West Capital Corp.	A-	Excellent	Significant
PNM Resources, Inc.	BBB+	Strong	Significant
Maritime Electric Co. Ltd.	**BBB+**	**Excellent**	**Significant**

D. <u>Financial Risk</u>

Financial risk exists to the extent a company incurs debt obligations in financing its operations. These fixed obligations increase the level of income required to cover interest payments before common stockholders receive any return. Fixed financial obligations also reduce a company's financial flexibility and its ability to respond to adverse economic circumstances and capital market conditions.

The capital structure relates to a company's financial risk, which represents the risk that a company may not have adequate cash flows to meet its financial obligations and is a function of the percentage of debt (or financial leverage) in the capital structure. As the percentage of debt in the capital structure increases, so do the fixed obligations for the repayment of that debt. Consequently, as the degree of financial leverage increases, the risk of financial distress for common equity holders (i.e., financial risk) also increases.[67] Since the capital structure can affect the Company's overall level of risk, it is an important consideration in establishing a fair return.

[67] *See* Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 45-46.

Under the provisions of the revised Electric Power Act, Maritime Electric is required to maintain a minimum of at least 35.00 percent common equity and not more than 40.00 percent common equity in its capital structure.

Maritime Electric issues First Mortgage Bonds ("FMB") to finance its rate base investments rather than senior unsecured debt. These FMBs, which are typically in the range of $40 million or less, are sold through private placements with Canadian based insurance companies rather than in the public debt market. The supply of potential investors is limited for Maritime Electric's debt offerings. For example, when the Company issued debt in 2016, it met with six prospective investors. Maritime Electric's FMBs are rated "A" by Moody's because the funds are secured by the utility assets of the Company. It is generally riskier for companies to issue FMBs than unsecured debt because the utility is agreeing to use its assets as collateral to secure the loan. Maritime Electric, however, has no choice but to issue FMBs due to the small size of the debt offering, which is a function of the small size of the Company itself.

1. Comparison to Other Investor-Owned Electric Utilities

One way to assess the reasonableness of Maritime Electric's proposed equity ratio is by comparison to other investor-owned electric utilities. As shown in Figure 25, Maritime Electric's proposed common equity ratio of 40.00 percent is consistent with the average common equity ratio of 39.40 percent for the other Canadian investor-owned electric utilities, and within the range of equity ratios from 37.00 percent to 45.00 percent.

Figure 25: Comparison of Authorized Equity Ratios

Operating Utility	Equity Ratio
Maritime Electric (current)	**40.0%**
Maritime Electric (proposed)	**40.0%**
ATCO Electric Distribution	37.0%
FortisAlberta	37.0%
FortisBC Electric	40.0%
Newfoundland Power	45.0%
FortisOntario and other Ontario Electric Distributors	40.0%
Nova Scotia Power	37.5%
Average	**39.4%**

As shown in Exhibit JPT-9, the average authorized common equity ratio for the operating companies in the U.S. Electric proxy group is approximately 49.40 percent, or more than 9.00 percentage points higher than Maritime Electric's proposed common equity ratio of 40.00 percent. Maritime Electric's proposed common equity ratio is lower than the authorized equity ratio of any operating utility in the U.S. proxy group except for AEP Texas Inc. (also at 40.00 percent), which does not have any regulated generation assets in rate base.

2. Assessment of Credit Metrics

Financial risk is also measured through credit metrics, such as the ratio of Funds From Operations ("FFO") to debt, as well as interest coverage ratios that compare Earnings Before Interest and Taxes ("EBITDA") and FFO to interest payments on long-term debt. As shown in Exhibit JPT-10, the S&P adjusted credit metrics for Maritime Electric in 2017 were generally stronger than the companies in the Canadian proxy group, but weaker than the average for the U.S. Electric proxy group, especially with respect to interest coverage ratios and debt to capital ratios. Figure 27 summarizes the key credit metrics for Maritime Electric and the average credit metrics for the companies in the Canadian proxy group and the U.S. Electric proxy group.

Figure 26: 2017 S&P Credit Metrics Comparison

Credit Metric	Maritime Electric	Canadian	U.S. Electric
Debt to Capital Ratio	63%	61%	55%
EBITDA to Interest Coverage	4.69	3.57	4.85
FFO to Interest Coverage	4.93	3.60	6.36
FFO / Debt (%)	20.6%	11.1%	19.3%
Debt / EBITDA	3.65	6.28	4.28

As shown in Figure 27, compared to the Canadian proxy group, Maritime Electric has a higher debt to capital ratio, stronger interest coverage ratios, a stronger FFO / Debt ratio, and a stronger Debt / EBITDA ratio. Compared to the U.S. Electric proxy group, Maritime Electric has a higher debt to capital ratio, a similar EBIDTA to interest coverage ratio, a weaker FFO to interest coverage ratio, a similar FFO / Debt ratio, and a stronger Debt / EBITDA ratio.

Maritime Electric's credit metrics have improved since 2014. Based on a comparison of the equity ratios and the credit metrics of Maritime Electric to the companies in the Canadian and U.S. proxy groups, my conclusion is that the Company has somewhat higher financial leverage, but stronger coverage ratios than the Canadian proxy group, and higher financial leverage and somewhat weaker coverage ratios than the U.S. Electric proxy group.

3. Credit Rating Agency View

Maritime Electric has consistently maintained a long-term issuer rating from S&P of "BBB+" since January 2004. An April 2018 S&P report reaffirmed the current rating for Maritime Electric, noting the supportive regulatory and business environment on PEI. However, S&P expressed some degree of caution with respect to the extent of government involvement in the business of Maritime Electric. In terms of Financial Risk, S&P ranks Maritime Electric as having "Significant" financial risk, which is consistent with the companies in the U.S. Electric Utility proxy group. As shown in Figure 27, two companies in the Canadian peer group also have "Significant" financial risk rankings, while Enbridge has an "Aggressive" financial risk ranking.

Figure 27: Canadian Proxy Group – S&P Rankings

Company	S&P Rating	Business Risk	Financial Risk
Canadian Utilities Ld.	A-	Excellent	Significant
Emera	BBB+	Excellent	Aggressive
Enbridge, Inc.	BBB+	Excellent	Significant
Valener, Inc.	Not Rated	---	---
Maritime Electric Co. Ltd.	**BBB+**	**Excellent**	**Significant**

4. Conclusions on Proposed Equity Ratio

Maritime Electric is proposing a capital structure consisting of 40.00 percent average common equity and 60.00 percent average long-term debt. Maritime Electric's proposed equity ratio is consistent with the average authorized equity ratio for the Canadian proxy group, but substantially lower than the authorized equity ratios of the electric utility companies in the U.S. Electric proxy group. For those reasons, my conclusion is that Maritime Electric's proposed common equity ratio of 40.00 percent is lower than that justified by its risk profile but is consistent with the range established by the Electric Power Act and should be adopted by the Commission.

VII. EARNINGS SHARING MECHANISM

Maritime Electric currently has a Rate of Return Adjustment deferral account that requires the Company to return to customers 100.00 percent of earnings above its authorized ROE of 9.35 percent. This deferral account places a hard cap on Maritime Electric's earnings and provides no financial incentive for the Company to seek cost savings and operating efficiencies. By contrast, many performance-based regulation ("PBR") plans offer the utility a financial incentive to achieve cost savings by allowing the utility to share in some portion of those savings. For example, if a utility achieves an earned return 75 basis points above its authorized ROE, the PBR plan might allow the utility to retain 50.00 percent of those savings, while returning the other 50.00 percent to customers.

The primary purpose of an Earnings Sharing Mechanism ("ESM") is to share with customers earnings that deviate in a meaningful way (either positive or negative) from the level of earnings associated with the authorized ROE. It is probable that revenues, costs and rate base will each deviate from the assumptions that are used as the basis for calculating rates whether the ratemaking approach is based on a historical test year with post-test period adjustments, or whether rate calculations are based on a forward-looking test year, as is the case with Maritime Electric. Thus, it is probable that the earned ROE will be higher or lower than the authorized ROE. The ESM apportions this variance in earnings between customers and the utility based on a prescribed formula.

An ESM helps to safeguard against an earnings outcome that may be unacceptable to either customers (or regulators on their behalf) or to the utility. In this respect, ESMs are a form of variance management. However, rather than focusing narrowly on a particular revenue, cost or rate base circumstance that contributes to the variation in earnings as is the case with a variance or deferral account, the ESM focuses on the end result and therefore captures all contributing circumstances in a single measure after any variance and deferral accounts have been reflected. By focusing on the end result, the ESM reduces the regulatory burden associated with a more detailed inquiry into the specific circumstances that contributed to earnings variations.

The ESM begins with the calculation of realized earnings for a preceding twelve-month period; this calculation is typically performed for each year of a multi-year rate plan. Using this comparison as a starting point, ESMs are defined by two key parameters: 1) the size of a "deadband" around the authorized ROE; and 2) the "customer sharing percentage" or the sharing of earnings with customers that applies when actual earnings fall outside the deadband.

The "deadband" is a range around the authorized ROE within which there is no sharing (i.e., the utility absorbs 100.00 percent of earnings "shortfalls" and retains 100.00 percent of "surplus" earnings). Customer sharing begins when the earned ROE falls outside the deadband. A common deadband is ± 50 to 100 basis points, but there are also examples of ESMs with deadbands between ± 200 and 350 basis points. There have also been a more limited number of

ESMs where there is no deadband, and customer sharing begins with the first dollar of earnings either above or below the authorized ROE.[68]

Maritime Electric is proposing a symmetrical ESM with a deadband of +/- 50 basis points around the authorized ROE of 9.35 percent. Under this proposal, the Company would receive the benefit of surplus earnings and assume the risk of an earnings shortfall within the deadband from 8.85 percent to 9.85 percent. For earnings greater than 9.85 percent, the Company would share 100.00 percent of those excess earnings with customers. For earnings below 8.85 percent, Maritime Electric would be allowed to raise customer rates in the following rate year in order to provide the Company with an earned ROE of no less than 8.85 percent.

VIII. OVERALL CONCLUSIONS AND RECOMMENDATIONS

For the reasons discussed throughout this report, it is appropriate to consider both the CAPM and DCF results when establishing the authorized ROE for Maritime Electric. The results of my CAPM and DCF analyses are summarized in Figure 28.

Figure 28: Summary of Results (including flotation costs)

	Canadian Regulated Utilities	US Electric	North American Electric	Average
CAPM	10.13%	9.47%	9.56%	9.72%
Constant Growth DCF	9.41%	9.26%	9.26%	9.31%
Multi-Stage DCF	10.13%	8.86%	9.03%	9.34%
Average	9.89%	9.20%	9.28%	9.46%

The average results of the Constant Growth and Multi-Stage DCF analyses for the three proxy groups are within a range from 9.31 percent to 9.34 percent, while the average CAPM results are 9.72 percent. The average results for the Canadian, U.S. Electric and North American Electric proxy groups range from 9.20 percent to 9.89 percent. Based on this analysis, I believe a

[68] Maritime Electric currently has an earnings cap. The Company returns every dollar of earnings above its authorized ROE of 9.35% to customers.

reasonable estimate of Maritime Electric's required cost of equity is within a range from 9.20 percent to 9.90 percent (bounded by the U.S. electric average for all methods of 9.20 percent on the low end, and the Canadian average of all methods of 9.89 percent on the high end). Within this range, the Company's proposed ROE of 9.35 percent is reasonable, if not conservative. In particular, the proposed ROE of 9.35 percent is toward the lower end of the range of reasonable results at a time when interest rates on government and corporate bond yields have been rising. In addition, the Company's proposed common equity ratio of 40.00 percent is lower than that justified by its risk profile and well below the average equity thickness for the U.S. electric and North American electric proxy groups. Maritime Electric is small relative to the companies in the Canadian and U.S. electric proxy groups; the long-term economic and demographic trends on Prince Edward Island are weaker than Canada overall: and Maritime Electric does not have many of the variance and deferral accounts that are common among other regulated electric utilities across Canada. Finally, I recommend that the Commission approve the Company's proposed symmetrical ESM with a deadband of +/- 50 basis points around the authorized ROE of 9.35 percent.

John P. Trogonoski
Senior Project Manager

Mr. Trogonoski is a Project Manager with approximately 25 years of experience in utility regulation, financial and economic analysis, business valuation, property taxation, and program administration. Since joining Concentric in 2008, Mr. Trogonoski has assisted clients with a variety of regulatory matters including expert testimony and reports on cost of capital and business and financial risk analysis. As a member of the Staff of the Colorado Public Utilities Commission, Mr. Trogonoski supervised the financial analysts in the energy and telecommunications sections and filed expert testimony on matters such as rate of return, revenue requirement, cost allocation, rate design, incentive regulation, and public policy. He has an M.S. in Business Administration and a B.S. in Marketing from the University of Colorado at Denver.

REPRESENTATIVE PROJECT EXPERIENCE

UTILITY CONSULTING

Since joining Concentric Energy Advisors in February 2008, Mr. Trogonoski has:

- Filed expert testimony on behalf of Hydro-Quebec Distribution and Transmission in support of the Company's request to the Régie de l'energie to modify its allowed return on equity. Performed risk analysis to determine whether it was appropriate to consider a U.S. peer group of regulated electric utilities as an appropriate proxy group for purposes of establishing the allowed ROE for Hydro-Quebec. This analysis included review of the business and financial risks of Canadian and U.S. peer groups on factors that are important to investors in assessing the relative risks of these companies and the regulatory protections that help to mitigate those risks.
- Prepared expert testimony and exhibits for return on equity analysis for numerous North American gas and electric utility clients. This included preparing direct testimony, responding to data requests, drafting rebuttal testimony in response to intervening witnesses, assisting with hearing preparation, and drafting post-hearing statements of position.
- Prepared expert testimony and exhibits for multiple clients seeking regulatory approval of mergers and acquisitions. This included summarizing credit rating agency reactions to the proposed mergers, researching merger approval standards, analyzing the benefits of increased financial scale in the utility industry, and developing financial and ring-fencing commitments in order to mitigate any risk that might result from the merger.
- Performed regulatory due diligence for clients considering the potential acquisition of a natural gas distribution company and an electric transmission company. Due diligence included a review of the regulatory framework in the jurisdiction of the target company, potential cost disallowances, an assessment of the projected ROE and capital structure, an evaluation of the reasonableness of projected capital spending based on forecasted economic growth in the service territory, and the implications of these factors on the value of the target company.
- Assisted in the development of a conservation program for New Jersey American Water, which was filed with the Board of Public Utilities in conjunction with the company's rate case. The program included rebates for various indoor and outdoor plumbing fixtures, as

well as estimated penetration of the proposed rebate programs, and a cost/benefit analysis in support of the various rebates.

- Prepared rebuttal testimony for Central Maine Power in response to a complaint from Staff of the Maine Public Utilities Commission concerning the billing and collection practices of the utility. Demonstrated that increase in late payments was attributable to economic conditions during the recession rather than to decision by the company to outsource the billing and collection function to a third-party provider.
- Reviewed de-list bids filed with the ISO New England by a merchant generation company that wished to withdraw from the Forward Capacity Market. Also prepared user manuals for ISO New England to assist project sponsors in completing a request to provide new supply generation in the Forward Capacity Market, and to assist market participants in completing a request to de-list existing capacity.
- Analyzed the internal policies and tariff of New Mexico Gas in response to service outages and determined if the time to restore service to customers was consistent with other major gas distribution outages that have occurred across the United States. Offered recommendations to improve the Company's communication with regulators and customers.
- Assisted in the development of a business valuation for Poseidon Water, LLC by reviewing and validating cost assumptions for construction costs, water rates, and electricity prices. Also developed cost of capital studies for proxy groups of regulated water utilities and wholesale power generators for use in this valuation.

EXPERT REPORTS

- Drafted a report for the Ontario Energy Board that reviewed low-income energy assistance programs that have been implemented in other jurisdictions, including Canada, the United States, the United Kingdom, the European Union countries, Australia, and New Zealand. Attended hearing and responded to questions related to research report on behalf of OEB staff.
- Drafted a report for the Ontario Energy Board that proposed revisions to the Board's existing rules for Demand Side Management for gas distribution companies in Ontario. Participated in workshop and responded to questions from stakeholders regarding the proposed changes to the Board's rules.

REGULATORY EXPERIENCE

While at the Colorado Public Utilities Commission, Mr. Trogonoski:

- Supervised financial analysts in the energy and telecommunications units from 2004 to 2008. In this capacity, he was responsible for the financial analysis, accounting, and auditing work of between five and nine financial analysts. This included preparation of expert testimony and recommendations concerning rate cases, applications for alternative forms of regulatory treatment, performance of managerial and financial audits, compliance with relevant statutes and Commission rules, and review of applications for certificates of public convenience and necessity, transfers of authority, franchise agreements, and discontinuance of service.

- Provided expert testimony on rate of return issues, capital structure, cost of debt, financial integrity, and credit quality in numerous rate case proceedings involving energy, telecommunications and water companies including Xcel Energy, Qwest Corporation, and Atmos Energy.
- Performed managerial and financial audits of regulated energy and telecommunications companies using the regulatory and accounting guidelines in the Uniform System of Accounts relied upon by the Federal Energy Regulatory Commission, the Federal Communications Commission, the Financial Accounting Standards Board, and the Commission's rules and regulations.
- Led Staff's review of an application for relaxed regulatory treatment by Qwest Corporation. Provided expert testimony regarding Qwest's market share in Colorado relative to cable providers, wireless providers, and Competitive Local Exchange Carriers. Assisted professional market research firm in designing questionnaire to examine customer preferences for purchasing telecommunications services, expectations concerning price and quality of those services, and desire for regulation over those services.
- Led Staff's investigation into a Competitive Local Exchange Carrier who was providing regulated telephone service to over 14,000 customers without the requisite Commission authority and without an effective tariff. This investigation resulted in a Commission order to cease and desist provision of regulated services, an order to transfer customers to an alternative provider, and sanctions against the principals.
- Administered the Colorado High Cost Support Mechanism, which provided universal telecommunications service to customers in rural, high costs areas through an assessment on all Colorado customers. Also, later supervised the position that administered this program.

PUBLICATIONS AND RESEARCH

- "Autopilot Error: Why Similar U.S. and Canadian Risk Profiles Yield Varied Rate-making Results" (with John Trogonoski), Public Utilities Fortnightly, May 2010

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2008 – Present)
Senior Project Manager
Project Manager
Senior Consultant

Colorado Public Utilities Commission (2004 – 2008)
Supervisory Financial Analyst, Telecommunications and Energy

Colorado Public Utilities Commission (1999 – 2004)
Financial Analyst, Telecommunications, Energy and Water

State of Colorado, Division of Property Taxation (1994 – 1999)
Property Tax Specialist

Nobel Sysco, Inc. (1992 – 1994)
Marketing Associate

State of Colorado, Division of Property Taxation (1989 – 1991)
Tax Appraiser Consultant

EDUCATION

M.S. in Business Administration, University of Colorado at Denver, 1987
B.S. in Marketing, University of Colorado at Denver, 1986

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Colorado Public Utilities Commission				
Colorado PUC Staff	2000	Qwest Corporation	99A-577T	Capital Structure Cost of Capital Cost of Debt Composite Income Tax Rate Interest During Construction factor Ad Valorem Tax factor
Colorado PUC Staff	2001	Peetz Cooperative Telephone	01S-321T	Cost of Capital Revenue Requirement Adjustments to Rate Base Adjustment to Operating Expenses Imputed Capital Structure Capital Credit Rotation
Colorado PUC Staff	2002	Mile High Telecom	02C-082T	Order to show cause Operating without CPCN or tariff Violation of stipulation – alleged fraud
Colorado PUC Staff	2002	Public Service Company of Colorado – Electric/Gas	02S-315EG	Cost of Capital Dissolution of PS Credit Corporation Financial Integrity and credit ratings Impact of NRG on regulated entity Dividend payments and capital spending
Colorado PUC Staff	2003	Aquila Networks, Inc.	02S-594E	Cost of Capital

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Colorado PUC Staff	2003	Lake Durango Water Company	03S-052W	Allowable expenses – depreciation and taxes Value of purchased water Operating Ratio method Rate design for retail and bulk customers Customer impact of proposed rates Enhancement of accounting & financial reports
Colorado PUC Staff	2003	Roggen Telephone	03S-246T	Cost of Capital
Colorado PUC Staff	2003	South Park Telephone	03A-277T	Request for HCSM support Adjustments to Rate Base Disallowance of Expenses Depreciation rates and USF impact Cost of Capital
Colorado PUC Staff	2003	Pine Drive Telephone	03S-314T	Cost of Capital
Colorado PUC Staff	2003	Phillips County Telephone	03S-315T	Cost of Capital
Colorado PUC Staff	2004	Aquila Networks, Inc.	04S-035E	Cost of Capital
Colorado PUC Staff	2004	SC TxLink, LLC	04A-508	CPCN for CLEC authority Financial Assurance - bonding
Colorado PUC Staff	2005	Qwest Corporation	04A-411T	History of CLEC competition since 1996 Wireless competition in Colorado Is Wireless substitute for wireline? Financial barriers to entry Introduce customer survey Analyze and interpret survey results Regulation of retail service in 14 states

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Colorado PUC Staff	2005	Public Service Company of Colorado – Gas	05S-264G	Cost of Capital – investor owned Rate design issues in Phase 2 – S&F Charge Impact on rate of return – minimum system
Colorado PUC Staff	2005	Public Service Company of Colorado - Steam	05S-369ST	Cost of Capital
Colorado PUC Staff	2006	Public Service Company of Colorado - Electric	06S-234EG	Cost of Capital Credit quality and cash flow Financial integrity and credit ratings Purchased power and imputed debt Performance based regulatory plan
Colorado PUC Staff	2007	Public Service Company of Colorado - Gas	06S-656G	Cost of Capital Financial integrity and credit ratings
Colorado PUC Staff	2007	Nunn Telephone	07A-124T	Overview of HCSM statutes and rules Information required by CRS 40-15-208 Use of separation program – revenue requirement Challenges faced with new petition process
Subpoenas to Provide Expert Testimony				
U.S. Bankruptcy Court – Denver, CO	2005	ON Systems, Inc.	N/A	Testify in U.S. bankruptcy court - value of CPCN
U.S. District Court, Southern District of Florida	2008	USA vs. Wetherald, et al	06-80199-CR-MARRA	Testify on behalf of U.S. government Wire fraud, mail fraud, money laundering
New York Public Service Commission				
New York State Gas and Electric Company and Rochester Gas and Electric	2015	New York State Gas and Electric Company and Rochester Gas and Electric	15G-0284	Cost of Capital (Rebuttal)

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Niagara Mohawk Power Corporation d/b/a National Grid	2017	Niagara Mohawk Power Corporation d/b/a National Grid	17-E-0238 17-G-0239	Cost of Capital (Rebuttal)
Régie de l'Energie du Quebec				
Hydro Quebec Distribution and Hydro Quebec TransÉnergie	2013	Hydro Quebec Distribution and Hydro Quebec TransÉnergie	R-3842-2013	Risk analysis in support of ROE testimony

Canadian & U.S. Macroeconomic Factors

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[9]	[10]	[11]	[11]	[12]	[13]	[14]
	Total Return on:		Total Return on:		Real GDP Growth		CPI Change		10-year Gov't Bond		30-year Gov't Bond		Exports		Unemployment		Currency
	S&P/TSX	S&P 500	S&P/TSX Utilities	S&P 500 Utilities	Canada	U.S.	Canada	U.S.	Canada	U.S.	Canada	U.S.	Canada to U.S./ Canadian GDP	U.S. to Canada / U.S. GDP	Canada	U.S.	Exchange Rate (CAD / USD)
1990	-18.7	-4.9	-1.6	-1.4	0.1	1.9	4.8	5.4	10.8	8.5	n/a	8.6	16.1	2.0	8.2	5.6	1.17
1991	8.4	31.9	-3.5	25.0	-2.1	-0.1	5.6	4.2	9.4	7.8	9.8	8.1	15.6	1.9	10.3	6.9	1.15
1992	-4.1	7.6	2.1	7.2	0.9	3.6	1.5	3.0	8.1	7.0	8.8	7.7	17.3	2.1	11.2	7.5	1.21
1993	32.2	10.1	16.3	13.4	2.7	2.7	1.9	3.0	7.2	5.9	8.0	6.6	20.0	2.5	11.4	6.9	1.29
1994	-1.3	1.2	3.8	-11.1	4.5	4.0	0.2	2.6	8.4	7.1	8.7	7.4	23.0	3.0	10.4	6.1	1.37
1995	15.1	37.6	-2.0	32.0	2.7	2.7	2.1	2.8	8.1	6.6	8.5	6.9	24.8	3.2	9.5	5.6	1.37
1996	26.7	22.0	17.5	5.2	1.6	3.8	1.6	3.0	7.2	6.4	7.8	6.7	25.9	3.1	9.6	5.4	1.36
1997	15.3	34.0	32.1	25.7	4.3	4.5	1.6	2.3	6.1	6.3	6.7	6.6	26.8	3.5	9.1	4.9	1.38
1998	-2.0	27.9	-0.2	15.3	3.9	4.4	1.0	1.6	5.3	5.3	5.6	5.6	28.7	3.9	8.3	4.5	1.48
1999	30.4	21.1	-30.8	-9.2	5.2	4.7	1.7	2.2	5.6	5.6	5.7	5.9	30.8	4.0	7.6	4.2	1.49
2000	10.1	-4.6	42.1	61.2	5.2	4.1	2.7	3.4	5.9	6.0	5.7	5.9	32.6	4.0	6.8	4.0	1.49
2001	-9.3	-9.3	7.3	-27.8	1.8	1.0	2.5	2.8	5.5	5.0	5.8	5.5	30.9	3.8	7.2	4.7	1.55
2002	-11.9	-22.6	3.4	-30.9	3.0	1.8	2.3	1.6	5.3	4.6	5.7	5.3	29.3	3.8	7.7	5.8	1.57
2003	24.2	24.5	23.4	23.3	1.8	2.8	2.8	2.3	4.8	4.0	5.3	4.9	26.3	3.0	7.6	6.0	1.40
2004	13.4	11.2	8.7	24.3	3.1	3.8	1.9	2.7	4.6	4.3	5.1	5.0	26.4	2.7	7.2	5.5	1.30
2005	25.4	7.0	37.6	19.2	3.2	3.3	2.2	3.4	4.1	4.3	4.4	4.6	26.0	2.5	6.8	5.1	1.21
2006	15.5	13.9	5.8	18.7	2.6	2.7	2.0	3.2	4.2	4.8	4.3	4.9	24.2	2.3	6.3	4.6	1.13
2007	11.6	5.7	11.8	18.9	2.1	1.8	2.1	2.8	4.3	4.6	4.3	4.8	22.6	2.1	6.0	4.6	1.07
2008	-33.5	-36.1	-20.4	-28.0	1.0	-0.3	2.4	3.8	3.6	3.6	4.1	4.3	22.4	2.1	6.2	5.8	1.07
2009	31.3	22.6	15.9	9.4	-2.9	-2.8	0.3	-0.4	3.2	3.2	3.9	4.1	17.3	1.9	8.4	9.3	1.14
2010	16.3	13.2	18.6	5.2	3.1	2.5	1.8	1.6	3.2	3.2	3.8	4.2	17.8	1.9	8.0	9.6	1.03
2011	-8.5	1.1	6.0	18.7	3.1	1.6	2.9	3.2	2.8	2.8	3.3	3.9	18.6	1.8	7.5	8.9	0.99
2012	4.9	14.2	3.3	3.0	1.7	2.2	1.5	2.1	1.9	1.8	2.4	2.9	18.5	1.8	7.3	8.1	1.00
2013	12.0	29.1	-4.9	11.2	2.5	1.7	0.9	1.5	2.3	2.3	2.8	3.4	18.8	1.8	7.1	7.4	1.03
2014	10.7	14.7	16.2	31.0	2.9	2.6	1.9	1.6	2.2	2.5	2.8	3.3	20.2	1.8	6.9	6.2	1.10
2015	-9.2	1.4	-4.4	-5.4	1.0	2.9	1.1	0.1	1.5	2.1	2.2	2.8	19.9	1.5	6.9	5.3	1.28
2016	21.9	13.7	18.7	16.6	1.4	1.5	1.4	1.3	1.3	1.8	1.9	2.6	19.3	1.4	7.0	4.9	1.32
2017	8.3	20.8	11.6	12.4	2.6	2.3	1.6	2.1	1.8	2.3	2.3	2.9	19.2	1.5	6.3	4.4	1.31
25-year Avg.	9.99	10.97	9.49	10.10	2.56	2.49	1.78	2.26	4.41	4.26	4.84	4.84	23.36	2.60	7.72	5.91	1.27
10-year Avg.	5.42	9.46	6.06	7.43	1.641	1.413	1.587	1.695	2.378	2.58	2.94	3.45	19.50	1.75	7.16	6.97	1.13
5-year Avg.	8.73	15.92	7.43	13.17	2.08	2.17	1.40	1.32	1.81	2.23	2.40	3.02	19.30	1.61	6.85	5.60	1.21
Correlation	0.70		0.61		0.85		0.63		0.97		0.98		0.92		0.24		--
							Consensus Forecasts [15]										
2019					1.90	2.60	2.00	2.10	2.70	3.20					5.90	3.90	1.26
2020					1.80	1.80	2.00	2.20	3.20	3.50					5.80	3.60	1.25
2021					1.60	1.90	1.90	2.20	3.30	3.50							

Notes:
[1] Source: Bloomberg Professional; total return index gross dividend yield
[2] Source: Bloomberg Professional; total return index gross dividend yield
[3] Source: Bloomberg Professional; total return index gross dividend yield
[4] Source: Bloomberg Professional; total return index gross dividend yield
[5] Source: Statistics Canada; expenditure-based GDP at market prices, chained 2007 prices, seasonally adjusted, accessed March 1, 2018
[6] Source: U.S. Bureau of Economic Analysis; Table 1.1.6 Real Gross Domestic Product, chained 2009 dollars, seasonally adjusted, accessed March 1, 2018
[7] Source: Statistics Canada; Consumer Price Index (2002=100), All items, not seasonally adjusted, accessed March 1, 2018
[8] Source: U.S. Bureau of Labor Statistics; CPI-All Urban Consumers (1982-84=100), all items, not seasonally adjusted, accessed March 1, 2018
[9] Source: Bank of Canada
[10] Source: Bloomberg Professional
[11] Source: Statistics Canada, Imports, exports and trade balance of goods by country and Gross domestic product, expenditure-based;
United States Census Bureau, trade in goods with Canada; and U.S. Bureau of Economic Analysis Table 1.1.5 GDP
[12] Source: Statistics Canada; Labour force survey estimates (LFS), unemployment rate, 15 years and over, seasonally adjusted, accessed March 1, 2018
[13] Source: U.S. Bureau of Labor Statistics, Unemployment Rate, seasonally adjusted, accessed March 1, 2018
[14] Source: Federal Reserve Economic Data
[15] Source: Consensus Forecasts, Survey Date April 9, 2018.

U.S. PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	S&P Rating	Pays Dividends (Yes/No)	Postive Earnings Growth by more than one Analyst (Yes/No)	Market Cap (US$ Million)	Total Electric Customers	Total Revenue ($ Million)	Total Assets ($ Million)	Owned Generation Assets (Yes/No)	Regulated Generation Assets (Yes/No)	Regulated Income / Total Income (%)	Regulated Electric Income / Total Regulated Income (%)	Involved in Merger (Yes/No)
ALLETE, Inc.	ALE	BBB+	Yes	Yes	3,856	160,000	1,444	5,080	Yes	Yes	83%	97%	No
Alliant Energy Corporation	LNT	A-	Yes	Yes	10,195	962,121	3,461	14,188	Yes	Yes	101%	95%	No
American Electric Power Company, Inc.	AEP	A-	Yes	Yes	35,358	5,400,000	15,874	64,729	Yes	Yes	91%	100%	No
Duke Energy Corporation	DUK	A-	Yes	Yes	57,872	7,595,791	24,064	137,914	Yes	Yes	106%	95%	No
Edison International	EIX	BBB+	Yes	Yes	21,416	5,097,818	12,475	52,580	Yes	Yes	106%	100%	No
Eversource Energy	ES	A+	Yes	Yes	19,783	3,187,126	7,830	36,220	Yes	No	97%	91%	No
OGE Energy Corporation	OGE	BBB+	Yes	Yes	7,356	841,830	2,478	10,413	Yes	Yes	102%	100%	No
Pinnacle West Capital Corporation	PNW	A-	Yes	Yes	8,796	1,221,485	3,616	17,019	Yes	Yes	72%	100%	No
PNM Resources, Inc.	PNM	BBB+	Yes	Yes	3,103	773,444	1,508	6,646	Yes	Yes	100%	100%	No
Average											95%	98%	

Notes:
[1] Source: SNL Financial
[2] Source: Bloomberg Professional
[3] Source: Value Line, Zacks and Yahoo Finance
[4] Source: Bloomberg Professional, as of August 31, 2018
[5] Source: SNL Financial, as of 12/31/2017
[6] Source: SNL Financial, as of 12/31/2017
[7] Source: SNL Financial, as of 12/31/2017
[8] Source: Company 10-K reports, most recent year
[9] Source: Company 10-K reports, most recent year
[10] - [11] Source: Company 10-K reports, average of three most recent years
[12] Source: Bloomberg Professional

CANADIAN PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	S&P Rating	Pays Dividends (Yes/No)	Postive Earnings Growth by more than one Analyst (Yes/No)	Market Cap (C$ Million)	Total Electric Customers	Total Revenue ($ Million)	Total Assets ($ Million)	Owned Generation Assets (Yes/No)	Regulated Generation Assets (Yes/No)	Regulated Oper Income / Total Income (%)	Regulated Electric Income / Total Regulated Income (%)	Involved in Merger (Yes/No)
Canadian Utilities Limited	CU	A-	Yes	Yes	6,292	256,343	4,095	20,825	Yes	No	50%	N/A	No
Emera Inc.	EMA	BBB+	Yes	Yes	9,574	1,121,516	6,352	28,771	Yes	Yes	94%	N/A	No
Enbridge Inc.	ENB	BBB+	Yes	Yes	76,353	n/a	45,932	162,093	Yes	No	28%	0.00%	No
Valener Inc.	VNR	N/A	Yes	No	786	n/a	74	922	No	Yes	N/A	N/A	No

Notes:
[1] Source: SNL Financial
[2] Source: Bloomberg Professional
[3] Source: Value Line, Zacks and Yahoo Finance
[4] Source: Bloomberg Professional, as of August 31, 2018
[5] Source: SNL Financial, as of 12/31/2017
[6] Source: SNL Financial, as of 12/31/2017
[7] Source: SNL Financial, as of 12/31/2017
[8] Source: Company 10-K reports, most recent year
[9] Source: Company 10-K reports, most recent year
[10] Source: Company Annual Reports, average of three most recent years
[11] Source: Company Annual Reports, average of three most recent years
[12] Source: Bloomberg Professional

NORTH AMERICA ELECTRIC PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	S&P Rating	Pays Dividends (Yes/No)	Postive Earnings Growth by more than one Analyst (Yes/No)	Market Cap ($ Million)	Total Electric Customers	Total Revenue ($ Million)	Total Assets ($ Million)	Owned Generation Assets (Yes/No)	Regulated Generation Assets (Yes/No)	Regulated Income / Total Income (%)	Regulated Electric Income / Total Regulated Income (%)	Involved in Merger (Yes/No)
ALLETE, Inc.	ALE	BBB+	Yes	Yes	3,856	160,000	1,444	5,080	Yes	Yes	83%	97%	No
Alliant Energy Corporation	LNT	A-	Yes	Yes	10,195	962,121	3,461	14,188	Yes	Yes	101%	95%	No
American Electric Power Company, Inc.	AEP	A-	Yes	Yes	35,358	5,400,000	15,874	64,729	Yes	Yes	91%	100%	No
Duke Energy Corporation	DUK	A-	Yes	Yes	57,872	7,595,791	24,064	137,914	Yes	Yes	106%	95%	No
Edison International	EIX	BBB+	Yes	Yes	21,416	5,097,818	12,475	52,580	Yes	Yes	106%	100%	No
Eversource Energy	ES	A+	Yes	Yes	19,783	3,187,126	7,830	36,220	Yes	No	97%	91%	No
OGE Energy Corporation	OGE	BBB+	Yes	Yes	7,356	841,830	2,478	10,413	Yes	Yes	102%	100%	No
Pinnacle West Capital Corporation	PNW	A-	Yes	Yes	8,796	1,221,485	3,616	17,019	Yes	Yes	72%	100%	No
PNM Resources, Inc.	PNM	BBB+	Yes	Yes	3,103	773,444	1,508	6,646	Yes	Yes	100%	100%	No
Canadian Utilities Limited	CU	A-	Yes	Yes	6,292	256,343	4,095	20,825	Yes	No	50%	N/A	No
Emera Inc.	EMA	BBB+	Yes	Yes	9,574	1,121,516	6,352	28,771	Yes	Yes	94%	N/A	No

Notes:
[1] Source: SNL Financial
[2] Source: Bloomberg Professional
[3] Source: Value Line, Zacks and Yahoo Finance
[4] Source: Bloomberg Professional, as of August 31, 2018
[5] Source: SNL Financial, as of 12/31/2017
[6] Source: SNL Financial, as of 12/31/2017
[7] Source: SNL Financial, as of 12/31/2017
[8] Source: Company 10-K reports, most recent year
[9] Source: Company 10-K reports, most recent year
[10] Source: Company 10-K reports, average of three most recent years
[11] Source: Company 10-K reports, average of three most recent years
[12] Source: Bloomberg Professional

30-DAY CONSTANT GROWTH DCF -- U.S. PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	SNL EPS Growth	First Call Growth	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
ALLETE, Inc.	ALE	$2.24	$76.95	2.91%	3.00%	6.00%	6.90%	6.00%	6.30%	9.00%	9.30%	9.91%
Alliant Energy Corporation	LNT	$1.34	$42.81	3.13%	3.22%	5.50%	5.74%	5.75%	5.66%	8.72%	8.88%	8.97%
American Electric Power Company, Inc.	AEP	$2.48	$71.08	3.49%	3.59%	5.60%	5.95%	5.59%	5.71%	9.18%	9.30%	9.54%
Duke Energy Corporation	DUK	$3.71	$81.01	4.58%	4.68%	4.60%	4.90%	4.13%	4.54%	8.80%	9.23%	9.59%
Edison International	EIX	$2.42	$67.24	3.60%	3.68%	5.80%	3.74%	3.44%	4.33%	7.10%	8.00%	9.50%
Eversource Energy	ES	$2.02	$61.35	3.29%	3.39%	5.90%	5.95%	5.80%	5.88%	9.19%	9.27%	9.34%
OGE Energy Corporation	OGE	$1.33	$36.62	3.63%	3.72%	4.80%	4.83%	4.70%	4.78%	8.42%	8.50%	8.55%
Pinnacle West Capital Corporation	PNW	$2.78	$80.58	3.45%	3.53%	4.50%	5.00%	3.72%	4.41%	7.23%	7.93%	8.54%
PNM Resources, Inc.	PNM	$1.06	$39.35	2.69%	2.76%	4.60%	5.10%	4.45%	4.72%	7.20%	7.47%	7.86%
MEAN				3.42%	3.51%	5.26%	5.35%	4.84%	5.15%	8.32%	8.65%	9.09%
Flotation Costs [12]										0.50%	0.50%	0.50%
										8.82%	9.15%	9.59%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 30-day average as of August 31, 2018
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks at August 31, 2018
[6] Source: SNL Financial Median Long-Term EPS Growth Rate as of September 12, 2018
[7] Source: Yahoo! Finance at August 31, 2018
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])
[12] The Commission allows 50 bps adjustment for flotation cost and financial flexibility.

30-DAY CONSTANT GROWTH DCF -- CANADIAN PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	SNL EPS Growth	First Call Growth	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
Canadian Utilities Limited	CU	$1.57	$32.33	4.87%	4.91%	n/a	2.05%	1.75%	1.90%	6.66%	6.81%	6.97%
Emera Inc.	EMA	$2.26	$41.53	5.44%	5.58%	n/a	5.90%	4.35%	5.13%	9.91%	10.71%	11.50%
Enbridge Inc.	ENB	$2.68	$46.17	5.81%	5.95%	9.00%	4.60%	0.92%	4.84%	6.76%	10.79%	15.07%
Valener Inc.	VNR	$1.16	$20.21	5.74%	5.77%	n/a	0.70%	1.68%	1.19%	6.46%	6.96%	7.47%
MEAN				5.46%	5.56%	9.00%	3.31%	2.18%	3.26%	7.45%	8.82%	10.25%
Flotation Costs [12]										0.50%	0.50%	0.50%
										7.95%	9.32%	10.75%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 30-day average as of August 31, 2018
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks at August 31, 2018
[6] Source: SNL Financial Median Long-Term EPS Growth Rate as of September 12, 2018
[7] Source: Yahoo! Finance at August 31, 2018
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])
[12] The Commission allows 50 bps adjustment for flotation cost and financial flexibility.

30-DAY CONSTANT GROWTH DCF -- NORTH AMERICA ELECTRIC PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	SNL EPS Growth	First Call Growth	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
ALLETE, Inc.	ALE	$2.24	$76.95	2.91%	3.00%	6.00%	6.90%	6.00%	6.30%	9.00%	9.30%	9.91%
Alliant Energy Corporation	LNT	$1.34	$42.81	3.13%	3.22%	5.50%	5.74%	5.75%	5.66%	8.72%	8.88%	8.97%
American Electric Power Company, Inc.	AEP	$2.48	$71.08	3.49%	3.59%	5.60%	5.95%	5.59%	5.71%	9.18%	9.30%	9.54%
Duke Energy Corporation	DUK	$3.71	$81.01	4.58%	4.68%	4.60%	4.90%	4.13%	4.54%	8.80%	9.23%	9.59%
Edison International	EIX	$2.42	$67.24	3.60%	3.68%	5.80%	3.74%	3.44%	4.33%	7.10%	8.00%	9.50%
Eversource Energy	ES	$2.02	$61.35	3.29%	3.39%	5.90%	5.95%	5.80%	5.88%	9.19%	9.27%	9.34%
OGE Energy Corporation	OGE	$1.33	$36.62	3.63%	3.72%	4.80%	4.83%	4.70%	4.78%	8.42%	8.50%	8.55%
Pinnacle West Capital Corporation	PNW	$2.78	$80.58	3.45%	3.53%	4.50%	5.00%	3.72%	4.41%	7.23%	7.93%	8.54%
PNM Resources, Inc.	PNM	$1.06	$39.35	2.69%	2.76%	4.60%	5.10%	4.45%	4.72%	7.20%	7.47%	7.86%
Canadian Utilities Limited	CU	$1.57	$32.33	4.87%	4.91%	n/a	2.05%	1.75%	1.90%	6.66%	6.81%	6.97%
Emera Inc.	EMA	$2.26	$41.53	5.44%	5.58%	n/a	5.90%	4.35%	5.13%	9.91%	10.71%	11.50%
MEAN				3.73%	3.82%	5.26%	5.10%	4.52%	4.85%	8.31%	8.67%	9.12%
Flotation Costs [12]										0.50%	0.50%	0.50%
										8.81%	9.17%	9.62%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 30-day average as of August 31, 2018
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks at August 31, 2018
[6] Source: SNL Financial Median Long-Term EPS Growth Rate as of September 12, 2018
[7] Source: Yahoo! Finance at August 31, 2018
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])
[12] The Commission allows 50 bps adjustment for flotation cost and financial flexibility.

90-DAY CONSTANT GROWTH DCF -- U.S. PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	SNL EPS Growth	First Call Growth	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
ALLETE, Inc.	ALE	$2.24	$76.49	2.93%	3.02%	6.00%	6.90%	6.00%	6.30%	9.02%	9.32%	9.93%
Alliant Energy Corporation	LNT	$1.34	$41.96	3.19%	3.28%	5.50%	5.74%	5.75%	5.66%	8.78%	8.95%	9.03%
American Electric Power Company, Inc.	AEP	$2.48	$68.86	3.60%	3.70%	5.60%	5.95%	5.59%	5.71%	9.29%	9.42%	9.66%
Duke Energy Corporation	DUK	$3.71	$78.63	4.72%	4.83%	4.60%	4.90%	4.13%	4.54%	8.95%	9.37%	9.73%
Edison International	EIX	$2.42	$64.17	3.77%	3.85%	5.80%	3.74%	3.44%	4.33%	7.28%	8.18%	9.68%
Eversource Energy	ES	$2.02	$58.69	3.44%	3.54%	5.90%	5.95%	5.80%	5.88%	9.34%	9.43%	9.49%
OGE Energy Corporation	OGE	$1.33	$35.12	3.79%	3.88%	4.80%	4.83%	4.70%	4.78%	8.58%	8.65%	8.71%
Pinnacle West Capital Corporation	PNW	$2.78	$79.21	3.51%	3.59%	4.50%	5.00%	3.72%	4.41%	7.29%	7.99%	8.60%
PNM Resources, Inc.	PNM	$1.06	$38.70	2.74%	2.80%	4.60%	5.10%	4.45%	4.72%	7.25%	7.52%	7.91%
MEAN				3.52%	3.61%	5.26%	5.35%	4.84%	5.15%	8.42%	8.76%	9.19%
Flotation Costs [12]										0.50%	0.50%	0.50%
										8.92%	9.26%	9.69%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of August 31, 2018
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks at August 31, 2018
[6] Source: SNL Financial Median Long-Term EPS Growth Rate as of September 12, 2018
[7] Source: Yahoo! Finance at August 31, 2018
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])
[12] The Commission allows 50 bps adjustment for flotation cost and financial flexibility.

90-DAY CONSTANT GROWTH DCF -- CANADIAN PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	SNL EPS Growth	First Call Growth	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
Canadian Utilities Limited	CU	$1.57	$32.31	4.87%	4.92%	n/a	2.05%	1.75%	1.90%	6.66%	6.82%	6.97%
Emera Inc.	EMA	$2.26	$41.33	5.47%	5.61%	n/a	5.90%	4.35%	5.13%	9.94%	10.73%	11.53%
Enbridge Inc.	ENB	$2.68	$43.61	6.15%	6.30%	9.00%	4.60%	0.92%	4.84%	7.10%	11.14%	15.43%
Valener Inc.	VNR	$1.16	$20.30	5.72%	5.75%	n/a	0.70%	1.68%	1.19%	6.44%	6.94%	7.44%
MEAN				5.55%	5.64%	9.00%	3.31%	2.18%	3.26%	7.53%	8.91%	10.34%
Flotation Costs [12]										0.50%	0.50%	0.50%
										8.03%	9.41%	10.84%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of August 31, 2018
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks at August 31, 2018
[6] Source: SNL Financial Median Long-Term EPS Growth Rate as of September 12, 2018
[7] Source: Yahoo! Finance at August 31, 2018
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])
[12] The Commission allows 50 bps adjustment for flotation cost and financial flexibility.

90-DAY CONSTANT GROWTH DCF -- NORTH AMERICA ELECTRIC PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	SNL EPS Growth	First Call Growth	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
ALLETE, Inc.	ALE	$2.24	$76.49	2.93%	3.02%	6.00%	6.90%	6.00%	6.30%	9.02%	9.32%	9.93%
Alliant Energy Corporation	LNT	$1.34	$41.96	3.19%	3.28%	5.50%	5.74%	5.75%	5.66%	8.78%	8.95%	9.03%
American Electric Power Company, Inc.	AEP	$2.48	$68.86	3.60%	3.70%	5.60%	5.95%	5.59%	5.71%	9.29%	9.42%	9.66%
Duke Energy Corporation	DUK	$3.71	$78.63	4.72%	4.83%	4.60%	4.90%	4.13%	4.54%	8.95%	9.37%	9.73%
Edison International	EIX	$2.42	$64.17	3.77%	3.85%	5.80%	3.74%	3.44%	4.33%	7.28%	8.18%	9.68%
Eversource Energy	ES	$2.02	$58.69	3.44%	3.54%	5.90%	5.95%	5.80%	5.88%	9.34%	9.43%	9.49%
OGE Energy Corporation	OGE	$1.33	$35.12	3.79%	3.88%	4.80%	4.83%	4.70%	4.78%	8.58%	8.65%	8.71%
Pinnacle West Capital Corporation	PNW	$2.78	$79.21	3.51%	3.59%	4.50%	5.00%	3.72%	4.41%	7.29%	7.99%	8.60%
PNM Resources, Inc.	PNM	$1.06	$38.70	2.74%	2.80%	4.60%	5.10%	4.45%	4.72%	7.25%	7.52%	7.91%
Canadian Utilities Limited	CU	$1.57	$32.31	4.87%	4.92%	n/a	2.05%	1.75%	1.90%	6.66%	6.82%	6.97%
Emera Inc.	EMA	$2.26	$41.33	5.47%	5.61%	n/a	5.90%	4.35%	5.13%	9.94%	10.73%	11.53%
MEAN				3.82%	3.91%	5.26%	5.10%	4.52%	4.85%	8.40%	8.76%	9.20%
Flotation Costs [12]										0.50%	0.50%	0.50%
										8.90%	9.26%	9.70%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of August 31, 2018
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks at August 31, 2018
[6] Source: SNL Financial Median Long-Term EPS Growth Rate as of September 12, 2018
[7] Source: Yahoo! Finance at August 31, 2018
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])
[12] The Commission allows 50 bps adjustment for flotation cost and financial flexibility.

30-DAY MULTI-STAGE DCF -- U.S. PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Annualized Dividend	Stock Price	Growth Rate, Years 1-5	Year 6	Year 7	Year 8	Year 9	Year 10	GDP Growth (perpetuity)	ROE
ALLETE, Inc.	ALE	$2.24	$76.95	6.30%	5.97%	5.65%	5.32%	5.00%	4.67%	4.35%	7.91%
Alliant Energy Corporation	LNT	$1.34	$42.81	5.66%	5.44%	5.22%	5.00%	4.79%	4.57%	4.35%	8.03%
American Electric Power Company, Inc.	AEP	$2.48	$71.08	5.71%	5.49%	5.26%	5.03%	4.80%	4.57%	4.35%	8.47%
Duke Energy Corporation	DUK	$3.71	$81.01	4.54%	4.51%	4.48%	4.44%	4.41%	4.38%	4.35%	9.40%
Edison International	EIX	$2.42	$67.24	4.33%	4.33%	4.33%	4.34%	4.34%	4.34%	4.35%	8.24%
Eversource Energy	ES	$2.02	$61.35	5.88%	5.63%	5.37%	5.11%	4.86%	4.60%	4.35%	8.28%
OGE Energy Corporation	OGE	$1.33	$36.62	4.78%	4.70%	4.63%	4.56%	4.49%	4.42%	4.35%	8.39%
Pinnacle West Capital Corporation	PNW	$2.78	$80.58	4.41%	4.40%	4.39%	4.38%	4.37%	4.36%	4.35%	8.10%
PNM Resources, Inc.	PNM	$1.06	$39.35	4.72%	4.65%	4.59%	4.53%	4.47%	4.41%	4.35%	7.31%
MEAN				5.15%	5.01%	4.88%	4.75%	4.61%	4.48%	4.35%	8.24%
Flotation Costs [11]											0.50%
											8.74%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 30-day average as of August 31, 2018
[3] Source: Constant Growth DCF
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Consensus Economics Inc., Consensus Forecasts, April 9, 2018, at 3.
[10] Internal rate of return
[11] The Commission allows 50 bps adjustment for flotation cost and financial flexibility.

30-DAY MULTI-STAGE DCF -- CANADIAN PROXY GROUP

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Growth Rate, Years 1-5	[4] Year 6	[5] Year 7	[6] Year 8	[7] Year 9	[8] Year 10	[9] GDP Growth (perpetuity)	[10] ROE
Canadian Utilities Limited	CU	$1.57	$32.33	1.90%	2.21%	2.51%	2.82%	3.12%	3.43%	3.73%	8.41%
Emera Inc.	EMA	$2.26	$41.53	5.13%	4.89%	4.66%	4.43%	4.20%	3.97%	3.73%	10.16%
Enbridge Inc.	ENB	$2.68	$46.17	4.84%	4.66%	4.47%	4.29%	4.10%	3.92%	3.73%	10.49%
Valener Inc.	VNR	$1.16	$20.21	1.19%	1.61%	2.04%	2.46%	2.89%	3.31%	3.73%	9.05%
MEAN				3.26%	3.34%	3.42%	3.50%	3.58%	3.66%	3.73%	9.53%
Flotation Costs [11]											0.50%
											10.03%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 30-day average as of August 31, 2018
[3] Source: Constant Growth DCF
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Consensus Economics Inc., Consensus Forecasts, April 9, 2018, at 28.
[10] Internal rate of return
[11] The Commission allows 50 bps adjustment for flotation cost and financial flexibility.

30-DAY MULTI-STAGE DCF -- NORTH AMERICA ELECTRIC PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Annualized Dividend	Stock Price	Growth Rate, Years 1-5	Year 6	Year 7	Year 8	Year 9	Year 10	GDP Growth (perpetuity)	ROE
ALLETE, Inc.	ALE	$2.24	$76.95	6.30%	5.97%	5.65%	5.32%	5.00%	4.67%	4.35%	7.91%
Alliant Energy Corporation	LNT	$1.34	$42.81	5.66%	5.44%	5.22%	5.00%	4.79%	4.57%	4.35%	8.03%
American Electric Power Company, Inc.	AEP	$2.48	$71.08	5.71%	5.49%	5.26%	5.03%	4.80%	4.57%	4.35%	8.47%
Duke Energy Corporation	DUK	$3.71	$81.01	4.54%	4.51%	4.48%	4.44%	4.41%	4.38%	4.35%	9.40%
Edison International	EIX	$2.42	$67.24	4.33%	4.33%	4.33%	4.34%	4.34%	4.34%	4.35%	8.24%
Eversource Energy	ES	$2.02	$61.35	5.88%	5.63%	5.37%	5.11%	4.86%	4.60%	4.35%	8.28%
OGE Energy Corporation	OGE	$1.33	$36.62	4.78%	4.70%	4.63%	4.56%	4.49%	4.42%	4.35%	8.39%
Pinnacle West Capital Corporation	PNW	$2.78	$80.58	4.41%	4.40%	4.39%	4.38%	4.37%	4.36%	4.35%	8.10%
PNM Resources, Inc.	PNM	$1.06	$39.35	4.72%	4.65%	4.59%	4.53%	4.47%	4.41%	4.35%	7.31%
Canadian Utilities Limited	CU	$1.57	$32.33	1.90%	2.21%	2.51%	2.82%	3.12%	3.43%	3.73%	8.41%
Emera Inc.	EMA	$2.26	$41.53	5.13%	4.89%	4.66%	4.43%	4.20%	3.97%	3.73%	10.16%
MEAN				4.85%	4.75%	4.65%	4.54%	4.44%	4.34%	4.23%	8.43%
Flotation Costs [11]											0.50%
											8.93%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 30-day average as of August 31, 2018
[3] Source: Constant Growth DCF
[4] Equals [3] – ([3] – [9]) / 6
[5] Equals [4] – ([3] – [9]) / 6
[6] Equals [5] – ([3] – [9]) / 6
[7] Equals [6] – ([3] – [9]) / 6
[8] Equals [7] – ([3] – [9]) / 6
[9] Consensus Economics Inc., Consensus Forecasts, April 9, 2018, at 3 and 28.
[10] Internal rate of return
[11] The Commission allows 50 bps adjustment for flotation cost and financial flexibility.

90-DAY MULTI-STAGE DCF -- U.S. PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Annualized Dividend	Stock Price	Growth Rate, Years 1-5	Year 6	Year 7	Year 8	Year 9	Year 10	GDP Growth (perpetuity)	ROE
ALLETE, Inc.	ALE	$2.24	$76.49	6.30%	5.97%	5.65%	5.32%	5.00%	4.67%	4.35%	7.93%
Alliant Energy Corporation	LNT	$1.34	$41.96	5.66%	5.44%	5.22%	5.00%	4.79%	4.57%	4.35%	8.11%
American Electric Power Company, Inc.	AEP	$2.48	$68.86	5.71%	5.49%	5.26%	5.03%	4.80%	4.57%	4.35%	8.61%
Duke Energy Corporation	DUK	$3.71	$78.63	4.54%	4.51%	4.48%	4.44%	4.41%	4.38%	4.35%	9.56%
Edison International	EIX	$2.42	$64.17	4.33%	4.33%	4.33%	4.34%	4.34%	4.34%	4.35%	8.43%
Eversource Energy	ES	$2.02	$58.69	5.88%	5.63%	5.37%	5.11%	4.86%	4.60%	4.35%	8.46%
OGE Energy Corporation	OGE	$1.33	$35.12	4.78%	4.70%	4.63%	4.56%	4.49%	4.42%	4.35%	8.57%
Pinnacle West Capital Corporation	PNW	$2.78	$79.21	4.41%	4.40%	4.39%	4.38%	4.37%	4.36%	4.35%	8.16%
PNM Resources, Inc.	PNM	$1.06	$38.70	4.72%	4.65%	4.59%	4.53%	4.47%	4.41%	4.35%	7.37%
MEAN				5.15%	5.01%	4.88%	4.75%	4.61%	4.48%	4.35%	8.36%
Flotation Costs [11]											0.50%
											8.86%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of August 31, 2018
[3] Source: Constant Growth DCF
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Consensus Economics Inc., Consensus Forecasts, April 9, 2018, at 3.
[10] Internal rate of return
[11] The Commission allows 50 bps adjustment for flotation cost and financial flexibility.

90-DAY MULTI-STAGE DCF -- CANADIAN PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Annualized Dividend	Stock Price	Growth Rate, Years 1-5	Year 6	Year 7	Year 8	Year 9	Year 10	GDP Growth (perpetuity)	ROE
Canadian Utilities Limited	CU	$1.57	$32.31	1.90%	2.21%	2.51%	2.82%	3.12%	3.43%	3.73%	8.42%
Emera Inc.	EMA	$2.26	$41.33	5.13%	4.89%	4.66%	4.43%	4.20%	3.97%	3.73%	10.20%
Enbridge Inc.	ENB	$2.68	$43.61	4.84%	4.66%	4.47%	4.29%	4.10%	3.92%	3.73%	10.90%
Valener Inc.	VNR	$1.16	$20.30	1.19%	1.61%	2.04%	2.46%	2.89%	3.31%	3.73%	9.02%
MEAN				3.26%	3.34%	3.42%	3.50%	3.58%	3.66%	3.73%	9.63%
Flotation Costs [11]											0.50%
											10.13%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of August 31, 2018
[3] Source: Constant Growth DCF
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Consensus Economics Inc., Consensus Forecasts, April 9, 2018, at 28.
[10] Internal rate of return
[11] The Commission allows 50 bps adjustment for flotation cost and financial flexibility.

90-DAY MULTI-STAGE DCF -- NORTH AMERICA ELECTRIC PROXY GROUP

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Growth Rate, Years 1-5	[4] Year 6	[5] Year 7	[6] Year 8	[7] Year 9	[8] Year 10	[9] GDP Growth (perpetuity)	[10] ROE
ALLETE, Inc.	ALE	$2.24	$76.49	6.30%	5.97%	5.65%	5.32%	5.00%	4.67%	4.35%	7.93%
Alliant Energy Corporation	LNT	$1.34	$41.96	5.66%	5.44%	5.22%	5.00%	4.79%	4.57%	4.35%	8.11%
American Electric Power Company, Inc.	AEP	$2.48	$68.86	5.71%	5.49%	5.26%	5.03%	4.80%	4.57%	4.35%	8.61%
Duke Energy Corporation	DUK	$3.71	$78.63	4.54%	4.51%	4.48%	4.44%	4.41%	4.38%	4.35%	9.56%
Edison International	EIX	$2.42	$64.17	4.33%	4.33%	4.33%	4.34%	4.34%	4.34%	4.35%	8.43%
Eversource Energy	ES	$2.02	$58.69	5.88%	5.63%	5.37%	5.11%	4.86%	4.60%	4.35%	8.46%
OGE Energy Corporation	OGE	$1.33	$35.12	4.78%	4.70%	4.63%	4.56%	4.49%	4.42%	4.35%	8.57%
Pinnacle West Capital Corporation	PNW	$2.78	$79.21	4.41%	4.40%	4.39%	4.38%	4.37%	4.36%	4.35%	8.16%
PNM Resources, Inc.	PNM	$1.06	$38.70	4.72%	4.65%	4.59%	4.53%	4.47%	4.41%	4.35%	7.37%
Canadian Utilities Limited	CU	$1.57	$32.31	1.90%	2.21%	2.51%	2.82%	3.12%	3.43%	3.73%	8.42%
Emera Inc.	EMA	$2.26	$41.33	5.13%	4.89%	4.66%	4.43%	4.20%	3.97%	3.73%	10.20%
MEAN				4.85%	4.75%	4.65%	4.54%	4.44%	4.34%	4.23%	8.53%
Flotation Costs [11]											0.50%
											9.03%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of August 31, 2018
[3] Source: Constant Growth DCF
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Consensus Economics Inc., Consensus Forecasts, April 9, 2018, at 3 and 28.
[10] Internal rate of return
[11] The Commission allows 50 bps adjustment for flotation cost and financial flexibility.

Market DCF Calculation as of August 31, 2018

	[1]	[2]	[3]	[4]	[5]	[6]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast Canadian Government Bond 30 Year	Equity Risk Premium
S&P/TSX UTILITIES INDEX	**3.27%**	**3.46%**	**11.21%**	**14.67%**	**3.08%**	**11.59%**

Company	Ticker	[7] Shares Outstanding (million)	[8] Price ($)	[9] Market Capitalization ($million)	[10] Percent of Total Market Capitalization	[11] Current Dividend Yield	[12] Long-Term Growth Estimate
Sun Life Financial Inc	SLF	607.01	51.87	31,486	1.83%	3.66%	8.70%
West Fraser Timber Co Ltd	WFT	71.35	86.57	6,177	0.36%	0.69%	3.30%
Saputo Inc	SAP	388.36	39.96	15,519	0.90%	1.65%	6.26%
Pembina Pipeline Corp	PPL	504.32	44.51	22,447	1.30%	5.12%	6.70%
Ritchie Bros Auctioneers Inc	RBA	108.20	49.75	5,383	0.31%	1.87%	10.65%
Gildan Activewear Inc	GIL	208.13	38.46	8,005	0.46%	1.53%	10.72%
Manulife Financial Corp	MFC	1,984.08	23.88	47,380	2.75%	3.69%	22.30%
FirstService Corp	FSV	34.63	111.65	3,867	0.22%	0.64%	20.00%
Canadian Pacific Railway Ltd	CP	142.57	274.49	39,135	2.27%	0.95%	8.93%
Husky Energy Inc	HSE	1,005.12	21.58	21,691	1.26%	2.32%	20.57%
George Weston Ltd	WN	128.00	101.64	13,010	0.76%	1.93%	2.10%
Hydro One Ltd	H	595.88	19.28	11,489	0.67%	4.77%	7.00%
Cameco Corp	CCO	395.79	13.56	5,367	0.31%	2.95%	47.78%
Nutrien Ltd	NTR	615.37	73.34	45,131	2.62%	2.85%	17.60%
Brookfield Infrastructure Partners LP	BIP-U	276.79	50.89	14,086	0.82%	4.80%	21.68%
Franco-Nevada Corp	FNV	186.18	83.42	15,531	0.90%	1.50%	4.00%
Metro Inc	MRU	256.25	40.86	10,470	0.61%	1.76%	9.41%
Tourmaline Oil Corp	TOU	272.08	21.26	5,785	0.34%	1.69%	13.10%
Bank of Montreal	BMO	639.93	106.97	68,453	3.97%	3.59%	7.23%
Bank of Nova Scotia/The	BNS	1,231.73	75.53	93,033	5.40%	4.50%	6.54%
Canadian Imperial Bank of Commerce	CM	443.27	122.30	54,212	3.15%	4.45%	3.47%
National Bank of Canada	NA	338.14	65.31	22,084	1.28%	3.80%	5.30%
Toronto-Dominion Bank/The	TD	1,828.63	78.65	143,822	8.35%	3.41%	8.10%
Osisko Gold Royalties Ltd	OR	156.26	10.35	1,617	0.09%	1.93%	6.92%
Restaurant Brands International Inc	QSR	250.02	74.85	18,714	1.09%	3.18%	13.97%
Suncor Energy Inc	SU	1,627.76	53.72	87,443	5.07%	2.68%	3.95%
Lundin Mining Corp	LUN	732.02	6.22	4,553	0.26%	1.93%	4.99%
Aecon Group Inc	ARE	59.82	17.35	1,038	0.06%	2.88%	9.90%
Royal Bank of Canada	RY	1,441.12	103.66	149,386	8.67%	3.78%	7.04%
Russel Metals Inc	RUS	62.08	28.53	1,771	0.10%	5.33%	48.90%
Toromont Industries Ltd	TIH	81.30	65.24	5,304	0.31%	1.41%	22.10%
Colliers International Group Inc	CIGI	37.87	106.43	4,030	0.23%	0.12%	25.00%
Cogeco Communications Inc	CCA	33.87	64.77	2,194	0.13%	2.93%	5.28%
First Quantum Minerals Ltd	FM	689.39	16.37	11,285	0.65%	0.06%	28.21%
Rogers Communications Inc	RCI/B	403.66	67.62	27,295	1.58%	2.84%	5.25%
Maple Leaf Foods Inc	MFI	125.72	31.60	3,973	0.23%	1.65%	6.43%
Inter Pipeline Ltd	IPL	387.80	23.98	9,299	0.54%	7.01%	5.90%
Algonquin Power & Utilities Corp	AQN	472.20	13.52	6,384	0.37%	4.96%	8.00%
Dream Global Real Estate Investment Trust	DRG-U	191.17	14.64	2,799	0.16%	5.46%	4.30%
Pan American Silver Corp	PAAS	153.29	20.39	3,126	0.18%	0.90%	4.00%
WestJet Airlines Ltd	WJA	113.95	19.15	2,182	0.13%	2.92%	1.29%
Emera Inc	EMA	231.86	41.29	9,574	0.56%	5.69%	9.86%
Waste Connections Inc	WCN	263.47	103.57	27,287	1.58%	0.70%	11.97%
Keyera Corp	KEY	207.35	35.96	7,456	0.43%	5.01%	13.70%
Cineplex Inc	CGX	63.33	32.91	2,084	0.12%	5.29%	10.30%
BCE Inc	BCE	898.00	53.23	47,800	2.77%	5.67%	4.05%
TransCanada Corp	TRP	907.30	55.58	50,428	2.93%	4.97%	7.33%
OceanaGold Corp	OGC	617.53	3.86	2,384	0.14%	1.35%	12.34%
Dollarama Inc	DOL	326.83	49.35	16,129	0.94%	0.32%	14.92%
Imperial Oil Ltd	IMO	799.30	40.67	32,508	1.89%	1.87%	38.60%
Brookfield Renewable Partners LP	BEP-U	180.27	40.11	7,230	0.42%	6.34%	9.00%
Alimentation Couche-Tard Inc	ATD/B	437.32	62.48	27,324	1.59%	0.64%	16.25%
Brookfield Property Partners LP	BPY-U	254.46	26.08	6,636	0.39%	6.27%	7.20%
Agnico Eagle Mines Ltd	AEM	234.23	44.98	10,535	0.61%	1.27%	3.00%
TELUS Corp	T	597.71	48.39	28,923	1.68%	4.34%	6.65%
CAE Inc	CAE	267.87	26.05	6,978	0.40%	1.54%	10.30%
Canadian Natural Resources Ltd	CNQ	1,221.07	44.56	54,411	3.16%	3.01%	6.43%
Canadian Tire Corp Ltd	CTC/A	61.43	163.27	10,030	0.58%	2.20%	10.52%
Finning International Inc	FTT	168.22	30.33	5,102	0.30%	2.64%	10.00%
Fortis Inc/Canada	FTS	424.83	42.72	18,149	1.05%	3.98%	5.00%
Goldcorp Inc	G	869.28	14.10	12,257	0.71%	0.74%	3.85%
BRP Inc/CA	DOO	34.15	68.12	2,326	0.13%	0.53%	15.60%
Enbridge Inc	ENB	1,715.42	44.51	76,353	4.43%	6.03%	5.58%
Magna International Inc	MG	342.89	70.66	24,229	1.41%	2.43%	4.23%
Shaw Communications Inc	SJR/B	483.34	26.32	12,721	0.74%	4.50%	2.35%
SNC-Lavalin Group Inc	SNC	175.55	52.53	9,222	0.54%	2.19%	7.90%
Thomson Reuters Corp	TRI	702.48	58.04	40,772	2.37%	3.13%	0.50%
Norbord Inc	OSB	86.66	49.66	4,304	0.25%	36.25%	5.51%
CI Financial Corp	CIX	261.51	21.00	5,492	0.32%	3.43%	10.50%
Yamana Gold Inc	YRI	949.04	3.62	3,436	0.20%	0.72%	19.00%
Wheaton Precious Metals Corp	WPM	443.56	22.36	9,918	0.58%	2.08%	5.00%
Quebecor Inc	QBR/B	156.12	26.28	4,103	0.24%	0.84%	11.84%
Open Text Corp	OTEX	267.85	51.18	13,709	0.80%	1.54%	14.00%
Alamos Gold Inc	AGI	389.38	5.74	2,235	0.13%	0.44%	37.42%
Canadian National Railway Co	CNR	734.17	116.06	85,207	4.94%	1.57%	7.23%
Mean for Companies Paying Dividends with Positive Long-Term Growth Estimates						**3.27%**	**11.21%**

Notes:
[1] Equals mean of Column [11]
[2] Equals Column [1] x (1 + 0.5 x Column [3])

Market DCF Calculation as of August 31, 2018

	[1] Dividend Yield	[2] Dividend Yield x (1 + 0.50g)	[3] Expected Growth Rate (g)	[4] Secondary Market Investor Required Return	[5] Forecast Canadian Government Bond 30 Year	[6] Equity Risk Premium
S&P/TSX UTILITIES INDEX	**3.27%**	**3.46%**	**11.21%**	**14.67%**	**3.08%**	**11.59%**

Company	Ticker	[7] Shares Outstanding (million)	[8] Price ($)	[9] Market Capitalization ($million)	[10] Percent of Total Market Capitalization	[11] Current Dividend Yield	[12] Long-Term Growth Estimate

[3] Equals mean of Column [12]
[4] Equals Column [2] + Column [3]
[5] Source: April 2018 Consensus Forecast Average 2019-2021 Forecasts 10-Year bond yield plus 30-day average spread between 10- and 30-year government bonds ending August 31, 2018
[6] Equals Column [4] - (Column [5])
[7] Source: Bloomberg Finance L.P., as of August 31, 2018
[8] Source: Bloomberg Finance L.P., as of August 31, 2018
[9] Equals Column [7] x Column [8]
[10] Equals percent of sum of Column [9]
[11] Source: Bloomberg Finance L.P., as of August 31, 2018
[12] Source: Bloomberg Finance L.P., as of August 31, 2018

Market DCF Calculation as of August 31, 2018

	[1]	[2]	[3]	[4]	[5]	[6]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast US Government 30 Year Yield	Equity Risk Premium
S&P 500	**2.25%**	**2.38%**	**11.45%**	**13.83%**	**3.55%**	**10.28%**

		[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price ($)	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	Long-Term Growth Estimate
LyondellBasell Industries NV	LYB	389.3	112.78	43,908	0.22%	3.55%	7.60%
American Express Co	AXP	861.1	105.98	91,255	0.46%	1.32%	17.30%
Verizon Communications Inc	VZ	4,131.9	54.37	224,653	1.13%	4.34%	4.58%
Broadcom Inc	AVGO	431.7	219.03	94,551	0.47%	3.20%	13.01%
Boeing Co/The	BA	574.5	342.79	196,936	0.99%	2.00%	15.37%
Caterpillar Inc	CAT	594.3	138.85	82,522	0.41%	2.48%	25.37%
JPMorgan Chase & Co	JPM	3,360.9	114.58	385,090	1.93%	1.96%	9.80%
Chevron Corp	CVX	1,916.1	118.46	226,987	1.14%	3.78%	6.76%
Coca-Cola Co/The	KO	4,252.9	44.57	189,553	0.95%	3.50%	7.82%
AbbVie Inc	ABBV	1,514.3	95.98	145,340	0.73%	4.00%	10.89%
Walt Disney Co/The	DIS	1,487.2	112.02	166,601	0.84%	1.50%	12.93%
Extra Space Storage Inc	EXR	126.5	92.21	11,665	0.06%	3.73%	6.18%
Exxon Mobil Corp	XOM	4,233.8	80.17	339,425	1.70%	4.09%	13.95%
Phillips 66	PSX	464.3	118.51	55,020	0.28%	2.70%	5.55%
General Electric Co	GE	8,691.1	12.94	112,463	0.56%	3.71%	3.67%
HP Inc	HPQ	1,582.4	24.65	39,006	0.20%	2.26%	8.79%
Home Depot Inc/The	HD	1,144.1	200.77	229,709	1.15%	2.05%	13.27%
International Business Machines Corp	IBM	912.8	146.48	133,702	0.67%	4.29%	2.40%
Johnson & Johnson	JNJ	2,682.8	134.69	361,340	1.81%	2.67%	7.49%
McDonald's Corp	MCD	775.8	162.23	125,858	0.63%	2.49%	8.69%
Merck & Co Inc	MRK	2,659.5	68.59	182,417	0.92%	2.80%	7.25%
3M Co	MMM	586.6	210.92	123,728	0.62%	2.58%	8.70%
American Water Works Co Inc	AWK	180.5	87.53	15,798	0.08%	2.08%	8.08%
Bank of America Corp	BAC	9,988.3	30.93	308,937	1.55%	1.94%	14.10%
Baker Hughes a GE Co	BHGE	411.7	32.97	13,572	0.07%	2.18%	33.00%
Pfizer Inc	PFE	5,862.1	41.52	243,395	1.22%	3.28%	6.88%
Procter & Gamble Co/The	PG	2,489.2	82.95	206,476	1.04%	3.46%	7.19%
Travelers Cos Inc/The	TRV	267.7	131.60	35,227	0.18%	2.34%	17.75%
United Technologies Corp	UTX	800.1	131.70	105,372	0.53%	2.13%	10.59%
Analog Devices Inc	ADI	371.7	98.85	36,740	0.18%	1.94%	9.53%
Walmart Inc	WMT	2,950.8	95.86	282,868	1.42%	2.17%	6.49%
Cisco Systems Inc	CSCO	4,702.9	47.77	224,657	1.13%	2.76%	7.18%
Intel Corp	INTC	4,611.0	48.43	223,311	1.12%	2.48%	9.36%
General Motors Co	GM	1,410.9	36.05	50,863	0.26%	4.22%	10.78%
Microsoft Corp	MSFT	7,668.2	112.33	861,371	4.32%	1.50%	10.03%
Dollar General Corp	DG	265.5	107.73	28,606	0.14%	1.08%	15.06%
Kinder Morgan Inc/DE	KMI	2,206.8	17.70	39,061	0.20%	4.52%	12.00%
Citigroup Inc	C	2,516.6	71.24	179,283	0.90%	2.53%	12.80%
American International Group Inc	AIG	888.4	53.17	47,239	0.24%	2.41%	11.00%
Honeywell International Inc	HON	742.6	159.06	118,120	0.59%	1.87%	16.96%
Altria Group Inc	MO	1,885.2	58.52	110,320	0.55%	5.47%	4.87%
HCA Healthcare Inc	HCA	346.0	134.11	46,408	0.23%	1.04%	13.58%
International Paper Co	IP	408.9	51.14	20,910	0.10%	3.72%	7.90%
Abbott Laboratories	ABT	1,754.3	66.84	117,259	0.59%	1.68%	13.00%
Aflac Inc	AFL	767.8	46.24	35,503	0.18%	2.25%	8.45%
Air Products & Chemicals Inc	APD	219.3	166.29	36,463	0.18%	2.65%	12.14%
Royal Caribbean Cruises Ltd	RCL	209.0	122.58	25,616	0.13%	1.96%	14.92%
American Electric Power Co Inc	AEP	492.9	71.73	35,358	0.18%	3.46%	5.47%
Anadarko Petroleum Corp	APC	512.1	64.40	32,978	0.17%	1.55%	17.74%
Aon PLC	AON	242.7	145.56	35,321	0.18%	1.10%	11.42%
Apache Corp	APA	382.5	43.83	16,764	0.08%	2.28%	7.01%
Archer-Daniels-Midland Co	ADM	559.7	50.40	28,211	0.14%	2.66%	11.40%
Automatic Data Processing Inc	ADP	438.1	146.75	64,289	0.32%	1.88%	13.50%
Avery Dennison Corp	AVY	87.4	105.18	9,195	0.05%	1.98%	10.37%
MSCI Inc	MSCI	88.8	180.26	16,013	0.08%	1.29%	13.45%
Ball Corp	BLL	343.9	41.88	14,403	0.07%	0.96%	5.60%
Bank of New York Mellon Corp/The	BK	999.9	52.15	52,147	0.26%	2.15%	7.80%

Market DCF Calculation as of August 31, 2018

	[1] Dividend Yield	[2] Dividend Yield x (1 + 0.50g)	[3] Expected Growth Rate (g)	[4] Secondary Market Investor Required Return	[5] Forecast US Government 30 Year Yield	[6] Equity Risk Premium
S&P 500	**2.25%**	**2.38%**	**11.45%**	**13.83%**	**3.55%**	**10.28%**

Company	Ticker	[7] Shares Outstanding (million)	[8] Price ($)	[9] Market Capitalization ($million)	[10] Percent of Total Market Capitalization	[11] Current Dividend Yield	[12] Long-Term Growth Estimate
Baxter International Inc	BAX	534.3	74.37	39,733	0.20%	1.02%	12.33%
Becton Dickinson and Co	BDX	267.6	261.87	70,067	0.35%	1.15%	15.23%
Best Buy Co Inc	BBY	279.4	79.56	22,228	0.11%	2.26%	12.46%
H&R Block Inc	HRB	205.5	27.06	5,560	0.03%	3.70%	10.00%
Bristol-Myers Squibb Co	BMY	1,631.9	60.55	98,810	0.50%	2.64%	9.37%
Fortune Brands Home & Security Inc	FBHS	142.4	52.98	7,545	0.04%	1.51%	12.83%
Brown-Forman Corp	BF/B	312.1	52.22	16,298	0.08%	1.21%	12.85%
Cabot Oil & Gas Corp	COG	441.2	23.83	10,513	0.05%	1.01%	44.72%
Campbell Soup Co	CPB	300.6	39.45	11,860	0.06%	3.55%	3.69%
Kansas City Southern	KSU	102.2	115.96	11,846	0.06%	1.24%	8.70%
Hilton Worldwide Holdings Inc	HLT	298.2	77.62	23,145	0.12%	0.77%	11.20%
Carnival Corp	CCL	530.6	61.49	32,627	0.16%	3.25%	13.80%
Cigna Corp	CI	243.4	188.34	45,835	0.23%	0.02%	12.03%
UDR Inc	UDR	267.7	39.97	10,699	0.05%	3.23%	5.51%
Clorox Co/The	CLX	128.1	144.98	18,570	0.09%	2.65%	9.07%
CMS Energy Corp	CMS	283.3	49.24	13,948	0.07%	2.90%	6.16%
Colgate-Palmolive Co	CL	867.7	66.41	57,627	0.29%	2.53%	7.86%
Comerica Inc	CMA	171.4	97.48	16,708	0.08%	2.46%	21.22%
CA Inc	CA	418.2	43.80	18,316	0.09%	2.33%	4.10%
Conagra Brands Inc	CAG	391.6	36.75	14,393	0.07%	2.31%	7.85%
Consolidated Edison Inc	ED	311.1	78.93	24,555	0.12%	3.62%	3.60%
SL Green Realty Corp	SLG	86.6	104.40	9,038	0.05%	3.11%	4.48%
Corning Inc	GLW	810.0	33.51	27,144	0.14%	2.15%	8.98%
Cummins Inc	CMI	163.3	141.80	23,157	0.12%	3.22%	9.16%
Danaher Corp	DHR	699.8	103.54	72,453	0.36%	0.62%	7.13%
Target Corp	TGT	526.4	87.50	46,056	0.23%	2.93%	6.70%
Deere & Co	DE	321.7	143.80	46,257	0.23%	1.92%	7.33%
Dominion Energy Inc	D	653.8	70.77	46,267	0.23%	4.72%	5.63%
Dover Corp	DOV	147.7	85.87	12,683	0.06%	2.24%	14.00%
Cboe Global Markets Inc	CBOE	111.8	100.80	11,271	0.06%	1.23%	12.92%
Duke Energy Corp	DUK	712.4	81.24	57,872	0.29%	4.57%	4.48%
Eaton Corp PLC	ETN	433.3	83.14	36,025	0.18%	3.18%	8.92%
Ecolab Inc	ECL	288.9	150.48	43,474	0.22%	1.09%	13.03%
PerkinElmer Inc	PKI	110.7	92.43	10,235	0.05%	0.30%	16.35%
Emerson Electric Co	EMR	628.5	76.73	48,222	0.24%	2.53%	12.07%
EOG Resources Inc	EOG	579.2	118.23	68,479	0.34%	0.74%	12.14%
Equifax Inc	EFX	120.4	133.97	16,132	0.08%	1.16%	7.43%
EQT Corp	EQT	264.0	51.02	13,469	0.07%	0.24%	17.50%
FedEx Corp	FDX	264.4	243.95	64,509	0.32%	1.07%	13.52%
Macy's Inc	M	307.0	36.55	11,220	0.06%	4.13%	0.50%
FMC Corp	FMC	134.6	85.45	11,504	0.06%	0.77%	24.50%
NextEra Energy Inc	NEE	471.6	170.10	80,220	0.40%	2.61%	8.38%
Franklin Resources Inc	BEN	527.1	31.74	16,729	0.08%	2.90%	10.00%
Gap Inc/The	GPS	384.7	30.35	11,676	0.06%	3.20%	10.22%
General Dynamics Corp	GD	296.3	193.40	57,301	0.29%	1.92%	11.28%
General Mills Inc	GIS	596.0	46.01	27,421	0.14%	4.26%	7.53%
Genuine Parts Co	GPC	146.8	99.85	14,653	0.07%	2.88%	5.68%
WW Grainger Inc	GWW	56.1	354.07	19,875	0.10%	1.54%	14.87%
Halliburton Co	HAL	879.9	39.89	35,099	0.18%	1.81%	74.00%
Harley-Davidson Inc	HOG	166.6	42.62	7,099	0.04%	3.47%	10.00%
Fortive Corp	FTV	349.2	83.98	29,322	0.15%	0.33%	13.63%
Hershey Co/The	HSY	148.7	100.52	14,947	0.08%	2.87%	9.00%
Synchrony Financial	SYF	740.7	31.67	23,458	0.12%	2.65%	7.35%
Hormel Foods Corp	HRL	530.5	39.15	20,769	0.10%	1.92%	6.55%
Arthur J Gallagher & Co	AJG	182.6	72.14	13,174	0.07%	2.27%	10.32%
Mondelez International Inc	MDLZ	1,466.6	42.72	62,651	0.31%	2.43%	10.26%
CenterPoint Energy Inc	CNP	431.6	27.79	11,993	0.06%	3.99%	6.32%
Humana Inc	HUM	137.8	333.26	45,911	0.23%	0.60%	14.40%
Willis Towers Watson PLC	WLTW	130.8	147.27	19,258	0.10%	1.63%	15.30%
Illinois Tool Works Inc	ITW	335.4	138.88	46,574	0.23%	2.88%	10.13%
Ingersoll-Rand PLC	IR	245.3	101.29	24,847	0.12%	2.09%	11.44%
Foot Locker Inc	FL	116.9	49.30	5,764	0.03%	2.80%	4.91%

Market DCF Calculation as of August 31, 2018

	[1] Dividend Yield	[2] Dividend Yield x (1 + 0.50g)	[3] Expected Growth Rate (g)	[4] Secondary Market Investor Required Return	[5] Forecast US Government 30 Year Yield	[6] Equity Risk Premium
S&P 500	**2.25%**	**2.38%**	**11.45%**	**13.83%**	**3.55%**	**10.28%**

Company	Ticker	[7] Shares Outstanding (million)	[8] Price ($)	[9] Market Capitalization ($million)	[10] Percent of Total Market Capitalization	[11] Current Dividend Yield	[12] Long-Term Growth Estimate
Interpublic Group of Cos Inc/The	IPG	383.8	23.35	8,961	0.04%	3.60%	6.43%
International Flavors & Fragrances Inc	IFF	79.0	130.29	10,299	0.05%	2.24%	9.20%
Jacobs Engineering Group Inc	JEC	141.9	72.69	10,315	0.05%	0.83%	17.01%
Hanesbrands Inc	HBI	360.5	17.54	6,323	0.03%	3.42%	5.04%
Kellogg Co	K	346.7	71.79	24,888	0.12%	3.12%	8.42%
Broadridge Financial Solutions Inc	BR	116.3	135.14	15,720	0.08%	1.44%	10.00%
Perrigo Co PLC	PRGO	136.8	76.51	10,469	0.05%	0.99%	7.40%
Kimberly-Clark Corp	KMB	347.7	115.54	40,169	0.20%	3.46%	6.26%
Kimco Realty Corp	KIM	421.4	17.11	7,210	0.04%	6.55%	3.04%
Kohl's Corp	KSS	167.1	79.11	13,219	0.07%	3.08%	7.23%
Oracle Corp	ORCL	3,981.2	48.58	193,405	0.97%	1.56%	7.68%
Kroger Co/The	KR	796.7	31.50	25,095	0.13%	1.78%	6.46%
Leggett & Platt Inc	LEG	130.2	45.44	5,914	0.03%	3.35%	10.00%
Lennar Corp	LEN	291.7	51.67	15,073	0.08%	0.31%	21.15%
Jefferies Financial Group Inc	JEF	333.3	23.22	7,740	0.04%	2.15%	18.00%
Eli Lilly & Co	LLY	1,074.0	105.65	113,467	0.57%	2.13%	11.65%
L Brands Inc	LB	277.2	26.43	7,327	0.04%	9.08%	9.33%
Lowe's Cos Inc	LOW	811.0	108.75	88,196	0.44%	1.77%	15.36%
Host Hotels & Resorts Inc	HST	741.7	21.53	15,968	0.08%	3.72%	3.98%
Marsh & McLennan Cos Inc	MMC	505.0	84.63	42,736	0.21%	1.96%	14.91%
Masco Corp	MAS	307.5	37.97	11,675	0.06%	1.11%	15.97%
S&P Global Inc	SPGI	251.5	207.05	52,073	0.26%	0.97%	11.60%
Medtronic PLC	MDT	1,350.5	96.41	130,203	0.65%	2.07%	7.90%
CVS Health Corp	CVS	1,018.1	75.24	76,599	0.38%	2.66%	11.66%
DowDuPont Inc	DWDP	2,307.4	70.13	161,816	0.81%	2.17%	8.37%
Motorola Solutions Inc	MSI	162.3	128.36	20,829	0.10%	1.62%	7.45%
Newell Brands Inc	NWL	472.5	21.72	10,263	0.05%	4.24%	2.76%
Twenty-First Century Fox Inc	FOXA	1,054.1	45.40	47,854	0.24%	0.79%	9.95%
NIKE Inc	NKE	1,280.5	82.20	105,256	0.53%	0.97%	14.06%
NiSource Inc	NI	363.0	27.07	9,827	0.05%	2.88%	5.63%
Noble Energy Inc	NBL	483.1	29.72	14,358	0.07%	1.48%	41.24%
Norfolk Southern Corp	NSC	280.0	173.84	48,680	0.24%	1.84%	10.20%
Principal Financial Group Inc	PFG	284.7	55.19	15,715	0.08%	3.84%	7.93%
Eversource Energy	ES	316.9	62.43	19,783	0.10%	3.24%	6.37%
Northrop Grumman Corp	NOC	174.1	298.49	51,974	0.26%	1.61%	15.18%
Wells Fargo & Co	WFC	4,816.1	58.48	281,648	1.41%	2.94%	13.41%
Nucor Corp	NUE	316.3	62.50	19,771	0.10%	2.43%	5.65%
PVH Corp	PVH	77.1	143.16	11,036	0.06%	0.10%	10.65%
Occidental Petroleum Corp	OXY	764.7	79.87	61,078	0.31%	3.91%	14.30%
Omnicom Group Inc	OMC	224.4	69.32	15,554	0.08%	3.46%	5.44%
ONEOK Inc	OKE	411.2	65.91	27,105	0.14%	5.01%	26.88%
Raymond James Financial Inc	RJF	145.9	93.04	13,573	0.07%	1.29%	17.00%
Parker-Hannifin Corp	PH	132.4	175.60	23,242	0.12%	1.73%	9.32%
PPL Corp	PPL	699.6	29.74	20,805	0.10%	5.51%	8.10%
Exelon Corp	EXC	965.9	43.71	42,220	0.21%	3.16%	4.45%
ConocoPhillips	COP	1,162.1	73.43	85,333	0.43%	1.55%	6.00%
PulteGroup Inc	PHM	284.0	27.95	7,938	0.04%	1.29%	21.34%
Pinnacle West Capital Corp	PNW	112.0	78.55	8,796	0.04%	3.54%	4.47%
PNC Financial Services Group Inc/The	PNC	464.3	143.54	66,646	0.33%	2.65%	9.79%
PPG Industries Inc	PPG	242.0	110.54	26,753	0.13%	1.74%	8.06%
Praxair Inc	PX	287.6	158.19	45,492	0.23%	2.09%	13.90%
Progressive Corp/The	PGR	583.1	67.53	39,377	0.20%	1.67%	9.20%
Public Service Enterprise Group Inc	PEG	505.3	52.35	26,454	0.13%	3.44%	7.35%
Raytheon Co	RTN	285.3	199.44	56,892	0.29%	1.74%	14.87%
Robert Half International Inc	RHI	122.4	78.18	9,573	0.05%	1.43%	17.10%
Edison International	EIX	325.8	65.73	21,416	0.11%	3.68%	5.35%
Schlumberger Ltd	SLB	1,384.1	63.16	87,421	0.44%	3.17%	35.00%
Charles Schwab Corp/The	SCHW	1,351.1	50.79	68,620	0.34%	1.02%	21.63%
Sherwin-Williams Co/The	SHW	93.4	455.58	42,543	0.21%	0.76%	11.42%
JM Smucker Co/The	SJM	113.7	103.38	11,758	0.06%	3.29%	4.05%
Snap-on Inc	SNA	56.4	176.78	9,971	0.05%	1.86%	7.95%
AMETEK Inc	AME	231.9	76.96	17,847	0.09%	0.73%	11.81%

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S&P 500	**2.25%**	**2.38%**	**11.45%**	**13.83%**	**3.55%**	**10.28%**

Company	Ticker	[7] Shares Outstanding (million)	[8] Price ($)	[9] Market Capitalization ($million)	[10] Percent of Total Market Capitalization	[11] Current Dividend Yield	[12] Long-Term Growth Estimate
Southern Co/The	SO	1,014.1	43.78	44,399	0.22%	5.48%	4.06%
BB&T Corp	BBT	774.4	51.66	40,008	0.20%	3.14%	14.92%
Southwest Airlines Co	LUV	573.0	61.30	35,126	0.18%	1.04%	11.12%
Stanley Black & Decker Inc	SWK	153.0	140.53	21,502	0.11%	1.88%	10.65%
Public Storage	PSA	174.2	212.58	37,040	0.19%	3.76%	5.42%
SunTrust Banks Inc	STI	460.7	73.56	33,891	0.17%	2.72%	14.78%
Sysco Corp	SYY	519.8	74.82	38,890	0.20%	1.92%	11.63%
Andeavor	ANDV	151.1	152.79	23,091	0.12%	1.54%	7.95%
Texas Instruments Inc	TXN	972.2	112.40	109,275	0.55%	2.21%	11.05%
Textron Inc	TXT	248.4	69.03	17,148	0.09%	0.12%	13.71%
Thermo Fisher Scientific Inc	TMO	402.8	239.10	96,309	0.48%	0.28%	11.50%
Tiffany & Co	TIF	122.4	122.65	15,014	0.08%	1.79%	12.54%
TJX Cos Inc/The	TJX	620.8	109.97	68,266	0.34%	1.42%	10.70%
Torchmark Corp	TMK	112.7	87.92	9,908	0.05%	0.73%	13.17%
Total System Services Inc	TSS	182.4	97.14	17,720	0.09%	0.54%	14.62%
Johnson Controls International plc	JCI	924.9	37.77	34,934	0.18%	2.75%	10.30%
Union Pacific Corp	UNP	739.5	150.62	111,383	0.56%	2.12%	14.20%
UnitedHealth Group Inc	UNH	962.5	268.46	258,386	1.30%	1.34%	13.06%
Unum Group	UNM	218.7	36.88	8,066	0.04%	2.82%	9.00%
Marathon Oil Corp	MRO	854.1	21.51	18,373	0.09%	0.93%	5.00%
Ventas Inc	VTR	356.4	59.87	21,340	0.11%	5.28%	1.84%
Vornado Realty Trust	VNO	190.2	77.00	14,648	0.07%	3.27%	0.48%
Vulcan Materials Co	VMC	132.3	110.80	14,655	0.07%	1.01%	20.36%
Weyerhaeuser Co	WY	757.7	34.71	26,299	0.13%	3.92%	16.20%
Whirlpool Corp	WHR	64.6	124.98	8,069	0.04%	3.68%	9.46%
WEC Energy Group Inc	WEC	315.5	67.58	21,324	0.11%	3.27%	2.90%
Xerox Corp	XRX	255.1	27.86	7,107	0.04%	3.59%	2.05%
AES Corp/VA	AES	661.7	13.46	8,906	0.04%	3.86%	8.88%
Amgen Inc	AMGN	647.3	199.81	129,331	0.65%	2.64%	6.46%
Apple Inc	AAPL	4,829.9	227.63	1,099,436	5.52%	1.28%	11.66%
Cintas Corp	CTAS	106.3	213.37	22,677	0.11%	0.76%	13.05%
Comcast Corp	CMCSA	4,572.5	36.99	169,136	0.85%	2.05%	14.85%
Molson Coors Brewing Co	TAP	195.6	66.74	13,055	0.07%	2.46%	5.13%
KLA-Tencor Corp	KLAC	156.1	116.21	18,144	0.09%	2.58%	7.37%
Marriott International Inc/MD	MAR	347.0	126.47	43,884	0.22%	1.30%	14.46%
McCormick & Co Inc/MD	MKC	121.3	124.88	15,146	0.08%	1.67%	8.80%
Nordstrom Inc	JWN	167.5	62.85	10,527	0.05%	2.35%	8.43%
PACCAR Inc	PCAR	350.5	68.42	23,984	0.12%	1.64%	6.03%
Costco Wholesale Corp	COST	438.5	233.13	102,237	0.51%	0.98%	10.81%
Stryker Corp	SYK	374.0	169.43	63,365	0.32%	1.11%	8.44%
Tyson Foods Inc	TSN	295.9	62.81	18,587	0.09%	1.91%	5.90%
Applied Materials Inc	AMAT	983.0	43.02	42,288	0.21%	1.86%	14.06%
American Airlines Group Inc	AAL	460.5	40.48	18,641	0.09%	0.99%	16.07%
Cardinal Health Inc	CAH	308.8	52.19	16,118	0.08%	3.65%	9.40%
DR Horton Inc	DHI	377.1	44.51	16,783	0.08%	1.12%	20.70%
Flowserve Corp	FLS	130.9	52.12	6,820	0.03%	1.46%	19.90%
Expeditors International of Washington Inc	EXPD	174.3	73.28	12,775	0.06%	1.23%	11.73%
Fastenal Co	FAST	286.9	58.36	16,746	0.08%	2.74%	17.55%
M&T Bank Corp	MTB	143.8	177.15	25,473	0.13%	2.26%	14.30%
Xcel Energy Inc	XEL	509.1	48.05	24,462	0.12%	3.16%	5.80%
Fifth Third Bancorp	FITB	666.3	29.43	19,611	0.10%	2.45%	5.65%
Gilead Sciences Inc	GILD	1,296.3	75.73	98,172	0.49%	3.01%	5.72%
Hasbro Inc	HAS	126.9	99.31	12,606	0.06%	2.54%	8.13%
Huntington Bancshares Inc/OH	HBAN	1,104.2	16.21	17,900	0.09%	3.45%	13.36%
Welltower Inc	WELL	372.0	66.71	24,818	0.12%	5.22%	5.90%
Northern Trust Corp	NTRS	223.3	107.46	23,994	0.12%	2.05%	16.78%
Packaging Corp of America	PKG	94.5	109.92	10,387	0.05%	2.87%	10.00%
Paychex Inc	PAYX	359.0	73.25	26,297	0.13%	3.06%	9.00%
People's United Financial Inc	PBCT	348.8	18.51	6,457	0.03%	3.78%	2.00%
QUALCOMM Inc	QCOM	1,469.1	68.71	100,943	0.51%	3.61%	12.32%
Roper Technologies Inc	ROP	103.3	298.37	30,835	0.15%	0.55%	13.40%
Ross Stores Inc	ROST	376.5	95.78	36,065	0.18%	0.94%	10.27%
Starbucks Corp	SBUX	1,349.1	53.45	72,109	0.36%	2.69%	14.30%
KeyCorp	KEY	1,052.0	21.07	22,166	0.11%	3.23%	16.21%
State Street Corp	STT	379.4	86.91	32,975	0.17%	2.16%	12.36%
US Bancorp	USB	1,629.0	54.11	88,148	0.44%	2.22%	7.45%

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AO Smith Corp	AOS	144.5	58.08	8,395	0.04%	1.24%	11.50%
Symantec Corp	SYMC	621.5	20.16	12,530	0.06%	1.49%	6.68%
T Rowe Price Group Inc	TROW	243.2	115.89	28,183	0.14%	2.42%	12.08%
Waste Management Inc	WM	428.7	90.90	38,970	0.20%	2.05%	11.61%
CBS Corp	CBS	338.5	53.02	17,949	0.09%	1.36%	18.52%
Allergan PLC	AGN	339.4	191.71	65,075	0.33%	1.50%	8.49%
Constellation Brands Inc	STZ	167.9	208.20	34,949	0.18%	1.42%	11.19%
Xilinx Inc	XLNX	252.9	77.83	19,684	0.10%	1.85%	11.60%
DENTSPLY SIRONA Inc	XRAY	222.3	39.92	8,876	0.04%	0.88%	6.93%
Zions Bancorporation	ZION	194.4	53.29	10,360	0.05%	2.25%	10.30%
Alaska Air Group Inc	ALK	123.1	67.49	8,311	0.04%	1.90%	7.51%
Invesco Ltd	IVZ	410.8	24.10	9,901	0.05%	4.98%	7.48%
Intuit Inc	INTU	258.7	219.47	56,771	0.28%	0.86%	16.38%
Morgan Stanley	MS	1,744.8	48.83	85,198	0.43%	2.46%	13.44%
Microchip Technology Inc	MCHP	235.6	86.03	20,265	0.10%	1.69%	14.55%
Chubb Ltd	CB	463.3	135.24	62,651	0.31%	2.16%	10.00%
Citizens Financial Group Inc	CFG	475.9	41.16	19,590	0.10%	2.62%	21.50%
Allstate Corp/The	ALL	346.2	100.57	34,821	0.17%	1.83%	9.00%
Equity Residential	EQR	368.3	67.75	24,951	0.13%	3.19%	5.25%
BorgWarner Inc	BWA	208.9	43.77	9,142	0.05%	1.55%	5.79%
Simon Property Group Inc	SPG	309.2	183.03	56,595	0.28%	4.37%	6.61%
Eastman Chemical Co	EMN	141.3	97.03	13,708	0.07%	2.31%	5.90%
AvalonBay Communities Inc	AVB	138.2	183.29	25,334	0.13%	3.21%	6.87%
Prudential Financial Inc	PRU	417.0	98.25	40,970	0.21%	3.66%	9.00%
United Parcel Service Inc	UPS	693.4	122.88	85,204	0.43%	2.96%	8.97%
Apartment Investment & Management Co	AIV	157.4	43.80	6,892	0.03%	3.47%	6.12%
Walgreens Boots Alliance Inc	WBA	992.4	68.56	68,040	0.34%	2.57%	10.64%
McKesson Corp	MCK	199.8	128.75	25,721	0.13%	1.21%	5.83%
Lockheed Martin Corp	LMT	284.8	320.41	91,247	0.46%	2.50%	25.21%
AmerisourceBergen Corp	ABC	216.4	89.97	19,466	0.10%	1.69%	10.05%
Capital One Financial Corp	COF	478.4	99.09	47,407	0.24%	1.61%	16.00%
Darden Restaurants Inc	DRI	123.5	116.04	14,336	0.07%	2.59%	10.09%
NetApp Inc	NTAP	259.3	86.81	22,507	0.11%	1.84%	15.95%
Citrix Systems Inc	CTXS	135.7	114.02	15,468	0.08%	1.23%	9.00%
DXC Technology Co	DXC	281.2	91.09	25,611	0.13%	0.83%	6.36%
Hartford Financial Services Group Inc/The	HIG	358.4	50.37	18,054	0.09%	2.38%	9.50%
Iron Mountain Inc	IRM	286.1	36.10	10,330	0.05%	6.51%	10.10%
Estee Lauder Cos Inc/The	EL	224.1	140.12	31,407	0.16%	1.08%	16.95%
Universal Health Services Inc	UHS	86.1	130.16	11,205	0.06%	0.31%	7.93%
Skyworks Solutions Inc	SWKS	179.0	91.30	16,341	0.08%	1.66%	12.04%
National Oilwell Varco Inc	NOV	382.6	47.07	18,010	0.09%	0.42%	41.00%
Quest Diagnostics Inc	DGX	136.7	109.98	15,031	0.08%	1.82%	9.20%
Activision Blizzard Inc	ATVI	762.4	72.10	54,970	0.28%	0.47%	13.90%
Rockwell Automation Inc	ROK	123.2	180.96	22,288	0.11%	2.03%	12.34%
Kraft Heinz Co/The	KHC	1,219.2	58.27	71,041	0.36%	4.29%	5.60%
American Tower Corp	AMT	440.8	149.12	65,737	0.33%	2.07%	16.10%
HollyFrontier Corp	HFC	176.2	74.52	13,129	0.07%	1.77%	8.43%
Ralph Lauren Corp	RL	55.2	132.81	7,338	0.04%	1.88%	6.83%
Boston Properties Inc	BXP	154.4	130.45	20,144	0.10%	2.45%	5.83%
Amphenol Corp	APH	300.4	94.58	28,407	0.14%	0.97%	11.81%
Arconic Inc	ARNC	483.0	22.38	10,809	0.05%	1.07%	16.00%
Pioneer Natural Resources Co	PXD	170.4	174.70	29,769	0.15%	0.18%	27.13%
Valero Energy Corp	VLO	427.4	117.88	50,382	0.25%	2.71%	16.65%
L3 Technologies Inc	LLL	78.3	213.72	16,740	0.08%	1.50%	12.64%
Western Union Co/The	WU	447.3	18.92	8,462	0.04%	4.02%	4.20%
CH Robinson Worldwide Inc	CHRW	138.5	96.08	13,311	0.07%	1.92%	10.23%
Accenture PLC	ACN	640.7	169.07	108,331	0.54%	1.57%	11.15%
Yum! Brands Inc	YUM	317.4	86.89	27,575	0.14%	1.66%	12.50%
Prologis Inc	PLD	629.4	67.18	42,283	0.21%	2.86%	6.68%
Ameren Corp	AEE	244.0	63.23	15,431	0.08%	2.89%	8.98%
NVIDIA Corp	NVDA	608.0	280.68	170,653	0.86%	0.21%	11.23%

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Sealed Air Corp	SEE	158.8	40.11	6,370	0.03%	1.60%	3.89%
Cognizant Technology Solutions Corp	CTSH	580.2	78.43	45,508	0.23%	1.02%	14.70%
Affiliated Managers Group Inc	AMG	53.4	146.09	7,806	0.04%	0.82%	11.68%
Aetna Inc	AET	327.4	200.27	65,568	0.33%	1.00%	10.69%
Republic Services Inc	RSG	325.4	73.36	23,868	0.12%	2.04%	11.92%
Goldman Sachs Group Inc/The	GS	377.6	237.81	89,787	0.45%	1.35%	12.69%
Sempra Energy	SRE	273.5	116.08	31,743	0.16%	3.08%	16.14%
Moody's Corp	MCO	191.9	178.02	34,162	0.17%	0.99%	8.00%
Devon Energy Corp	DVN	508.8	42.93	21,843	0.11%	0.75%	14.46%
Allegion PLC	ALLE	95.0	87.22	8,286	0.04%	0.96%	11.23%
Agilent Technologies Inc	A	318.8	67.54	21,530	0.11%	0.88%	10.35%
Anthem Inc	ANTM	260.0	264.73	68,818	0.35%	1.13%	11.59%
CME Group Inc	CME	340.6	174.73	59,511	0.30%	1.60%	15.00%
Juniper Networks Inc	JNPR	344.8	28.43	9,803	0.05%	2.53%	9.40%
BlackRock Inc	BLK	159.6	479.06	76,450	0.38%	2.61%	10.67%
DTE Energy Co	DTE	181.5	111.14	20,170	0.10%	3.18%	6.03%
Nasdaq Inc	NDAQ	164.5	95.44	15,701	0.08%	1.84%	11.27%
Philip Morris International Inc	PM	1,554.5	77.89	121,081	0.61%	5.85%	10.33%
Huntington Ingalls Industries Inc	HII	43.3	244.47	10,590	0.05%	1.18%	27.50%
MetLife Inc	MET	994.8	45.89	45,653	0.23%	3.66%	12.58%
Tapestry Inc	TPR	288.0	50.69	14,601	0.07%	2.66%	11.60%
Fluor Corp	FLR	140.6	57.41	8,073	0.04%	1.46%	25.82%
CSX Corp	CSX	858.8	74.16	63,689	0.32%	1.19%	11.96%
Rockwell Collins Inc	COL	164.4	135.95	22,346	0.11%	0.97%	11.60%
TechnipFMC PLC	FTI	454.5	30.63	13,921	0.07%	1.70%	8.70%
Zimmer Biomet Holdings Inc	ZBH	203.5	123.63	25,157	0.13%	0.78%	3.64%
Mastercard Inc	MA	1,025.1	215.56	220,961	1.11%	0.46%	21.42%
Intercontinental Exchange Inc	ICE	573.4	76.23	43,713	0.22%	1.26%	8.32%
Fidelity National Information Services Inc	FIS	328.8	108.17	35,569	0.18%	1.18%	4.40%
Wynn Resorts Ltd	WYNN	108.6	148.34	16,116	0.08%	2.02%	18.30%
NRG Energy Inc	NRG	303.4	35.39	10,738	0.05%	0.34%	15.69%
Regions Financial Corp	RF	1,102.5	19.46	21,454	0.11%	2.88%	22.28%
Mosaic Co/The	MOS	385.5	31.27	12,053	0.06%	0.32%	7.00%
Expedia Group Inc	EXPE	136.7	130.50	17,833	0.09%	0.98%	14.23%
Evergy Inc	EVRG	271.7	57.05	15,500	0.08%	3.23%	8.59%
CF Industries Holdings Inc	CF	233.5	51.95	12,129	0.06%	2.31%	15.30%
Viacom Inc	VIAB	353.4	29.28	10,349	0.05%	2.73%	6.56%
TE Connectivity Ltd	TEL	348.5	91.68	31,947	0.16%	1.92%	9.25%
Cooper Cos Inc/The	COO	49.1	255.78	12,569	0.06%	0.02%	10.80%
Discover Financial Services	DFS	342.7	78.12	26,768	0.13%	2.05%	9.18%
Visa Inc	V	1,776.7	146.89	260,973	1.31%	0.57%	17.90%
Xylem Inc/NY	XYL	179.6	75.91	13,635	0.07%	1.11%	8.60%
Marathon Petroleum Corp	MPC	451.0	82.29	37,113	0.19%	2.24%	20.43%
Tractor Supply Co	TSCO	121.8	88.28	10,753	0.05%	1.40%	13.43%
ResMed Inc	RMD	142.7	111.41	15,896	0.08%	1.33%	12.15%
Albemarle Corp	ALB	108.5	95.52	10,359	0.05%	1.40%	13.53%
Essex Property Trust Inc	ESS	66.1	246.28	16,267	0.08%	3.02%	6.51%
Realty Income Corp	O	290.0	58.57	16,988	0.09%	4.51%	4.36%
WestRock Co	WRK	255.1	55.08	14,052	0.07%	3.12%	6.50%
Western Digital Corp	WDC	291.4	63.24	18,425	0.09%	3.16%	3.52%
PepsiCo Inc	PEP	1,414.3	112.01	158,418	0.79%	3.31%	6.72%
Church & Dwight Co Inc	CHD	245.4	56.58	13,885	0.07%	1.54%	9.63%
Duke Realty Corp	DRE	357.3	28.49	10,179	0.05%	2.81%	5.34%
Federal Realty Investment Trust	FRT	73.5	130.61	9,599	0.05%	3.12%	4.85%
MGM Resorts International	MGM	537.9	28.99	15,594	0.08%	1.66%	3.72%
Twenty-First Century Fox Inc	FOX	798.5	44.90	35,854	0.18%	0.80%	9.95%
Alliant Energy Corp	LNT	238.0	42.84	10,195	0.05%	3.13%	5.86%
JB Hunt Transport Services Inc	JBHT	109.3	120.75	13,203	0.07%	0.80%	13.46%
Lam Research Corp	LRCX	157.6	173.09	27,276	0.14%	2.54%	13.55%
Pentair PLC	PNR	175.4	43.48	7,627	0.04%	1.61%	11.05%
Alexandria Real Estate Equities Inc	ARE	105.8	128.35	13,574	0.07%	2.90%	6.82%
Delta Air Lines Inc	DAL	691.3	58.48	40,429	0.20%	2.39%	15.22%
News Corp	NWS	199.6	13.60	2,715	0.01%	1.47%	26.30%
Regency Centers Corp	REG	169.4	66.03	11,188	0.06%	3.36%	9.68%
Macerich Co/The	MAC	141.1	58.74	8,285	0.04%	5.04%	6.07%
Martin Marietta Materials Inc	MLM	63.0	198.72	12,522	0.06%	0.97%	14.09%
Coty Inc	COTY	750.8	12.36	9,280	0.05%	4.05%	13.06%
Everest Re Group Ltd	RE	40.9	223.02	9,111	0.05%	2.33%	10.00%

Market DCF Calculation as of August 31, 2018

	[1] Dividend Yield	[2] Dividend Yield x (1 + 0.50g)	[3] Expected Growth Rate (g)	[4] Secondary Market Investor Required Return	[5] Forecast US Government 30 Year Yield	[6] Equity Risk Premium
S&P 500	**2.25%**	**2.38%**	**11.45%**	**13.83%**	**3.55%**	**10.28%**

Company	Ticker	[7] Shares Outstanding (million)	[8] Price ($)	[9] Market Capitalization ($million)	[10] Percent of Total Market Capitalization	[11] Current Dividend Yield	[12] Long-Term Growth Estimate
News Corp	NWSA	383.4	13.07	5,011	0.03%	1.53%	26.30%
Global Payments Inc	GPN	158.2	124.58	19,707	0.10%	0.03%	17.00%
Crown Castle International Corp	CCI	414.8	114.03	47,304	0.24%	3.68%	19.23%
Aptiv PLC	APTV	264.7	88.01	23,300	0.12%	1.00%	13.12%
Advance Auto Parts Inc	AAP	74.1	164.03	12,152	0.06%	0.15%	17.52%
Alliance Data Systems Corp	ADS	54.9	238.58	13,109	0.07%	0.96%	11.93%
Nielsen Holdings PLC	NLSN	355.2	26.00	9,235	0.05%	5.38%	12.00%
Garmin Ltd	GRMN	188.8	68.14	12,865	0.06%	3.11%	5.98%
Cimarex Energy Co	XEC	95.4	84.48	8,056	0.04%	0.85%	72.05%
Zoetis Inc	ZTS	481.8	90.60	43,653	0.22%	0.56%	17.87%
Digital Realty Trust Inc	DLR	206.1	124.28	25,614	0.13%	3.25%	7.28%
Equinix Inc	EQIX	79.5	436.13	34,676	0.17%	2.09%	15.76%
Mean for Companies Paying Dividends with Positive Long-Term Growth Estimates						**2.25%**	**11.45%**

Notes:
[1] Equals mean of Column [11]
[2] Equals Column [1] x (1 + 0.5 x Column [3])
[3] Equals mean of Column [12]
[4] Equals Column [2] + Column [3]
[5] Source: April 2018 Consensus Forecast Average 2019-2021 Forecasts 10-Year bond yield plus 30-day average spread between 10- and 30-year government bonds ending August 31, 2018
[6] Equals Column [4] - (Column [5])
[7] Source: Bloomberg Finance L.P., as of August 31, 2018
[8] Source: Bloomberg Finance L.P., as of August 31, 2018
[9] Equals Column [7] x Column [8]
[10] Equals percent of sum of Column [9]
[11] Source: Bloomberg Finance L.P., as of August 31, 2018
[12] Source: Bloomberg Finance L.P., as of August 31, 2018

Capital Asset Pricing Model

US Proxy Group	Ticker	[1] Bloomberg	[2] Value Line	[3] Average Beta	[4] Risk Free Rate	[5] Average Market Risk Premium	[6] Basic CAPM Calculation	[7] Flotation Cost	[8] Total CAPM
ALLETE, Inc.	ALE	0.59	0.75	0.67	3.55%	8.61%	9.30%	0.50%	9.80%
Alliant Energy Corporation	LNT	0.56	0.70	0.63	3.55%	8.61%	8.99%	0.50%	9.49%
American Electric Power Company, Inc.	AEP	0.55	0.65	0.60	3.55%	8.61%	8.73%	0.50%	9.23%
Duke Energy Corporation	DUK	0.46	0.55	0.51	3.55%	8.61%	7.90%	0.50%	8.40%
Edison International	EIX	0.55	0.60	0.58	3.55%	8.61%	8.50%	0.50%	9.00%
Eversource Energy	ES	0.58	0.60	0.59	3.55%	8.61%	8.65%	0.50%	9.15%
OGE Energy Corporation	OGE	0.67	0.95	0.81	3.55%	8.61%	10.54%	0.50%	11.04%
Pinnacle West Capital Corporation	PNW	0.56	0.65	0.61	3.55%	8.61%	8.77%	0.50%	9.27%
PNM Resources, Inc.	PNM	0.61	0.75	0.68	3.55%	8.61%	9.39%	0.50%	9.89%
MEAN		0.57	0.69	0.63			8.97%		9.47%

Canada Proxy Group	Ticker	Bloomberg	Value Line	Average Beta	Risk Free Rate	Average Market Risk Premium	Basic CAPM Calculation	Flotation Cost	Total CAPM
Canadian Utilities Limited	CU	0.82	n/a	0.82	3.08%	8.59%	10.16%	0.50%	10.66%
Emera Inc.	EMA	0.66	n/a	0.66	3.08%	8.59%	8.74%	0.50%	9.24%
Enbridge Inc.	ENB	1.03	n/a	1.03	3.08%	8.59%	11.94%	0.50%	12.44%
Valener Inc.	VNR	0.53	n/a	0.53	3.08%	8.59%	7.66%	0.50%	8.16%
MEAN		0.76		0.76			9.63%		10.13%

North American Electric Proxy Group	Ticker	Bloomberg	Value Line	Average Beta	Risk Free Rate	Average Market Risk Premium	Basic CAPM Calculation	Flotation Cost	Total CAPM
ALLETE, Inc.	ALE	0.59	0.75	0.67	3.55%	8.61%	9.30%	0.50%	9.80%
Alliant Energy Corporation	LNT	0.56	0.70	0.63	3.55%	8.61%	8.99%	0.50%	9.49%
American Electric Power Company, Inc.	AEP	0.55	0.65	0.60	3.55%	8.61%	8.73%	0.50%	9.23%
Duke Energy Corporation	DUK	0.46	0.55	0.51	3.55%	8.61%	7.90%	0.50%	8.40%
Edison International	EIX	0.55	0.60	0.58	3.55%	8.61%	8.50%	0.50%	9.00%
Eversource Energy	ES	0.58	0.60	0.59	3.55%	8.61%	8.65%	0.50%	9.15%
OGE Energy Corporation	OGE	0.67	0.95	0.81	3.55%	8.61%	10.54%	0.50%	11.04%
Pinnacle West Capital Corporation	PNW	0.56	0.65	0.61	3.55%	8.61%	8.77%	0.50%	9.27%
PNM Resources, Inc.	PNM	0.61	0.75	0.68	3.55%	8.61%	9.39%	0.50%	9.89%
Canadian Utilities Limited	CU	0.82	n/a	0.82	3.08%	8.59%	10.16%	0.50%	10.66%
Emera Inc.	EMA	0.66	n/a	0.66	3.08%	8.59%	8.74%	0.50%	9.24%
MEAN		0.60	0.69	0.65			9.06%		9.56%

Notes:
[1] Source: Bloomberg Professional as of August 31, 2018; weekly changes in equity stock price against SPX index (U.S.) or SPTSX (Canada) Index for the past five years
[2] Source: Value Line as of August 31, 2018
[3] Equals mean of [1] and [2]
[4] Source: Equals average long-term Consensus Forecast of 10-year government bond yields for the period 2019-2021 as of April 9, 2018. (Pg. 3, 28)
plus the 30-day average spread between 10- and 30-year bond ending August 31, 2018.
[5] Source: Canada - Bloomberg TSX total return less [4] as of August 31, 2018; U.S. - Bloomberg S&P 500 total return less [4] as of August 31, 2018
[6] Equals [4] + ([5] x [3])
[7] The Commission allows 50 bps adjustment for flotation cost and financial flexibility.
[8] Equals [6] + [7]

2015-2017% Regulated

Utility	**% Regulated Income**	**% Electric Revenues**	**% Electric Income**	**% Electric Assets**
ALLETE, Inc.	83%	98%	97%	99%
Alliant Energy Corp	101%	87%	95%	85%
American Electric Power Company	91%	100%	100%	100%
Duke Energy Corporation	106%	95%	95%	93%
Edison International	106%	100%	100%	100%
Eversource Energy	97%	88%	91%	89%
OG&E Energy Corp	102%	100%	100%	100%
Pinnacle West Capital	72%	100%	100%	100%
PNM Resources	100%	100%	100%	100%
U.S. Proxy Group Average	**95%**	**96%**	**98%**	**96%**

Note: Percentage of operating income may exceed 100% due to losses at affiliates.

Regulatory Risk Assessment

Company	Ticker	Electric Operating Subsidiary	[1] S&P Rating	[2] Electric Jurisdiction	[3] RRA Ranking	[4] Test Year	[5] Rate Base	[6] Approved ROE (%)	[7] Approved Equity Ratio (%)	[8] Generation Assets in Rate Base
ALLETE, Inc.	ALE	Minnesota Power	BBB+	Minnesota	Average / 2	Partially-Forecasted	Average	9.25	53.81	Yes
Alliant Energy Corporation	LNT	Interstate Power and Light Company	A-	Iowa	Average / 1	Historical	Average	9.98	49.02	Yes
		Wisconsin Power and Light Company	A	Wisconsin	Above Average / 2	Fully-Forecasted	Average	10.00	52.00	Yes
American Electric Power	AEP	AEP Texas, Inc.	A-	Texas	Average / 3	Historical	Year-end	9.96	40.00	No
		Appalachian Power Company	A-	Virginia	Above Average / 2	Historical	Year-end	9.70	42.89	Yes
				West Virginia	Below Average / 2	Historical	Average	9.75	47.16	Yes
		Indiana Michigan Power Company	A-	Indiana	Average / 1	Historical	Year-end	9.95	46.14	Yes
				Michigan	Above Average / 3	Fully-Forecasted	Average	9.90	46.08	Yes
		Kentucky Power Company	A-	Kentucky	Average / 1	Historical	Year-end	9.70	41.68	Yes
		Kingsport Power		Tennessee	Above Average / 3	Fully-Forecasted	Average	9.85	40.25	Yes
		Ohio Power Company	A-	Ohio	Average / 2	Partially-Forecasted	Date certain	10.30	53.79	No
		Public Service Company of Oklahoma	A-	Oklahoma	Average / 3	Historical	Year-end	9.30	48.51	Yes
		Southwestern Electric Power Company	A-	Arkansas	Average / 1	Partially-Forecasted	N/A	10.25	43.18	Yes
				Louisiana	Average / 2	Historical	N/A	10.00	N/A	Yes
				Texas	Average / 3	Historical	Year-end	9.60	48.46	Yes
Duke Energy Corp	DUK	Duke Energy Carolinas, LLC	A-	North Carolina	Average / 1	Historical	Year-end	9.90	52.00	Yes
				South Carolina	Average / 2	Historical	Year-end	10.20	53.00	Yes
		Duke Energy Florida, LLC	A-	Florida	Above Average / 2	Fully-Forecasted	Average	10.50	49.09	Yes
		Duke Energy Indiana, LLC	A-	Indiana	Average / 1	Historical	Year-end	10.50	52.44	Yes
		Duke Energy Kentucky, Inc.	A-	Kentucky	Average / 1	Fully-Forecasted	Year-end	9.73	49.25	Yes
		Duke Energy Ohio, Inc.	A-	Ohio	Average / 2	Partially-Forecasted	Date certain	9.84	53.30	No
		Duke Energy Progress, LLC	A-	North Carolina	Average / 1	Historical	Year-end	9.90	52.00	Yes
				South Carolina	Average / 3	Historical	Year-end	10.10	53.00	Yes
Edison International	EIX	Southern California Edison Company	BBB+	California	Above Average / 3	Fully-Forecasted	Average	10.30	48.00	Yes
Eversource Energy	ES	Connecticut Light and Power Company	A+	Connecticut	Below Average / 1	Historical	Average	9.20	53.00	No
		NSTAR Electric Company	A+	Massachusetts	Average / 2	Historical	Year-end	10.00	53.34	No
		Public Service Company of New Hampshire	A+	New Hampshire	Average / 3	Historical	N/A	9.67	52.40	No
		Western Massachusetts Electric Company	A+	Massachusetts	Average / 2	Historical	Year-end	10.00	54.51	No
OGE Energy Corporation	OGE	Oklahoma Gas and Electric Company	BBB+	Arkansas	Average / 1	Partially-Forecasted	Year-end	9.50	49.61	Yes
			BBB+	Oklahoma	Average / 3	Historical	Year-end	9.50	53.31	Yes
Pinnacle West Capital Corp.	PNW	Arizona Public Service Company	A-	Arizona	Average / 3	Historical	Year-end	10.00	55.80	Yes
PNM Resources, Inc.	PNM	Public Service Company of New Mexico	BBB+	New Mexico	Below Average / 2	Fully-Forecasted	Year-end	9.58	49.61	Yes
		Texas-New Mexico Power	BBB+	Texas	Average / 3	Historical	Year-end	10.13	45.00	No
Proxy Group Total			Average	Total	Average	8		Average	Average	Total
			A-	34	Average / 2	5		9.88	49.43	26
						21				76%
Fortis, Inc.	FTS	Maritime Electric	BBB+	PEI		Fully-Forecasted	Average	9.35	40.00	Yes

Regulatory Risk Assessment

			[9]	[10]		[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]
				Revenue Decoupling				Capital Costs					
Company	Ticker	Electric Operating Subsidiary	Fuel Cost Pass Through	Full	Partial	Conservation Program Expense	Capital Costs	Renewable Expense	Environmental Compliance	Generation Capacity	Generic Infrastructure	RTO-related Transmission Expense	Storm Cost Recovery
ALLETE, Inc.	ALE	Minnesota Power	✓			✓	CWIP	✓	✓			✓	
Alliant Energy Corporation	LNT	Interstate Power and Light Company	✓			✓	Pre-approval	✓	✓			✓	
		Wisconsin Power and Light Company	✓				CWIP on 50%, pre-approval						
American Electric Power	AEP	AEP Texas, Inc.	✓			✓	surcharge mechanism for certain T&D				✓	✓	
		Appalachian Power Company	✓			✓	CWIP	✓		✓		✓	
			✓			✓	CWIP for large gen and trans projects	✓			✓		
		Indiana Michigan Power Company	✓		✓	✓	CWIP	✓	✓		✓	✓	
			✓			✓	Pre-approval of projects > $100 mil	✓					
		Kentucky Power Company	✓		✓	✓	CWIP	✓	✓	✓			
		Kingsport Power	✓				CWIP						
		Ohio Power Company	*		✓	✓	CWIP if 75% complete	✓			✓	✓	✓
		Public Service Company of Oklahoma	✓		✓	✓	Pre-approval for new construction		✓		✓	✓	
		Southwestern Electric Power Company	✓		✓	✓	No		✓	✓			
			✓		✓	✓	CWIP for nuclear		✓				
			✓			✓	surcharge mechanism for certain T&D				✓	✓	
Duke Energy Corp	DUK	Duke Energy Carolinas, LLC	✓			✓	CWIP and pre-approval for baseload gen	✓	✓				✓
			✓				CWIP and pre-approval of costs		✓				✓
		Duke Energy Florida, LLC	✓			✓	CWIP for nuclear, IGCC, or trans		✓	✓			✓
		Duke Energy Indiana, LLC	✓		✓	✓	CWIP	✓	✓	✓	✓	✓	
		Duke Energy Kentucky, Inc.	✓		✓	✓	CWIP	✓					
		Duke Energy Ohio, Inc.	*		✓	✓	CWIP if 75% complete	✓			✓	✓	✓
		Duke Energy Progress, LLC	✓			✓	CWIP and pre-approval for baseload gen	✓	✓				✓
			✓				CWIP and pre-approval of costs		✓				✓
Edison International	EIX	Southern California Edison Company	✓	✓			Adder for 50% of CWIP, pre-approval of costs						
Eversource Energy	ES	Connecticut Light and Power Company		✓		✓	No					✓	✓
		NSTAR Electric Company	*			✓	No					✓	✓
		Public Service Company of New Hampshire	✓				No				✓	✓	✓
		Western Massachusetts Electric Company	*	✓		✓	No	✓		✓		✓	✓
OGE Energy Corporation	OGE	Oklahoma Gas and Electric Company	✓		✓	✓	No	✓	✓	✓	✓	✓	
			✓		✓	✓	Pre-approval for new construction	✓	✓		✓	✓	✓
Pinnacle West Capital Corp.	PNW	Arizona Public Service Company	✓		✓	✓	No	✓	✓	✓		✓	
PNM Resources, Inc.	PNM	Public Service Company of New Mexico	✓			✓	CWIP, if costs are reasonable	✓	✓		✓		
		Texas-New Mexico Power	✓			✓	surcharge mechanism for certain T&D				✓	✓	
Proxy Group Total			Adjustment Clauses Count and Percentage of total proxy group										
			28	3	12	27	27	18	17	8	13	18	12
			82%	9%	35%	79%	79%	53%	50%	24%	38%	53%	35%
Fortis, Inc.	FTS	Maritime Electric	Yes	No	Yes	No	Pre-approval	No	No	No	No	No	No

Notes

[1] Source: SNL Financial, S&P Long-Term Rating
[2] Source: SNL Financial
[3] Source: Regulatory Research Associates
[4] Source: Regulatory Research Associates
[5] Source: Regulatory Research Associates
[6] and [7] Source: Regulatory Research Associates;
* An adjustment was made to those capital structures authorized in Arkansas, Florida, Indiana and Michigan as those states include zero cost of capital items in the capital structure
[8] Source: SNL Financial
[9] Source: "Adjustment Clauses: A State-by-state Overview," Regulatory Research Associates, September 12, 2017 and SNL Financial
* Ohio: Gas utilities are permitted to use a gas cost recovery, or GCR, clause, which provides for quarterly adjustments, with an annual review and hearing.
* Massachusetts: Cost of gas adjustments, or CGAs, are determined semi-annually based on seasonally-differentiated peak and off-peak costs.
* Pennsylvania: generation required to meet provider of last resort, or POLR, obligations is competitively procured and priced; therefore, the utilities are not at risk for changes in power prices
[10] to [11] and [13] to [17] Source: "Adjustment Clauses: A State-by-state Overview," Regulatory Research Associates, September 12, 2017
[12] Source: Regulatory Research Associates
[18] Source: SEC Form 10-K for each holding company

CREDIT METRICS ANALYSIS

Company Name	Ticker	Rating		Debt to Capital Ratio	EBITDA to Interest Coverage	FFO to Interest Coverage	FFO / Debt (%)	Debt to EBITDA
Maritime Electric		BBB+		63%	4.69	4.93	20.6%	3.65
		U.S. Proxy Group						
ALLETE, Inc.	ALE	BBB+		47%	4.85	7.10	20.0%	3.96
Alliant Energy Corporation	LNT	A-		59%	4.73	5.88	17.5%	4.83
American Electric Power Company, Inc.	AEP	A-		56%	5.07	6.11	18.9%	4.25
Duke Energy Corporation	DUK	A-		56%	4.01	5.24	15.4%	5.01
Edison International	EIX	BBB+		58%	4.45	8.10	22.9%	3.59
Eversource Energy	ES	A+		57%	5.36	6.11	14.6%	5.29
OGE Energy Corporation	OGE	BBB+		47%	5.47	6.07	22.6%	3.58
Pinnacle West Capital Corporation	PNW	A-		50%	5.66	7.38	24.7%	3.29
PNM Resources, Inc.	PNM	BBB+		63%	4.04	5.29	16.7%	4.70
U.S. Proxy Group				55%	4.85	6.36	19.3%	4.28
		Canadian Proxy Group						
Canadian Utilities Limited	CU	A-		66%	3.89	4.14	12.5%	5.79
Emera Incorporated	EMA	BBB+		67%	3.23	3.46	10.4%	6.38
Enbridge Inc.	ENB	BBB+		50%	3.60	3.20	10.6%	6.67
Valener, Inc.	VNR	NR	[1]					
Canadian Proxy Group				61%	3.57	3.60	11.1%	6.28

Notes & Sources:
All values are based on Standard and Poor's 2017 adjusted credit metrics for the holding company
[1] Credit rating for Valener was withdrawn by S&P in 2016.

RESPONSE TO INTERROGATORIES FROM COMMISSION STAFF

Section IR-97

APPENDIX 2

JT BROWNE CONSULTING

assisting clients
in applying regulatory principles
and dealing with financial, accounting and costing issues related to rate regulation

COMMENTS
ON
RETROACTIVE RATEMAKING

JT Browne Consulting
December 2014

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JOHN T. BROWNE

John Browne has been addressing issues related to rate-regulated entities for over 25 years. He has:

- Prepared independent expert evidence on accounting, costing, financial and regulatory issues for presentation to regulatory tribunals.

- Assisted rate-regulated entities in the preparation of their regulatory submissions.

- Advised management on regulatory issues such as potential regulatory options and the implications of regulation on the operations of their business.

- Completed special studies involving costing, financial analysis and trends in rate rate-regulated industries to support management decision-making.

A Chartered Professional Accountant (CPA, CA), Mr. Browne has a Bachelor of Commerce degree and a Master of Arts degree in economics. He chaired the Canadian Institute of Chartered Accountants (CICA) Study Group that produced the research report “Financial Reporting by Rate-Regulated Enterprises”.

INTRODUCTION

Regulators avoid retroactive ratemaking and there can be legal restrictions on the practice. However, there may be confusion as to what constitutes retroactive rate making, or at least unacceptable retroactive ratemaking, and the extent to which regulators will avoid it.

This paper addresses retroactive ratemaking from the perspective of general regulatory practice. It discusses:

- normal practice in setting rates;
- retroactive rate making; and
- exceptions to the normal practice of not revisiting past periods.

The final section sets out the conclusion as to general regulatory practice concerning retroactive ratemaking.

NORMAL PRACTICE

Rates are normally set prospectively. In accordance with the cost of service standard, rates are set to give a utility an opportunity to recover its costs of providing service, including a fair return[1] – no more and no less. It should be emphasized that the cost of service standard refers to an opportunity to recover costs, not a guarantee.

The rate setting process starts by establishing what is often referred to as a utility's revenue requirement. This amount is the estimated costs of providing service in the period covered by the rates. An estimate is then made of the expected demand for the utility's services. Based on the revenue requirement and estimated demand, rates are set so that expected revenues[2] will equal the revenue requirement.

Realized revenues may not equal realized costs: actual costs may vary from what was assumed in establishing a utility's revenue requirement; or actual demand may vary from what was assumed in setting rates. Any variances accrue to the utility: if actual revenues

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[1] In what follows, it is assumed that the costs of providing regulated service include a fair return. This is consistent with general regulatory practice.

[2] At least in theory, expected revenues, costs and returns are the probability weighted average of the possible revenues, costs and returns.

exceed actual costs, the excess is kept by the utility; if actual revenues are less than actual costs, the deficiency is borne by the utility.

Customers compensate utilities for the risk that realized revenues will not equal realized costs. A fair return is included in the costs that allowed rates are set to recover. This fair return reflects the legitimate risks that the utility faces. The greater the risk, the greater the return included in the utility's revenue requirement, and the greater the return the utility will be given an opportunity to earn.

There has been a movement away from traditional cost of service regulation to incentive and performance based regulatory methodologies. However, the newer forms of regulation tend to be a modification of traditional regulation. Initial rates are usually set so that expected revenues will cover the utility's revenue requirement; the rates are then allowed to increase in accordance with a formula where the formula is expected to reflect the cost pressures on the utility.

Compared to traditional regulation, the newer methodologies increase the extent to which actual revenues may differ from actual costs. However, rates are still set prospectively with any difference between realized revenues and costs accruing to the utility. Also rates are normally set so that expected revenues will equal the expected costs of providing service in the period covered by the rates[3].

There are benefits associated with the normal practice. It provides greater certainty for both customers and utilities: customers know how much they will have to pay for services when they purchase the services; utilities know the compensation they will receive from providing services when the services are provided. It results in the costs of providing service in a period being borne by the customers of that period, and not customers of a past or future period. It also provides an incentive for utilities to manage their costs since they bear the risk of differences between actual costs and the estimated costs used in setting rates.

The normal practice for setting rates also reflects what would be expected in a competitive market.

3 In some cases, expected revenues may exceed expected costs so as to provide an incentive to a utility. For example, an achievable increase in efficiency gains may be ignored in setting rates, resulting in expected revenues exceeding expected costs. This would allow the utility to earn high returns if it achieves the gains – at least until its next rate review, and provide an incentive for the utility to achieve these gains. However, achievable efficiency gains are often considered in setting rates so that expected revenues will equal expected costs. The incentive for the utility is that if it does not achieve the gains it will not earn a fair return.

RETROACTIVE RATEMAKING

Retroactive ratemaking represents an exception to the normal practice for setting rates.

Regulators normally avoid retroactive ratemaking. For example, in a 2005 decision, the Ontario Energy Board ("OEB") stated:

> *… As the Board has stated in numerous cases, the Board does not endorse retroactive ratemaking. …*[4]

There may also be legal constraints against retroactive ratemaking. For example, the OEB went on to state:

> *We are also of the view that the Board is limited in its decision by legal precedent. The Supreme Court of Canada has ruled on the issue of retroactive ratemaking.*[5]

This raises the question as to what constitutes retroactive ratemaking, or at least unacceptable retroactive ratemaking.

Definition

It is not always clear as to what is meant by retroactive ratemaking; however, it involves revisiting the past.

It may be defined as making changes to the allowed rates for services provided in the past – i.e., retroactively setting rates.

The definition may be extended to include adjustments to allowed rates to account for an under or over recovery of past costs (although it may be more appropriate to refer to this as retrospective ratemaking). Whether past rates or future rates are changed on account of a past under or over recovery, the end result is often very similar.

From a utility's perspective, there is usually little difference, if any. For example, where a utility is to be compensated for the under recovery of a past cost, both a re-billing of past customers and an adjustment to future rates is intended to provide revenues equal to the under recovery. An adjustment to future rates may not produce an amount exactly equal to what was intended; however, the actual amount received is usually very close to

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4 OEB; EB-2005-0031; February 24, 2006; pg. 7.

5 OEB; EB-2005-0031; February 24, 2006; pg. 7.

the intended amount. Where there is a material amount of time before under or over recoveries are reflected in rates, the delay in recovery will affect a utility's financing costs; however, regulators usually adjust what a utility is given an opportunity to recover so as to account for the impact of the delay on its financing costs[6].

From an individual customer's perspective, there can be differences, but overall the impact tends to be similar. Over time the customers of a utility can change: some customers will move away and new customers may move into the area served by the utility. Also the amount of service that a customer acquires from a utility can vary from period to period. However, a rate-regulated utility tends to provide an essential service with little or no effective competition. As a result, for most customers, there will often be little difference whether an adjustment is made to past or future rates.

Where an adjustment for past under or over recoveries is appropriate, it is more likely that future rates will be adjusted rather than past rates. At least where there are a large number of customers, it is much simpler and less confusing to adjust future rates than to re-bill customers for past services.

The above definitions imply that retroactive ratemaking refers to adjusting rates for past service: either adjusting past rates or adjusting future rates as a result of the under or over recovery of past costs. However, retroactive ratemaking, or at least unacceptable retroactive ratemaking, may refer to changing the terms on which past rates were based. It may be defined as adjusting rates for a past period, or adjusting rates on account of the under or over recovery of costs in a past period, where such adjustments were not part of the terms on which the rates for the past period were based.

This latter definition is supported by comments made by the Alberta Energy and Utilities Board ("AEUB") in a 2006 decision. The comments refer to deferred gas accounts ("DGAs") which result in certain differences between estimated and actual costs being deferred and included in the determination of future rates:

> *… the deferral nature of the DGAs is specifically contemplated and acknowledged when the rates are set. Deferral accounts, by their nature, anticipate adjustments such as the ones at issue in this matter and, as such, cannot be said to constitute retroactive rate-making.…*[7]

Retroactive ratemaking is usually discussed in the context of regulatory decisions that revisit the past. However, it might at least be argued that to not revisit the past would also constitute

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6 These financing costs include not only the cost of debt but also the cost of equity.

7 AEUB; Decision 2006-042; May 11, 2006; pg. 4.

retroactive ratemaking where the requirement to do so formed part of the basis on which rates for that past period were set. To not revisit the past would result in retroactively changing the terms on which past rates were based.

Practice

However retroactive ratemaking is defined, as a general rule, regulators avoid revisiting past: either adjusting past rates or adjusting future rates as a result of the under or over recovery of past costs. Still, there are a significant number of exceptions.

REVISITING PAST PERIODS

There are a number of cases where regulators revisit the past. These exceptions to normal practice generally fall within one of the following categories:

- interim rates;
- anticipated deferrals;
- unanticipated deferrals; and
- earning caps.

As a general rule, regulators only revisit a past period where this is required, or at least allowed, by the terms on which rates for that past period were based.

Interim Rates

Interim rates may be used to deal with regulatory lag.

Changing allowed rates can be a long process. It can take up to a year or more from the time that a utility identifies a need for increased rates until the time it is allowed to charge the new approved rates. In some cases, the workload on a regulator may prevent it from dealing with a rate application within a reasonable period of time, at least with the rigour that the regulator requires.

Especially where a utility faces significant cost pressures, the delay may prevent a utility from having a reasonable opportunity to recover its costs of providing service. It may even jeopardize the financial viability of the utility.

To deal with this problem, regulators may approve interim rates. These interim rates may reflect an increase or just a continuation of existing rates. Once final rates are approved, an adjustment is made for differences with the final rates. In many cases, the difference between the interim and final rates is reflected through an adjustment to future rates.

It should be noted that any adjustment will cover only the period back to the date that the interim rates were set, which may include the date that the regulator determined that the existing rates were to be interim.

Where interim rates are charged, it is known that there could be an adjustment for differences with the final approved rates, and this forms part of the terms on which the interim rates are based.

Anticipated Deferrals

Normally allowed rates are set to recover the expected costs of providing service in the period covered by the rates. However regulators may defer the recovery of costs resulting in a reduction in current rates that will be offset by an increase in future rates.

One reason for deferring costs is to enhance rate stability and predictability. Where faced with a large unusual cost, regulators may defer part of the cost: in this way, a significant fluctuation in rates can be avoided, or at least reduced. Where faced with a large permanent increase in costs, a regulator may defer some of the costs of the period: in this way, rates can be increased in a more gradual and predictable manner.

Another common reason is to deal with uncertainty. Where there is a significant amount of uncertainty as to the estimated amount of a cost, the actual cost may be significantly lower or higher than estimated. This could result in a windfall gain for the utility at the cost of its customers; alternatively it could result in a large loss for the utility that might negatively impact its financial viability. The uncertainty would also tend to increase the risk of the utility which would tend to increase its cost of capital, a cost that is included in the determination of a utility's revenue requirement and passed onto customers through allowed rates.

To deal with uncertainty, costs may be deferred. Costs that are difficult to estimate are removed for the revenue requirement of the period in which they will be incurred and included in the revenue requirement of a future period or periods when the amount of the cost is known[8]. The deferrals are usually limited to costs that are largely outside the control of the utility. Where a utility has significant control over the cost, a regulator may want the utility to bear the risk of any difference between the estimated and actual

[8] The cost of financing deferred amounts is usually added to the deferral and included in the determination of future revenue requirements.

amount of the cost so as to provide an incentive for the utility to effectively manage the cost.

The above discussion deals with deferring costs, which is the most common type of deferrals; however, revenues, losses and gains may also be deferred. For example, a large unusual increase in revenue maybe deferred and used to reduce future revenue requirements – this would smooth out the impact of the gain and reduce or even eliminate any fluctuation in allowed rates.

Variance accounts are a form of deferral accounts. With such accounts, it is expected that the actual cost, and only the actual cost, will be included in the revenue requirements that a utility will be given an opportunity to recover. Initially, an estimate of the cost is included in the revenue requirement for the period in which the cost is expected to be incurred. After the cost is incurred, the difference between the estimated and actual amount is deferred and included in the revenue requirement of a future period or periods[9]. By initially including an estimate in the utility's revenue requirement, customers that benefit from the incurrence of the cost will pay for at least part of the cost rather than having the full amount of the cost passed on to future customers. It also tends to reduce the rate instability in future periods when any deferred amounts are included in the utility's revenue requirement.

In the case of anticipated deferrals, rates are set on the basis that the deferred amounts arising during the period covered by the rates will be included in the determination of future rates.

Unanticipated Deferrals

Unanticipated deferrals are not specifically anticipated when rates are set for the period in which the deferral arises, whether the amount being deferred is a cost, revenue, loss or gain. They deal with amounts that were not considered when rates for the period were set.

An example of an unanticipated deferral is where an electric distribution utility defers significant repair costs resulting from an unusual storm. Rates are usually set based on normal weather conditions and do not consider the impact of a large unusual storm. Even if a regulator wished to consider such a storm, it would be difficult to estimate whether such a storm would occur during the period covered by the rates; and even if the

[9] The difference between the estimate and actual costs may be adjusted for volume differences. For example, the amount deferred may be calculated as the difference between the estimated and actual unit cost times the actual number of units.

possibility of such a storm could be determined, it would be difficult to estimate the resulting damage and associated repair costs.

Obviously unanticipated deferrals are not specifically anticipated. However, the cost of service standard is a fundamental principle of rate regulation. In accordance with this standard, a utility should have an opportunity to recover its cost of providing service – no more and no less. Where amounts are not considered when rates are set, the amounts must be deferred and included in the determination of future rates if the cost of service standard is to be met. Therefore, it could at least be argued that rates are set on the basis that material amounts arising in the period covered by the rates, but not considered in those setting those rates, will be deferred.

Earning Caps

There are cases where regulators impose earning caps. The utility is usually allowed to earn returns within a given range. If earnings exceed that range, either part or all of the earnings must returned to customers. In most cases, the excess is returned to customers through a reduction if future allowed rates.

Although regulators may impose an earning cap, they almost never, if not never, set an earning floor. However, utilities are usually allowed to seek new rates if realized revenues are significantly less than the realized costs of providing service.[10]

Where earning caps are imposed, it may be appropriate to increase allowed rates. Rates should be set to give a utility an opportunity to recover its costs of providing service. In any period, actual results may produce revenues that are more or less than the costs of providing service. However, the possibility of over and under earning should be offsetting[11]; and on average, realized revenues should tend to equal realized costs. If the upside for earnings is capped while no limits are placed on the downside; on average, realized revenues may tend to fall short of realized costs. Where this is the case, allowed rates must be increased if the utility is to have expected revenues that equal expected costs – i.e., if the utility is to have a reasonable opportunity to recover it costs of providing service.

As a general rule, earning caps are imposed at the time rates covered by the cap are set. As a result, rates are set on the basis that there will be an earning cap.

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[10] As noted earlier, the costs of providing service include a fair return.

[11] The expected difference should be zero – i.e., the probability weighted average difference between possible revenues and costs should be zero.

Basis For Setting Past Rates

The above exceptions represent cases where regulators deviate from normal rate setting practice by revisiting the past. They either adjust rates for services provided in the past, or adjust future rates on account of the under or over recovery of costs in a past period. However, with all of the above exceptions, there is usually no retroactive change to the terms on which past rates were based.

Except for the unanticipated deferrals; the requirement to revisit the past, or at least the possibility of revisiting the past, is specifically recognized when rates for the past period are set. This requirement, or possibility, forms part of the terms on which the rates for that period were based.

In the case of unanticipated deferrals, the deferrals are not specifically anticipated when rates for the period giving rise to the deferral are set; however, it could at least be argued that the possibility of such deferrals is implicitly included as part of the terms on which those rates are based. The cost of service standard is a fundamental regulatory principle. It requires that allowed rates provide a regulated utility an opportunity to recover its costs of providing service – no more and no less. Where the amount of the deferral was not considered in setting rates for the period in which the deferred amount arose, it must be considered in setting future rates if the cost of service standard is to be met.

It appears the rule against retroactive ratemaking does not necessarily prevent a regulator from revisiting the past. What it does prevent is revisiting the past where the requirement to do so, or at least the possibility to do so, did not form part of the terms on which rates for that past period were based. For example, in a 2014 decision, Alberta Utilities Commission ("AUC") stated:

> *An adjustment to rates arising from a deferral account or interim rates is not considered retroactive ratemaking as the parties are aware that rates were subject to change.*[12]

CONCLUSION

It appears the rule against retroactive rate making prevents a regulator from retroactively changing the terms on which previous rates were based.

[12] AUC; Decision 2014-100; April 15,2014; para 34.

As a general rule, regulators set rates prospectively. The rates are set so that expected revenues will equal the expected costs of providing service in the period covered by the rates. Any difference between realized revenues and costs accrues to the regulated utility.

There are benefits to setting rates prospectively: it provides greater certainty for both customers and utilities; it results in the costs of providing service in a period being borne by the customers of that period; and it provides an incentive for utilities to manage their costs. Setting rates prospectively is also consistent with how prices would be set in a competitive market.

Consistent with setting rates prospectively, regulators normally avoid revisiting the past: either adjusting past rates or considering under or over recoveries of past costs in the determination of future rates. However, there are a significant number of exceptions.

As a general rule, it appears that the exemptions occur only where the terms on which past rates were based require those exceptions, or at least allow for those exceptions.

OTHER MONOGRAPHS & COMMENT PAPERS AVAILABLE ON REQUEST

- Fundamentals of Rate Regulation
- Comments on Managing the Regulatory Relationship
- Survey of Regulatory Objectives
- Comments on the Prudence Standard
- Comments on the Future of Cost of Service Regulation
- Comments on Control and Compliance for Regulatory Codes of Conduct
- Comments on Focused and Efficient Regulatory Controls
- Comments on Regulatory Costing - What Utility Managers Should Consider
- Financial Modeling for Management & Regulatory Purposes
- Comments on Corporate Cost Allocations
- Affiliate Transactions - Comments on a Recent OEB Decision (2002)
- Changes to the Ontario Energy Board's Affiliate Relationships Code for Gas Utilities (2004)
- Corporate Cost Allocations - Comments on a Recent OEB Decision (2006)
- Comments on Deferral Accounts to Deal with Uncertainty.
- Comments on Determining the Net Working Capital Allowance
- Comments on the Recovery of Unexpected Costs
- Comments on Differences Between Regulatory Accounting Policies and Financial Reporting Standards
- Comments on IASB Exposure Draft - Rate-regulated Activities
- Comments on Regulatory Assets and the Views of IASB Staff
- Comments on Regulatory Liabilities and the Views of IASB Staff

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