MARITIME ELECTRIC
A FORTIS COMPANY

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FEB 15 2019
The Island Regulatory and Appeals Commission

February 15, 2019

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

Dear Ms. Mosher:

General Rate Application - Docket UE20944
Response to Interrogatories from Commission Staff

Please find attached the Company's response to Interrogatories from Commission Staff with respect to the General Rate Application filed on November 30, 2018.

Yours truly,

MARITIME ELECTRIC

Gloria Crockett

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

GCC08
Enclosure

Section 3 – Introduction

IR-1 Please explain how the forecasted energy sales (2018-2021) contained in Schedule 3-1 (page 7) are calculated. Please provide all supporting calculations and documentation in support of the forecasted energy sales for the years 2018-2021 (inclusive).

Response

The forecast sales in Schedule 3-1 are derived from the Company's detailed energy sales regression analysis model as discussed in Section 7.2 of the application. Further details and supporting calculations are provided in response to IR-12.

Section 4 – Provincial Costs Recoverable

IR-2 Please explain how the annual costs recoverable from customers on behalf of the Province (Schedule 4-2 at page 16) are calculated.

a. Please provide all supporting calculations and documentation in support of MECL's calculated annual payment.

b. Please advise when this debt is projected to be eliminated, and provide all supporting projections and calculations upon which MECL relies.

c. Per the Collection of Debt Agreement with the Government of Prince Edward Island, Maritime Electric Company, Limited and the Prince Edward Island Energy Corporation, the costs are to be collected on behalf of the Province by MECL at a pre-set rate of $0.00536. Please explain how changing the method of payment and collection through the ECAM account is in line with the Agreement.

Response

a. The following table is as summary of how the annual costs recoverable from customers on behalf of the Province presented in Schedule 4-2 is calculated:

Calculation of Schedule 4-2				
Annual Payments of Costs Recoverable From Customers on Behalf of the Province				
Funding Requirements		**2019**	**2020**	**2021**
Dalhousie	A	$ 1,168,352	$ 1,168,352	$ 97,363
Lepreau	B	4,871,498	4,871,498	5,620,285
Subtotal – PEIEC Debt Repayments (March 1 - February 28)	C = A + B	6,039,850	6,039,850	5,717,648
2018 - 2019 Collections in Excess of Payments	D	(300,000)	(300,000)	-
Subtotal Annual Payments to be paid by MECL to PEIEC (March 1 - February 28)	E = C + D	5,739,850	5,739,850	5,717,648
Monthly Payments	F = E ÷ 12	478,321	478,321	476,471
Number of Monthly Payments	G	10	12	12
Total Payments to be paid by MECL to the PEIEC - Calendar Year (January 1 - December 31)	**H = F x G**	**$ 4,783,209**	**$ 5,739,850**	**$ 5,721,348**[1]

This table is provided as IR-2 - Attachment 1 to this response as well as in electronic format. The amounts are based on information provided by the PEI Energy Corporation ("PEIEC") which is included in IR-2 - Attachment 2 to this response as well as in electronic format and will be filed with the Commission on a confidential basis.

[1] Payments for 2021 = 2 months x $478,321 + 10 months x $476,471 = $5,721,352
(January and February) (March and December)

As discussed in the Application, the approved rate rider under the General Rate Agreement results in variable payments to the Province. In 2018-2019, increased sales levels resulted in collections from customers in excess of the payments required on the debt. These excess collections are forecast by the PEIEC to be $600,000 by February 28, 2019 and will be used to reduce the required debt repayments for 2019 and 2020.

As indicated in Schedule 4-1, collections for January and February 2019 will be in accordance with the existing General Rate Agreement as a rate rider of $0.00536 per kWh of energy sold. The proposed refinancing will commence on March 1, 2019 and as such, there will be ten months of payments reflected in 2019.

b. The final payment from Maritime Electric to the PEIEC on the debt associated with exiting the Dalhousie Participation Agreement will be in March 2021 to allow the PEIEC to fully repay the debt in April 2021. The complete amortization schedule for the Dalhousie Debt is provided in IR-2 - Attachment 2 to this response which will be filed with the Commission on a confidential basis.

The debt associated with the Point Lepreau replacement energy is being amortized until March 2038, over the expected remaining life of the Point Lepreau facility. Amortization schedules for the two PEIEC loans comprising the Point Lepreau debt are included in IR-2 - Attachment 2 to this response which will be filed with the Commission on a confidential basis.

c. As discussed in the preamble to the Debt Collection Agreement, pursuant to the terms of the Energy Accord, Section 49 of the EPA and the Agreement, the Debts owing to the Province are to be collected by the Company from its customers as part of the its lawful rates, tolls and charges. Further, in the Agreement, Sections 6 (Additional Funding Received in Relation to the Debts), 5.4 and 5.8 contemplate changes to the collection rates upon the occurrence of a material change.

The receipt of the settlement proceeds and the PEIEC's intent to refinance the outstanding debt with fixed repayment terms, as detailed in the letter from the PEIEC included with this response as IR-2 – Attachment 3, constitute the material changes upon which changes to the collection of the debt from customers is contemplated. The parties have agreed to amend the Debt Collection Agreement to enable the recovery of a fixed monthly amount as proposed in the Company's application, subject to the Commission's approval.

The debts to be recovered pursuant to Section 49 of the EPA and the Debt Collection Agreement are energy related costs associated with the refurbishment of the Point Lepreau Nuclear Generating Station and the closure of the Dalhousie Generating Station. The inclusion of all energy related costs in ECAM was approved by IRAC in Order UE05-01 and confirmed in Order UE05-06 based upon the Company's application filed in its May 2004 General Rate Application (Docket UE20934). In that application, it was proposed that all energy related costs be included in the ECAM including the fixed rate amortization of deferred charges related to the Point Lepreau writedown. Recovery of the costs recoverable on behalf of the Province through the ECAM is therefore considered appropriate and consistent with past Commission approvals.

Section 5 – Regulatory Deferrals

IR-3 Please explain how the ECAM base rates contained in Schedule 5-1 (page 20) are calculated. Please provide all supporting calculations and documentation in support of the ECAM base rates.

Response

A two-step approach has been taken to calculate the proposed ECAM Base rate as set out in the General Rate Application. The first step is to calculate the annual Energy Supply Cost per kWh for each year. This is calculated by taking the Energy Supply Cost by Source (Schedule 8-4) and dividing by the Net Purchased and Produced Energy (Schedule 8-3) converted to kWh in each year.

The second step is adjusting the ECAM Base rate to stabilize the rate increases over the three year application period. In paragraph 53 of the Commission's Order UE16-04R states:

> *The Commission encourages multi-year rate setting, whenever possible, so as to allow for stable and predictable electricity rates for customers…*

To develop stable customer electricity rate adjustments in each year, the ECAM Base rate is adjusted in each year over the three year rate period. That being said, it is important to note that the ECAM base rate is set such that all proposed energy supply costs are recovered by the end of the three year rate period. The table below shows the annual calculation of the ECAM Base rate and is also provided in electronic format as IR-3 - Attachment 1 to this response.

Calculation of Annual ECAM Base Rate					
Description	**GRA Reference**		**2019 Forecast**	**2020 Forecast**	**2021 Forecast**
Energy Supply by Source ($)	Schedule 8-4	A	$128,543,600	$134,807,900	$136,509,600
Net Purchased and Produced Energy X 1,000,000 (GWh converted to kWh)	Schedule 8-3	B	1,365,034,762	1,401,254,102	1,423,094,943
Energy Supply Cost per kWh		C = A/B	$ 0.09417	$ 0.09621	$ 0.09592
Rate Stability Adjustment		D	(0.00082)	(0.00145)	(0.00001)
ECAM Base Rates (March 1 - February 28)	**Schedule 5-1**	**C + D**	**$ 0.09335**	**$ 0.09475**	**$ 0.09591**

IR-4 Please provide the monthly and year-end balances for both the Weather Normalization Reserve account and the Rate of Return Adjustment ("RORA") Account from January 1, 2016 to present.

Response

The monthly and year end balances for the Weather Normalization Reserve account and the Rate of Return Adjustment account from January 1, 2016 to December 31, 2018 have been provided in IR-4 - Attachment 1 to this response as well as in electronic format.

IR-5 What (if any) impact has the Weather Normalization Reserve had on the balance of the RORA Account since implemented on January 1, 2016?

Response

The change in the Weather Normalization Reserve in a particular year will only impact the balance in the RORA account if there is also a RORA adjustment during that year.

When the Heating Degree Day ("HDD") variation is below normal there would be a shortfall in net revenue. This shortfall would result in an adjustment to the weather normalization reserve and the amount of the shortfall would be recorded as revenue and an amount to be recovered from customers in the Weather Normalization Reserve account. If the Company is in an over earnings position for the year, this incremental revenue will contribute to the over earnings which will be offset by the RORA adjustment for the year, effectively increasing the balance of the RORA account to be refunded to customers.

Likewise, when the HDD variation is above normal there would be an excess of net revenue. This excess revenue would result in an adjustment to the Weather Normalization Reserve and the amount of the excess would be recorded as an expense and an amount to be refunded to customers in the Weather Normalization Reserve account. If the Company is in an over earnings position for the year, the remaining over earnings amount will be added to the RORA account.

In both 2016 and 2017, the HDD variation was below normal causing the Company to record additional revenue of $126,031 and $52,155 respectively. These amounts were, in turn, added to the Weather Normalization Reserve account as recoverable from customers. Since the Company was in an over earnings position in each of these years, the additional revenue recorded through the Weather Normalization adjustment increased the RORA adjustment for the year resulting in an increase in the amount owing to customers.

In 2018, the HDD variation was above normal causing the Company to record an offset against (or reduction in) revenue of $469,169 and an amount to be refunded to customers in the Weather Normalization Reserve account. After recording the Weather Normalization adjustment for the year, the Company remained in an over earnings position and then recorded a RORA adjustment to recognize the remaining amount owing to customers as part of the RORA account.

IR-6 If the Weather Normalization Reserve is not approved by the Commission for the period March 1, 2019 to February 28, 2022:

a. What (if any) impact will this have on the rates, tolls and charges for electric service during this time period?

b. What (if any) impact will this have on the balance of the RORA Account during this time period?

Response

a. Subject to the Commission's determination with respect to any residual balance in the Weather Normalization Reserve at February 28, 2019, there would be no impact on rates.

b. Sales forecast projections are based on normal HDDs therefore no Weather Normalization Reserve entries are forecast. If the Weather Normalization Reserve is not approved, any changes in projected net revenue resulting from variations in HDD from normal will flow through the Company's income statement rather than being captured and deferred in the Weather Normalization Reserve to the extent that HDDs are greater or lesser than normal. The proposals in the Company's General Rate Application do not result in excess earnings during the period so there are no additions to the RORA account projected. As a result, there would be no impact on the balance of the RORA account.

IR-7 Please explain how the Post-2015 RORA Payable to Customers contained in Schedule 5-5 (page 28) is calculated. Please provide all supporting calculations and documentation in support of the forecasted RORA payable to customers.

Response

The balance of the post-2015 RORA Payable to Customers, as shown in Table 1 below, reflects actual over earnings adjustments recorded in the Company's financial statements in 2016 and 2017 as well as the forecast overearnings adjustment for 2018. Interest is calculated on the outstanding balance each month and added to the balance as detailed in IR-7 – Attachment 1 to this response.

IR – 7 - Table 1		
Post-2015 RORA		
Balance, December 31, 2015		$ -
Actual RORA - 2016	See "A" below	2,100,000
Actual RORA - 2017	See "B" below	2,767,885
2017 Accrued Interest	See Attachment 1	61,922
Forecast RORA - 2018	See "C" below	3,952,400
2018 Forecast Accrued Interest	See Attachment 1	116,493
Balance, December 31, 2018		$ 8,998,700
Transfer Balance Pre-2016 RORA to Post-2015 Balance	IR – 7 Table 2 below	768,700
Forecast Balance March 1, 2018		**$ 9,767,400**

A = Actual RORA 2016:	
Net Income Before Tax and RORA	$ 20,339,716
Less: RORA	(2,100,000)
Less: Income Taxes	(5,754,350)
Add: Non Recoverable Fortis Inc. Costs	456,090
Regulated Earnings	12,941,456
Average Regulated Common Equity	$ 138,342,099
Allowed ROE	9.35%

B = Actual RORA 2017:	
Net Income Before Tax and RORA	$ 21,636,768
Less: RORA	(2,767,885)
Less: Income Taxes	(5,940,740)
Add: Non Recoverable Fortis Inc. Costs	422,280
Regulated Earnings	13,350,423
Average Regulated Common Equity	$ 142,798,854
Allowed ROE	9.35%
C = Forecast RORA 2018:	
Net Income Before Tax and RORA	$ 23,416,525
Less: RORA	(3,952,400)
Less: Income Taxes	(6,085,701)
Add: Non Recoverable Fortis Inc. Costs	409,860
Regulated Earnings	13,788,284
Average Regulated Common Equity	147,452,138
Allowed ROE	9.35%

The balance transferred from the Pre-2016 RORA represents the forecast balance remaining in the account as of March 1, 2018 as shown in Table 2 below and detailed in IR-7 – Attachment 2 to this response.

IR - 7 - Table 2		
Pre-2016 RORA		
Balance, December 31, 2015		**$ 15,156,765**
Refund to Customers 2016		
Actual Sales in kWh January & February - 2016	224,065,884	
Refund Rate per kWh	$0.00071	(159,087)
Actual Sales in kWh - March to December 2016	964,358,529	
Refund Rate per kWh	$0.00410	(3,953,870)
Accrued Interest	See Attachment 2	360,528
Balance, December 31, 2016		**$ 11,404,336**
Refund to Customers 2017		
Actual Sales in kWh January & February - 2017	233,000,053	
Refund Rate per kWh	$0.00410	(955,300)
Actual Sales in kWh - March to December 2017	975,058,175	
Refund Rate per kWh	$0.00473	(4,612,025)
Accrued Interest	See Attachment 2	243,471
Balance, December 31, 2017		**$ 6,080,482**
Forecast Refund to Customers 2018		
Actual Sales in kWh January & February - 2018	244,261,639	
Refund Rate per kWh	$0.00473	(1,155,358)
Forecast Sales in kWh - March to December 2018	990,572,630	
Refund Rate per kWh	$0.00345	(3,417,476)
Forecast Accrued Interest	See Attachment 2	96,018
Rounding Adjustments		4,933
Balance, December 31, 2018		**$ 1,608,600**
Forecast Sales in kWh January & February - 2019	243,778,281	
Refund Rate per kWh	$0.00345	(841,035)
Rounding Adjustments		1,135
Transfer Balance Pre-2016 RORA to Post-2015 Balance		**(768,700)**
Balance March 1, 2018		**$ (0)**

Supporting calculations provided in IR-7 - Attachments 1 and 2 to this response are also provided in electronic format.

IR-8 Please explain how the repayment of the Post-2015 RORA Payable to Customers of $0.00250/kWh is calculated. Please provide all supporting calculations and documentation.

Response

The RORA repayment rate is calculated as follows:

		Forecast kWh Sales
March - December 2019	10 months	1,023,213,596
January - December 2020	Annual	1,300,906,376
January - December 2021	Annual	1,321,357,361
January - February 2022	2 months	255,441,249
Total kWh Sales March 1 2019 - February 28, 2022	A	3,900,918,582
Forecast RORA Balance - February 28, 2019	B	$ 9,767,400
RORA Refund Rate per kWh	C = B/A	$ 0.00250

Section 6 – Charlottetown Thermal Generating Station Decommissioning Study

IR-9 Various MECL documents indicate that the CTGS plant site will remain with MECL "*for the foreseeable future*". In MECL's response to IR-3 from Synapse Energy Economics, Inc. (filed November 16, 2018), it states that "*MECL intends to retain the property for future uses relating to its existing function as an electricity transmission/distribution hub*":

a. Specifically, what future use(s) is projected for this site?

b. Is this the best site for future generation assets?

c. What long-term planning has been done?

Response

a. The future uses of this site include future generation, location for substation rebuilds and substation expansions and location for transformation expansion.

b. Yes, the site is ideal for future generation assets. It is a strategic location for load serving and fuel delivery purposes. Additional generation located here, like CT3, is well situated to provide energy and system support to both Charlottetown and eastern P.E.I. through the T-2 transmission line connecting the Charlottetown Substation to Lorne Valley and beyond.

Locating future generation on the CTGS plant site avoids the cost of duplicating diesel fuel delivery equipment, combustion turbine auxillary equipment and some substation investments that would be required with a green field site.

The additional diesel storage tank associated with future generation on this site would provide flexibility to shift fuel between the existing and new tank.

This enables internal tank inspections as required by the Provincial Environmental Protection Act Petroleum Storage Tank Regulations. At present, to comply with Provincial EPA Regulations, the diesel storage tank must be drained and inspected only when CT3 is removed from service for extended maintenance. The location also provides the opportunity for having fuel delivered via marine transport which Maritime Electric is currently investigating due to land transport restrictions experienced during the last several winter seasons.

The location of future generation in close proximity to the Irving tank farm on Riverside Drive is also a strategic security benefit.

c. Maritime Electric's system planning has identified the need for additional on-Island generation over the long-term. The CTGS is a very attractive location for the establishment of future generation. The CTGS area is an industrial "brown field" site with suitable buffers for future development. The buffers were established with the purchase of the Canada Packers properties on Grafton and Cumberland Streets.

IR-10 According to MECL's response to IR-3 from Synapse Energy Economics, Inc. (filed November 16, 2018), CT3 is expected to remain on-site for an additional 35 plus years. Has MECL done any long-term analysis on whether there is a better site for diesel storage and CT3?

Response

Maritime Electric has not done any long-term analysis on whether there is a better site for diesel storage and CT3. A high level estimate was provided in response to Interrogatory #10 from the PEI Energy Corporation in 2015 under Docket UE20723 (CT4): "What are the economics of relocating the diesel storage, the transmission infrastructure and CT3 one the CTGS is retired so that the CTGS property could be sold off and redeveloped as a prime waterfront location?"

A copy of the response is included with this response as IR-10 - Attachment 1.

IR-11 Will the full remaining CTGS site still used and useful after demolition is completed? Will it form part of the rate base?

Response

The remaining CTGS site will be used and useful after demolition is completed. The land is an integral part of the operations of the Charlottetown Plant site and the future uses are identified in response IR-9 a. The land also provides a buffer for the generation, substations and fuel storage remaining on site. The majority of the property that the steam plant occupies does not form part of the Maritime Electric's rate base as it is leased from the Cumberland Trust for a 999 year period.

Section 7 – Energy Sales Forecast

IR-12 On page 40, MECL provides the forecasted energy sales for 2018-2021 and states that the forecast involves a "detailed sales regression analysis". Please provide the detailed sales regression analysis as well as an explanation of the assumptions made in formulating the analysis.

Response

The following is an explanation of the components of the regression analysis by customer class.

Residential

Residential sales consist of two main components – space heating and non-space heating. The regression equation for the increase in the coefficient for space heating load (expressed as MWh/HDD (MegaWatt-hours/Heating Degree Day)) is:

Three year increase (MWh/HDD) = 18.30 x average ratio of the price of furnace oil to the price of equivalent amount of electricity for heating for previous three years

+ 4.95 x dummy variable to represent impact of mini-split heat pumps and environmental concerns associated with furnace oil tanks. (Dummy variable set at 1 beginning for 2013, and set at 0 for previous years)
- 13.26

The forecast of furnace oil price is sourced from the U.S Energy Information Administration's Annual Energy Outlook.

Real price of electricity for Residential is assumed to increase by 0.5% annually beginning in 2020, to reflect assumed adjustments based on Cost Allocation Study results.

The MWh/HDD coefficient for a forecast year is calculated by adding the estimated three year MWh/HDD increase from the above equation to the MWh/HDD coefficient for the third prior year. The space heating load for the forecast year is then the MWh/HDD coefficient x the ten year average annual HDD reported for the Charlottetown Airport.

The MWh/HDD coefficient for a historical year is estimated using regression analysis. The regression equation for the October 2017 to May 2018 heating season is:

Average monthly Residential sales (MWh/day) = 48.0 x average monthly HDD/day

+ 36.46 x average monthly fewer daylight hours/day compared to May
+ 844

From the above equation, the space heating coefficient for the October 2017 to May 2018 heating season is 48.0 MWh/HDD.

The forecast sales for Residential non-space heating loads is number of year round customers x annual average kWh/customer for appliances and lighting + number of year round customers x annual average kWh/customer for all other usage.

The regression equation for the number of year round Residential customers is:

Number of December customers = 85.05 x PEI population (in thousands)
+ 604.4 x year (e.g. 2020)
- 1,169,139

The forecast of PEI population is sourced from the Conference Board of Canada.

The forecast of annual average kWh/customer for appliances and lighting is based on trends in efficiency improvements.

The forecast in annual average kWh/customers for all other usage is from trending.

General Service
The regression equation for General Service sales (also includes Small Industrial and Unmetered) is:

Sales (GWh) = 0.613 x previous year's GWh sales
+ 0.0353 x real PEI GDP in 2007 $ x millions for the year
- 3.70 x real price of electricity in 2002 $ average cents per kWh for General Service for the previous year
+ 66.25

The forecast of PEI GDP is sourced from the Conference Board of Canada.

Real price of electricity for General Service is assumed to decline by 1% annually starting in 2020, to reflect assumed adjustments based on Cost Allocation Study results.

Large Industrial
Sales for the Large Industrial class are forecast based on a customer-by-customer assessment of the load for each customer in the class.

Street Lighting
Street Lighting sales are forecast to decline over the next few years due to the ongoing conversion from high pressure sodium lighting to LED lighting. The LED fixtures use approximately 55% of the energy used by corresponding high pressure sodium fixtures.

IR-13 On Page 40, Schedule 7-1, MECL provides the actual and forecasted Energy Sales for 2016-2021. Please provide the previous forecasted energy sales for 2016 and 2017. In addition, please provide the 2018 actual energy sales.

Response

The following table shows the forecast for 2016 and 2017 energy sales that were presented in Appendix B – Schedule 7-1 of the 2016 General Rate Agreement:

Schedule 7-1 Energy Sales (GWh)		
Measure	**2016 Forecast**	**2017 Forecast**
Regression Analysis Growth	1,193.8	1,218.5
Two-year Average Growth	1,234.1	1,271.0
Year-To-Date Growth	1,212.8	1,240.2

The energy sales forecast, based on the energy sales regression analysis model, was 1,193.8 GWh in 2016 and 1,218.5 GWh in 2017.

Total actual sales for 2018 were 1,257.3 GWh.

IR-14 On page 40, MECL states that it performed a two-year average growth rate calculation and a year-to-date growth rate calculation. From these, MECL estimates projected sales over the three year period from 2019-2021 and these estimates are set out in Schedule 7-3. Is this correct?

Response

No, as stated in the application at the beginning of Page 41:

> “Management’s forecast of energy sales for the period 2019 - 2021 is based upon the energy sales regression analysis for the above stated reasons.”

On Page 40, the Company discusses the development of the energy sales growth forecast using a detailed energy sales regression analysis. As part of its assessment of the reasonableness of the results of the regression analysis, the Company also reviews recent trends in historic sales growth, including the two year average growth rate and year-to-date growth over the previous period. Although calculations of historic trends are informative, the detailed sales regression model is the basis of the Company’s sales forecast.

IR-15 MECL has forecasted an overall energy sales growth rate of 2.6% in 2019, 2.7% in 2020, but only 1.6% in 2021 (see Schedule 7-3 at page 41). Is the growth rate for 2021 based solely on the factors set out in Schedule 7-2 (page 40)? If not, what other factors are involved in determining the growth rate?

Response

The purpose of Schedule 7-2 on page 40 is to explain why the forecast energy sales growth rate drops from 2.7% in 2020 to 1.6% in 2021. The table below shows that without the expected impacts of new cannabis industry loads and efficiencyPEI's energy efficiency plan, the forecast energy sales growth rate for 2020 and 2021 would be essentially the same.

Forecast Energy Sales Growth Rates (%)					
	Schedule	**2018**	**2019**	**2020**	**2021**
Overall growth rate	7-3	2.2	2.6	2.7	1.6
Add back reductions due to energy efficiency	7-2	0.1	0.3	0.5	0.7
Subtract growth due to new cannabis industry loads	7-2	(0.0)	(1.4)	(1.0)	(0.0)
Forecast growth rates before adjustments		2.3	1.5	2.2	2.3

IR-16 Please provide the analysis and supporting documentation which forms the basis of the projections contained in Schedule 7.2 – Estimated Change in Energy Sales (page 40).

Response

The table below shows estimated growth in energy sales due to new cannabis industry loads.

Forecast of Energy Sales Due to New Cannabis Industry Loads				
	Customer 1	**Customer 2**	**Total**	**Annual Increase**
Expected in-service date	Apr 2019	Nov 2019		
Size of load, from customer (MW)	5.0	0.75		
Assumed annual load factor	0.60	0.50		
Estimated annual energy (GWh)	26.3	3.3		
2018 forecast energy sales (GWh)	0.0	0.0	0.0	0.0
2019 forecast energy sales (GWh)	17.0	0.5	17.5	17.5
2020 forecast energy sales (GWh)	26.3	3.3	29.6	12.1
2021 forecast energy sales (GWh)	26.3	3.3	29.6	0.0

The following table shows efficiencyPEI's forecast of energy efficiency savings, as of late 2017. The forecast was based on program delivery starting in April 2018.

efficiencyPEI Forecast of Energy Efficiency Savings			
Government Fiscal Year	**Incremental Savings for Residential (GWh)**	**Incremental Savings for Businesses (GWh)**	**Total Incremental Savings (GWh)**
2018/2019	1.8	1.5	3.3
2019/2020	3.2	3.5	6.7
2020/2021	4.0	5.5	9.5

The load forecast for Maritime Electric's current GRA filing was prepared in August 2018. The forecast of the impact of energy efficiency was based on efficiencyPEI's forecast, as follows:

- Program delivery was assumed to begin in October 2018;
- Maritime Electric serves 90% of the PEI electricity load, so it would see 90% of the energy savings;
- Incremental annual savings would continue at 9.5 GWh after 2020/2021;
- Savings for 2018: 3.3 GWh x 0.25 x 0.9 = 0.7 GWh;
- Savings for 2019: (3.3 GWh x 0.75 + 6.7 GWh x 0.25) x 0.9 = 3.7 GWh;
- Savings for 2020: (6.7 GWh x 0.75 + 9.5 GWh x 0.25) x 0.9 = 6.7 GWh; and
- Savings for 2021: (9.5 GWh x 0.75 + 9.5 GWh x 0.25) x 0.9 = 8.6 GWh.

Section 8 – Energy Supply Expenses

IR-17 With 3% or less of the projected energy supply costs during the period 2019-2021 (Schedule 8-1 at page 43) dependent upon fossil fuel costs, what is the rationale for retaining the ECAM which was instituted in the 1970s at a time when fossil fuel prices were quite volatile and fossil fuels were a major portion of energy expense costs?

Response

During the 1970s, the Commission had approved the use of the Fuel Adjustment Mechanism ("FAM") to address fluctuations in fossil fuel costs during a time (pre September 1977) when the Company generated all of the energy supply requirements on-Island using fossil fuel. At that time costs for fuel, either Bunker C at Charlottetown or light oil at Borden varied with world oil prices, exchange rates and with the quantity of energy generated at each source. The FAM captured these variations in fuel supply costs and set out the timeframes to recover or refund the variations from or to customers.

In 1986, the Commission ordered a change in the deferral mechanism from a FAM to an ECAM. At that time, most of the Company's energy supply requirement was imported from New Brunswick and pricing was based on split increment pricing and oil prices.

Today's ECAM, approved for adoption by IRAC in Order UE05-01 effective January 1, 2004 (when Maritime Electric returned to Cost of Service regulation), captures all fluctuations in the cost of purchased and produced energy from the base rate included customer rates. The inclusion of all such costs acknowledges that Maritime Electric now meets PEI's electrical needs from a number of energy sources and contracts and that the cost of the energy purchased or produced can vary by contract, by fuel source, by supply mix, and also for unforeseen interruptions in supply or contract curtailment.

For example, during the most recent rate setting period, the forecast and actual energy supply costs included in ECAM for 2016 - 2018 were as follows:

	Per MWh				
Year	**GRA Forecast**	**Actual**	**Variance**	**MWh**	**Variance**
2016	$86.05	$86.60	$0.55	1,280,483	$ 704,266
2017	$89.88	$90.99	$1.11	1,297,936	1,440,709
2018	$91.61	$92.76	$1.15	1,349,045	1,551,402
Total					**$ 3,696,337**

The Company's experience through the PEI Energy Accord and the subsequent three year General Rate Agreement has been that customers have come to appreciate the stability and predictability of electricity rates. The ECAM is an effective measure in meeting this objective.

As well, the Commission's preference for multi-year rate setting is stated at paragraph 29 of Order UE16-04R:

> *"Multi-year agreements, whenever possible, are to be encouraged as allowing for rate stability and decreasing the cost of regulation – a cost that is ultimately borne by taxpayers."*

Thus, the use of the ECAM to capture variations in energy supply costs over multi-year rate setting periods supports customer rate predictability and eliminates the need for frequent and costly hearings to adjust customer rates in response to changes in energy supply costs.

IR-18 According to Schedule 8-2 (page 44), MECL will be capacity deficient by one MW in 2020 and 2021. MECL's capacity deficiency will increase further in 2022, upon the shutdown of the final 38 MW of CTGS capacity. Is this correct? If not, please explain why not.

a. What is the long-term plan to replace this capacity deficiency?

b. Is it correct to conclude that if CTGS is not operational as of 2022, and there is no additional capacity acquired on PEI beyond the projected additional wind turbines, that PEI will be required to obtain 60% [(105+29+38) or 172 of its 286 MW] of its capacity needs from New Brunswick?

Response

a. Schedule 8-2 has been expanded below to show years 2022 and 2023:

Schedule 8-2 Expanded to include 2022-2023						
Maritime Electric Generating Capacity Requirement (MW)						
	2018	**2019**	**2020**	**2021**	**2022**	**2023**
Maritime Electric capacity requirement (MW):						
- Maritime Electric peak load	244	256	265	266	272	282
- less impact of DSM	0	1	2	3	6	7
- less interruptible load	14	14	14	14	14	14
- plus 15% planning reserve	34	36	37	37	38	39
	264	277	286	286	290	300
Maritime Electric capacity resources (MW):						
- Charlottetown Thermal Plant	55	48	38	38	-	-
- Borden Plant	40	40	40	40	40	40
- Combustion Turbine 3	49	49	49	49	49	49
- Point Lepreau (at Murray Corner)	29	29	29	29	29	29
- Wind ELCC	21	21	24	24	24	24
- Short-term capacity purchases	80	95	105	105	145	145
Subtotal	274	282	285	285	287	287
Surplus (deficit)	10	5	(1)	(1)	(3)	(13)

Maritime Electric has purchased short-term capacity through the EPA until the end of the EPA contract term in February 2024, but has not secured short-term capacity beyond that. In the event of a capacity shortfall during the EPA term, Maritime Electric has the option to increase the short-term capacity purchases with sufficient notice. As such, the capacity deficiencies in 2020 and 2021 due to the staged shutdown of the CTGS have been provided for through a) short-term capacity purchases from New Brunswick in the new EPA, and b) additional short-term capacity purchases from New Brunswick to cover the projected shortfall.

In addition, Maritime Electric determined that it would encounter a capacity shortfall in 2019 due to higher load increases than previously forecast. The updated capacity purchases are highlighted in the updated Schedule 8-2 below:

Schedule 8-2 Expanded and Updated with Recent Short-Term Capacity Purchases						
Maritime Electric Generating Capacity Requirement (MW)						
	2018	**2019**	**2020**	**2021**	**2022**	**2023**
Maritime Electric capacity requirement (MW):						
- Maritime Electric peak load	244	256	265	266	272	282
- less impact of DSM	0	1	2	3	6	7
- less interruptible load	14	14	14	14	14	14
- plus 15% planning reserve	34	36	37	37	38	39
	264	277	286	286	290	300
Maritime Electric capacity resources (MW):						
- Charlottetown Thermal Plant	55	48	38	38	-	-
- Borden Plant	40	40	40	40	40	40
- Combustion Turbine 3	49	49	49	49	49	49
- Point Lepreau (at Murray Corner)	29	29	29	29	29	29
- wind ELCC	21	21	24	24	24	24
- short-term capacity purchases	80	**105**	**110**	**110**	145	145
Subtotal	**274**	**292**	**290**	**290**	**287**	**287**
Surplus (deficit)	**10**	**15**	**4**	**4**	**(3)**	**(13)**

Planning capacity is the minimum amount of capacity that is required under contract, and additional capacity may be needed to meet day-to-day operational requirements, as is the case for Maritime Electric in 2019. Maritime Electric has not yet purchases additional short-term capacity to cover projected shortfalls in 2022 or 2023, as the Company is waiting until closer to the time to get a better idea of its needs.

The NB Power Integrated Resource Plan shows a surplus of generating capacity in New Brunswick until 2027, at which point the Mactaquac Generating Station is scheduled to be taken offline for major restorative work. There may be generating capacity deficiencies in the region while the Mactaquac project is ongoing unless additional capacity is added beforehand.

b. The above table is for Maritime Electric only, which supplies 90% of the PEI load. The table shows that Maritime Electric's on-Island generation capacity after the planned decommissioning of the CTGS will be as follows:

	MW
Borden CT1 and CT2	40
Charlottetown CT3	49
Wind ELCC	24[2]
Total	113

Thus Maritime Electric will be required to obtain 60% of its generating capacity off-Island after the closure of the CTGS.

[2] Addition of 30 MW of PEI Energy Corporation wind energy generation to MECL's supply portfolio in 2020 increases wind ELCC by only 3 MW.

IR-19 Also with respect to Schedule 8-2 (page 44):

a. What is MECL's current capacity for on-island generation?

b. What will MECL's capacity for on-island generation be after the planned decommissioning of the CTGS?

c. In the event MECL's on-island generation capacity is less than peak load, how does MECL intend to furnish reasonably safe and adequate service in the event energy that is purchased from New Brunswick cannot be transmitted to PEI (due, for example, to issues with the cables, the NB transmission system, etc.)?

Response

a. Maritime Electric's current (2019) capacity for on-Island generation is as follows:

	MW
Borden CT1 and CT2	40
Charlottetown CT3	49
CTGS	48
Wind ELCC[3]	21
Total	158

b. Maritime Electric's capacity for on-Island generation after the planned decommissioning of the CTGS will be as follows:

	MW
Borden CT1 and CT2	40
Charlottetown CT3	49
Wind ELCC	24[4]
Total	113

c. Off-Island supply can be limited due to both transmission and generation issues.

Total Loss of Transmission

In order for the New Brunswick (NB) supply to be lost completely, there has to be one of the following transmission issues:

a. Loss of all three 138 kV lines connecting the Memramcook substation to PEI;
b. Collapse of the local southeastern NB transmission system, such that supplies to the Island are lost; or
c. Collapse of the entire NB transmission system.

[3] ELCC – Effective Load Carry Capability
[4] Addition of 30 MW of PEI Energy Corporation wind energy generation to MECL's supply portfolio in 2020 increases wind ELCC by only 3 MW.

Situation b) (collapse of the local southwestern New Brunswick transmission system) most recently occurred on November 29, 2018 when two of the three transmission lines supplying the Memramcook substation tripped offline due to storm conditions, and the remaining line subsequently tripped offline due to thermal overloading.

Complete loss of the interconnection with NB is a rare occurrence; the last full Island outage happened in 2007 when agricultural equipment contacted one overhead 138 kV line near the Searletown Rd (PE) and tripped both the line and its adjoining submarine cable. This caused an overload on the remaining submarine cable, which tripped off due to thermal overload, cutting all supply to the Island. The addition of the two new submarine cables and Borden Riser Station has diversified the on-Island interconnection resources, meaning loss of a single transmission element on-Island (cable or line) will not result in a total loss of supply from the mainland.

Following an unplanned loss of the NB connection, all Island load would likely be lost because Maritime Electric's generation – which is used for backup and emergency purposes – is typically offline, and wind generation cannot supply load on its own as it does not regulate system voltage or frequency. Maritime Electric would supply as much load as possible with available on-Island resources; however there would be rolling blackouts until the New Brunswick connection was restored.

Transmission Constraint
A more likely scenario of supply limitation from NB due to transmission issues is a limitation due to the existing transmission constraint in southeastern NB. Currently the maximum firm transmission capacity across the NB-NS/PEI interface is 300 MW, based on the worst single contingency event on the NB transmission system. However, situations can arise in NB or Nova Scotia that result in the transfer capacity becoming less than 300 MW.

If the amount of transmission available for Maritime Electric supply were to be reduced to less than the amount of firm generating capacity that Maritime Electric has contracted for from NBEM (in 2019 it is 105 MW[5] of short term firm capacity plus 29 MW from Point Lepreau), Maritime Electric must shed firm load. Maritime Electric does not share this responsibility alone; to the extent Maritime Electric sheds firm load, NB Power is contractually required to shed a corresponding amount of load in southeastern NB, and Summerside would have obligations to shed an amount of firm load as well.

Generation Shortage
A further scenario would be a severe generation shortage in the region, causing a temporary restriction on what could be delivered to Maritime Electric. In this scenario, Maritime Electric would be required to shed firm load if NB Power could not deliver the full amount of the firm generating capacity that Maritime Electric has contracted for from NBEM. To the extent that Maritime Electric must shed firm load, NB Power is contractually required to shed a corresponding amount of load, and Summerside may have obligations to shed an amount of firm load as well.

[5] Recently increased from 95 MW; see table in IR-18.

IR-20 What is the lead time for the construction of new generation capacity on PEI?

Response

The lead time for construction of new dispatchable generation capacity on PEI is estimated to be approximately two years from receiving Regulatory approval. This estimate is based upon current unit deliveries.

IR-21 What is the maximum amount of grid capacity that is recommended to be provided from any one generating source?

<u>Response</u>

Maritime Electric is limited to a maximum of 30% of its grid capacity from any one generating source, according to the existing *Interconnection Agreement Between The New Brunswick Electric Power Commission and Maritime Electric Company, Limited and Maritime Electric (P.E.I.) Limited (August 1981)*.

Supplement III contained within this agreement states the following:

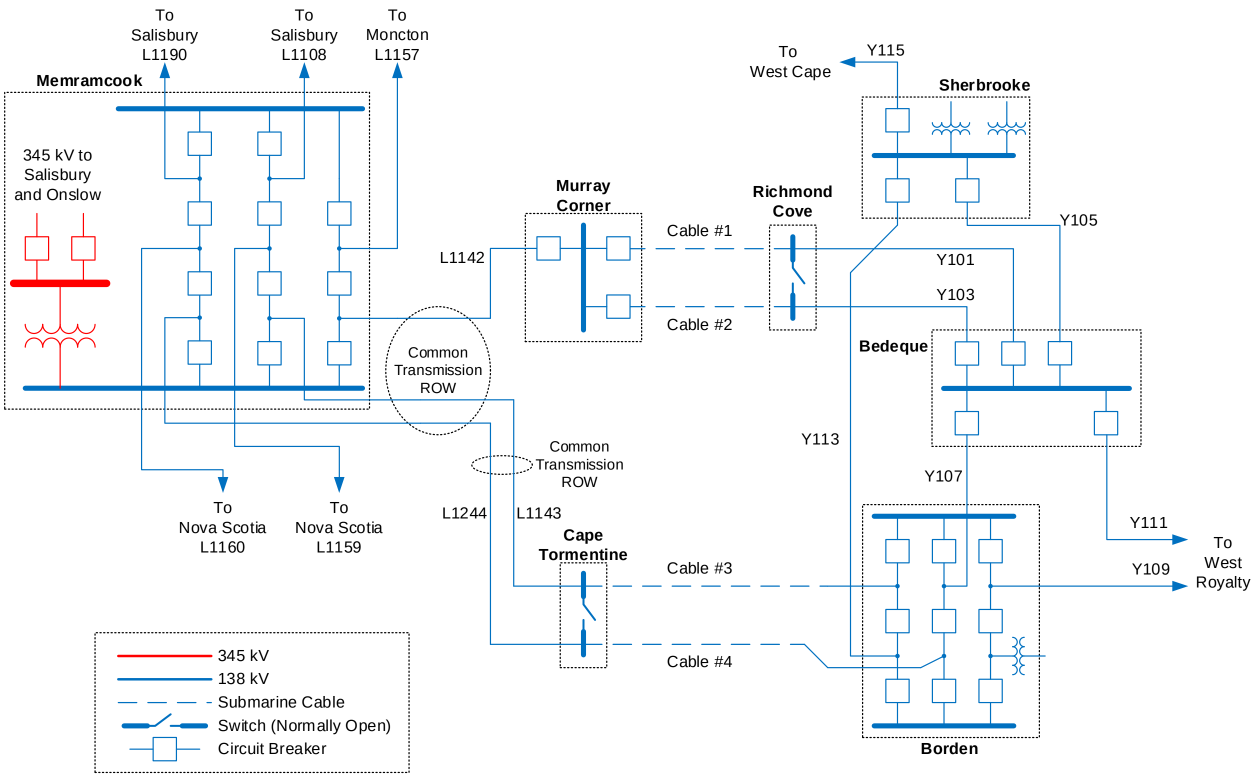
> *"<u>Capacity Deficiency</u>*
> *Additions to the MECL system either through the installation of new units or the purchase of firm capacity must be no larger than 30% of the MECL Accredited Demand in any year unless by mutual agreement."*

IR-22 Even if the New Brunswick supplied generation is not all from one source, is it good utility practice to have the delivery of this energy over one transmission line (namely, the NB line to Murray Corner)?

Response

There are three separate 138 kV transmission lines in New Brunswick that connect to the submarine cables – one line (L1142) that connects the Memramcook NB substation to the Murray Corner NB switching station, and two lines (L1143 and L1244) that connect Memramcook to the Cape Tormentine Cable Riser Station. There are two submarine cables between the Murray Corner substation and PEI, and two submarine cables between Cape Tormentine and PEI. The three 138 kV transmission lines in New Brunswick share a common transmission corridor for roughly 40 km before diverging.

The following is a diagram of the interconnection facilities between Memramcook, New Brunswick and PEI.



It is considered good utility practice to have both base load and backup supplies sourced from a variety of geographically-dispersed resources, so that supplies can be reasonably assured during weather related and contingency events.

The reason behind the 30% upper limit of generation capacity from one source (as explained in IR-21) is to ensure that Maritime Electric does not overly rely on one source for its generating capacity. Generation is inherently less reliable than transmission – generators typically have 90

– 95% reliability, while transmission is typically in excess of 99%.

After the CTGS has been decommissioned, Maritime Electric will be obtaining 60% of its generating capacity from off-Island sources through the single transmission corridor. While loss of all three lines is considered a low-risk of occurrence event, there is a possibility that such an outage could occur during an extreme weather event. Additional on-Island diesel-fired combustion turbine generation would reduce the impact of a loss of the transmission corridor.

IR-23 What assurances (if any) does MECL have that the new 30 MW wind farm will be operational by September 2020? If the new wind farm is not operational by September 2020, how does MECL intend to provide both energy and capacity?

Response

Other than verbal communications with the PEI Energy Corporation on the progress of the project confirming:

i. The Environmental Assessment process has been initiated;
ii. The Request for Proposals for the procurement of Turbines has been issued; and
iii. The Request for Proposals for Project Management has been issued.

Maritime Electric has no further assurances that the new 30 MW wind farm will be operational by September 2020. Maritime Electric will purchase energy under the Energy Purchase Agreement to meet its requirements in the event the project timeline of the new 30 MW wind farm is protracted.

The new 30 MW wind farm will provide only 3 MW of additional generating capacity to Maritime Electric and therefore a small amount of capacity will have to be purchased if completion of the wind farm is delayed.

IR-24 The application states that although MECL intends to place the Charlottetown Plant into long-term layup starting in March 2019, it is subject to a 90 day return to service requirement under the Energy Purchase Agreement (see page 48). Please explain what is meant by this, with specific reference to all relevant provisions of the Energy Purchase Agreement.

Response

The new Energy Purchase Agreement (March 1, 2019 – February 29, 2024) provides for an Assured Energy product of up to 50 MWh/h that is backed-up by capacity. Assured Energy is energy for which the pricing can be changed after the provision of written notification to Maritime Electric from NB Energy Marketing. The notification specifies a period of time after which the Assured Energy can be Interrupted or Curtailed on ten minutes' notice.

The Assured Energy product is intended to minimize the operation of Maritime Electric's generating resources while Maritime Electric provides backup using Maritime Electric's available operable capacity.

The Assured Energy product is backed-up as follows:

- Summer Period – during the Summer Period the Assured Energy product is capacity backed under contract with NB Energy Marketing (NBEM) during the first 90 days of the Notification Period then backed by the CTGS if the event continues beyond the 90 days.

- Winter Period - during the Winter Period the Assured Energy product is capacity backed by the Borden Generating Station (BGS) during the first 90 days of the Notification Period and then by the CTGS if the event continues beyond the 90 days. During the "Winter Period" Maritime Electric will purchase 10 Minute and 30 Minute Supplementary Non-Spinning Reserve from the NBP-System Operator.

The longer return to service period of 90 days is due to the longer time frame that would be required to remove steam boilers and steam turbines from long-term layup in preparation for operation. The 90 day return to service period also accommodates a reduced compliment of CTGS operating staff. Many CTGS operating staff employees have been re-trained and have been redeployed to other Maritime Electric departments in order to more efficiently utilize these labour resources until such time as the completion of the CTGS decommissioning project proposed for 2022/2023. The 90 day period will provide Maritime Electric management with enough time to bring these redeployed staff back to the CTGS, to temporarily backfill their positions in the other Maritime Electric departments and to provide refresher safety and operations training for the staff returning to operate the Steam Plant.

IR-25 On page 49, it is stated that CT3 is, in addition to its peaking purposes, to be used during periods of curtailment of contract energy and transmission curtailment by New Brunswick. Please provide the full contractual provisions which would lead to a curtailment of either contract energy or transmission.

Response

CT3, in addition to its use for peaking purposes, is dispatched for periods of a) curtailment of contracted Secure Energy, and b) transmission curtailment by the NBP-System Operator (NBP-SO).

In the case of curtailment of the contracted Secure Energy product, NB Energy Marketing (NBEM) will communicate to Maritime Electric that a Notification Period has begun. Both the current EPA and the new EPA have Summer Notification Periods (from April 1st to October 31st) and Winter Notification Periods (from November 1st to March 31st). The Summer Notification Period is one week, while the Winter Notification Period is 24 hours. As part of the contract, NBEM will backstop the Secure Energy during the Notification Period, and Maritime Electric is responsible for backstopping the Secure Energy after the Notification Period has ended. Once Notification has been provided, the price of the energy can be curtailed on ten minutes' notice.

Transmission Curtailments are not necessarily contractual but they are required based on the NB Power Open Access Transmission Tariff (OATT). When the NB transmission system becomes constrained - in particular the Southeast quadrant of New Brunswick (which impacts the Nova Scotia /PEI interface) - or there is a thermal overload or outage on any of the transmission lines feeding PEI, the constraint would be communicated in the form of a Short Term Operating Procedure (STOP). The STOP identifies whether the issue is generation-related, transmission-related or both, as well as other contingencies of concern. The STOP would also indicate the limitation on the interface and post-contingency actions.

In the circumstance that Maritime Electric had submitted an energy schedule on the interface, the NBP-System Operator (NBP-SO) would curtail the energy to the Limitation amount and Maritime Electric would then be required to dispatch CT3 to generate the curtailed amount. If the schedule was submitted based on the Limitation and Maritime Electric's load was higher, the NBP-SO would issue a "Hold to Schedule" for the hour and Maritime Electric would be required to dispatch CT3 to generate the required energy to satisfy the Hold to Schedule. The most common cause for a Hold to Schedule is on-Island wind production being less than forecast.

IR-26 Please provide justification for the internal labour costs for the Energy Control Centre Operations (see pages 50-51), together with supporting documentation. Please explain why the labour costs are forecasted to increase in each of 2018, 2019, 2020 and 2021. Please provide all calculations and supporting documentation in support of the forecasted labour costs.

Response

2017

In 2017, Maritime Electric transitioned its ECC staffing from having three 'Spare' ECC System Operators to having two 'Floating' ECC System Operator positions.

Previously, Spare System Operators were seconded from other Maritime Electric departments on a part-time basis to cover-off vacations, sick time, and other absences throughout the year. However, their substantive position remained in another Maritime Electric Departments (outside of the ECC).

This method of operation worked most of the time; however, there were times when the secondment occurred during the other department's busiest work period. This conflict negatively impacted the other department when they were seconded to the ECC, or the request for a secondment to the ECC was denied.

In early 2017, two float positions were created for the Energy Control Centre, one was filled in late 2017 and one in mid-2018. These positions are based out of the ECC (e.g. substantive position) and when the employees are not required to work at the ECC they are redeployed to a position in another department where they are qualified to work. This enables the float position to fulfill the needs of the ECC to cover off vacations, sick time and other absences without drawing upon other departments' labour resources. The float position also provides the flexibility within the ECC to provide necessary training and to prepare operating procedures and documentation.

2018

In 2018, due to the timing of the 2nd float position, the total cost for the year was only for six months for that position. The first ECC float position was at the ECC for the entire year. The increase in costs also included other operations costs as well as inflationary cost adjustments.

2019

In 2019, the increase is mainly due to the two full-time ECC float positions for the entire year as well as inflationary cost adjustments.

2020 and 2021

The increase in costs in these two years includes inflationary cost adjustments.

Support schedules are provided in IR-26 - Attachment 1 of this response.

IR-27 With respect to Amortization of Deferred Charges (page 53):

a. Please provide justification for recovering costs on behalf of the Province through the Energy Cost Adjustment Mechanism ("ECAM").

b. At page 15 of the application, MECL states that PEIEC intends to restructure the financing with fixed repayment terms. If the costs are fixed and not variable, why should they be recovered through ECAM?

c. How are costs recoverable on behalf of the Province currently collected and remitted? If the costs are not currently recovered through the ECAM, please explain why Maritime Electric is proposing a change in the collection method.

d. If the Commission does not approve the collection of Provincial costs recoverable through the ECAM, what (if any) impact will this have on the proposed rates?

e. If the Commission does not approve the collection of costs recoverable through the ECAM, is there any justification for the increased ECAM base rates set out in Schedule 5-1 (page 20)?

f. At page 15, MECL states that recovering the Provincial costs as energy related costs "*will eliminate the variability in the monthly repayment amount associated with a rate rider based on monthly consumption levels*". Please explain and provide justification for this statement.

g. What (if any) impact will there be on the proposed rates if the Provincial costs are recovered by a rate rider?

Response

The energy supply expenses outlined in Page 53 of the GRA application relate to the following categories of cost:

1. <u>PEI Energy Corporation Dalhouse and Lepreau Debt Repayment</u>
These costs are discussed in Section 4.1 of the application wherein the Company proposes to amend the Debt Collection Agreement with the PEI Energy Corporation and establish fixed repayments terms, and recovery through ECAM, for Costs Recoverable from Customers on behalf of the Province.

2. <u>Amortization of Deferred Charges</u>
These costs are discussed on Page 53 of the application and include the following;

    a. Annual amortization of the Company's share of the 1998 writedown of the Point Lepreau Nuclear Generating Station as per Order UE05-08;
    b. Annual amortization of the Company's DSM programming costs for public outreach and education as per Order UE15-02. The recovery of DSM costs through ECAM was approved by IRAC Order UE08-02; and
    c. Year 1 target funding requirements of the PEI Energy Corporation's: Electricity

Efficiency and Conservation Plan 2018-2021 as discussed in Section 4.2 of the application. These costs have been incurred and recorded in 2017 and 2018 only. There are no related costs in the 2019-2021 period as the PEI Energy Corporation's programming costs are proposed to be recovered as a rate rider on customer bills.

a. Please refer to the response to IR-2 (c). The recovery of costs on behalf of the Province relates to the Dalhousie and Lepreau Debt Repayment as discussed in Section 4.1 of the application.

b. Please refer to the response to IR-2 (c).

c. Since March 1, 2011, electricity rates charged to customers have included a rider on the rates for the collection of costs recoverable from customers on behalf of the Province. The current rate rider is $0.00536/kWh. These amounts are collected monthly through customer electricity billings and remitted to the Province by the 7th business day of the following month pursuant to Section 3 of the Debt Collection Agreement.

Please refer to the response to IR-2 (c).

d. If the Commission does not approve the collection of Provincial Debt Repayments through ECAM it will not have any impact on the rates proposed in the GRA. As shown in the table below, if the debt service costs for the Lepreau and Dalhousie debt are treated as an operating cost not recovered through ECAM, the costs will move from an energy supply cost to other operating costs with no material change to revenue requirement:

Impact of Not Approving the Collection of Provincial Costs Recoverable Through ECAM				
Description	**GRA Reference**	**2019 Forecast**	**2020 Forecast**	**2021 Forecast**
Proposed Energy Supply Expenses	Schedule 8-4	$ 128,543,600	$ 134,807,900	$ 136,509,600
Proposed ECAM Adjustment	Schedule 14-2	(1,557,700)	(2,408,100)	(327,300)
Proposed Energy Supply Costs, net of ECAM		126,985,900	132,399,800	136,182,300
Revised Energy Supply Expenses		$ 123,760,400	$ 129,068,000	$ 130,788,300
Revised ECAM Adjustment		(1,556,600)	(2,409,200)	(323,200)
Revised Energy Supply Costs, net of ECAM		122,203,800	126,658,800	130,465,100
Decrease in Energy Supply Costs, net of ECAM		(4,782,100)	(5,741,000)	(5,717,200)
Increase in Other Operating Costs		4,783,200	5,739,900	5,721,300
Change in Revenue Requirement		$ 1,100	$ (1,100)	$ 4,100

e. If the Commission does not approve the recovery of the Provincial Costs through ECAM, the ECAM base rate would need to be adjusted to reflect the lower energy supply costs. The table below shows the revised ECAM Base Rates associated with excluding these costs from ECAM. As discussed in the Company's response to IR-3, the ECAM rates proposed include a stabilization factor or adjustment over the three year rate setting period. This stabilization adjustment would change as well. However, the ECAM base rate is set such that all proposed energy supply related costs are recovered by the end of the three year rate period.

Revised Calculation of Annual ECAM Base Rate					
Description	**GRA Reference**		**2019 Forecast**	**2020 Forecast**	**2021 Forecast**
Energy Supply by Source ($)	Schedule 8-4	A	$ 128,543,600	$ 134,807,900	$ 136,509,600
Less: PEIEC Lepreau & Dalhousie Debt Repayments			(4,783,200)	(5,739,900)	(5,721,300)
Revised Energy Supply Costs			$ 123,760,400	$ 129,068,000	$ 130,788,300
Net Purchased and Produced Energy X 1000 (GWh converted to kWh)	Schedule 8-3	B	1,365,034,762	1,401,254,102	1,423,094,943
Energy Supply Cost per kWh		C = A / B	$ 0.09066	$ 0.09211	$ 0.09190
Rate Stability Adjustment		D	(0.00161)	(0.00141)	-
Revised ECAM Base Rates (March 1 - February 28)	**Schedule 5-1**	**C + D**	**$ 0.08905**	**$ 0.09070**	**$ 0.09190**

f. It is not the Company's application that recovering the Provincial costs recoverable as an energy related cost will eliminate the variability in the monthly repayment. Rather, it is the ability and intent of the PEI Energy Corporation to refinance the debt (after receipt of the settlement proceeds) with fixed repayment terms that eliminates the variability in the repayment in comparison to the rate rider approach to collections currently used.

This variability associated with a rate rider is illustrated in Schedule 4-1 of the application. From 2015 – 2017, when the rate rider was $0.00536/kWh, the amounts collected and remitted to the Province varied each year from $6,345,495 to $6,475,192.

g. Section 5.1 of the Debt Collection Agreement states that the Debt Collection rates are intended to provide the Province with full recovery of the debt and associated financing. Further, Section 5.5 of the Agreement enables the Province to seek an annual adjustment to the collection rates to take effect on March 1 each year if so required to ensure full recovery. Any impact on customer electricity costs related to recovering the Provincial Cost Recoverable as a rate rider will be dependent upon the rate proposed by the PEI Energy Corporation for the rider and the frequency with which the rate is changed.

It is both the Company's and the PEI Energy Corporation's view that the ability and intent of the PEI Energy Corporation to refinance the Debt will facilitate the establishment of a fixed monthly repayment amount which will provide stability and predictability for customer electricity rates. Confirmation from the PEI Energy Corporation of this planned amendment is included with this response as IR-2 – Attachment 3. The recovery of the Debt as a fixed amount rather than a rate rider reflects the intention of the parties.

IR-28 Also with respect to Amortization of Deferred Charges (page 53), please explain and provide justification for recovering DSM expenditures through the ECAM.

Response

The recovery of the DSM expenditures through ECAM is based upon past Orders UE-08-02 and UE15-02. These orders have addressed DSM costs and directed recovery through the ECAM. Order UE-15-02 in particular relates to the current DSM costs related to the Company's annual public outreach and education programming.

Section 10 – General and Administrative Expenses

IR-29 Please provide a detailed breakdown of the external and internal costs for the Corporate Services and Support expenses contained in Schedule 10-1 – General and Administrative Expenses (page 65).

a. Which of these costs are incurred by, or reimbursed to, Fortis or any other Fortis related company?

b. Please provide details on the Employee Future Benefit Costs in Schedule 10-2. Including details on the previous treatment of the identified gain and forecasts for this account.

Response

THE RESPONSE HAS BEEN FILED WITH THE COMMISSION ON A CONFIDENTIAL BASIS.

IR-30 What is MECL's policy on the payment of director's fees? Please provide a copy of the policy.

Response

THE RESPONSE HAS BEEN FILED WITH THE COMMISSION ON A CONFIDENTIAL BASIS.

IR-31 Please provide a detailed breakdown of compensation paid, or forecasted to be paid, to MECL's senior management and executive position employees for the years 2016 to 2022 (inclusive). The breakdown should clearly show the compensation paid to each senior management and executive position, identifying the title of the position and a breakdown of the compensation paid by salary, bonus(es), stock option(s), and any other compensation paid or payable.

Response

THE RESPONSE HAS BEEN FILED WITH THE COMMISSION ON A CONFIDENTIAL BASIS.

Section 11 – Amortization Expenses

IR-32 Is it correct to conclude that the CTGS contributes to neither the capacity nor energy needs for MECL after 2021 when Units 9 and 10 of the CTGS are shut down (pages 48 and 85)?

Response

Correct. Under the terms of the Energy Purchase Agreement with NB Power and in accordance with the Company's Decommissioning Plan, the CTGS is scheduled for full closure by January 1, 2022 with planned decommissioning in 2022 and 2023.

IR-33 If CTGS will not be operational after 2021, why continue to amortize the proposed regulatory deferral account during 2022-2023, or for any period beyond 2021, other than to counter potential rate shock?

Response

The impact on customer electricity costs associated with shortening the amortization period to 2019 – 2021 is an important consideration in setting an appropriate time period over which to recover the remaining costs related to the CTGS. Since the Commission last reviewed and set depreciation rates in Order UE16-04 based upon the 2014 Depreciation Study, the following factors have impacted the estimated remaining costs to be recovered related to the CTGS:

- recommended depreciation rates from the 2014 Depreciation Study starting January 1, 2015 were not implemented until January 1, 2016;
- the cost to decommission the CTGS increased from preliminary estimates of $6.2 million in the 2014 Depreciation Study to $11.298 million based upon the 2018 Decommissioning Study prepared by GHD;
- the 2017 Depreciation Study proposes new depreciation rates effective January 1, 2018, however, depreciation rates are set by Order UE16-04 until 2019; and
- the revised depreciation rates reflect the assumed end of life (capacity and energy) timelines for the various turbines and boiler units based upon the recognized availability of the units under the EPA with NB Power.

The proposed regulatory deferral account amortization will also enable the Company and IRAC to address any variances associated with the estimates and timelines discussed above. In particular, the various factors impacting the estimated decommissioning costs will not be known or realized until 2022 and 2023 when decommissioning is planned to occur. There will inevitability be a residual variance to be recovered from or returned to customers upon completion of the CTGS decommissioning. Setting the amortization period from 2019 to 2023 will assist in capturing and understanding these changes over the decommissioning period while mitigating the overall impact on customer electricity costs during this period.

IR-34 Is it correct that if the reserve variance account were amortized over three years (2019-2021) that the amortization expense related to CTGS, together with the deferral, would amount to $5.415 million per year? (see page79)

a. Does this calculation assume that IRAC will approve the revised amortization as of January 1, 2019?

Response

The application filed with respect to depreciation rates and reserve variance amortization is based upon the application of new depreciation rates and amortization periods as of January 1, 2019.

There are two components related to the projected depreciation of the CTGS: depreciation of the remaining gross asset value and amortization of the projected accumulated reserve variance at December 31, 2018. The $5.415 million referenced on Page 79 of the application relates only to projected impact on amortizing the accumulated reserve variance over the 2019 – 2021 time frame.

In Appendix 11 of the application, the Company outlines the proposed annual depreciation of the remaining gross asset value and the amortization of the projected accumulated reserve variance over the 2019 -2023 period. As shown in Appendix 11, the total estimated amount to be depreciated and amortized is $24,960,558 which, if recovered over the three year period from 2019 to 2021 would result in an combined annual depreciation and amortization of $8,320,186 ($24,960,558)/3 years).

IR-35 What effect on customer rates would occur if the revenue variance account is amortized only until CTGS is decommissioned (that is 2019-2021)?

Response

Appendix 10 of the application presents the projected accumulated reserve variance at December 31, 2018 related to the CTGS to be $16.245 million. On Page 79 of the application, the Company states:

> *Assuming this projected balance is amortized over the remaining three year period from 2019 – 2021, the amortization of the accumulated reserve variance would increase by approximately $3.314 million,"*

Based on annual electricity sales revenue of approximately $195 million, an increase in the CTGS reserve variance amortization of $3.314 million would result in a one time annual increase in the Company's revenue requirement and resulting customer electricity costs of approximately 1.7% ($3.314 million/$195 million).

IR-36 Please provide all working papers and calculations to support the depreciation and reserve variance amortization forecasts in electronic form. In addition, include support for Appendix 9, 10 and 11.

Response

The working papers and calculations to support the proposed depreciation and reserve variance amortization forecasts are provided as IR-36 - Attachment 1 to this response as well as in electronic format.

IR-37 MECL proposes to only amortize the accumulated reserve variance account by the variance for CTGS over a five year period. However, there is no attention given to the approximate $23 million variance identified at the Distribution Plant. Please explain why this variance has not been proposed to be dealt with in the current application.

a. What (if any) impact will there be on the proposed rates if the Distribution Plant reserve variance is amortized over the remaining useful life of the assets?

Response

Schedule 11-3 of the application contains the calculated accumulated reserve variances and recommended annual amortization by asset class from the 2017 Depreciation Study prepared by Gannett Fleming. The study indicates an accumulated reserve variance for Distribution Plant of $22.931 million and a recommended annual amortization of $1.090 million.

Based on annual electricity sales revenue of approximately $195 million, an increase of $1.090 million in annual depreciation to recover the accumulated reserve variance for Distribution Plant would result in a one-time annual increase in the Company's revenue requirement and resulting customer electricity costs of approximately 0.6% ($1.090 million/$195 million).

The Company recognizes that to further adopt some or all of the Gannett Fleming recommendations for the other asset classes would result in additional increases in depreciation expenses and resulting increased customer electricity rates. The proposals in the application relating to deprecation are intended to maintain a reasonable balance between the rate impact on customers and the need to maintain good utility practice with respect to depreciation policy with appropriate adjustments to depreciation rates over a reasonable and prudent period of time.

The other recommendations in the Gannett Fleming Study will be reviewed as part of future depreciation study updates and addressed in further applications to the Commission.

Section 12 – Financial Objectives

IR-38 Please explain what is meant by a “non-regulated equity contribution” (pages 90-91).

a. Please provide the amount of the non-regulated equity contributions for 2016 and 2017, as well as the forecasted non-regulated equity contributions for 2018-2021 (inclusive).

b. Please provide justification for non-regulated equity contributions, having particular regard to the common equity requirements in section 12.1 of the *Electric Power Act*.

c. Please explain why the non-regulated dividends for 2018 are significantly higher than those in 2016 and 2017, and than those forecasted for 2019-2021.

d. Please provide a description of the process MECL uses to forecast regulated and non-regulated dividend payouts.

Response

The non-regulated equity contribution refers to the net tax savings to Maritime Electric associated with the annual transfer of Part VI.1 tax payable by Fortis Inc. as permitted under the Income Tax Act. Under Canadian accounting rules, the net tax savings are to be accounted for as an equity contribution from Fortis. The following is an illustration of the calculation of this amount based upon the 2018 Part VI.1 transfer:

Part VI.1 Tax Transfer	$ 3,500,000	(A)
Deduction against Taxable Income (3.5 x A)	$ 12,250,000	(B)
MECL Tax Rate	31%	
MECL Tax Savings	$ 3,797,500	(C)
Non-Regulated Equity (net tax savings)	$ 297,500	(C) – (A)

In this illustration, Maritime Electric pays $3,500,000 in Part VI.1 tax which provides savings on the tax on its regular taxable income in the amount of $3,797,500. The net benefit or savings, under Canadian accounting rules constitutes an equity contribution from Fortis and since it does not relate to the regulated operations of the Company, it is classified as non-regulated equity. As a non-regulated equity contribution, the Company does not earn a regulated return on this amount so it is returned to Fortis as a non-regulated dividend either in the year of transfer or in the immediately following fiscal year.

a. As noted above, non-regulated equity contributions are returned to the parent in the year received or in the immediately following fiscal year. The following schedule shows the non-regulated equity contributions received and the non-regulated dividends paid for 2016 – 2018 and forecast for 2019 – 2021.

Non-Regulated Equity							
($millions)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**Net**
Contribution Received	0.298	1.247	0.298	0.298	0.298	0.298	
Dividend Paid	(0.298)	(0.298)	(1.247)	(0.298)	(0.298)	(0.298)	
Net	-	0.949	(0.949)	-	-	-	-

b. Section 12.1 of the Electric Power Act establishes the minimum and maximum amount of common equity the Company is required to have invested in the power system. Non-regulated equity contributions do not relate to the power system (regulated operations) and as such are not subject to Section 12.1 of the Electric Power Act.

As discussed in the response above, non-regulated equity contributions are returned to the parent in the year received or in the immediately following fiscal year. Where the non-regulated equity has not been returned in the year received (for example, 2017), the amount is excluded from the Company's regulated common equity and regulated return on average common equity calculations for that year. As a result, there is no return or earnings associated with this equity and hence no impact on customers.

c. In 2017, the Company had originally planned a Part VI.1 transfer that would result in a $0.298 million non-regulated equity contribution. However, before the end of the 2017 fiscal year, the Company elected to increase the amount of Part VI.1 tax transfer from Fortis resulting in a non-regulated equity contribution in 2017 of $1.247 million.

Since the Company's Board of Directors had only approved payment of non-regulated dividends of $0.298 million in 2017, the remaining $0.949 million in non-regulated equity was retained until 2018. In 2018, the Company's Board of Directors approved the payment of the remaining $0.949 million as a non-regulated dividend as illustrated in the table in response (a) above.

d. The forecast of non-regulated dividends is determined by the expected amount of the Part VI.1 tax transfer from Fortis for the year and the resulting non-regulated equity contribution to be recorded.

The forecast for regulated dividend payments is based upon the Company's regulated capital structure (Debt and Equity) forecast for the year, its financial objectives of maintaining a target debt to equity ratio of 60 : 40 and the legislative requirements of Section 12.1 – Common Equity of the Electric Power Act.

Regular or regulated dividends are forecast at such levels so as to ensure compliance with the minimum and maximum equity requirements of Section 12.1 and to keep the average common equity percentage for the year as close to the 40% target as possible.

IR-39 In Section 12, MECL states that it is seeking a return on average common equity of 9.35% based on 40% average common equity:

a. In the General Rate Application filed by Maritime Electric on October 28, 2015 in Commission Docket UE20942 (the "2016 GRA"), MECL was seeking a return on average common equity of 9.7% and a return on average rate base of 7.64%. What return on average rate base is MECL seeking in the present application? If MECL is not seeking a return on average rate base, please explain why.

b. In the 2016 GRA, MECL derived its revenue requirement based, *inter alia*, on the return on average rate base (see 2016 GRA at page 141). In the present application, MECL derived its revenue requirement based, *inter alia*, on the return on average common equity (see page 152). Please explain and provide justification for this change in the derivation of the revenue requirement.

c. What would MECL's estimated revenue requirement be in the present application if it was derived from the return on average rate base, rather than the return on average common equity?

Response

a. Since returning to cost of service regulation under the Electric Power Act effective January 1, 2004, the Company has, with the exception of the period of the PEI Energy Accord (2011 – 2015), filed General Rate Applications to set its annual revenue requirement and the resulting customer electricity rates. Those applications included the proposed rate of return on average common equity to be included in both revenue requirement and in the calculation of return on average rate base.

Although the Commission has directed the Company to report annually on both its return on average common equity and return on average rate base, the Commission's orders with respect to setting the Company's allowable maximum rate of return (earnings) have been based only upon the rate of return on average common equity. As a result, the Company has not filed application on the return on average rate base calculation in the present application before IRAC.

The derivation of the return on average rate base is a function of the Company's average capital structure (debt and equity), average rate base and the weighted average cost of capital which is based upon the allowed return on average common equity.

As a formula,

$$\text{Return on Average Rate Base} = \text{WACC} \times \frac{\text{Average Capitalization}}{\text{Average Rate Base}}$$

Where,

WACC[6] = the weighted average cost of capital

Average Capitalization = the total average debt and equity for the year

Average Rate Base = the total average rate base for the year

The calculation of the Company's forecast of rate base and return on average rate base for 2019 – 2021, based upon the various inputs in GRA application, is included with this response as IR-39 – Attachment 1. Based upon an allowed return on average common equity of 9.35% on a 40% average common equity component, the Return on Average Rate Base for the years 2019 – 2021 is as follows:

	Forecast Return on Average Rate Base (%)
2019	6.94
2020	6.86
2021	6.82

The Company's application also proposes the adoption of an Earnings Sharing Mechanism which sets a ± 50 basis points range or band around the allowed return on average common equity or an allowed range of 8.85% to 9.85%. The comparable allowed return on average rate base, as calculated in IR-39 – Attachment 2, for 2019 – 2021 is as follows:

	Forecast Return on Average Rate Base (%)	
	Lower	Upper
2019	6.75	7.14
2020	6.66	7.06
2021	6.62	7.02

b. There has been no change in the derivation of revenue requirement from the 2016 GRA to the present GRA application before the Commission. As explained in response IR-39 (a) above, the return on average rate base, as defined, is a function of the return on average common equity.

The allowable earnings included in revenue requirement, whether expressed as a percentage rate of return on average common equity or average rate base, remains the same.

c. There would be no change in the forecast revenue requirement in this application if it was derived from a return on average rate base or a return on average common equity.

The components of revenue requirement are set out in Schedule 14-4 (Page 153) of the application. The return on equity included in Schedule 14-4 represents the Company's

6 For Maritime Electric, the WACC is calculated as the regulated return on average common equity multiplied by the yearend average common equity component of the capital structure plus the yearend after tax cost of debt multiplied by the yearend average debt component of the capital structure as illustrated in IR-39 – Attachment 2.

forecast earnings based upon an allowed return on average common equity of 9.35% in each of the years 2019 – 2021. This equates to a return on average rate base in the years 2019, 2020 and 2021 of 6.94%, 6.86% and 6.82% respectively as calculated in response (a) above.

IR-40 What return on average rate base has MECL earned in each year from March 1, 2016 to present?

Response

The annual return on average rate base for 2016 to 2018 is as follows:

	%
2016	7.69
2017	7.29
2018	7.07

Although the actual return on average rate base in each year exceeded that forecast in the Appendix 2 – Schedule of Inputs in Order UE16-04, Company's regulated return on average common equity (9.35%) did not exceed the maximum set by Order UE16-04. The variance between the forecast and actual return on average rate base results primarily from changes between forecast and actual average rate base with regulated earning capped at the maximum 9.35% return on a verge common equity.

IR-41 If the return on average rate base was greater than that approved by Commission Order UE16-04 (7.43% in 2016, 7.17% in 2017, and 7.05% in 2018), are the over-earnings recorded in the RORA Account to be refunded to ratepayers?

a. If no, please explain why.

b. If yes, how much was contributed to RORA in each of 2016, 2017 and 2018 due to overearnings on the return on average rate base?

Response

a. The over-earnings recorded in the RORA account are determined based upon the Company's return on average common equity pursuant to Commission Order UE16-04. Paragraph 1 of Order UE16-04 established customer electricity rates for the period from March 1, 2016 to February 28, 2019 based upon the forecast values and input values set forth in Appendix 2. The Appendix 2 – Schedule of Inputs contains forecasts of various inputs including sales, revenues, expenses, average financing rate, average rate base, return on average rate base and return on average common equity. These forecast inputs are the basis for which the three year schedule of customer electricity rates was approved.

However, paragraph 2 of Order UE16-04 states that:

> *"Maritime Electric* ***shall be entitled to earn a maximum return on average common equity of 9.35 per cent*** *for each of the calendar years 2016, 2017 and 2018, and thereafter until varied by the Commission.*

As a result, the over earnings recorded in the RORA account for the years 2016, 2017 and 2018 represent those earnings in excess of the allowed maximum return on average common equity for the year of 9.35%.

b. As discussed in (a), the basis upon which a contribution to the RORA account is determined is earnings above the maximum allowed return on average common equity of 9.35% for each year. On this basis, the following amounts have been recorded as a contribution to the RORA account over the period 2016 – 2018:

Year	RORA Calculation
2016	2,100,000
2017	2,767,885
2018	5,239,809
	10,107,694

IR-42 Please provide a Schedule of Inputs for 2019-2021 comparable to Appendix 2 (Schedule of Inputs) attached to Commission Order UE16-04.

Response

A Schedule of Inputs for 2019 – 2021 comparable to Appendix 2 of Commission Order UE16-04 is provided as IR-42 - Attachment 1 to this response.

IR-43 Appendix 2 (Schedule of Inputs) attached to Commission Order UE16-04 is based on forecasted numbers for 2016-2018:

a. Please provide an updated Appendix 2 which shows the forecasted versus actual values for 2016, 2017 and 2018 for each line item contained in Appendix 2.

b. Has there been any material change in any of the inputs? If so, please disclose and explain.

Response

b. IR-43 - Attachment 1 to this response provides the updated Appendix 2 with the forecast and actual values for 2016, 2017 and 2018.

b. The changes in the inputs from that originally forecast are not considered material. Any variances are captured through the RORA which will be returned to customers through future rates.

IR-44 Appendix 2 (Schedule of Inputs) attached to Commission Order UE16-04 includes forecasted transmission revenue for each of 2016, 2017 and 2018. A revised OATT was approved by the Commission effective August 1, 2018 (see Commission Order UE18-05). What (if any) impact has the approved OATT had on the 2018 transmission revenue as forecasted in Appendix 2?

Response

Section 8.0 of the Company's Application for Approval of the 2016 General Rate Agreement (Docket UE20942) discusses the treatment of forecast costs related to the planned interconnection project.

At the time, the Company proposed that the costs associated with the interconnection be recovered through the OATT. The costs proposed in the 2016 General Rate Agreement Application included two components:

- Financing of the capital cost of construction of the cables of $4.0 million per year; and
- Monthly schedule 9 charges from NB Power for dedicated interconnection facilities in New Brunswick of $1.6 million per year.

In the process of negotiating the terms of the interconnection lease and debt collection agreements, it was decided that the debt collection or financing component would not be collected through the OATT but rather the costs would be shared by the customers of Maritime Electric and the City of Summerside Electric Utility based on their expected share of usage. As a result of this change, the transmission revenue for 2018 is $4.0 million lower than shown in Appendix 2 – Schedule of Inputs attached to Commission Order UE16-04.

The schedule 9 charges from NB Power for the interconnection facilities located in New Brunswick are included in the OATT approved in Order UE18-05. However, the actual annual cost is $1.16 million, approximately $415,000 less than the amount proposed in the 2016 General Rate Agreement and included in transmission revenue in UE16-04 Appendix 2 – Schedule of Inputs.

The two above noted items account for $4.4 million of the $4.5 million change in the 2018 forecast OATT revenue from that proposed in Appendix 2 - Schedule of Inputs attached to Commission Order UE16-04.

IR-45 Please advise which Canadian regulators have allowed an earnings sharing mechanism and which have disallowed it. For those regulators that have allowed an earnings sharing mechanism, please provide full details of the approved earnings sharing mechanism.

Response

The Concentric report filed with the Company's application states that the primary purpose of an Earnings Sharing Mechanism ("ESM") is to share with customers earnings that deviate in a meaningful way from the level of earnings associated with the authorized ROE. Although the terminology or description will differ across jurisdictions, ESMs are characterized by two key parameters: i) the size of the allowed range of ROE, and 2) the percentage of sharing of the earnings outside the allowed range between the utility and customers.

In its 2006 General Rate Application, Maritime Electric proposed the establishment of an allowed range of ROE around the authorized ROE. Although the Commission did not specifically deny the request by Order, the Commission's decision in its Order on the application did not address or allow the proposed range of ROE. In addition, a range of ROE around the authorized ROE was proposed in the 2015 General Rate Application filing. However, this application was replaced by the General Rate Agreement approved in Order UE16-04. The Company has not been able to identify applications in other jurisdictions in Canada where a request for an ESM has been denied.

The following information, by Province, comprises the details of the ROE banding and earnings sharing parameters that the Company has identified.

British Columbia

In 2014, the British Columbia Utilities Commission ("BCUC") approved the Multi-year Performance Based Ratemaking ("PBR") Plan for 2014 through 2018 for FortisBC Inc. The relevant pages from the BCUC's decision related to the allowed range of ROE and earnings sharing are included with this response as IR-45 – Attachment 1.

In its decision, the BCUC discusses the earnings sharing methodology in Section 2.2.1 – Earnings Sharing Mechanism (Pages 119-121) and the banding parameters (or off-ramps) around the ROE in Section 2.2.24 – Off Ramps (Pages 151-155). Under the approved formula, earnings are shared 50 : 50 with customers around an ROE range of ± 200 basis points on a post-sharing basis in one year or if the average earnings for two consecutive years vary ± 150 basis points on a post-sharing basis.

Alberta

In 2016, the Alberta Utilities Commission ("AUC") issued its decision on a PBR plan for the 2018 – 2022 period for four electric and two gas utilities in Alberta. The relevant pages from the AUC's decision related to the allowed range of ROE are included with this response as IR-45 – Attachment 2.

In Section 7 – Calculation of Returns for Reopener Purposes (Pages 71 – 79) of the AUC decision, the AUC establishes the band around the utility's ROE that must be exceeded, either above or below, before the AUC will consider reopening the PBR plan to address variations in the ROE. The AUC, in its decision, stated that it will continue to use a ± 500 basis points threshold in a single year and a ± 300 basis points threshold for two consecutive years as the level at which it would consider reviewing the PBR plan in relation to the achieve ROEs.

Maritime Electric has not identified any previous decisions of the AUC with regard to any sharing of earnings outside the prescribed ROE bands. However, in June 2018, the AUC did establish a proceeding to determine whether or not to re-open, or review, the achieved ROEs for ATCO Electric and ATCO Gas for 2016 and 2017. To date, the AUC has not issued a decision on this proceeding.

Saskatchewan

SaskPower and Manitoba Hydro are provincially owned utilities. The Company has no application to indicate any form of an ESM in place in these jurisdictions.

Ontario

The Ontario Energy Board ("OEB") uses incentive based rate setting for electricity distribution utilities in Ontario. On July 12, 2018, the OEB released its guidelines for applications, included with this response as IR-45 – Attachment 3.

In Section 3.3.5 – Off-Ramp (Page 30) of the OEB guidelines, the OEB states that a regulatory review may be triggered if the achieved earnings are outside a ± 300 basis points threshold or deadband. Since the review is not automatic, there are no guidelines specified with respect to the disposition of any excess earnings outside the deadband.

In consultation with FortisOntario, an electric distribution utility in Ontario, Maritime Electric has not identified any instances where earnings have been outside the ± 300 basis points deadband and the OEB has ordered sharing with customers. The Company therefore concludes that the utilities have either not had earnings outside the deadband or have, in accordance with the application of the OEB guidelines, refrained from seeking prospective adjustments to base rates.

Quebec and New Brunswick

Hydro Quebec and New Brunswick Power are provincially owned utilities. The Company has no application to indicate any form of an ESM in place in these jurisdictions.

Nova Scotia Power

Nova Scotia Power Inc. ("NSPI") has had an allowable range of ROE (or deadband) since its privatization in 1992. At that time, the allowable range was established by the Nova Scotia Utility and Review Board ("NSUARB") to be 50 basis points (± 25 basis points) which remains in place today.

The NSUARB's decision on NSPI's 2009 General Rate Application, included with this response as IR-45 – Attachment 4, describes the ± 25 basis points range and the NSUARB's views on the disposition of any excess earnings in paragraphs 110 – 115. At that time, paragraph 110 states that excess earnings will be applied to reduce two deferral accounts. In consultation with a representative at NSPI, the Company has been informed that, through a 2012 settlement agreement, this approval remains in place with any excess earnings to be credited for the benefit of customers to the Fuel Adjustment Mechanism deferral account.

Newfoundland

The Newfoundland Public Utilities Board ("PUB") requires Newfoundland Power Inc. ("NP") to use an Excess Earnings Account that is to be credited with any earnings in excess of the upper limit of the allowed return on rate base as approved by the PUB. The upper limit of NP's allowed return on rate base was set at 0.18% above the rate of return on rate base used for rate making by Order P.U.19 (2003), Pages 75 – 76, included with this response as IR-45 – Attachment 5.

PUB Order P.U.19 (2003) establishes the allowed range of return on rate base at 36 basis points (± 18 basis points). This 18 basis points return on rate base upper limit represents a 40 – 50 basis points upper limit in NP's return on equity as discussed in its response to Request for Information CA-NP-092 included with this response as IR-45 – Attachment 6.

Any earnings in excess of the upper limit are credited to the Excess Earnings Account and are then subject to disposition by order of the PUB. Where the amounts are material, the balance has typically been disposed of via a refund to customers, as illustrated in PUB Order P.U.37 (2000 – 2001) included with this response as IR-45 – Attachment 7. NP has indicated that where the amounts are immaterial, they have been deferred and used to offset revenue requirement in a future year.

Section 13 – Cost Allocation Study

IR-46 MECL is seeking to further delay changes to the residential second block. If the Commission does not allow the proposed phasing out of second block, and instead orders that second block be eliminated immediately:

a. What (if any) impact will this have on the proposed rates for each class of residential customers?

b. What (if any) impact will this have on the revenue to cost ratios for each class of customers?

Response

a. The impact on each class of residential customer due to eliminating the second block immediately would depend on how the incremental revenue is allocated to the various rate classes. If we assume that the incremental revenue generated from this change is to be used to reduce General Service class rates and lower its revenue to cost ratio for example, the only change to rates for the residential classes would be on the rate on consumption greater than 2,000 kWh from March 1, 2019 to February 28, 2022 making it equivalent to the first block rate.

This could have a significant impact on the annual cost for customers whose monthly consumption is greater than 2,000 kWh per month. The following table is an excerpt from Schedule 13-9 on page 133 of the General Rate Application:

Schedule 13-9
Number of Residential Customers by Monthly Consumption Range
February 2017 and July 2017

Monthly Consumption Range (kWh)	February 2017 Customers						July 2017 Customers					
	Farm		Non-farm		Total		Farm		Non-farm		Total	
	Customers	%	Customers	%	Customers	%	Customers	%	Customers	%	Customers	%
2,001 to 5,000	333	16.6%	6,477	11.4%	6,810	11.5%	136	6.6%	678	1.1%	814	1.3%
5,001 to 10,000	168		392		560		80		63		143	
10,000 and greater	134	15.1%	48	0.8%	182	1.3%	64	7.0%	14	0.1%	78	0.3%
TOTAL	**635**	**31.7%**	**6,917**	**12.2%**	**7,552**	**12.8%**	**280**	**13.6%**	**755**	**1.2%**	**1,035**	**1.6%**

As indicated by the table, approximately 12.8% or 7,552 residential customers will be impacted by eliminating the residential second block in the winter months based on their February 2017 consumption and 1.6% or 1,035 residential customers will be impacted in the summer months based on their July 2017 consumption.

The impact of the proposed changes from a customer perspective will be dependent on that customer's consumption level and pattern as well as their classification as urban or rural. Schedules 13-13 and 13-14 of the GRA show the impact of the proposed elimination of the second block based on a selection of actual customer consumption data using the Residential rates in effect on March 1, 2018. Schedules 13-13 and 13-14 below have been updated to reflect the impact of an immediate elimination of the second block rate:

Schedule 13-13 Elimination of Second Block effective March 1, 2019 Annual Impact of Second Block and Service Charge Changes - Rural								
Annual Consumption	2019		2020		2021		3 Year Average	
kWh	$	%	$	%	$	%	$	%
7,800	$ (18.16)	(1.3)	$ (4.70)	(0.3)	$ -	-	$ (7.62)	(0.5)
30,008	$ 223.33	5.1	$ 39.64	0.9	$ -	-	$ 87.66	2.0
42,009	$ 476.13	8.2	$ 78.90	1.3	$ -	-	$ 185.01	3.2
54,030	$ 768.75	11.0	$ 316.82	4.1	$ -	-	$ 361.86	5.0
90,060	$ 1,921.27	17.2	$ 135.72	1.0	$ -	-	$ 685.66	6.1
146,280	$ 3,131.40	17.7	$ 525.12	2.5	$ -	-	$ 1,218.84	6.8

Schedule 13-14 Elimination of Second Block effective March 1, 2019 Annual Impact of Second Block and Service Charge Changes - Urban								
Annual Consumption	2019		2020		2021		3 Year Average	
kWh	$	%	$	%	$	%	$	%
7,800	$ 5.34	0.4	$ -	-	$ -	-	$ 1.78	0.1
30,008	$ 246.83	5.7	$ 44.34	1.0	$ -	-	$ 97.06	2.2
42,009	$ 499.63	8.7	$ 83.60	1.3	$ -	-	$ 194.41	3.3
54,030	$ 792.25	11.4	$ 321.52	4.2	$ -	-	$ 371.26	5.2
90,060	$ 1,944.77	17.4	$ 140.42	1.1	$ -	-	$ 695.06	6.2
146,280	$ 3,154.90	17.9	$ 529.82	2.5	$ -	-	$ 1,228.24	6.8

As discussed on Page 134 of the Application, leaving the first block at 2,000 kWh until March 1, 2021, will allow higher use Residential customers sufficient time to assess the impact on their annual electricity costs and take steps to reduce energy consumption where possible. In addition, it will allow the Company additional time to complete a study of farm customers and a Load Research Study as discussed further in our response to IR-54.

b. The impact of immediately eliminating the second block for Residential Rate Classes on the revenue to cost ratios for each class of customers would depend on how the incremental revenue collected from the Residential classes is allocated. IR-46 - Attachment 1 to this response contemplates the impact of two options discussed below.

First, the incremental revenue could be used to reduce the energy charge rate for all residential customers which would have no impact on the RTCs for each class of customers but would reduce the per kWh rate for the residential rate classes by $0.0035 per kWh.

Alternatively, as assumed in response to IR 47(a), the incremental revenue could be used to reduce rates for the General Service class. This would increase the RTC for the Residential classes from 91 to 93. It would also reduce the RTC for the General Service classes from 121 to 117 and reduce overall General Service rates by approximately 3.4%.

IR-47 If the Commission determines the second block will be increased to 5000 kWh immediately, what (if any) impact will this have on the proposed rates for each class of residential customers?

Response

Increasing the first block to 5000 kWh immediately would result in incremental revenue of $2,504,000 over the three year rate term as follows:

2019: 26,195 MWh X ($0.1437-$0.1142)	=	$ 773,000	(March – December)
2020: 42,446 MWh X ($0.1437-$0.1142)	=	$ 1,252,000	(Full Year)
2021: 16,251 MWh X ($0.1437-$0.1142)	=	$ 479,000	(January – February)
Total Incremental Revenue	=	$ 2,504,000	

The impact on each class of residential customer of increasing the first block to 5,000 kWh immediately would depend on how the incremental revenue is allocated to the various rate classes. If we assume that the incremental revenue generated from this change is to be used to reduce General Service class rates and lower its revenue to cost ratio for example, the only change to rates for the residential classes would be on the second block rate between 2,000 and 5,000 kWh from March 1, 2019 to February 28, 2021.

This may have a significant impact on the annual cost for customers whose monthly consumption is greater than the current 2,000 kWh per month (see the excerpt from Schedule 13-9 on page 133 of the GRA in our response to IR-46). As indicated by this table, it is expected that approximately 12.8% or 7,552 residential customers would be impacted by increasing the first block to 5,000 kWh in the winter months based on their February 2017 consumption and 1.6% or 1,035 residential customers would be impacted in the summer months based on their July 2017 consumption.

As discussed in the application, the impact of the proposed changes from a customer perspective will be dependent on that customer's consumption level and pattern as well as their classification as urban or rural. Schedules 13-13 and 13-14 of the GRA show the impact of the proposed increase in the first block to 5,000 kWh based on a selection of actual customer consumption data using the Residential rates in effect until March 1, 2019. Schedules 13-3 and 13-4 below have been updated to reflect an immediate increase in the second block to 5,000 kWh:

Schedule 13-13 Increase First Block to 5,000 kWh effective March 1, 2019 Annual Impact of First Block and Service Charge Changes - Rural								
Annual Consumption	2019		2020		2021		3 Year Average	
kWh	$	%	$	%	$	%	$	%
7,800	$ (18.16)	(1.3)	$ (4.70)	(0.3)	$ -	-	$ (7.62)	(0.5)
30,008	$ 223.33	5.1	$ 39.64	0.9	$ -	-	$ 87.66	2.0
42,009	$ 420.08	7.3	$ 78.90	1.3	$ -	-	$ 166.33	2.8
54,030	$ 517.71	7.4	$ 124.24	1.7	$ -	-	$ 213.98	3.0
90,060	$ 717.08	6.4	$ 118.61	1.0	$ -	-	$ 278.56	2.5
146,280	$ 938.96	5.3	$ 172.30	0.9	$ -	-	$ 370.42	2.1

Schedule 13-14 Increase First Block to 5,000 kWh effective March 1, 2019 Annual Impact of First Block and Service Charge Changes - Urban								
Annual Consumption	2019		2020		2021		3 Year Average	
kWh	$	%	$	%	$	%	$	%
7,800	$ 5.34	0.4	$ -	-	$ -	-	$ 1.78	0.1
30,008	$ 246.83	5.7	$ 44.34	1.0	$ -	-	$ 97.06	2.2
42,009	$ 443.58	7.7	$ 83.60	1.4	$ -	-	$ 175.73	3.0
54,030	$ 541.21	7.8	$ 128.94	1.7	$ -	-	$ 223.38	3.2
90,060	$ 740.58	6.6	$ 123.31	1.0	$ -	-	$ 287.96	2.6
146,280	$ 962.46	5.5	$ 177.00	1.0	$ -	-	$ 379.82	2.1

As discussed on Page 134 of the Application, leaving the first block at 2,000 kWh until March 1, 2021, will allow higher use Residential customers sufficient time to assess the impact on their annual electricity costs and take steps to reduce energy consumption where possible. In addition, it will allow the Company additional time to complete a study of farm customers and a Load Research Study as discussed further in our response to IR-54.

IR-48 What rates would be required to be charged to each of the customer classes set out in Schedule 13-7 if IRAC mandated an immediate change in rates to bring the revenue to cost ratio for each of these classes to 1:1?

Response

The table below shows the calculations to develop revised energy charges for each rate class for March 1, 2019 that are intended to immediately bring the revenue to cost ratios to 100%:

RATES NEEDED TO BRING REVENUE TO COST RATIOS TO 100%							
	Change in average rate for R/C equal to 100%	March 1, 2019 energy charges as proposed		March 1, 2019 energy charges for 100% R/C		March 1, 2019 energy charges for 100% R/C	
Rate Classes	($/kWh)	First block ($/kWh)	Second block ($/kWh)	First block ($/kWh)	Second block ($/kWh)	First block % Change	Second block % Change
Residential	0.0167	0.1456	0.1155	0.1623	0.1322	11%	14%
Residential Seasonal							
Residential Farms							
General Service	(0.0272)	0.1793	0.1167	0.1521	0.0895	-15%	-23%
General Seasonal							
Small Industrial	(0.0031)	0.1756	0.0879	0.1725	0.0848	-2%	-4%
Large Industrial	0.0061	0.0723		0.0784		8%	
Street Lighting	0.0415						
Unmetered	(0.0066)	0.1757		0.1691		-4%	

This table as well as the supporting schedules are provided in IR-48 - Attachment 1 to this response as well as in electronic format.

For simplicity, the monthly service charges and the demand charges as proposed in Maritime Electric's GRA filing have not been changed – the move to 100% has been derived solely through adjustments to the energy charges.

Under the Residential Rate the same energy charges apply to year round customers, seasonal customers and farms, so they have been grouped together for the purpose of adjusting the energy charges. The same applies for General Service and General Service Seasonal.

For Street Lighting a further step would be needed. The energy charge adjustment as shown in the table would have to be applied to the monthly kWh usage for each fixture type and size in order to get a $ amount adjustment to apply to each of the monthly charges.

IR-49 What rates would be required to be charged to each of the customer classes set out in Schedule 13-7 if IRAC mandated an immediate change in rates to bring the revenue to cost ratio for each of these classes within a 95% -105% revenue to cost ratio?

Response

The table below shows the calculations to develop revised energy charges for each rate class for March 1, 2019 that are intended to immediately bring the revenue to cost ratios to within 95% - 105%.

RATES NEEDED TO BRING REVENUE TO COST RATIOS TO WITHIN 95% TO 105%							
	Change in average rate for R/C within 95% to 105% ($/kWh)	March 1, 2019 energy charges as proposed		March 1, 2019 energy charges for 95% - 105% R/C		March 1, 2019 energy charges for 95% - 105% R/C	
Rate Classes		First block ($/kWh)	Second block ($/kWh)	First block ($/kWh)	Second block ($/kWh)	First block % Change	Second block % Change
Residential	0.0126	0.1456	0.1155	0.1582	0.1281	9%	11%
Residential Seasonal							
Residential Farms							
General Service	(0.0208)	0.1793	0.1167	0.1585	0.0959	-12%	-18%
General Seasonal							
Small Industrial	-	0.1756	0.0879	0.1756	0.0879	0%	0%
Large Industrial	0.0039	0.0723		0.0762		5%	
Street Lighting	0.0307						
Unmetered	-	0.1757		0.1757		0%	

This table as well as the supporting schedules are provided in IR-49 - Attachment 1 to this response as well as in electronic format.

For simplicity, the monthly service charges and the demand charges as proposed in Maritime Electric's GRA filing have not been changed – the move to within 95% - 105% has been done solely through adjustments to the energy charges.

The calculations to move to within 95% - 105% require an extra step as compared to the calculations to move to 100%. The reason is that the increase in revenue due to moving the rate classes that are below 95% up to 95% is less than the decrease in revenue due to moving the rate classes that are above 105% down to 105%. The result is that the rate classes that are below 95% need to be moved to 98% in order for the adjustments to be revenue neutral overall.

Under the Residential Rate the same energy charges apply to year round customers, seasonal customers and farms, so they have been grouped together for the purpose of adjusting the energy charges. The same applies for General Service and General Service Seasonal.

For Street Lighting a further step would be needed. The energy charge adjustment as shown in the table would have to be applied to the monthly kWh usage for each fixture type and size in order to get a $ amount adjustment to apply to each of the monthly charges.

IR-50 What rates would be required to be charged to each of the customer classes set out in Schedule 13-7 if IRAC mandated an immediate change in rates to bring the revenue to cost ratio for each of these classes within a 90% -110% revenue to cost ratio?

Response

The table below shows the calculations to develop revised energy charges for each rate class for March 1, 2019 that are intended to immediately bring the revenue to cost ratios to within 90% - 110%.

RATES NEEDED TO BRING REVENUE TO COST RATIOS TO WITHIN 90% TO 110%							
	Change in average rate for R/C within 90% to 110%	March 1, 2019 energy charges as proposed		March 1, 2019 energy charges for 90% - 110% R/C		March 1, 2019 energy charges for 90% - 110% R/C	
Rate Class	($/kWh)	First block ($/kWh)	Second block ($/kWh)	First block ($/kWh)	Second block ($/kWh)	First block % Change	Second block % Change
Residential	0.0084	0.1456	0.1155	0.1540	0.1239	6%	7%
Residential Seasonal							
Residential Farms							
General Service	(0.0144)	0.1793	0.1167	0.1649	0.1023	-8%	-12%
General Seasonal							
Small Industrial	-	0.1756	0.0879	0.1756	0.0879	0%	0%
Large Industrial	0.0038	0.0723		0.0761		5%	
Street Lighting	0.0186						
Unmetered	-	0.1757		0.1757		0%	

This table as well as the supporting schedules are provided in IR-50 - Attachment 1 to this response as well as in electronic format.

For simplicity, the monthly service charges and the demand charges as proposed in Maritime Electric's GRA filing have not been changed – the move to within 90% - 110% has been done solely through adjustments to the energy charges.

The calculations to move to within 90% - 110% require an extra step as compared to the calculations to move to 100%. The reason is that the increase in revenue due to moving the rate classes that are below 90% up to 90% is less than the decrease in revenue due to moving the rate classes that are above 110% down to 110%. The result is that the rate classes that are below 90% need to be moved to more than 90% in order for the adjustments to be revenue neutral overall.

Under the Residential Rate the same energy charges apply to year round customers, seasonal customers and farms, so they have been grouped together for the purpose of adjusting the energy charges. The same applies for General Service and General Service Seasonal.

For Street Lighting a further step would be needed. The energy charge adjustment as shown in the table would have to be applied to the monthly kWh usage for each fixture type and size in order to get a $ amount adjustment to apply to each of the monthly charges.

IR-51 Please provide a table showing, on a yearly basis, the percentage change in rates for each customer class if IRAC were to order that rates be adjusted to a 1:1 revenue to cost ratio with the change being phased in over a 4 or 5 year period.

Response

The following table shows the annual change in rates needed to bring the revenue to cost ratios to 100% over a four year period:

Annual % change in rates needed to bring R/C ratios to 100% over a 4 year period				
Rate Class	**Mar 1, 2019**	**Mar 1, 2020**	**Mar 1, 2021**	**Mar 1, 2022**
Residential	2.29	2.29	2.29	2.29
Residential Seasonal	1.16	1.16	1.16	1.16
Residential Farms	5.08	5.08	5.08	5.08
General Service	(4.74)	(4.74)	(4.74)	(4.74)
General Seasonal	(2.98)	(2.98)	(2.98)	(2.98)
Small Industrial	(0.59)	(0.59)	(0.59)	(0.59)
Large Industrial	1.68	1.68	1.68	1.68
Street Lighting	2.37	2.37	2.37	2.37
Unmetered	(1.00)	(1.00)	(1.00)	(1.00)

The following table shows the annual change in rates needed to bring the revenue to cost ratios to 100% over a five year period:

Annual % change in rates needed to bring R/C ratios to 100% over a 5 year period					
Rate Class	**Mar 1, 2019**	**Mar 1, 2020**	**Mar 1, 2021**	**Mar 1, 2022**	**Mar 1, 2023**
Residential	1.83	1.83	1.83	1.83	1.83
Residential Seasonal	0.92	0.92	0.92	0.92	0.92
Residential Farms	4.04	4.04	4.04	4.04	4.04
General Service	(3.81)	(3.81)	(3.81)	(3.81)	(3.81)
General Seasonal	(2.39)	(2.39)	(2.39)	(2.39)	(2.39)
Small Industrial	(0.47)	(0.47)	(0.47)	(0.47)	(0.47)
Large Industrial	1.34	1.34	1.34	1.34	1.34
Street Lighting	1.89	1.89	1.89	1.89	1.89
Unmetered	(0.80)	(0.80)	(0.80)	(0.80)	(0.80)

These changes would be in addition to the rate changes already proposed by Maritime Electric to meet its revenue requirement. These tables as well as the supporting calculations are provided in IR-51 - Attachment 1 to this response as well as in electronic format.

IR-52 Please provide a table showing, on a yearly basis, the percentage change in rates for each customer class if IRAC were to order that rates be adjusted to a 95% - 105% revenue to cost ratio with the change being phased in over a 4 or 5 year period.

Response

The following table shows the annual change in rates needed to bring the revenue to cost ratios to ratios to within 95% to 105% over a four year period:

Annual % change in rates needed to bring R/C ratios to within 95% to 105% over a 4 year period				
Rate Class	**Mar 1, 2019**	**Mar 1, 2020**	**Mar 1, 2021**	**Mar 1, 2022**
Residential	1.69	1.69	1.69	1.69
Residential Seasonal	0.69	0.69	0.69	0.69
Residential Farms	4.46	4.46	4.46	4.46
General Service	(3.57)	(3.57)	(3.57)	(3.57)
General Seasonal	(1.78)	(1.78)	(1.78)	(1.78)
Small Industrial	-	-	-	-
Large Industrial	1.09	1.09	1.09	1.09
Street Lighting	1.77	1.77	1.77	1.77
Unmetered	-	-	-	-

The following table shows the annual change in rates needed to bring the revenue to cost ratios to ratios to within 95% to 105% over a five year period:

Annual % change in rates needed to bring R/C ratios ratios to within 95% to 105% over a 5 year period					
Rate Class	**Mar 1, 2019**	**Mar 1, 2020**	**Mar 1, 2021**	**Mar 1, 2022**	**Mar 1, 2023**
Residential	1.35	1.35	1.35	1.35	1.35
Residential Seasonal	0.56	0.56	0.56	0.56	0.56
Residential Farms	3.55	3.55	3.55	3.55	3.55
General Service	(2.87)	(2.87)	(2.87)	(2.87)	(2.87)
General Seasonal	(1.43)	(1.43)	(1.43)	(1.43)	(1.43)
Small Industrial	-	-	-	-	-
Large Industrial	0.87	0.87	0.87	0.87	0.87
Street Lighting	1.42	1.42	1.42	1.42	1.42
Unmetered	-	-	-	-	-

These changes would be in addition to the rate changes already proposed by Maritime Electric to meet its revenue requirement. These tables as well as the supporting calculations are provided in IR-52 - Attachment 1 to this response as well as in electronic format.

IR-53 The rationale for equalizing rural and urban residential service charges appears to be based upon the fact that there is no material cost difference to service these different classes with changes in meter reading technology and increases in rural customer density (see page 128). Why is it appropriate to maintain a higher monthly service charge ($26.92) for seasonal residential customers when the urban/rural residential rate has been equalized at $24.57 per month?

Response

The reason is that the results of the 2017 Chymko Cost Allocation Study show that the average Site-related costs (i.e. costs that vary with the number of customers connected to the system) for Residential Seasonal customers are higher than for Residential year round customers.

For Residential year round customers, the calculation is straightforward, as shown below (the numbers do not include farms).

Site-related costs for 2017 ($ x 1,000) (From bottom line of Schedule 1.4 of the Chymko Study)	16,915
Number of bills issued in 2017 (57,286 x 12) (From line 39 of Schedule 2.2 of the Chymko Study)	687,432
Average cost ($/bill)	24.61

The average cost per bill of $24.61 is close to the Residential Urban monthly service charge of $24.57. Therefore, the Company has proposed to reduce the Residential Rural monthly service charge to be the same as the Urban. (The Residential monthly service charges are intended to recover Site-related costs)

For Residential Seasonal customers, the calculation is not as straightforward because there are two groups of Seasonal customers:

- The Rate Code 131 group is for cottages and summer homes that are used for more than just four to six months per year. For this group the meters are read and bills are issued monthly (i.e. 12 times per year). The monthly service charge for Rate Code 131 is $26.92, the same as for Residential Rural.
- The Rate Code 133 group is for cottages and summer homes that are used primarily for six months per year or less. The meters are read for each of the months May through October, and six bills are issued per year. The monthly service charge for Rate Code 133 is $37.50. An eligibility requirement for Rate Code 133 is that the customer's kWh consumption for the May meter reading is no more than 50% of the previous year's summer season kWh consumption.

The Site-related costs allocated to Residential Seasonal in the 2017 Chymko Cost Allocation Study are $2,272,000 (bottom line of Schedule 1.4). The starting point for a calculation of average Site-related costs to be recovered through the monthly service charge for each of Rate Code 131 and 133 is the table below, which shows a breakdown of the Site-related cost components between those that do not vary with the number of bills issued and those that can be considered to vary with the number of bills issued.

2017 Residential Seasonal Site-Related Costs			
	Costs that do not vary with number of bills ($ x 1,000)	**Costs that do vary with number of bills ($ x 1,000)**	**Total ($ x 1,000)**
Primary Lines	682		682
Transformers	399		399
Secondary Lines	236		236
Service Lines	683		683
Meter Assets	125		125
Meter Reading		49	49
Billing		54	54
Remittance & Collection		39	39
Uncollectibles & Damage Claims		47	47
Service Connections		(27)	(27)
Late Payments		(15)	(15)
Totals	2,125	147	2,272
12,668 bills issued for Code 131 in 2017			
38,994 bills issued for Code 133 in 2017			
If all Seasonals were Rate Code 131:			
- Site-related costs would be	2,125	258 (1)	2,383
- Annual number of bills would be			90,656 (2)
- Average Site-related $/bill would be			26.29
If all Seasonals were Rate Code 133:			
- Site-related costs would be	2,125	129 (3)	2,254
- Annual number of bills would be			45,328 (4)
- Average Site-related $/bill would be			49.73

Notes: (1) $147,000 x (12,668 + 38,994 x 2) / (12,668 + 38,994) = $258,000
(2) 12,668 + 38,994 x 2 = 90,656
(3) $147,000 x (12,668/2 + 38,994) / (12,668 + 38,994) = $129,000
(4) 12,668/2 + 38,994 = 45,328

Since the current Residential Seasonal Rate Code 131 monthly service charge of $26.92 is reasonably close to the estimated average monthly Site-related costs of $26.29/bill, the Company has not proposed to change it.

For Seasonal Rate Code 133, the monthly service charge of $37.50 is below the estimated average monthly site-related costs of $49.73 per bill. Rate Code 133 customers see an annual savings of $98.04 ($26.92 x 12 - $37.50 x 6) relative to Rate Code 131. This rate code was developed as an option for seasonal customers when Maritime Electric adopted the NB Power tariff under the Maritime Electric Company, Limited Regulation Act. Maritime Electric's original tariff had a Seasonal (cottage) Customer rate on which customers were billed for five months a year with the monthly service charge and energy charge consistent with year round residential customers.

The NB Power Tariff being adopted at that time made no distinction between seasonal and year round rural residential customers. Under the legislation, Maritime Electric had to provide terms and conditions of service that, in their entirety, were not less favourable to customers generally than the most nearly equivalent terms and conditions of NB Power for its customers in New Brunswick. This allowed Maritime Electric the ability to design an optional seasonal rate that collected additional revenue from its existing cottage customers compared to the rate in effect prior to adopting the NB Power tariff. At that time the manual meter reading associated with year round service to these customers would be challenging as accessibility to most cottages was limited throughout winter. As a result, there was a benefit associated with not having to read the seasonal customers during the winter months.

With the installation of the radio frequency interrogation (RF) meter reading system, meter reading costs have reduced since the establishment of the Seasonal Option Rate. However, the $49.73 calculated estimated for seasonal residential customers does suggest a need to further review and adjust the current $37.50 seasonal rate monthly charge as part of a future cost allocation study.

IR-54 The revenue to cost ratio for the General Service rate class is currently 122. Please explain why the current application does not rectify this issue, and provide justification for the continuation of a revenue to cost ratio of 122 for General Service customers.

Response

Maritime Electric operates under a traditional cost of service regulatory model. Under cost of service regulation, the utility's rates are intended to recover the cost of proving electricity service to customers. To enable an assessment of the fairness of the rates charged to each of the customer classes, Maritime Electric periodically does a cost allocation study. The results of a cost allocation study also provide a benchmark to guide rate design.

The basic approach followed in a cost allocation study is to first separate the utility's costs by function, and then break down the costs for each function into the following three categories:

- Demand costs – these are costs that vary as a function of the maximum load (coincident peak) that the Company is required to serve during a year. The amount of generating capacity that must be installed or purchased is an example. Demand costs for the distribution system can also be driven by non-coincident peak loads; e.g. when the peak load for a given customer class occurs at a different time than the time of the annual system peak load.
- Energy costs – these are costs that vary as a function of the total amount of electricity supplied by the Company during the course of a year. Generation fuel is an example.
- Customer costs – these are costs that vary as a function of the number of customers that the Company serves. Meter reading is an example.

The final step is to allocate to each customer class their appropriate share of each of the above three types of costs. For Energy costs and Customer costs this is relatively straightforward because the number of kWh used by each customer class and the number of customers in each customer class are known quantities.

However, allocating the Demand costs is not straightforward because for some of the customer classes, either the maximum load or the class load at the time of system peak for some of the customer classes is not known and cannot be measured directly. This is the case for the Residential customer class, and small General Service customers' classes which together represent approximately 80% of Maritime Electric's load. The allocation of Demand costs to these customer classes relies on estimates of their peak loads. These estimates are based in part on load research done in the early 1990s. That research involved collecting hourly load data for a representative sample of Residential and General Service customers that was then used to improve the estimates of coincident and non-coincident peak loads for those customer classes in subsequent cost allocation studies.

As stated in Section 13.4.2 of the application, the Company has expanded its 2018 Bridge Meter Project in its 2019 Capital Budget Application to conduct a load research study for Residential and General Service customers. The Company will collect hourly load data for a sample of Residential and General Service customers beginning in 2019 and continuing through 2020. The results of this load study will form the basis of the next Cost Allocation Study expected to be conducted in 2021. The study will provide a more accurate allocation of load between residential and general service customers which will in turn impact the allocation of demand costs and resulting RTCs of both of these classes. This is one reason the Company did not propose rate design changes for the General Service Class at this time.

Another reason is the uncertainty with regard to determining the appropriate rate classification for farms. The Company is currently gathering and analyzing load and consumption data for farms included in the residential rate class that will provide information necessary to ensure farms customers are classified in the appropriate rate class. The results of this study may conclude that some of these farms should be classified as general service or small industrial which would impact the cost and revenue allocations to these classes as well as the resulting RTCs. Using data from Schedule 1.0 of the Chymko 2017 Cost Allocation Study, the table below shows for illustration purposes that the Revenue to Cost ratio for the General Service rate class would decrease from 121% without Farms to 116% with Farms.

Effect of Combining Farms with Small Industrial			
	Farm	**General Service**	**Farm + General Service**
Base Revenue ($ x 1,000)	6,868	58,151	65,019
Allocated Cost ($ x 1,000)	8,732	47,880	56,252
Revenue to Cost Ratio (%)	82	121	116

Using data from Schedule 1.0 of the Chymko 2017 Cost Allocation Study, the table below shows that the Revenue to Cost ratio for the Small Industrial rate class would decrease from 102% to 94% with Farms included.

Effect of Combining Farms with Small Industrial			
	Farm	**Small Industrial**	**Farm + Small Industrial**
Base Revenue ($ x 1,000)	6,868	11,675	18,543
Allocated Cost ($ x 1,000)	8,732	11,402	19,774
Revenue to Cost Ratio (%)	82	102	94

The Company believes it is prudent to consider the impact of both the load study and the farm study on cost allocation and RTCs for all classes prior to making recommendations regarding rate design for the General Service class.

Section 15 – Impact of Proposal on Customers

IR-55 The percentage annual increase in electric rates for residential customers is based on the continuation of the Clean Energy Price Incentive for the next three years. The Incentive is a Provincial Government rebate of 10% on the first 2,000 kWh per month of energy consumed by residential customers (page 161).

a. MECL states that the Clean Energy Price Incentive "*is expected to continue to provide relief during the proposed three year rate setting period*" (page 161). Please provide justification for this assumption. Does MECL have any written agreement or assurances from the Government of Prince Edward Island that the Clean Energy Price Incentive will continue without change until February 28, 2022?

b. What will the total annual cost, and percentage annual increase in rates, be for a residential customer in each of 2019, 2020 and 2021 if the Clean Energy Price Incentive is removed from the calculations in Schedules 15-2 and 15-3 (pages 161-162)?

Response

a. The Company does not have assurance or confirmation that the Clean Energy Price Incentive will continue without change until February 28, 2022. However, without confirmation that the incentive will end during this period, the Company has assumed its continuation for illustrative purposes to show the projected customer bill on a tax included basis.

Section 3.3 of the application discusses the before tax impact of the Company's proposals in this application. The typical customer in each rate class will experience a 1.1% increase in each of the next three years with the exception of the rural residential customer who will experience a 0.9% decrease in the first year as a result of the proposed reduction in the monthly service charge.

To illustrate, Schedules 15-2 (Rural Residential) and 15-3 (Urban Residential) are reproduced below on a before tax basis.

Schedule 15-2 – Before Tax						
Annual Cost for Rural Residential Customer (650 kWh per Month/7,800 kWh per Year)						
Bill Component	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2019 Forecast**	**2020 Forecast**	**2021 Forecast**
Service Charge	$ 323.04	$ 323.04	$ 323.04	$ 294.84	$ 294.84	$ 294.84
Basic Energy Charge	1,029.60	1,072.50	1,099.02	1,121.64	1,151.28	1,169.22
ECAM Charge	16.06	9.26	4.48	28.42	13.92	11.51
Provincial Costs Recoverable	41.81	41.81	41.81	-	-	-
Provincial Energy Efficiency Program	-	-	-	5.46	6.24	7.02
Cable Contingency Fund*	2.11	2.11	2.11	-	-	-
RORA	(31.96)	(36.91)	(26.87)	(19.53)	(19.53)	(19.53)
Sub-Total – Before Tax	**1,380.66**	**1,411.81**	**1,443.59**	**1,430.83**	**1,446.75**	**1,463.06**
Percentage Annual Increase (%)	**2.3%**	**2.3%**	**2.3%**	**(0.9)%**	**1.1%**	**1.1%**

* *Effective March 1, 2019, recovered as an OATT charge under the Interconnection Lease Agreement*

Schedule 15-3 – Before Tax						
Annual Cost for Urban Residential Customer (650 kWh per Month/7,800 kWh per Year)						
Bill Component	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2019 Forecast**	**2020 Forecast**	**2021 Forecast**
Service Charge	$ 294.84	$ 294.84	$ 294.84	$ 294.84	$ 294.84	$ 294.84
Basic Energy Charge	1,029.60	1,072.50	1,099.02	1,121.64	1,151.28	1,169.22
ECAM Charge	16.06	9.26	4.48	28.42	13.92	11.51
Provincial Costs Recoverable	41.81	41.81	41.81	-	-	-
Provincial Energy Efficiency Program	-	-	-	5.46	6.24	7.02
Cable Contingency Fund*	2.11	2.11	2.11	-	-	-
RORA	(31.96)	(36.91)	(26.87)	(19.53)	(19.53)	(19.53)
Sub-Total – Before Tax	**1,352.46**	**1,383.61**	**1,415.39**	**1,430.83**	**1,446.75**	**1,463.06**
Percentage Annual Increase (%)	**2.3%**	**2.3%**	**2.3%**	**1.1%**	**1.1%**	**1.1%**

* *Effective March 1, 2019, recovered as an OATT charge under the Interconnection Lease Agreement*

b. Schedules 15-2 and 15-3 are reproduced below to show the annual cost and percentage change if there were no Clean Energy Price Incentive in 2019, 2020 or 2021.

Schedule 15-2 Annual Cost for Rural Residential Customer (650 kWh per Month/7,800 kWh per Year)						
Bill Component	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2019 Forecast**	**2020 Forecast**	**2021 Forecast**
Service Charge	$ 323.04	$ 323.04	$ 323.04	$ 294.84	$ 294.84	$ 294.84
Basic Energy Charge	1,029.60	1,072.50	1,099.02	1,121.64	1,151.28	1,169.22
ECAM Charge	16.06	9.26	4.48	28.42	13.92	11.51
Provincial Costs Recoverable	41.81	41.81	41.81	-	-	-
Provincial Energy Efficiency Program	-	-	-	5.46	6.24	7.02
Cable Contingency Fund*	2.11	2.11	2.11	-	-	-
RORA	(31.96)	(36.91)	(26.87)	(19.53)	(19.53)	(19.53)
Sub-Total	1,380.66	1,411.81	1,443.59	1,430.83	1,446.75	1,463.06
HST**	199.05	211.78	216.54	214.62	217.01	219.46
Provincial Clean Energy Rebate***	-	-	(74.70)	-	-	-
Total Annual Cost	**$ 1,579.71**	**$ 1,623.59**	**$ 1,585.43**	**$ 1,645.45**	**$ 1,663.76**	**$ 1,682.52**
Percentage Annual Increase (%)	**2.7%**	**2.8%**	**-2.4%**	**3.8%**	**1.1%**	**1.1%**

* *Effective March 1, 2019, recovered as an OATT charge under the Interconnection Lease Agreement*
** *HST Rate increased from 14% to 15% effective October 1, 2016*
*** *Effective July 16, 2018 on first 2,000 kWh of consumption; no rebate post 2018*

Schedule 15-3 Annual Cost for Urban Residential Customer (650 kWh per Month/7,800 kWh per Year)						
Bill Component	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2019 Forecast**	**2020 Forecast**	**2021 Forecast**
Service Charge	$ 294.84	$ 294.84	$ 294.84	$ 294.84	$ 294.84	$ 294.84
Basic Energy Charge	1,029.60	1,072.50	1,099.02	1,121.64	1,151.28	1,169.22
ECAM Charge	16.06	9.26	4.48	28.42	13.92	11.51
Provincial Costs Recoverable	41.81	41.81	41.81	-	-	-
Provincial Energy Efficiency Program	-	-	-	5.46	6.24	7.02
Cable Contingency Fund*	2.11	2.11	2.11	-	-	-
RORA	(31.96)	(36.91)	(26.87)	(19.53)	(19.53)	(19.53)
Sub-Total	1,352.46	1,383.61	1,415.39	1,430.83	1,446.75	1,463.06
HST**	194.98	207.55	212.31	214.62	217.01	219.46
Provincial Clean Energy Rebate***	-	-	(74.70)	-	-	-
Total Annual Cost	**$ 1,547.44**	**$ 1,591.16**	**$ 1,553.00**	**$ 1,645.45**	**$ 1,663.76**	**$ 1,682.52**
Percentage Annual Increase (%)	**2.7%**	**2.8%**	**-2.4%**	**6.0%**	**1.1%**	**1.1%**

* *Effective March 1, 2019, recovered as an OATT charge under the Interconnection Lease Agreement*
** *HST Rate increased from 14% to 15% effective October 1, 2016*
*** *Effective July 16, 2018 on first 2,000 kWh of consumption; no rebate post 2018*

Calculation of Schedule 4-2					
Annual Payments of Costs Recoverable From Customers on Behalf of the Province					
Funding Requirements		2019	2020	2021	
Dalhousie	A	$ 1,168,352	$ 1,168,352	$ 97,363	
Lepreau	B	4,871,498	4,871,498	5,620,285	
Subtotal - PEIEC Debt Repayments March 1 - February 28	C = A + B	6,039,851	6,039,851	5,717,647	
2018 - 2019 Collections in Excess of Payments	D	(300,000)	(300,000)	-	
Subtotal Annual Payments to be paid by MECL to PEIEC - March 1 - February 28	E = C + D	5,739,851	5,739,851	5,717,647	
Monthly Payments	F = E / 12	478,321	478,321	476,471	
Number of Monthly Payments	G	10	12	12	
Total Payments to be paid by MECL to PEIEC - Calendar Year (January 1 - December 31)	**H = F x G**	**$ 4,783,209**	**$ 5,739,851**	**$ 5,721,348**	*

* Payments for 2021 = 2 months (Janaury & February) x $478,321 + 10 months (March - December) = $5,721,348.

IR-2 – Attachment 2

THE ATTACHMENT HAS BEEN FILED WITH THE COMMISSION ON A CONFIDENTIAL BASIS.

Prince Edward Island
CANADA

Energy Corporation

Société de l'énergie

Île-du-Prince-Édouard
CANADA

PO Box 2000, Charlottetown
Prince Edward Island
Canada C1A 7N8

C.P. 2000, Charlottetown
Île-du-Prince-Édouard
Canada C1A 7N8

January 23, 2019

Mr. Jason Roberts, CPA, CA
Vice President, Finance & CFO
Maritime Electric Company Limited
180 Kent Street
Charlottetown, PE C1A 7N2

Dear Mr. Roberts:

Further to our previous discussions, I am writing to document our request to amend the Debt Collection Agreement in respect of the debts assumed by the PEI Energy Corporation in relation to the refurbishment and closure of the Point Lepreau Nuclear and Dalhousie Generating Stations, respectively.

The PEI Energy Corporation has received insurance settlement proceeds which, pursuant to section 6.1 of the Debt Collection Agreement, are to be used to reduce the principal of the outstanding debt. This reduction in principal constitutes a material change under section 5.8 of the Debt Collection Agreement, thus enabling us to request adjustment of the debt collection rates. To assist in determining an appropriate new collection rate, we completed a review of our financing arrangements with respect to the Dalhousie and Point Lepreau debts and concluded that it would be in the best interests of ratepayers to refinance one of the Point Lepreau loans. This refinancing will facilitate the establishment of a fixed monthly repayment amount which will provide stability and predictability in terms of the impact on electricity rates and ensure equity among ratepayers as, when considered collectively, ratepayers who benefit from Point Lepreau electricity today and in the future will share in the cost equally.

The aforementioned refinancing is currently underway and is expected to be completed prior to March 1, 2019. It is estimated that, as of March 1, 2019, the total outstanding principal on the Dalhousie and Point Lepreau loans will be approximately $80 million. The interest rate applicable to the refinanced loan will not be finalized until the refinancing is complete. However, the new interest rate is expected to be comparable to the rates on the existing Dalhousie and Point Lepreau loans, which range from 1.87% to 3.41%. The collection rate required to cover the principal and interest payments on this debt until it is fully repaid in March 2038 is estimated to be approximately $480,000 per month. Please note that the amounts recovered from ratepayers are equal to the PEI Energy Corporation's costs. Neither Maritime Electric nor the PEI Energy Corporation earns a profit on the recovery of these debts.

We look forward to working with Maritime Electric over the coming month to amend the Debt Collection Agreement to establish a fixed monthly repayment amount. If you have any questions or concerns, please don't hesitate to contact me.

Sincerely,

Crystal Burrows, CPA, CA
Chief Financial Officer

Calculation of Annual ECAM Base Rate					
Description	GRA Reference		2019 Forecast	2020 Forecast	2021 Forecast
Energy Supply by Source ($)	SCHEDULE 8-4	A	$ 128,543,600	$ 134,807,900	$ 136,509,600
Net Purchased and Produced Energy X 1000 (GWh converted to kWh)	SCHEDULE 8-3	B	1,365,034,762	1,401,254,102	1,423,094,943
Energy Supply Cost per kWh		C = A / B	$ 0.09417	$ 0.09621	$ 0.09592
Rate Stability Adjustment		D	(0.00082)	(0.00145)	(0.00001)
ECAM Base Rates (March 1 - February 28)	**SCHEDULE 5-1**	**C + D**	**$ 0.09335**	**$ 0.09475**	**$ 0.09591**

Date	Pre-2016 RORA Balance	Post 2015 Balance	WNRA	Total
12/31/2015	(18,473,242.88)	-	-	**(18,473,242.88)**
01/31/2016	(18,438,493.63)	-	-	(18,438,493.63)
02/29/2016	(15,064,497.63)	-	254,797.62	(14,809,700.01)
03/31/2016	(14,981,767.69)	-	219,449.97	(14,762,317.72)
04/30/2016	(14,600,739.61)	-	104,990.92	(14,495,748.69)
05/31/2016	(14,255,525.68)	-	116,563.07	(14,138,962.61)
06/30/2016	(15,185,977.30)	-	93,418.78	(15,092,558.52)
07/31/2016	(13,240,632.39)	(1,600,000.00)	65,014.42	(14,775,617.97)
08/31/2016	(12,881,706.56)	(1,600,000.00)	67,539.25	(14,414,167.31)
09/30/2016	(12,517,470.21)	(2,600,000.00)	80,373.81	(15,037,096.40)
10/31/2016	(12,173,167.79)	(2,600,000.00)	117,825.48	(14,655,342.31)
11/30/2016	(11,815,291.59)	(2,600,000.00)	161,589.23	(14,253,702.36)
12/31/2016	**(11,405,336.50)**	**(2,100,000.00)**	**126,031.18**	**(13,379,305.32)**
01/31/2017	(10,943,339.08)	(2,104,815.62)	209,549.20	(12,838,605.50)
02/28/2017	(10,495,767.03)	(2,109,175.18)	310,199.12	(12,294,743.09)
03/31/2017	(10,025,011.92)	(2,514,011.84)	215,973.67	(12,323,050.09)
04/30/2017	(9,544,038.12)	(2,518,703.21)	254,520.45	(11,808,220.88)
05/31/2017	(9,125,996.23)	(2,523,561.72)	237,388.55	(11,412,169.40)
06/30/2017	(8,705,722.16)	(3,728,274.28)	282,359.79	(12,151,636.65)
07/31/2017	(8,283,279.63)	(3,733,606.63)	250,237.48	(11,766,648.78)
08/31/2017	(7,849,942.41)	(3,738,952.34)	237,388.55	(11,351,506.20)
09/30/2017	(7,414,559.68)	(3,744,578.08)	222,943.67	(10,936,194.09)
10/31/2017	(7,009,890.46)	(3,750,406.63)	387,409.92	(10,372,887.17)
11/30/2017	(6,580,770.97)	(3,756,062.49)	352,931.97	(9,983,901.49)
12/31/2017	**(6,080,481.54)**	**(4,929,807.25)**	**178,186.58**	**(10,832,102.21)**
01/31/2018	(5,506,175.89)	(4,936,141.98)	167,877.80	(10,274,440.07)
02/28/2018	(4,954,287.99)	(4,941,880.44)	351,278.20	(9,544,890.23)
03/31/2018	(4,610,766.81)	(6,148,250.54)	471,387.48	(10,287,629.87)
04/30/2018	(4,256,238.30)	(6,185,961.58)	459,400.53	(9,982,799.35)
05/31/2018	(3,935,557.74)	(6,200,571.13)	444,536.71	(9,691,592.16)
06/30/2018	(3,620,666.10)	(7,014,750.83)	333,297.78	(10,302,119.15)
07/31/2018	(3,308,181.84)	(7,030,509.51)	314,837.99	(10,023,853.36)
08/31/2018	(2,954,381.37)	(7,046,317.71)	340,010.59	(9,660,688.49)
09/30/2018	(2,615,944.26)	(8,061,664.05)	292,062.77	(10,385,545.54)
10/31/2018	(2,308,681.61)	(8,078,644.89)	135,752.89	(10,251,573.61)
11/30/2018	(1,959,447.16)	(8,095,133.09)	(80,252.00)	(10,134,832.25)
12/31/2018	**(1,558,404.65)**	**(10,352,034.74)**	**(290,982.79)**	**(12,201,422.18)**

IR - 7 Table 1		
Post-2015 RORA		
Balance, December 31, 2015		$ -
Actual RORA - 2016	See "A" below	2,100,000
Actual RORA - 2017	See "B" below	2,767,885
2017 Accrued Interest	See Attachment 1	61,922
Forecast RORA - 2018	See "C" below	3,952,400
2018 Forecast Accrued Interest	See Attachment 1	116,493
Balance, December 31, 2018		$ 8,998,700
Transfer Balance Pre-2016 RORA to Post-2015 Balance		768,700
Forecast Balance March 1, 2018		$ 9,767,400
A = Actual RORA 2016:		
Net Income Before Tax and RORA		$ 20,339,716
Less: RORA		(2,100,000)
Less: Income Taxes		(5,754,350)
Add: Non Recoverable Fortis Inc. Costs		456,090
Regulated Earnings		12,941,456
Average Regulated Common Equity		$ 138,342,099
Allowed ROE		9.35%
B = Actual RORA 2017:		
Net Income Before Tax and RORA		$ 21,636,768
Less: RORA		(2,767,885)
Less: Income Taxes		(5,940,740)
Add: Non Recoverable Fortis Inc. Costs		422,280
Regulated Earnings		13,350,423
Average Regulated Common Equity		$ 142,798,854
Allowed ROE		9.35%
C = Forecast RORA 2018:		
Net Income Before Tax and RORA		$ 23,416,525
Less: RORA		(3,952,400)
Less: Income Taxes		(6,085,701)
Add: Non Recoverable Fortis Inc. Costs		409,860
Regulated Earnings		13,788,284
Average Regulated Common Equity		147,452,138
Allowed ROE		9.35%

Interest on Post-2015 RORA:

	Opening Balance	Transfer to RORA	Balance for Interest	Prime	# Days	Interest on Balance
Jan-17	-	$ 2,100,000	2,100,000	2.70%	31	4,816
Feb-17	2,104,816		2,104,816	2.70%	28	4,360
Mar-17	2,109,175		2,109,175	2.70%	31	4,837
Apr-17	2,114,012		2,114,012	2.70%	30	4,691
May-17	2,118,703		2,118,703	2.70%	31	4,859
Jun-17	2,123,562		2,123,562	2.70%	30	4,713
Jul-17	2,128,274		2,128,274	2.95%	31	5,332
Aug-17	2,133,607		2,133,607	2.95%	31	5,346
Sep-17	2,138,952		2,138,952	3.20%	30	5,626
Oct-17	2,144,578		2,144,578	3.20%	31	5,829
Nov-17	2,150,407		2,150,407	3.20%	30	5,656
Dec-17	2,156,062		2,156,062	3.20%	31	5,860
	Total 2017 Interest - Pre-2016 RORA					**$ 61,922**
Jan-18	2,161,922	2,767,885	4,929,807	3.45%	31	14,445
Feb-18	4,944,252		4,944,252	3.45%	28	13,085
Mar-18	4,957,338		4,957,338	3.45%	31	14,526
Apr-18	4,971,863		4,971,863	3.45%	30	14,098
May-18	4,985,962		4,985,962	3.45%	31	14,610
Jun-18	5,000,571		5,000,571	3.45%	30	14,180
Jul-18	5,014,751		5,014,751	3.70%	31	15,759
Aug-18	5,030,510		5,030,510	3.70%	31	15,808
	Total 2018 Interest - Pre-2016 RORA					**$ 116,510**

Rounding adjustment of $(17)

Note: Interest was not forecast beyond actual recorded for August 2018 as the offsetting expense would result in reducing the 2018 RORA adjustment and the balance would be the same in the end.

IR - 7 Table 2
Pre-2016 RORA

Balance, December 31, 2015		**$ 15,156,765**
Refund to Customers 2016		
Actual Sales in kWh January & February - 2016	224,065,884	-
Refund Rate per kWh	0.00071	(159,087)
Actual Sales in kWh - March to December 2016	964,358,529	-
Refund Rate per kWh	0.00410	(3,953,870)
Accrued Interest		360,528
Balance, December 31, 2016		**$ 11,404,336**
Refund to Customers 2017		
Actual Sales in kWh January & February - 2017	233,000,053	-
Refund Rate per kWh	0.00410	(955,300)
Actual Sales in kWh - March to December 2017	975,058,175	-
Refund Rate per kWh	0.00473	(4,612,025)
Accrued Interest		243,471
Balance, December 31, 2017		**$ 6,080,482**
Forecast Refund to Customers 2018		
Actual Sales in kWh January & February - 2018	244,261,639	-
Refund Rate per kWh	0.00473	(1,155,358)
Forecast Sales in kWh - March to December 2018	990,572,630	-
Refund Rate per kWh	0.00345	(3,417,476)
Forecast Accrued Interest		96,018
Rounding Adjustments		4,933
Balance, December 31, 2018		**$ 1,608,600**
Forecast Sales in kWh January & February - 2019	243,778,281	
Refund Rate per kWh	0.00345	(841,035)
Rounding Adjustments		1,135
Transfer Balance Pre-2016 RORA to Post-2015 Balance		**(768,700)**
Balance March 1, 2018		**$ (0)**

Interest on Pre-2016 RORA:

	Opening Balance	Refunded	Balance for Interest	Prime	# Days	Interest on Balance
Jan-16	15,156,765	(80,389)	15,076,376	2.70%	31	34,478
Feb-16	15,110,854	(78,698)	15,032,156	2.70%	29	32,159
Mar-16	15,064,315	(427,381)	14,636,934	2.70%	31	33,473
Apr-16	14,670,407	(423,383)	14,247,025	2.70%	30	31,530
May-16	14,278,555	(388,172)	13,890,383	2.70%	31	31,766
Jun-16	13,922,149	(366,704)	13,555,445	2.70%	30	30,000
Jul-16	13,585,444	(375,638)	13,209,806	2.70%	31	30,209
Aug-16	13,240,015	(388,398)	12,851,618	2.70%	31	29,390
Sep-16	12,881,008	(391,961)	12,489,046	2.70%	30	27,640
Oct-16	12,516,686	(372,146)	12,144,541	2.70%	31	27,773
Nov-16	12,172,314	(384,038)	11,788,275	2.70%	30	26,089
Dec-16	11,814,364	(436,049)	11,378,315	2.70%	31	26,021
	Total 2016 Interest - Pre-2016 RORA					**360,528**
Jan-17	11,404,336	(486,034)	10,918,302	2.70%	31	25,037
Feb-17	10,943,339	(469,266)	10,474,073	2.70%	28	21,694
Mar-17	10,495,767	(493,691)	10,002,076	2.70%	31	22,936
Apr-17	10,025,012	(502,107)	9,522,905	2.70%	30	21,133
May-17	9,544,038	(438,921)	9,105,117	2.70%	31	20,879
Jun-17	9,125,996	(439,551)	8,686,445	2.70%	30	19,277
Jul-17	8,705,722	(443,144)	8,262,578	2.95%	31	20,702
Aug-17	8,283,280	(452,956)	7,830,324	2.95%	31	19,619
Sep-17	7,849,942	(454,833)	7,395,110	3.20%	30	19,450
Oct-17	7,414,560	(423,669)	6,990,891	3.20%	31	19,000
Nov-17	7,009,890	(446,382)	6,563,508	3.20%	30	17,263
Dec-17	6,580,771	(516,770)	6,064,001	3.20%	31	16,481
	Total 2017 Interest - Pre-2016 RORA					**243,471**
Jan-18	6,080,482	(590,392)	5,490,089	3.45%	31	16,087
Feb-18	5,506,176	(564,965)	4,941,211	3.45%	28	13,077
Mar-18	4,954,288	(356,383)	4,597,906	3.45%	31	13,472
Apr-18	4,611,378	(367,175)	4,244,203	3.45%	30	12,035
May-18	4,256,238	(332,178)	3,924,060	3.45%	31	11,498
Jun-18	3,935,558	(325,129)	3,610,429	3.45%	30	10,238
Jul-18	3,620,666	(322,848)	3,297,819	3.70%	31	10,363
Aug-18	3,308,182	(363,055)	2,945,127	3.70%	31	9,255
	Total 2018 Interest - Pre-2016 RORA					**$ 96,025**

Rounding adjustment of $(7)

Note: Interest was not forecast beyond actual recorded for August 2018 as the offsetting expense would result in reducing the 2018 RORA adjustment and the balance would be the same in the end.

RORA Repayment Rate Calculation

			Forecast kWh Sales
March - December 2019			1,023,213,596
January - December 2020			1,300,906,376
January - December 2021			1,321,357,361
January - February 2022			255,441,249
Total kWh Sales March 1 2019 - February 28, 2022	A		3,900,918,582
Projected RORA Balance - Febraury 28, 2019	B	$	9,768,400
Collection Rate per kWh	C = B/A	$	0.00250

10. PEIEC
Charlottetown Thermal Generating Station (CTGS)
If CT4 is located on PEI, in considering where it should be located, has MECL thought about other uses for the CTGS site once the CTGS is retired? By putting CT4 there it ties up the site for another 50 years. What are the economics of relocating the diesel storage, the transmission infrastructure and CT3 once the CTGS is retired, so that the CTGS property could be sold off and redeveloped as a prime waterfront location?

Response:

The CTGS – the heavy fuel oil-fired thermal generating station - is one component of the Charlottetown Plant site, which also includes CT3, Bunker C and diesel fuel storage facilities, the Energy Control Centre, and the Charlottetown Substation. Maritime Electric is committed to the Charlottetown Plant site in the long run, given its strategic location for both load-serving as well as fuel delivery purposes.

The Charlottetown Substation, located on the Charlottetown Plant site, is a key feature of the site's infrastructure. It provides the stepdown location (from 69kV to 13.8kV) for supply to Charlottetown's downtown and east side customers. It also provides a reliable source of supply for these areas, and helps to reduce distribution-level losses given its proximity to the load it serves. Moving this substation would mean extra rights of way for both distribution and transmission lines, in addition to the cost and space required for a new substation.

CT3 is also well-situated at the Charlottetown Plant site to provide much needed energy and system support to both Charlottetown and eastern PEI through the T-2 transmission line connecting the Charlottetown Substation to Lorne Valley and beyond. Its proximity to the Charlottetown Harbour gives Maritime Electric the long-term option of having diesel fuel delivered via marine transport, which Maritime Electric is currently investigating due to land transport restrictions encountered during the last several winter seasons.

If natural gas becomes available in commercial quantities in the Charlottetown area, the Charlottetown Harbour provides a natural cooling water source in the event that Maritime Electric adds a heat recovery steam generator to provide greater fuel efficiencies to the generating station.

The cost to move CT3 to a new location depends on where the facility is to be located. Below is an order of magnitude estimate of the relocation costs to a site in the greater Charlottetown area:

ITEM	COST (nominal millions)	COMMENT
CT3 Disassembly, Transport, and Site Acquisition and Prep	$ 3.0	Labour, materials and transport to disassemble CT3 and move to the new site, which has to be acquired and prepared.
CT3 Reassemble and Commission*****	$18.1	Includes EPC work (civil works, electrical and fuel buildings, cabling, balance of plant equipment, connections, engineering, construction management), permitting, regulatory, contingency and interest during construction.
Fuel Storage	$ 2.2	Cost of sufficient fuel storage tanks, piping, fuel offloading, and containment berms.
Substation	$ 2.0	Cost to establish new substation site and attach CT3 to new substation. Does not include cost a) of replacing distribution circuits that would be removed from Charlottetown Plant site, or b) to run 69kV or 138kV transmission line to the new substation.
Water Supply	$ 0.5	Assumes deep water well system has to be developed to supply NOx controls, as well as waste water facilities installed. Water conditioning equipment assumed to be relocated from CTGS.
Total	**$25.8**	

*** Many of the tasks to site, install, reassemble and commission CT3 would be similar to cost to install, assemble and commission CT4, except that a portion of the engineering design has already been completed.**

Costs to locate CT3 elsewhere in the Province would be similar except for the cost of water supply and transmission costs, which are highly location-dependent.

To put the above \$ 25.8 million estimate into perspective, approximately half of the cost for a simple cycle combustion turbine is the combustion turbine equipment supply cost from the manufacturer. The other half is the cost of balance of plant equipment and the costs for installation, commissioning, engineering and project management and interest during construction. Much of this other half of the cost would be incurred in relocating an already installed combustion turbine. Half of the \$ 68 million estimated cost for CT4 is \$ 34 million, and thus the \$ 25.8 million estimate to relocate CT3 looks reasonable as compared to \$ 34 million for the “other half” of the estimated cost for CT4.

Details of Actual and Forecast Energy Control Centre Labour Costs

			Actuals				Forecasts 2018 Hourly Rate, 2% CPI and 20% Overhead Rate			
			2016	2017	2018		2018	2019	2020	2021
			5 Operators	6 Operators	6.5 Operators	Budget	6.5 Operators	7 Operators	7 Operators	7 Operators
Hourly			$ 42.92	$ 44.00	$ 45.10	Hours	$ 45.10	$ 46.00	$ 46.92	$ 47.86
Regular		2184	$ 342,159	$ 465,980	$ 590,403	2184	$ 640,240	$ 703,279	$ 717,344	$ 731,691
OT		10	$ 2,078	$ 2,034	$ 6,252	10	$ 4,397	$ 4,830	$ 4,927	$ 5,025
DT		200	$ 42,615	$ 66,355	$ 51,649	200	$ 117,260	$ 128,806	$ 131,382	$ 134,009
						20%	$ 152,379	$ 167,383	$ 170,731	$ 174,145
							$ 914,276	$ 1,004,297	$ 1,024,383	$ 1,044,871
							75%	75%	75%	75%
			$ 386,852	$ 534,369	$ 648,304	Note 2	$ 685,707	$ 753,223	$ 768,287	$ 783,653
Supervision and Management	Note 1		128,980	123,397	170,292		185,200	200,197	225,115	219,715
Spare Operators from Other Departments			256,657	90,544	66,982	Note 3	72,693	115,480	114,098	119,532
			$ 772,489	$ 748,310	$ 885,578		$ 943,600	$ 1,068,900	$ 1,107,500	$ 1,122,900

Note 1 - 2016 & part of 2017, Manager was seconded to be project manager of cable project.

Note 2 - For budgeting purposes, 75% of ECC Operators time is allocated to ECC Operations and 25% to OATT Administration.

Note 3 - Timing of budget in spring of 2018 before full complement of ECC operators were hired so 2019 - 2021 budget still reflects an allocation for "spare" operators from other departments. As a result, budget for ECC operations should be lower and budget labour in T & D and generation should be higher.

MARITIME ELECTRIC COMPANY

TABLE 1. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST, CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ELECTRIC PLANT AT DECEMBER 31, 2017

	DEPRECIABLE GROUP	PROBABLE RETIREMENT YEAR	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AT 12/31/2017	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	CALCULATED ACCRUED DEPRECIATION
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(5)	(8)
DEPRECIABLE ELECTRIC PLANT								
STEAM PRODUCTION PLANT								
CHARLOTTETOWN STEAM PLANT								
311	STRUCTURES AND IMPROVEM	12-2021	80 - S0	(19)	9,006,038	547,357	6.08	8,546,939
312	BOILER PLANT EQUIPMENT	12-2021	75 - R2	(19)	26,445,980	1,285,317	4.86	26,377,078
314	TURBOGENERATOR UNITS							
	UNIT 7	12-2019	100 - S0	(19)	1,954,691	113,005	5.78	2,100,717
	UNIT 8	12-2020	100 - S0	(19)	3,909,382	209,582	5.36	4,026,569
	UNITS 9 AND 10	12-2021	100 - S0	(19)	15,637,528	796,856	5.10	15,442,475
	TOTAL TURBOGENERATOR UNITS				*21,501,600*	*1,119,443*	*5.21*	*21,569,761*
315	ACCESSORY ELECTRICAL EQU	12-2021	80 - R2	(19)	2,283,113	68,942	3.02	2,444,835
316	MISCELLANEOUS POWER PLA	12-2021	70 - L0	(19)	1,512,887	68,526	4.53	1,531,750
TOTAL STEAM PRODUCTION PLANT					**60,749,618**	**3,089,585**	**5.09**	**60,470,363**
OTHER PRODUCTION PLANT								
BORDEN								
341	STRUCTURES AND IMPROVEM	06-2031	70 - S0	(3)	481,306	14,050	2.92	316,843
344	GENERATORS	06-2031	65 - S0.5	(3)	12,865,545	535,707	4.16	6,266,803
346	MISCELLANEOUS POWER PLA	06-2031	30 - L3	(3)	320,116	13,054	4.08	187,125
SUBTOTAL BORDEN					*13,666,966*	*562,811*	*4.12*	*6,770,771*
CHARLOTTETOWN - CT3								
344	GENERATORS	06-2056	65 - S0.5	(3)	35,297,121	824,633	2.34	8,505,193
TOTAL OTHER PRODUCTION PLANT					**48,964,087**	**1,387,444**	**2.83**	**15,275,964**
TRANSMISSION PLANT								
350.2	RIGHTS OF WAY AND EASEMENTS		70 - R5	0	4,462,985	63,821	1.43	1,066,585
353	SUBSTATION EQUIPMENT		57 - R3	(5)	50,295,933	924,188	1.84	13,293,620
354	TOWERS AND FIXTURES		60 - R4	(20)	878,834	17,612	2.00	642,774
355	POLES AND FIXTURES		52 - R2.5	(70)	22,861,634	746,204	3.26	8,531,641
356	OVERHEAD CONDUCTORS		60 - R3	(70)	45,621,955	1,295,207	2.84	13,823,101
359	ROADS AND TRAILS		50 - S2	0	73,263	1,465	2.00	12,411
TOTAL TRANSMISSION PLANT					**124,194,604**	**3,048,497**	**2.45**	**37,370,132**
DISTRIBUTION PLANT								
360.2	RIGHT OF WAY		70 - R5	0	282,000	4,033	1.43	56,490
362	SUBSTATION EQUIPMENT		47 - R3	(5)	3,289,859	73,578	2.24	1,021,848

MARITIME ELECTRIC COMPANY

TABLE 1. ESTIMATED SURVIVOR CURVE, NET SALVAGE, ORIGINAL COST, CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO ELECTRIC PLANT AT DECEMBER 31, 2017

	DEPRECIABLE GROUP	PROBABLE RETIREMENT YEAR	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AT 12/31/2017	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	CALCULATED ACCRUED DEPRECIATION
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(5)	(8)
364	POLES, TOWERS AND FIXTURES		47 - R1.5	(60)	75,601,860	2,576,511	3.41	29,150,175
365	OVERHEAD CONDUCTORS		52 - R2.5	(60)	93,875,166	2,883,845	3.07	31,574,543
367	UNDERGROUND CONDUCTORS		50 - R3	(10)	3,097,194	68,138	2.20	1,238,516
368.1	LINE TRANSFORMERS		34 - R2.5	(20)	69,024,150	2,435,172	3.53	26,297,861
368.2	LINE TRANSFORMER INSTALLATIONS		34 - R2.5	(20)	12,591,274	444,220	3.53	3,802,327
369.01	SERVICES - OVERHEAD		46 - R3	(60)	67,238,249	2,334,512	3.47	33,734,931
369.02	SERVICES - UNDERGROUND		45 - R3	(10)	2,076,695	50,713	2.44	1,021,271
370.1	METERS		21 - S2	(2)	14,245,974	691,671	4.86	6,207,289
370.2	METER INSTALLATIONS		30 - L3	0	651,341	21,690	3.33	72,818
373	STREET LIGHTING AND SIGNAL SYSTEMS		27 - R2	(25)	6,053,459	279,972	4.62	2,324,282
373.2	STREET LIGHTING & SIGNAL SYSTEMS - UNDER		27 - R2	(10)	653,789	26,609	4.07	551,668
TOTAL DISTRIBUTION PLANT					**348,681,010**	**11,890,664**	**3.41**	**137,054,019**
GENERAL PLANT								
390	STRUCTURES & IMPROVEMENTS - ENERGY COI		40 - R1	0	903,406	22,585	2.50	436,181
390.11	STRUCTURES & IMPROVEMENTS - OFFICE		40 - R1	0	4,981,390	124,535	2.50	1,899,606
390.12	STRUCTURES & IMPROVEMENTS - DISTRICTS		40 - R1	0	6,358,301	158,958	2.50	2,271,342
391.12	OFFICE FURNITURE & EQUIP. - EQUIPMENT		15 - SQ	0	77,037	5,138	6.67	33,465
391.3	OFFICE FURNITURE & EQUIP. - COMPUTER HAR		5 - SQ	0	1,127,561	225,512	20.00	496,829
391.4	OFFICE FURNITURE & EQUIP. - COMPUTER SOF		10 - SQ	0	5,977,486	597,749	10.00	2,735,085
392	TRANSPORTATION EQUIPMENT		13 - S2	10	11,944,126	799,747	6.70	5,068,505
394	TOOLS, SHOP AND GARAGE EQUIPMENT		20 - SQ	0	1,115,936	55,797	5.00	376,109
397	COMMUNICATION EQUIPMENT		20 - S4	(5)	10,214,242	489,939	4.80	5,919,193
397.5	COMMUNICATION EQUIPMENT - SCADA		15 - S2	0	1,815,241	106,400	5.86	1,152,993
TOTAL GENERAL PLANT					**44,514,726**	**2,586,360**	**5.81**	**20,389,308**
TOTAL DEPRECIABLE ELECTRIC PLANT					**627,104,044**	**22,002,550**	**3.51**	**270,559,786**
NONDEPRECIABLE PLANT								
310	LAND AND LAND RIGHTS				2,261,810			
340	LAND AND LAND RIGHTS				43,567			
350	LAND AND LAND RIGHTS				1,101,484			
360	LAND AND LAND RIGHTS				9,973			
389	LAND AND LAND RIGHTS				350,201			
TOTAL NONDEPRECIABLE PLANT					**3,767,035**			
TOTAL ELECTRIC PLANT IN SERVICE					**630,871,079**			

a Intangible Developed Software is included in Account 391.4 for depreciation purposes.

MARITIME ELECTRIC COMPANY

TABLE 2. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF RESERVE
VARIANCE AMORTIZATIONS RELATED TO ELECTRIC PLANT AT DECEMBER 31, 201

	DEPRECIABLE GROUP	ORIGINAL COST AT 12/31/2017	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	RESERVE VARIANCE AMOUNT	RESERVE VARIANCE PERCENT	REM. LIFE AMORTIZATION PERIOD	RESERVE VARIANCE AMORTIZATION
	(1)	(2)	(3)	(4)	(5)=(3)-(4)	(6)=(5)/(3)	(7)	(8)=(5)/(7)
DEPRECIABLE ELECTRIC PLANT								
STEAM PRODUCTION PLANT								
CHARLOTTETOWN STEAM PLANT								
311	STRUCTURES & IMPROVEME	9,006,038	8,546,939	5,576,582	2,970,357	35%	3.96	750,090
312	BOILER PLANT EQUIPMENT	26,445,980	26,377,078	19,588,953	6,788,125	26%	3.96	1,714,173
314	TURBOGENERATOR UNITS							
	UNIT 7	1,954,691	2,100,717	1,373,687	727,030	35%	1.99	365,342
	UNIT 8	3,909,382	4,026,569	2,633,028	1,393,541	35%	2.98	467,631
	UNITS 9 AND 10	15,637,528	15,442,475	10,098,042	5,344,433	35%	3.97	1,346,205
	TOTAL TURBOGENERATOR U	*21,501,600*	*21,569,761*	*14,104,757*	*7,465,004*	*35%*		*2,179,178*
315	ACCESSORY ELECTRICAL EC	2,283,113	2,444,835	1,996,684	448,151	18%	3.95	113,456
316	MISCELLANEOUS POWER PL	1,512,887	1,531,750	1,196,410	335,340	22%	3.92	85,546
TOTAL STEAM PRODUCTION PLANT		**60,749,618**	**60,470,363**	**42,463,386**	**18,006,977**	**30%**		**4,842,443**
OTHER PRODUCTION PLANT								
BORDEN								
341	STRUCTURES AND IMPROVE	481,306	316,843	212,391	104,452	33%	12.73	8,205
344	GENERATORS	12,865,545	6,266,803	3,388,934	2,877,869	46%	13.04	220,695
346	MISCELLANEOUS POWER PL	320,116	187,125	125,928	61,197	33%	10.92	5,604
SUBTOTAL BORDEN		*13,666,966*	*6,770,771*	*3,727,253*	*3,043,518*	*45%*		*234,504*
CHARLOTTETOWN - CT3								
344	GENERATORS	35,297,121	8,505,193	6,671,148	1,834,045	22%	33.77	54,310
TOTAL OTHER PRODUCTION PLANT		**48,964,087**	**15,275,964**	**10,398,401**	**4,877,563**	**32%**		**288,814**
TRANSMISSION PLANT								
350.2	RIGHTS OF WAY AND EASEM	4,462,985	1,066,585	1,410,494	(343,909)	-32%	53.22	(6,462)
353	SUBSTATION EQUIPMENT	50,295,933	13,293,620	17,490,414	(4,196,794)	-32%	42.76	(98,148)
354	TOWERS AND FIXTURES	878,834	642,774	727,879	(85,105)	-13%	23.38	(3,640)
355	POLES AND FIXTURES	22,861,634	8,531,641	6,574,086	1,957,555	23%	40.65	48,156
356	OVERHEAD CONDUCTORS	45,621,955	13,823,101	13,281,996	541,105	4%	49.21	10,996
359	ROAD & TRAILS	73,263	12,411	13,867	(1,456)	-12%	41.53	(35)
TOTAL TRANSMISSION PLANT		**124,194,604**	**37,370,132**	**39,498,736**	**(2,128,604)**	**-6%**		**(49,133)**
DISTRIBUTION PLANT								
360.2	RIGHT OF WAY	282,000	56,490	62,209	(5,719)	-10%	55.92	(102)
362	SUBSTATION EQUIPMENT	3,289,859	1,021,848	778,876	242,972	24%	33.06	7,349
364	POLES, TOWERS AND FIXTUI	75,601,860	29,150,175	32,224,334	(3,074,159)	-11%	35.63	(86,280)
365	OVERHEAD CONDUCTORS	93,875,166	31,574,543	27,300,129	4,274,414	14%	41.13	103,924

MARITIME ELECTRIC COMPANY

TABLE 2. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF RESERVE VARIANCE AMORTIZATIONS RELATED TO ELECTRIC PLANT AT DECEMBER 31, 201

		ORIGINAL COST	CALCULATED	BOOK	RESERVE VARIANCE		REM. LIFE		RESERVE
DEPRECIABLE GROUP		AT 12/31/2017	ACCRUED DEPRECIATION	ACCUMULATED DEPRECIATION	AMOUNT	PERCENT	AMORTIZATION PERIOD		VARIANCE AMORTIZATION
(1)		(2)	(3)	(4)	(5)=(3)-(4)	(6)=(5)/(3)	(7)		(8)=(5)/(7)
367	UNDERGROUND CONDUCTO	3,097,194	1,238,516	1,339,416	(100,900)	-8%	31.82		(3,171)
368.1	LINE TRANSFORMERS	69,024,150	26,297,861	16,616,504	9,681,357	37%	23.21		417,120
368.2	LINE TRANSFORMER INSTAL	12,591,274	3,802,327	2,136,492	1,665,835	44%	25.45		65,455
369.01	SERVICES - OVERHEAD	67,238,249	33,734,931	30,225,357	3,509,574	10%	31.63		110,957
369.02	SERVICES - UNDERGROUND	2,076,695	1,021,271	1,033,873	(12,602)	-1%	24.91		(506)
370.1	METERS	14,245,974	6,207,289	1,555,741	4,651,548	75%	12.03		386,662
370.2	METER INSTALLATIONS	651,341	72,818	(1,216,851)	1,289,669	1771%	26.67		48,357
373	STREET LIGHTING AND SIGN	6,053,459	2,324,282	1,484,641	839,641	36%	18.73		44,829
373.2	STREET LIGHTING & SIGNAL	653,789	551,668	582,596	(30,928)	-6%	6.29		(4,917)
TOTAL DISTRIBUTION PLANT		**348,681,010**	**137,054,019**	**114,123,316**	**22,930,703**	**17%**			**1,089,677**
GENERAL PLANT									
390	STRUCTURES & IMPROVEME	903,406	436,181	420,757	15,424	4%	20.69		745
390.11	STRUCTURES & IMPROVEME	4,981,390	1,899,606	2,214,718	(315,112)	-17%	24.75		(12,732)
390.12	STRUCTURES & IMPROVEME	6,358,301	2,271,342	2,537,901	(266,559)	-12%	25.71		(10,368)
391.12	OFFICE FURNITURE & EQUIP	77,037	33,465	(182,855)	216,320	646%	8.48		25,509
391.3	OFFICE FURNITURE & EQUIP	1,127,561	496,829	(150,809)	647,638	130%	5.00	b	129,528
391.4	OFFICE FURNITURE & EQUIP	5,977,486	2,735,085	3,324,011	(588,926)	-22%	5.42		(108,658)
392	TRANSPORTATION EQUIPME	11,944,126	5,068,505	4,716,477	352,028	7%	7.10		49,581
394	TOOLS, SHOP & GARAGE EQ	1,115,936	376,109	18,027	358,082	95%	13.26		27,005
397	COMMUNICATION EQUIPMEN	10,214,242	5,919,193	5,982,950	(63,757)	-1%	9.81		(6,499)
397.5	COMMUNICATION EQUIPMEN	1,815,241	1,152,993	1,221,842	(68,849)	-6%	6.22		(11,069)
TOTAL GENERAL PLANT		**44,514,726**	**20,389,308**	**20,103,018**	**286,290**	**1%**			**83,042**
TOTAL DEPRECIABLE ELECTRIC PLANT		**627,104,044**	**270,559,786**	**226,586,858**	**43,972,928**	**16%**			**6,254,843**

a Intangible Developed Software is included in Account 391.4 for depreciation purposes.
b Mass Plant Accounts with a remaining life of less than 5 years were given an amortization period of 5 years.

MARITIME ELECTRIC COMPANY

TABLE 3. CALCULATION OF TOTAL ANNUAL DEPRECIATION INCLUDING AMORTIZATIONS OF THE RESERVE VARIANCE
RELATED TO ELECTRIC PLANT AT DECEMBER 31, 2017

DEPRECIABLE GROUP		ORIGINAL COST AT 12/31/2017	ANNUAL ACCRUAL AMOUNT	RESERVE VARIANCE AMORTIZATION	TOTAL ANNUAL DEPRECIATION	ANNUAL RATE % INCL TRUE-UP
(1)		(2)	(3)	(4)	(5)	(6)
DEPRECIABLE ELECTRIC PLANT						
STEAM PRODUCTION PLANT						
CHARLOTTETOWN STEAM PLANT						
311	STRUCTURES & IMPROVEME	9,006,038	547,357	750,090	1,297,447	14.41
312	BOILER PLANT EQUIPMENT	26,445,980	1,285,317	1,714,173	2,999,490	11.34
314	TURBOGENERATOR UNITS					
	UNIT 7	1,954,691	113,005	365,342	478,347	24.47
	UNIT 8	3,909,382	209,582	467,631	677,213	17.32
	UNITS 9 AND 10	15,637,528	796,856	1,346,205	2,143,061	13.70
	TOTAL TURBOGENERATOR U	*21,501,600*	*1,119,443*	*2,179,178*	*3,298,621*	*15.34*
315	ACCESSORY ELECTRICAL EC	2,283,113	68,942	113,456	182,398	7.99
316	MISCELLANEOUS POWER PL/	1,512,887	68,526	85,546	154,072	10.18
TOTAL STEAM PRODUCTION PLANT		**60,749,618**	**3,089,585**	**4,842,443**	**7,932,028**	**13.06**
OTHER PRODUCTION PLANT						
BORDEN						
341	STRUCTURES AND IMPROVEI	481,306	14,050	8,205	22,255	4.62
344	GENERATORS	12,865,545	535,707	220,695	756,402	5.88
346	MISCELLANEOUS POWER PL/	320,116	13,054	5,604	18,658	5.83
SUBTOTAL BORDEN		*13,666,966*	*562,811*	*234,504*	*797,315*	*5.83*
CHARLOTTETOWN - CT3						
344	GENERATORS	35,297,121	824,633	54,310	878,943	2.49
TOTAL OTHER PRODUCTION PLANT		**48,964,087**	**1,387,444**	**288,814**	**1,676,258**	**3.42**
TRANSMISSION PLANT						
350.2	RIGHTS OF WAY AND EASEM	4,462,985	63,821	(6,462)	57,359	1.29
353	SUBSTATION EQUIPMENT	50,295,933	924,188	(98,148)	826,040	1.64
354	TOWERS AND FIXTURES	878,834	17,612	(3,640)	13,972	1.59
355	POLES AND FIXTURES	22,861,634	746,204	48,156	794,360	3.47
356	OVERHEAD CONDUCTORS	45,621,955	1,295,207	10,996	1,306,203	2.86
359	ROAD & TRAILS	73,263	1,465	(35)	1,430	1.95
TOTAL TRANSMISSION PLANT		**124,194,604**	**3,048,497**	**(49,133)**	**2,999,364**	**2.42**

MARITIME ELECTRIC COMPANY

TABLE 3. CALCULATION OF TOTAL ANNUAL DEPRECIATION INCLUDING AMORTIZATIONS OF THE RESERVE VARIANCE RELATED TO ELECTRIC PLANT AT DECEMBER 31, 2017

DEPRECIABLE GROUP		ORIGINAL COST AT 12/31/2017	ANNUAL ACCRUAL AMOUNT	RESERVE VARIANCE AMORTIZATION	TOTAL ANNUAL DEPRECIATION	ANNUAL RATE % INCL TRUE-UP
(1)		(2)	(3)	(4)	(5)	(6)
DISTRIBUTION PLANT						
360.2	RIGHT OF WAY	282,000	4,033	(102)	3,931	1.39
362	SUBSTATION EQUIPMENT	3,289,859	73,578	7,349	80,927	2.46
364	POLES, TOWERS AND FIXTUF	75,601,860	2,576,511	(86,280)	2,490,231	3.29
365	OVERHEAD CONDUCTORS	93,875,166	2,883,845	103,924	2,987,769	3.18
367	UNDERGROUND CONDUCTOI	3,097,194	68,138	(3,171)	64,967	2.10
368.1	LINE TRANSFORMERS	69,024,150	2,435,172	417,120	2,852,292	4.13
368.2	LINE TRANSFORMER INSTALI	12,591,274	444,220	65,455	509,675	4.05
369.01	SERVICES - OVERHEAD	67,238,249	2,334,512	110,957	2,445,469	3.64
369.02	SERVICES - UNDERGROUND	2,076,695	50,713	(506)	50,207	2.42
370.1	METERS	14,245,974	691,671	386,662	1,078,333	7.57
370.2	METER INSTALLATIONS	651,341	21,690	48,357	70,047	10.75
373	STREET LIGHTING AND SIGN/	6,053,459	279,972	44,829	324,801	5.37
373.2	STREET LIGHTING & SIGNAL !	653,789	26,609	(4,917)	21,692	3.32
TOTAL DISTRIBUTION PLANT		**348,681,010**	**11,890,664**	**1,089,677**	**12,980,341**	**3.72**
GENERAL PLANT						
390	STRUCTURES & IMPROVEME	903,406	22,585	745	23,330	2.58
390.11	STRUCTURES & IMPROVEME	4,981,390	124,535	(12,732)	111,803	2.24
390.12	STRUCTURES & IMPROVEME	6,358,301	158,958	(10,368)	148,590	2.34
391.12	OFFICE FURNITURE & EQUIP.	77,037	5,138	25,509	30,647	39.78
391.3	OFFICE FURNITURE & EQUIP.	1,127,561	225,512	129,528	355,040	31.49
391.4	OFFICE FURNITURE & EQUIP.	5,977,486	597,749	(108,658)	489,091	8.18
392	TRANSPORTATION EQUIPMEI	11,944,126	799,747	49,581	849,328	7.11
394	TOOLS, SHOP & GARAGE EQI	1,115,936	55,797	27,005	82,802	7.42
397	COMMUNICATION EQUIPMEN	10,214,242	489,939	(6,499)	483,440	4.73
397.5	COMMUNICATION EQUIPMEN	1,815,241	106,400	(11,069)	95,331	5.25
TOTAL GENERAL PLANT		**44,514,726**	**2,586,360**	**83,042**	**2,669,402**	**6.00**
TOTAL DEPRECIABLE ELECTRIC PLANT		**627,104,044**	**22,002,550**	**6,254,843**	**28,257,393**	**4.51**

a Intangible Developed Software is included in Account 391.4 for depreciation purposes.

MARITIME ELECTRIC COMPANY

TABLE 4. COMPARISON OF EXISTING AND PROPOSED ANNUAL ACCRUAL RATES AND AMOUNTS RELATED TO ELECTRIC PLANT AT DECEMBER 31, 2017

			EXISTING				PROPOSED					
		ORIGINAL COST	SURVIVOR		ANNUAL ACCRUAL[b]		SURVIVOR		ANNUAL ACCRUAL[b]		DIFFERENCE	
	DEPRECIABLE GROUP	AT 12/31/2017	CURVE	SALV %	RATE	AMOUNT	CURVE	SALV %	RATE	AMOUNT	AMOUNT	PCT.
	(1)	(2)	(3)	(4)	(5)	(6)=(2)*(5)	(7)	(8)	(9)	(10)	(11)=(10)-(6)	(12)=(11)/(6)
	DEPRECIABLE ELECTRIC PLANT											
	STEAM PRODUCTION PLANT											
	CHARLOTTETOWN STEAM PLANT											
311	STRUCTURES & IMPROVEMENTS	9,006,038	120 - S0	(10)	9.35	842,065	80 - S0	(19)	14.41	1,297,447	455,382	54%
312	BOILER PLANT EQUIPMENT	26,445,980	60 - S0	(10)	7.65	2,023,117	75 - R2	(19)	11.34	2,999,490	976,373	48%
314	TURBOGENERATOR UNITS											
	UNIT 7	1,954,691	100 - S0	(10)	8.20	160,285	100 - S0	(19)	24.47	478,347	318,062	198%
	UNIT 8	3,909,382	100 - S0	(10)	8.20	320,569	100 - S0	(19)	17.32	677,213	356,644	111%
	UNITS 9 AND 10	15,637,528	100 - S0	(10)	8.20	1,282,277	100 - S0	(19)	13.70	2,143,061	860,784	67%
	TOTAL TURBOGENERATOR UNITS	*21,501,600*										
315	ACCESSORY ELECTRICAL EQUIPMENT	2,283,113	80 - R2	(10)	5.14	117,352	80 - R2	(19)	7.99	182,398	65,046	55%
316	MISCELLANEOUS POWER PLANT EQUIPMENT	1,512,887	70 - L0	(10)	6.99	105,751	70 - L0	(19)	10.18	154,072	48,321	46%
	TOTAL STEAM PRODUCTION PLANT	**60,749,618**			**7.99**	**4,851,416**			**13.06**	**7,932,028**	**3,080,612**	**63%**
	OTHER PRODUCTION PLANT											
	BORDEN											
341	STRUCTURES AND IMPROVEMENTS	481,306	70 - S0	(3)	3.38	16,268	70 - S0	(3)	2.92	14,050	(2,218)	-14%
344	GENERATORS	12,865,545	70 - S0.5	(3)	4.88	627,839	65 - S0.5	(3)	4.16	535,707	(92,132)	-15%
346	MISCELLANEOUS POWER PLANT EQUIPMENT	320,116	SQUARE	(3)	4.30	13,765	30 - L3	(3)	4.08	13,054	(711)	-5%
	SUBTOTAL BORDEN	*13,666,966*			*4.81*	*657,872*			*4.12*	*562,811*	*(95,061)*	*-14%*
	CHARLOTTETOWN - CT3											
344	GENERATORS	35,297,121	70 - S0.5	(3)	2.28	804,774	65 - S0.5	(3)	2.34	824,633	19,859	2%
	TOTAL OTHER PRODUCTION PLANT	**48,964,087**			**2.99**	**1,462,646**			**2.83**	**1,387,444**	**(75,202)**	**-5%**
	TRANSMISSION PLANT											
350.2	RIGHTS OF WAY AND EASEMENTS	4,462,985	70 - R5	0	1.43	63,821	70 - R5	0	1.43	63,821	0	0%
353	SUBSTATION EQUIPMENT	50,295,933	55 - R3	(3)	1.87	940,534	57 - R3	(5)	1.84	924,188	(16,346)	-2%
354	TOWERS AND FIXTURES	878,834	60 - R4	(20)	2.00	17,577	60 - R4	(20)	2.00	17,612	35	0%
355	POLES AND FIXTURES	22,861,634	50 - R2	(50)	3.00	685,849	52 - R2.5	(70)	3.26	746,204	60,355	9%
356	OVERHEAD CONDUCTORS	45,621,955	55 - R3	(35)	2.46	1,122,300	60 - R3	(70)	2.84	1,295,207	172,907	15%
359	ROAD & TRAILS	73,263	50 - S2	0	2.00	1,465	50 - S2	0	2.00	1,465	(0)	0%
	TOTAL TRANSMISSION PLANT	**124,194,604**			**2.28**	**2,831,546**			**2.45**	**3,048,497**	**216,951**	**8%**
	DISTRIBUTION PLANT											
360.2	RIGHT OF WAY	282,000	70 - R5	0	1.43	4,033	70 - R5	0	1.43	4,033	0	0%
362	SUBSTATION EQUIPMENT	3,289,859	47 - R3	(3)	2.19	72,048	47 - R3	(5)	2.24	73,578	1,530	2%
364	POLES, TOWERS AND FIXTURES	75,601,860	43 - R1.5	(50)	3.49	2,638,505	47 - R1.5	(60)	3.41	2,576,511	(61,994)	-2%
365	OVERHEAD CONDUCTORS	93,875,166	51 - R2.5	(60)	3.14	2,947,680	52 - R2.5	(60)	3.07	2,883,845	(63,835)	-2%
367	UNDERGROUND CONDUCTORS	3,097,194	45 - R3	(10)	2.44	75,572	50 - R3	(10)	2.20	68,138	(7,434)	-10%
368.1	LINE TRANSFORMERS	69,024,150	35 - R2.5	(15)	3.29	2,270,895	34 - R2.5	(20)	3.53	2,435,172	164,277	7%
368.2	LINE TRANSFORMER INSTALLATIONS	12,591,274	35 - R2.5	(15)	3.29	414,253	34 - R2.5	(20)	3.53	444,220	29,967	7%
369.01	SERVICES - OVERHEAD	67,238,249	48 - R3	(50)	3.12	2,097,833	46 - R3	(60)	3.47	2,334,512	236,679	11%
369.02	SERVICES - UNDERGROUND	2,076,695	45 - R3	(10)	2.44	50,671	45 - R3	(10)	2.44	50,713	42	0%
370.1	METERS	14,245,974	20 - R3	(3)	5.01	713,723	21 - S2	(2)	4.86	691,671	(22,052)	-3%
370.2	METER INSTALLATIONS	651,341	30 - L3	0	3.33	21,690	30 - L3	0	3.33	21,690	0	0%
373	STREET LIGHTING AND SIGNAL SYSTEMS	6,053,459	25 - R1.5	(15)	4.60	278,459	27 - R2	(25)	4.62	279,972	1,513	1%
373.2	STREET LIGHTING & SIGNAL SYSTEMS - UNDERGROUND	653,789	25 - R1.5	(10)	4.40	28,767	27 - R2	(10)	4.07	26,609	(2,158)	-8%
	TOTAL DISTRIBUTION PLANT	**348,681,010**			**3.33**	**11,614,128**			**3.41**	**11,890,664**	**276,536**	**2%**

MARITIME ELECTRIC COMPANY

TABLE 4. COMPARISON OF EXISTING AND PROPOSED ANNUAL ACCRUAL RATES AND AMOUNTS RELATED TO ELECTRIC PLANT AT DECEMBER 31, 2017

			EXISTING				PROPOSED					
		ORIGINAL COST	SURVIVOR		ANNUAL ACCRUAL[b]		SURVIVOR		ANNUAL ACCRUAL[b]		DIFFERENCE	
	DEPRECIABLE GROUP	AT 12/31/2017	CURVE	SALV %	RATE	AMOUNT	CURVE	SALV %	RATE	AMOUNT	AMOUNT	PCT.
	(1)	(2)	(3)	(4)	(5)	(6)=(2)*(5)	(7)	(8)	(9)	(10)	(11)=(10)-(6)	(12)=(11)/(6)
GENERAL PLANT												
390	STRUCTURES & IMPROVEMENTS - ENERGY CONTROL CTR.	903,406	40 - R1	0	2.50	22,585	40 - R1	0	2.50	22,585	(0)	0%
390.11	STRUCTURES & IMPROVEMENTS - OFFICE	4,981,390	40 - R1	0	2.50	124,535	40 - R1	0	2.50	124,535	0	0%
390.12	STRUCTURES & IMPROVEMENTS - DISTRICTS	6,358,301	40 - R1	0	2.50	158,958	40 - R1	0	2.50	158,958	0	0%
391.12	OFFICE FURNITURE & EQUIP. - EQUIPMENT	77,037	15 - SQ	0	6.67	5,138	15 - SQ	0	6.67	5,138	(0)	0%
391.3	OFFICE FURNITURE & EQUIP. - COMPUTER HARDWARE	1,127,561	5 - SQ	0	20.00	225,512	5 - SQ	0	20.00	225,512	(0)	0%
391.4	OFFICE FURNITURE & EQUIP. - COMPUTER SOFTWARE[a]	5,977,486	10 - SQ	0	10.00	597,749	10 - SQ	0	10.00	597,749	0	0%
392	TRANSPORTATION EQUIPMENT	11,944,126	12 - R3	10	7.00	836,089	13 - S2	10	6.70	799,747	(36,342)	-4%
394	TOOLS, SHOP & GARAGE EQUIPMENT	1,115,936	20 - SQ	0	5.00	55,797	20 - SQ	0	5.00	55,797	0	0%
397	COMMUNICATION EQUIPMENT	10,214,242	20 - S4	(5)	4.77	487,219	20 - S4	(5)	4.80	489,939	2,720	1%
397.5	COMMUNICATION EQUIPMENT - SCADA	1,815,241	15 - S2	0	6.67	121,077	15 - S2	0	5.86	106,400	(14,677)	-12%
TOTAL GENERAL PLANT		**44,514,726**			**5.92**	**2,634,658**			**5.81**	**2,586,360**	**(48,298)**	**-2%**
TOTAL DEPRECIABLE ELECTRIC PLANT		**627,104,044**			**3.73**	**23,394,394**			**4.28**	**26,844,993**	**3,450,599**	**15%**
RESERVE VARIANCE AMORTIZATION (EXCLUDING CHARLOTTETOWN STEAM PLANT)						-				1,412,400	1,412,400	
TOTAL ANNUAL IMPACT						**23,394,394**				**28,257,393**	**4,862,999**	**21%**

a Intangible Developed Software is included in Account 391.4 for depreciation purposes.

b The annual accrual rates and amounts shown for the Charlottetown Steam Plant include the reserve variance amortization. All other accounts do not.

APPENDIX 9

SUMMARY OF PROPOSED ADJUSTMENTS TO DEPRECIATION RATES AND INCREASE IN DEPRECIATION EXPENSE RELATED TO ELECTRIC PLANT AT DECEMBER 31, 2017

DEPRECIABLE GROUP	ORIGINAL COST AT 12/31/2017 [1]	EXISTING ANNUAL RATE [2]	ACCRUAL AMOUNT	PROPOSED ANNUAL RATE	ANNUAL ACCRUAL AMOUNT	DIFFERENCE AMOUNT	DIFFERENCE PERCENT
	A	B	C=AXB	D=E/A	E	F=E-C	G=F/C
DEPRECIABLE ELECTRIC PLANT							
Total Steam Production Plant	60,749,618	4.53%	2,750,835 [3]	5.09	3,089,585	338,750	12.3%
Borden Generating Station	13,666,966	4.81%	657,872	4.12	562,811	(95,061)	-14.4%
Combustion Turbine #3	35,297,121	2.28%	804,774	2.34	824,633	19,859	2.5%
Transmission Plant							
Poles and Fixtures	22,861,634		685,849		746,204	60,355	8.8%
Overhead Conductors	45,621,955		1,122,300		1,295,207	172,907	15.4%
Other - Net	55,711,015		1,023,397		1,007,086	(16,311)	-1.6%
Total Transmission Plant	124,194,604	2.27%	2,831,546	2.45	3,048,497	216,951	7.7%
Distribution Plant							
Line Transformers	69,024,150		2,270,895		2,435,172	164,277	7.2%
Services - Overhead	67,238,249		2,097,833 [4]		2,334,512	236,679	11.3%
Other - Net	212,418,611		7,245,401		7,120,980	(124,421)	-1.7%
Total Distribution Plant	348,681,010	3.32%	11,614,129	3.41	11,890,664	276,535	2.4%
General Plant							
Transportation Equipment	11,944,126		836,089		799,747	(36,342)	-4.3%
Communication Equipment - SCADA	1,815,241		121,077		106,400	(14,677)	-12.1%
Other - Net	30,755,359		1,677,493		1,680,213	2,720	0.2%
Total General Plant	44,514,726	5.92%	2,634,659	5.81	2,586,360	(48,299)	-1.8%
TOTAL ANNUAL IMPACT	**$ 627,104,045**	**3.41**	**$ 21,293,815**	**3.51**	**$ 22,002,550**	**$ 708,735**	**3.3%**

References:
1 2017 Study - Part VI - Table 1
2 Rate shown is the composite rate for the asset group - refer to 2014 Depreciation Study - Page VI - Table 1 for the underlying rates used to calculate the Existing Annual Accrual Amount.
3 Based on depreciation rates approved in the 2016 General Rate Agreement, approved by Order UE16-04 excluding the accumulated reserve variance depreciation.
4 Originally reported as $2,087,833 in error.

APPENDIX 10
CTGS PROJECTED ACCUMULATED RESERVE VARIANCE AS AT DECEMBER 31, 2018

CTGS Steam Production Plant	Original Cost At 12/31/2017	Annual Depr Accrual Amt Per 2017 Study	Annual Depr Accrual Amt Per UE16-04	2018 Depr Shortfall	Reserve Variance 12/31/2017	Res Var Amort Per UE16-04	Projected Reserve Variance 12/31/18
	(A)	(B)	(C)	(D) = (B) - (C)	(E)	(F)	(G) = (E) - (F) + (D)
Structures and Improvements	9,006,038	547,357	481,823	65,534	2,970,357	360,242	2,675,649
Boiler Plant Equipment	26,445,980	1,285,317	1,198,003	87,314	6,788,125	825,115	6,050,324
Turbogenerator Units							
Unit 7	1,954,691	113,005			727,030		
Unit 8	3,909,382	209,582			1,393,541		
Units 9 and 10	15,637,528	796,856			5,344,433		
Total Turbogenerator Units	21,501,600	1,119,443	943,920	175,523	7,465,004	819,211	6,821,316
Accessory Electrical Equipment	2,283,113	68,942	63,699	5,243	448,151	53,653	399,741
Miscellaneous Power Plant Equipment	1,512,887	68,526	63,390	5,136	335,340	42,361	298,115
Total	60,749,618	3,089,585	2,750,835	338,750	18,006,977	2,100,581	16,245,146

REVISED APPENDIX 11
CTGS Proposed Annual Depreciation and Amortization of Accumulated Reserve Variance Deferral Account
2019 - 2023

CTGS Steam Production Plant	Original Cost At 12/31/2017	Annual Depr Accrual Amt Per 2017 Study	Remaining Life Amort Period	Proposed Annual Depreciation Rate (%)	Estimated Annual Depreciation ($) 2019	2020	2021	2022	2023	Total
Structures and Improvements	9,006,038	547,357	2.96	6.08	547,357	547,357	525,463	-	-	
Boiler Plant Equipment	26,445,980	1,285,317	2.96	4.86	1,285,317	1,285,317	1,233,904	-	-	
Turbogenerator Units										
Unit 7	1,954,691	113,005	0.99	5.78	111,875	-	-	-	-	
Unit 8	3,909,382	209,582	1.95	5.36	209,582	199,103	-	-	-	
Units 9 and 10	15,637,528	796,856	2.97	5.10	796,856	796,856	772,950	-	-	
Total Turbogenerator Units	21,501,600	1,119,443			1,118,313	995,959	772,950	-	-	
Accessory Electrical Equipment	2,283,113	68,942	2.95	3.02	68,942	68,942	65,495	-	-	
Miscellaneous Power Plant Equipment	1,512,887	68,526	2.92	4.53	68,526	68,526	63,044	-	-	
Annual Depreciation Accrual - CTGS	60,749,618	3,089,585			3,088,455	2,966,101	2,660,856	-	-	8,715,412
Amortization of Estimated Accumulated Reserve Variance - CTGS					3,249,029	3,249,029	3,249,029	3,249,029	3,249,029	16,245,144
CTGS - Total Annual Depreciation Incl. Reserve Variance Amortization					6,337,484	6,215,130	5,909,886	3,249,029	3,249,029	24,960,556

IR # 39 Attachment 1			
Calculation of Rate Base ($)			
Components	**2019 Forecast**	**2020 Forecast**	**2021 Forecast**
Fixed Assets	$ 687,018,800	$ 719,532,800	$ 697,822,200
Less: Capital Work in Progress	-	-	-
Less: Accumulated Amortization	(261,593,100)	(279,672,900)	(245,662,300)
Less: Contributions in Aid of Construction (net of amortization)	(23,347,600)	(23,460,500)	(22,546,800)
Less (Add): Future Income Tax Liability (Asset) - net of Long Term Receivable	(11,559,600)	(14,400,500)	(17,442,600)
Less (Add): Costs Payable to (Recoverable from) Customers Post 2003	1,989,000	1,610,900	(90,000)
Add: Deferred Financing Costs	872,100	855,700	838,700
Add: Intangible Assets	4,150,000	4,300,000	4,450,000
Add: Deferred Demand Side Management Costs	167,000	167,000	-
Add: Deferred Charge (Section 47(4)(a)(ii) of the EPA)	1,487,600	1,394,200	1,300,800
Less: Employee Future Benefits Liability	(7,751,402)	(7,836,437)	(8,104,627)
Less (Add): Regulatory Liability OPEB	3,045,800	3,342,400	2,888,400
Less: Regulatory Liability - Rebates Payable to Customers	(11,110,700)	(7,989,100)	(4,817,700)
Less (Add): Regulatory Liability (Asset) - As Established by Commission Order	340,000	340,000	340,000
Plus: Working Capital Allowance Comprised of: - Inventory	2,500,000	2,000,000	2,000,000
- Gross Operating Expenses X 3.6% (net of disallowed costs)	5,568,400	5,860,000	5,980,100
Income Taxes Paid X 3.6%	134,200	133,500	133,600
Total Rate Base	**$ 391,910,498**	**$ 406,177,063**	**$ 417,089,773**
Average Rate Base	**$ 386,857,400**	**$ 399,043,800**	**$ 411,633,400**

Calculation of Return on Average Rate Base ($) & (%)			
	2019 Forecast	**2020 Forecast**	**2021 Forecast**
Total Revenue	$ 212,659,600	$ 221,763,500	$ 229,095,400
Less: Operating Expenses (net of ECAM)	(153,120,200)	(160,368,900)	(165,787,300)
Less: Amortization of debt issue costs	(15,800)	(16,400)	(17,000)
	59,523,600	61,378,200	63,291,100
Less: Amortization Fixed Assets	(25,871,500)	(27,008,300)	(28,006,000)
Less: Amortization Deferred Charges	(260,400)	(260,400)	(260,400)
	(26,131,900)	(27,268,700)	(28,266,400)
Earnings Before Income Taxes and Financing Costs	33,391,700	34,109,500	35,024,700
Income Taxes	(6,529,500)	(6,741,000)	(6,950,300)
Earnings on Average Rate Base (interest expense excluded)	$ 26,862,200	$ 27,368,500	$ 28,074,400
Rate Base - Year End Average	$ 386,857,400	$ 399,043,800	$ 411,633,400
Forecast Return on Average Rate Base	**6.94%**	**6.86%**	**6.82%**

IR # 39 - Attachment 2
Maritime Electric
Proposed Range of Return on Average Rate Base

		Debt	Common	Total	Rate of Return on Average Rate Base
2019					
Percent of Capital		60.21%	39.79%	100.00%	
Cost of Capital		5.48	9.85		
		3.30	3.92	7.22	
Conversion of Return on Average Capitalization to Return on Average Rate Base					**Upper Limit**
	Average Capitalization	382,732,243	X	7.22	7.14
	Average Rate Base	386,857,400			
Percent of Capital		60.21%	39.79%	100.00%	
Cost of Capital		5.48	8.85		
		3.30	3.52	6.82	
Conversion of Return on Average Capitalization to Return on Average Rate Base					**Lower Limit**
	Average Capitalization	382,732,243	X	6.82	6.75
	Average Rate Base	386,857,400			
2020					
Percent of Capital		60.02%	39.98%	100.00%	
Cost of Capital		5.36	9.85		
		3.21	3.94	7.15	
Conversion of Return on Average Capitalization to Return on Average Rate Base					**Upper Limit**
	Average Capitalization	$ 393,634,405	X	7.15	7.06
	Average Rate Base	$ 399,043,800			
Percent of Capital		60.02%	39.98%	100.00%	
Cost of Capital		5.36	8.85		
		3.21	3.54	6.75	
Conversion of Return on Average Capitalization to Return on Average Rate Base					**Lower Limit**
	Average Capitalization	$ 393,634,405	X	6.75	6.66
	Average Rate Base	$ 399,043,800			
2021					
Percent of Capital		60.01%	39.99%	100.00%	
Cost of Capital		5.29	9.85		
		3.17	3.94	7.11	
Conversion of Return on Average Capitalization to Return on Average Rate Base					**Upper Limit**
	Average Capitalization	$ 406,102,800	X	7.11	7.02
	Average Rate Base	$ 411,633,500			
Percent of Capital		60.01%	39.99%	100.00%	
Cost of Capital		5.29	8.85		
		3.17	3.54	6.71	
Conversion of Return on Average Capitalization to Return on Average Rate Base					**Lower Limit**
	Average Capitalization	$ 406,102,800	X	6.71	6.62
	Average Rate Base	$ 411,633,500			

Maritime Electric Company, Limited
Schedule of Inputs

	2019	2020	2021
Summary of Forecast NPP and Sales			
Net Purchased & Produced (kWh)	1,365,034,800	1,401,254,100	1,423,094,900
Sales (kWh)			
Residential	620,682,000	647,530,000	667,023,000
General Service	389,733,000	391,988,000	392,308,000
Large Industrial	154,700,000	159,200,000	159,996,000
Small Industrial	94,407,000	94,953,000	95,031,000
Street Lighting	5,031,000	4,790,000	4,550,000
Unmetered	2,438,000	2,444,000	2,450,000
	1,266,991,000	1,300,905,000	1,321,358,000
ECAM Base Rate per kWh (Effective March 1)	0.09335	0.09475	0.09591
RORA Rebate per kWh (Effective March 1)	0.00250	0.00250	0.00250
Capital Structure (Average)			
Debt	60.20%	60.00%	60.00%
Equity	39.80%	40.00%	40.00%
	100.00%	100.00%	100.00%
Return on Average Common Equity	9.35%	9.35%	9.35%
Rate Base (Average)	386,880,000	399,151,000	411,826,000
Return on Average Rate Base	6.94%	6.86%	6.82%
Average Short Term Financing Rate	3.8%	3.8%	4.0%
Annual Capital Expenditures	32,877,000	37,674,000	35,925,000
Summary of Revenues and Expenses			
Basic Rate Revenue			
Residential	106,639,000	112,816,000	118,588,000
General Service	64,105,000	65,848,000	66,877,000
Large Industrial	14,028,000	14,757,000	15,042,000
Small Industrial	12,967,000	13,310,000	13,504,000
Street Lighting	2,343,000	2,280,000	2,197,000
Unmetered	416,000	428,000	436,000
	200,498,000	209,439,000	216,644,000
Transmission Revenue	10,185,000	10,247,000	10,382,000
Miscellaneous Revenue	1,977,000	2,078,000	2,069,000
Total Revenue	212,660,000	221,764,000	229,095,000
Operating Expenses			
Energy Costs , net of ECAM	127,615,000	133,056,000	136,893,000
Distribution & Transmission	7,989,000	8,214,000	8,438,000
Transmission - OATT (Other)	8,137,000	8,214,000	8,356,000
Corporate	9,973,000	11,497,000	12,733,000
Amortization - Fixed Assets & Other	26,132,000	27,269,000	28,266,000
Financing Expenses	12,637,000	12,671,000	12,908,000
Income Taxes	6,345,000	6,552,000	6,754,000
Net Earnings	13,832,000	14,291,000	14,747,000

Maritime Electric Company, Limited
Schedule of Inputs - 2016

	As Approved Order UE16-04	Actual	Note
Summary of Forecast NPP and Sales			
Net Purchased & Produced (kWh)	1,287,845,600	1,280,483,447	1
Sales (kWh)			
Residential	563,660,000	563,466,190	
General Service	391,720,000	386,827,041	
Large Industrial	131,336,000	129,893,508	
Small Industrial	98,933,000	100,074,575	
Street Lighting	5,670,000	5,757,805	
Unmetered	2,460,000	2,405,294	
	1,193,779,000	1,188,424,413	1
ECAM Base Rate per kWh (Effective March 1)	0.08605	0.08605	
RORA Rebate per kWh (Effective March 1)	0.00410	0.00410	
Capital Structure (Average)			
Debt	59.10%	59.09%	
Equity	40.90%	40.91%	
	100.00%	100.00%	
Return on Average Common Equity	9.35%	9.35%	
Rate Base (Average)	340,818,000	329,211,650	2
Return on Average Rate Base	7.43%	7.69%	2
Average Short Term Financing Rate	2.9%	2.7%	
Annual Capital Expenditures	30,660,000	31,610,139	3
Summary of Revenues and Expenses			
Basic Rate Revenue			
Residential	92,947,000	92,562,937	
General Service	60,012,000	59,016,156	
Large Industrial	10,854,000	10,786,613	
Small Industrial	12,603,000	12,968,350	
Street Lighting	2,137,000	2,420,167	
Unmetered	397,000	403,098	
	178,950,000	178,157,320	1
Transmission Revenue	8,110,000	8,390,842	
Miscellaneous Revenue	1,627,000	1,763,211	
Other Revenue	9,737,000	10,154,053	
Total Revenue	188,687,000	188,311,373	
Operating Expenses			
Energy Costs	111,986,000	111,185,220	1
Distribution & Transmission	8,176,000	7,268,360	4
Transmission - OATT (Cable)	-	-	
Transmission - OATT (Other)	6,665,000	6,842,196	
Corporate	10,094,000	9,384,106	5
Amortization - Fixed Assets & Other	21,139,000	21,039,434	
Financing Expenses	12,388,000	12,378,373	
Income Taxes	5,768,000	5,754,350	
Due From Customers - Weather Normalization Reserve	N/A	(126,031)	
Due To Customers - Rate of Return Adjustment (RORA)	N/A	2,100,000	
Net Earnings	12,471,000	12,485,365	

Notes:

1 Sales 0.45% below forecast mainly due to milder winter in 2016, resulted in lower energy purchases (0.57%) than forecast.
2 See response to IR-39.
3 2016 Capital Budget Variance filed with IRAC on February 28, 2017 & approved by IRAC Order UE17-03.
4 Variance mainly due to lower than expected spending in transmission line ROWs ($230K), T & D line maintenance ($345k) and property taxes ($245K).
5 Variances mainly due to lower than forecast customer service costs ($175k), lower regulatory costs ($145K) and lower corporate services and support ($320K).

Maritime Electric Company, Limited
Schedule of Inputs - 2017

	As Approved Order UE16-04	Actual	Note
Summary of Forecast NPP and Sales			
Net Purchased & Produced (kWh)	1,314,420,900	1,297,936,168	1
Sales (kWh)			
Residential	580,352,000	577,013,980	
General Service	394,887,000	384,918,468	
Large Industrial	131,704,000	133,621,837	
Small Industrial	103,731,000	104,569,569	
Street Lighting	5,390,000	5,518,763	
Unmetered	2,478,000	2,415,611	
	1,218,542,000	1,208,058,228	1
ECAM Base Rate per kWh (Effective March 1)	0.08988	0.08988	
RORA Rebate per kWh (Effective March 1)	0.00473	0.00473	
Capital Structure (Average)			
Debt	60.00%	60.33%	
Equity	40.00%	39.67%	
	100.00%	100.00%	
Return on Average Common Equity	9.35%	9.35%	
Rate Base (Average)	359,398,000	351,097,841	2
Return on Average Rate Base	7.17%	7.29%	2
Average Short Term Financing Rate	3.3%	2.9%	
Annual Capital Expenditures	29,399,000	29,400,425	3
Summary of Revenues and Expenses			
Basic Rate Revenue			
Residential	97,759,000	96,868,216	
General Service	62,138,000	60,498,583	
Large Industrial	11,208,000	11,481,970	
Small Industrial	13,494,000	13,640,807	
Street Lighting	2,101,000	2,424,681	
Unmetered	414,000	412,465	
	187,114,000	185,326,722	1
Transmission Revenue	12,380,000	7,961,884	4
Miscellaneous Revenue	2,025,000	1,962,405	
Other Revenue	14,405,000	9,924,289	
Total Revenue	201,519,000	195,251,011	
Operating Expenses			
Energy Costs	117,726,000	116,106,441	
Distribution & Transmission	8,727,000	7,752,015	5
Transmission - OATT (Cable)	4,133,000	-	4
Transmission - OATT (Other)	6,813,000	6,272,903	
Corporate	10,484,000	9,059,706	6
Amortization - Fixed Assets & Other	22,397,000	22,223,525	
Financing Expenses	12,433,000	12,251,808	
Income Taxes	5,943,000	5,940,740	
Due From Customers - Weather Normalization Reserve	N/A	(52,155)	
Due To Customers - Rate of Return Adjustment (RORA)	N/A	2,767,885	
Net Earnings	12,863,000	12,928,143	

Notes

1 Sales 0.86% below forecast mainly due to lower than expected load growth, resulted in lower energy purchases (1.25%) than forecast.
2 See response to IR-39.
3 2017 Capital Budget Variance filed with IRAC on February 28, 2017 & approved by IRAC Order UE18-09
4 New Interconnection lease charges originally forecast to be recovered through OATT in GRA but instead recovered under a Debt Collection Agreement therefore recorded directly as an energy charge and recovered through ECAM.
5 Variance mainly due to lower than forecast line & transformer maintenance costs due to relatively low storm activity ($500K) and lower property taxes ($300K).
6 Variances mainly due to lower than forecast customer service costs ($370k), lower finance & accounting costs ($150K), lower regulatory costs ($165K) and lower corporate services and support ($525K).

Maritime Electric Company, Limited
Schedule of Inputs - 2018

	As Approved Order UE16-04	Actual	Note
Summary of Forecast NPP and Sales			
Net Purchased & Produced (kWh)	1,340,478,000	1,349,045,314	1
Sales (kWh)			
Residential	596,667,000	612,763,141	
General Service	397,870,000	393,555,865	
Large Industrial	132,086,000	151,702,962	
Small Industrial	108,397,000	91,653,039	
Street Lighting	5,109,000	5,175,526	
Unmetered	2,491,000	2,458,006	
	1,242,620,000	1,257,308,539	1
ECAM Base Rate per kWh (Effective March 1)	0.09161	0.09161	
RORA Rebate per kWh (Effective March 1)	0.00345	0.00345	
Capital Structure (Average)			
Debt	60.00%	60.73%	
Equity	40.00%	39.27%	
	100.00%	100.00%	
Return on Average Common Equity	9.35%	9.35%	
Rate Base (Average)	374,717,000	373,575,121	2
Return on Average Rate Base	7.05%	7.07%	2
Average Short Term Financing Rate	3.5%	3.6%	
Annual Capital Expenditures	30,815,000	32,497,846	3
Summary of Revenues and Expenses			
Basic Rate Revenue			
Residential	102,449,000	104,126,939	
General Service	64,033,000	63,326,321	
Large Industrial	11,448,000	13,701,483	
Small Industrial	14,331,000	12,713,699	
Street Lighting	2,022,000	2,381,685	
Unmetered	422,000	431,049	
	194,705,000	196,681,176	1
Transmission Revenue	13,963,000	9,451,985	4
Miscellaneous Revenue	1,953,000	2,841,315	5
Other Revenue	15,916,000	12,293,300	
Total Revenue	210,621,000	208,974,476	
Operating Expenses			
Energy Costs	122,657,000	123,351,097	
Distribution & Transmission	8,968,000	7,726,597	6
Transmission - OATT (Cable)	5,590,000	-	7
Transmission - OATT (Other)	6,937,000	7,488,580	7
Corporate	10,783,000	9,354,098	8
Amortization - Fixed Assets & Other	23,650,000	23,200,828	
Financing Expenses	12,645,000	12,618,847	
Income Taxes	6,123,000	6,101,048	
Due From Customers - Weather Normalization Reserve	N/A	469,169	
Due To Customers - Rate of Return Adjustment (RORA)	N/A	5,239,809	
Net Earnings	13,268,000	13,424,403	

Notes

1 Sales 1.18% higher than forecast due to increased load growth, resulted in higher energy purchases (0.64%) than forecast.

2 See response to IR-39.

3 Includes approved capital expenditures for 2018 that were deferred until 2019 totaling $2,898,000. 2018 Capital Budget Variance will be filed with IRAC by February 28, 2019.

4 New Interconnection lease charges originally forecast at $4.0 million to be recovered through OATT in GRA but instead recovered under a Debt Collection Agreement recorded directly as an energy charge and recovered through ECAM.
NB Schedule 9 charges related to interconnection facilities in NB are $415,000 lower than proposed in 2015.

5 2018 miscellaneous revenue includes refund from Province of PEI rights of ways access from 1998-2001 plus interest totalling $952,384.

6 Variance mainly due to lower than expected spending T & D line ROWs ($580K), T & D line maintenance ($150k) and property taxes ($300K).

7 Variances mainly due to difference in treatment of cable lease and NB interconnection costs (see 4 above) as well as certain other OATT changes not forecast such as imbalance, residual uplift and OATT hearing costs.

8 Variances mainly due to lower than forecast customer service costs ($300k), and lower corporate services and support ($900K).

IN THE MATTER OF

FortisBC Inc.

Multi-Year Performance Based Ratemaking Plan For 2014 Through 2018

Decision

September 15, 2014

Before:

D.A. Cote, Panel Chair/Commissioner
N.E. MacMurchy, Commissioner
D.M. Morton, Commissioner

ratio be calculated as the ratio of the number customers or service line additions one year previous, to the number of customers or service line additions two years previous. The Panel recognizes that this introduces some lag into the formula calculation, but we consider it necessary in order to eliminate the potential of upward bias. This is the same approach we took in the case of the Inflation Factor. **Accordingly, the Commission Panel approved Growth Terms of 0.5 * (SLA_{t-1}/SLA_{t-2}) for FEI's growth capital and 0.5 * (AC_{t-1}/AC_{t-2}) for all other cases.**

If Fortis has evidence that a different growth term is more appropriate, it can bring forward that evidence at any time.

2.2 Key PBR Plan Components

2.2.1 Earnings Sharing Mechanism

An Earnings Sharing Mechanism (ESM) is a mechanism added to some PBRs to allow for the sharing of efficiency cost savings between the customer and the utility. ESMs are described as "regulatory tools in a PBR that are designed to enhance the alignment between customer and company interests and share the risks and the benefits of the PBR plan." In addition, if symmetrical, they serve to soften the impact of unintended consequences such as excessive utility gains or losses within a PBR. FBC states that in regulatory literature there are two schools of thought regarding ESM usage. One school asserts that ESMs decrease the incentive power of the PBR plan and impose additional regulatory burden and cost. The other indicates that ESMs allow for improved cost tracking and mitigates concerns with excessive profits or losses and represents a fair approach to sharing the benefits of a PBR plan. (FBC Exhibit B-1, p. 64)

Fortis, citing support from B&V, has proposed that a symmetric ESM be made a component of the PBR Plan. The proposal is for an ESM based on the 2007 PBR which called for sharing on a 50:50 basis among customers and the utilities of earnings either above or below the allowed ROE in a given year. The plan is for the shared earnings to be projected during each Annual Review process but finalized after year-end when actual results are known. (FBC Exhibit B-1, pp. 64–65)

Intervener Submissions

CEC submits that the proposed plan has eliminated an opportunity for the customer to address concerns and adjust earnings accordingly and has also eliminated the no surprise clause and the line-by-line review process to determine levels of sharing. CEC considers that these changes represent a departure from customer interests. CEC also submits that the ESM does not limit customer risk as it does not limit the extent of utility financial earnings and serves to support a longer period between rebasing because the utility must share its earnings. This extended period has its downside for customers, one of which is the lack of transparency as there is no oversight over the five-year period. This extended period provides an additional three years with which to take advantage of additional earnings as compared to a standard two-year cost of service process. (CEC Final Argument, pp. 109–120)

None of the other Interveners had specific comments with regard to the ESM.

Fortis Reply

Fortis, in Reply, notes much of what CEC has to say relates to the PBR generally and are out of context. With respect to the ESM failing to limit the risk to the customer because it does not limit the earnings available to the utility, Fortis points out that the ESM serves to mitigate risk as there is equal sharing of both upside and downside results thereby creating balance. (Fortis PBR Reply, p. 45)

Commission Determination

The Commission Panel determines that the inclusion of a symmetric ESM is beneficial to both Fortis and its customers. In our view, the inclusion of an earnings sharing mechanism balances the interests of the customer and the utility. That is, to the extent that there are gains or losses relative to the approved ROE, the fact that they are shared on a 50:50 basis between the ratepayer and the utility is reasonable. The Panel notes that the purpose of implementing a PBR mechanism is to provide an environment where efficiencies are created through actions initiated by the utility. Accordingly, there is an expectation that all things being equal, the Fortis utilities will, over the course of this PBR, generate efficiency savings resulting in earnings which allow them to exceed the approved ROE return. Fortis has proposed that these savings be shared. To deny the customer the opportunity of sharing these savings would not be in their interest. However, the Panel does acknowledge that in approving a symmetrical ESM we are, in effect, reducing the risk faced by Fortis on the downside and there is a potential negative rate impact in the event of unforeseen circumstances. However, given the historical performance of the Fortis utilities in achieving their approved ROE, we consider this downside risk to be limited.

The Commission Panel has considered the submissions of CEC with respect to the inclusion of an ESM. The points raised by CEC seem to be more concerned with the approval of a PBR and how it is designed than with the ESM itself. These include matters such as the elimination of the no surprise clause, the potential for earnings by simply not spending and the proposed term of the PBR relative to a more traditional cost of service agreement with a shorter time frame. While the Panel acknowledges that these matters are important, we agree with Fortis that with respect to having an ESM or not, CEC's arguments are out of context. To the extent possible, matters such as these will be dealt with in other parts of this Decision.

Given the apparent lack of trust between the parties in this proceeding and concerns with the potential to game the results, the Commission Panel considers the inclusion of an ESM to be a positive measure in that there is a sharing of gains or losses and does not favour either side. Additionally, the Panel notes that none of the parties have proposed its elimination. Given these factors, the Commission Panel considers an ESM mechanism to be appropriate at this time.

2.2.2 Efficiency Carry-Over Mechanism

An Efficiency Carry-Over Mechanism (ECM) is a plan component that allows the utility to receive benefits in periods following a PBR period for savings resulting from measures taken and costs incurred during the PBR period. Fortis describes the ECM as a means to incent the utility to pursue efficiency initiatives throughout the entire PBR period. It is justified on the basis that without it, the utility will have decreasing levels of motivation to initiate efficiency improvements as the PBR period moves forward. Fortis states this is because under a fixed-term PBR, the payback to a utility's investment in efficiency improvements is earned only on those savings up to the end of the PBR. Therefore, the utility is motivated to initiate changes resulting in savings early in the PBR period to maximize its payback or in some cases to put off such projects because there is insufficient time remaining in the PBR to earn a return even recover costs. Inclusion of an ECM allows the utility to initiate efficiency improvements later in the PBR period but continue to earn a share of the return into the period following the PBR. (FEI Exhibit B-1, pp. 72–73; FBC Exhibit B-1, pp. 65–68)

The Commission approved the use of an ECM in the 2004 PBR Plan for FEI. The ECM allowed accumulated capital carrying cost and depreciation benefits to continue at a rate of 2/3 in the first year and 1/3 in the second year following the end of the PBR. In the current Applications, Fortis is proposing an enhanced ECM for both FEI and FBC which includes two additional components; the inclusion of O&M savings in addition to capital and the use of a five-year rolling carry-over period for the sharing of savings following the year in which the improvement occurred, regardless of when the PBR period ends. Fortis states that including O&M savings in the ECM maintains a balance between capital and O&M savings initiatives, and that the inclusion of a five-year rolling carry-over period eliminates concerns with timing from decision-making and promotes ongoing efficiency improvement initiatives. (FEI Exhibit B-1, p. 74; FBC, Exhibit B-1, pp. 66–67)

Based on this, Fortis proposes implementing the five-year carry-over plan where the incremental O&M and capital savings are calculated as the sum of:

1. Variance of current year formula based O&M less cumulative O&M savings from prior years of the PBR Plan; and

2. Current year plant additions savings relative to current year allowed plant additions derived from PBR capital formula multiplied by a base rate factor of 12 percent (15 percent for FEI).

Fortis states that the 12 percent rate base factor represents the avoided revenue requirements from reduced capital expenditures. Avoided revenue requirements components include return on rate base, depreciation expense and associated taxes. The 50:50 sharing between ratepayer and shareholder will apply to the ECM in the same manner as it does within the PBR period.

Fortis states that the inclusion of an ECM has the support of B&V "because it permits the utility to maintain a continuous improvement culture rather than be concerned about the inability to earn the required return on investments made in efficiency and productivity in the later years of the PBR Plan." This is possible because disincentives to install new productivity initiatives as the PBR Plan ends do not exist. (FEI Exhibit B-1, pp.74–75; FBC Exhibit B-1, pp. 67–68)

Intervener Submissions

CEC considers the proposed ECM to be detrimental to ratepayer interests and does not agree with the mechanism proposed by Fortis. CEC recommends the ECM as proposed by the utility be rejected outright. It submits that its issues with the proposed ECM mechanism are significant and that the theory and rationale behind the mechanism is incorrect and the benefit claims are "presumed rather than actual."

CEC considers the inclusion of O&M in the ECM represents additional ratepayer costs with no additional benefits. This "amplifies the underspending of an overly generous formula." CEC further states that in addition to the inclusion of O&M and a rolling carry-over mechanism, the current ECM proposal includes a full payment rather than a declining one, has a longer term and includes an increase of the rate base benefit factor (from14 percent to 15 percent for FEI). It submits that these changes are detrimental from a customer perspective and are not well supported in evidence.

CEC has numerous other issues with the proposed ECM mechanism. These include perverse incentives, basing rewards or benefits on a presumption that they last for at least 5 years and its inclusion eliminates benefits which would have been derived from rebasing. In CEC's view the key issue is the determination of the appropriate time for rebasing embedded savings and further submits that this could vary considerably based on the nature of the efficiency project and life of potential savings.

CEC accepts that there will be instances where there will be value in the utility having longer payback periods available. These may be warranted where the utility has made a significant investment in efficiency measures. However, in such instances deferral accounts could be used as a mechanism to manage such longer-term payback periods. These would not limit the payback to any term and would reduce risk for the utility and ratepayers in addition to ensuring that there will be greater Commission oversight. (CEC Final Argument, pp. 23, 125–130)

BCPSO notes that ECMs are not common in PBR plans, pointing out that Fortis was only able to identify two jurisdictions in Canada where they exist. BCPSO's concern with the use of ECMs in this instance is that Fortis is using the building block model where:

> "the utility can under spend on O&M and capital in each year and earn superior returns, and then claim an ECM. But there is no need, in circumstances where the utility can benefit from underspending the formula, to also provide an additional incentive to underspend in the form of an ECM." (BCPSO PBR Final Argument, p. 11)

BCPSO's overarching concern is best summarized in the following statement: "the issue is that the company can spend less O&M and Capital, and in effect double dip, gain during the PBR period by spending less, and then achieve superior returns after the end of the PBR for the same reductions." It submits that there is not a need for an ECM in this PBR. (BCPSO Final Argument, pp. 11–13)

BCPSO points out that Fortis' ESM is also a Loss Sharing Mechanism, in that it provides for a 50:50 sharing of earnings above and below the allowed ROE. In the event Fortis fails to earn its allowed return during the PBR period, the ESM requires ratepayer contribution above the formula derived costs during the PBR term, then additionally, the ECM requires ratepayer's shared contributions after the PBR term. (BCPSO PBR Final Argument, p. 14)

ICG does not support an ECM as it "does not believe that regulatory parameters affect efficiency initiatives in the manner suggested by FBC, at least sufficiently to justify the excess returns." ICG submits that an ECM must not be a windfall for the utility and the Panel needs to be certain that its inclusion will benefit customers. However, if approved, the efficiency gains have to be measured and must be allocated symmetrically. That is "if efficiency gains are achieved then the utility receives a higher return, but if efficiency losses are realized then the utility receives a lower return." (ICG Final Argument, pp. 23–25)

ICG considers the utility to be responsible for achieving and then measuring efficiency savings. It provides a hypothetical example where the utility spends $1 million on an efficiency initiative to achieve a $500,000 efficiency saving. If the savings are than expected results then the utility, not the customer, pays the difference between the cost of the efficiency measure and actual savings. It appears that ICG is recommending that the 50:50 sharing mechanism which has been proposed by Fortis and approved by the Panel be suspended for the ECM applied beyond the end of the PBR period. In this way, the utility would receive the credit for any gains and also bear any losses related to an approved ECM in the period following the PBR. (ICG Final Argument, pp. 23–25)

Fortis Reply

Fortis, in Reply, views the position taken by CEC as to the "the customer continu[ing] to reward the utility when there are no earnings which it is 'sharing with the customer'" as "starting from the wrong premise." It reiterates that the inclusion of an ECM is designed to make the company whole for the costs not yet recovered in rates prior to the end of the PBR. In addition, it takes issue with CEC's suggestion that the lack of research and documentation is the reason the ECM should be rejected pointing out that the concept is familiar in that ECMs have been used in previous PBRs and are currently in place in Alberta and Quebec. Fortis also notes that Dr. Lowry's comments on ECMs were largely supportive of including this component.

Fortis had no additional comments regarding CEC's concerns with respect to term length of the current ECM proposed and the move away from a declining payment schedule which had characterized earlier iterations.

Fortis also withheld comment on CEC's contention that the time for rebasing savings is not always five years and varies by the nature of the efficiency project and the length of potential savings. The Commission Panel notes that Fortis had previously addressed CEC's suggestion that as an alternative deferral accounts could be used as a mechanism to manage longer payback periods. In response to CEC FEI 3a.38.5 Fortis states: "FEI believes that a deferral account approach would involve more regulatory process and would run counter to the objectives under PBR of streamlining the regulatory process and aligning the interests of customers with the interests of the utility." Fortis further states that such an approach may be possible and could be applied to larger scale initiatives but it would be less practical to employ this with smaller scale programs. (Fortis Reply, pp. 49–52; FEI Exhibit B2-2, CEC 3a.38.5)

Fortis states in response to BCPSO's comments that the underlying premise of its argument "is that the Commission is incapable of doing its job" and the inclusion of an ECM represents a significant downside for the customer. In Fortis' view, the Commission should be reviewing this Application on the basis that it will be able to determine just and reasonable rates when next there is a COS Application. (Fortis PBR Reply, pp. 47–49)

Fortis makes no reply to the ICG submissions.

Commission Determination

The Commission Panel cannot help but acknowledge the level of cynicism and distrust implicit in the submissions of the interveners with respect to the inclusion of an ECM in the Fortis PBR. It is clear from these submissions that the interveners view the proposed ECM as being one-sided and very much in favour of the utility. BCPSO is perhaps most emphatic when it states that in spite of under spending on both O&M and capital in each year and earning what might be described as superior returns, Fortis then gets to claim their part of the ECM in the period subsequent to the PBR period. Concerning BCPSO's comments, Fortis' interpretation is that it is based on the underlying premise that "the Commission is incapable of doing its job" and in its view the Commission should consider this Application from the perspective that it will be able to determine just and reasonable rates in the next COS Application. The Commission Panel agrees. Our review of this Application should lead to determinations that, to the best degree possible, we can anticipate and control the ability of the utility to "game" any element of the PBR and minimize opportunities for Fortis to benefit at the expense of the ratepayer.

In the view of the Commission Panel, the ECM proposal put forward by Fortis favours the utility and puts the ratepayer at risk for future payments following the PBR period with no assurance that the savings will carry forward. Specific concerns of the Panel include:

<u>Five-Year Rolling Carry-Over Period</u>

As structured, the ECM is based on the assumption that any savings which occur warrant a payback period (which is shared between the ratepayer and the utility) of five years. There has been no compelling evidence to suggest that five years is an appropriate time period for all or any efficiency initiatives. The Panel notes that ECMs do not appear to be commonplace and, where they exist, no evidence has been presented to suggest they have a five-year payback period. There are variations of ECMs in both Alberta and Gaz Metro but neither of these extend for a five year period. (T2:305)

<u>The Use of a Formula Driven O&M ECM Calculation</u>

The ECM, as proposed, rewards additional O&M savings in later years of the PBR by carrying the reward for them over to the post PBR period. This, in the view of Fortis, provides an incentive to continue to develop efficiency measures in later years of the PBR. The Panel acknowledges there is some logic to this but also notes that there has been no attempt in the proposal to separate those savings that are related to an actual initiative from those that result from simply not spending the funds or being unable to do so due to circumstances unforeseen by Fortis. In either case, the savings would apply and carry over (albeit shared with ratepayers) into the post PBR period. Even if identified during the rebasing process, there would be instances where the Commission would have no option but to approve the inclusion of these savings as justified new expenses in future revenue requirements while, at the same time, allowing the savings for them to carry forward into the post PBR period. The Commission Panel considers the risk associated with this to be considerable. Moreover, while incenting the development of efficiency initiatives later in the PBR period, the Fortis proposal equally incents under-spending or gaming the formula.

The Use of a Formula Driven Capital ECM Calculation

Many of the concerns raised with respect to the O&M ECM formula also apply to capital. Delay of projects, whether through circumstances beyond the utility's control or by design are a commonplace occurrence. To apply a formula without consideration of the individual circumstances would leave it open for unintended consequences and potentially a windfall for the utility.

Given these reasons, the Commission Panel denies the Fortis request for the proposed ECM methodology. However, the Panel acknowledges that there will be instances where there are efficiency related programs with associated costs which may remain unimplemented if an ECM did not exist. Therefore, in spite of the concerns raised, we are persuaded that there is value in the inclusion of some form of ECM mechanism as a means of incenting the development of efficiency initiatives throughout the PBR period. However, the ECM mechanism must be transparent, flexible and allow a decision to be made on each initiative based on its individual circumstances taking into account the benefits, the period of the benefits, costs and likelihood for success. In addition, there is a need to track these investments and determine whether they deliver on the promised benefits. Creating a formal process to deal with ECM initiatives will provide greater transparency and hopefully reduce the distrust and cynicism referred to earlier.

Accordingly, the Commission Panel determines that the following steps are required in order for Fortis to receive approval for an ECM initiative;

1. **ECMs will in most cases be handled within the context of the Annual Review although where warranted, the Commission could consider an ECM measure within the year.**
2. **For each proposed initiative for which the benefits are expected to extend beyond the term of the PBR, Fortis will file an ECM proposal providing a description of the proposal, its timing, costs and benefits, and reasoning as to why it is appropriate and how long benefits should be paid.**
3. **Parties will have the opportunity to comment on the proposal.**

If agreed to by the parties, the proposal will go to the Commission with a recommendation for approval. If not agreed to, the proposal will go to the Commission for a Decision or development of further process. Based on these submissions, the Commission will make a determination as to the justification of each ECM proposal on a case-by-case basis.

2.2.3 Managing Service Quality

2.2.3.1 Purpose of SQIs

One of the more contentious issues with the Fortis PBR proposal is determining the role that SQIs play within a PBR Mechanism. SQIs have been recognized as an effective way to measure the performance of a utility from a variety of perspectives. These may include but are not limited to safety, customer service and service availability. As noted by FEI in its Application, SQIs "are used in the context of PBR to ensure that the utility is encouraged to pursue efficiencies that do not sacrifice service quality" (FEI Exhibit B-1, p. 77). This raises the question that if service quality has been compromised in the interests of cost savings or efficiencies or simply suffers with no linkage to a particular act, what should be the consequences?

The Fortis proposal envisions that each year during the Annual Review, it will present the FEI and FBC projected results for SQIs to the parties and the related discussion will serve to provide an understanding of issues affecting the Companies' ability to meet established benchmarks. Fortis has further clarified this issue by stating that unsatisfactory performance as measured by non-financial SQIs are more appropriately assessed at the mid-term review allowing for measurement over a longer time horizon. (Exhibit B-1-1, Appendix D7, p. 17; Exhibit B2-8, BCUC 3.25.1) Thus, it seems that while SQIs will be a matter for discussion at the Annual Review, Fortis views the Mid-Term Review as the appropriate time to determine whether a serious problem or degradation of service exists.

Fortis has outlined no specific process for dealing with a degradation of SQI results. It takes the position that if there has been a serious unaddressed degradation in results that remains unaddressed, the Commission can explore potential off-ramps. Fortis describes the "off-ramp provision" as contemplating a complete regulatory review of the PBR Plan. This would be triggered only if there was "sustained serious degradation of the SQIs." (Exhibit B2-8, BCUC 3.25.2) This is in contrast to previous PBRs where the SQIs were reviewed annually and interveners had some level of input as to the level of earnings share if SQI benchmarks were not met.

Fortis' position on penalties or rewards is that given Fortis' lack of control, they should not be linked to SQI performance relative to their benchmarks. As an example, Fortis notes that "colder than normal weather coupled with higher gas costs can increase call centre volume dramatically and result in a one-time reduction in SQI beyond the reasonable control of the Company." In such instances, it should not necessarily be rewarded or penalized. Fortis acknowledges that one of the themes throughout the proceeding is that the Commission should be concerned that Fortis' SQI proposal lacks enforceable consequences. It points to its ongoing history with the management of SQIs as support for its current proposal. It also states that its witnesses have consistently voiced their commitment to managing the business in a manner that maintains existing service levels. (Fortis PBR Final Argument, pp. 151–152; Exhibit B2-11 CEC 3.40.1; Exhibit B2-8, BCUC 3.25.3)

Intervener Submissions

CEC submits that in the event of performance failures without adequate explanations, it is appropriate to enforce consequences. It also notes the lack of a definition for a serious service degradation and cites the AUC Decision[13] which developed a consultation process as a means of setting performance measures within PBR. CEC sees this as "an appropriate method of ensuring that the most important performance metrics are established and included as criteria for incentive payments." CEC believes the Fortis proposal leaves too much ground between the degradation of service and the move toward off-ramps. If service is degraded, the Commission is placed in the position of either accepting the results of degraded service or having to reconsider the entire regulatory process. CEC recommends that where targets are missed, the utility be subject to Commission examination during the Annual Review with a determination of appropriate consequences. (CEC PBR Final Argument, pp. 210–212)

[13] Included as Exhibit B-1-1, Appendix D8, pp. 91, 881–883

ICG considers the purpose of SQIs is to ensure the utility does not sacrifice service quality during a PBR. However, its position is that SQIs are "not sufficiently sensitive, with too many confounding factors, for service quality indicators to detect any changes to either O&M activities or capital investments during a PBR Plan." ICG argues that while reliability indicators like System Average Interruption Duration Index (SAIDI) or System Average Interruption Frequency Index (SAIFI) can change over time if maintenance activities or investments in infrastructure change, year-to-year changes are more affected by weather than any other factor. Consequently, ICG does not consider the professed purpose of SQIs to be achievable. (ICG Final Argument, pp. 35–36)

BCPSO notes that in the previous PBR, SQI results were reviewed annually and participants were able to make submissions with regard to whether a deviation from a benchmark was sufficient to warrant a limiting of incentive payments to the utility. Its view is that this approach should be taken in the current PBR plan as it falls short of cancelling the PBR in its entirety yet recognizes that customers suffer from a drop in service quality and should be compensated. (BCPSO PBR Final Argument, para. 64)

COPE states that at the "heart of the problem with the Companies' Service Quality Indicators proposal is that the way it approaches the *service* side of the [regulatory] compact is not consistent with its approach to the financial *performance and reward* side. It adopts a mechanism of financial risks and rewards to boost the financial performance of the utilities, but rejects that approach to service performance." (COPE Final Argument, p. 6)

COPE's expert witness, Ms. Alexander provides substantial commentary on the application of penalties for sub-standard performance on SQI's and recommends a program be put in place. These are also referred to as "compensation credits" designed to compensate the customer who has suffered the poor service quality (T5:875). Ms. Alexander was able to provide numerous examples in other jurisdictions where such penalty schemes are in place. (FEI Exhibit C2-13, BCUC 1.14.2)

In Final Argument, COPE muses that the use of the word "penalty" was unfortunate in that it was not an accurate reflection of Ms. Alexander's concept, which was compensatory in nature and not really punitive. In spite of extolling the virtues of the approach recommended by its witness, COPE stops short of specifically advocating that the Commission consider implementation of a penalty based regimen. In its conclusions COPE states that it agrees emphatically with the Fortis statement made in Final Argument:

> "In the event that the Commission considers the proposed PBR Plan and the existing statutory mechanisms to be insufficient, and considers it necessary to incorporate a term into the PBR Plan that makes earnings sharing conditional upon maintaining service quality, the Commission should proceed with caution to ensure that the PBR Plan remains compliant with the UCA and fair to the Company as well as rate payers" (FEI PBR Final Argument, p. 161)

COPE's concern is that the PBR is slanted toward the utilities and a reinforcement of the customer service side of the regulatory compact is needed. It views the SQI component of the PBR proposal as seriously deficient and asserts there is a need for mechanisms to ensure sufficiently robust service standards that will inhibit any incentive the utility may have to cut corners. To this end COPE states that "SQI's must be meaningful, they must be measurable, and they must have teeth" recommending the Commission develop an effective mechanism to rebalance PBR incentives to achieve this. (COPE Final Argument, pp. 46–50)

IRG does not support Ms. Alexander's penalty recommendations and recommends the Commission reject them. In IRG's view, the avoidance of penalties would become a distraction for FBC management and staff and not result in any material increases in service quality, reliability or safety. (IRG Final Argument, p. 12)

<u>Fortis Reply</u>

Fortis acknowledges that using Off-Ramps as an enforcement tool for SQIs is a blunt instrument. The Companies see it as a tool of last resort, stating that they have proposed the same service quality trigger that existed in previous PBRs. Related to this, Fortis does not define sustained serious service degradation considering it best to allow the Commission to consider all of the circumstances before a decision is made to terminate the PBR. (Fortis PBR Final Argument, pp. 88–89)

In considering the proposal to limit PBR incentives as a means of enforcing service quality, Fortis makes the following submission:

> "Under section 59 of the UCA, a rate is 'unjust' or 'unreasonable' if the rate is either '(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility' or (b) insufficient to yield a fair return. The rates under PBR are set based on the utility taking appropriate steps to deliver a particular level of service quality. The rate yielded by the PBR Plan is, in effect, too high if service quality declines materially as a result of some imprudent conduct by the utility. A finding of imprudence is a precondition to disallowing a portion of the incentive because the overall PBR must still confer an opportunity to earn a fair return. The presumption of prudence would apply." (Fortis PBR Reply, p. 90)

Commission Determination

There does not appear to be consensus among the interveners with respect to the Fortis SQI proposal. CEC, BCPSO and COPE are all in agreement that the Fortis proposal for the handling of SQIs falls well short of optimum and, to be effective, has to include consequences for serious degradation of service. For ICG and IRG the primary concern appears to be access to reliable service and neither supports the introduction of a penalty regimen as a means of achieving this. ICG has also raised concerns as to the effect of confounding factors such as weather on key reliability measures or whether established measures are effective at measuring the impact of changes in maintenance and infrastructure over shorter PBR time periods.

The Commission Panel is in general agreement with CEC, BCPSO and COPE with respect to the need for consequences related to service degradation. The Fortis proposal for the management of SQIs within PBR is much too vague and lacks consequences other than the potential for an off-ramp. The PBR is being approved with incentives for the utility to create efficiencies and reduce unnecessary cost. However, if O&M and maintenance capital are too tightly constrained this may result in a degradation of key service level areas. Therefore, the Panel considers that incentives related to reducing costs and creating efficiencies need to be counter balanced to ensure this occurs without a degradation of service levels as measured by SQIs. Confounding this somewhat is the point raised by ICG that the short-term actions taken by the utility affect long-term SQI results but may have limited effect on short-term measurements for some SQIs. On the other hand, external factors such as weather may have a significant impact on short-term SQI measurements which dissipate when considered over the longer term. Fortis has acknowledged this latter point by recommending that an assessment of unsatisfactory performance on SQIs should not occur until the mid-term review following year three of PBR. The Panel notes there is no evidence on the record concerning the length of time it takes for an action undertaken by a utility to be reflected in SQI performance. In the Panel's view a drop in performance on a SQI would likely depend on the particular performance measure and the severity of the action or inaction of the utility. Therefore, the Commission Panel is not persuaded there is justification for SQI review to be delayed beyond the next Annual Review.

Considering these issues the Commission Panel determines that there is a need for consequences to be tied to the failure to achieve reasonable performance on defined SQIs. The Panel considers that a failure to underline the importance of SQIs sends the wrong message to the utility and invites behaviours which may not support the achievement of safe and reliable service.

The next question is "what consequences are most appropriate?" The ultimate consequence as proposed by Fortis is to invoke the off-ramp option and cancel the PBR. In the view of the Panel this should remain but in addition there is a need for less drastic alternatives to terminating the PBR. Ms. Alexander has proposed that the Commission institute a penalty regimen with predefined penalties (also referred to as compensation credits) assessed to the utility for failure to meet one or more SQI targets. This option received little support from the intervener group. Another option is to tie the achievement of the full earnings-sharing ratio conditional upon maintaining service quality levels. This approach, which was recommended by BCPSO, addresses a number of the concerns of interveners and creates consequences for failure to achieve satisfactory levels of service quality without going to a penalty based regimen as proposed by Ms. Alexander. This modified approach offers the advantage of linking consequences only to incentive earnings which exceed the Commission approved I-X formula driven ROE returns. Reducing excess earnings to no lower than the approved ROE is not unjust or unreasonable. In addition, because the maintenance of service quality is tied to the earnings sharing mechanism, it will only apply when there are incentive earnings to share. This clearly establishes the achievement of service quality standards as a precondition to the earning of incentives. As a consequence, concern that a utility may be motivated to put the achievement of service standards at risk in order to earn an incentive is, to a degree, mitigated. **Therefore, the Commission Panel determines that the incentives earned must be linked to the achievement of service quality standards.**

2.2.3.2 What SQIs are Appropriate?

The issues related to which SQIs are appropriate for this PBR received extensive review within the proceeding. Fortis has proposed a set of SQIs it considers appropriate for the purposes of the PBR. It has also provided a proposal for discontinuing some of the SQIs currently in place. The Fortis proposal and related issues raised by interveners will now be discussed.

<u>Fortis’ Proposed SQIs</u>

Table 2.25 outlines the SQIs FEI and FBC have proposed. Fortis has proposed a benchmark as a measure of service quality for many of these.

Table 2.25 Service Quality Indicators (SQIs) Proposed by FEI and FBC

Performance Measure	FEI Indicator	FEI Benchmark	FBC Indicator	FBC Benchmark
Emergency response time	Percent of calls responded to within one hour	95%	Percent of calls responded to within two hours	85%
First contact resolution	Percent of customers who achieved call resolution in one call	78%	Percent of customers who achieved call resolution in one call	78%
Billing Index	Measure of customer bills produced meeting performance criteria	5	Measure of customer bills produced meeting performance criteria	5
Meter reading accuracy	Number of scheduled meters that were read	95%	Number of scheduled meters that were read	97%
Telephone service factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	70%	Percent of calls answered within 30 seconds or less	70%
Meter exchange appointment	Percent of appointments met for meter exchanges	95%	N/A	N/A
Telephone service factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	95%	N/A	N/A
All injury frequency rate	Informational indicator – 3 year rolling average of lost time injuries plus medical treatment injuries per 200,000 hours worked	--	Informational indicator – 3 year rolling average of lost time injuries plus medical treatment injuries	--
Customer satisfaction index	Informational indicator	--	Informational indicator	--
Public contact with pipelines	Informational Indicator – 3 year rolling average of number of line damages per 1,000 BC One calls received	--	N/A	N/A
System Average Interruption Duration Index	N/A	N/A	Informational indicator- 3 year rolling average of SAIDI (average cumulative customer outage time)	--
System Average Interruption Frequency Index	N/A	N/A	Informational indicator- 3 year rolling average of SAIFI (average customer outages)	--

(Source: FBC Exhibit B-1, p. 69; FEI Exhibit B-1, p. 76)

Discontinued SQIs Proposed by Fortis

As previously noted, Fortis has also proposed to discontinue a number of existing SQIs which they believe are of little value going forward. These include the following:

FEI Discontinued SQIs Proposal

- Transmission Reportable Incidents
- Leaks per Km of Distribution System Mains
- Number of Third Party Distribution System Incidents
- Accuracy of Transportation Meter Measurement First Report
- Number of Customer Complaints to the BCUC
- Percent of Industrial Customer Bills Accurate
- Number of Prior Period Adjustments

(FEI Exhibit B-1-1, Appendix D7, pp. 16–17)

FBC Discontinued SQI Proposal

- Generator Forced Outage Rate
- Residential Connections Completion Time
- Residential Extension Quoting Time
- Residential Extensions Completion Time
- Injury Severity Rate
- Vehicle Incident Rate

(FBC Exhibit B-1-1, Appendix D6, pp. 12, 13)

Intervener Submissions

More generally, CEC takes the position that the SQIs put forward by Fortis do not adequately protect the ratepayer. An example of this is the lack of asset health SQIs which may incent the delay of maintenance activities resulting in undesired consequences. It considers many of the proposed SQIs to be of greater interest to residential customers than to commercial customers noting that FEI has no insight into commercial sector satisfaction given the cancellation of the Large Commercial Customer Satisfaction Survey. (CEC PBR Final Argument, pp. 194–196; pp. 203–204)

In assessing SQIs, CEC recommends the Commission consider measures that:

- Provide long-term protection to all ratepayer groups from service degradation or increased expenses;
- Deter cost–cutting in areas that can or could affect service quality and reliability;
- Adequately address all areas of service, especially those that may be likely targets for cost-cutting; and
- Are measurable/quantifiable.

(CEC PBR Final Argument, p. 193)

COPE considers Ms. Alexander's approach to calibration of benchmarks to be reasonable and balanced and urges the Commission to adopt best practices and not rely "on the lowest common denominator in establishing its policies for SQI in the context of a PBR." COPE supports the notion of relying on 3 year averages as a means of controlling service volatility. (COPE PBR Final Argument, pp. 27–30)

Interveners have made the following recommendations with respect to specific SQIs proposed by the Companies in their applications:

(i) Emergency Response Time

FEI proposes to change to the Canadian Gas Association (CGA) definition of an emergency event and the CGA response time calculation. Based on the CGA definition, FEI has, over the 2010 to 2012 period, responded to emergency calls within one hour 97.7 percent of the time. FEI proposes to set its emergency response benchmark at 95 percent stating that it is approximately equal to the industry average and in the top quartile of CGA members. (FBC Application, Exhibit B-1-1, Appendix D7, pp. 5–6)

CEC and BCPSO recommend that FEI should be required to maintain its emergency response time metric at current levels (97.4 percent) which it has been able to achieve on a consistent basis, rather than setting it at a lower level (95 percent). (CEC PBR Final Argument, p. 215; BCPSO PBR Final Argument, p. 19)

Over the same period FBC has responded to an initial identification of a loss of power, to arrival of FBC staff at the trouble site within two hours or less, 93 percent of the time. FBC states that its current benchmark is 85 percent and represents a level of response expected by its customers. It proposes to maintain the benchmark at this level.

BCPSO submits that the FBC emergency services benchmark should be set at least 90 percent as since 2007 FBC has achieved a level of 91 percent or higher and this is the level that customers have been receiving and has been sustained at current expenditure levels. (BCPSO PBR Final Argument, p. 16)

(ii) Meter Exchange Appointment

CEC and BCPSO agree with FEI's proposed 95 percent benchmark. CEC does not support the COPE proposal to replace this metric with a missed appointment customer credit of $25. (CEC PBR Final Argument, pp. 215, 216; BCPSO PBR Final Argument, p. 19)

(iii) First Contact Resolution

CEC considers first contact resolution as important to customers, but its usefulness complements other measures (CEC PBR Final Argument, p. 217).

(iv) Telephone Service Factor (emergency)

CEC and BCPSO agree with the proposed benchmark that 95 percent of calls be answered within 30 seconds or less (CEC PBR Final Argument PBR, p. 216; BCPSO PBR Final Argument, p. 19).

(v) Telephone Service Factor (Non-emergency*)*

CEC submits that the average wait time is not necessarily indicative of the wait time experienced by some customers. CEC recommends the Companies develop an abandonment rate measure and SQI. (CEC PBR Final Argument, pp. 216–217)

Ms. Alexander recommends 80 percent for both FEI and FBC referring to this as the best practice standard. (FEI Exhibit C2-10, p.27) BCPSO had no objection to the proposed Telephone Service metric (BCPSO PBR Final Argument, p. 19).

(vi) Billing Index and Meter Reading Accuracy

Ms. Alexander recommends that both of these indexes be eliminated for FBC as modern computerized billing systems make billing and meter reading highly accurate and timely. However, the metric should be retained for the gas utility. (FEI Exhibit C2-10, pp.28–31)

CEC disagrees with COPE pointing out the measure allows for the identification of problems. (CEC PBR Final Argument, p. 217)

<u>Fortis Discontinued or Informational Only SQIs</u>

Both CEC and COPE have concerns that the Companies have removed any SQIs with benchmarks or targets that are related to reliability. CEC notes that establishing SQIs intended to reflect the experience between the customer and the company are inadequate protection of customer interests pointing out that the interests of ratepayers go far beyond the typical 'customer experience'. CEC list customer interests such as asset health, corporate responsibility, special irrigation concerns or energy efficiency activities as examples of customer interests which are not covered by SQIs. (CEC PBR Final Argument, p. 202) Specific issues related to dropped or Informational Only SQIs are as follows:

(i) SAIDI and SAIFI

FBC proposes to report on the SAIDI and SAIFI service quality indicators on an informational basis only. Fortis suggests that these indicators are not considered to have a significant linkage between costs and results and it may take years for the results to be evident.

CEC believes that whether an indicator responds immediately or not to cost cutting should not exclude its use. In CEC's view, the ratepayer needs protection from long-term degradation in reliability which in its view stems from asset health which can be affected by the level of expenditures on maintenance. (CEC PBR Final Argument PBR, p. 203–205)

COPE submits that FBC's generally acceptable performance for reliability as exhibited by SAIFI and SAIDI would be placed at risk during the PBR period by relegating it to an informational SQI with no performance target. (COPE Final Argument, p. 18)

(ii) All Injury Frequency Rate (AIFR*)*

Both FEI and FBC propose the use of the AIFR as an informational SQI. COPE argues that the Companies should be held accountable for AIFR results. While recognizing that the Companies cannot control the conduct of all their employees at all times, its expert witness, Ms. Alexander notes "management is in charge of the workplace culture, the safety systems, and the educational activities designed to prevent as many workplace accidents as possible." (COPE Final Argument, p. 40)

(iii) Public Contact with Pipelines

FEI has introduced the public contact with pipelines SQI to reflect the importance of educating the public on the risk associated with pipeline contact. The SQI is a "measure of the overall effectiveness of the public's awareness to minimize damage to the gas system, which will reduce risk to public safety and service interruptions for customers." FEI proposes that this SQI be an informational measure with no benchmark. (FEI Application, Exhibit B-1-1, Appendix D7, pp. 12, 13)

COPE argues that this is an important measure related directly to public safety and FEI should conduct itself in a way which mitigates risks and be held accountable for the results (COPE Final Argument, p. 38).

Fortis Reply

Fortis considers it appropriate that it has relied on a suite of SQI's that focus on the direct customer experience noting that the interveners seek to include additional performance indicators concerning a variety of matters including asset health and corporate responsibility. Fortis acknowledges that these matters may be of interest to customers but argues that it does not necessarily follow that SQIs related to these matters should be covered under the PBR plan. In support of its approach, Fortis notes that the Companies do not have the discretion to allow assets to deteriorate and they already report to the Commission in considerable detail in a more useful format (citing comments from T6:1196 with reference to metrics on the state of the assets and the reporting regimen through the Oil and Gas Commission).

Fortis argues that its current level of service is high and

> "[i]ncreasing service level requirements above the benchmarks proposed by FortisBC will give rise to asymmetric risk in circumstances where there is no direct correlation between utility spending and service levels." In other words, the odds are higher of missing a high benchmark metric as compared to a lower one unless it can be determined that additional expenditures can produce the desired results. It explains that it has set a reduced benchmark of 95 percent in the case of Emergency Response times because "the odds of falling below the benchmark of 97.6% for reasons beyond utility control are significantly higher than would be the case with a benchmark set at 95%." (Fortis PBR Reply, p. 84)

Commission Determination

There are two key issues that the Commission Panel must address. The first of these is concerned with whether the SQI's proposed by Fortis are appropriate. If not, what SQIs should be added? Related to this is whether the informational indicators as proposed, should be so categorized or whether some of these should be upgraded to full SQIs with performance benchmarks. The second issue deals with the level of the performance benchmarks.

<u>Are Fortis' Proposed SQIs Appropriate?</u>

Under the *Utilities Commission Act* the Commission has an obligation to ensure the utility is supplying "reasonable, safe, adequate and fair service" (s. 25). Reasonable, safe and adequate service entails providing services that are reliable, responsive to consumer needs and protective of the safety of the public which includes both ratepayers and employees of the Utilities. The Commission Panel considers Fortis' contention that SQIs should be focused on the customer experience as being too narrow in scope. In our view, the SQIs are a mechanism to assist the Commission to ascertain whether the Companies are living up to the obligations envisaged in the regulatory compact and legislated under the UCA.

The proposed benchmarked SQIs are focused primarily on the areas of direct interaction between the Companies and customers and don't fully reflect all of its service obligations. **Therefore, the Commission Panel finds that they are not a balanced set of indicators covering reliability, responsiveness to consumer needs and providing for the safety of the public.** All of these are required to enable the Commission to evaluate whether the Companies are meeting obligations under the UCA.

The Commission Panel notes that only two of the benchmarked SQIs proposed by FEI relate to safety (Emergency Response Time and Telephone Response – Emergency) and only one FBC SQI is safety related (Emergency Response Time). The remaining benchmarked SQIs, five in the case of FEI and four for FBC relate to customer/company interactions. Further, FEI has no service quality indicators dealing with reliability of service while FBC has only two, SAIFI and SAIDI, both of which are proposed as informational indicators. In our view, this does not reflect a balanced approach.

A concern has been raised by many interveners with respect to the elimination or a move to informational status of reliability related SQIs. Given the length of term of the PBR, the Panel agrees and is equally concerned that there are no SQIs with established performance targets to address reliability. Moreover, in our view, the lack of SQIs fails to meet the Commission's need to assure itself that service quality, as required by legislation, is being met.

The Commission Panel has separated SQIs into three categories: Safety, Customer Needs and Reliability. **Within these categories the Commission Panel approves the following SQIs proposed by Fortis:**

- **Safety**
    - **Emergency Response Time**
    - **Telephone Service Factor (emergency)**
- **Customer needs**
    - **First Contact Resolution**
    - **Billing Index**

- **Meter Reading Accuracy**
- **Telephone Service Factor (non-emergency)**
- **Meter Exchange Appointment**

In addition, the Commission Panel directs that a number of Fortis' proposed informational SQIs be re-classified as benchmarked SQIs. These include:

- **Safety**
    - **All Injury Frequency Rate**
    - **Public Contact with Pipelines**
- **Reliability**
    - **SAIDI (weather normalized) FBC only**
    - **SAIFI (weather normalized) FBC only**

Further, the Panel approves the following informational indicators:

- **Customer Satisfaction Index**
- **Telephone Abandon Rate**

and we direct Fortis to reinitiate the following informational indicators:

- **Generator Forced Outage Rate**
- **Transmission Reportable Incidents**
- **Leaks per KM of Distribution System Mains**

Telephone Abandon Rate, while reported by Fortis to be very low (T6:1275), has not been reported previously. The Panel considers this a useful measure in determining the level of service failure which is important given the Fortis proposal to lower its Telephone Service Factor SQI benchmark metric. The Panel has also directed Fortis to reinstate Generator Forced Outage Rate, Transmission Reportable Incidents and Leaks per KM of Distribution System Mains as informational indicators. While the Panel accepts the FBC argument that it has a portfolio of resources to draw upon if a generator fails, we note that a generation failure might impact power purchases thereby having an impact on rates. Because of this, it remains a valuable indicator. Likewise the Panel considers

Transmission Reportable Incidents a valuable informational indicator as it tracks the number of reportable incidents to outside agencies such as the BC Oil and Gas Commission and WorkSafe BC.

With respect to the proposed SQIs which have been approved, the Panel notes the position of Fortis that the Billing Index and Meter Reading accuracy may not be needed due to their consistently positive results, and agrees with Fortis' assessment of the value to customers. However, we recommend that this be revisited at some future Annual Review during the PBR.

The Panel has changed a number of informational indicators to benchmarked SQIs. Under Safety, AIFR and Public Contact with Pipelines have been added. In the view of the Panel both of these measures reflect important safety concerns. The Panel agrees with COPE that while the Companies cannot control the actions of their employees, they are accountable for them, and as such, are responsible to take steps to mitigate any harmful behaviour. Therefore, this is an appropriate SQI metric which should be benchmarked and managed. The Panel has a similar view with Public Contact with Pipelines. As pointed out, performance on this SQI is a reflection of public awareness and while the public cannot be controlled, FEI can heavily influence performance on this SQI through the activities it undertakes to create awareness.

Under Reliability, the Panel has added SAIDI and SAIFI as benchmarked SQIs for FBC. We agree with COPE's and CEC's arguments that the ratepayer should not be placed at risk over the PBR period by relegating this to an informational indicator. This SQI goes to the heart of concerns raised by interveners with respect to underspending of capital. While the Panel acknowledges that both of these measures have to be viewed over the longer term and may be more affected by weather in the short term, we consider them valuable as indicators of utility performance.

Level of Performance Benchmarks

With regard to existing SQIs, Fortis proposes changes to two performance benchmarks. FEI proposes that Emergency Response Time be reduced from its average performance level over the 2010 to 2012 period of 97.7 percent to a slightly reduced performance benchmark of 95 percent. **The Commission Panel considers the performance benchmark of 97.7 percent (FEI Exhibit B-1-1,**

Appendix D7, p.6) to be appropriate as it reflects current performance and directs Fortis to set the SQI benchmark at this level for the purposes of the PBR. The Panel further directs that the FBC Emergency Response benchmark be set at 93 percent, which reflects the average Emergency Response achieved over the 2010 to 2012 period. The Panel acknowledges the concerns raised by Fortis with respect to the odds of falling below this level. This concern is dealt with in Section 2.3.3.3 where the introduction of "satisfactory performance ranges" is addressed.

A second change recommended by Fortis is related to FEI's non-emergency Telephone Service Factor. Fortis proposes to reduce the percentage of calls answered in 30 seconds to 70 percent from 75 percent. **The Commission Panel approves the reduction to 70 percent.** Although there is evidence that the industry standard is 80 percent, the Panel grants this approval for two reasons:

- Fortis reports a very low abandon rate in the 2 percent range for both FEI and FBC.
- FEI has implemented the call-back capability of its new system with substantial uptake. This mitigates to an extent the impact of unreasonable wait times.

In consideration of these factors, the Panel is persuaded that customer needs are being met. In addition, the Panel has ordered that in the future Fortis track phone call abandon rate as an informational indicator. If there is an increase in abandon rates the Commission may revisit telephone service SQIs in the future. **The Commission Panel approves the Fortis proposed benchmarks for all other proposed benchmarked SQIs.** The Panel notes that all of these are sufficiently high to be reasonable or reflect an average of recent performance levels.

For all new benchmarked SQIs the Panel directs Fortis to rely upon a 3 year average for 2010, 2011 and 2012 in calculating its performance benchmark. This methodology will be addressed further in Section 2.3.3.3.

A summary of these determinations and performance benchmarks are included in Table 2.26. **The Commission Panel directs Fortis to utilize the SQIs set out below for the PBR period. The Panel considers these to be balanced and collectively address service reliability, safety and customer needs.**

Table 2.26 Approved Service Quality Indicators (SQIs)

Performance Measure	FEI Indicator	FEI Benchmark	FBC Indicator	FBC Benchmark
Safety SQIs				
Emergency Response Time[3,5]	Percent of calls responded to within one hour	97.7%	Percent of calls responded to within two hours	93%
Telephone Service Factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	95%	N/A	N/A
All Injury frequency rate[1,5]	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	2.08	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	1.64
Public contact with pipelines[1,5]	3 year average of number of line damages per 1,000 BC One calls received	16	N/A	N/A
Responsiveness to Customer Needs SQIs				
First Contact Resolution	Percent of customers who achieved call resolution in one call	78%	Percent of customers who achieved call resolution in one call	78%
Billing Index	Measure of customer bills produced meeting performance criteria	5	Measure of customer bills produced meeting performance criteria	5
Meter Reading Accuracy	Number of scheduled meters that were read	95%	Number of scheduled meters that were read	97%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	70%	Percent of calls answered within 30 seconds or less	70%
Meter Exchange Appointment	Percent of appointments met for meter exchanges	95%	N/A	N/A
Customer Satisfaction Index	Informational indicator	--	Informational indicator	--
Reliability SQIs				
System Average Interruption Duration Index – Normalized[1,5]	N/A	N/A	3 year average of SAIDI (average cumulative customer outage time)	2.22
System Average Interruption Frequency Index – Normalized[1,5]	N/A	N/A	3 year average of SAIFI (average customer outages)	1.64
Generator Forced Outage Rate[2]	N/A	N/A	Informational indicator.	--
Transmission Reportable Incidents[2]	Informational indicator – Number of reportable incidents to outside agencies	--	N/A	
Leaks per KM of Distribution System Mains[2]	Informational indicator	--	N/A	

[1]Changed from an informational indicator to a benchmarked indicator

[2]Added as informational Indicator
[3]Benchmark changed
[4]Added benchmarked SQI
[5]Benchmark calculated as the average over the 2010, 2011 and 2012 period

2.2.3.3 Process to Review and Manage SQIs

The first issue the Panel must consider is whether holding the Companies to firm performance benchmarks is a reasonable approach to manage SQIs in a PBR context. Once this has been determined, the next issue is how best to implement a process to tie consequences to the failure to achieve reasonable performance on SQIs.

FEI explains that in establishing the SQI benchmarks it has relied on the Company's performance over recent years or on general industry standards. (FEI Exhibit B-1-1, Appendix D7, p. 2). It believes it is appropriate to base the proposed benchmarks on performance in recent years because the benchmarks are then reflective of the costs required to provide the service levels. (FEI Exhibit B-6, BCPSO 1.26.1) The use of a rolling average acts to smooth out annual results providing for a longer term indicator of any trends that may be developing. (FEI Exhibit B-6, BCPSO 1.26.1; FBC Exhibit B-7, BCUC 1.60.1.1)

As noted earlier, COPE has taken the position that the best way to determine SQIs and reduce volatility in results is to rely on a three year average for determining performance benchmarks for SQIs. Fortis has responded by pointing out that a drawback to relying upon an average is that actual amounts will fall above and below the average. Thus, what might be interpreted as a decline in service may not be reflective of what is occurring. (Fortis PBR Reply pp. 82–83)

Fortis has noted that in using a three-year average to set the SQI benchmark, by definition there will be years within the average that are below the average. For these reasons the Companies do not see the merit of tying specific consequences to the SQI benchmark targets. (Fortis PBR Reply, pp. 82-83)

Commission Determination

The Commission Panel agrees with Fortis and determines that it is not appropriate to require Fortis to be held to a specific performance benchmark for the following reasons. First, it does not take into account why SQIs are part of the PBR in the first place; that is to help mitigate the potential of serious degradation of service levels. Does being a percentage point below a prescribed performance benchmark result in a serious degradation of service? In most cases a drop of this amount would have minimal impact yet could result in a penalty being imposed. Second, there is the issue of averages. If averages are relied upon to determine the performance benchmarks it follows that results will fall below the benchmark approximately one half of the time. **Taking these points into consideration, the Commission Panel determines that the most effective way to manage SQIs is to set a satisfactory performance range.** The achievement of performance metrics that fall within this range is acceptable. Performance outside of this range would be unacceptable representing a serious degradation of service which would be subject to consequences. Performance benchmarks would continue to be determined which would serve as a target only and failure to reach them would not have consequences.

Determining the Performance Benchmarks and an Acceptable Performance Range

While the Panel agrees with Fortis that a three-year average helps to smooth out annual results, we do not agree with the use of a rolling average. Use of a rolling average is inconsistent with the concept of a satisfactory performance range as it could perpetuate a downward trend. The Panel agrees with BPCSO that setting the benchmark based on the last three-year period for which annual data was available (2010, 2011 and 2012) establishes the benchmark at a level that is reflective of the costs required to provide this level of service. The Panel has previously approved a performance range which provides for normal annual variability. **The Panel determines it to be appropriate to use a three-year average of 2010, 2011 and 2012 to set the benchmark around which a range can be established and we direct the use of this approach in setting benchmarks for the SQIs that the Panel has directed to be modified or added.** Once set, these will serve as performance benchmarks for the balance of the PBR.

The Commission Panel has considered options for setting an acceptable performance range for SQI metrics. In our view this is not simply a matter of setting a plus or minus percentage range that would be applied to all SQIs. Rather, a variety of factors like the economy, weather and the potential for variation must be considered in determining the range**. For this reason, the Panel directs the Companies, in consultation with stakeholders, to develop a performance range for each SQI covering the range of scores where performance would be found to be satisfactory.** An appropriate time to deal with this is in the period leading to the first Annual Review. Consultation among the parties should form a part of the process with recommendations flowing from it. **In providing its recommendations the Companies are directed to forward to the Commission any comments on the recommendations provided to them by stakeholders and Commission staff.**

In establishing the performance range for SQIs, the Panel expects the Companies and the stakeholders to take into consideration the following factors:

- The variance that has been experienced in the benchmark historically;
- The historic trend in the benchmark;
- The level of the benchmark relative to the SQI levels achieved by other utilities, including utilities in other jurisdictions;
- The sensitivity of the benchmark to external factors such as weather or economic conditions; and
- The impact of lower SQI levels on the provision of reliable, safe or adequate service.

<u>Failure to Meet SQI Benchmarks</u>

Where one or more of FEI or FBC's SQI performance metrics are outside the established range, the matter will be handled as part of the Annual Review. **Where the parties are unable to agree on a resolution to mitigate the problem or the parties consider further process to be warranted, the Panel directs them to refer the matter to the Commission.**

Where, after due process, the Commission finds that Fortis has failed to provide adequate service and the failure was, in whole or in part, due to the actions (or inactions) of Fortis, the Commission may reduce the share of earnings above the allowed rate of return that would otherwise flow to the Company. The reduced share of earnings would be credited to customers in the form of a compensation credit. **The Panel directs that the maximum reduction to the incentive earnings will be an adjustment to the earnings sharing mechanism to reflect a 60 percent ESM share to the customer rather than the standard 50 percent.**

When assessing the magnitude of any reduction in each Company's share of the incentive earnings, the Commission will take into account the following factors:

- Any economic gain made by each Company in allowing service levels to deteriorate;
- The impact on the delivery of safe, reliable and adequate service;
- Whether the impact is seen to be transitory or of a sustained nature; and
- Whether each Company has taken measures to ameliorate the deterioration in service.

Where there are no incentive earnings to share (i.e. the rate of return achieved by the Companies are at or below the approved rate of return), the Commission may still assess whether the level of service provided by the Company is adequate. In this case, the actions taken will be driven by the provisions in the UCA. This might include ordering Fortis, under section 25 of the UCA, to take certain actions to remedy a service deficiency or the imposition of an administrative penalty under section 109.2 of the UCA.

2.2.4 Off-Ramps

Off-ramps are described in the Companies' Applications as "a term of a PBR Plan that contemplates a complete regulatory review of the PBR Plan in particular limited circumstances" (FBC Exhibit B-1 pp. 69–70; FEI Exhibit B-1 p. 77). This section addresses off-ramps that could lead to a broader review of the entire PBR Plan and potentially to a termination of the PBR Plan altogether.

There are two off-ramp triggers proposed, a financial trigger and a non-financial trigger. The financial trigger is engaged when the post-sharing earnings of the Company exceeds or drops below the allowed ROE by 200 basis points. Given the 50:50 earnings sharing mechanism, this means that actual earnings would have to be above or below the approved ROE by 400 basis points to trigger a review of the PBR Plan. Fortis states that the allowed variance between the actual and approved ROE before the off ramp is triggered must be large enough to incent the Companies to pursue efficiencies while at the same time be limited enough to safeguard against potential excessive profits or losses. (FBC Exhibit B-1, p. 71; FEI Exhibit B-1, p. 78)

Fortis proposes that the non-financial trigger would be engaged if the Companies' service levels fell to an unacceptable level. In the Companies' view, only a "sustained serious degradation of the SQIs" would warrant a review of the PBR plan. Fortis does not see the failure to meet one (or more) of the SQI benchmarks as necessarily constituting unacceptable performance. Fortis maintains that assessment of the failure to meet an SQI(s) must take into account variance in performance that occurs due to random events or events beyond the full control of the Companies. (FBC Exhibit B-1, p. 71; FEI Exhibit B-1, p. 78)

2.2.4.1 Financial Trigger

Previous Fortis PBR Plans in British Columbia

Neither of the earlier PBR plans of FEI or FBC included a firm quantitative reopener or off-ramp. However FEI and FBC, as part of the Annual Review process had the right to request a change or termination of the PBR Plan if there were unacceptable outcomes associated with it.

B&V states: "[t]his provision does not represent the best approach to addressing serious issues with a PBR plan." However, B&V sees the provision as "understandable" within a negotiated settlement that includes a number of other provisions. (FEI and FBC Exhibit B-1-1, Appendix D1, pp. 46–47)

The 2004 FEI PBR Plan had a trigger of +/- 150 basis points around the approved ROE (after earnings sharing) but this was not considered an automatic off-ramp. It was open for parties to request a Commission review of the 2004 Plan if the threshold was exceeded. The 2007 FBC PBR Plan had a trigger mechanism of +/- 200 basis points around the approved ROE but this was not an off-ramp. If the earnings threshold was exceeded, the earnings variance (positive or negative) would be placed in a deferral account for review and disposition at the next Annual Review. (Fortis PBR Final Argument, p. 56)

In the previous PBR period, the Companies exceeded their allowed rate of return by a maximum of 145 basis point (FEI) and by 115 basis points (FBC) (Exhibit B2-11, CEC 45.4). Considering its previous PBR plan, FBC states: "FBC's going-in rates for this PBR Plan already incorporate substantial productivity savings achieved through the 2007-2011 PBR period, and those that have been realized in the 2012-2013 period through a renewed productivity focus. As a result, it will be challenging for this PBR Plan to produce the same level of savings that were realized under the 2007 Plan." (FBC Exhibit B-1, p. 5)

Intervener Submissions

CEC submits that the +/- 200 basis point differential post-sharing is too high. CEC notes this is equivalent to a +/- 400 basis point variance if there were no earnings sharing mechanism and is 50 basis points higher than the previous FEI PBR plan. CEC states that there is "little justification for either the number itself or for an increase." The proposed financial trigger is viewed by CEC as relatively high in comparison to other jurisdictions where the trigger is +/- 300 basis points with no earnings sharing mechanism. (CEC PBR Final Argument, pp. 165–166)

CEC recommends that the financial off-ramp should be set at the level of +/- 150 basis points (CEC PBR Final Argument, p. 171). CEC further advocates the use of a multi-pronged trigger to better protect customer interests if a PBR plan is approved (CEC PBR Final Argument, pp.167–168).

CEC also contends that the financial trigger is asymmetric in that Fortis, regardless of the PBR trigger, has the ability to file a cost of service application at any time if its actual rate of return falls too far below the allowed return. CEC does not see the consumer having the same redress if actual ROE is consistently significantly above the allowed ROE but below the trigger. CEC further asserts that Fortis could moderate or apply a cap to its earnings to avoid triggering an off-ramp.
Fortis refutes the suggestion that the off-ramp is asymmetric. Fortis submits that customers have the same opportunities afforded by an off-ramp as the Companies. Fortis may address financial

distress through an application to the Commission while customers may use an equivalent mechanism of filing a complaint to the Commission. In addition, Fortis states there is nothing in the PBR Plan "that would (i) purport to unlawfully fetter the Commission's discretion in the future, or (ii) skirt the rule against retroactive ratemaking." (Fortis PBR Reply, pp. 52–53)

Fortis also refutes the concept of a multi-prong trigger. In response to a CEC information request, stating it would not support a two-year trigger concept because:

- Dual trigger points are more prone to controversy for potential gaming concerns. (i.e. by increasing expenditures in one year to lower the actual ROE to compensate for a high ROE achieved in a previous year); and
- Fortis intends to pursue efficiencies and savings on a consistent basis throughout the PBR term. In Fortis' view this means that if the two-year trigger was set significantly below the single year trigger, there is a high likelihood that if one year's results were above the two-year trigger level, the subsequent year likely would be as well. This would trigger the off-ramp to the detriment of achieving longer-term benefits under the plan. (Exhibit B2-11, Fortis CEC 3.45.3, pp. 114–115)

Fortis submits that CEC has provided no rationale to explain why a multi-prong trigger point is more appropriate than a single trigger point. (Fortis PBR Reply, p. 53)

ICG supported the off-ramp elements of the Fortis application (ICG PBR Final Argument, p. 25). No other interveners addressed the financial trigger in the off-ramp.

Commission Determination

The Commission Panel views the triggering of an off-ramp as setting in motion a two-stage process. The first stage consists of a process before the Commission to assess potential remedies to the situation, including the potential for amending or re-calibrating the PBR plan to allow it to continue. A second stage to the process would be triggered if satisfactory solutions could not be found through modification of the PBR plan. This stage would deal with how to exit from the plan. This could include a variety of options from going back to a cost of service methodology to a redesign of the PBR.

With respect to the financial trigger, the Commission Panel agrees with Fortis that it should strike a balance between being high enough to incent the utility to vigorously pursue efficiencies and savings while being low enough to provide a safeguard for customers and the utility if either profits or losses become excessive. The applied for +/- 200 basis points post-sharing means that the achieved ROE before the earnings sharing is calculated would be +/- 400 basis points. This compares to the one year trigger point set in Alberta at +/- 500 basis points (with no revenue sharing) and the OEB trigger point of +/- 300 basis points, both of which are criticized by Fortis' consultant as being too broad. The AUC tempered its one-year trigger by also imposing a two-year trigger of +/- 300 basis points. The Panel notes that Fortis' expert witness testified that "I'm not aware that any utility would get to the point of being 200 basis points below their allowed return without filing a cost of service application" (T4:791).

In the Commission Panel's best judgement, a multi-pronged trigger strikes an appropriate balance between incenting the Companies to find efficiencies and savings and protecting the interest of the ratepayers. The Panel directs that an off-ramp be triggered if earnings in any one year vary from the approved ROE by more than +/- 200 basis points (post sharing). The Commission Panel further directs that should earnings average more than +/- 150 basis points (post sharing) from the approved ROE for two consecutive years, the off-ramp will be triggered.

The Panel is of the view that a 50 basis point differential is in all likelihood not significant enough to give rise to Fortis' concern regarding multi-year triggers being "significantly below" single year triggers.

Regarding intervener concerns that the single-year trigger is too high, the Panel notes that even with substantial productivity savings, Fortis did not exceed their allowed rate of return in their previous PBR periods. The Panel is of the view that the trigger points approved in this Decision will not stifle efficiency efforts and will provide an appropriate balance of protection for the Companies and the ratepayers.

2.2.4.2 Non-Financial Trigger

Fortis proposes that the non-financial trigger would be engaged if service levels fell to an unacceptable level. In the Companies' view only a "sustained serious degradation" of service quality, as measured by the SQIs, would warrant a review of the PBR plan. Fortis does not see the failure to meet one (or more) of the SQI benchmarks as necessarily constituting unacceptable performance. Fortis maintains that assessment of the failure to meet one or more SQIs must take into account variance in performance that occurs due to random events or events beyond the full control of the Companies. (FBC Exhibit B-1, p. 71; FEI Exhibit B-1, p. 2)

Fortis also submits that there are less drastic options to deal with declining service levels, noting that SQIs will be reviewed at each Annual Review. If appropriate, the Companies will work cooperatively with the interveners and the Commission to address any performance deficiencies. (Fortis PBR Final Argument, p. 58)

Fortis further submits that in the event there is a finding that some action of Fortis directly caused or contributed to a decline in service quality, the Commission has options under the UCA that include:

- Ordering Fortis to take certain steps to address service quality; and
- The power to levy administrative penalties after a hearing if the Companies breach the Commission order.

(Fortis PBR Final Argument, p. 155)

<u>Intervener Submissions</u>

CEC raises a number of concerns with respect to the non-financial trigger and submits that:

- the non-financial triggers act as a 'framework for determining whether there is need for a complete regulatory review of the PBR plan' rather than as an off-ramp under which a complete regulatory review of the PBR would be undertaken;
- there is no obligation to maintain specific benchmarks;
- the term "sustained serious degradation" is extremely vague and open to interpretation and debate and should be defined by the Commission.

CEC agrees that the off-ramp should not be triggered if the issue is not caused by the Companies' actions. CEC recommends that the definition of when the off-ramp is triggered should encompass the concept of "prudent Utility management." (CEC PBR Final Argument, pp. 168–169)

BCPSO notes that in the 2004 PBR there was an option for participants in the Annual Review to make submissions to limit incentive payments to the Company if a deviation from an SQI Benchmark was significant. BCPSO recommends that this option be included in the current PBR plan. (BCPSO PBR Final Argument, p. 20)

COPE submits that:

- The Applications and evidence are "bereft of any guidance" as to the definition of a "sustained serious degradation of service quality" (COPE Final Argument, p. 7);
- A review as to whether there was a serious degradation in service quality would not occur until the Mid-term Review. This, in COPE's view would make it "difficult, if not impossible" for the off-ramp to be executed before the final days of the PBR (COPE Final Argument, p. 9);
- Fortis intends the off-ramp to be triggered only if there is a consensus it should be. This, in COPE's view, makes the off-ramp meaningless (COPE Final Argument, p. 10); and
- Even if it is determined that there is a serious sustained degradation of the SQIs, and the off-ramp provision is executed this would still not result in an adjustment to the financial results achieved. (COPE Final Argument, p. 13)

ICG supports the off ramp provisions of the FBC Application (ICG Final Argument, p. 25). Other interveners did not comment specifically on the merits of the non-financial trigger.

Commission Determination

<u>Definition of "Sustained Serious Degradation"</u>

Several interveners have raised concerns with respect to the lack of definition as to what encompasses a sustained serious degradation of service that would warrant the triggering of a review of the complete PBR plan and potentially the termination of the plan. Fortis, by stating that the Mid-Term Review would be the earliest time one could assess whether serious degradation has occurred, implies that "sustained" means degradation is ongoing over two or more years. The concept of what constitutes "serious" degradation is even more vague, with Fortis stating that failure to meet one or more benchmarks does not necessarily constitute unacceptable performance, particularly where under normal conditions there are circumstances that impact the SQI that are outside the Companies' control. (Fortis PBR Final Argument, p. 58)

The Commission Panel finds that providing a specific definition of what constitutes a "sustained serious degradation" in service is not practical. The determination of a sustained serious degradation entails judgments that can only be made based on the specifics of the circumstances that have given rise to the purported degradation. The Panel recommends the following criteria as the basis of the assessment of whether "sustained serious degradation" has occurred:

- Has the degradation persisted for two or more years and can it be reasonably anticipated to occur in the future?
- Has Fortis undertaken actions that are expected to mitigate the deficiency?
- Is the degradation due to random events that are not expected to recur?
- If the events impacting the SQI also are affecting other utilities, are the other utilities experiencing the same degradation of service quality?

In Section 2.3.3.3 the Panel sets out the consequences if Fortis fails to provide adequate safe and reliable service. We have also added additional SQIs to those proposed and amended some of the filed SQIs. We are of the view that this provides adequate incentive to the Companies to maintain appropriate service levels. This should render less likely the occurrence of "sustained serious degradation" of service quality.

Parties are directed to review the concept of "sustained serious degradation" of service levels at each Annual Review and provide recommendations to the Commission as to whether additional considerations to those set out above are appropriate. In particular, parties are requested to bring recommendations forward to the Commission where there have been a "sustained serious degradation" of service.

AUC
Alberta Utilities Commission

Errata to Decision 20414-D01-2016

2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities

February 6, 2017

Alberta Utilities Commission
Decision 20414-D01-2016 (Errata)
2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities
Proceeding 20414

February 6, 2017

Published by the:
Alberta Utilities Commission
Fifth Avenue Place, Fourth Floor, 425 First Street S.W.
Calgary, Alberta
T2P 3L8

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Alberta Utilities Commission

Calgary, Alberta

2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities | **Decision 20414-D01-2016 (Errata)** | **Proceeding 20414**

1. On December 16, 2016, the Alberta Utilities Commission issued Decision 20414-D01-2016,[1] to establish the parameters to be included in the next generation of performance-based regulation (PBR) plans (next generation PBR plans) to be implemented for the 2018 to 2022 period. This decision applies to four electric distribution utilities, ATCO Electric Ltd. (distribution), ENMAX Power Corporation (distribution), EPCOR Distribution & Transmission Inc. (distribution), and FortisAlberta Inc. and two gas distribution utilities, AltaGas Utilities Inc., and ATCO Gas and Pipelines Ltd. (distribution), together referred to as the distribution utilities.

2. Section 48.1 of the Commission's Rule 001: *Rules of Practice* provides that the Commission may correct typographical errors, errors of calculation and similar errors made in any of its orders, decisions or directions. The Commission corrects errors of this nature through the issuance of an errata to the original decision.

3. Upon review of Decision 20414-D01-2016, the Commission has noted a section reference typographical error and required correction.

4. A correction to the subsection numbering is required in Section 5. Currently there are two subsections numbered 5.4. The headings in Section 5 read as follows:

5.4 Commission determination of the X factor for the 2018-2022 PBR plans

5.4 X factor for ENMAX's 2015-2017 PBR plan

5.5 Proposals for a non-negative I-X provision

5. The heading references to sections 5.4 and 5.5 of Decision 20414-D01-2016 are hereby amended to read as follows:

5.4 Commission determination of the X factor for the 2018-2022 PBR plans

5.5 X factor for ENMAX's 2015-2017 PBR plan

5.6 Proposals for a non-negative I-X provision

6. All references to these subsections within the decision will remain as they appeared in the original decision.

7. In accordance with provisions of Decision 20414-D01-2016, the base K-bar calculation involves the use of an accounting test similar to the one currently employed for the capital tracker mechanism used during the current PBR term (albeit with certain modifications).[2] The

[1] Decision 20414-D01-2016: 2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities, Proceeding 20414, December 16, 2016.

[2] Decision 20414-D01-2016, paragraph 242.

Commission has noted that the order of the steps for the calculation of the interim base K-bar, as outlined in paragraph 254 of the decision, does not follow the order of the K factor calculation process as outlined in paragraphs 498 to 501 of Decision 2013-435[3] and is inconsistent with the resulting terminology set out in paragraph 14 of Decision 3434-D01-2015[4] and adopted in subsequent capital tracker decisions. Specifically, Step 1 in paragraph 254 of Decision 20414-D01-2016 currently corresponds to the second component of the accounting test, defined in Decision 3434-D01-2015, while Step 2 currently corresponds to the first component. This inconsistency does not affect the resulting base K-bar amount calculated, but the Commission considers that it may cause unnecessary confusion for parties calculating and evaluating the results of the base K-bar accounting test. Consequently, the decision will be amended to re-order the steps in paragraph 254 such that the original Step 2 becomes Step 1, consistent with the first component of the accounting test as defined previously. The original Step 1 will, therefore, become Step 2.

8. Further, an error occurred in the placement of the last sentence of the original Step 2, part (i) in paragraph 254 of Decision 20414-D01-2016, which provides instructions for the calculation of the interim base K-bar amount. This sentence reads:

> Distribution utilities should use a four-year average of inflation-adjusted retirements from 2013 to 2016 as an assumption in the accounting test.

9. This sentence should be removed from the original Step 2, part (i) and added as the last sentence of the original Step 1, part (v) of paragraph 254.

10. The changes described above affect all the steps for calculating base K-bar described in paragraph 254 of Decision 20414-D01-2016. Paragraph 254 and the resulting steps are hereby amended to read as follows:

> 254. To summarize, the calculation of interim base K-bar will involve the following steps:
>
> Step 1: Calculate the revenue requirement that is recovered in the base rates under the I-X mechanism for Type 2 K-bar projects or programs for 2018.
>
> (i) Calculate the amount of revenue requirement by program or project recovered in base rates under the I-X mechanism for 2018 using going-in capital-related revenue requirement by program or project, using the method for calculating recovered capital-related revenue requirement from the capital tracker accounting test approved in the current generation PBR plans. There will, however, no longer be a materiality threshold in the accounting test, and the accounting test must be applied to all Type 2 projects or programs, not just those with positive accounting test results.

[3] Decision 2013-435: Distribution Performance-Based Regulation 2013 Capital Tracker Applications, Proceeding 2131, Application 1608827-1, December 6, 2013.

[4] Decision 3434-D01-2015: Distribution Performance-Based Regulation Commission-Initiated Review of Assumptions Used in the Accounting Test for Capital Trackers, Proceeding 3434, Application 1610877-1, February 5, 2015.

Step 2: Calculate the projected revenue requirement for Type 2 K-bar projects or programs for 2018.

(i) Distribution utilities on the 2013-2017 PBR plans will determine the capital additions for each K-bar project for each of 2013 to 2016, and ENMAX will determine the capital additions for each K-bar project for 2015 and 2016. K-bar projects include all capital projects or programs that have historical rate base associated with them at the time of the rebasing applications. For non-capital tracker programs from the current generation PBR plans, use the actual capital additions as determined to be prudent in the rebasing application, and for capital tracker projects or programs from the current generation PBR plans, use the actual capital additions approved in the capital tracker decisions. As 2016 actual capital tracker additions will not have received Commission approval at the time of the rebasing application, use the 2016 applied-for actual costs from the 2016 capital tracker true-up application. The 2016 actual costs will be trued up to the amounts approved in the 2016 capital tracker true-up decisions at a later date. ENMAX will not have Commission approval for any of its capital tracker actuals. As such, ENMAX will use the applied-for actuals from its recent capital tracker true-up application for both 2015 and 2016. These amounts will be trued up at a later date.

(ii) Inflate the capital additions to 2017 dollars using the I-X methodology with the approved I factor for each year and the approved X factor for the 2013-2017 PBR plans, which is equal to 1.16. As ENMAX was not on the 2013-2017 PBR plans, it will use the X factor approved for ENMAX's 2015-2017 PBR plan, which is equal to 0.3, as noted in Section 5.5.

(iii) Calculate the average K-bar capital additions, by project, in 2017 dollars for the 2013 to 2016 period, or the 2015 to 2016 period for ENMAX.

(iv) Inflate the average K-bar capital additions by project to 2018 dollars using the I-X methodology with the approved I factor for 2018 and the X factor for the next generation PBR plans.

(v) Calculate the amount of K-bar capital cost incurred for 2018, by program or project, based on the 2018 capital additions from Step 2(iv) and the 2017 mid-year rate base using the method for calculating incurred capital costs from the capital tracker accounting test approved in Decision 2013-435. Distribution utilities should use a four-year average of inflation-adjusted retirements from 2013 to 2016 as an assumption in the accounting test.

Step 3: Calculate the base K-bar.

(i) Calculate the difference between the 2018 K-bar capital-related revenue requirement required on a projected basis by program or project (from Step 2) and the 2018 K-bar capital-related revenue requirement recovered in the base rates by program or project (from Step 1). The result is the capital funding shortfall or surplus amount for each program or project for 2018.

(ii) Sum the capital funding shortfall and surplus amounts, including both negative accounting test results and positive accounting test results without any materiality considerations, for all Type 2 projects and programs from Step 3(i) to get the total interim base K-bar for 2018.

11. For ease of reference, a corrected version of Decision 20414-D01-2016 is appended to this errata decision.

Dated on February 6, 2017.

Alberta Utilities Commission

(original signed by)

Willie Grieve, QC
Chair

(original signed by)

Neil Jamieson
Commission Member

(original signed by)

Henry van Egteren
Commission Member

Decision **20414-D01-2016**

Alberta Utilities Commission

2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities

December 16, 2016

Alberta Utilities Commission
Decision 20414-D01-2016
2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities
Proceeding 20414

December 16, 2016

Published by the:
Alberta Utilities Commission
Fifth Avenue Place, Fourth Floor, 425 First Street S.W.
Calgary, Alberta
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7 Calculation of returns for reopener purposes

261. A reopener provision is commonly included in PBR plans, including the current generation PBR plans, to provide a mechanism during the term of the plan to identify, assess and potentially address design or operational problems within the plan. Reopener provisions are triggered by positive or negative financial results that were unanticipated at the commencement of the plan, material and which cannot be addressed by other features of the plan.[310]

262. In Decision 2012-237, the Commission approved an ROE-based reopener mechanism for all PBR plans and determined that an earned ROE that is 500 basis points above or below the approved ROE in a single year, or 300 basis points above or below the approved ROE for two consecutive years, is sufficient to warrant consideration of a reopening and review of a PBR plan.[311] The "base" ROE against which to calculate the +/-300 or +/-500 basis point reopener thresholds for that year is the allowed ROE for a given year determined by the Commission in a generic cost of capital proceeding.[312] The actual ROE of the distribution utilities to be used to determine whether a reopener is warranted will be the ROE reported in the distribution utilities' annual Rule 005 filings.[313] [314]

263. The Commission also highlighted that a reopening of the PBR plans will not be automatic. As with any other matter before the Commission, a reopening of a PBR plan may be initiated on the Commission's own motion or on application of an interested party. The onus is on the applicant to demonstrate that a reopening is warranted.[315] The Commission further noted:

> … In order to ensure fairness to all parties, parties are directed to notify the Commission of all events that they consider signal the need for a re-opener as soon as possible after they have been identified. The Commission also directs that the financial impact of any such event be captured in a separate account pending a ruling from the Commission. Any proposed financial impact is to be measured from the time the event occurred. The disposition of the balance in that account (positive or negative) would follow the Commission's ruling.[316] [footnotes removed]

264. On February 2, 2016, the Commission issued Bulletin 2016-03,[317] in which it included, among other matters, a clarification regarding the restatement of Rule 005 results and, specifically, ROEs, as a result of adjustments to placeholder values for the distribution utilities under PBR plans. The Commission indicated that because Decision 2012-237 did not direct any specific changes to the way that ROE is to be calculated in Rule 005 filings, the distribution utilities should generally only make adjustments to the ROE that would typically have been required prior to the onset of PBR, subject to other clarifications in the bulletin.[318] The Commission emphasized that guidance was specific to distribution utilities under PBR plans

310 Decision 2012-237, paragraphs 723-724 and 727.
311 Decision 2012-237, paragraph 737.
312 Decision 2012-237, paragraph 738.
313 Decision 2012-237, paragraph 739.
314 Rule 005: *Annual Reporting Requirements of Financial and Operational Results* are annual reports filed by the distribution utilities in May of the year which follows the reporting year. The reporting year is defined as January 1 to December 31 of the year preceding the May filing deadline.
315 Decision 2012-237, paragraph 757.
316 Decision 2012-237, paragraph 758.
317 Bulletin 2016-03, Clarification of Rule 005 financial reporting requirements, February 2, 2016.
318 Bulletin 2016-03, sections 3 and 3.2.

established in Decision 2012-237, and may be subject to change for the next generation of PBR, based on determinations in this proceeding.[319]

265. In its August 21, 2015 letter establishing the scope of this proceeding, the Commission indicated that changes to Rule 005 were outside the scope of this proceeding, given that the requirements of Rule 005 apply to all utilities and not just the distribution utilities registered in this proceeding.[320] However, the Commission stated it saw merit in "clarifying the reopener parameters for a next generation PBR plan" and included the issue of calculating ROE for reopener purposes in the final issues list.[321]

266. The Commission heard evidence on whether to continue to use ROE as reported in Rule 005 filings for reopener purposes in the next generation PBR plans or to use an ROE reflective of final approved adjustment amounts for the reporting year arising from the Commission's subsequent decisions and rules. To the extent these final approved amounts are not available at the time of the Rule 005 filings, the latter approach would require a restatement of an ROE result reported in Rule 005 for that year.

267. Parties' views on this issue were divided among two main approaches, with some variations. The ATCO utilities and Fortis proposed to continue to use the ROE from Rule 005 reports, in accordance with the method approved in Decision 2012-237 and clarified in Bulletin 2016-03.[322] AltaGas, Calgary, the CCA, EPCOR and the UCA supported some form of a restatement of actual ROEs reported in Rule 005 or a reconciliation between Rule 005 returns and the changes after Rule 005 filings have been made, to adjust for the changes arising from subsequent Commission decisions and rules.[323] In its PBR plan proposal, ENMAX supported using the returns reported in Rule 005 without any adjustments.[324] However, in response to a Commission IR, ENMAX indicated it would not object to normalizing the Rule 005 ROE for reopener purposes, to reflect material revenue effects resulting from the Commission's rulings and decisions.[325]

268. The objective of the reopener provision has always been to ensure, to the extent possible, that a utility's performance under PBR is measured accurately, and on a timely and consistent basis. Accurate performance information is essential in order to identify, assess and consider timely adjustments to the plan prior to the end of the term.

269. In paragraph 758 of Decision 2012-237, reproduced earlier in this section, the Commission directed parties "to notify the Commission of all events that they consider signal the

319 Bulletin 2016-03, Section 4.
320 Exhibit 20414-X0026, AUC letter – Final issues list, August 21, 2015, paragraph 47.
321 Exhibit 20414-X0026, AUC letter – Final issues list, August 21, 2015, paragraph 48 and attachment, PDF page 12.
322 Decision 2012-237, paragraphs 737-739; Exhibit 20414-X0070, ATCO PBR plan proposal, paragraphs 81-85; 20414-X0073, Fortis PBR plan proposal, paragraph 115.
323 Exhibit 20414-X0081, AltaGas PBR plan proposal, paragraphs 100-104; Exhibit 20414-X0616, AltaGas argument, PDF pages 34-35; Exhibit 20414-X0071, Calgary PBR plan proposal, PDF pages 64-69; Exhibit 20414-X0625, Calgary argument, paragraphs 180-186; Exhibit 20414-X0630, CCA revised argument, paragraph 129; Exhibit 20414-X0422, CCA rebuttal evidence of Mr. Thygesen, paragraphs 70-73; Exhibit 20414-X0074, EPCOR PBR plan proposal, paragraphs 160-167; Exhibit 20414-X0256, EDTI-AUC-2016APR15-031; Transcript, Volume 13, page 2566, lines 12-20 (Mr. Baraniecki); Exhibit 20414-X0066, UCA evidence of Mr. Bell, PDF pages 31-33; Exhibit 20414-X0632, UCA reply argument, paragraph 84.
324 Exhibit 20414-X0069, ENMAX PBR plan proposal, paragraph 57.
325 Exhibit 20414-X0157, EPC-AUC-2016APR15-017(d).

need for a re-opener as soon as possible after they have been identified." The Commission continues to hold this view. The ROE from Rule 005 reports may serve as an initial indicator that a reopener threshold has been met.

270. In considering whether a reopener may be required based on the ROE from a Rule 005 report, a distribution utility may be asked for ROE adjustments to account for any outstanding true-up amounts and unusual events that may have affected a distribution utility's earnings. ENMAX referred to this process as an ROE "normalization" that would ensure the approved revenues and costs for the reporting year are aligned.

271. Parties to this proceeding pointed out that differences in timing as to when certain revenues and costs (for example, approved capital additions to rate base) are recognized in distribution utilities' financial statements, and when these items are collected from customers, affect the ROE calculation. As a result, depending on the assumptions used, an ROE reported in Rule 005 may not be reflective of the most accurate matching of approved revenues and costs for the reporting year. In the 2013-2017 PBR term, capital tracker revenues were the most prominent source of such mismatching because the amounts were material and because the final approved amounts were not known until a year or two after related costs were reflected in a Rule 005 report.

272. The Commission agrees with the submissions of those parties who indicated that restating the Rule 005 ROE to reflect the final approved amounts from subsequent Commission decisions and rules would ensure that approved revenues for a given year are matched better to actual costs for that year, resulting in a more accurate measurement of the distribution utilities' performances under PBR.[326] Additionally, the restated ROEs, reflective of final approved amounts and actual costs, rather than of individual distribution utility assumptions based on the information available at the time, will result in greater comparability of achieved returns among distribution utilities operating under PBR. For these reasons, the Commission will require the distribution utilities to restate the ROEs reported in their Rule 005 reports.

273. Those parties supporting the use of restated ROEs for reopener purposes differed in their views on what qualifies for a restatement and how often to restate. Regarding the frequency of restatements, the Commission considers that multiple adjustments throughout the year as suggested by Calgary,[327] are unnecessary. The Commission finds reasonable the proposal by AltaGas, Mr. Thygesen, on behalf of the CCA, ENMAX and EPCOR to restate ROE annually, as part of the annual PBR rate adjustment filings.[328] The Commission considers that a continued annual adjustment of the ROE is warranted where new final data becomes available. For instance, the 2018 ROE reported in the Rule 005 filing made in May 2019, could be restated in the 2020 annual PBR rate adjustment filing in September 2019 and updated again in the 2021 annual PBR rate adjustment filing, and so on, as more final data pertaining to 2018 becomes available.

326 Exhibit 20414-X0081, AltaGas PBR plan proposal, paragraphs 98-99; Exhibit 20414-X0625, Calgary argument, paragraph 183; Exhibit 20414-X0074, EPCOR PBR plan proposal, paragraphs 161 and 165; Transcript, Volume 13, page 2566, lines 12-20 (Mr. Baraniecki).

327 Exhibit 20414-X0625, Calgary argument, paragraph 184.

328 Exhibit 20414-X0081, AltaGas PBR plan proposal, paragraphs 101-103; Exhibit 20414-X0422, CCA rebuttal evidence of Mr. Thygesen, paragraph 71; Exhibit 20414-X0554, undertaking response by Mr. Hildebrandt to Ms. Wall at Transcript, Volume 8, page 1570, lines 16-19; Exhibit 20414-X0074, EPCOR PBR plan proposal, paragraph 164.

274. The Commission is of the view that the distribution utilities do not need to restate the entirety of the Rule 005 schedules from a given year. The Commission finds reasonable the proposals of AltaGas and EPCOR, supported by Mr. Thygesen, on behalf of the CCA, that restated ROE calculations can be provided annually in a separate schedule filed with the annual PBR rate adjustment filings.[329] Accordingly, the Commission directs each of the distribution utilities to include in each annual PBR rate adjustment filing commencing in 2019, an ROE adjustment schedule for each completed year during the next generation PBR term following the format of the Reconciliation of Financial & Utility Returns schedule, as required by paragraph 861 of Decision 2012-237, currently filed as part of the annual PBR rate adjustment filings. The new schedule should start with the ROE number from the Rule 005 report for a given year, and then list line items capturing the effects of any regulatory decisions not included in the original Rule 005 report that affect the distribution utility's revenues and costs, including the amount of equity, to arrive at the restated ROE number for that year. As part of this schedule, the distribution utilities are directed to provide a detailed description of each adjustment, with references to Commission decisions or rules approving the final amounts from which the adjustment arises.

275. Since the regulatory burden (i.e., the required explanations and supporting schedules) associated with this approach is commensurate with the number and magnitude of adjustments to an ROE number, the Commission will not adopt the materiality criteria for ROE restatements, as proposed by some parties.[330] The distribution utilities are directed to restate an ROE for a given year based on all of the available final approved amounts pertaining to that year. The Commission considers that in this case too, an ROE normalization process may be warranted; that is, in considering whether a reopener may be required, a distribution utility may be asked for ROE adjustments to account for any outstanding true-up amounts and unusual events that may have affected a distribution utility's earnings.

276. In order to achieve a continuity of restated ROE numbers, in all subsequent ROE adjustment schedules for a given year, the distribution utilities are directed to carry forward the line items and the resulting subtotals and the ROE result from the previous ROE adjustment schedule for that year. The newly identified line items, their subtotals and the new ROE result should then be presented below the previously restated ROE number. This way, in each subsequent ROE adjustment schedule, parties will have available the ROE from Rule 005 reports, each of the previously restated ROE results as well as the latest restated ROE number.

277. The latest information available, be it the initial Rule 005 filing or a subsequent ROE restatement filed as part of the annual PBR rate adjustment filing, can serve as a basis for a reopener application. To clarify, a Rule 005 ROE for a given year may serve as a reopener trigger only prior to the filing of a restated ROE for that year. When several restated ROEs for a given year are available, the most recent restatement from the latest annual PBR rate adjustment filing is to be used.

[329] Exhibit 20414-X0081, AltaGas PBR plan proposal, paragraphs 101-103; Exhibit 20414-X0639, AltaGas reply argument, paragraphs 75-76; Exhibit 20414-X0422, CCA rebuttal evidence of Mr. Thygesen, paragraph 71; Exhibit 20414-X0074, EPCOR PBR plan proposal, paragraph 166.

[330] Exhibit 20414-X0081, AltaGas PBR plan proposal, paragraph 104; Transcript, Volume 10, page 2079, lines 17-19 (Mr. Thygesen); Transcript, Volume 14, page 3000, line 9 to page 3003, line 7 (Mr. Baraniecki, Mr. Zurek, Mr. Chaudhary); Exhibit 20414-X0582, undertaking response by Mr. Chaudhary to Ms. Wall at Transcript, Volume 14, page 3003, lines 17-22.

278. Finally, AltaGas, the ATCO utilities, Calgary and Fortis proposed that the calculation of the ROE for assessing reopeners should not include amounts provided to the distribution utilities through the ECM approved in the 2013-2017 PBR plans, that will be collected in 2018 and 2019, in accordance with the approvals in Section 4.4 of this decision.[331] Although the distribution utilities will include the dollar amounts associated with the ECM approved in the 2013-2017 PBR plans in their financial reports for 2018 and 2019, the Commission agrees that the calculation of the ROE for assessing reopeners should not include amounts provided to the distribution utilities by the ECM approved in the 2013-2017 PBR plans, because these amounts arise from the operation of the previous generation of PBR and would not be indicative of potential design or operational problems under the terms of the next generation PBR plans. Accordingly, these ECM amounts should not be factored into the calculation of the reports filed to consider the potential need for a reopener.

279. Reopener considerations, other than the calculation of ROE based on Rule 005 filings or final returns, are outside the scope of this proceeding. Accordingly, with the exception of the Commission's determinations above on the ROE to be used for the purpose of determining if the reopener thresholds have been met, no other changes will be made to the reopener provisions set out in Decision 2012-237.

280. Specifically, the Commission will continue to employ the +/-500 basis point threshold in a single year and the +/-300 basis point thresholds for two consecutive years as warranting consideration of a reopening and review of a PBR plan.[332] The UCA's proposal for a +/-800 basis points threshold to be applied on a cumulative ROE basis over a PBR term is outside the scope of this proceeding.[333] AltaGas' proposal to use a blended generic ROE calculated by using a weighted average of the various PBR formula components is similarly outside the scope of this proceeding.[334] The Commission will utilize an allowed ROE for a given year, as determined by the Commission in a generic cost of capital proceeding, as the "base" ROE against which to calculate the +/-300 or +/-500 basis point reopener thresholds for that year.[335]

8 Other matters

281. In their submissions, in addition to addressing the four issues in scope for this proceeding, parties made proposals or filed evidence relating to other PBR-related matters. Some of these issues, for example, re-examining the I factor,[336] or shorting the term of the next generation PBR plan,[337] have been expressly excluded from consideration as a result of the scoping process that resulted in the Commission's final issues list. Other issues would require a specialized proceeding. For example, the UCA's and ENMAX's rate design proposals to alter

331 Exhibit 20414-X0616, AltaGas argument, paragraph 100; Transcript, Volume 5, page 847, lines 10-15 (Mr. Stock); Exhibit 20414-X0070, ATCO PBR plan proposal, paragraph 86; Exhibit 20414-X0636, Calgary reply argument, paragraph 184; Transcript, Volume 16, page 3314, lines 17-25 (Mr. Johnson); Exhibit 20414-X0073, Fortis PBR plan proposal, paragraph 46.

332 Decision 2012-237, paragraph 737.

333 Exhibit 20414-X0451, PARTIES(UCA)-AUC-2016JUN03-018(d).

334 Exhibit 20414-X0081, AltaGas PBR plan proposal, paragraphs 108-109.

335 Decision 2012-237, paragraph 738.

336 Exhibit 20414-X0616, AltaGas argument, paragraphs 8 and 24-25; Exhibit 20414-X0619, ENMAX argument, paragraph 94.

337 Exhibit 20414-X0622, ATCO argument, paragraphs 6 and 31; Exhibit 20414-X0632, UCA reply argument, paragraphs 27-28.

the proportion of distribution fixed and variable charges included in rates, are Phase II matters best addressed in a Phase II utility specific, or generic, proceeding.

282. AltaGas proposed to re-evaluate the current method for calculating billing determinants, approved in Decision 2012-237, to take into account the potential effect of lag from use of rolling averages, particularly during periods of economic volatility.[338] The CCA proposed an enhancement to the distribution utilities' reporting requirements to make them more tailored to the PBR framework, such as, for example, to show separately costs subject to I-X and costs subject to other factors, although it appears that this proposal was made in a context of rebasing.[339]

283. Although these proposals are beyond the scope of the present proceeding, the Commission is prepared to entertain proposals of this type, after the next generation rebasing process has been completed and 2018 PBR rates have been set on an interim basis. Any such proposal must be able to demonstrate that the proposal will result in improved efficiencies without affecting the incentive properties of next generation PBR plans or would address issues of improved rate design or cost allocation among rate classes.

9 Conclusion

284. In this decision, the Commission has sought to build on its experience with the 2013 to 2017 PBR plans as well as its experience with the 2007 to 2013 ENMAX FBR plan and to respond to the requests of the parties to this proceeding to develop a next generation PBR framework built on the five PBR principles adopted by the Commission in Bulletin 2010-20.[340] Those principles are:[341]

> **Principle 1.** A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality.
>
> **Principle 2.** A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.
>
> **Principle 3.** A PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.
>
> **Principle 4.** A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design.
>
> **Principle 5.** Customers and the regulated companies should share the benefits of a PBR plan.

285. The Commission's approach to building a PBR regime based on the five PBR principles has been to consider the inter-relationships among all of the PBR elements, both those being considered in this proceeding and those that will remain from the 2013 to 2017 PBR plans, rather

338 Exhibit 20414-X0616, AltaGas argument, paragraphs 8 and 28-29; Exhibit 20414-X0639, AltaGas reply argument, paragraphs 30-31.
339 Exhibit 20414-X0630, CCA revised argument, paragraphs 61, 105 and 109.
340 Bulletin 2010-20, Regulated Rate Initiative – PBR Principles, July 15, 2010.
341 Decision 2012-237, paragraph 28.

than only considering each element discretely. For example, in this proceeding the Commission's focus in setting the 2017 going-in rates for each distribution utility will be on using its judgement to estimate the costs that each distribution utility operating under the incentives of the PBR mechanism, unencumbered by incentives inconsistent with the PBR incentives, would have incurred in 2017 rather than being based on the distribution utilities' cost forecasts. The Commission has turned its attention to the going-in rates in recognition of the significant effects those rates can have on the distribution utilities' decision making and the outcomes of a PBR plan. Without going-in rates that seek to emulate competitive market cost structures achieved under the PBR incentives, other objectives of PBR can be compromised.

286. The Commission has also responded to concerns that the capital tracker mechanism adopted in the 2013-2017 PBR plans had the unintended effect of placing a considerable amount of capital outside of the incentive-enhancing I-X mechanism. In effect, capital trackers had to be administered in a manner similar to traditional COS regulation which parties agree has inferior incentive properties. Accordingly, the Commission has adopted a capital funding model that provides the necessary incremental capital funding for the distribution utilities while enhancing significantly the incentives to plan, design and construct capital assets efficiently. The Commission's approach to incremental capital funding is expected to reduce the regulatory burden over time, is easier to understand than the current capital tracker model, expands PBR incentives to the vast majority of overall costs and also allows the PBR plan to recognize the unique circumstances of each distribution utility and how the Alberta economy may affect each distribution utility.

287. The Commission is mindful that the distribution utilities raised concerns about a reasonable opportunity to earn their allowed rate of return and did so often in discrete discussions about each of the individual elements of PBR being considered in this proceeding. The Commission emphasizes that one cannot assess the opportunity to earn a reasonable rate of return based on examining each individual PBR parameter in isolation. Nor can the distribution utilities assume that any decision of the Commission to provide less assurance of cost recovery for one discrete element than they may have requested amounts to a denial of a reasonable opportunity to earn the allowed rate of return over the next generation PBR plans. The reasonable opportunity to earn their allowed rate of return is premised not only on the Commission's duty to turn its mind to regulated revenue streams for the distribution utilities, it also includes a duty of the distribution utilities to conduct their business in a way that meets their obligations and to do so in a way that contributes to their own success in earning their allowed rate of return or better.

288. The Commission has addressed the distribution utilities' reasonable opportunity to earn their allowed rates of return through the going-in rates and the incremental capital funding within the context of the overall next generation PBR plan, including the I-X formula. The X factor, combined with the I factor, is designed to create incentives similar to those in competitive markets. The Commission will apply the I-X formula to the 2017 notional going-in rates for each distribution utility as determined by the Commission. The Commission will then apply the incremental capital funding to recognize the unique circumstances of each distribution utility, and take into account all of the other elements of the PBR plan in place to mitigate the effects of unexpected cost increases or decreases. Based on its experience, administering the capital trackers in the 2013-2017 PBR plans and observing the evolution of operating and maintenance expenses of the distribution utilities during that time, having regard to the evidence filed in this proceeding and the elements of the PBR plans that it has approved in this decision, and applying

its expertise and judgement in carrying out its mandate to set just and reasonable rates, the Commission is satisfied that the distribution utilities will have a reasonable opportunity to earn their allowed rates of return over the next generation PBR plans.

10 Order

289. It is hereby ordered that:

(1) Each of AltaGas Utilities Inc., ATCO Electric Ltd. (distribution), ATCO Gas and Pipelines Ltd. (distribution), ENMAX Power Corporation (distribution), EPCOR Distribution & Transmission Inc. (distribution) and FortisAlberta Inc. shall file a compliance filing by way of a rebasing application in accordance with the directions set out in this decision by March 31, 2017. The rebasing applications by each distribution utility shall provide the proposed components of a 2017 notional revenue requirements with supporting documentation. The rebasing applications may include placeholder values and shall be updated with supplemental filings as information on actual or approved numbers becomes available. The updates are directed to be filed as follows:

- On or before July 1, 2017, each of the distribution utilities shall update its rebasing application by filing the audited 2016 actual financial results from its Rule 005 reports as well as the applied-for 2016 actual capital tracker amounts and, if applicable, final approved 2015 actual capital tracker amounts.
- On or before September 10, 2017, each of the distribution utilities will update its rebasing application by updating its 2017 notional revenue requirement and requesting approval on an interim basis of 2018 PBR rates calculated based on the application of the I-X index and any K factor, K-bar factor, Y factor, and Z factor amounts to the going-in rates calculated in the manner directed in Section 4 of this decision.

Dated on December 16, 2016.

Alberta Utilities Commission

(original signed by)

Willie Grieve, QC
Chair

(original signed by)

Neil Jamieson
Commission Member

(original signed by)

Henry van Egteren
Commission Member

VT INCEPIT FIDELIS SIC PERMANET
Ontario

Ontario Energy Board

Filing Requirements For
Electricity Distribution Rate Applications
- 2018 Edition for 2019 Rate Applications -

Chapter 3

Incentive Rate-Setting Applications

July 12, 2018

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Chapter 3 Filing Requirements for Incentive Rate-Setting Applications subject to the OEB's Index Adjustments

3.1 Introduction

On October 13, 2016, the OEB released its *Handbook for Utility Rate Applications* (the Handbook) to provide guidance to utilities and stakeholders on applications to the OEB for approval of rates under the renewed regulatory framework (RRF). The Handbook outlines the key principles and expectations the OEB will apply when reviewing rate applications and is applicable to all rate regulated utilities, including electricity distributors, electricity transmitters, natural gas utilities and Ontario Power Generation. The OEB expects utilities to file rate applications consistent with the Handbook unless a utility can demonstrate a strong rationale for departing from it. The Handbook describes three incentive rate-setting (IR) methods established by the RRF: Price Cap IR, Custom IR and the Annual IR Index.

These filing requirements set out the OEB's expectations for electricity distributors' annual rate adjustment applications in between cost of service (CoS) applications under Price Cap IR, or the Annual IR Index, also known as incentive rate-setting mechanism (IRM) applications. These filing requirements replace the 2017 edition of the Chapter 3 Incentive Rate-Setting Filing Requirements for Electricity Distribution Rate Applications, dated July 20, 2017.

The key elements for the three rate-setting methods were set out in the Renewed Regulatory Framework for Electricity (RRFE) in the following table:

Table 1: Rate-setting Overview – Elements of the Three Methods

<table>
<tr><th colspan="2"></th><th>Price Cap IR</th><th>Custom IR</th><th>Annual IR Index</th></tr>
<tr><td colspan="5">Setting of Rates</td></tr>
<tr><td colspan="2">“Going in” Rates</td><td>Determined in single forward test-year cost of service review</td><td>Determined in multi-year application review</td><td>No cost of service review, existing rates adjusted by the Annual Adjustment Mechanism</td></tr>
<tr><td colspan="2">Form</td><td>Price Cap Index</td><td>Custom Index</td><td>Price Cap Index</td></tr>
<tr><td colspan="2">Coverage</td><td colspan="3">Comprehensive (i.e., Capital and OM&A)</td></tr>
<tr><td rowspan="2">Annual Adjustment Mechanism</td><td>Inflation</td><td>Composite Index</td><td rowspan="3">Distributor-specific rate trend for the plan term to be determined by the Board, informed by: (1) the distributor's forecasts (revenue and costs, inflation, productivity); (2) the Board's inflation and productivity analyses; and (3) benchmarking to assess the reasonableness of the distributor's forecasts</td><td>Composite Index</td></tr>
<tr><td>Productivity</td><td>Peer Group X-factors comprised of: (1) Industry TFP growth potential; and (2) a stretch factor</td><td>Based on 4th Generation IR X-factors</td></tr>
<tr><td colspan="2">Role of Benchmarking</td><td>To assess reasonableness of distributor cost forecasts and to assign stretch factor</td><td>n/a</td></tr>
<tr><td colspan="2" rowspan="2">Sharing of Benefits</td><td colspan="3">Productivity factor</td></tr>
<tr><td>Stretch factor</td><td>Case-by-case</td><td>Highest 4th Generation IR stretch factor</td></tr>
<tr><td colspan="2">Term</td><td>5 years (rebasing plus 4 years).</td><td>Minimum term of 5 years.</td><td>No fixed term.</td></tr>
<tr><td colspan="2">Incremental Capital Module</td><td>On application</td><td>N/A</td><td>N/A</td></tr>
<tr><td colspan="2">Treatment of Unforeseen Events</td><td colspan="3">The Board's policies in relation to the treatment of unforeseen events, as set out in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, will continue under all three menu options.</td></tr>
<tr><td colspan="2">Deferral and Variance</td><td>Status quo</td><td>Status quo, plus as needed to track capital spending against plan</td><td>Disposition limited to Group 1
Separate application for Group 2</td></tr>
<tr><td colspan="2">Performance Reporting and Monitoring</td><td colspan="3">A regulatory review may be initiated if a distributor's annual reports show performance outside of the ±300 basis points earnings dead band or if performance erodes to unacceptable levels.</td></tr>
</table>

3.1.1 Grouping for Filings

Distributors that are seeking rate adjustments effective January 1, 2019 under IRM will be required to file their application by August 13, 2018. The OEB has assigned distributors seeking IRM rate adjustments effective May 1, 2019 to one of three application groupings noted below based on the expected level of complexity of the application. The length of time required to review an application is commensurate with its level of complexity. Applications of greater complexity will be expected to be filed first.

The OEB conducted a survey in May 2018 to identify the expected elements of an applicant's IRM application for the assignment of IRM filing deadlines. If a distributor expects that its application will be significantly more complex than it disclosed during the survey, it should advise the OEB and is encouraged to file in an earlier grouping.

Staggering the applications allows the OEB and other stakeholders to schedule resources to allow for adequate review of the applications. The deadlines for filing an IRM application have been determined so that, in the normal course of events, a decision and order will be issued in time for a May 1 implementation date.

The application deadlines are as follows:

- September 24, 2018
- October 15, 2018
- November 5, 2018

The assignment of distributors to these filing dates has been detailed in the cover letter accompanying these filing requirements.

3.1.2 Components of the Application Filing

Whether filing under Price Cap IR or the Annual IR Index, each application must include:

1. A manager's summary thoroughly documenting and explaining all rate adjustments requested.

2. The contact information for the application - the primary contact for the application may be a person within the applicant's organization other than the primary licence contact. The OEB will communicate with this person during the

course of the application. After completion of the application, the OEB will revert communication to the primary licence contact.

3. A completed rate generator model[1] and supplementary workforms[2] as applicable, provided by the OEB, both in Excel and Adobe PDF format.
4. A PDF copy of the current tariff sheet.
5. Supporting documentation cited within the application (e.g. excerpt of relevant past decisions and/or settlement agreements; validated reporting and record-keeping requirements (RRR) data pre-populated in the rate generator model; other RRR data referred to in the application; and, the revenue requirement workform (RRWF).[3]
6. A statement as to who will be affected by the application, including identification of any specific customer(s) or customer groups that are or will be affected by a particular request or proposal.
7. Confirmation of the applicant's internet address for purposes of viewing the application and related documents.
8. A statement confirming the accuracy of the billing determinants for pre-populated models.
9. A text-searchable Adobe PDF format for all documents.

3.1.3 Applications and Electronic Models

The models issued by the OEB assist the applicant in filing a rate application and provide formatting consistency across all applications.

For 2019 IRM applications, the OEB has taken steps to streamline the process further by pre-populating its models with distributor-specific RRR data, and by incorporating more automation with respect to the calculation of Global Adjustment (GA) and Capacity Based Recovery (CBR) charges and rate riders. The 2019 rate generator model will be

[1] The Rate Generator is a Microsoft Excel workbook that calculates a distributor's proposed tariff of rates and charges in a Price Cap IR or Annual IR Index application.

[2] Includes the GA Analysis Workform, Revenue Cost Ratio Adjustment Workform and the Incremental Capital Module/Advanced Capital Module (ICM) (ACM) Workform, as applicable.

[3] The Revenue Requirement Workform was filed as part of the draft rate order in the last CoS application.

populated with a distributor's most recent tariff of rates and charges, load and customer data and Group 1 balances as reported through RRR. Distributors will be required to confirm the accuracy of the data. Remaining inputs will be marked with green input cells.

The OEB will provide passwords to distributors filing a 2019 IRM application to access their distributor-specific rate generator model through the OEB's website. Any distributor that did not receive an individual password, but wishes to file an IR application for the 2019 rate year, must notify the OEB as soon as possible.

The rate generator model will update base rates, retail transmission service rates and if applicable, shared tax saving adjustments. It will also calculate rate riders for the disposition of deferral and variance account balances.

The rate generator model continues to include a bill impact calculation by rate class, in which commodity rates based on time-of-use and regulatory charges are held constant. These will be based on the regulated price plan (RPP) prices at the time the rate generator model was published. A typical residential customer has been defined as consuming 750 kWh in accordance with the *Report of the Board – Defining Ontario's Typical Residential Customer*.

In addition to the rate generator model, all distributors must file the GA Analysis Workform. The workform compares the General Ledger principal balance to an expected principal balance based on monthly GA volumes, revenues and costs. The workform helps the OEB assess if the annual balance in Account 1589 is reasonable. One or all of the following models are required when applications involve certain additional requests.

A distributor seeking a revenue-to-cost ratio adjustment due to a previous OEB decision must continue to file the OEB's revenue-to-cost ratio adjustment workform in addition to the rate generator model.

For an incremental or pre-approved advanced capital module (ICM/ACM) cost recovery and associated rate rider(s), a distributor must file the Capital Module Applicable to ACM and ICM.

A distributor seeking to dispose of lost revenue amounts from conservation and demand management activities, during an IRM term, must file the Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) Workform.

Starting for the 2019 rate applications, distributors who meet the requirements for disposition of residual balances of Account 1595 sub-accounts, must file the 1595

Analysis Workform. This new workform will help the OEB assess if the residual balances proposed for disposition are reasonable.

The models and workforms issued by the OEB are provided to assist the applicant in filing a rate application, and to provide consistent formatting for all distributors for greater efficiency of the review process. An applicant is responsible for the completeness and accuracy of its application. The applicant bears the responsibility to ensure the accuracy and appropriateness of all inputs and outputs from the models that it uses in supporting its application. The use of an OEB model does not guarantee that the OEB will approve the results. The OEB expects that the models and workforms be used by all distributors. If an applicant makes any changes to OEB models or workforms to address its own circumstances, it must highlight in the managers summary and provide justification for such changes.

3.2 Elements of the Price Cap IR and the Annual IR Index Plan

3.2.1 Annual Adjustment Mechanism

The annual adjustment follows an OEB-approved formula that includes components for inflation and the OEB's expectations of efficiency and productivity gains.[4] The components in the formula are also approved by the OEB annually. The formula is a rate adjustment equal to the inflation factor minus the distributor's X-factor.

Inflation Factor

In its *Report of the Board: Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* the OEB adopted a two factor industry-specific price index methodology. The inflation factor is based on two weighted price indicators (labour and non-labour) which provide an input price that reflects Ontario's electricity industry.

X-factor

The X-factor has two parts: a productivity factor and a stretch factor. The OEB has determined that the appropriate value for the productivity factor (industry total factor productivity) for the Price Cap IR and Annual IR Index is zero. For the stretch factor,

[4] Report on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors (December 4, 2013).

distributors will be assigned into one of five groups ranging from 0.0% to 0.6%. The most efficient distributor, based on the cost evaluation ranking, would be assigned the lowest stretch factor of 0.0%. All Annual IR Index applicants will be assigned a stretch factor of 0.6%.

Distributors shall use the 2018 rate-setting parameters as a placeholder until the stretch factor assignment and inflation factor for 2019 are issued by the OEB. OEB staff will update each distributor's rate generator model with the 2019 price cap parameters once they are available. Distributors will have an opportunity to comment on the accuracy of OEB staff's update as part of the application process.

3.2.1.1 Application of the Annual Adjustment Mechanism

The annual adjustment mechanism will apply to distribution rates (fixed and variable charges) uniformly across customer rate classes.

The annual adjustment mechanism will not be applied to the following components of delivery rates:

- Rate Adders
- Rate Riders
- Low Voltage Service Charges
- Retail Transmission Service Rates
- Wholesale Market Service Rate
- Rural and Remote Rate Protection Benefit and Charge
- Standard Supply Service – Administrative Charge
- Capacity Based Recovery
- MicroFIT Service Charge
- Specific Service Charges
- Transformation and Primary Metering Allowances[5]
- Smart Metering Entity Charge

[5] And any other allowances the OEB may determine.

3.2.2 Revenue-to-Cost Ratio Adjustments

OEB decisions regarding CoS rate applications may sometimes prescribe a phase-in period to adjust the revenue-to-cost ratios. The OEB's revenue-to-cost ratio adjustment workform and rate generator model include schedules for a distributor to adjust the revenue-to-cost ratio if previously approved by the OEB. The model will adjust base distribution rates before the application of the price cap adjustment.

3.2.3 Rate Design for Residential Electricity Customers

On April 2, 2015, the OEB released its *Board Policy: A New Distribution Rate Design for Residential Electricity Customers*[6], which stated that electricity distributors will transition to a fully fixed monthly distribution service charge for residential customers. The transition began in 2016 and in most cases will be implemented over a period of four years.

The OEB issued decisions affecting 2016, 2017 and 2018 rates for Price Cap IR and Annual Index IR applicants consistent with this policy. In this fourth year of transition, the distributor must follow the approach set out in Tab 16. Rev2Cost_GDPIPI of the rate generator model.

Distributors are expected to propose a fully fixed rate design for new charges applicable to the residential class provided that those charges are specifically related to the distribution of electricity.[7] Pass-through costs (e.g. transmission rates, Low Voltage charges, and Group 1 deferral and variance accounts) and LRAMVA amounts are to continue to be recovered as variable charges because they predominantly relate to energy charges. Previously approved distribution-specific charges or rate riders on a distributor's tariff should remain unchanged until they expire, even if they were declared interim.

Residential Rate Design – Exceptions and Mitigation

In order to support the initial transition to fully fixed distribution rates, the OEB designed two tests to determine when mitigation should be proposed – a threshold test for the

[6] EB-2014-0210

[7] Examples of distribution-specific charges include Shared Tax Savings, Z-Factors, ACM and ICM rate riders.

change in the fixed charge, and an overall bill impact test. The OEB is requiring distributors once again to calculate and report on the rate impacts of the change in 2019 so that mitigation strategies may be employed to smooth the transition for the customers most impacted, such as those that consume less electricity.

In 2019, the last year of transition for most distributors, a distributor is expected to apply to extend its OEB-approved transition period if necessary, to continue to comply with the policy. For 2019, the monthly service charge would have to rise more than $4 per year in order to affect the length of the transition to fixed rates. It is expected that in most cases, only an additional transition year would be required to make the changes within the $4 impact threshold identified in the policy. A distributor shall propose an alternative or additional strategy in the event that an additional transition year is insufficient. Consistent with OEB policy regarding mitigation, a distributor may propose as part of its application that no extension is necessary; such a position must be substantiated with reasons.

While the rate design is revenue neutral across the residential class, the impact on individual customers will vary with consumption. The OEB requires distributors to calculate the combined impact of the fixed rate increase and any other changes in the cost of distribution service for those residential RPP customers who are at the 10th percentile of overall consumption.[8] That is, 10% of a distributor's residential customers consume at or less than this level of consumption on a monthly basis. Sorting or segmentation of residential class data by consumption level will be required. Distributors must provide a description of the method they used to derive the 10th consumption percentile. The description should include a discussion regarding the nature of the data that was used (e.g. was the source data for all residential customers or a representative sample of residential customers).

If the total bill impact of the elements proposed in the application is 10% or greater for RPP customers consuming at the 10th percentile, a distributor must file a plan to mitigate the impact for the whole residential class or indicate why such a plan is not required. The distributor will have the ability to propose the approach to mitigation, including, but not limited to, the option to extend the transition to fixed rates over a longer period. A detailed rationale must be provided.

It is the OEB's expectation that the approach to mitigation will target only the residential class, to avoid any material cross-subsidy between classes.

[8] To a minimum of 50 kWh per month.

Beyond the issue of residential rate design specifically addressed in this section, distributors are reminded that they must file a mitigation plan if total bill increases for any customer class exceed 10%.

3.2.4 Electricity Distribution Retail Transmission Service Rates

In preparing its application, the distributor should refer to the OEB's *Guideline G-2008-0001: Electricity Distribution Retail Transmission Service Rates (RTSR), Revision 4.0, issued June 28, 2012.*[9]

The OEB's rate generator model will assist in calculating the distributor's class-specific RTSRs. The rate generator model will reflect the most recent uniform transmission rates (UTRs) approved by the OEB.[10] Once any January 1, 2019 UTR adjustments have been determined, OEB staff will adjust each distributor's 2019 RTSR section of the rate generator model to incorporate these changes where applicable. The rate generator model will also reflect the most recent sub-transmission rates approved by the OEB.[11] Likewise, OEB staff will update these rates as they become available.

3.2.5 Review and Disposition of Group 1 Deferral and Variance Account Balances

The Report of the Board on Electricity Distributors' Deferral and Variance Account Review Report (EDDVAR) provides that under the Price Cap IR or the Annual IR Index, the distributor's Group 1 audited account balances will be reviewed, and disposed if the pre-set disposition threshold of $0.001 per kWh (debit or credit) is exceeded. The onus is on the distributor to justify why any account balance in excess of the threshold should not be disposed. Consistent with a letter from the OEB on July 25, 2014, distributors may elect to dispose of Group 1 account balances below the threshold. Distributors should assess the practicality of disposing what may be small balances for one or more classes; for further guidance on considerations relevant to rate riders, see Appendix B.

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[9] Originally issued October 22, 2008.

[10] Decision and Rate Order, EB-2017-0359, February 1, 2018.

[11] Hydro One Networks Inc., Decision and Rate Order, EB-2016-0081, December 21, 2016; other distributors sub-transmission rates are approved in their decision and order.

In their application, distributors must include Group 1 balances as of December 31, 2017 to determine if the threshold has been exceeded. The continuity schedule, found on Tab 3 of the rate generator model, must be completed as part of the application.

Group 1 consists of the following Uniform System of Accounts (USoA):

- 1550 Low Voltage Account
- 1551 Smart Metering Entity Charge Variance
- 1580 RSVA Wholesale Market Service Charge Account
  - 1580 Variance WMS, Sub-Account CBR Class A
  - 1580 Variance WMS, Sub-Account CBR Class B
- 1584 RSVA Retail Transmission Network Charges Account
- 1586 RSVA Retail Transmission Connection Charge Account
- 1588 RSVA Power Account
- 1589 RSVA Global Adjustment Account
- 1595 Disposition and Recovery/Refund of Regulatory Balances Account

Distributors must provide an explanation if the account balances on *Tab 3. Continuity Schedule* of the rate generator model differ from the account balances in the trial balance reported through the RRR and the audited financial statements and which have been reflected in the prepopulated rate generator model.

The OEB expects that no adjustments will be made to any deferral and variance account (DVA) balances previously approved by the OEB on a final basis. Distributors must make a statement in their application as to whether or not any such adjustments were made. If adjustments have taken place, a distributor must provide explanations in its application for the nature and amounts of the adjustments and include supporting documentation under a section titled “Adjustments to Deferral and Variance Accounts”.

If the RRR balances do not agree to the year end balances in the continuity schedule, a distributor must reconcile and explain the differences.

The rate generator model will calculate the DVA disposition threshold using the last full year of actual load data as reported through the RRR. The default billing determinants used in the calculation of the Group 1 DVA rate riders will also be based on recent load data. The use of recent actuals should reduce residual variances by reflecting changes in customer class composition. A distributor may propose an alternative method with supporting rationale. In that case, revisions to the rate generator model may be required.

All GA rate riders will be calculated on an energy basis (kWh) – (see section 3.2.5.2).

EDDVAR states that the default disposition period to clear the Group 1 account balances by means of a rate rider should be one year. However, a distributor could propose a different disposition period to mitigate rate impacts or address any other applicable considerations, where appropriate.

3.2.5.1 Wholesale Market Participants

A wholesale market participant (WMP) refers to any entity that participates directly in any of the Independent Electricity System Operator (IESO) administered markets. These participants settle commodity and market-related charges with the IESO even if they are embedded in a distributor's distribution system. As a consequence, a distributor must not allocate any balances to these customers from Account 1580 RSVA - Wholesale Market Services Charge, Account 1580 Variance WMS, Sub-Account CBR Class B, Account 1588 RSVA - Power, and Account 1589 RSVA - Global Adjustment to a WMP.

A distributor must also ensure that rate riders are appropriately calculated for the following remaining charges that are still settled with a distributor. These include Account 1584 RSVA – Retail Transmission Network Charge, Account 1586 RSVA – Retail Transmission Connection Charge and Account 1595 – Disposition/Refund of Regulatory Balances.

3.2.5.2 Global Adjustment

Class B and A Customers

Most customers pay the GA charge based on the amount of electricity they consume in a month (kWh). These customers are referred to as Class B. Customers who participate in the Industrial Conservation Initiative (ICI), referred to as Class A, pay GA based on their percentage contribution to the top five peak Ontario demand hours (i.e. peak demand factor) over a year-long period.[12] Distributors that settle GA costs with Class A customers on the basis of actual GA prices, shall allocate no GA variance balance to these customers for the period that customers were designated Class A.

For non-RPP Class B customers, the GA variance account (Account 1589) captures the difference between the amounts billed (or estimated to be billed) by the distributor and the actual amount paid by the distributor to the IESO (or host distributor) for those customers.

When clearing balances from the GA variance account, distributors must establish a separate rate rider included in the delivery component of the bill that would apply prospectively to non-RPP Class B customers. Effective in 2017, the billing determinant and all the rate riders for the GA were calculated on an energy basis (kWh) regardless of the billing determinant used for distribution rates for the particular class.

The rate generator model will allocate the portion of Account 1589 GA to customers who transitioned between Class A and Class B based on customer specific consumption levels. All transition customers will only be responsible for the customer specific amount allocated to them. They will not be charged/refunded the general GA rate rider. Customers should be charged in a consistent manner for the entire rate rider period until the sunset date, regardless of whether customers transition between Class A and Class B during the disposition period.

GA Analysis Workform

Starting for 2018 rate applications, all distributors were required to complete the GA Analysis Workform. The new workform will help the OEB assess if the annual balance in Account 1589 is reasonable. The workform compares the General Ledger principal balance to an expected principal balance based on monthly GA volumes, revenues and costs.

A discrepancy between the actual and expected balance may be explained and quantified by a number of factors, such as an outstanding IESO settlement true-up payment. The explanatory items should reduce the discrepancy and provide distributor-specific information to the OEB. Any remaining, unexplained discrepancy will be assessed for materiality and could prompt further analysis before disposition is

[12] As of July 1, 2015, per O.Reg 429/04, an eligible customer with a maximum hourly demand over three megawatts, but less than five megawatts, can elect to become a Class A for an applicable adjustment period of one year. Effective January 1, 2017, the ICI expanded to include all electricity users with an average monthly peak demand over 1 MW. In April 2017, the ICI further reduced the ICI threshold to 500 kW to make targeted manufacturing and industrial sectors, including greenhouses, eligible to opt-in to the ICI.

approved. Unexplained discrepancies should be calculated separately for each calendar year and any unexplained discrepancy for each year greater than +/- 1% of total annual IESO GA charges will be considered material.

The GA Analysis Workform is available on the OEB's web site and is to be filed in live Microsoft Excel format.

Description of Settlement Process

A distributor must support its GA claims with a description of its settlement process with the IESO or host distributor. The description should include the following:

- The GA prices the distributor uses to bill (and record unbilled entries) to its various customer classes (i.e. 1st estimate, 2nd estimate or actual).

  As part of this description, the distributor shall confirm that the GA rate that is used is applied consistently for all billing and unbilled revenue transactions for non-RPP Class B customers in each customer class. In addition, where the same GA rate is not used for non-RPP Class B customers in all customer classes, the distributor shall explain what GA rate is applied to each customer class.

- The distributor's process for providing consumption estimates to the IESO as part of its RPP settlement process and the RPP settlement process used to true-up estimated amounts to actual amounts.

  Specifically, the distributor should indicate what type of data is used to determine the volume estimates of RPP customers at different TOU periods or Tier 1 and 2 blocks. A distributor must also provide the time when actual data becomes available and its true-up process.

- The distributor's method for estimating RPP and non-RPP consumption, as well as its treatment of volumes related to embedded generation or embedded distribution customers.

- The distributor's internal control tests, if any, in validating estimated and actual consumption figures used in its RPP settlement process and subsequent true-up adjustments.

Distributors are expected to use accrual accounting.

Description of Accounting Methods and Transactions for Each Year in which the Applicant is Requesting the Balances for Disposition

A distributor must provide the OEB with a description of its financial accounting practices as they relate to its initial recording of transactions in Commodity Accounts 1588 and 1589. In addition, a distributor must disclose the nature, timing, and dollar impact of any subsequent adjustments recorded after the reporting period that adjust the initial transactions from preliminary estimates to actual figures based on consumption data. In order to provide the above-noted information to the OEB, distributors must complete the GA Analysis Workform for each applicable fiscal year subsequent to the most recent year in which Accounts 1588 and 1589 were approved for disposition on a final basis by the OEB.

If a distributor uses the actual GA price to bill non-RPP Class B customers for an entire rate class, it must make a proposal to exclude these customer classes from the allocation of the balance of account 1589 RSVA GA and the calculation of the resulting rate riders. These rate classes are not to be charged/refunded the GA rate rider as they did not contribute to the accumulation of the balance of account 1589 RSVA GA.

3.2.5.3 Commodity Accounts 1588 and 1589

RPP Settlement True-Ups

Effective May 23, 2017, per the OEB's letter titled Guidance on Disposition of Accounts 1588 and 1589, applicants must reflect RPP Settlement true-up claims pertaining to the period that is being requested for disposition in the RSVA Power (Account 1588) and RSVA GA (Account 1589) variance accounts. In doing so, distributors are to follow the guidance provided in the above noted letter.

Certification of Evidence

Given issues that have arisen with commodity accounts 1588 RSVA Power and 1589 RSVA GA balances, the OEB now requires a certification by the Chief Executive Officer (CEO), or Chief Financial Officer (CFO), or equivalent. The application must include a certification that the distributor has robust processes and internal controls in place for the preparation, review, verification and oversight of the account balances being disposed, consistent with the certification requirements in Chapter 1 of the filing requirements.

3.2.5.4 Capacity Based Recovery (CBR)

Distributors should follow accounting guidance on the disposition of CBR variances. In *Tab 3 Continuity Schedule* of the rate generator model, the distributor must indicate whether it had any Class A customers during the period where the Account 1580 CBR

Class B Sub-account balance accumulated. If yes, a separate rate rider will be calculated in *Tab 6.2 CBR B* in the rate generator model. However, in the event that the allocated CBR Class B amount results in a volumetric rate rider that rounds to zero at the fourth decimal place in one or more rate classes, the entire balance in Account 1580, Sub-account CBR Class B will be added to the Account 1580 WMS control account to be disposed through the general purpose Group 1 DVA rate riders (accounting guidance to be updated to reflect this change). The balance in Sub-Account CBR B must be disposed over the default period of one year. If the distributor did not have any Class A customers during the period where the Account 1580 CBR Class B sub-account balance accumulated, the rate generator model will also transfer the sub-account balance to Account 1580 WMS control account and include the CBR amounts as part of the general purpose Group 1 DVA rate riders. Account 1580 Sub-Account CBR Class A is not to be disposed through rates proceedings but rather follow the OEB's accounting guidance.

The rate generator model will also allocate the portion of Account 1580, Sub-account CBR Class B to customers who transitioned between Class A and Class B based on customer specific consumption levels. All transition customers will only be responsible for the customer specific amount allocated to them. They will not be charged/refunded the general CBR Class B rider. Customers should be charged in a consistent manner for the entire rate rider period until the sunset date, regardless of whether customers transition between Class A and Class B during the disposition period.

3.2.6 Lost Revenue Adjustment Mechanism Variance Account

The LRAMVA is a retrospective adjustment designed to account for differences between forecast revenue loss attributable to CDM activity embedded in rates and actual revenue loss due to the impacts of CDM programs. The OEB established Account 1568 as the LRAMVA to capture the difference between the OEB-approved CDM forecast and actual results at the customer rate class level.

On April 26, 2012, the OEB issued the CDM Guidelines (2012 CDM Guidelines). The 2012 CDM Guidelines provide details on the LRAMVA for the 2011 to 2014 period. Accounting guidelines on the LRAMVA can be found in Appendix B of the 2012 CDM Guidelines. Distributors should refer to the 2012 CDM Guidelines for further details.

On May 19, 2016, the OEB issued the *Report of the OEB: Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand*

Savings from Conservation and Demand Management Programs (the LRAMVA Report). The OEB updated its policy on how peak demand savings from energy efficiency and demand response programs should be treated for LRAMVA purposes. The OEB expects that distributors refer to the LRAMVA Report and follow the new policy.

The LRAMVA Workform provides distributors with a consistent approach to calculate LRAMVA. The LRAMVA Workform consolidates information that distributors have received from the IESO.

In December 2016, the OEB indicated in various decisions[13] that changes to an approved LRAMVA amount were not permitted. This policy affects the treatment of verified savings adjustments that can be claimed by distributors. If an LRAMVA amount was approved, the persistence of the savings adjustment(s) can only be claimed on a go-forward basis.[14] Distributors cannot seek recovery of LRAMVA amounts related to savings adjustments for a year in which the corresponding LRAMVA amount has been approved by the OEB. For example, if a distributor has received approval of its 2016 LRAMVA balance, excluding 2016 savings adjustments, the distributor must forgo any LRAMVA amounts related to the 2016 savings adjustments as the 2016 LRAMVA balance was approved by the OEB on a final basis.

3.2.6.1 Disposition of the LRAMVA

At a minimum, distributors must apply for the clearance of its energy and/or demand related LRAMVA balances attributable to energy efficiency programs in a CoS application. Distributors may apply for the disposition of the balance in the LRAMVA on an annual basis, as part of their IRM rate applications, if the balance is deemed significant by the applicant.

The distributor shall compare the OEB-approved LRAMVA threshold to actual CDM results at a rate class level. The variances calculated from this comparison shall be recorded in separate Sub-Accounts for the applicable customer rate classes. Distributors

[13] EB-2016-0075 (Guelph Hydro 2017 IRM) and EB-2016-0080 (Hydro One Brampton 2017 IRM).

[14] See EB-2016-0214 for an example (North Bay Hydro 2017 IRM).

must continue to track the variances between the OEB-approved LRAMVA threshold and actual CDM results in the LRAMVA for the 2015-2020 period.[15]

In reference to the LRAMVA Report, Demand Response 3 (DR3) savings should generally not be included in the LRAM savings unless supported by empirical evidence to be reviewed in a CoS application. Any requests for approval of lost revenues related to peak demand savings from demand response programs can only be part of a rebasing application due to the complexity and unique nature of the calculation of lost revenues from peak demand savings. As a result, lost revenues related to peak demand savings from demand response programs will nor be evaluated in an IRM rate application. Those distributors who are planning to seek recovery of lost revenue associated with DR3 and have recorded amounts to the end of December 31, 2014 in Account 1568 may transfer the accumulated amounts to Sub-Account 1568-0001 LRAMVA Demand Response, or forego recovery, in accordance with the OEB's updated accounting guidance issued on July 18, 2017. However, if a distributor has already received OEB approval for disposition of Account 1568 as of December 31, 2014 on a final basis, no amounts are to be recorded in Account 1568 Sub-Account 1568 LRAMVA Demand Response. This Sub-Account is only available to distributors for transferring amounts from Account 1568 LRAMVA with respect to savings for period from 2011-2014, and only if they have not already received OEB approval for disposition of Account 1568 on a final basis, for amounts recorded for 2011-2014.

The following information should be provided in the application:

- A statement identifying the year(s) of new lost revenues and prior year savings persistence claimed in the LRAMVA disposition.
- A statement confirming that LRAMVA was based on verified savings results that are supported by the distributor's Final CDM Annual Report and Persistence Savings Report issued by the IESO. Both reports must be filed in Excel format. A statement indicating that the distributor has relied on the most recent input assumptions available at the time of program evaluation.
- A summary table showing the principal and carrying charges amounts by rate class and the resultant rate riders for each rate class. Projected carrying charges related to the disposition should be calculated in the LRAMVA Workform.
- A statement confirming the period of rate recovery. Rationale must be provided for disposing the balance in the LRAMVA, if one or more rate classes do not

[15] Conservation and Demand Management Requirement Guidelines for Electricity Distributors, December 19, 2014 (EB-2014-0278).

generate significant rate riders.

- Details for the forecast CDM savings included in the LRAMVA calculation including reference to the OEB's approval, or an explanation if there are no forecast CDM savings
- A statement confirming how the rate class allocations for actual CDM savings were determined by customer class and program each year. Documentation (e.g., tables supporting the rate class allocations) should be filed in Tab 3-a of the LRAMVA workform.
- A statement confirming whether additional documentation or data was provided in support of projects that were not included in the distributor's Final CDM Annual Report (i.e., street lighting projects). Distributor billing data by project must be included in the workform in Tab 8, as applicable. For distributor street lighting project(s) which may have been completed in collaboration with local municipalities:
    - Explain the methodology to calculate street lighting savings;
    - Confirm whether the street lighting savings were calculated in accordance with OEB-approved load profiles for street lighting projects; and,
    - Confirm whether the street lighting project(s) received funding from the IESO and provide the appropriate net-to-gross assumption used to calculate street lighting savings.

An application to dispose of the balance in an LRAMVA may only be filed as part of an Annual IR Index application if the OEB's decision for the distributor's last CoS (or settlement agreement approved by the OEB) has a clear description of class-specific CDM adjustments made to the load forecast to be used in the calculation of the LRAMVA balance. Any LRAMVA applications determined by the OEB to be more complicated than appropriate for an Annual IR Index application will be bifurcated and heard separately from the Annual IR Index application.

3.2.7 Tax Changes

OEB policy, as described in the OEB's 2008 report entitled Supplemental Report of the *Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (the Supplemental Report), prescribes a 50/50 sharing of impacts of legislated tax changes from distributors' tax rates embedded in its OEB approved base rate known at the time of application. These amounts will be refunded to or recovered from customers over a 12-month period. If applicable, applicants must complete sheets 8 and 9 of the rate generator model. The rate generator model will calculate an applicable rate rider using the appropriate customer class data underlying the OEB approved rates. A rate rider to four decimal places must be generated for all applicable customer classes in order to dispose of the amounts. If one or more customer classes does not generate a rate rider to the fourth decimal place, the entire 50/50 sharing amount will be transferred to Account 1595 for disposition at a future date.

3.2.8 Z-factor Claims

Price Cap IR applicants have the ability to include in their application a request to recover costs associated with unforeseen events that are outside the control of a distributor's ability to manage. The cost to a distributor must be material and its causation clear. Costs are to be recorded in Account 1572, Extraordinary Events Costs. To recover these amounts, a distributor must follow the guidelines discussed in section 2.6 of the *Board's Report on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* – July 14, 2008. The materiality thresholds, described in the above noted OEB report, must be met on an individual event basis in order for the distributor to apply for recovery of the relevant costs.

3.2.8.1 Z-factor Filing Guidelines

A distributor must submit evidence that the costs incurred meet the three eligibility criteria. A distributor must also:

- Notify the OEB promptly by letter to the Board Secretary of all Z-factor events. Failure to notify the OEB within six months of the event may result in disallowance of the claim.
- Apply to the OEB for any cost recovery of amounts recorded in the OEB-approved deferral account claimed under Z-factor treatment. This will allow the OEB and any affected distributor the flexibility to address extraordinary events in a timely manner. Subsequently, the OEB may review and prospectively adjust the amounts for which Z-factor treatment is claimed.
- Provide a clear demonstration that the management of the distributor could not have been able to plan and budget for the event and that the harm caused by

extraordinary events is genuinely incremental to their experience or reasonable expectations.

- Demonstrate that the costs were incurred within a 12-month period and are incremental to those already being recovered in rates as part of ongoing business exposure risk.

3.2.8.2 Z-factor Accounting Treatment

The distributor will record eligible Z-factor cost amounts in Account 1572, Extraordinary Event Costs, of the OEB's USoA contained in the Accounting Procedures Handbook (APH) for electricity distributors. Monthly carrying charges shall be recorded in Account 1572. Carrying charges are calculated using simple interest applied to the monthly opening balances in the account and recorded in a separate Sub-Account of this account. The rate of interest shall be the rate prescribed by the OEB for deferral and variance accounts for the respective quarterly period published on the OEB's web site.

3.2.8.3 Recovery of Z-Factor Costs

As part of its claim, a distributor must outline the manner in which it intends to allocate the incremental revenue requirement to the various customer rate classes, the rationale for the selected approach and a discussion of the merits of alternative allocation methods. Recovery will be through a rate rider.[16] The request must specify whether the rate rider(s) will apply on a fixed or variable basis or a combination thereof, and the length of the disposition period and a rationale for this proposal. As discussed at section 3.2.3, any new rate riders that apply to residential classes must only be applied on a fixed basis. A detailed calculation of the incremental revenue requirement and resulting rate rider(s) must be provided.

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[16] See Appendix B.

3.3 Elements Specific only to the Price Cap IR Plan

3.3.1 Advanced Capital Module

On September 18, 2014, the OEB issued the *Report of the Board - New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*[17] (ACM Report). The Advanced Capital Module (ACM) reflects an evolution of the Incremental Capital Module (ICM) adopted by the OEB in 2008. The ACM approach seeks to increase regulatory efficiency during the Price Cap IR term and provides a distributor with the opportunity to smooth out its capital program over the five year period between CoS applications.

A distributor must make any ACM requests as part of a CoS application. At that time, the need for and prudence of any such requests will be determined. Cost recovery (i.e. rate riders) for qualifying ACM projects will be determined in the subsequent Price Cap IR application for the year in which the capital investment will come into service.

While an ACM request must be made in a CoS application, a Price Cap IR application is the vehicle in which an applicant may calculate the rate rider to recover the amounts approved in a CoS application. A distributor seeking cost recovery through a Price Cap IR application should carefully review the ACM Report before making such a request.

A distributor approved for an ACM in its most recent CoS application must file its most recent calculation of its regulated return[18] at the time of the applicable Price Cap IR application in which funding for the project, and recovery through rate riders, would commence. If the regulated return exceeds 300 basis points above the deemed return on equity embedded in the distributor's rates, the funding for any incremental capital project will not be allowed. Therefore, any approvals provided for an ACM in a CoS application will be subject to the distributor passing the means test in order to receive its funding during the IR term. The same means test shall also apply going forward for new projects proposed as ICMs during the Price Cap IR term.

A distributor meeting this requirement must provide for the relevant project or projects updated cost projections, confirmation that the project or projects are on schedule to be completed as planned and an updated ACM/ICM module in Excel format. If the proposed cost recovery differs significantly from the pre-approved amount, the

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[17] EB-2014-0219

[18] RRR 2.1.5.6

distributor must provide a detailed explanation. Any changes in the scope or timing of the project must be clearly explained and justified.

If the updated cost projections are 30% greater than the pre-approved amount, the distributor must treat the project as a new ICM project and re-file the business case and other relevant material in the applicable IR year.

As part of the distributor's subsequent rebasing application, the OEB will carry out a prudence review of the actual costs to determine the amounts to be incorporated in rate base. At that time, the OEB will also make a determination regarding the treatment of differences between forecast and actual spending during the remainder of the IRM plan term (i.e. if any true-up is required).

On January 22, 2016, the OEB issued the *Report of the OEB on New Policy Options for the Funding of Capital Investments: Supplemental Report*. This report made changes to the materiality threshold on which ACM and ICM proposals are assessed, but otherwise does not alter the requirements for ACM and ICM proposals by an applicant. The Supplemental Report also reaffirms the applicability of the half-year rule for determining the return of and return on capital in the first year that assets enter service.

An associated and updated Capital Funding Module to reflect the changes to the materiality threshold was also issued along with the Supplemental Report, and is available on the OEB's website. A distributor filing for ACM/ICM rate riders must use the current model.

3.3.2 Incremental Capital Module

The ICM remains available to electricity distributors opting for Price Cap IR. The ICM is intended to address the treatment of capital investment needs that arise during the rate-setting plan which are incremental to the materiality threshold defined below. The ICM is available for discretionary and non-discretionary projects. The ICM is also available for capital projects that were not included in the distributor's last filed Distribution System Plan. Even for approved ACM projects, an ICM is available if an updated ACM budget exceeds the approved ACM budget by 30%. Distributors with multiple capital projects should consider the Custom IR option to address capital needs in the context of their Distribution System Plan, rather than submit multiple ICM applications or ICM applications that consistently use up a substantial amount of the eligible available capital amount.

The ICM is not available for incremental funding if a distributor's regulated return exceeds 300 basis points above the deemed return on equity embedded in the distributor's rates.

The requested amount for an ICM claim must be incremental to a distributor's capital requirements within the context of its financial capacities underpinned by existing rates and satisfy the eligibility criteria of materiality, need and prudence set out in section 4.1.5 of the ACM Report.

Criteria	Description
Materiality	A capital budget will be deemed to be material, and as such reflect eligible projects, if it exceeds the OEB-defined materiality threshold. Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount (as defined in this ACM Report) and must clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing. Minor expenditures in comparison to the overall capital budget should be considered ineligible for ACM or ICM treatment. A certain degree of project expenditure over and above the OEB-defined threshold calculation is expected to be absorbed within the total capital budget.
Need	The distributor must pass the Means Test (as defined in the ACM Report). Amounts must be based on discrete projects, and should be directly related to the claimed driver. The amounts must be clearly outside of the base upon which the rates were derived.
Prudence	The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

3.3.2.1 ICM Filing Requirements

The OEB requires that a distributor requesting relief for incremental capital during the IRM plan term include comprehensive evidence to support the need, which should include the following:

- An analysis demonstrating that the materiality threshold test has been met and that the amounts will have a significant influence on the operation of the distributor.
- Justification that the amounts to be incurred will be prudent. This means that the distributor's decision to incur the amounts represents the most cost-effective option (but not necessarily the least initial cost) for ratepayers.
- Justification that amounts being sought are directly related to the cause, which must be clearly outside of the base upon which current rates were derived.
- Evidence that the incremental revenue requested will not be recovered through other means (e.g., it is not, in full or in part, included in base rates or being funded by the expansion of service to include new customers and other load growth).
- Details by project for the proposed capital spending plan for the expected in-service year.
- A description of the proposed capital projects and expected in-service dates.
- Calculation of the revenue requirement (i.e. the cost of capital, depreciation, and PILs) associated with each proposed incremental capital project.
- Calculation of each incremental project's revenue requirements that will be offset by revenue generated through other means (e.g. customer contributions in aid of construction).
- A description of the actions the distributor would take in the event that the OEB does not approve the application.
- Calculation of a rate rider to recover the incremental revenue from each applicable customer class. The distributor must identify and provide a rationale for its proposed rider design, whether variable, fixed or a combination of fixed and variable riders. As discussed at section 3.2.3, any new rate rider for the residential class must be applied on a fixed basis.

3.3.2.2 ACM/ICM Materiality Threshold

The ACM/ICM materiality threshold is discussed in section 4.5 of the supplemental report.

The OEB determined that the following formula is to be used by a distributor to calculate the materiality threshold:

$$Threshold\ Value\ (\%) = \left(1 + \left[\left(\frac{RB}{d}\right) \times \left(g + PCI \times (1+g)\right)\right]\right) \times \left((1+g) \times (1+PCI)\right)^{n-1} + X\%$$

where n is the number of years since the CoS rebasing. Many of the parameters remain unchanged from the original formula except for the following:

- the growth factor g is annualized
- the dead band X has been reduced to 10%
- the stretch factor used in the PCI will be the factor assigned to the middle cohort (currently 0.3%) for all distributors

3.3.2.3 Assessment of Materiality

In the ACM report, the OEB mentioned that the eligible incremental capital amount sought for recovery should be capital in excess of the ACM/ICM materiality threshold defined in section 3.3.2.2. This threshold level of capital expenditures is the amount that a distributor should be able to manage with its current rates, growth in demand and normal volatility in business conditions. Accordingly, the materiality threshold value, as calculated using the formula discussed in section 4 of the ACM report, marks the base from which to calculate the maximum amount eligible for recovery. A distributor applying for recovery of incremental capital should calculate the maximum allowable capital amount by taking the difference between the forecasted 2019 total capital expenditures and the ACM/ICM materiality threshold.

For individual projects included within an ACM/ICM request, it is not appropriate to apply the materiality thresholds established in the Chapter 2 Filing Requirements[19] for the purpose of evaluating the materiality of an individual project. These materiality thresholds are for the purpose of variance explanations for annual changes to rate

[19] *Section 2.0.8*

base, capital expenditures and operations, maintenance and administration costs as part of a CoS rate application.

In the Funding of Capital Report[20], the OEB adopted an approach establishing the following three principles with respect to the eligibility of a capital project for ACM/ICM treatment:

(1) minor expenditures in comparison to the overall capital budget should not be considered eligible for ICM treatment;

(2) a certain degree of project expenditure over and above the threshold calculation is expected to be absorbed within the total capital budget; and

(3) the project amount being proposed for recovery should be significant within the context of the distributor's overall capital budget.

For merged utilities, the above principles are applicable to the merged distributor, not the individual rate zones.

3.3.2.4 Application of the Half-Year Rule

The OEB's general guidance on the application of the half-year rule was originally provided in the supplemental report. In that report the OEB determined that the half-year rule should not apply so as not to build a deficiency for the subsequent years of the IRM plan term. This approach is unchanged in the new ACM/ICM policy. However, the OEB's approach in decisions has been to apply the half-year rule in cases in which the ICM request coincides with the final year of a distributor's IRM plan term.[21]

[20] EB-2014-0219 Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module September 18, 2014 p.17.

[21] EB-2010-0130, Guelph Hydro Electric Systems Inc., Decision and Order, p. 15.

3.3.2.5 ACM/ICM Accounting Treatment

The distributor will record eligible ICM amounts in Account 1508 – Other Regulatory Asset, Sub-Account Incremental Capital Expenditures, subject to the assets being used and useful. For incremental capital assets under construction, the normal construction work in progress (CWIP) accounting treatment will apply until these assets go into service and are eligible to be recorded in the 1508 Sub-Accounts listed below.

Distributors shall record actual amounts in the following Sub-Accounts of Account 1508 – Other Regulatory Assets:

- Account 1508 – Other Regulatory Assets, Sub-Account Incremental Capital Expenditures
- Account 1508 – Other Regulatory Assets, Sub-Account Depreciation Expense
- Account 1508 – Other Regulatory Assets, Sub-Account Accumulated Depreciation
- Account 1508 – Other Regulatory Assets, Sub-Account Incremental Capital Expenditures Rate Rider Revenues

The distributor shall also record monthly carrying charges in the following Sub-Accounts. Carrying charge amounts are calculated by applying simple interest to the monthly opening balances:

- Account 1508 – Other Regulatory Assets, Sub-Account Incremental Capital Expenditures, Carrying charges
- Account 1508 – Other Regulatory Assets, Sub-Account Incremental Capital Expenditures Rate Rider Revenues, Carrying Charges

The applicable rate of interest for deferral and variance accounts for the respective quarterly period is prescribed by the OEB and published on the OEB's web site.

All Sub-Accounts should be used for both approved ACM and ICM projects. If the OEB approves the true-up of any variances for ACM/ICM projects at the next CoS application, the recalculated revenue requirement relating to the actual ACM/ICM capital expenditures should be compared to the rate rider revenues collected in the same period, plus the carrying charges in the respective Sub-Accounts. These variances would then be refunded to, or collected from, customers through rate riders.

3.3.2.6 Rate Generator and Supplemental Filing Module for ACM/ICM

The filing module for ACM/ICM will assist the distributor in calculating the distributor's threshold. The distributor will then tabulate the value of its eligible investments and compare this to the threshold result to determine the amount that would be eligible for recovery. Once all tabs are completed and listed in the filing module for ACM/ICM, the tabulated revenue requirement will be converted into class-specific rate riders. The rate riders will need to be added to Tab 18 – Additional Rates – of the rate generator model in order for them to be displayed on the Tariff of Rates and Charges.

3.3.3 Treatment of Costs for 'eligible investments'

On March 28, 2013, the OEB issued *Filing Requirements for Electricity Transmission and Distribution Applications – Chapter 5: Consolidated Distribution System Plan Filing Requirements* (Chapter 5). As noted in section 5.0.5, Chapter 5 supersedes the *Filing Requirements: Distribution System Plans - Filing under Deemed Conditions of Licence*.

As indicated in the cover letter to Chapter 5 dated March 28, 2013, distributors who have yet to file under Chapter 5 will continue to be able to record renewable energy generation costs and smart grid development costs in the deferral accounts that were established for that purpose. However, no new deferral accounts for these types of expenditures will be established. Distributors under Price Cap IR who have yet to file a CoS application containing a consolidated capital plan pursuant to Chapter 5 will continue to be able to request advance funding through a funding adder for renewable generation connection costs and smart grid development costs. Where a distributor seeks a funding adder, sufficient information must be provided to allow the OEB to assess the need for the mechanism and the nature and quantum of the costs to be collected from ratepayers and the basis for calculating the funding adder.

The costs recovered through the funding adder will be subject to a prudence review in the first CoS application following the implementation of the funding adder. Distributors should refer to Section 2.0.9 of the revised Chapter 2 Filing Requirements for further information on materiality levels for requests of provincial funding for renewable generation connections.

Distributors proposing to file an Annual IR Index application must make a Chapter 5 filing within five years of the date of the most recent OEB decision approving their rates in a CoS proceeding and are required to do so at five year intervals thereafter while using the Annual IR Index method.

3.3.4 Conservation and Demand Management Costs for Distributors

CDM activity is funded either through IESO Contracted Province Wide CDM Programs, or through an OEB-approved CDM program.

3.3.5 Off-ramps

For each of the OEB's three rate-setting options, a regulatory review may be triggered if a distributor's earnings are outside of a dead band of +/- 300 basis points from the OEB-approved return on equity. The OEB monitors results filed by distributors as part of their reporting and record-keeping requirements and determines if a regulatory review is warranted. Any such review will be prospective, and could result in modifications, termination or the continuation of the respective Price Cap IR or Annual IR Index plan for that distributor.

A distributor whose earnings are in excess of the dead band is expected to refrain from seeking an adjustment to its base rates through a Price Cap IR or Annual IR Index plan. If a distributor whose earnings are in excess of the dead band nevertheless applies for an increase to its base rates, the OEB expects it to substantiate its reasons for doing so. The applicant should anticipate that the level of earnings will be raised as an issue in the application.

A distributor may choose to file only for disposition of Group 1 deferral and variance account balances in accordance with OEB policies, without applying for adjustments to its base rates.

3.4 Specific Exclusions from Price Cap IR or Annual IR Index Applications

The IRM application process is intended to be mechanistic in nature. For this reason, the OEB has determined that the IRM process is not the appropriate way for a distributor to seek relief on issues which are specific to only one or a few distributors, more complicated relative to issues typical of an IRM application, or potentially contentious. The following are examples of specific exclusions from the IRM rate application process:

- Rate Harmonization, other than that pursuant to a prior OEB decision
- Disposition of the balance of Account 1555 – Smart Meter Capital Costs, Sub-Account Stranded Meter Net Book Value
- Changes to revenue-to-cost ratios, other than pursuant to a prior OEB decision
- Loss Factor Changes
- Establishing or changing Specific Service Charges
- Loss Carry Forward Adjustments to PILs/Taxes
- Disposition of Group 2 Deferral and Variance Accounts
- Loss of Customer Load

These items are to be addressed in the distributor's next CoS application. The exclusions above also apply to the Annual IR Index plan. In addition, distributors seeking adjustments that are inconsistent with OEB policy should consider whether one of the other rate-setting options is more appropriate. As indicated in the Handbook, distributors filing under the Annual IR Index plan must file a separate, stand-alone application for the review and disposition of Group 2 Deferral and Variance Accounts.

Appendix A: Application of Recoveries in Account 1595

When approval for disposition of deferral and variance account balances is received from the OEB, the approved amounts of principal and carrying charges are transferred to Account 1595 for that rate year.

Applicants are expected to request disposition of residual balances in Account 1595 Sub-accounts for each vintage year only once, on a final basis. Distributors are expected to seek disposition of the audited account balances a year after a rate rider's sunset date has expired. No further transactions are expected to flow through the Account 1595 Sub-accounts once the residual balance has been disposed.

1595 Analysis Workform

Starting for the 2019 rate applications, distributors who meet the requirements for disposition of residual balances of Account 1595 sub-accounts, must complete the 1595 Analysis Workform. The new workform will help the OEB assess if the residual balances in Account 1595 Sub-accounts for each vintage year are reasonable. The workform compares principal and interest amounts previously approved for disposition to the residual balances remaining after amounts have been recovered/refunded to customers through rate riders.

Initially, residual balances will be assessed for materiality and could prompt further review before disposition is approved. Balances in Account 1595 will first be assessed in two groups of accounts; one being the amounts attributable to GA, and the other being the remainder of Group 1 and Group 2 Accounts (if applicable). A residual balance in either of the two groups of accounts exceeding +/- 10% of the original amounts previously approved for disposition would be considered material.

Material residual balances will require further analysis, consisting of separating the components of the residual balances by each applicable rate rider[22] and by customer rate class. Distributors are expected to provide detailed explanations for any significant residual balances attributable to specific rate riders for each customer rate class. Explanations must include for example, volume differences between forecast volumes (used to calculate the rate riders) as compared to actual volumes at which the rate riders were billed.

[22] Residual account balances will be made up of amounts relating to at least two rate riders, i.e. the GA Rate Rider and the DVA Rate Rider.

The 1595 Analysis Workform is available on the OEB's web site and is to be filed in live Microsoft Excel format.

Appendix B: Rate Adder versus Rate Rider

Rate Adder

A rate adder (or funding adder) is a tool designed to provide advance funding on an interim basis to distributors for certain investments or expenses as prescribed by the OEB and to mitigate or smooth the anticipated rate impact when recovery of these costs are approved by the OEB. Approval of a rate adder does not constitute regulatory approval of any costs actually incurred. The prudence of incurring such costs is examined, and the costs may be approved in whole or in part, at the time at which the distributor brings the matter forward for regulatory review.

Rate adders are identified and listed separately on a distributor's tariff of rates and charges and may have a termination date.

Rate Rider

A rate rider differs from a rate adder in that it is designed to recover or refund OEB-approved amounts following a review of the proposed costs to determine that it is reasonable for the distributor to incur and recover them. Rate riders are identified and listed separately on a distributor's tariff of rates and charges, with an explicit termination date.

Treatment of Negligible Rate Adders and Rate Riders

Rate adders and rate riders normally apply to one or more select rate classes on a fixed basis, a volumetric basis or a combination of both. A rate adder or rate rider is usually determined by dividing the OEB-approved allocated amounts by the OEB-approved forecast or historical energy use or demand.

Occasionally, the calculated rate adders or rate riders for one or more rate classes may be negligible. In the event where the calculation of any rate adder or rate rider results in a volumetric rate rider that rounds to zero at five significant digits (i.e., the fourth decimal place) per kWh or per kW, the entire OEB-approved amount for recovery or refund will typically be recorded in a USoA account to be determined by the OEB for disposition in a future rate setting. Distributors may propose alternatives to this approach in the event that there is a significant discrepancy in the size of the riders among classes (e.g., if a rider is of a non-negligible size for one or more classes, but negligible or insignificant for another class).

Appendix C: Key References

The documents listed in Appendix C are key to understanding these Filing Requirements. Incentive Rate-setting applications filed by distributors must be consistent with the key references listed.

- *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach - October 18, 2012*
- *Report of the Board: Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors - corrected December 4, 2013*
- *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities - December 11, 2009*
- *Guidelines for Electricity Distributors' Conservation and Demand Management - April 26, 2012 (2012 CDM Guidelines)*
- *Guidelines for Electricity Distributors' Conservation and Demand Management - December 19, 2014 (2014 CDM Guidelines)*
- *Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module - September 18, 2014*
- *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors - July 14, 2008*
- *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors - September 17, 2008*
- *Addendum to the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors - January 28, 2009*
- *Guideline (G-2008-0001) on Retail Transmission Service Rates - October 22, 2008 (Revision 3.0 June 22,2011 and any subsequent updates)*
- *Guideline G-2011-0001: Smart Meter Funding and Cost Recovery - Final Disposition, December 15, 2011*
- *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR) - July 31, 2009*

- *Chapter 5 - Filing Requirements for Electricity Transmission and Distribution Applications: Consolidated Distribution System Plan Filing Requirements - March 28, 2013*
- *Report of the Board on Transition to International Financial Reporting Standards (EB-2008-0408) - July 28, 2009*
- *Addendum to Report of the Board EB-2008-0408 - Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment - June 13, 2011*
- *Report of the Board - Performance Measurement for Electricity Distributors: A Scorecard Approach - March 5, 2014*
- *Board Policy (EB-2012-0410) - A New Distribution Rate Design for Residential Electricity Customers - April 2, 2015*
- *Report of the Ontario Energy Board - Defining Ontario's Typical Electricity Customer – April 14, 2016*
- *Report of the Ontario Energy Board - New Policy Options for the Funding of Capital Investments: Supplemental Report – January 22, 2016*
- *Report of the Ontario Energy Board - Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs – May 19, 2016*

Additions for 2017:

- *Guidelines for Electricity Distributors' Conservation and Demand Management - December 19, 2014 (2014 CDM Guidelines) – Updated August 11, 2016*
- *Handbook for Utility Rate Applications – October 13, 2016*
- *Report of the Ontario Energy Board - Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs*
- *Guidance on Wholesale Market Service Accounting for Capacity Based Demand Response (CBDR) and new IESO Charge Type 9920 – March 29, 2016*
- *Guidance on the Disposition of Accounts 1588 and 1589 – May 23, 2017*

- *Updated Guidance on LRAM Variance Account 1568 – New Sub-Account 1568-0001 LRAMVA Demand Response – July 18, 2017*

DECISION **NSUARB-NSPI-P-888**
2008 NSUARB 140

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF THE PUBLIC UTILITIES ACT

- and -

IN THE MATTER OF AN APPLICATION by **Nova Scotia Power Incorporated** for approval of certain Revisions to its Rates, Charges and Regulations

BEFORE:
Peter W. Gurnham, Q.C., Panel Chair
Roland A. Deveau, LL.B., Member
Kulvinder S. Dhillon, P. Eng., Member

COUNSEL:

NOVA SCOTIA POWER INCORPORATED
René Gallant, LL.B.
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Nicole Godbout, LL.B.

AFFORDABLE ENERGY COALITION
Susan Nasser

AVON VALLEY *et al.*
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HALIFAX REGIONAL MUNICIPALITY
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MUNICIPAL ELECTRIC UTILITIES OF NOVA SCOTIA CO-OPERATIVE
Don Regan

NDP CAUCUS OFFICE
Graham Steele, MLA

PROVINCE OF NOVA SCOTIA (Department of Energy)
Stephen T. McGrath, LL.B.
Scott McCoombs
Richard Penny

NEWPAGE PORT HAWKESBURY LIMITED and **BOWATER MERSEY PAPER COMPANY LIMITED**
George T. H. Cooper, Q.C.
David S. MacDougall, LL.B.
James MacDuff, LL.B.

QUETTA INC.
John H. Reynolds

HEARING DATES: September 15, 17 & 18, 2008

FINAL SUBMISSIONS: September 25 and 29, 2008

LIST OF INTERVENORS: APPENDIX A

BOARD COUNSEL: S. Bruce Outhouse, Q.C.

DECISION DATE: **November 5, 2008**

DECISION: **Settlement Agreement approved; Average rate increase of 9.3% effective January 1, 2009.**

TABLE OF CONTENTS

1.0 INTRODUCTION

[1] This decision is further to a public hearing conducted by the Nova Scotia Utility and Review Board (the "Board") on September 15, 17 and 18, 2008, in the matter of an application by Nova Scotia Power Incorporated ("NSPI", the "Company", the "Utility") for approval of revisions to its Rates, Charges and Regulations.

[2] NSPI is engaged in the production and supply of electrical energy. It distributes electricity through a province-wide system and, as at December 31, 2007, served approximately 478,038[1] customers, including six municipal electric utilities.

[3] In its application, dated May 27, 2008, NSPI requested an increase in rates in order to meet its estimated revenue requirement increase for 2009 of $132.5 million. NSPI used 2009 estimated costs as a 'test year' for the purpose of determining the additional revenue it required and the corresponding rate increases for its various customer classes should its application be approved. The proposed overall average rate increase was 11.9%, with certain customer classes subject to a higher or lower rate increase. For example, residential customers would see a 12.1% increase with increases ranging from 9.6% to 17.4% for all other metered classes of customers.

[4] The public hearing was duly advertised in accordance with sections *64* and *86* of the *Public Utilities Act*, R.S.N.S. 1989, c. 380, as amended (the "*Act*"), which read as follows:

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[1] NSPI 2007 Annual Report, p. 62

Approval of schedule of rates and charges of utility

64 (1) No public utility shall charge, demand, collect or receive any compensation for any service performed by it until such public utility has first submitted for the approval of the Board a schedule of rates, tolls and charges and has obtained the approval of the Board thereof.

Filing with Board

(2) The schedule of rates, tolls and charges so approved shall be filed with the Board and shall be the only lawful rates, tolls and charges of such public utility until altered, reduced or modified as provided in this Act. R.S., c. 380, s. 64.

Notice of hearing of application for rate changes

86 Notice of the hearing of any application, for the approval of or providing for an increase or decrease in the rates, tolls and charges of any public utility, shall be given by advertisement in one or more newspapers published or circulating in the cities, towns or municipalities where such changes are sought, for three consecutive weekly insertions preceding the date of said hearing, unless otherwise ordered by the Board. R.S., c. 380, s. 86.

[5] A total of 31 formal intervenors responded to NSPI's application. A number of these parties (identified in Appendix A attached) were represented at the hearing by counsel. The Nova Scotia Department of Energy (the "Province"); the Small Business Advocate and Consumer Advocate (the "CA"); Avon Valley *et al.* ("Avon"), whose Counsel represented 17 intervenors; NewPage Port Hawkesbury Limited and Bowater Mersey Paper Company Limited ("NPB"); Halifax Regional Municipality ("HRM"); Affordable Energy Coalition ("AEC"); the NDP Caucus office; the Municipal Electric Utilities of Nova Scotia Co-operative ("MEUNSC"); and Quetta Inc., all participated in the hearing. The Board also received numerous submissions from members of the public opposing NSPI's application.

2.0 BACKGROUND

[6] NSPI is a vertically integrated, investor-owned, regulated public utility with a virtual monopoly on electricity service throughout the Province. It is the primary electricity supplier in Nova Scotia, providing over 95% of the electricity generation, transmission and distribution in the Province. The Board regulates NSPI in the public interest on a cost-of-service basis. The *Act* gives the Board broad regulatory oversight over public utilities and provides it with the authority to discharge its regulatory responsibilities. In addition to statutory requirements to be considered during a general rate application, the Board is also guided by long-established, fundamental rate-making principles. In its Decision dated March 31, 2005, on a rate application by NSPI, the Board explained these guidelines as follows:

> In utility regulation, there are generally accepted principles which govern the rate-making exercise. The object of rate-making under a cost-of-service-based model is that, to the extent reasonably possible, rates should reflect the cost to the utility of providing electric service to each distinct customer class. In regulating NSPI, the Board is guided by these generally accepted principles as well as by case law.
>
> A widely-accepted publication written by Dr. James Bonbright entitled **Principles of Public Utility Rates,** sets out the following guidelines for determining appropriate rates:
>
> **CRITERIA OF A SOUND RATE STRUCTURE**
>
> 1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
> 2. Freedom from controversies as to proper interpretation.
> 3. Effectiveness in yielding total revenue requirements under the fair-return standard.
> 4. Revenue stability from year to year.
> 5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")
> 6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
> 7. Avoidance of "undue discrimination" in rate relationships.
> 8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
>   (a) in the control of the total amounts of service supplied by the company;

> (b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).
>
> [Board Decision, March 31, 2005, p. 14]

[7] The Board continues to make its decisions in accordance with the *Act*, and the principles noted above.

[8] At the commencement of the public hearing on September 15, 2008, NSPI notified the Board it had reached a Settlement Agreement (the “Agreement”), which was endorsed by most of the formal intervenors, including all who filed evidence in this proceeding. The Board adjourned the hearing to provide an opportunity to all parties to review the document, and when the hearing reconvened on September 18, 2008, additional specific information regarding the impact of the Agreement (i.e., the revenue to cost (“R/C”) ratios and proposed rate increases) was filed by NSPI[2].

3.0 SETTLEMENT AGREEMENT

3.1 The Board's approach with respect to this Settlement Agreement

[9] Several parties discussed the approach the Board should take in considering the Agreement. NSPI, in its final submission, stated:

[2] Exhibit N-69

The Board must consider whether the adoption of the Settlement Agreement is in the public interest. The Board has recently considered the public interest in its approval of the FAM Settlement Agreement (P-887) and of the DSM Settlement Agreement (P-884).

In *re Sale of Assets of Kentville Electric Commission* [1998] N.S.U.A.R.B. No. 100, Board Counsel made submissions on the issue of public interest, which the Board quoted in its decision. The Board has dealt with "public interest" in earlier decisions, but because of the broad nature of that concept has not formulated a precise definition. Essentially, the Board must consider broadly the effect of the request, and weigh the benefits and risks to both the utility and customers.

[NSPI Closing Submission, pp. 1-2]

[10] Avon *et al.* made the following observation:

The process leading up to a settlement involved compromises by all participants. The Board should feel confident that a Settlement Agreement which has the support of all customer classes - from the largest electrical consumers to the residentials should be given significant weight. The diversity of interests is not only as between NSPI and its customers but also among customer classes as well. Despite these competing interests, the parties were able to arrive at a negotiated settlement respecting both the revenue requirement and cost allocation.

[Avon *et al.* Final Submission, p. 1]

[11] The CA, in a thoughtful generic submission on settlement, stated as follows:

A settlement is a consensual solution. It of necessity involves a compromise between the optimal outcomes sought by the contending parties. The CA was tempted to reject the settlement and leave it to the UARB to determine the outcome after a contested hearing. That would have the advantage of the public seeing the requested increase resisted vigorously with the result being imposed by the UARB. There would be no suspicions of "deals" or of NSPI somehow manipulating to achieve its profit-seeking goals. There is some merit to forcing a contested hearing when the increase being sought is high. But if the most likely outcome of a contested hearing would be no better than could be achieved by negotiation and consensus, common sense mandates that the consensus be put to the UARB for review and possible acceptance.

There is the further consideration that ideally NSPI and its customers can move to a relationship of complete disclosure and candor that will allow more matters to be resolved by discussion and consensus with a diminished need for expensive and contentious adversarial hearings. The CA does not say that relationship has happened, but progress is being made.

[CA Final Submission, p. 3]

[12] The Board's *Regulatory Rules* facilitate settlement discussions. The Board welcomes and appreciates the efforts of parties to, in good faith, settle issues, even where, as sometimes happens, a settlement cannot be ultimately achieved.

[13] Where, as here, the Agreement is supported by representatives of all of the customer classes, the Board can have confidence that the Agreement is in the public interest.

[14] Customers of NSPI and members of the public are, perhaps understandably, wary of the settlement process. Many of those customers and members of the public may not appreciate that by the time the hearing commences 80% of the rate hearing process has already happened. NSPI filed extensive evidence, as required by the Board, to support its rate request. Interested parties and Board Staff asked NSPI many hundreds of written questions (Information Requests), to which responses were filed.

[15] All of the parties who chose to do so filed evidence, including expert evidence. Written questions (Information Requests) have been asked of and answered by interested parties who filed evidence. NSPI filed reply evidence. As noted, all of this happened before the hearing was scheduled to begin so that the parties and the Board are well informed about the case in advance of any oral public hearing.

[16] The public can rest assured that the Board Members hearing the matter have also thoroughly reviewed all of the material in advance of coming to a decision as to whether to approve the Agreement as being in the public interest.

[17] Settlement agreements, while relatively new in regulatory matters before the Board, are common in the litigation process. Within the Board's adjudicative mandate, for example, assessment appeals, planning appeals and other matters are often settled. In the civil courts of Nova Scotia, a much higher percentage of cases are settled than go to trial.

[18] That is not to say that the Board would hesitate to reject a settlement agreement it did not consider to be in the public interest, however, it should be understood that a properly supported settlement is a success of the regulatory process, not a failure.

3.2 The Settlement Agreement in the present case

[19] The Agreement reads as follows:

2009 General Rate Application Settlement Agreement

Whereas Nova Scotia Power Inc (NSPI) filed an Application for a General Rate Increase with the Nova Scotia Utility and Review Board (UARB) on May 27, 2008, proposing an increase in revenue requirement of $132.5 million and seeking an average rate increase of 11.9% effective January 1, 2009 (the "Application");

And whereas NSPI, New Page Port Hawkesbury Ltd. and Bowater Mersey Paper Company Ltd. (NPB), the Avon group (Avon), the Consumer Advocate (CA), the Municipal Electric Utilities of Nova Scotia Cooperative (MEUNSC) and the Department of Energy (DOE) have worked together with staff and consultants to the UARB to develop and implement a Fuel Adjustment Mechanism (FAM) for NSPI;

And whereas the Parties to this Agreement agree that the FAM will be ready to operate effective January 1, 2009 and NSPI will be ready for the FAM; And whereas NSPI is forecasting revenue requirement increases in the 2009 test year consisting primarily of fuel expenses and other costs, which have been disclosed in the Application and examined during the course of the Application pre-hearing discovery processes;

And whereas the Parties desire to resolve the Application, and to continue to work collaboratively to accomplish objectives that will benefit customers over the long term;

The signatories to this agreement hereby agree:

FAM and Fuel Related Items:

1. The FAM, including supporting documentation, is substantially complete, and there are no remaining issues that would cause any of the Parties to object to the operation of the FAM on January 1, 2009.

2. The Parties request that the UARB approve the FAM to commence on January 1, 2009, as an outcome of this General Rate Application and in lieu of the formal schedule for approval previously established by the UARB in its December 10, 2007 Decision.

3. The Parties will finalize the FAM documentation and NSPI will file a final proposed Tariff and Plan of Administration no later than October 15, 2008 for UARB approval. Any matters regarding the FAM documentation which remain outstanding between the Parties will be determined by the UARB, and Parties other than NSPI, including UARB consultants, shall file any comments on outstanding issues with the UARB by October 22, 2008. Other aspects of FAM implementation, as directed by the UARB in its December 10, 2007 Decision, will continue throughout 2008.

4. The Parties agree that the Base Cost of Fuel in rates will increase by $75 million and will be set in the amount of $545 million, (and adjusted for the FAM per Schedule 2, Appendix A of the FAM Plan of Administration to calculate the average cost per MWh, of $42.41 per MWh, and for each customer class), and that NSPI will recover the Base Cost of Fuel from customers in 2009 rates that are effective January 1, 2009.

5. NSPI has advised the Parties, each of whom hereby specifically acknowledges, that NSPI forecasts fuel costs in 2009 to increase by approximately $82 million above the amount requested to be incorporated into rates in NSPI's Application as filed. The actual amount of the fuel adjustment for 2010 will be determined per the FAM process, and Parties will retain their rights to investigate and litigate these fuel amounts in a hearing before the UARB as part of the FAM process.

6. The Parties agree that recovery of up to $8 Million of the 2008 natural gas sales margin deferral (subject to a reduction of this deferral amount in the event NSPI would otherwise earn in excess of 9.8% ROE in 2008), as approved by the UARB on July 23, 2007, will be recovered in the first FAM adjustment, including carrying charges from January 1, 2009, and shall not be a rate base item.

7. The Parties agree that for the purposes of calculating the FAM incentive, the Base Cost of Fuel in rates will be assumed to be re-set at $590 million (as adjusted per Schedule 2, Appendix A of the FAM Plan of Administration to calculate an average cost per MWh, of $45.95 per MWh, and for each customer class) until the Base Cost of Fuel is again actually re-set, either pursuant to the FAM or during a future General Rate Application.

8. The Parties acknowledge and advise the UARB that an outcome of delayed recovery of a portion of NSPI's forecasted increased 2009 fuel costs described in paragraph 5 above is that the first FAM adjustment will most likely result in an increased recovery from customers beginning on January 1, 2010.

Other Costs and Items:

9. Beginning on January 1, 2009, the revenue for rate setting purposes for each customer class shall be as set out in Schedule 1 attached. The increase in revenue requirement will be $104.2 million, comprised of the $75 million noted in paragraph 4 and the $29.2 million noted in paragraph 10.

10. NSPI has advised the Parties and the UARB of non-fuel cost increases in the 2009 test year. The Parties agree to an increase in revenue requirement of $29.2 million to recover non-fuel cost increases and which increase is in addition to the fuel cost recovery provided above in paragraph 4.

11. The non-fuel increase incorporates reductions in NSPI's forecasted 2009 revenue requirement, compared to the Application, in the non-fuel related areas of the Application, including a reduction of $3.4 million in Vegetation Management costs, extension of the amortization period for Demand Side Management costs to six years to reduce revenue requirement by $3.6 million, removal of the 2008 fuel deferral from rate base as noted above in paragraph 6, and other OM&G and rate base reductions in the total amount of $6.0 million. This increase incorporates the ROE reduction requested in the Application. NSPI's proposed rates and proof of revenue for 2009 shall be as set out in Schedule I attached.

12. The revenue requirement increase will be allocated proportionately to each customer class, on an "across the board" basis, with revenue from each customer class increasing by the same percentage as other customer classes in order to recover in total the increased revenue requirement.

a. This is a one time allocation approach and does not create any precedent for future cases, including the adjustments noted below in sub-paragraphs b) and c).

b. Subsequent to such allocation, the Unmetered class rate and revenue will be reduced to the point where the Unmetered class revenue to cost ratio would be 1.00. This reduction in revenue will not be recovered from other customers.

c. A further adjustment will be made so that the group of Large Industrial Class customers who receive the Interruptible credit will see the same average rate increase as other classes. This will be accomplished by applying a temporary equalization adjustment. The adjustment will be cost neutral to other classes and will not affect the interruptible credit value.

13. The Parties also acknowledge that their agreement to the non-fuel average revenue increase should not be construed as an acceptance by any of the Parties of any allocation or amortization of future DSM or other costs to such Parties, and that the average increase in this Agreement shall not be adjusted on account of any future DSM or other decision by the UARB. In particular, the Parties may take any position on DSM cost recovery and allocation in respect of post-2009 DSM programs and costs.

14. Unless revised by the terms of this Agreement, all other aspects of NSPI's Application are adopted for the purposes of this Agreement only, and this Agreement does

not preclude NSPI or any of the other Parties from taking any positions in future regulatory proceedings or otherwise.

15. NSPI will provide a Cost of Service Study in electronic form to Parties, subject to appropriate confidentiality undertakings and on condition that the model not be used for commercial purposes. Such information shall likewise be available in electronic form for subsequent proceedings.

All of which is hereby agreed this 15th day of September, 2008.

2009 General Rate Application
Settlement Agreement
Schedule 1

Schedule 1 (page 1)	Current Revenue	Proposed Revenue	Revenue Increase	% Revenue Increase	R/C Ratios
ABOVE-THE-LINE CLASSES					
Residential	**$496.3**	**$542.8**	**$46.5**	**9.4%**	**98.9%**
Commercial					
Small General	$30.7	$33.6	$2.9	9.4%	102.3%
General Demand	$252.8	$276.6	$23.7	9.4%	107.2%
Large General	$34.8	$38.0	$3.3	9.4%	98.7%
Total Commercial	**$318.3**	**$348.2**	**$29.8**	**9.4%**	**105.7%**
Industrial					
Small Industrial	$23.9	$26.1	$2.2	9.4%	102.0%
Medium Industrial	$48.6	$53.2	$4.6	9.4%	100.8%
Large Industrial	$65.0	$71.1	$6.1	9.4%	97.5%
ELI 2P-RTP	$119.2	$130.3	$11.2	9.4%	91.0%
Total Industrial	**$256.6**	**$280.6**	**$24.1**	**9.4%**	**95.3%**
Other					
Municipal	$16.1	$17.6	$1.5	9.4%	99.8%
Unmetered	$24.0	$25.2	$1.2	5.0%	100.0%
Total Other	**$40.1**	**$42.8**	**$2.7**	**6.8%**	**99.9%**
Total Above-the-line classes	**$1,111.3**	**$1,214.5**	**$103.2**	**9.3%**	**99.9%**
Below-the-line	**$21.2**	**$22.1**	**$0.9**	**4.5%**	
Exports	**$4.6**	**$4.6**	**$0.0**	**0.0%**	
Miscellaneous	**$14.2**	**$14.7**	**$0.4**	**2.9%**	
Total Revenue	**$1,151.3**	**$1,255.8**	**$104.5**	**9.1%**	

[Exhibit N-69]

[20] The Agreement presented to the Board has the support of representatives of all of the customer classes including the domestic class. The Board's consultants Dr. John Stutz and Mr. John Antonuk recommend its approval.

[21] As noted by NPB, not only were most of the parties to the Agreement represented by experienced counsel, they also had experienced expert advisors with respect to the various issues before the Board including fuel, rates, OM&G, etc.

[22] For the reasons explained below, and having concluded that it is in the public interest, the Board approves the Agreement.

4.0 FUEL

4.1 Fuel Cost

[23] NSPI, in its application, stated that:

> Current rates include fuel and purchased power expenses of $470 million. The test year fuel cost requested in this Application is $559.5 million, or $89.5 million higher than the amount included in the 2007 Compliance Filing (2007C)...
>
> [Exhibit N-1(a), p. 9]

[24] The majority of intervenors initially questioned NSPI's estimate of 2009 fuel cost on grounds such as generation cost allocation, load forecast, prioritization of generation facilities, currency exchange, Cost of Service Study, etc.

[25] Liberty, however, in their evidence recommended that:

> NSPI's fuel expense estimate for the Rate Year (2009) as filed should be used to set base rates, because its actual costs, even after considering appropriate offsets are reasonably certain to equal or exceed the amount set forth in the filing...
>
> [Exhibit N-30, pp. 6-7]

[26] On September 5, 2008, NSPI filed an update to its 2009 fuel cost:

> This forecast uses the fuel forecasting methodology collaboratively developed by NSPI, Liberty Consulting Group, NPB and other Intervenors in the FAM process. An adjustment was made to the FAM methodology to reflect the outstanding matter related to import energy and combustion turbine usage identified for resolution in the methodology (noted in the August 7 Evidence of Liberty). The result of this forecast is that the estimated cost for fuel and purchased power in 2009 is now $641.7 million. This is $82.2 million higher than the forecast contained in NSPI's initial Application...
>
> [Exhibit N-67, p.1]

[27] The Agreement deals with the 2009 fuel cost as follows:

> 4. The Parties agree that the Base Cost of Fuel in rates will increase by $75 million and will be set in the amount of $545 million, (and adjusted for the FAM per Schedule 2, Appendix A of the FAM Plan of Administration to calculate the average cost per MWh, of $42.41 per MWh, and for each customer class), and that NSPI will recover the Base Cost of Fuel from customers in 2009 rates that are effective January 1, 2009.
>
> 5. NSPI has advised the Parties, each of whom hereby specifically acknowledges, that NSPI forecasts fuel costs in 2009 to increase by approximately $82 million above the amount requested to be incorporated into rates in NSPI's Application as filed. The actual amount of the fuel adjustment for 2010 will be determined per the FAM process, and Parties will retain their rights to investigate and litigate these fuel amounts in a hearing before the UARB as part of the FAM process.
>
> 6. The Parties agree that recovery of up to $8 Million of the 2008 natural gas sales margin deferral (subject to a reduction of this deferral amount in the event NSPI would otherwise earn in excess of 9.8% ROE in 2008), as approved by the UARB on July 23, 2007, will be recovered in the first FAM adjustment, including carrying charges from January 1, 2009, and shall not be a rate base item.
>
> [Exhibit N-69, p. 2]

[28] The Agreement proposes that the base fuel cost for 2009 rate making purposes be set at $545 million, an increase of $75 million over the 2007 compliance fuel cost. As per NSPI's update[3], the actual cost of fuel for 2009 may be $82 million more than the $559.5 million proposed in the application. The difference between the base fuel cost for 2009 of $545 million and actual fuel cost for 2009 is proposed to be recovered through the proposed Fuel Adjustment Mechanism starting on January 1, 2010, as discussed later

---

[3] Exhibit N-67

in this decision. If fuel costs were to drop below estimates, that would be credited to customers under the Fuel Adjustment Mechanism.

[29] NSPI uses coal to produce 71% of its energy requirement[4]. In addition, NSPI purchases its fuel using a portfolio strategy previously approved by the Board. The Board in its decision dated March 31, 2005[5] directed NSPI to use a short, medium and long term fuel procurement strategy to protect customers from short term price fluctuation.

[30] Recently the price of oil has come down in world markets. However, NSPI utilizes very little heavy fuel oil to produce electricity. The world price of coal, which is NSPI's dominant fuel to produce electricity, has not fallen nearly as dramatically. The effect of any decrease in coal prices will be delayed due to the use of the fuel procurement strategy, which includes long term commitments already in place prior to the decrease in world fuel prices.

4.1.1 Findings

[31] The Board has considered the evidence filed relating to the fuel cost. The evidence before the Board is that the actual cost of fuel most likely will exceed the proposed base cost for 2009 of $545 million. NSPI estimates that the actual cost may be as high as $640 million[6].

[32] The Board approves the proposed fuel cost for 2009 as noted in the Agreement.

---

[4] Exhibit N-1 (a), p. 13

[5] 2005 NSUARB 27

[6] NSPI update dated September 5, 2008

4.2 Future Natural Gas Requirements and Purchased Power

[33] Liberty, in its Statement, raised two issues for the Board's consideration:

> ... We therefore would like to underscore two points of future vigilance suggested by our testimony, as NSPI continues to pursue efforts to minimize fuel costs. One particularly notable feature of both the original and updated forecasts is that NSPI now expects that the dual-fuel steam units at Tuft's Cove will run essentially entirely on gas in 2009. That places NSPI in a different situation from what has been experienced in the past, when large amounts of natural gas were available for resale in a manner that produced large cost offsets to the benefit of customers.
>
> NSPI thus will not have the same opportunities in 2009 to resell natural gas that it has had in the past, unless oil prices move the great distance required to come more into line with their historical relationship to natural gas. In any event, NSPI's opportunities to reduce costs through the sale of natural gas are fast approaching an end. NSPI's primary gas-supply contract has only two years remaining. We therefore want to re-emphasize the point made in our evidence that NSPI continues not to have a strong track record of dealing with gas suppliers other than its affiliate. The physical and contractual aspects of the gas-supply relationships that NSPI will have to cope with in the not-too-distant future are complex, will take substantial time to conclude, and are generally undertaken by utilities having broader relationships with participants in the marketplace. Consequently, we underscore the need for the Company to be identifying its alternatives and developing a strategy for pursuing them aggressively now. We believe it is very important for NSPI to keep the Board and its stakeholders apprised of its progress in this important area as the next months unfold.
>
> Another matter our evidence addressed is the value that imports of electric power produce for NSPI's customers. Such imports have grown rapidly over the last several years. NSPI acknowledges the attraction of low-cost power imports, but points to practical limits that constrain its ability to make more comparatively economical imports. One example is the transmission capacity connecting Nova Scotia to New Brunswick. Liberty believes that it will be important in the near term for NSPI to analyze and pursue all measures that may serve at reasonable cost to eliminate barriers to making economical, off-system electricity purchases, and to demonstrate to the Board that it is doing so.
>
> [Liberty Statement, Exhibit N-74, p. 2]

[34] In response to Board Counsel's question, Mr. Antonuk stated:

> ... We do, however, want to state that whether or not the settlement is accepted we continue to believe that a couple of very important issues remain for NSPI to focus on as markets continue, as we expect them, to be volatile into the future. We think it's important to keep in mind matters such as replacing natural gas supply when the current agreement with Shell runs out in the very short term, and ensuring that NSPI's system can accommodate full participation in off-system electricity purchases will be important in securing economical and continuous supply in future uncertain energy markets. So, we look forward to hearing more in the coming months about the company's plans in those two important areas.
>
> [Transcript, September 18, 2008, pp. 129-130]

[35] Rob Bennett, President and CEO of NSPI, shared Liberty's comments in his Opening Statement:

> ... There's certainly more to do in terms of exploring the development of new transmission infrastructure. This will enable the aspirations we have for renewable energy, which we know are shared by Nova Scotians.
>
> [NSPI Opening Statement, Exhibit N-73, p. 2]

[36] The Honourable Stephen McNeil, MLA, Leader of the Nova Scotia Liberal Party, also noted the importance of interprovincial transmission capacity.

4.2.1 Findings

[37] The Board accepts Liberty's comments with respect to the sale of natural gas contracts. NSPI purchases its natural gas under contract from its suppliers and sells the surplus quantity to third parties, after its use of a portion of the supply to generate power. In a majority of cases, NSPI has used Emera Energy, an affiliate company, to purchase its surplus natural gas and to sell it. The Board understands Liberty's concern that NSPI has not built enough market contact and transparency to ensure that its future gas procurement will be competitively priced.

[38] The Board directs NSPI to review Liberty's comments with respect to future natural gas purchases and file a report with the Board, no later than April 30, 2009, on how it plans to address this concern.

[39] The Board also accepts Liberty's comments on the second issue relating to NSPI's transmission capacity to import and export power. NSPI is directed to consider this issue and file a report with the Board no later than June 30, 2009, outlining its plans for improvements to its transmission capacity to facilitate power imports. The Board is mindful

that NSPI has, in the 2008 ACE Plan, included a request for capital expenditures related to this issue.

5.0 OM&G

5.1 Overview

[40] In its original application, NSPI requested a $20.6 million increase in Operating, Maintenance and General Expenses ("OM&G") for the 2009 test year.

[41] As a result of the Agreement, the proposed increase for OM&G costs was reduced to $15.8 million. The $4.8 million reduction is comprised of the following components: a $3.4 million decrease from the amount originally proposed for vegetation management, a reduction of $1.0 million to the projected net bad debt expense and a $400,000 reduction for insurance costs.

[42] As noted above, most of the formal intervenors joined as signatories to the Agreement, which specifically addressed the proposed $3.4 million reduction for vegetation management from the amount originally requested in the rate application. However, at the hearing, this proposed reduction was opposed by the NDP Caucus.

[43] Mr. Steele also expressed concerns during the hearing with respect to executive compensation, an issue also identified in many letters received by the Board from members of the public.

[44] Moreover, over the past two years leading to the present rate application, NSPI has undergone an operations review ordered by the Board with respect to its organizational structure and its level of OM&G expenditures.

[45] The issues of vegetation management, the operations review, and executive compensation are canvassed more fully below.

5.2 Vegetation Management

5.2.1 Submissions - NSPI

[46] In his Opening Statement, delivered at the commencement of the hearing, Mr. Bennett submitted that the proposed expenditure increase for vegetation management should be approved by the Board:

> I want to underline the importance about increasing spending on tree trimming and vegetation management. We are taking important steps in this program.
>
> Stable and reliable transmission and distribution systems are rightfully an expectation of this Board. It's also the expectation of regulatory bodies that oversee the bulk power system. For example, the North American Electric Reliability Corporation - or NERC - has recently enhanced transmission line tree trimming requirements.
>
> [NSPI Opening Statement, Exhibit N-73]

[47] NSPI reasserted its position in its Closing Submission, citing Mr. Bennett's testimony at the hearing about vegetation management and its impact upon reliability:

> When Mr. Steele asked about vegetation management spending and its relationship to reliability, Mr. Bennett explained:
>
>> In fact, the decision to change the degree of funding in the vegetation management program was arrived at with a balanced consideration for all of the needs of our customers and reliability going forward. That includes the need to sustain our workforce through succession planning and other operational activities in the business that require funding.
>>
>> I believe that we've achieved that balance of a significant level of additional funding in the vegetation program. $3.6 million more than is being spent today will definitely increase the reliability of the system. It will allow us to execute programs that will effectively storm-harden the system, and at the same time the settlement agreement allows us to, in a balanced way, take on those other challenges that have long-term beneficial impacts, such as sustaining, developing and training our workforce to deal with our customers' needs in the future.
>>
>> So, I'm very comfortable that the level of investment that we will be making will make a difference. I should also note that the choice of $3.6 million was

> arrived at because it had been reviewed in the past by various consultants with the Board and there was an understanding of that level of additional investment as being important and effective.

> Importantly, all parties to the Settlement Agreement consider that the increase in vegetation management expenditure of $3.6 million is a reasonable and appropriate enhancement. All parties are also aware that, in future, it may be necessary to consider the additional investment that was proposed by NSPI in this proceeding but will not be implemented.
>
> [NSPI Closing Submission, September 25, 2008, pp. 3-4]

5.2.2 Submissions - NDP Caucus

[48] The NDP Caucus was the only formal intervenor who raised this issue at the hearing. In his closing argument, Mr. Steele stated:

> With respect to system reliability or what I might refer to as outages, Nova Scotia Power has this year proposed an extensive program of vegetation management in order to improve system reliability. The company's evidence appears to acknowledge that it is possible for the company to raise its game on vegetation management to another level so that the level of outages caused by vegetation contact can get down to the levels already achieved by New Brunswick Power. But we note the settlement agreement contains a cut of 3.4 million dollars from this vegetation management program. A program designed to address specifically and directly a major concern to the public has been cut as part of the settlement agreement.
>
> For that reason, it is difficult to see how the company can possibly achieve its goals with respect to outages caused by vegetation. We believe it is regrettable that of all the items that could have been picked to find the necessary savings that that item has been picked.
>
> [Transcript, September 18, 2008, pp. 149-150]

[49] He concluded:

> ... It may be that the global amount of cost savings have been agreed upon by the signatories to the settlement agreement but it seems to us fair and we recommend to the Board that the expense for vegetation management be restored and that the difference be made up by taking at least some of that amount from executive compensation. That may be a symbolic move by the company but I believe it would be a very important one.
>
> [Transcript, September 18, 2008, p. 151]

5.2.3 Findings

[50] With respect to vegetation management, NSPI is requesting a net increase in proposed expenditures.

[51] In its original rate application, NSPI requested an increase of $7.0 million over the prior year, which would have amounted to a total of $13.8 million for 2009. Thus, despite the $3.4 million reduction resulting from the Agreement, an overall net increase in vegetation management activity will be achieved. Vegetation management expenses will increase to $10.4 million for the 2009 test year, a net increase of $3.6 million over the last compliance filing.

[52] The Board notes the testimony of Mr. Bennett, who stated that increased activity in vegetation management will enhance service reliability for NSPI's customers.

[53] Further, the Board is also mindful that the Agreement specifically addressed the issue of vegetation management. The formal intervenors who signed the Agreement represent all rate classes of NSPI's customers.

[54] Taking into account all of the evidence, the Board is satisfied that the proposed total expenditure of $10.4 million for vegetation management (an increase of $3.6 million), as contemplated under the terms of the Agreement, is reasonable and appropriate in the circumstances.

5.3 Operations Review

5.3.1 Introduction

[55] In its decision dated March 10, 2006, the Board ordered a review of NSPI's operations:

> The Board directs that an operations review be carried out on NSPI's operations. The review shall encompass a detailed examination of NSPI's organizational structure, its level of OM&G expenditures, and any other pertinent areas which may come to light, with a view to determining whether cost savings and operational efficiencies can be achieved. NSPI is directed to prepare the terms of reference for the operations review and submit them to the Board for approval by May 31, 2006. The terms of reference shall also set out the procedures for identifying and selecting the firm or person who will perform the operations review.
>
> [Board Order, P-882, April 12, 2006, Schedule "C"]

[56] In response to this direction, NSPI filed a report prepared by Accenture Inc. on January 8, 2007 (the "Accenture Report").

[57] The Board ordered that the Accenture Report be filed in advance of the 2007 rate hearing. In that Rate Decision, the Board directed that interested stakeholders provide input on the review process:

> [54] The Board has determined that the process concerning the operations review will continue following this decision and that interested stakeholders will have an opportunity to participate - the CA already has. The Board is interested in soliciting views of parties to the rate case proceeding with respect to the appropriate course of action. Accordingly, the Board will provide an opportunity for input concerning the desirability of a further review of NSPI's operations as suggested by the CA or whether parties are satisfied that Accenture has met the Board's terms of reference.
>
> [Board Decision, February 5, 2007, P-886, pp. 24-25]

[58] Following its review, the Board determined that the scope of the Accenture Report was much narrower than the terms of reference developed for the operations review. It concluded that the Report's focus was limited to the Corporate Services component of NSPI's overall OM&G functions (i.e., which comprised less than 20% of the total OM&G costs).

[59] Accordingly, in a letter dated May 18, 2007, the Board directed that it would engage an independent expert to carry out a review of the sectors of NSPI's OM&G costs not covered in the Accenture Report, including executive compensation. It retained Kaiser Associates to conduct the operations review and the findings were contained in a report dated June 19, 2008 (the "Kaiser Report"). Kaiser Associates released a separate report with respect to executive compensation on June 16, 2008 ("Kaiser's Executive Compensation Review"), which is canvassed in greater detail in the next section of this decision.

[60] The Kaiser Report concluded:

> Following its research and analysis presented in the detailed findings, Kaiser believes that NSPI is a well managed utility that operates at a lower OM&G cost basis than its comparators when adjusted for its scale. NSPI has shown a rise in costs from 2004-2006, driven by investments in Emergency Services Restoration, vegetation management and a onetime adjustment made for pension expense. These expenses were reviewed and approved by the UARB. In addition NSPI was affected by external factors, for example: particularly adverse weather in the province; and, a major customer was not in service in 2006, depressing revenue. Preliminary data for 2007 shows OM&G expenditures are projected to remain flat. . . .
>
> [Kaiser Report, June 19, 2008, Exhibit N-5, p. i]

[61] However, the Kaiser Report identified NSPI's Work Management System as an area of concern:

> Work Management System (WMS) - Rather than use an integrated WMS, NSPI relies on a number of different WMSs aligned by function (customer operations, maintenance, etc.) leading to lack of coordination and sub-optimal utilization. NSPI management is aware of this problem and is taking steps to address the WMS; NSPI management has a $6-7M application for a transmission and distribution WMS upgrade in its 2008 capital budget. WMS is a key area of study in benchmarking and a critical recommendation. Although the integrated nature of WMS means it affects multiple areas of company operations, Kaiser has presented its findings and recommendations related to WMS in the Customer Operations section (pages 75-86). As Kaiser has cautioned the UARB, there are significant efficiencies to be gained, however, implementing an enterprise-wide, integrated WMS is a substantial investment which carries significant risk and will require the commitment of personnel resources.
>
> [Kaiser Report, June 19, 2008, Exhibit N-5, p. ii]

[62] The organizational design of NSPI's existing power production plants was also identified as an area of improvement:

> Organizational Design - NSPI does not utilize a standard organizational design across its existing plants. Due to attrition in its Point Tupper plant, NSPI is testing an alternate organizational structure, which after evaluation may be expanded for use in other facilities. This structure is much less hierarchical in nature, therefore relies less on highly experienced supervisory staff. NSPI uses a distributed model in organizing its plants, allowing for operational flexibility but also possibly creating redundancies in engineering and support functions.
>
> [Kaiser Report, June 19, 2008, Exhibit N-5, p. ii]

[63] The Kaiser Report recommended:

> **[Organizational] Design**
>
> Research indicates that NSPI has a greater number of direct reports as well as less accountability in plants, particularly in the maintenance and planning areas. NSPI should develop a plan for the board identifying its [organizational] design and workforce plan over the coming years as part of its succession planning initiative. The plan should address some of the standardization of organization and centralization issues raised in the detailed findings.
>
> [Kaiser Report, June 19, 2008, Exhibit N-5, p. iv]

5.3.2 Submissions - NSPI

[64] In its application, NSPI listed a number of reviews undertaken with respect to OM&G costs. It stated that the findings of these reviews have been generally supportive of NSPI's management of OM&G expenses[7]. Further, NSPI stated that, in constant dollars, it has reduced OM&G expenditures since 2000, through effective cost control mechanisms.

[65] In its Reply Evidence, NSPI questioned a number of the findings in the Kaiser Report, including recommendations with respect to website and Interactive Voice Response System automation, meter reading and customer service staffing levels. The

[7] Exhibit N-1, p. 98

Board observes that most of these issues identified in the Kaiser Report were addressed and clarified during the Information Request process of this hearing.

5.3.3 Submissions - Intervenors

[66] The formal intervenors made no submissions at the hearing with respect to the OM&G operations review.

5.3.4 Findings

[67] As noted above, as a result of prior Rate Decisions, the Board ordered a comprehensive operations review of NSPI's organizational structure and its level of OM&G expenditures.

[68] The Kaiser Report concluded "that NSPI is a well managed utility that operates at a lower OM&G cost basis than its comparators when adjusted for its scale"[8]. Further, it observed "that NSPI compares favorably to the benchmark firms on OM&G expense when normalized by power generated, number of customers, number of employees and amount of revenue generated"[9].

[69] Stakeholders provided their input with respect to the terms of reference of the operations review prior to the work undertaken by Kaiser Associates. The Kaiser Report was reviewed by the formal intervenors who participated in this hearing. While some of the intervenors submitted evidence suggesting reductions to certain aspects of NSPI's OM&G costs, the Board found no evidence that these intervenors challenged the Kaiser Report's

[8] Exhibit N-5, p. i

[9] Exhibit N-5, p. iii

conclusion that NSPI is "a well managed utility", which "compares favorably to the benchmark firms on OM&G expense when normalized [over a number of factors]".

[70] While NSPI, in its Reply Evidence, appeared to distance itself from some of the findings in the Kaiser Report, the Board interprets this Report as being favourable, in most respects, to NSPI's management of OM&G expenses.

[71] Taking all of the evidence into account, the Board accepts the findings of the Kaiser Report, as well as that of the Accenture Report, that NSPI's organizational structure is appropriate and its management of OM&G expenditures is reasonable.

[72] However, the Kaiser Report identifies NSPI's Work Management System as a recommended area of improvement, stating that an integrated system would improve coordination and efficiency. NSPI has committed to the implementation of a Work Management System with respect to its transmission and distribution operations. This new system will, according to NSPI, benefit NSPI's customers by the more efficient and timely handling of the "work order" process. Accordingly, the Board directs that NSPI advise the Board on the balance of the Kaiser Report's recommendation about extending an integrated Work Management System to the remainder of NSPI's operations. This report shall be filed no later than December 31, 2008.

[73] The Kaiser Report also recommends that NSPI develop a plan for the Board identifying NSPI's organizational design and workforce plan for its power production plants, as part of its succession planning initiative. NSPI is currently testing an alternate organizational structure at one of its plants. The Board directs that NSPI file a report on its progress no later than March 31, 2009. The Board also reserves the right to issue further directions on this issue.

5.4 Executive Compensation

5.4.1 Introduction

[74] The issue of executive compensation has been a matter which has arisen in this and prior rate applications.

[75] As a result of a much broader OM&G operations review (discussed in greater detail in the section above), the Board retained Kaiser Associates to conduct an Executive Compensation Review. As part of this review, Kaiser Associates examined a report prepared for NSPI by Towers Perrin, which is part of an annual reporting required by the Board.

[76] With respect to salary, NSPI sets its target salary at the 50th percentile mark within a group of comparable operators consisting of Canadian utilities. Towers Perrin concluded that NSPI executives (a management team comprised of 11 members) are paid compensation which is 11% lower than the median pay of the comparator utilities chosen for its review.

[77] However, applying changes which it recommends to Towers Perrin's methodology, Kaiser Associates concluded that NSPI's management team is actually paid a salary which is 0.5% higher than the median pay of the comparators it identified for its study. Further, Kaiser Associates found that the two highest paid NSPI executives earn about 41% more than executives at comparable utilities, while the two lowest paid executives make 24% and 37% less, respectively, than the benchmarks.

[78] Kaiser Associates recommends that future benchmarking studies of NSPI's executive compensation incorporate the following elements:

- Including the whole bonus figures in TTC [Total Target Cash] benchmarking;
- Include stock-based compensation as part of the analysis;
- Look at compensation position by position as well as in the aggregate;
- Factor in cost of living adjustments;
- Benchmark targets and achievement on executive scorecard against comparators.

[Kaiser Executive Compensation Review, Exhibit N-3, p.1]

[79] The review by Kaiser Associates revealed that the Towers Perrin report utilizes 50% of the target cash bonus for NSPI in its TTC benchmarking, compared to 100% for the comparator utilities. Further, Kaiser Associates concluded that the Towers Perrin analysis may be distorted based on differences in the regional cost of living factors which it applied.

[80] However, Kaiser Associates also found that NSPI executives tend to be better qualified in terms of tenure and professional degrees as compared to comparator utilities.

5.4.2. Submissions - NSPI

[81] In its Reply Evidence, NSPI stated that Kaiser's Executive Compensation Review, conducted on behalf of the Board, supports NSPI's view that it is paying reasonable compensation to its executive team. However, NSPI opposes the recommendations made by Kaiser Associates with respect to the methodology for reviewing executive compensation.

[82] NSPI further asserts that the issue of executive compensation was canvassed in this rate application. In its Closing Submission, it submitted:

> The parties to the Settlement Agreement have had access to the Kaiser Report on Executive Compensation from early in the proceeding - a Report that concludes that NSPI's executive compensation is on target at the mid-point of the range for comparable companies. IRs were posed on this topic by some parties and answered by NSPI. As Mr. Bennett explained, all

> areas of cost have been carefully examined and a balance has been achieved following careful consideration and input of stakeholders.
>
> [NSPI Closing Submission, September 25, 2008, p. 3]

5.4.3 Submissions - NDP Caucus

[83] During closing argument, Mr. Steele submitted:

> With respect to executive compensation, the settlement agreement ensures that this topic will go unexamined for at least another year. Even though it is the one topic that probably catches the public's attention the most. Although not everyone will claim to be an expert on rate setting for Nova Scotia Power, it is fair to say that just about everyone considers themselves to be an expert on incomes, whether that be a politician's income or a power executive's income. And while Nova Scotia Power compensation levels may be comparable to the mid range of other public utilities across Canada, the fact is that the levels of compensation are simply enormously out of keeping with other incomes in the Province of Nova Scotia. There must be a problem with the comparators.
>
> It is difficult for most Nova Scotians whose incomes are fixed or rising much more slowly than the cost of living to pay higher rates to a Nova Scotia company whose executives earn high six figure incomes, sometimes approaching a million dollars a year in salary, stock options and bonuses. We are mindful of the fact that Nova Scotia Power is free to pay their executives whatever they chose and we accept that the issue for this hearing is what portion of that executive compensation is included in the rate base to recover from rate payers. It may be that the global amount of cost savings have been agreed upon by the signatories to the settlement agreement but it seems to us fair and we recommend to the Board that the expense for vegetation management be restored and that the difference be made up by taking at least some of that amount from executive compensation. That may be a symbolic move by the company but I believe it would be a very important one.
>
> [Transcript, September 18, 2008, pp. 150-151]

5.4.4 Findings

[84] Taking into account all of the evidence, the Board finds that the compensation presently paid to NSPI's management team, as viewed on a collective basis, is not materially higher than that paid to comparable Canadian utilities, even adopting the methodology recommended by Kaiser Associates.

[85] The Board's obligation is to ensure that the OM&G expenses, including the collective compensation paid to managers as a group, is reasonable. Setting of individual

salaries within the envelope approved by the Board is a matter for NSPI's Board of Directors and Management. The Board observes that few, if any, issues have attracted public comment, often amounting to outrage, as did the salary paid to NSPI's highest paid executives. The Board trusts that NSPI's Board and Management have heard the message.

[86] The Board directs that NSPI continue to file an annual report with the Board respecting executive compensation. In the interim, and in light of this decision, NSPI should further consider the recommendations contained in Kaiser's Executive Compensation Review. The Board will continue to monitor this issue and it reserves the jurisdiction to issue further directions with respect to the reporting of executive compensation.

5.5 Conclusion - OM&G

[87] As noted above, taking into account all of the evidence (including but not limited to the evidentiary filings in this application, the Agreement, and the submissions of the parties), the Board approves a $15.8 million increase in OM&G expenses for the 2009 test year. This increase will result in a total OM&G expenditure of $216.6 million for the test year. The Board directs NSPI to incorporate the specific reductions to OM&G set out in the Agreement (i.e., those outlined for vegetation management, net bad debt expense and insurance costs).

[88] Further, based upon its consideration of the operations review, the Board concludes that NSPI's organizational structure is appropriate and that its management of OM&G expenses is reasonable. Subject to Work Order approval, NSPI will proceed with

the implementation of its Work Management System associated with its transmission and distribution operations. NSPI must report on the implementation of an integrated Work Management System to the remainder of its operations, no later than December 31, 2008. NSPI is also directed to continue the review of its organizational design for its existing power production plants and to provide a status report to the Board no later than March 31, 2009.

[89] With respect to executive compensation, the Board is satisfied that the overall level of compensation currently paid to NSPI's executive team is reasonable, when compared to other Canadian utilities used as comparators. NSPI must continue to file an annual report with the Board with respect to executive compensation. Further, the Board reserves the jurisdiction to issue further directions with respect to the reporting of executive compensation.

6.0 FINANCIAL ISSUES

6.1 Calculation of Return on Equity

[90] It became apparent during the examination of NSPI's Policy Panel that there was a difference of opinion between the Company and intervenors concerning the proper method of calculating return on equity in any given year. Briefly stated, the Company's position is that the calculation should be made on the basis of the company's actual equity, up to the 40% maximum approved by the Board (the maximum equity will increase to 45% under the Agreement). The intervenors' position, on the other hand, is that return on equity

should be calculated based on the common equity ratio of 37.5% approved by the Board "for rate making purposes".

[91] The Board adjourned the hearing to enable Board Counsel to consult with NSPI and the intervenors about this issue. When the hearing resumed, Board Counsel indicated that the parties were unable to reach agreement on the issue and that it should be resolved in a separate process. Board Counsel also noted that the issue would probably not crystallize until a determination has to be made whether the Company's regulated earnings in 2008 would represent a return on equity in excess of 9.8%.

[92] Neither the Company nor any of the intervenors requested that the Board deal with this issue in the context of the settlement and the issue was not mentioned in any of the post-hearing submissions. Obviously, the parties are prepared to have the Board approve the settlement without first resolving the return on equity calculation issue.

[93] Having regard to the foregoing, the Board will deal with the calculation issue in a subsequent proceeding which can be initiated at the request of the Company, any intervenor in the present proceeding or on the Board's own motion.

7.0 ABOVE THE LINE RATES

7.1 Revenue to cost ratios

[94] As noted, the Agreement proposes that the 9.3% increase in revenue be applied equally across all rate classes. As a result, the revenue to cost ratio for the General Demand class increases to 107.2% and the ELI 2P-RTP class reduces to 91%.

[95] The Board has, for many years, set a target revenue to cost ratio of 95% to 105% for all customer classes. The Agreement causes a weakening in the revenue to cost ratios from that approved in the last rate case.

[96] Dr. Stutz, in his Statement recommending approval of the Agreement, comments on this issue:

> ... The Agreement deals with two key areas raised in my prefiled evidence:
>
> - The increase in total revenues for 2009 has been reduced.
> - The spread in the increases in class revenue responsibility has been narrowed.
>
> [Stutz Statement, Exhibit N-75]

[97] He goes on to state:

> - As I explained in my evidence, rate stability justifies moving the increase for the ELI 2P-RTP rate toward the average, even at the "cost" of an R/C ratio below 95%.
>
> [Stutz Statement, Exhibit N-75]

[98] Dr. Stutz was questioned by Mr. Steele about the revenue to cost ratios:

> Q. Now, given that the rationale for the 95 percent ratio has not been borne out by experience, what justification can you offer for the revenue to cost ratio in that class actually going under 95 percent now if the settlement agreement is approved sitting at 91 percent?
>
> A. The rationale is provided in the last paragraph of my statement.
> There are a variety of considerations, one of which -- and the Board has taken this into account in many occasions before is rate stability.
> In my original evidence, I in fact proposed a revenue to cost ratio below 95 percent, because I felt it was important to preserve revenue stability.
>
> . . .
>
> Q. Would you agree with the proposition that the members of the commercial general class are paying more than their fair share?
>
> A. No, I have difficulty with that proposition. Because it suggests that the revenue to cost ratio is the sole indicator of what's fair. And I think fairness is a very broad concept.
> I think, for example, it's not fair if you're charging everyone 9 percent to give someone 18. So, I wouldn't agree with it.

> I would agree that [that] one indicator which the Board has relied on, to some extent, shows them outside the range the Board would like to se [see].
>
> [Transcript, September 18, 2007, pp. 137-138]

[99] Leanne Hachey, on behalf of the Canadian Federation of Independent Business, raised the concern that cross-subsidization is taking place if the revenue to cost ratio of one class is 91% and another class is 107%. She went on to say:

> . . . And why CFIB believes these inequities should be address[ed] is one, they do clearly contravene Bonbright's principles of public utility rates that the fairness of the specific rates and the apportionment of total cost of service among the different consumers the avoidance of undue discrimination and the efficiency of rate classes to discourage wasteful use of service.
>
> In other words, in layman's' terms everybody should pay their fare share. People shouldn't be paying the costs of others.
>
> [Transcript, September 17, 2008, p. 52]

[100] The CA also dealt with the issue in his written submission:

> The CA is concerned by the impact of the “across the board” increase on the revenue/cost ratios. That is a variance that is beyond the target zone of 95% to 105% set by the Board and represents a cross-subsidization that, the greater the variance, the greater difficulty in justification.
>
> However, the “across the board” allocation of the agreed-upon increase was a trade-off of a number of factors (see for example, the statement of Dr. Stutz dated September 18, 2008 exhibit N-75).
>
> Ultimately, each of the proponents of the Settlement Agreement was prepared to accept the impact on the revenue/cost ratios for the purposes of achieving the settlement.
>
> [CA Submission, September 25, 2008, p. 4]

7.2 Findings

[101] The Board is concerned about the weakening in revenue to cost ratios. However, the Board accepts the evidence of Dr. Stutz that revenue to cost ratios are not the sole indication of what is fair. Dr. Stutz noted in his evidence that one of the rate

classes had a disproportionate increase relative to the average increase. By virtue of the Agreement, he noted that the spread in increases in revenue class responsibility had been narrowed. He also spoke to the importance of rate stability which is, of course, one of Bonbright's criteria of a sound rate structure.

[102] As noted earlier in the decision, the Agreement enjoys the support of representatives of all of the customer classes. In the interest of achieving rate stability in this proceeding, the Board will permit the deterioration in revenue to class ratios caused by the Agreement.

[103] The Board anticipates, however, that at the next opportunity an adjustment to bring the two rate classifications back within the target range will be a priority.

8.0 DEMAND SIDE MANAGEMENT

8.1 Submissions

[104] NSPI in its application stated that:

> The parties agreed that NSPI would be the temporary DSM administrator and that early DSM program implementation by the Company would transition to the new administrator. The parties also agreed to changes to the timing and mix of DSM programs resulting in DSM spending of up to $3.1 million for 2008 and $9.8 million for 2009. The total expenditure over the 2008-2009 period was identified to be $12.9 million, the same level of investment as proposed for that period in the January 31, 2008 filing. Similarly, cumulative energy and demand savings targets would remain at 66 GWh and 8.8 MW respectively, the same as identified in the January 31, 2008 filing for the 2008-2009 period.
>
> The Settlement Agreement deferred UARB consideration of several issues that were not necessary to resolve during the April 2008 hearing. These issues included NSPI's proposal for a DSM Cost Recovery Mechanism, including a Lost Revenue Adjustment Mechanism (LRAM), performance indicators, incentives and penalties, and the proposed role and structure of the DSM Steering Committee and DSM Advisory Council. The Parties agreed that NSPI could defer DSM program expenditures in 2008 and 2009 for future recovery over a reasonable period determined by the Board, and that the appropriate allocation of costs among customer classes would be considered at the time of NSPI's request for recovery of the DSM expenditures.

[Exhibit N-1(a), p. 85]

[105] NSPI's application proposed to recover the 2008 and 2009 Demand Side Management (DSM) costs as follows:

> With the DSM investment as outlined in the DSM Settlement Agreement of $3.1 million for 2008 and $9.8 million for 2009, the total forecast expenditure over the 2008-2009 period is $12.9 million. NSPI is requesting recovery of this $12.9 million in equal increments over 2009, 2010 and 2011. NSPI proposes that $4.3 million be incorporated into the 2009 test year revenue requirement to reflect DSM costs. The recovery is further discussed in Section 5 of this Application.
>
> [Exhibit N-1(a), p. 86]

[106] The Agreement proposes that the amortization period for the 2008 and 2009 DSM costs be increased from three years to six years[10]. The net effect of this change is the reduction of the revenue requirement by $2.1 million in 2009[11].

8.2 Findings

[107] The Board has considered the amortization of the 2008 and 2009 DSM program costs over six years as proposed in the Agreement. Based on the size of rate increases proposed in the application, the Board agrees that it is reasonable to amortize these expenditures over a longer period than the three years proposed in the Application. The Board approves the amortization of DSM expenditures for 2008 and 2009 in the amount of $12.9 million over six years starting in 2009.

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[10] Exhibit –69, para. 11

[11] Exhibit N-72

9.0 NSPI EARNINGS

[108] Included in the List of Issues was "NSPI's 2008 earnings (including Q1)".

[109] The NSPI panel was asked about NSPI's 2008 earnings to date:

A. (Blunden) Yes, so at an average rate base and of course with the equity thickness range and the ROE, it generally ranges from, for regulated purposes, somewheres around 100 [million dollars] to maybe 107, 108, or something like that, I think.

Q. And Q1 earnings were 57.9?

A. (Blunden) I believe that's correct, yes.

Q. And Q2 earnings were 30 some odd?

A. (Blunden) That's about right, yes.

Q. And about that and despite the range, you still think you're going to hit the rate of return?

A. (Blunden) Yes. As indicated by Mr. Bennett, we're expecting our fuel costs over the balance of the year to be 40 to $50,000,000 higher than they were in the same period of last year. So although optimistic, between the higher fuel prices and of course with the settlement agreement in place, the catch earnings we're expecting to be in the range from this, from where we sit today.

[Transcript, September 18, 2008, p.104]

[110] For purposes of the 2008 fiscal year, as a result of the settlement agreement in the 2007 rate proceeding, voluntarily entered into by NSPI, earnings in excess of 9.8% will be applied to reduce two deferral accounts previously approved by the Board, and will not go to NSPI's shareholders. The first is a gas deferral in the amount of $8 million and the other a deferral of tax payable by NSPI with a balance of approximately $120 million.

[111] In the final submission on behalf of the NDP Caucus, the Board was asked to include in the final Order specific direction as to how excess profits, if any, in 2009 will be applied. Mr. Steele, on behalf of the NDP Caucus, went on to say:

> ...This will go a long way to reassure the public that at the same time they are paying significantly more that the company is not earning excess profits.
>
> [Transcript, September 18, 2008, p. 143]

[112] Under the *Act*, the Board is required to provide NSPI with the opportunity to earn a "reasonable rate of return on rate base". One of the key components of return on rate base is return on common equity. Pursuant to the Agreement, the allowed return on equity is between 9.1% and 9.6%, with rates being set at 9.35%.

[113] The Board's remedy, if NSPI is likely to over earn, is to step in and lower rates. The Board does not direct the application of excess earnings nor does it allow NSPI to retroactively collect from customers if it fails to earn its allowed rate of return. The implementation of a FAM will reduce the possibility of over earning as fuel is the largest of NSPI's costs that may vary significantly from forecast. Under the Fuel Adjustment Mechanism, any over earning related to fuel will be adjusted the following year.

[114] Nevertheless, the Board recognizes the fact that NSPI had unusually high earnings in Q1 and Q2 of 2008 at the same time it was seeking a 12.1% increase in rates, causing great consternation with the public, already very skeptical of NSPI's need for increased revenues.

[115] The Board will closely monitor NSPI's earnings in 2009, mindful of its power to step in and remedy an over earning situation by a reduction in rates.

10.0 FUEL ADJUSTMENT MECHANISM

10.1 Introduction

[116] In its rate application, NSPI requested implementation of a Fuel Adjustment Mechanism (FAM), effective January 1, 2009.

[117] In a decision dated December 10, 2007[12], the Board determined that the approval of a FAM is in the public interest, provided NSPI satisfies certain conditions prior to the implementation of the FAM. The preconditions imposed on NSPI by the Board included the filing of templates for monthly and annual information reports, the filing of a standard methodology for fuel forecasts and the filing of the FAM tariff documents. The Board directed NSPI to engage in a stakeholder process leading to its implementation, with a potential start date of January 1, 2009.

10.2 Submissions - NSPI

[118] NSPI submits that it has concluded its preparatory work in collaboration with its stakeholders and that it has reached the point where it is appropriate to implement the FAM, effective January 1, 2009. It submits that reporting, forecasting methodology and auditing requirements have been developed to allow the FAM to function properly.

[119] In its application, NSPI stated that it is appropriate to implement the FAM in the context of this general rate application:

> Under the FAM Framework, NSPI may reset base fuel costs through a General Rate Application (GRA) or every two years under a FAM. NSPI has forecast fuel costs for 2009 and has included increased fuel costs in this Application for 2009 rates. Through this General Rate Application, the Board would establish the initial Base Cost of Fuel for the FAM, and

[12] 2007 NSUARB 174

> incorporate the agreed reduction in Return on Equity effective with the implementation of the FAM.
>
> [NSPI Application, Exhibit N-1, p. 75]

[120] In its Reply Evidence, NSPI quoted comments contained in a letter dated June 23, 2008, from counsel for the Nova Scotia Department of Energy ("NSDOE") as indicative of the satisfaction of stakeholders with the consultative process undertaken for the development of the FAM:

> NSDOE has been a party to these discussions and, to date, is generally satisfied with the level of discourse and cooperation between NSPI, consultants, and stakeholders in the development of the FAM Plan of Administration, and the degree to which the principles of transparency and disclosure have been adhered to in relation to the administration of the fuel procurement policy and the proposed Plan of Administration for the FAM. The stakeholder process has facilitated settlement between NSPI, Board consultants, and stakeholders on key points in the POA [Plan of Administration].
>
> [NSPI Reply Evidence, Exhibit N-66, p. 9]

[121] Further, in his Opening Statement at the hearing[13], Mr. Bennett noted that the parties to the Agreement concur with the implementation of the FAM on January 1, 2009.

10.3 Submissions - Formal Intervenors

[122] The formal intervenors made no submissions at the hearing with respect to the implementation of the FAM. The Board observes that all signatories to the Agreement have agreed that the FAM should commence as of January 1, 2009.

[13] Exhibit N-73

10.4 Submissions - Board Consultants

[123] Both Dr. Stutz and Mr. Antonuk indicated in their testimony at the hearing that they are satisfied the FAM is ready to be implemented.

[124] Dr. Stutz concluded in his Statement:

> Sections 1 to 8 of the Agreement deal with the Fuel Adjustment Mechanism (FAM). I agree that the FAM is substantially complete. The arrangements to finalize it provided in the Agreement are reasonable and appropriate. I know of no "unsettled issue" likely to prevent the FAM from coming into operation on January 1, 2009.
>
> [Stutz Statement, Exhibit N-75]

[125] In his testimony, Mr. Antonuk of Liberty indicated that it is appropriate to implement the FAM at this point and that three remaining issues can be resolved prior to its implementation:

> Yes. We believe that that is appropriate and it's difficult to see the settlement operating without the adoption of a FAM based on the way it's structured, and I think its structure clearly contemplates that. For our part, we're optimistic that while there remain issues to be resolved with respect to the FAM that those can and should, and I hope will, be resolved by the parties amicably. In the event they're not, I think they're the kinds of issues that are clearly amenable to prompt and effective resolution by the Board in any event. And those issues are three. One is the use of the API-4 index for performing the forecast of solid fuels. We're in agreement with the NSPI proposal to use that forecast but want that forecast use to be revisited in approximately a year. I believe we actually have agreement on that at the present time but it's not yet committed to writing. The second issue is that we are still working on language that addresses the degree to which there will or won't be consultation by the fuel auditor prior to the commencement of the fuel audits called for by the FAM, and the third is the method to be used for estimating import power sales, and on those latter two discussions -- or issues, discussions have been active among the FAM collaborative participants and I expect those discussions to continue and hopefully to be resolved in the immediate future.
>
> [Transcript, September 18, 2008, pp. 130-131]

10.5 Findings

[126] The implementation of the FAM received full support from the signatories to the Agreement, effective January 1, 2009. In clause 3 of the Agreement, the parties undertake to finalize the FAM documentation and NSPI agrees to file, for Board approval,

a final Tariff and Plan of Administration no later than October 15, 2008. Those documents have been filed and are under review by the Board. The Base Cost of Fuel is proposed to be set at $545 million in 2009 rates.

[127] Further, the Board observes that implementation of the FAM was not opposed by the formal intervenors who did not sign the Agreement.

[128] In their testimony at the hearing, Dr. Stutz and Mr. Antonuk, the Board's consultants, agreed that it was appropriate to implement the FAM at this point. While a few points remain outstanding, they are confident that any such items can be resolved prior to the proposed implementation date.

[129] In this regard, the Board observes that the development of the FAM has followed an extensive collaborative process between NSPI and its stakeholders. The Board's consultants were also involved throughout the entire process. All parties involved in this consultative exercise expressed their general satisfaction with the preliminary Plan of Administration filed with the Board in June 2008.

[130] In its Rate Decision dated February 5, 2007, and in its Decision dated December 10, 2007 giving conditional approval to the FAM, the Board identified at least four prerequisites prior to the implementation of a FAM:

> ...
>
> 1. an adequate and appropriate fuel procurement policy at NSPI in which the Board has confidence;
>
> 2. timely disclosure of complete and adequate information by NSPI so as to ensure confidence that the procurement policy is being appropriately administered;
>
> 3. disclosure and transparency with respect to the administration of the FAM;
>
> 4. a meaningful audit process under the administration of the Board.
>
> [Board Decision, P-887, December 10, 2007, para. 45]

[131] Based upon its review of the evidence and the submissions of the parties, the Board is satisfied that these prerequisites have been fulfilled. The consultative process has also addressed other issues.

[132] The Board is mindful of the concerns of NSPI's customers with respect to the implementation of a FAM. While some may contend that a FAM could result in reduced transparency and less oversight, the reality is quite the opposite. Any future adjustments to the Base Cost of Fuel will occur in an even more transparent manner than is presently the case. Under the FAM, the fuel forecasting process will be subjected to more periodic review by the Board and intervenors.

[133] The Board refers to its previous comments on these points:

> [76] The Board views a FAM as a tool which can actually provide a closer and more timely oversight of NSPI's fuel costs than is presently the case. As noted elsewhere in this decision, under a FAM, assessments as to the reasonableness of fuel expenses and NSPI's performance in obtaining fuel at the lowest price reasonably possible, will be carried out by the Board, as well as Intervenors, on an ongoing and more frequent basis than in the past. In the last ten years, this form of fuel costs examination has occurred four times—always in conjunction with general rate applications. Under a FAM, fuel costs will be determined on an annual basis, following the reporting, analysis and stakeholder involvement in the FAM process throughout the preceding year, which forms the basis for any adjustment.
>
> [77] Customers should also understand that, under a FAM, the rate they pay to NSPI will not go up and down every time the cost of fuel fluctuates. In other words, a FAM will not operate in the same manner as they experience at the gas pumps, where prices can change every week.
>
> [78] Even under the proposed January 1, 2009 implementation date of the FAM, the earliest time a fuel adjustment change to rates could possibly occur would be January 1, 2010. Also, it could only occur then if the previous year's fuel costs passed all the reporting, auditing, and review tests designed to ensure that the cost to be passed on to ratepayers is as low as reasonably possible—a result which, in the Board's opinion, improves its ability to protect the public interest.
>
> [Board Decision, P-887, December 10, 2007, paras. 76-78]

[134] The Board also observes that the implementation of the FAM is accompanied by a 0.2% reduction in the return on equity that can be earned by NSPI (i.e., the target

ROE will decrease from 9.55% to 9.35%). The lower return on equity results in a reduced revenue requirement to be recovered in customers' rates.

[135] Finally, there is a further benefit of a FAM for customers. The implementation of the FAM will allow NSPI to recover its prudently incurred fuel costs. This, in turn, will lower NSPI's business risk profile and foster the improved financial health of the utility over the long term, which could possibly lead to an improved outlook from bond-rating agencies and cause them to upgrade their rating for NSPI. Ultimately, this could benefit ratepayers by reducing NSPI's debt and interest charges, possibly lessening the pressure for rate increases in the future. An improved rating could also positively impact NSPI's ability to procure fuel commodities and to access capital markets for upcoming infrastructure projects.

[136] Taking into account all of the foregoing, the Board approves the FAM, on the basis of the provisions contained in the Agreement. The FAM shall take effect on January 1, 2009, conditional on the final approval of the Tariff and Plan of Administration.

11.0 WRITTEN AND ORAL SUBMISSIONS FROM THE PUBLIC

[137] In the advertised Notice of Public Hearing concerning NSPI’s rate application, the public was advised that they could file submissions with the Board outlining their views regarding NSPI’s application. In response to this notification, the Board received thirty-one written submissions from the public, plus six individuals made presentations at the evening session on September 17, 2008.

[138] Many of the written submissions expressed concerns relating to the adverse impact of another rate increase (the fifth in seven years) on customers, particularly those on fixed or low incomes. Some of the submissions questioned the validity of NSPI's forecasted fuel costs, while others focused on the high level of executive compensation, the strong first quarter earnings, power outages related to tree contacts, and the need for alternative or renewable energy sources.

[139] During the evening session, some of these same concerns were also raised. Presentations were made by two individuals on their own behalf, by a representative from each of the three main political parties in the province, and by a representative from the Canadian Federation of Independent Business ("CFIB"). Some of their comments are noted below.

[140] The Honourable Murray Scott, MLA, urged the Board to seriously consider the impact of the high increase being requested by NSPI and to consider how it will affect seniors, hardworking families, and businesses.

[141] Linda Power, representing the Nova Scotia New Democratic Party, presented a petition containing over 8,700 signatures, which asked the "Government of Nova Scotia to cancel the 8 percent tax on basic electricity and [calling] on the Utility and Review Board to approve no more electricity rate increases until Nova Scotia Power and the government are required to help individuals and families save money on their electricity bill." Ms. Power also stated that NSPI profits "should not be used for investments made by Emera outside the jurisdiction of this Board", and urged the Board to "highlight in [its] decision where

government and the utility can do more to enable Nova Scotians to save their family budget by significantly reducing their use of electricity".

[142] The Honourable Stephen McNeil, MLA, Leader of the Nova Scotia Liberal Party, emphasized the need for a long term plan from NSPI or the government on how to move away from the current dependency on fossil fuels with high, volatile prices. He also noted that expanding the use of renewable energy sources will require "an enhanced focus and investment on transmission infrastructure".

[143] Leanne Hachey, representing the CFIB and its 5,200 members in Nova Scotia, addressed three main points:

i) the inequity of cost allocation between customer classes as noted by the large difference in the Revenue to Cost (R/C) ratios between rate classes;

ii) the need to appoint a Small Business Advocate (“SBA”) who is separate from the Consumer Advocate;

iii) the need to change existing legislation to ensure that the SBA representation is based on electricity usage (i.e. rate class 10 & 11), not on the number of employees within a small business.

[144] Ms. Hachey also emphasized the great value that was realized by having small business represented by an Advocate during this application, but noted that a separate SBA will be needed in the future.

[145] The Board takes the views of the public as expressed in these submissions, as well as its responsibility to protect the public interest, very seriously and has reviewed all of the material which was filed.

[146] With respect to some of the public's concerns noted above, enhanced vegetation management is being facilitated through an increased funding allocation by NSPI; increased utilization of renewable energy sources is being addressed through the IRP process and NSPI's compliance with the Province's Renewable Energy Standard; and potential savings in electricity usage by ratepayers are being addressed through various DSM initiatives which were the subject of a separate hearing held earlier this year in April 2008.

[147] Regarding the issue of a SBA, the Board recognizes the need for an advocate that is separate from the consumer (residential) group and will, in future proceedings, appoint a separate SBA. The Board appreciates Mr. Merrick's work in balancing the two assignments in this proceeding. Mr. Merrick will continue his role as the Consumer Advocate.

[148] With respect to the public's objections to any form of rate increase, while no one wants to see increases in rates for electricity, circumstances can occur which justify an increase in rates. In this specific rate application, significant escalation in the cost of fuel used for generating electricity has been identified as a primary factor in the proposed rate increases. Similar cost escalations have also been experienced by the general public in the form of fuel for home heating, fuel for transportation, and the overall cost of goods

and services that have been impacted by higher fuel costs. For the reasons outlined in this decision, the Board has concluded that the rate increases which result from the Agreement are reasonable and justified.

[149] The Board wishes to convey its appreciation for the time, effort and interest shown by those individuals who have expressed their views to the Board during this hearing.

12.0 COMPLIANCE FILINGS

[150] NSPI is directed to file a compliance filing no later than November 19, 2008.

[151] The formal intervenors must provide comments, if any, no later than November 26, 2008.

[152] An Order will issue accordingly.

DATED at Halifax, Nova Scotia, this 5th day of November, 2008.

____

Peter W. Gurnham

____

Roland A. Deveau

____

Kulvinder S. Dhillon

APPENDIX - A
FORMAL INTERVENORS

Affordable Energy Coalition	Claire McNeil and Susan Nasser
Avon Valley et al. (Avon Valley Greenhouses Ltd.) (Canadian Salt Company Limited) (CKF Inc.) (Crown Fibre Tube Inc.) (Halifax Grain Elevator Limited) (High Liner Foods Incorporated) (Imperial Oil Limited) (Intertape Polymer Inc.) (J. D. Irving Ltd., Saw Mills Division) (Lafarge Canada Inc.) (Louisiana Pacific Canada Ltd.) (Maritime Paper Products Ltd.) (Michelin North America (Canada) Inc.) (Minas Basin Pulp & Power Company Ltd.) (Oxford Frozen Foods Limited) (Sifto Canada Corp.) (Statia Terminals Canada [A Valero LP Company])	Robert G. Grant, Q.C., Nancy G. Rubin and Mark Freeman
Canadian Manufacturers & Exporters	Ann E. Janega, Robert Patzelt, Q.C. and Kristin Harris
Consumer Advocate	John Merrick, Q.C., and William Mahody
Ecology Action Centre	Cheryl Ratchford and Janice Ashworth
Halifax Regional Municipality	Mary Ellen Donovan, Martin C. Ward, Q.C., Julian Boyle and Angus Doyle
Liberal Caucus Office (Nova Scotia)	Michel Samson and Ryan Grant
Municipal Electric Utilities Co-operative of Nova Scotia	Don Regan
New Democratic Party Caucus Office (NDP)	Frank Corbett, MLA and Richard D. Starr

NewPage Port Hawkesbury Limited and **Bowater Mersey Paper Company Limited**	George T. H. Cooper, Q.C., David S. MacDougall and James MacDuff
Province of Nova Scotia - Department of Energy	Stephen T. McGrath, Scott McCoombs and Richard Penny
Sierra Club of Canada	Bruno Marcocchio
Town of Lunenburg	Bea Renton
Quetta Inc.	John L. Reynolds, P. Eng.

APPENDIX - B

APPEARANCES AT THE PUBLIC HEARING - EVENING SESSION

Name	**On Behalf Of**
Charlotte MacKeeman	On her own behalf
The Honourable Murray Scott	The people of Cumberland South Constituency
Linda Power	NDP Caucus
The Honourable Stephen McNeil	As Leader of the Nova Scotia Liberal Party and as MLA for Annapolis
Leanne Hachey	Canadian Federation of Independent Business
Janice Ashworth	On her own behalf

Newfoundland
& Labrador

BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

IN THE MATTER OF THE

2003 GENERAL RATE APPLICATION

FILED BY

NEWFOUNDLAND POWER INC.

DECISION AND ORDER

OF THE BOARD

ORDER No. P.U. 19 (2003)

BEFORE:

Mr. Robert Noseworthy
Chair and Chief Executive Officer

Ms. Darlene Whalen, P.Eng.
Vice-Chair

Mr. John William Finn, Q.C.
Commissioner

VII. RATE BASE

1. Average Rate Base and Return on Rate Base

NP's average rate base comprises investment in plant and equipment less accumulated depreciation to which is added an amount owed to NP by its customers in the Weather Normalization Reserve and allowances for inventory and cash working capital and from which is deducted amounts for Contribution in Aid of Construction ("CIAC"). The return on rate base comprises the cost of debt, rate of return on preferred equity and rate of return on regulated common equity.

The average rate base, return on rate base and rate of return on rate base is calculated on pg. 8 of Exhibit BVP-1 (1st Revision) for 1998 through to 2002 and forecast for 2003 and 2004. A summary of the relevant rate base figures presented by NP is as follows:

Financial Results and Forecasts Rate of Return on Rate Base (000's)							
	Historical Data					Proposed	
	1998	1999	2000	2001	2002	2003	2004
Return on Regulated Common Equity	$ 22,299	$ 23,639	$ 27,237	$ 29,699	$ 29,518	$ 31,822	$ 33,429
Return on Preferred Equity	626	626	626	623	613	613	613
Finance Charges	25,233	26,488	26,641	26,700	26,853	30,774	31,626
Return on Rate Base	48,158	50,753	54,494[1]	57,024[1]	56,984	63,209	65,668
Average Rate Base	488,204	505,688	520,979	545,162	573,337	599,245	622,650
Rate of Return on Rate Base	9.86%	10.04%	10.46%	10.46%	9.94%	10.55%	10.55%

[1] Subject to rounding

NP's proposed rate of return on average rate base for 2003 and 2004 is 10.55% arrived at by dividing a forecast return on rate base of $63,209,000 (2003) and $65,668,000 (2004), by an average rate base of $599,245,000 and $622,650,000 respectively.

Grant Thornton conducted a review of the pre-filed evidence comparable to these revised figures and concluded that the results were calculated in accordance with established practice and contained no discrepancies. (Grant Thornton Report – NP 2003 GRA, pgs. 21; 26)

The Board heard no evidence contesting NP's proposed rate base calculations for 2003 and 2004 but notes these specific numbers will change based on other findings of the Board as contained in this Decision.

Specifically, the Board has determined that effective in 2003 the Asset Rate Base method will replace the Invested Capital approach currently used to calculate NP's rate base and as a result deferred charges will now be incorporated in this rate base.

Based on this decision the Board calculates the impact on average rate base for the 2003-2004 test year period as follows:

	2003 (000's)	**2004 (000's)**
Average Rate Base as proposed by NP	$599,245	$622,650
Average deferred charges	$72,970	$80,452
Revised average Rate Base	$672,215	$703,102

The rate of return on rate base proposed by NP for the test year period is 10.55%. The decision to include deferred charges in rate base affects the translation of the weighted average cost of capital into an allowed rate of return on rate base. In moving to the Asset Rate Base method the Board accepts the premise that the change should be neutral in terms of its impact on total allowed return and revenue requirement. The Board calculates the change in revised rate of return on rate base for the test year period based on NP's Application and incorporating the Board's decisions on rate base and ROE as follows:

Applying Formulas Designated A & B:

A. Weighted Average Cost of Capital (WACC) =

% Debt x Embedded Cost of Debt
+ % Preferred Equity x Rate of Return on Preferred Equity
+ % Common Equity x Rate of Return on Regulated Common Equity

B.

Rate of Return On Rate Base (RORB) $= \boxed{\dfrac{\text{Invested Capital}}{\text{Rate Base}} \times \text{WACC}} + \dfrac{Z}{\text{Rate Base}}$

Calculations

2003

A. **WACC** = (54.28% x 8.54%) + (1.45% x 6.31%) + (44.27% x 9.75%)
= 9.04%

B. **RORB** =

$$\boxed{\frac{\$668{,}416}{\$672{,}215} \times 9.04\%} + \frac{(208)}{\$672{,}215}$$

= 8.96%

2004

A. **WACC** = (54.05% x 8.39%) + (1.39% x 6.31%) + (44.55% x 9.75%)
= 8.97%

B. **RORB** =

$$\boxed{\frac{\$700{,}244}{\$703{,}102} \times 8.97\%} + \frac{(150)}{\$703{,}102}$$

= 8.91%

With respect to the calculation of WACC above, the Board has considered the various components which factor into this calculation.

In previous sections of this Decision, the Board has stated its findings with respect to the capital structure and the cost of equity (ROE).

The cost of preferred equity proposed by NP is 6.31%. The calculation of this rate is detailed in Exhibit BVP-14. This rate compares with the 6.33% cost assigned to preferred equity in Order No. P.U. 16(1998-99). The Board did not hear any evidence contesting this rate of return for preferred shares and accepts the 6.31% as the cost of preferred equity as proposed. This rate of return of 6.31% will also be used as the allowed rate of return on any regulated common equity in excess of 45%.

The embedded cost of debt proposed by NP is 8.54% for 2003 and 8.39% for 2004. The calculation of these rates are detailed in Exhibit BVP-12 (1st Revision). The Board has reviewed the evidence relating to embedded cost of debt, including the forecast short-term interest rates, and accepts the embedded cost of debt as proposed for 2003 and 2004 of 8.54% and 8.39% respectively.

NP will be required to file a revised calculation of rate base and return on rate base for test years 2003 and 2004 which reflects the decisions taken by the Board.

2. Range of Rate of Return on Rate Base

In Order No. P.U. 36(1998-99) the Board approved an increase in the range of return on rate base from 24 basis points to 36 basis points, stating at pg. 70:

> *"The introduction of an expanded range of 36 basis points will provide an incentive for the company to improve productivity and will allow for some variation in financial variables other than those adjusted by the formula."*

In this Application NP has proposed an increase in the range of return on rate base from 36 basis points to 50 basis points. According to NP the small changes in customer rates in 2000 and 2002 suggests that the range of rate of return on rate base used in the Formula is too narrow. The offsetting rate changes would not have occurred with a wider range. NP concludes that a wide range of rate of return on rate base will potentially result in greater rate stability and predictability for both NP and its customers. [Pre-filed Evidence, B. V. Perry, (1st Revision), pg. 50]

NP's cost of capital expert witnesses also supported the expansion of the range, stating that it will promote efficiency and result in less frequent rate changes. (Written Submissions, NP, Section B, pg. 11/9-12)

The Consumer Advocate does not support expanding the range to 50 basis points, stating that *"There is no verifiable evidence to show that the increased range from twenty-four basis points to thirty-six basis points provided a corresponding improvement in efficiency…."* (Final Submission, Consumer Advocate, pg. 30):

The Consumer Advocate argued that the only beneficiary was NP which benefited from additional revenue in 2000 and 2001 as a result of an expanded range of rate of return on rate base. If the range had been maintained at 24 basis points the Consumer Advocate submitted NP would have over earned in those years, and that this additional revenue would have gone into the Excess Revenue Account. (Final Submission, Consumer Advocate, pgs. 30-31)

In assessing this proposal Grant Thornton provided the following caution to the Board (Supplementary Evidence, Grant Thornton Report, pg. 7/15-18):

> *"In assessing the Company's proposal to expand the range of allowed return the Board should consider the issue in the context of the determination of the overall cost of capital. All of the factors related to rates of return and cost of capital are interrelated and none, including the range of allowed return, should be assessed in isolation."*

Grant Thornton also suggested the Board consider three additional factors in assessing the appropriateness of an expanded range of rate of return on rate base:

i) an expanded range will potentially decrease the number of rate changes and result in greater rate stability and predictability;
ii) expanding the range results in a higher upper limit for the allowed return on rate base; and

iii) the range of rate of return can provide an incentive for NP to improve productivity and generate operating efficiencies resulting in lower costs which would be passed on to ratepayers in a subsequent rate hearing.

The proposed change in the range of rate of return on rate base does not affect the determination of NP's overall revenue requirement for the test year period since the allowed return on rate base is the mid-point of the allowed range. The proposed change would result in a higher upper limit for the allowed return and for the purposes of defining the Excess Revenue Account.

In Exhibit BVP-20 (1st Revision) NP demonstrates that the proposed 50 basis point range of return on rate base is based on a 100 basis point range for rate of return on regulated common equity. In Supplementary Evidence (pg. 7/12-13), Grant Thornton stated that the current 36 basis point range for return on rate base has an implied 73 basis point range of return on regulated common equity for 2003. The Board notes that with the inclusion of deferred charges in rate base, this implied range of return on regulated common equity increases from 73 to 81 basis points. This change is not considered significant enough to warrant a change in the range of rate of return.

In the Board's view the range of rate of return on rate base can act as an incentive device to encourage NP to seek efficiencies between rate hearings, which can then be passed on to customers. This is evidenced in the operational efficiencies and cost savings that have been implemented by NP since the last rate hearing in 1998. The Board does not agree with the Consumer Advocate that only NP has benefited from the expanded range set by the Board in 1998. Ratepayers will derive the benefit for the efficiencies through lower costs, and hence lower rates into the future. The Board believes it is important to maintain the range as an incentive for NP to continue to seek efficiencies and productivity improvements in its operations.

The Board is not convinced however that a further expansion in the range from 36 basis points to 50 basis points, as proposed by NP, is warranted or necessary at this time. In the Board's view, while there are opportunities for future operating efficiencies, the Board feels that the existing range of 36 basis points has served both NP and ratepayers well over the period of operation of the Formula and should be maintained.

The Board will approve a range of 36 basis points for the rate of return on rate base for test years 2003 and 2004 and for use with the Formula, unless otherwise ordered by the Board.

Q. Please provide the actual return on equity and the allowed ROE for each year since 1990 and discuss any deviations of the actual from allowed outside of the band set by the board. Please discuss any material deviations and whether such causes are now covered by deferral accounts.

A. Newfoundland Power is regulated on return on rate base. In determining the Company's allowed return on rate base, the Board approves a ratemaking return on equity ("ROE").[1]

Newfoundland Power has an Excess Earnings Account which is credited with any earnings in excess of the upper limit of the allowed return on rate base as approved by the Board.[2] The sole purpose of the Excess Earnings Account is to protect customer interests by ensuring that Newfoundland Power's earned returns do not materially exceed those approved by the Board for ratemaking purposes. This limits the Company's return on equity to approximately 40-50 basis points above the approved return for ratemaking purposes.

Table 1 shows Newfoundland Power's actual ROE and approved ROE for the years 1990 through 2017.

Table 1
Actual ROE and Approved ROE
1990-2017

Year	Approved ROE	Actual ROE
1990	13.95%	13.71%
1991	13.95%	13.29%
1992	13.25%	13.47%
1993	13.25%	12.79%
1994[3]	13.25%	12.03%
1995[4]	13.25%	12.07%
1996	11.00%	11.21%

[1] In Order No. P.U. 19 (2003), the Board ordered, in effect, that Newfoundland Power file a report explaining the circumstances and facts contributing to any difference between an actual rate of ROE that was greater than 50 basis points (0.50%) above the cost of equity as determined by the Formula.

[2] The upper limit on the allowed rate of return on rate base, as established by the Board in Order No. P.U. 19 (2003), is 18 basis points above that used for ratemaking purposes.

[3] In 1994 Newfoundland Power's actual return on equity was 1.2% percent less than the approved return. This was related to a severe sleet storm in 1994.

[4] In 1995, Newfoundland Power's actual return on equity was 1.2% below the ratemaking return due primarily to a 1995 Early Retirement Program and costs related to an income tax reassessment.

Table 1
Actual ROE and Approved ROE
1990-2017
(Cont'd)

1997	11.00%	11.14%
1998	9.25%	9.58%
1999	9.25%	9.81%
2000[5]	9.59%	10.80%
2001[5]	9.59%	11.35%
2002[5]	9.05%	10.65%
2003	9.75%	10.22%
2004	9.75%	10.12%
2005	9.24%	9.60%
2006	9.24%	9.46%
2007	8.60%	8.66%
2008	8.95%	9.13%
2009	8.95%	8.96%
2010	9.00%	9.21%
2011	8.38%	9.00%
2012	8.80%	8.98%
2013	8.80%	9.16%
2014	8.80%	9.15%
2015	8.80%	8.98%
2016	8.50%	8.90%
2017	8.50%	8.93%

[5] In 2000, 2001 and 2002, Newfoundland Power's actual return on equity was 1.2%, 1.8% and 1.6%, respectively, over the approved returns. The variances in regulated returns for 2000 through 2002 were primarily attributable to the successful conclusion of a tax reassessment audit by the Canada Revenue Agency.

P.U. 37 (2000-2001)

IN THE MATTER OF the
PUBLIC UTILITIES ACT,
R.S.N. 1990, c. P-47, as amended
("the Act")

AND

IN THE MATTER OF the application by
Newfoundland Power Inc. ("the Applicant")
for an Order, pursuant to Sections 58 and
80 and all other enabling powers of the
Act and Orders of the Board, approving
the disposition of revenue credited to
the Applicant's excess revenue account
through a rebate to customers.

WHEREAS the Applicant is a corporation duly organized and existing under the laws of the Province of Newfoundland and Labrador, is a public utility within the meaning of the Act, and is also subject to the provisions of the *Electrical Power Control Act, 1994 (EPCA);* and

WHEREAS pursuant to Section 80 of the Act and by Order No. P. U. 20 (1999-2000) the Board approved an allowed return on rate base for the Applicant for 2000 of 10.28 per cent within a range of 10.10 per cent to 10.46 per cent; and

WHEREAS the Applicant's System of Accounts as prescribed by the Board pursuant to Section 58 of the Act includes an Excess Revenue Account and by Order No. P. U. 25 (1999-2000), the Board approved a definition of the Excess Revenue Account which provides that the Excess Revenue Account shall be credited with any revenue in excess of the upper limit of the Applicant's allowed range of return on rate base as determined by the Board and that, for 2000 and subsequent years, all earnings in excess of 10.46 per cent rate of return on rate base shall, unless otherwise ordered by the Board, be credited to the Excess Revenue Account; and

WHEREAS the Applicant's financial results for 2000 without adjustment yields a return on rate base for 2000 in excess of 10.46 per cent; and

WHEREAS the amount of revenue the Applicant has credited to the Excess Revenue Account, as at December 31, 2000 is $6,733,000 (the "Excess Revenue"); and

WHEREAS by definition, and pursuant to Order No. P. U. 25 (1999-2000), the Excess Revenue shall be disposed of in a manner determined by the Board; and

WHEREAS the Board received an application on February 8, 2001, wherein the Applicant proposes that the Excess Revenue be disposed of through a rebate to its customers of 1.90% of customers' total billing amounts, inclusive of Harmonized Sales Tax (HST), on electric service bills issued during the period January 2000 to December 2000 by means of a one-time credit on customers' April 2001 electric service bills; and

WHEREAS the total proposed amount to be rebated to customers is $7,743,000 consisting of the Excess Revenue of $6,733,000 and HST of $1,010,000; and

WHEREAS the Board retained its financial consultant, Bill Brushett, C.A., Partner, Grant Thornton, to review the Application and supporting documentation and provide a report on the accuracy and appropriateness of the following items:

i) Calculation of the return on rate base;

ii) The determination of the amount of the excess revenue; and

iii) The methodology used to calculate the rebate to customers;

and

WHEREAS the report produced by Grant Thornton was filed on March 9th, 2001, as Exhibit “A” to the Affidavit of William Brushett, C.A.; and

WHEREAS the Grant Thornton report confirmed the accuracy and the calculations of the return on rate base and the Excess Revenue and also found that the methodology used to calculate the rebate to customers was reasonable; and

WHEREAS, after public notice, the Board conducted a public hearing on March 12, 2001 to consider the application in its Hearings Room in St. John’s; and

WHEREAS Ian F. Kelly, Q.C., and Peter Alteen were present as Counsel for the Applicant; and

WHEREAS Randall Pelletier was present as Counsel to the Board; and

WHEREAS evidence in support of the application was presented by Barry Perry, Vice-President, Finance and Chief Financial Officer of the Applicant; and

WHEREAS the proposed disposition of the Excess Revenue is consistent with generally accepted sound public utility practice and reflects an appropriate balance between the interests of the Applicant and its customers that is in accordance with the Act, the EPCA, and Orders of the Board made pursuant thereto.

IT IS THEREFORE ORDERED THAT:

1. The balance in the Applicant’s Excess Revenue Account, as at December 31, 2000, of $6,733,000 be rebated to customers, together with HST of $1,010,000, through a one-time credit to each of its customers on their April 2001 electric service bills of 1.90% of the

customer's total billing amounts on electric service bills issued during the period January 2000 to December 2000.

2. The Applicant file with the Board on or before June 30, 2001 a report showing the actual disposition by rate class of the Excess Revenue Account and any amounts not distributed.

3. The Applicant file with the Board at least three days in advance of the first April billing in which the rebate will be credited, a copy of any billing insert or other information**,** as well as copies of any other public communiqué or press release to be distributed in connection with this matter.

4. The Applicant shall pay the expenses of the Board arising out of this application.

DATED at St. John's, Newfoundland this 15th day of March, 2001.

____
Robert Noseworthy, P.Eng.,
Chair& Chief Executive Officer.

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Darlene Whalen, P.Eng.,
Vice-Chairperson.

____
Don R. Powell, C.A.,
Commissioner.

____
G. Cheryl Blundon,
Board Secretary.

Orders / Home

IMPACT OF IMMEDIATELY ELIMINATING SECOND BLOCK RATE AND USING INCREMENTAL REVENUE TO REDUCE RESIDENTIAL ENERGY CHARGE PER kWh

	A	B	C	D = C / B	E	F	G = C + D + E	H = G / B	I = H / A
	From 2017 Cost Allocation Study				Change in class revenue for Immediate Removal of Second Block ($ x 1,000)*	Allocation of Additional 2nd Block Revenue to reduce Residential per kWh rate ($ x 1,000)	Revised Base revenue ($ x 1,000)	Revised Revenue to Cost Ratio (%)	Change in average $ / kWh Energy Residential Rate ($ / kWh)
	Energy sales (MWh)	Net revenue requirement ($ x 1,000)	Base revenue ($ x 1,000)	Revenue to Cost ratio (%)					
Residential	577,014	104,690	95,037	91	2,039	(2,039)	95,037	91	$ (0.0035)
General Service	384,918	49,445	59,917	121			59,917	121	-
Small Industrial	88,162	11,402	11,675	102			11,675	102	-
Large Industrial	150,029	14,115	13,205	94			13,205	94	-
Street Lighting	5,519	2,559	2,330	91			2,330	91	-
Unmetered	2,416	391	407	104			407	104	-
	1,208,058	182,602	182,571	100	2,039	(2,039)	182,571	100	

* Second block kWh sales were 69,123 MWh in 2017. * First block/second block differential (March 1, 2018) is $0.1437 - $0.1142 = $0.0295.
69,123,000 kWh x $0.0295/kWh = $2,039,000

IMPACT OF IMMEDIATELY ELIMINATING SECOND BLOCK RATE AND USING INCREMENTAL REVENUE TO REDUCE GENERAL SERVICE RATES

	A	B	C	D = C / B	E	F	G = C + D + E	H = G / B	I = 100 * F / C
	From 2017 Cost Allocation Study				Change in class revenue for Immediate Removal of Second Block ($ x 1,000)*	Allocation of Additional 2nd Block Revenue to General Service ($ x 1,000)	Revised Base revenue ($ x 1,000)	Revised Revenue to Cost Ratio (%)	Overall change in GS rates to eliminate 2nd Block Immediately (%)
	Energy sales (MWh)	Net revenue requirement ($ x 1,000)	Base revenue ($ x 1,000)	Revenue to Cost ratio (%)					
Residential	577,014	104,690	95,037	91	2,039	-	97,076	93	-
General Service	384,918	49,445	59,917	121		(2,039)	57,878	117	(3.4)
Small Industrial	88,162	11,402	11,675	102		-	11,675	102	-
Large Industrial	150,029	14,115	13,205	94		-	13,205	94	-
Street Lighting	5,519	2,559	2,330	91		-	2,330	91	-
Unmetered	2,416	391	407	104		-	407	104	-
	1,208,058	182,602	182,571	100	2,039	(2,039)	182,571	100	

* Increase second block kWh sales would be 69,123 MWh in 2017 * increase in second block rate (March 1, 2018) of $0.0295 = $2,039 incremental revenue.

COMMISSION STAFF IR-48
RATES NEEDED TO BRING REVENUE TO COST RATIOS TO 100%

	A	B	C	D	E	F	G	H	I
				C / B	B - C	(C + E) / B	E / A		H * G
	From 2017 Cost Allocation Study								
	Energy sales (MWh)	Net revenue requirement ($ x 1,000)	Base revenue ($ x 1,000)	Revenue to Cost ratio (%)	Change in class revenue for R/C equal to to 100 % ($ x 1,000)	Resulting Revenue to Cost ratio (%)	Change in average $ / kWh for R/C equal to 100% ($ / kWh)	2019 forecast energy sales (MWh)	Resulting 2019 change in revenue ($ x 1,000)
Residential	505,169	91,806	83,860	91	7,946	100	0.0167	620,700	10,384
Residential Seasonal	19,523	4,512	4,309	96	203	100			
Residential Farms	52,322	8,372	6,868	82	1,504	100			
General Service	375,639	47,880	58,151	121	(10,271)	100	(0.0272)	389,700	(10,602)
General Seasonal	9,279	1,565	1,766	113	(201)	100			
Small Industrial	88,162	11,402	11,675	102	(273)	100	(0.0031)	94,400	(292)
Large Industrial	150,029	14,115	13,205	94	910	100	0.0061	154,700	938
Street Lighting	5,519	2,559	2,330	91	229	100	0.0415	5,000	207
Unmetered	2,416	391	407	104	(16)	100	(0.0066)	2,500	(17)
	1,208,058	182,602	182,571	100	31			1,267,000	619

Leave March 1, 2019 proposed service charges and demand charges unchanged.
A further step would be required for Street Lighting, based on monthly kWh used by each fixture type and size.

COMMISSION STAFF IR-48
RATES NEEDED TO BRING REVENUE TO COST RATIOS TO 100%

	Change in average $ / kWh for R/C equal to 100% ($ / kWh)	March 1, 2019 energy charges as proposed		March 1, 2019 energy charges for 100% R/C	
		First block ($ / kWh)	Second block ($ / kWh)	First block ($ / kWh)	Second block ($ / kWh)
Residential	0.0167	0.1456	0.1155	0.1623	0.1322
Residential Seasonal					
Residential Farms					
General Service	(0.0272)	0.1793	0.1167	0.1521	0.0895
General Seasonal					
Small Industrial	(0.0031)	0.1756	0.0879	0.1725	0.0848
Large Industrial	0.0061	0.0723		0.0784	
Street Lighting	0.0415				
Unmetered	(0.0066)	0.1757		0.1691	

Leave March 1, 2019 proposed service charges and demand charges unchanged.
A further step would be required for Street Lighting, based on monthly kWh used by each fixture type and size.

COMMISSION STAFF IR-49

RATES NEEDED TO BRING REVENUE TO COST RATIOS TO WITHIN 95% - 105%

	A	B	C	D	E	F	G	H	I	J	K
				C / B			E + F	(C + G) / B	G / A		J * K
	From 2017 Cost Allocation Study				Change in class revenue for R/C to within 95% - 105% ($ x 1,000)	Adjustment to make revenue neutral overall ($ x 1,000)	Adjusted change in class revenue ($ x 1,000)	Resulting Revenue to Cost ratio (%)	Change in average $ / kWh for R/C to within 95% - 105% ($ / kWh)	2019 forecast energy sales (MWh)	Resulting 2019 change in revenue ($ x 1,000)
	Energy sales (MWh)	Net revenue requirement ($ x 1,000)	Base revenue ($ x 1,000)	Revenue to Cost ratio (%)							
Residential	505,169	91,806	83,860	91	3,356	2,461	5,817	98	0.0126	620,700	7,796
Residential Seasonal	19,523	4,512	4,309	96	-	121	121	98			
Residential Farms	52,322	8,372	6,868	82	1,085	224	1,310	98			
General Service	375,639	47,880	58,151	121	(7,877)	-	(7,877)	105	(0.0208)	389,700	(8,099)
General Seasonal	9,279	1,565	1,766	113	(123)	-	(123)	105			
Small Industrial	88,162	11,402	11,675	102	-	-	-	102	-	94,400	-
Large Industrial	150,029	14,115	13,205	94	204	378	583	98	0.0039	154,700	601
Street Lighting	5,519	2,559	2,330	91	101	69	170	98	0.0307	5,000	154
Unmetered	2,416	391	407	104	-	-	-	104	-	2,500	-
	1,208,058	182,602	182,571	100	(3,253)	3,253	(0)			1,267,000	452

Leave March 1, 2019 proposed service charges and demand charges unchanged.

A further step would be required for Street Lighting, based on monthly kWh used by each fixture type and size.

COMMISSION STAFF IR-49

RATES NEEDED TO BRING REVENUE TO COST RATIOS TO WITHIN 95% - 105%

	Change in average $ / kWh for R/C to within 95% - 105% ($ / kWh)	March 1, 2019 energy charges as proposed		March 1, 2019 energy charges for 95% - 105% R/C	
		First block ($ / kWh)	Second block ($ / kWh)	First block ($ / kWh)	Second block ($ / kWh)
Residential	0.0126	0.1456	0.1155	0.1582	0.1281
Residential Seasonal					
Residential Farms					
General Service	(0.0208)	0.1793	0.1167	0.1585	0.0959
General Seasonal					
Small Industrial	-	0.1756	0.0879	0.1756	0.0879
Large Industrial	0.0039	0.0723		0.0762	
Street Lighting	0.0307				
Unmetered	-	0.1757		0.1757	

Leave March 1, 2019 proposed service charges and demand charges unchanged.
A further step would be required for Street Lighting, based on monthly kWh used by each fixture type and size.

COMMISSION STAFF IR-50

RATES NEEDED TO BRING REVENUE TO COST RATIOS TO WITHIN 90% - 110%

	A	B	C	D	E	F	G	H	I	J	K
				C / B			E + F	(C + G) / B	G / A		J * K
	From 2017 Cost Allocation Study										
	Energy sales (MWh)	Net revenue requirement ($ x 1,000)	Base revenue ($ x 1,000)	Revenue to Cost ratio (%)	Change in class revenue for R/C to within 90% - 110% ($ x 1,000)	Adjustment to make revenue neutral overall ($ x 1,000)	Adjusted change in class revenue ($ x 1,000)	Resulting Revenue to Cost ratio (%)	Change in average $ / kWh for R/C to within 90% - 110% ($ / kWh)	2019 forecast energy sales (MWh)	Resulting 2019 change in revenue ($ x 1,000)
Residential	505,169	91,806	83,860	91	-	3,677	3,677	95	0.0084	620,700	5,228
Residential Seasonal	19,523	4,512	4,309	96	-	181	181	100			
Residential Farms	52,322	8,372	6,868	82	667	335	1,002	94			
General Service	375,639	47,880	58,151	121	(5,483)	-	(5,483)	110	(0.0144)	389,700	(5,596)
General Seasonal	9,279	1,565	1,766	113	(44)	-	(44)	110			
Small Industrial	88,162	11,402	11,675	102	-	-	-	102	-	94,400	-
Large Industrial	150,029	14,115	13,205	94	-	565	565	98	0.0038	154,700	583
Street Lighting	5,519	2,559	2,330	91	-	102	102	95	0.0186	5,000	93
Unmetered	2,416	391	407	104	-	-	-	104	-	2,500	-
	1,208,058	182,602	182,571	100	(4,861)	4,861	0			1,267,000	307

Leave March 1, 2019 proposed service charges and demand charges unchanged.
A further step would be required for Street Lighting, based on monthly kWh used by each fixture type and size.

COMMISSION STAFF IR-50
RATES NEEDED TO BRING REVENUE TO COST RATIOS TO WITHIN 90% - 110%

	Change in average \$ / kWh for R/C to within 90% - 110% (\$ / kWh)	March 1, 2019 energy charges as proposed		March 1, 2019 energy charges for 90% - 110% R/C	
		First block (\$ / kWh)	Second block (\$ / kWh)	First block (\$ / kWh)	Second block (\$ / kWh)
Residential	0.0084	0.1456	0.1155	0.1540	0.1239
Residential Seasonal					
Residential Farms					
General Service	(0.0144)	0.1793	0.1167	0.1649	0.1023
General Seasonal					
Small Industrial	-	0.1756	0.0879	0.1756	0.0879
Large Industrial	0.0038	0.0723		0.0761	
Street Lighting	0.0186				
Unmetered	-	0.1757		0.1757	

Leave March 1, 2019 proposed service charges and demand charges unchanged.
A further step would be required for Street Lighting, based on monthly kWh used by each fixture type and size.

COMMISSION STAFF IR-51

ANNUAL CHANGES IN RATES NEEDED TO BRING REVENUE TO COST RATIOS TO 100%

(5 year phase in period)

Annual change in rates needed to bring R/C ratios to 100% over a 5 year period

(This would be in addition to the rate changes normally proposed by MECL to meet changing revenue requirements, such as the 1.1 % increase in rates proposed for each of March 1, 2019, March 1, 2020 and March 1, 2021)

	A	B	C	D	E						
				C / B	B - C	100 * E / C					
	From 2017 Cost Allocation Study										
	Energy sales (MWh)	Net revenue requirement ($ x 1,000)	Base revenue ($ x 1,000)	Revenue to Cost ratio (%)	Change in class revenue for R/C equal to to 100 % ($ x 1,000)	Overall change in rates for R/C equal to to 100 % (%)	Mar 1, 2019 (%)	Mar 1, 2020 (%)	Mar 1, 2021 (%)	Mar 1, 2022 (%)	Mar 1, 2023 (%)
Residential	505,169	91,806	83,860	91	7,946	9.5	1.83	1.83	1.83	1.83	1.83
Residential Seasonal	19,523	4,512	4,309	96	203	4.7	0.92	0.92	0.92	0.92	0.92
Residential Farms	52,322	8,372	6,868	82	1,504	21.9	4.04	4.04	4.04	4.04	4.04
General Service	375,639	47,880	58,151	121	(10,271)	(17.7)	(3.81)	(3.81)	(3.81)	(3.81)	(3.81)
General Seasonal	9,279	1,565	1,766	113	(201)	(11.4)	(2.39)	(2.39)	(2.39)	(2.39)	(2.39)
Small Industrial	88,162	11,402	11,675	102	(273)	(2.3)	(0.47)	(0.47)	(0.47)	(0.47)	(0.47)
Large Industrial	150,029	14,115	13,205	94	910	6.9	1.34	1.34	1.34	1.34	1.34
Street Lighting	5,519	2,559	2,330	91	229	9.8	1.89	1.89	1.89	1.89	1.89
Unmetered	2,416	391	407	104	(16)	(3.9)	(0.80)	(0.80)	(0.80)	(0.80)	(0.80)
	1,208,058	182,602	182,571	100	31						

COMMISSION STAFF IR-51
ANNUAL CHANGES IN RATES NEEDED TO BRING REVENUE TO COST RATIOS TO 100%
(4 year phase in period)

	A	B	C	D	E		Annual change in rates needed to bring R/C ratios to 100% over a 4 year period (This would be in addition to the rate changes normally proposed by MECL to meet changing revenue requirements, such as the 1.1 % increase in rates proposed for each of March 1, 2019, March 1, 2020 and March 1, 2021)			
	From 2017 Cost Allocation Study			C / B	B - C	100 * E / C				
	Energy sales (MWh)	Net revenue requirement ($ x 1,000)	Base revenue ($ x 1,000)	Revenue to Cost ratio (%)	Change in class revenue for R/C equal to to 100 % ($ x 1,000)	Overall change in rates for R/C equal to to 100 % (%)	Mar 1, 2019 (%)	Mar 1, 2020 (%)	Mar 1, 2021 (%)	Mar 1, 2022 (%)
Residential	505,169	91,806	83,860	91	7,946	9.5	2.29	2.29	2.29	2.29
Residential Seasonal	19,523	4,512	4,309	96	203	4.7	1.16	1.16	1.16	1.16
Residential Farms	52,322	8,372	6,868	82	1,504	21.9	5.08	5.08	5.08	5.08
General Service	375,639	47,880	58,151	121	(10,271)	(17.7)	(4.74)	(4.74)	(4.74)	(4.74)
General Seasonal	9,279	1,565	1,766	113	(201)	(11.4)	(2.98)	(2.98)	(2.98)	(2.98)
Small Industrial	88,162	11,402	11,675	102	(273)	(2.3)	(0.59)	(0.59)	(0.59)	(0.59)
Large Industrial	150,029	14,115	13,205	94	910	6.9	1.68	1.68	1.68	1.68
Street Lighting	5,519	2,559	2,330	91	229	9.8	2.37	2.37	2.37	2.37
Unmetered	2,416	391	407	104	(16)	(3.9)	(1.00)	(1.00)	(1.00)	(1.00)
	1,208,058	182,602	182,571	100	31					

2019 IRs of IRAC Staff
2019-01-30

COMMISSION STAFF IR-52

ANNUAL CHANGES IN RATES NEEDED TO BRING REVENUE TO COST RATIOS TO WITHIN 95% - 105%

(5 year phase in period)

Annual change in rates needed to bring R/C ratios to within 95% - 105% over 5 years

(This would be in addition to the rate changes normally proposed by MECL to meet changing revenue requirements, such as the 1.1 % increase in rates proposed for each of March 1, 2019, March 1, 2020 and March 1, 2021)

	A	B	C	D	E	F	G	H						
	From 2017 Cost Allocation Study			C / B			E + F	(C + G) / B	100 * G / C					
	Energy sales (MWh)	Net revenue requirement ($ x 1,000)	Base revenue ($ x 1,000)	Revenue to Cost ratio (%)	Change in class revenue for R/C to within 95% - 105% ($ x 1,000)	Adjustment to make revenue neutral overall ($ x 1,000)	Adjusted change in class revenue ($ x 1,000)	Resulting Revenue to Cost ratio (%)	Overall change in rates for R/C to within 95% - 105% (%)	Mar 1, 2019 (%)	Mar 1, 2020 (%)	Mar 1, 2021 (%)	Mar 1, 2022 (%)	Mar 1, 2023 (%)
Residential	505,169	91,806	83,860	91	3,356	2,461	5,817	98	6.9	1.35	1.35	1.35	1.35	1.35
Residential Seasonal	19,523	4,512	4,309	96	-	121	121	98	2.8	0.56	0.56	0.56	0.56	0.56
Residential Farms	52,322	8,372	6,868	82	1,085	224	1,310	98	19.1	3.55	3.55	3.55	3.55	3.55
General Service	375,639	47,880	58,151	121	(7,877)	-	(7,877)	105	(13.5)	(2.87)	(2.87)	(2.87)	(2.87)	(2.87)
General Seasonal	9,279	1,565	1,766	113	(123)	-	(123)	105	(7.0)	(1.43)	(1.43)	(1.43)	(1.43)	(1.43)
Small Industrial	88,162	11,402	11,675	102	-	-	-	102	-	-	-	-	-	-
Large Industrial	150,029	14,115	13,205	94	204	378	583	98	4.4	0.87	0.87	0.87	0.87	0.87
Street Lighting	5,519	2,559	2,330	91	101	69	170	98	7.3	1.42	1.42	1.42	1.42	1.42
Unmetered	2,416	391	407	104	-	-	-	104	-	-	-	-	-	-
	1,208,058	182,602	182,571	100	(3,253)	3,253	(0)							

2019 IRs of IRAC Staff
2019-01-30

COMMISSION STAFF IR-52

ANNUAL CHANGES IN RATES NEEDED TO BRING REVENUE TO COST RATIOS TO WITHIN 95% - 105%

(4 year phase in period)

	A	B	C	D	E	F	G	H		Annual change in rates needed to bring R/C ratios to within 95% - 105% over 4 years			
				C / B			E + F	(C + G) / B	100 * G / C	(This would be in addition to the rate changes normally proposed by MECL to meet changing revenue requirements, such as the 1.1 % increase in rates proposed for each of March 1, 2019, March 1, 2020 and March 1, 2021)			
	From 2017 Cost Allocation Study												
	Energy sales (MWh)	Net revenue requirement ($ x 1,000)	Base revenue ($ x 1,000)	Revenue to Cost ratio (%)	Change in class revenue for R/C to within 95% - 105% ($ x 1,000)	Adjustment to make revenue neutral overall ($ x 1,000)	Adjusted change in class revenue ($ x 1,000)	Resulting Revenue to Cost ratio (%)	Overall change in rates for R/C to within 95% - 105% (%)	Mar 1, 2019 (%)	Mar 1, 2020 (%)	Mar 1, 2021 (%)	Mar 1, 2022 (%)
Residential	505,169	91,806	83,860	91	3,356	2,461	5,817	98	6.9	1.69	1.69	1.69	1.69
Residential Seasonal	19,523	4,512	4,309	96	-	121	121	98	2.8	0.69	0.69	0.69	0.69
Residential Farms	52,322	8,372	6,868	82	1,085	224	1,310	98	19.1	4.46	4.46	4.46	4.46
General Service	375,639	47,880	58,151	121	(7,877)	-	(7,877)	105	(13.5)	(3.57)	(3.57)	(3.57)	(3.57)
General Seasonal	9,279	1,565	1,766	113	(123)	-	(123)	105	(7.0)	(1.78)	(1.78)	(1.78)	(1.78)
Small Industrial	88,162	11,402	11,675	102	-	-	-	102	-	-	-	-	-
Large Industrial	150,029	14,115	13,205	94	204	378	583	98	4.4	1.09	1.09	1.09	1.09
Street Lighting	5,519	2,559	2,330	91	101	69	170	98	7.3	1.77	1.77	1.77	1.77
Unmetered	2,416	391	407	104	-	-	-	104	-	-	-	-	-
	1,208,058	182,602	182,571	100	(3,253)	3,253	(0)						