MARITIME ELECTRIC
A FORTIS COMPANY

October 28, 2015

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The Island Regulatory and Appeals Commission

Island Regulatory & Appeals Commission
PO Box 577
Charlottetown PE C1A 7L1

Dear Commissioners:

Please find enclosed 10 copies of Maritime Electric's General Rates Case Application and Evidence for approval of a revised schedule of rates, tolls and charges to be effective March 1, 2016. An electronic copy will be forwarded shortly.

If you require further information, please do not hesitate to contact me at (902) 629-3667.

Yours truly,

MARITIME ELECTRIC

S. D. Loggie
Vice President,
Finance & Chief Financial Officer

SLD44
Encl. as noted

C A N A D A

PROVINCE OF PRINCE EDWARD ISLAND

BEFORE THE ISLAND REGULATORY AND APPEALS COMMISSION

IN THE MATTER of Section 20 of the

Electric Power Act (R.S.P.E.I. 1988, Cap. E-4) and **IN THE MATTER** of the Application of Maritime Electric Company, Limited for an order of the Commission approving rates, tolls and charges for electric service for the period beginning March 1, 2016 and for certain approvals incidental to such an order.

APPLICATION AND EVIDENCE OF MARITIME ELECTRIC COMPANY, LIMITED

Date: October 21, 2015

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1.0 APPLICATION

C A N A D A

PROVINCE OF PRINCE EDWARD ISLAND

**BEFORE THE ISLAND REGULATORY
AND APPEALS COMMISSION**

IN THE MATTER of Section 20 of the Electric Power Act (R.S.P.E.I. 1988, Cap. E-4) and **IN THE MATTER** of the Application of Maritime Electric Company, Limited for an order of the Commission approving rates, tolls and charges for electric service for the period beginning March 1, 2016 and for certain approvals incidental to such an order.

Introduction

1. Maritime Electric Company, Limited ("Maritime Electric" or the "Company") is a public utility subject to the Electric Power Act ("EPA" or the "Act") engaged in the production, purchase, transmission, distribution and sale of electricity within Prince Edward Island.

Application

2. Maritime Electric hereby applies for an order of the Island Regulatory and Appeals Commission ("IRAC" or the "Commission") approving the rates, tolls and charges ("rates") for electric service, which are outlined in Appendix 1, for the period beginning March 1, 2016 as well as certain other approvals incidental thereto. Maritime Electric proposes adjustment to the base rate per kWh contained in the Energy Cost Adjustment Mechanism calculation to reflect changes in forecast energy related costs. The Company is also requesting

confirmation of its Rate Base and a Return on Average Rate Base order from the Commission in respect of the 2016 fiscal year.

3. The proposals contained in this Application represent a just and reasonable balance of the interests of Maritime Electric and those of its customers and will, if approved, allow the Company to continue to provide a high level of service at prices that are, in all circumstances, reasonable.

Procedure

4. Filed herewith is the Affidavit of Frederick J. O'Brien, Steven D. Loggie, John D. Gaudet and Angus S. Orford which contains the evidence on which Maritime Electric relies in this Application.

Dated at Charlottetown, Province of Prince Edward Island, this 21st day of October, 2015.

D. Spencer Campbell, Q.C.

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2.0 AFFIDAVIT

C A N A D A

PROVINCE OF PRINCE EDWARD ISLAND

BEFORE THE ISLAND REGULATORY AND APPEALS COMMISSION

IN THE MATTER of Section 20 of the Electric Power Act (R.S.P.E.I. 1988, Cap. E-4) and **IN THE MATTER** of the Application of Maritime Electric Company, Limited for an order of the Commission approving rates, tolls and charges for electric service for the period beginning March 1, 2016 and for certain approvals incidental to such an order.

AFFIDAVIT

We, Frederick James O'Brien, of Alberton, in Prince County, Steven David Loggie, John David Gaudet and Angus Sumner Orford of Charlottetown, in Queens County, Province of Prince Edward Island, MAKE OATH AND SAY AS FOLLOWS:

1. We are the President and Chief Executive Officer, Vice President, Finance and Chief Financial Officer, Vice President, Corporate Planning and Energy Supply and Vice President, Customer Service for Maritime Electric Company, Limited ("Maritime Electric" or the "Company") respectively and as such have personal knowledge of the matters deposed to herein, except where noted, in which case we rely upon the information of others and in which case we verily believe such information to be true.

2. Maritime Electric is a public utility subject to the provisions of the Electric Power Act engaged in the production, purchase, transmission, distribution and sale of electricity within Prince Edward Island.

3. We prepared or supervised the preparation of the evidence and to the best of our knowledge and belief the evidence is true in substance and in fact. A copy of the evidence is attached to this our Affidavit, and is collectively known as Exhibit "A", contained at Tabs 3 through 18 inclusive.

4. The evidence found at Tab 3 (the "Introduction") contains a brief overview of Maritime Electric and a summary of the impact of the proposals on customer electricity costs.

5. The evidence found at Tab 4 (the "PEI Energy Accord") contains information on the PEI Energy Accord.

6. The evidence found at Tab 5 (the "Energy Cost Adjustment Mechanism" or "ECAM") contains background information on the history and operation of the Energy Cost Adjustment Mechanism.

7. The evidence found at Tab 6 (the "Rebasing of ECAM") contains information on the proposed rebasing of the ECAM.

8. The evidence found at Tab 7 (the "Energy Sales Forecast") outlines the Company's energy sales forecast.

9. The evidence found at Tab 8 (the "Energy Supply Expenses") contains a summary of the energy, by source, required to meet the forecast energy sales.

10. The evidence found at Tab 9 (the "Transmission and Distribution Expenses") outlines the cost to deliver the forecast energy (the "wires" cost) to customers.

11. The evidence found at Tab 10 (the "General and Administrative Expenses") details the administrative and overhead costs, not directly related to energy sales, required to operate the Company.

12. The evidence contained at Tab 11 (the "Amortization Expenses") contains information on the amortization rates for the Company's fixed assets.

13. The evidence found at Tab 12 (the "Financial Objectives") contains an outline of the Company's financial objectives.

14. The evidence found at Tab 13 (the "Cost Allocation Study") contains information on the results and proposals from the 2014 Cost Allocation Study.

15. The evidence found at Tab 14 (the "Street and Area Lighting") contains information on the Company's Street and Area Lighting conversion to LED fixtures.

16. The evidence found at Tab 15 (the "Financial Forecast") contains the forecast financial results based on the evidence contained in the Application.

17. The evidence found at Tab 16 (the "Impact of Proposals on Customers") illustrates the impact of the proposals in the Company's Application on a cross section of Customers' annual costs in the residential and commercial rate classes.

18. Tab 17 contains a proposed Order of the Commission based on the Company's Application.

19. The evidence found at Tab 18 (the "Appendices") contains Appendix 1 through 11 inclusive which are referred to in the evidence.

SWORN TO SEVERALLY at
Charlottetown, Prince Edward
Island, the 21st day of October, 2015.
Before me:

Frederick J. O'Brien

Steven D. Loggie

John D. Gaudet

Angus S. Orford

A Commissioner for taking affidavits
in the Supreme Court of Prince Edward Island.

3.0 INTRODUCTION

3.1 Corporate Profile

Maritime Electric Company, Limited owns and operates a fully integrated system providing for the purchase, generation, transmission, distribution and sale of electricity throughout Prince Edward Island. The Company's head office is located in Charlottetown with generating facilities in Charlottetown and Borden-Carleton. The Company has contractual entitlement to capacity and energy from NB Power's Point Lepreau Nuclear Generating Station ("Point Lepreau") and an agreement for the purchase of capacity and system energy from NB Power delivered via two submarine cables leased from the Province of Prince Edward Island. The Company purchases 92.5 MW of wind powered energy under contract with the PEI Energy Corporation.

3.2 Overview of Evidence

The evidence in support of the Company's Application for rates, tolls and charges for service to its customers on Prince Edward Island for the period beginning March 1, 2016 is filed pursuant to Section 20 of the EPA.

In support of this Application, the Company has pre-filed the following Applications: 2016 Capital Budget (Docket UE21406), 2014 Depreciation Study (Docket UE21603) and 2015-2020 Demand Side Management Plan (Docket UE21406), which to varying degrees, have implications for customer rate adjustments proposed in this Application. These pre-filed Applications are addressed within the applicable areas of this Application.

The proposals in this Application, with respect to the adjustment of customer electricity costs effective March 1, 2016, are derived from two fundamental drivers.

Section 13 of the Application presents the results of the 2014 Cost Allocation Study which provides the basis for the recommendation to change rates and rate structures within the Residential and General Service rate classes. This Study concluded that the Company is under collecting from the Residential rate class and over-collecting from the General Service rate class. The proposed adjustments to these rate classes are designed to ensure that the revenue collected in each rate class are representative of the costs incurred to service each rate class. The proposed adjustments are revenue neutral from the Company's perspective as increases in revenue in the Residential rate class are offset by decreases in revenue in the General Service rate class such that the net impact on the Company's total revenue is zero.

The second source of adjustment to customer electricity costs is derived from the Company's forecast revenue requirement and other required collections, as detailed in Section 4 through 15, exclusive of Section 13. The 2016 revenue requirement represents the Company's forecast of costs to be incurred to provide safe reliable service to customers while the other required collections represent the amounts to be recovered from customers on behalf of the Province of PEI. Together these costs form the basis of a general adjustment to electricity rates for all customers.

3.3 Summary of Impact of Proposals on Customer Electricity Costs

The Company is proposing a general rate adjustment that will result in a 2.5 per cent increase in electricity costs (approximately $2.82 per month before taxes) for a typical rural residential customer using 650 kWh per month. Because the Company does not recommend a change in the fixed service charge for Residential customers, the impact on electricity costs for residential customers will vary depending on consumption volume (i.e. customers with average monthly electricity consumption greater than 650 kWh per month will see annual cost increases of more than 2.5 per cent while customers using less than 650 kWh per month will see a change in an annual electricity costs of less than 2.5 per cent).

Similarly, typical customers in Commercial and Industrial rate classes will experience a general rate adjustment of approximately 2.5 per cent and customers in these rate classes will experience variations in the impact on annual electricity costs as a result of the general rate adjustment depending on their relative level of consumption.

The Company is also proposing changes to rates or the rate structure as a result of the 2014 Cost Allocation Study as outlined in Section 13. The Company is recommending that the residential (lower cost) second block threshold be increased from the current 2,000 kWh threshold to 5,000 kWh for all residential customers over a three year period with the first block increase to 3,000 kWh effective March 1, 2016. The large majority of Residential customers will not be impacted by this proposal. Based on recent typical cold month (February 2015) and warm month (July 2015) data, approximately 15 per cent and 1.4 percent of all residential customers billed in those months, respectively, accessed the lower cost second block and would be impacted by this proposal.

The estimated incremental revenue derived from the proposed increase in the second block threshold over three years (approximately $773,000) is proposed to be used to lower electricity costs (than would otherwise be incurred) for customers in the General Service rate class.

Section 16 of the Application provides further discussion on the impact on customer electricity costs as a result of the Company's proposals outlined in this Application.

4.0 PEI ENERGY ACCORD

4.1 Background

The PEI Energy Accord is a collaborative five year agreement ending February 29, 2016 between the Company and the Province of PEI intended to provide lower, stable electricity rates for PEI consumers and increase reliance on locally owned wind power. Through legislative amendments to the EPA, electricity costs for the typical customer in each of the Company's rate classes were lowered by 14 per cent on March 1, 2011 and remained at this level for two years until February 28, 2013. The legislative amendments then provided for annual increases in electricity costs of 2.2 per cent for each of the subsequent three years commencing March 1, 2013 for typical customers in each rate class.

The five year rate plan under the Accord, which expires February 29, 2016, was based upon a set of annual inputs for the Company which included, among other things, kWh sales and revenue forecasts, operating and capital expenditures and financing costs for the years 2011 to 2015. The Accord also set out Government's commitment to achieving lower customer electrical costs by assuming, and financing, certain extraordinary costs incurred by the Company to serve customers during the Point Lepreau refurbishment and to exit the Dalhousie Participation Agreement.

4.2 Costs Recoverable from Customers on Behalf of the Province of PEI

In addition to the EPA legislative amendments to reduce customer electricity costs during the Accord, the Province also passed Section 49 of the EPA to deem the amounts assumed by the Province during the Accord, regarding the extraordinary costs incurred during the Point Lepreau Generating Station refurbishment and to exit the Dalhousie Generating Station participation agreement, as debts owing by Maritime Electric customers to the Province. The EPA further states that these amounts are to be recovered by Maritime

Electric through rates and remitted to the Province.

The legislated electricity rates set during the Accord include rates for the collection of costs recoverable from customers on behalf of the Province. These rates were designed, using forecast sales levels, to provide sufficient cash flows to the Province to fund and repay the extraordinary costs financed under the Accord over the term of the associated financing.

Schedule 4-1 shows the rate included in customer electricity rates for the years 2011 to 2016 to fund repayment of the debt associated with the costs financed by the Province under the Accord.

SCHEDULE 4-1	
Costs Recoverable From Customers on Behalf of Province	
	Rate ($/kWh)
2011	0.00130
2012	0.00170
2013	0.00676
2014	0.00525
2015	0.00536
2016	0.00536

4.3 Rate of Return Adjustment

The EPA was first amended in late 2010 with the introduction of the Electric Power (Electricity Rate Reduction) Amendment Act to implement the first two years of the Accord commencing March 1, 2011. This legislation enacted Section 48(13) which required the Company to return to customers, in the following year, any earnings in excess of a maximum 8 per cent return on average rate base. This maximum return on the rate base was calculated using an allowed return on average common equity of 9.75 per cent.

Although the Company did not exceed the 8 per cent cap on return on rate base in 2011 or 2012, in the absence of a regulatory adjustment, it would have exceeded the allowed 9.75 per cent return on average common equity included in the Accord input assumptions due to sales growth being higher than forecast in developing the Accord. Accordingly, the Company sought and received direction from IRAC, in Order UE11-04 dated December 22, 2011, to establish a Rate of Return Adjustment ("RORA") account to defer amounts in excess of the allowed 9.75 per cent return, with interest, and return these amounts to customers once the Accord had ended.

In 2012, Maritime Electric and the Province negotiated and established the annual Schedule of Inputs for 2013 to 2015 and resulting electricity rates for the remaining three years of the Accord. The legislation enacted to implement these final three years was called the Electric Power (Energy Accord Continuation) Amendment Act. In this Act, Section 48(13) was repealed and replaced with Section 48.1(9) which requires the Company to return to customers any earnings in excess of its allowed return on average common equity during the Accord over the period March 1, 2013 to February 28, 2017.

On March 1, 2013, in accordance with these legislative provisions and the IRAC Order, the Company began refunding to customers the actual 2011 RORA and the forecast RORA for 2012 at a rate of $0.00071/kWh. This rate is included in the rates legislated in the Fall of 2012 for the period March 1, 2013 to February 29, 2016 under the Electric Power (Energy Accord Continuation) Amendment Act and remains part of electricity rates until February 29, 2016.

In addition to the RORA recorded in 2011 and 2012, the Company has also recorded a RORA in both 2013 and 2014 and is forecasting a RORA for 2015 as well. In each of the years of the Accord, without a RORA, the Company would have exceeded the allowed return on average common equity due to higher than forecasted sales growth, driven primarily by the accelerated adoption of electricity based sources for space heating during the period. In accordance with the EPA, the Company has (and will for 2015) reduce its earnings to the allowed return on average common equity by recording an amount for refund to customers.

Although the electricity rates in effect until February 29, 2016 include a refund of RORA to customers at the rate of $0.00071/kWh, the Company is forecasting a balance owing to customers upon expiry of the Accord and a return to full cost of service regulation on March 1, 2016.

Schedule 4-2 below provides details of the accumulated RORA deferral account and the forecast balance remaining for refund to customers at the end of the Accord.

SCHEDULE 4-2 Rate of Return Adjustment (RORA) Payable to Customers ($)				
	RORA	**Interest**	**Refunded to Customers**	**Balance Owing to Customers**
2011	$ 1,874,268	$ -	$ -	$ 1,874,268
2012	2,239,130	57,166	-	4,170,564
2013	3,586,955	117,873	(648,556)	7,226,836
2014	3,674,728	205,812	(829,060)	10,278,316
2015 (Forecast)	3,660,000	276,800	(848,700)	13,366,416
2016 (Jan - Feb Forecast)	-	60,000	(160,700)	13,265,716
Total	$15,035,081	$ 717,651	$ (2,487,016)	$ 13,265,716

As part of this Application, Maritime Electric is proposing to refund the RORA owing to customers over the two year period from March 1, 2016 to February 28, 2018. By returning the RORA to customers over the period March 1, 2016 to February 28, 2018 (24 months), this approach will serve to smooth the impact on customers' electricity costs over a two year period and assist in providing stable and predictable rate adjustments during this time. Currently Sections 48(13) and 48.1(9) of the EPA require the Company to return the RORA balance over the period March 1, 2013 to February 28, 2017, however on March 1, 2016 these Sections are repealed by the Electric Power (Energy Accord Continuation) Amendment Act when the Accord ends and the Company returns to the Commission's oversight for all regulatory matters including electricity rates. As a result, the Commission has discretion to set the manner in which the RORA is returned to customers.

Based upon forecast sales levels, the Company is proposing to return an estimated \$6,384,400 (48 per cent) of the RORA balance owing to customers over the period March 1, 2016 to February 28, 2017 by applying a credit of \$0.00533/kWh to the per kWh rate for each rate class. Disposition of the remaining forecast RORA balance of \$6,881,316 would be addressed in the Company's next rate application (for rates effective March 1, 2017) to reflect the sales levels forecast for the period March 1, 2017 to February 28, 2018 and any variance in RORA balance caused by changes in actual sales compared to forecast sales in year one. This coincides with the expected completion date of the submarine cable project and the commencement of the recovery of the project costs from customers through rates.

4.4 Cable Contingency Fund

The two submarine cables connecting PEI to the mainland were installed in 1977 with funding from both the Federal and Provincial governments. Under an Interconnection Lease Agreement, the Province of Prince Edward Island (owner of the cables) leases this infrastructure to Maritime Electric for a nominal annual fee. The Interconnection Lease Agreement currently provides for the establishment of a \$3.0 million Contingency Fund, which is owned and managed by the Province.

In March 2012, a leak of insulating oil in one of the submarine cables was detected. This required considerable time and cost by Maritime Electric to locate and ultimately repair two leaks that were present in this cable. Also during this time, the cable had to be taken out of service, effectively cutting the interconnection capacity in half and requiring Maritime Electric to generate more costly replacement energy from its on-Island thermal generating facilities. To mitigate these significant unplanned costs, the accumulated balance in the Province's Cable Contingency Fund was utilized to fund a significant portion of the repairs.

In accordance with the requirements of the Interconnection Agreement to maintain the Cable Contingency Fund, Maritime Electric and the Province agreed during the Accord that the Fund would be replenished through a collection from Maritime Electric ratepayers over a ten year period commencing March 1, 2013 at a rate of $0.00027/kWh. Based upon sales projections used in developing the Accord, this rate is expected to generate an annual contribution to the Cable Contingency Fund of approximately $300,000 per year over the ten year period.

4.5 Summary

A summary of this section follows:

- Through the PEI Energy Accord and related legislative amendments, electricity costs for PEI consumers has been stable and predictable over the last five years;
- The Company is required to recover from customers the extraordinary costs financed by the Province at a rate of $0.00536/kWh;
- The Company proposes to refund approximately 48 per cent of the forecast RORA to customers at a rate of $0.00533/kWh over the period March 1, 2016 to February 28, 2017;
- The Company proposes disposition of the remaining RORA balance

would be subject to Commission review in the next General Rate Application; and

- The Cable Contingency Fund will be replenished over a ten year period, which commenced on March 1, 2013, at a rate of $0.00027/kWh.

5.0 ENERGY COST ADJUSTMENT MECHANISM

5.1 Background

The amount charged to customers for electrical service contains several components. These include amounts to be recovered related to the annual operations of Maritime Electric as well as amounts to be recovered on behalf of the Province of PEI with respect to the PEI Energy Accord and the Cable Contingency Fund. The PEI Energy Accord and Cable Contingency Fund amounts are discussed in Section 4.

5.2 Annual Operations

The first component related to the Company's operations is the Service Charge which collects the cost of investment in fixed assets required to deliver energy. The next component related to the Company's operations is the Basic Rate which recovers the balance of the revenue requirement, including a base amount for energy related costs. Another component is the Rate of Return Adjustment credit which is discussed in Section 4. The final component related to the Company's operations is the Energy Cost Adjustment Mechanism, which enables the utility to collect/return fluctuations in approved energy related costs above/below the forecast base amount per kilowatt-hour ("kWh") included in the Basic Rates. In a period of volatile energy costs the ECAM provides a smoothing effect to the collection or rebate of these costs.

Maritime Electric has had a mechanism to recover/rebate energy costs above/below a base amount in place since the 1970's[1]. The mechanism has undergone several modifications during that period; however, the fundamental objective has remained the same. The most recent modification occurred in 2011, with amendments to the EPA to implement the PEI Energy Accord. The ECAM was modified to change the calculation of the rate charged to customers from monthly, based upon the

[1] During the period 1994 – 2000 there was no mechanism in place.

ECAM balance and kWh sales two months prior, to annually, based upon the ECAM balance at December 31 of the prior year and the forecast kWh sales for the period March 1 to February 28 following. This change provided stability in customers' monthly rates for the ECAM costs during the Accord.

5.3 Operation of the ECAM

Under the operation of the ECAM the Company charges to expense, on a monthly basis, an amount equal to the net purchased and produced energy for the month ("NPP") multiplied by a base amount per kWh, currently set at $0.08760/kWh. This amount is subtracted from the actual cost of energy purchased or produced during the month with the difference (positive or negative) added to the Company's Balance Sheet for future recovery from or return to customers over a period of time as approved by the Commission.

Schedule 5-1 shows the cost per kWh to purchase and produce the energy required to meet customers' requirements during the years 2014 – 2016 which together recover the Company's energy related revenue requirement and those energy costs deferred by the Company for future recovery.

SCHEDULE 5-1			
Cost of Purchased and Produced Energy per kWh ($)			
	2014 Actual	**2015 Forecast**	**2016 Forecast**
Cost of Purchased and Produced Energy per kWh	$ 0.08475	$ 0.08747	$ 0.08605

Schedule 5-2 shows the balance of Costs Recoverable From (Payable To) Customers at December 31 for the years 2014 – 2016.

SCHEDULE 5-2			
Costs Recoverable From (Payable To) Customers ($)			
	2014 Actual	**2015 Forecast**	**2016 Forecast**
Cost Recoverable From (Payable To) Customers	$ (5,061,928)	$ 2,881,920	$ 1,532,952

The fluctuations in the balance of Costs Recoverable From (Payable To) Customers account are driven, in part, by how the ECAM Base Rate was previously set. The Base Rate had been previously set to provide a somewhat longer term, and smoother, transition of customer rates towards including full energy costs. During the term of the Accord, the ECAM Base Rate has been transitioned to more closely reflect the actual annual energy supply costs. The Company proposes, in this Application, to reset the Base Rate at the forecast rate per kWh for energy supply costs during the year for which revised customer rates are sought.

In addition, fluctuations in the balance of Costs Recoverable From (Payable To) Customers were also caused by the manner in which the rate charged to customers for ECAM was calculated. By setting the customers' ECAM rate based upon historic (two months prior) balances and sales, the Company was unable to reflect forecast changes in energy purchase costs and sales volumes in customer rates on a timely basis. Modifications to the ECAM implemented under the PEI Energy Accord have partially mitigated this delay. The Company proposes, in this Application, to further modify the ECAM to reflect forecast energy supply costs in customers' rates during the period in which they will be incurred. These changes are included in the proposed new definition of ECAM in Appendix 3.

5.4 Summary

A summary of this section follows:

- An ECAM has been in place since the early 1970's and has been effective in providing for the recovery/return of energy related costs above/below a pre-determined rate per kWh.
- Rate stability from month to month can be achieved by resetting the ECAM annually instead of monthly.
- The forecast energy supply costs used in the ECAM formula, as defined in Appendix 3, will better reflect forecast energy supply costs in customers' rates during the period in which the costs are incurred.

6.0 REBASING OF ECAM

6.1 Background

Included in this section is information with respect to the rebasing of ECAM during the Accord and the Company's proposal for the new Base Rate effective March 1, 2016.

On August 1, 2010, pursuant to IRAC Order UE10-03, the Company increased the base rate used in the ECAM calculation from $0.0770/kWh to $0.103/kWh to facilitate an increase in the collection of energy costs from customers. Subsequent to the Order, the Company was successful in negotiating a new five year energy purchase agreement with NB Power and also in partnering with the Province of PEI through the PEI Energy Accord which, together, led to lower overall energy purchase costs and allowed for lower ECAM base rates during the term of the Accord.

Schedule 6-1 below shows the ECAM base rates during the Accord.

SCHEDULE 6-1	
ECAM Base Rates During the Accord (March 1 - February 28)	
Year	**Rate ($/kWh)**
2011	0.08300
2012	0.09055
2013	0.09880
2014	0.09365
2015	0.08760

With the extension of the Energy Purchase Agreement for an additional three years to February 28, 2019, the Company can reasonably estimate the average unit cost of energy purchases for 2016, barring any unplanned events (for example, unplanned outages at Point Lepreau or curtailments in excess of forecast amount). The Company believes that energy costs should be recovered in a timely manner and, as discussed in Section 5, has proposed a change to the ECAM to permit recovery based upon the forecast ECAM balance at December 31, 2015 and the forecast sales for the upcoming March - February period.

A further way to ensure the timely recovery of energy costs is to set the base ECAM rate at the forecast average unit cost of $0.08605/kWh for the upcoming period. The average unit cost is calculated by dividing the total ECAM eligible energy and deferred charge amortization costs for 2016 by the forecast GWh net purchased and produced energy for 2016.

Changing the base rate in the ECAM calculation will result in the following:

i. A reduction in the amount of energy costs being deferred (collected) for future collection (return), and

ii. The timely collection of energy costs through Basic Rates.

The forecast monthly calculation of the ECAM adjustment and balance for 2016 is included in Appendix 4.

6.2 Summary

Maritime Electric proposes to adjust the base rate per kWh in the ECAM calculation from $0.08760/kWh to $0.08605/kWh effective March 1, 2016 to more closely reflect the forecast per unit energy costs for the upcoming period in Basic Rates.

7.0 ENERGY SALES FORECAST

7.1 Economic Outlook[2]

The Conference Board of Canada, in its most recent Provincial Economic Outlook publications, provides the following outlook for Prince Edward Island.

> *"Thanks to the one-two punch of construction and manufacturing, as well as a surging export sector, the Island possesses solid economic prospects this year and next. The past winter saw a record amount of snowfall that postponed the opening of lobster season; however, despite the winter setback, the fishing industry is still expected to perform well this year, thanks to strong demand for lobster from China. In general, the Island's export sector will be a major positive for the province due mainly to a booming U.S. economy and the weaker Canadian dollar. As well, building construction intentions are strong for 2015 and that, combined with a surge in housing starts next year, will support the construction sector over the near term. All these signs point to a healthy economy over the next two years on the Island, putting the province ahead of the national average. In particular, real GDP is expected to grow by 2.4 per cent this year and 1.9 per cent in 2016. The recently re-elected Liberal government released its annual budget on June 19 and, as expected, the province continued its mandate of controlled spending. Despite the frugality, the province had to push out its balanced-budget target by one year to 2016-17. Tight spending measures translate into weak growth in non-commercial services such as education and health and social services, which puts a damper on overall economic growth. This makes the positive economic outlook for the Island that much more impressive. With the combination of a strong economy and tighter spending, the province should certainly achieve its new fiscal balance goal for 2016-17."*

7.2 Weather Normalization Reserve

Weather normalization reserves are common in approach throughout the utility industry and are part of a broader group of deferral reserves designed to mitigate volume or demand fluctuations. The purpose of a Weather Normalization

[2] See attached Appendix 5 - The Conference Board of Canada - Provincial Outlook Executive Summary and Provincial Outlook Economic Forecast (Summer 2015)

Reserve is to stabilize electricity rates to customers by removing the volatility in sales and energy supply costs caused by temperature changes relative to historical averages. Where the Heating Degree Days[3] (HDD) variation is above normal, the Company will experience incremental marginal net revenue (revenue less energy costs) which would need to be returned to customers but when HDD variation is below normal there will be a shortfall in net revenue which will need to be recovered from customers.

Due to increases in the use of electricity for space heating in recent years, Maritime Electric's sales revenues and energy supply costs have become subject to greater volatility due to variations in the number of HDDs from normal or historic levels.

To mitigate this increasing volatility and uncertainty with respect to customer electricity rates, the Company is proposing the implementation of a Weather Normalization Reserve effective January 1, 2016.

Conceptually, the balance in the Weather Normalization Reserve on the Company's balance sheet will represent the cumulative change in contribution from sales resulting from variations in HDD from normal and should, over time, net to zero (contribution equals revenue from additional kWh sales minus the cost of purchasing additional kWh sales or marginal net revenue times the additional kWh sales). As illustrated in Schedule 1 of Appendix 6, in a year when HDD are higher than normal (2013 and 2014), a marginal net revenue amount will be subtracted on the Company's income statement and added to the Reserve. When HDD are lower than normal (2010 – 2012), a marginal net revenue amount will be added to the Company's income statement and subtracted from the Reserve. Over the ten year period, the variation from average HDD balances to zero as

[3] http://climate.weather.gc.ca/glossary_e.html - Heating degree-days for a given day are the number of degrees Celsius that the mean temperature is below 18°C. If the temperature is equal to or greater than 18°C, then the number will be zero. For example, a day with a mean temperature of 15.5°C has 2.5 heating degree-days; a day with a mean temperature of 20.5°C has zero heating degree-days.

does the balance in the reserve account. Thus, there would be no need for an adjustment mechanism to deal with Reserve balances if approved by the Commission.

The following describes the components and operation of the Weather Normalization Reserve.

Determination of Average HDD Value

The first step in establishing the mechanics of the Weather Normalization Reserve is the determination of the Average HDD Value. The Company proposes using the rolling 10 year average HDD value based upon the most recent 10 years of information available as measured by Environment Canada for the Charlottetown Airport weather station. As calculated in Schedule 2 of Appendix 6, the average annual HDD value to be used for 2016 is calculated to be 4,339 (2005-2014).

Calculation of MWh/HDD Coefficient

The next step is the determination of the annual MWh/HDD Coefficient (the "Coefficient") to be used for the upcoming year using econometric modelling. As shown in Schedule 3 of Appendix 6, using a linear regression analysis the Company has calculated the Coefficient at 41.73 (based on October 2014 to May 2015 data), which is the estimated change in MWh sales (customer usage) resulting from a unit variation in HDD (i.e. 41.73 MWh per HDD). The Company has excluded from the analysis the data for the months of June to September as these months are primarily cooling months, which would distort the Coefficient calculation for HDD and reduce its accuracy. In addition, only sales for year round Residential, General Service and Small Industrial classes were used as these are the only classes materially affected by variations in HDD.

Calculation of Marginal Net Revenue

The final variable is the Marginal Net Revenue rate which is calculated as the forecast unit revenue per kWh less the forecast energy cost per kWh. For the same reason noted above, the Company recommends that the unit revenue be comprised of only demand and energy charge revenues (i.e. excluding the service charge or site revenue) for Residential, General Service and Small Industrial classes as these are the only revenue factors and rate classes affected by variations in HDD. In addition, with the proposed continued operation of the ECAM, the energy cost per kWh is set in the Company's income statement at the Base Rate in the ECAM as approved by the Commission. Schedule 4 of Appendix 6 shows the calculation of the Marginal Net Revenue Rate of $50.42/MWh based upon the proposals contained in this Application.

Summary

To mitigate the increased volatility resulting from the growing load of electricity for space heating, the Company requests that the Commission approve the adoption of a Weather Normalization Reserve, effective January 1, 2016. The Company proposes to calculate the Weather Normalization Reserve adjustment on a monthly basis as described above so that timely adjustments can be made to address the variations caused by HDD.

7.3 Energy Sales Forecast

The energy sales forecast is the basis of the short-term and long-term energy supply planning process. The sales forecast is used to calculate the total energy required to serve customers and the associated energy related costs. The development of the sales growth forecast involves a detailed sales regression analysis which reflects a number of variables such as population growth, changes in the Consumer Price Index, the number of customers expected to exit and enter the system, furnace oil prices, heating and cooling degree day experience and the rate of adoption of electricity based space heating. Management also conducts a review of trends in historic sales growth which includes a two-year average growth rate calculation and an analysis of year-to-date growth over the previous period. These results are then compared to actual results to date and any other known economic inputs. Based on this process, a forecast of energy sales is made.

Schedule 7-1 shows the results of the regression analysis model, the two-year average growth rate calculation and the year-to-date growth over the previous period for 2014-2016.

SCHEDULE 7-1			
Energy Sales (GWh)			
Measure	**2014 Actual**	**2015 Forecast**	**2016 Forecast**
Regression analysis growth	1,167.7	1,195.3	1,193.8
Two-year average growth	1,173.3	1,207.1	1,249.5
Year-to-date growth	1,167.7	1,203.5	1,243.3

There are a number of factors contributing to the lower sales growth level forecast for 2016 based on regression analysis as compared to the forecasts based on historical/trend analysis. These include:

- the closure of the McCain Foods processing facility in Borden-Carleton in October 2014;
- an assumption of Heating Degree Days based upon a 10 year historical average for 2016, whereas HDD for 2015 are forecast to be above average (the two year average and year to date growth rate projections reflect above normal Heating Degree Days experience in recent years).
- the large reduction in oil prices beginning in the fourth quarter of 2014, which is expected to reduce the growth in electric space heating as compared to prior years. The US Energy Information Agency's ("EIA") oil price forecast shows that oil prices are not expected to increase significantly until 2016; and

- the Company's proposed Demand Side Management plan filed with IRAC which will have a minimal electricity sales impact of 0.1 per cent annually starting in 2016.
- the transition to more energy efficient LED street and area lighting.

Management's forecast of energy sales for 2015 and 2016 is based upon the energy sales regression analysis for the above stated reasons. Schedule 7-2 shows the actual energy sales for 2014 and the forecast of energy sales for 2015 and 2016.

SCHEDULE 7-2			
Energy Sales (GWh) (%)			
	2014 Actual	**2015 Forecast**	**2016 Forecast**
Energy Sales (GWh)			
Residential	541.4	573.0	563.7
General Service I	377.2	378.1	381.0
General Service II[4]	9.4	10.1	10.8
Large Industrial	142.2	132.6	131.3
Small Industrial	88.9	93.1	98.9
Street Lighting/Unmetered	8.6	8.4	8.1
Total Energy Sales	**1,167.7**	**1,195.3**	**1,193.8**
Growth Rate (%)			
Residential	5.27	5.84	(1.62)
General Service I	1.81	0.24	0.77
General Service II[4]	-	7.45	6.93
Large Industrial	(0.84)	(6.75)	(0.98)
Small Industrial	9.89	7.72	6.23
Street Lighting/Unmetered	-	(2.33)	(3.57)
Overall Growth Rate	**3.60**	**2.36**	**(0.13)**

[4] The Company is proposing in Section 13 of this Application, that customers currently in the General Service II rate class begin to be billed as General Service I customers effective March 1, 2016.

7.4 Summary

A summary of this section follows:

- The Company proposes the adoption of a Weather Normalization Reserve to adjust the marginal net revenue associated with sales variances caused by fluctuations in temperature.
- Energy sales are forecast to be 1,195.3 GWh for 2015 and 1,193.8 GWh for 2016.

8.0 ENERGY SUPPLY EXPENSES

8.1 Energy Supply Expenses

The forecast expenditures for energy supply that follow are based upon Management's expectations for 2015 and 2016 and incorporate the latest available updates from third party suppliers.

SCHEDULE 8-1 Forecast of Energy Costs by Source Based on Continuation of Energy Supply Agreements (%)		
	2015	**2016**
Point Lepreau Entitlement	15.2	16.2
Energy Purchase Agreement (System Energy)	59.9	59.4
On-Island Renewable (Wind)	24.2	23.6
Company Self Supply	0.7	0.8
	100.0	**100.0**

The largest component of Maritime Electric's energy supply portfolio is its Energy Purchase Agreement with NB Power, with unit costs fixed, on an annual basis, in Canadian dollars, out to February 28, 2019.

The Company's generation facilities at Charlottetown and Borden-Carleton are forecast to continue their role as backup energy supply for system disturbance and energy supply issues associated with the supply agreements or transmission curtailments in New Brunswick.

8.2 Net Purchased and Produced Energy Requirement

The Company's energy supply requirement is comprised of energy sales to customers, energy usage for Company use and an estimate for system losses. This total is referred to as the Net Purchased and Produced (NPP) energy requirement and represents the total amount that must be acquired to supply the system.

SCHEDULE 8-2			
Net Purchased and Produced Energy (GWh)			
	2014 Actual	**2015 Forecast**	**2016 Forecast**
Energy Sales	1,167.7	1,195.3	1,193.8
Company Use and System Losses	88.0	94.7	94.0
Total	**1,255.7**	**1,290.0**	**1,287.8**

8.3 Energy Supply by Source

In addition to determining the NPP requirement, an analysis is conducted to determine an hourly usage model that takes into account customer usage patterns based upon historical trends. The objective is to purchase or produce the hourly forecast energy supply requirement in the most efficient, economical manner. As the Point Lepreau Agreement is essentially a take or pay contract, it is factored in first. The on-Island wind energy agreements are added next as they are also take or pay contracts. Next to be included is an amount for firm energy purchases, typically as part of the Energy Purchase Agreement (EPA) with some flexibility negotiated such as a prescribed minimum monthly capacity factor. The balance of Maritime Electric's hourly energy supply requirements are met through system energy purchases under the EPA. A small amount of production is forecast from the Company's Charlottetown and Borden-Carleton Plants based upon operator training requirements, a provision for transmission and supply curtailments, system voltage support and management of the submarine cable load flows to ensure that operating limits are not exceeded. Total energy supply costs are forecast to be $112,839,200 for 2015 and $110,818,500 for 2016.

The following Schedule outlines the forecast cost of energy supply by source.

SCHEDULE 8-3			
Energy Supply Cost by Source ($)			
	2014 Actual	**2015 Forecast**	**2016 Forecast**
Point Lepreau	$ 20,873,776	$ 20,878,700	$ 19,856,100
EPA - Firm Energy Purchases	24,355,745	25,704,600	26,591,300
EPA - System Energy Purchases	29,953,290	32,231,200	31,754,600
Charlottetown Plant	4,000,868	4,126,100	3,509,000
Combustion Turbine #3	1,463,019	1,985,900	1,793,300
Borden-Carleton Plant	271,642	317,600	350,700
Energy Control Centre Operations	825,353	756,000	835,800
Wind	23,063,472	24,895,500	24,108,900
Ancillary Services	578,276	529,000	540,900
Other Purchases	698,623	1,207,800	1,384,500
Amortization of Deferred Charges	329,000	206,800	93,400
Total	**$ 106,413,064**	**$ 112,839,200**	**$ 110,818,500**

Point Lepreau –

$20,873,776 (2014), $20,878,700 (2015), $19,856,100 (2016)

These forecast expenditures are based upon inputs from NB Power and reflect Maritime Electric’s participation in the costs to operate the facility, including provisions for decommissioning and irradiated fuel storage. The refurbishment of Point Lepreau was completed in the Fall of 2012 at which point the unit returned to service with an expected service life of 27 years.

Under normal operating conditions, Point Lepreau is scheduled for bi-annual maintenance outages that last 6 - 8 weeks. The next scheduled maintenance outage is planned for April/May 2016. During this period, replacement energy will be sourced through the EPA with NB Power.

EPA - Firm Energy Purchases –

$24,355,745 (2014), $25,704,600 (2015), $26,591,300 (2016)

Firm Energy Purchases are used to supplement the Point Lepreau purchases to provide the base load requirement for Maritime Electric through the Energy Purchase Agreement with a minimum monthly capacity factor of 85 per cent. This capacity factor provides flexibility in managing other purchases.

EPA - System Energy Purchases –

$29,953,290 (2014), $32,231,200 (2015), $31,754,600 (2016)

System Energy is made up of two components: Secure Energy and Assured/Interruptible Energy. Both energy components can be curtailed based upon predefined situations, with varying notice periods for each of the energy components.

Secure Energy is backed up by the 50 MW Combustion Turbine ("CT3") located at the Charlottetown Plant site and is interruptible on 24 hours notice during the Winter period (November through March) and seven days notice during the Summer period (April through October).

Assured/Interruptible Energy is backed up by the 60 MW of oil-fired generation at the Charlottetown Plant and the 40 MW Borden-Carleton Generating Station with the assured purchases curtailable on either seven days notice during the April to October period or two days notice during December and January and four days notice for all other months. The Interruptible purchases are curtailable on ten minutes notice. This type of interruptible energy purchase allows Maritime Electric to better preserve the power boilers at the Charlottetown Plant during the Summer and reduce deterioration and operating costs when not in operation. During the winter season the Charlottetown Plant is in warm standby mode and is capable of full output within 48 hours.

Charlottetown Plant –

$4,000,868 (2014), $4,126,100 (2015), $3,509,000 (2016)

The Charlottetown Plant's role is primarily one of back up for the submarine cables and to back up purchases of Assured/Interruptible Energy. It limits the exposure the Company faces during times that the Energy Purchase Agreement is curtailed as energy purchases during curtailment are only made when the price is below the generation cost at the Charlottetown Plant. The Plant may be dispatched in December or January, during Maritime Electric's peak, to assist with load management on the submarine cables and to provide voltage support to the eastern end of the Province. The amount of energy produced by the facility varies significantly from year to year and is difficult to predict with any accuracy. A small amount of energy production is forecast based upon the tightening energy supply and transmission constraints in the Maritime Provinces and for training of operating personnel in December and January to coincide with the Company's peak as well as the Nova Scotia and New Brunswick peak load period.

Schedule 8-4 outlines the expenditures necessary to maintain the facility and to produce energy on an as-needed basis.

SCHEDULE 8-4			
Charlottetown Plant Operating Expenses ($)			
Description	**2014 Actual**	**2015 Forecast**	**2016 Forecast**
Buildings and Services	$ 443,283	$ 529,300	$ 524,000
Plant Maintenance	655,540	876,300	1,559,800
Plant Operating	471,350	556,000	489,800
Superintendence	319,697	371,100	276,600
Generation Fuel and Plant Heating	2,110,998	1,793,400	658,800
Total	**$ 4,000,868**	**$ 4,126,100**	**$ 3,509,000**

50 MW Combustion Turbine –

$1,463,019 (2014), $1,985,900 (2015), $1,793,300 (2016)

The 50 MW combustion turbine, CT3, is forecast to be used for peaking purposes with a provisional amount of generation that allows for periods of curtailment of contract energy and transmission curtailment in New Brunswick. This facility backstops the Secure Energy component of the Energy Purchase Agreement as well as supplying non-spinning reserve capacity. The forecast of operating expenses is shown in Schedule 8-5.

SCHEDULE 8-5			
Combustion Turbine #3 Operating Expenses ($)			
Description	**2014 Actual**	**2015 Forecast**	**2016 Forecast**
Buildings and Services	$ 6,696	$ 4,000	$ 6,100
Plant Maintenance	267,295	205,600	126,400
Plant Operating	151,708	91,100	19,700
Generation Fuel	1,037,320	1,685,200	1,641,100
Total	**$ 1,463,019**	**$ 1,985,900**	**$ 1,793,300**

Borden-Carleton Plant –

$271,642 (2014), $317,600 (2015), $350,700 (2016)

These expenses are required to ensure the continued availability of the two generating units that serve to backstop the Company's purchase of Assured/Interruptible Energy and are a source of non-spinning reserve capacity as required for reliability purposes. The Borden-Carleton Plant is forecast to operate in 2015 and 2016 for system maintenance and voltage support purposes only.

The following Schedule outlines the expenditures necessary to maintain the facility and to produce energy on an as-needed basis.

SCHEDULE 8-6			
Borden-Carleton Plant Operating Expenses ($)			
Description	**2014 Actual**	**2015 Forecast**	**2016 Forecast**
Buildings and Services	$ -	$ 4,800	$ 3,600
Plant Operating	7,785	10,400	6,800
Plant Maintenance	100,248	136,600	133,200
Generation Fuel	163,609	165,800	207,100
Total	**$ 271,642**	**$ 317,600**	**$ 350,700**

Energy Control Centre (ECC) Operations –

$825,353 (2014), $756,000 (2015), $835,800 (2016)

Included in this category are internal labour, training and communication costs associated with operating the ECC 24/7. The ECC is responsible for monitoring and operating the Company's transmission and distribution system, managing the submarine cable loading and dispatching on-Island generation when called upon.

Wind –

$23,063,472 (2014), $24,895,500 (2015), $24,108,900 (2016)

The Company has a total of 92.5 MW of wind generation under contract through the PEI Energy Corporation as summarized in Schedule 8-7:

SCHEDULE 8-7	
PEI Energy Corporation Wind Generation Contracts (MW)	
North Cape	10.5
East Point	30.0
Hermanville	30.0
Norway	9.0
Norway - Suez	3.0
Norway - WEICan	10.0
Total	**92.5**

The 10.5 MW of wind generation from North Cape and the 3.0 MW from Norway - Suez are under contract with defined pricing methodologies while the additional 79 MW of wind generation is based on escalating purchase costs comparable to the Minimum Purchase Price Regulations under the Renewable Energy Act.

Ancillary Services –

$578,276 (2014), $529,000 (2015), $540,900 (2016)

Other costs which arise in energy supply are ancillary services, transmission access through New Brunswick, and operations and maintenance costs associated with the Murray Corner and Memramcook substations in New Brunswick. Ancillary services such as load following, regulation, spinning reserve, non-spinning reserve, reactive power supply and voltage control are charged to Maritime Electric as set out in NB Power's Open Access Transmission Tariff.

The rates for ancillary services vary based on NB Power's costs to administer and supply these services and on the Company's peak load in comparison to the peak load in the Maritimes as ancillary services are allocated based on the Company's share of the Maritime peak load.

Other Purchases –

$698,623 (2014), $1,207,800 (2015), $1,384,500 (2016)

This amount provides for a variety of miscellaneous charges, the largest of which is for the provision of off-Island energy purchases during times that the Energy Purchase Agreement has been curtailed and the purchase price of the replacement energy is less than on-Island generation costs.

Amortization of Deferred Charges –

$329,000 (2014), $206,800 (2015), $93,400 (2016)

This represents the amount associated with the amortization of Maritime Electric's portion of the 1998 NB Power $450,000,000 write-down in the value of the Point Lepreau Nuclear Generating Station. Maritime Electric's portion was $5,976,506. At December 31, 2014, the unamortized balance was $1,961,343. The accounting treatment applied to this is to amortize it over the remaining useful life of the unit. The annual amortization expense of $93,400 was approved by the Commission in Order UE05-08 and is proposed to continue to be recovered through the operation of the ECAM. The recovery of this amount is also provided for in Section 47(4)(a)(ii) of the EPA.

The account also includes the amortization of the Company's past expenditures under its Demand Side Management Plan ("DSM") as approved by IRAC under Order UE08-02 dated February 21, 2008. The amount amortized is $113,362 for 2015, representing the final amount to be amortized under the former 2010 DSM plan. There is no DSM amortization forecast for 2016 since the proposal before the Commission with respect to the 2015-2020 DSM Plan (Docket UE21406) proposes to commence amortization of the costs in 2017.

8.4 Energy Supply Expenses - Other

The accounts in Schedule 8-8 provide for other expenses that relate to energy supply.

SCHEDULE 8-8			
Energy Supply Expenses - Other ($)			
Description	**2014 Actual**	**2015 Forecast**	**2016 Forecast**
Insurance	$ 537,773	$ 507,000	$ 561,400
Property Tax	196,189	205,000	210,100
Professional Development and Training	20,153	52,500	119,400
Total	**$ 754,115**	**$ 764,500**	**$ 890,900**

Insurance –

$537,773 (2014), $507,000 (2015), $561,400 (2016)

This amount includes the cost of providing the necessary property, equipment and liability insurance coverage for the Company's generating assets.

Property Tax –

$196,189 (2014), $205,000 (2015), $210,100 (2016)

This amount includes the cost of property taxes attributed to the Company's generating facilities based upon the assessed values of the physical properties.

Professional Development and Training -
$20,153 (2014), $52,500 (2015), $119,400 (2016)

This amount captures the professional development and training costs for employees working to maintain the Company's generating assets and run the ECC operations.

8.5 Summary

A summary of this section follows:

- The net purchased and produced energy required to meet forecast energy sales was 1,255.7 GWh in 2014 and is forecast to be 1,290.0 GWh in 2015 and 1,287.8 GWh in 2016.
- Total energy related operating expenses were $106,413,064 in 2014 and are forecast to be $112,839,200 for 2015 and $110,818,500 for 2016.
- Total energy supply expenses - other were $754,115 in 2014 and are forecast to be $764,500 for 2015 and $890,900 for 2016.

9.0 TRANSMISSION AND DISTRIBUTION EXPENSES

The Transmission and Distribution component of the Company's operations plays a significant role in ensuring system reliability and the delivery of customer service. Productivity and efficiency gains continue to be sought in the areas of improved work methods and materials, improved accuracy of field data, increased equipment automation and improved technical skills.

9.1 Transmission Expenses

The accounts in Schedule 9-1 provide for the day-to-day operation and maintenance of the Company's transmission system.

SCHEDULE 9-1			
Transmission Expenses ($)			
Description	**2014 Actual**	**2015 Forecast**	**2016 Forecast**
Substations	$ 45,365	$ 53,100	$ 55,400
Rights of Way	483,938	125,000	309,000
Line Maintenance	259,343	273,300	355,900
Line Control Devices	52,276	70,000	69,200
Engineering	80,705	107,700	110,600
Open Access Transmission Tariff	6,638,573	6,594,900	6,665,100
Total	**$ 7,560,200**	**$ 7,224,000**	**$ 7,565,200**

Substations –

$45,365 (2014), $53,100 (2015), $55,400 (2016)

This account provides for the maintenance and inspection of the Company's transmission substations. It includes labour, material, and transportation to maintain the transmission switches, insulators, bus connectors, and transformers.

Rights of Way –

$483,938 (2014), $125,000 (2015), $309,000 (2016)

This account provides for the maintenance and inspection of the Company's transmission rights of way. The majority of the expenditure in this account is for contract labour related to vegetation management which plays a vital role in system reliability and service quality. Transmission rights of way maintenance is scheduled on a cyclical and priority basis such that vegetation management is conducted on all transmission lines at least every eight to ten years. To improve reliability, the Company has been working towards a five to seven year cycle.

Line Maintenance –

$259,343 (2014), $273,300 (2015), $355,900 (2016)

This account provides for the maintenance and inspection of over 700 km of transmission lines and is driven by preventative maintenance, storm damage and wear. Activities include repairing wires, connectors, and insulators, straightening poles and retightening guy wires and other hardware.

Line Control Devices –

$52,276 (2014), $70,000 (2015), $69,200 (2016)

This account provides for the inspection and preventative maintenance of the transmission voltage circuit breakers and switches located in the Company's substations. The activities include inspection, replacing broken bushings, repainting and repairing control modules.

Engineering –

$80,705 (2014), $107,700 (2015), $110,600 (2016)

This account provides for the engineering support and analysis to operate and maintain the transmission system. Activities include power flow analysis, equipment monitoring, and engineering analysis to ensure optimal system operation.

Open Access Transmission Tariff ("OATT") –
$6,638,573 (2014), $6,594,900 (2015), $6,665,100 (2016)

This account provides for the costs associated with the administration and operation of the Company's OATT as well as the Company's OATT costs under the interim tariff approved by IRAC. Under Canadian Accounting Standards for Private Enterprises ("ASPE"), the Company is required to record and disclose both the expense and offsetting revenue (see Section 15.7 - Revenue) applicable to its participation in the OATT as well as any other costs incurred and recovered from other participants. These amounts are presented in Schedule 9-2 below as represented by the interim OATT charges for/under Network Service, Schedules 1, 2, 3C, 4, 9 and 10 expenses while the OATT Operations expense is the amount, primarily supervision and labour costs, for the OATT administration and operation.

SCHEDULE 9-2			
Maritime Electric OATT Expenses ($)			
Description	**2014 Actual**	**2015 Forecast**	**2016 Forecast**
Network Service	$ 5,124,080	$ 5,543,800	$ 5,681,300
Schedule 1	203,133	219,800	225,200
Schedule 2	328,445	355,300	364,200
Schedule 3C	11,472	-	-
Schedule 4	653,390	-	-
Schedule 9	74,928	74,900	74,900
Schedule 10	70,956	36,100	-
OATT Operations	172,169	365,000	319,500
Total	**$ 6,638,573**	**$ 6,594,900**	**$ 6,665,100**

9.2 Distribution Expenses

The accounts in Schedule 9-3 provide for the day-to-day operation and maintenance of the Company's energy distribution system.

SCHEDULE 9-3			
Distribution Expenses ($)			
Description	**2014 Actual**	**2015 Forecast**	**2016 Forecast**
Substations	$ 74,392	$ 102,200	$ 103,300
Rights of Way	1,081,972	1,191,300	1,328,900
Line Maintenance	1,596,394	1,983,200	1,867,700
Line Control Devices	46,953	71,600	84,000
Transformers	418,842	453,800	557,500
Meters	154,819	181,300	238,800
Communications Systems	169,065	197,600	207,500
Supervisory SCADA	92,321	104,000	121,700
Engineering	290,446	350,600	459,400
Total	**$ 3,925,204**	**$ 4,635,600**	**$ 4,968,800**

Substations –

$74,392 (2014), $102,200 (2015), $103,300 (2016)

This account provides for the inspection and maintenance of the Company's distribution substations. It also includes labour, material and transportation to maintain the switches, insulators, bus connectors, substation fence and ground grid and vegetation management inside the substation fence.

Rights of Way –

$1,081,972 (2014), $1,191,300 (2015), $1,328,900 (2016)

This account provides for the inspection and maintenance of the rights of way for the Company's approximately 5,000 km of distribution lines. Cyclical tree trimming and clearing over a targeted five to seven year timeline, plays a significant role in reliability and service quality, particularly in the windy environment of PEI, and results in variances from year to year. The majority of the expenditure in this account is for contract labour.

Line Maintenance –
$1,596,394 (2014), $1,983,200 (2015), $1,867,700 (2016)

This account provides for the maintenance and inspection of over 5,000 km of distribution lines, service lines to over 78,000 customers and 10,000 streetlights. Expenditures are driven by preventative maintenance, customer requests, and storm damage. Activities include repairing wires and connectors during no power calls, replacing fuses, straightening poles, retightening guy wires, repairs to underground services and streetlight maintenance. This account also includes expenditures for small tool and equipment purchases, flame resistant safety clothing, and tool and equipment testing.

Line Control Devices –
$46,953 (2014), $71,600 (2015), $84,000 (2016)

This account provides for the maintenance and inspection of capacitors, voltage regulators and reclosers including inspection, replacing broken bushings, repainting and repairing control modules.

Transformers –
$418,842 (2014), $453,800 (2015), $557,500 (2016)

This account provides for the inspection and maintenance of over 33,200 distribution transformers, which includes both polemount and padmount units. The activities include inspection, testing, replacing broken bushings, repainting, PCB management and oil spill cleanup.

Meters –

$154,819 (2014), $181,300 (2015), $238,800 (2016)

This account provides for the inspection and maintenance of over 78,000 revenue meters. Maintenance is driven by compliance with Measurement Canada rules and regulations and the number of units maintained changes year over year. Meters are sent to an outside lab for testing to determine if the sample set of meters meet industry standards or require replacement.

Communications Systems –

$169,065 (2014), $197,600 (2015), $207,500 (2016)

This account collects the costs required to maintain radios installed in vehicles, hand held radios, fibre optic cables and power line carrier equipment to operate the Company's protection and control facilities and communications systems.

Supervisory SCADA –

$92,321 (2014), $104,000 (2015), $121,700 (2016)

This account collects the costs to maintain the SCADA system which controls and acquires data from the distribution and transmission system and transmits this information through the communication system to the Energy Control Centre. Equipment inspection and maintenance and licensing fees account for the majority of the expenditures.

Engineering –

$290,446 (2014), $350,600 (2015), $459,400 (2016)

This account provides for the engineering support and analysis required to design, operate and maintain the energy distribution system. Activities include fuse coordination studies, power flow analysis to ensure lines are not overloaded or the voltage is too low, changing protection equipment settings to meet load growth and overall system oversight and planning not associated with capital projects.

9.3 Transmission and Distribution Expenses - Other

The accounts in Schedule 9-4 provide for other expenses that are common to both the transmission and energy distribution system.

SCHEDULE 9-4 Transmission and Distribution Expenses - Other ($)			
Description	**2014 Actual**	**2015 Forecast**	**2016 Forecast**
Insurance	$ 96,234	$ 100,000	$ 99,900
Property Tax	1,897,754	1,928,000	2,113,600
Professional Development and Training	69,927	92,700	93,400
Total	**$ 2,063,915**	**$ 2,120,700**	**$ 2,306,900**

Insurance –

$96,234 (2014), $100,000 (2015), $99,900 (2016)

This amount includes the cost of providing the necessary insurance coverage available for the Company’s transmission and distribution system substation assets. Insurance is procured by Fortis on behalf of its group members which allows Maritime Electric to obtain insurance coverage on assets that is economically priced and for which it would be unable to procure if it were seeking coverage independently.

Property Tax –

$1,897,754 (2014), $1,928,000 (2015), $2,113,600 (2016)

This amount includes the cost of property taxes attributable to the Company’s transmission and distribution system. Property taxes are levied as either a tax on physical properties based upon their assessed values or a revenue related tax calculated at 1.0 per cent of the Company’s annual revenue. The revenue related tax is used as a proxy for the taxation of the Company’s transmission and distribution assets situated on public right of ways.

Professional Development and Training –

$69,927 (2014), $92,700 (2015), $93,400 (2016)

This account captures the professional development and training costs for employees working to maintain a reliable transmission and distribution system.

9.4 Summary

A summary of this section follows:

- Total transmission system related operating expenses were $7,560,200 in 2014 and are forecast to be $7,224,000 for 2015 and $7,565,200 for 2016.
- Total distribution system related operating expenses were $3,925,204 in 2014 and are forecast to be $4,635,600 for 2015 and $4,968,800 for 2016.
- Total transmission and distribution expenses - other were $2,063,915 in 2014 and are forecast to be $2,120,700 for 2015 and $2,306,900 for 2016.

10.0 GENERAL AND ADMINISTRATIVE EXPENSES

General and Administrative Expenses are comprised of internal and external costs required for the overall operation and management of the Company. In Order UE09-02 the Commission disallowed, for the purpose of determining the Company's annual revenue requirement, all Fortis Inc. head office administrative costs charged to the Company. As a result, the costs presented in this section do not contain any Fortis Inc. administrative costs.

10.1 General and Administrative Expenses

Schedule 10-1 outlines the General and Administrative Expenses for the period 2014 – 2016.

SCHEDULE 10-1			
General and Administrative Expenses ($)			
Description	**2014 Actual**	**2015 Forecast**	**2016 Forecast**
Customer Service and Meter Reading	$ 2,097,854	$ 2,238,100	$ 2,234,200
Finance and Accounting	1,373,771	1,444,500	1,469,300
Corporate Communications and Public Affairs	539,372	511,000	457,100
Information Technology	498,968	531,500	512,500
Regulation	714,279	922,200	1,009,300
Directors' Fees and Expenses	167,041	246,000	220,500
General Property - Tax and Maintenance	720,184	730,900	719,900
Corporate Services and Support	4,300,466	3,804,500	3,007,100
Total	**$ 10,411,935**	**$ 10,428,700**	**$ 9,629,900**

Customer Service and Meter Reading –
$2,097,854 (2014), $2,238,100 (2015), $2,234,200 (2016)

These costs reflect the operation of the Company's Customer Service and Meter Reading functions. Included are internal labour and training costs related to meter reading and the customer service staff, costs paid to collection agents, damage claims, materials and supplies.

This category also includes bill payment processing costs related to collection of overdue accounts, customer communications costs, bad debt expense and other miscellaneous costs.

The cost of reading customers' meters for billing purposes also includes materials, meter reading device maintenance costs and transportation costs.

Finance and Accounting -
$1,373,771 (2014), $1,444,500 (2015), $1,469,300 (2016)

This category captures the costs associated with maintaining accurate and complete financial records, financial reporting and internal controls. Included are costs associated with customer billing including related internal labour and training, bill printing, enclosing and postage. This category also includes the cost of the annual external audit of the Company's financial statements.

Corporate Communications and Public Affairs -
$539,372 (2014), $511,000 (2015), $457,100 (2016)

Included in this category are the internal labour and training costs for those responsible for all aspects of disseminating information and communicating with stakeholders regarding the activities of the Company. Delivery of educational and safety programs, donations to Island charities and community activities, development and delivery of business services and customer based web services, and public consultations are also included in these activities.

Information Technology -

$498,968 (2014), $531,500 (2015), $512,500 (2016)

Included in this category are internal labour and training costs as well as costs associated with certain ongoing software maintenance agreements required to maintain the key IT systems of the Company. Such systems include work planning, customer information and billing, service order management, outage management and dispatching as well as cyber security and web site management.

Regulation –

$714,279 (2014), $922,200 (2015), $1,009,300 (2016)

Included in this category is the annual assessment by IRAC as well as the cost of internal resources associated with regulatory filings and proceedings. This account also captures the external legal and consulting costs related to various regulatory matters.

Directors' Fees and Expenses –

$167,041 (2014), $246,000 (2015), $220,500 (2016)

This account captures the fees paid to Maritime Electric's Board of Directors and expenses incurred by them while performing their duties as Board members. This account may also be charged with legal and consulting costs if such work is required by the Board. The fees are reviewed every three years to ensure they remain competitive, enabling Maritime Electric to attract quality people to serve on the Board.

General Property - Tax and Maintenance

$720,184 (2014), $730,900 (2015), $719,900 (2016)

This account collects the cost of operating and maintaining the Company's buildings at 180 Kent Street, West Royalty, Sherbrooke and Roseneath Service Centres. Included are costs for general maintenance, janitorial services, security, fire prevention, elevator repair and maintenance, snow removal, HVAC and other miscellaneous costs as well as the property taxes associated with these properties. Property taxes related to the generating activities, distribution and transmission are discussed in Sections 8 and 9 respectively.

Corporate Services and Support -
$4,300,466 (2014), $3,804,500 (2015), $3,007,100 (2016)

This category captures the labour related costs for the Executive and certain Managerial and Supervisory staff associated with administrative support, health, safety and environment, human resources, internal audit and corporate planning as well as the related supplies and materials, communications and courier charges.

Rating fees charged by Standard & Poor's, trustee fees on Corporate bonds, costs related to employee future benefits, travel costs, employee training costs, legal fees and other general operating costs are also charged here. This account also includes the cost of providing the necessary General Liability and Directors and Officers insurance coverage for the Company. Insurance costs specific to the generating activities and distribution and transmission equipment are discussed in Sections 8 and 9 respectively.

10.2 Summary

A summary of this section follows:

- General and Administrative operating expenses were $10,411,935 in 2014 and are forecast to be $10,428,700 for 2015 and $9,629,900 for 2016.

11.0 AMORTIZATION EXPENSES

11.1 Background

Proper and adequate depreciation requires the Company to maintain depreciation accounts whereby, over the useful life of the various asset classes, the capital asset costs incurred by the Company are expensed and recovered from customers as a cost of providing electric service.

Depreciation expense is calculated on the basis of rates of depreciation assigned to each class of the Company's assets. Good utility practice is to consider changes to depreciation for rate making purposes based upon studies of experts who examine the various asset classes and determine the average service life of these assets for depreciation purposes.

11.2 Depreciation Study

On January 1, 2004, the Company returned to cost of service regulation by IRAC under the terms and provisions of the EPA. In response to Commission Order UE06-02 on August 31, 2006, the Company filed a Depreciation Study prepared by Gannett Fleming based on 2005 financial results ("the 2005 Study"). The Commission subsequently ordered (UE07-01) on March 1, 2007 that the current rates of depreciation of the Company remain in effect until otherwise ordered by the Commission and that a further Depreciation Study be filed with the Commission within 36 months of the date of the Order.

Prior to completing the next depreciation study, the Company advised the Commission of the impending changes announced by the Canadian Accounting Standards Board and that the appropriate methodology (the Equal Life Group Methodology or the Average Service Life Methodology) for purposes of undertaking a Depreciation Study, for those companies impacted by the changes, had not been determined. As a result, on March 8, 2008, the Commission ordered

(UE08-07) Maritime Electric to defer completion of the Depreciation Study required under Order UE07-01 until further ordered by the Commission and that Maritime Electric provide quarterly updates to the Commission on the proposed accounting standards.

On December 9, 2010, the Provincial Government enacted the Electric Power (Electricity Rate Reduction) Amendment Act, (S.P.E.I. 2010, c. 9) and on December 7, 2012, the Provincial Government enacted the Electric Power (Energy Accord Continuation) Amendment Act, (S.P.E.I. 2012, c. 6). These two pieces of legislation established a period between March 1, 2011 and February 29, 2016, collectively referred to as the PEI Energy Accord, which among other things established annual input factors for the years 2011-2015, including depreciation, and fixed the rates, tolls and charges of Maritime Electric.

Recognizing the PEI Energy Accord's end on February 29, 2016 and the Company's return to cost of service regulation for purposes of rate setting effective March 1, 2016, the Company, in 2014, engaged Gannett Fleming, a firm with expertise in preparing depreciation studies for utilities, to prepare a depreciation study ("2014 Gannett Fleming Depreciation Study" or "the 2014 Study"). The 2014 Study was based upon financial results and the assets in service up to and including December 31, 2014.

The 2014 Study was included as part of a Depreciation Study Application (IRAC Docket UE21603) filed by the Company to adjust depreciation rates effective January 1, 2016 since the Accord did not establish input factors for the period between January 1, 2016 and February 29, 2016. For purposes of establishing the 2016 revenue requirement and resulting customer electricity rates, this Application reflects the proposals contained in the Depreciation Study Application filed with the Commission on July 23, 2015.

In the Depreciation Study filing, the Company proposes the following:

a. Depreciation Rates:

The Company proposes to adopt the depreciation rates (as summarized in Section 11.2) recommended in the 2014 Depreciation Study that, prospectively, incorporate the estimated average service life of assets and a prudent allowance for the cost of removal of assets upon retirement. It is proposed that these depreciation rates be calculated and adopted as of January 1, 2016 and be incorporated into this Application for approval of new rates, tolls and charges for electric service for the period beginning March 1, 2016. This change in depreciation rates will serve to prevent further increases in the accumulated reserve variance (assuming status quo in other variables). This proposed change in depreciation rates will result in an increase of approximately $1.981 million (based on 2014 asset values) in annual depreciation expense.

b. Accumulated Reserve Variance Amortization

i. Given the Charlottetown Thermal Generating Station's (CTGS) impending retirement, it is proposed that the Company be ordered to adjust depreciation rates to incorporate the amortization of the accumulated reserve variance associated with the CTGS as recommended by the 2014 Depreciation Study. This increase in depreciation rates would result in an estimated increase in annual depreciation expense of $2.117 million (based on 2014 asset values).

ii. With respect to all other asset classes, including the Borden Generating Station (BGS), it is proposed, given the need to balance the rate impact of the proposed increases in a) and b)(i) above, that further steps required to amortize the accumulated reserve variance be deferred, until the filing of a subsequent Depreciation Study.

c. Other Matters

i. The Company proposes to undertake a Decommissioning Study with respect to the CTGS that will provide an estimate of the cost of decommissioning and retiring the facility and incorporates Management's plans to potentially stage the retirement of individual generation units at the CTGS, and that this study be filed with the Commission no later than June 30, 2018.

ii. A Depreciation Study will be prepared incorporating financial results up to December 31, 2017 and filed with the Commission no later than June 30, 2018. The study shall be part of an Application that will include: a) recommendations on the amortization of the accumulated reserve variance for all other asset classes; b) an updated proposed depreciation rate adjustment recommendation reflecting Management's updated plans with respect to the timing of the retirement of the CTGS; and c) the findings from the Decommissioning Study noted above, to ensure a prudent plan is implemented to provide for adequate and prudent depreciation rates and an adequate reserve for future site removal of the CTGS.

Schedule 11-1 below provides a summary of the impact of the proposals in a) and b) above, based upon 2014 asset values.

SCHEDULE 11-1			
Estimated Impact* of Depreciation Study Proposals on Annual Depreciation Expense ($ 000's)			
Asset Class	**New Depreciation Rates**	**Amortization of Accumulated Reserve Variance**	**Total**
Charlottetown Thermal Generating Station	$ 1,239	$ 2,117	$ 3,356
Borden Generating Station	295	-	295
Combustion Turbine #3	(76)	-	(76)
Transmission Plant	(31)	-	(31)
Distribution Plant	978	-	978
General Plant and Other	(424)	-	(424)
Total	**$ 1,981**	**$ 2,117**	**$ 4,098**

* *based on 2014 values*

11.3 Amortization of Fixed Assets

The purpose of amortization (or depreciation) of fixed assets is to recover the previously approved cost of these assets, through rates, over their useful life. Amortization is an estimate based upon the best information available. Maritime Electric uses the straight line method of amortization, based on the estimated average service lives of the assets. Only ½ year of amortization expense is recorded in the assets' first year of service. The amortization of customer contributions toward the cost of construction of service lines or line extensions is netted against the amortization of fixed assets as per current Accounting Standards for Private Enterprises ("ASPE"). The fixed asset amortization rates used by Maritime Electric since 2003 and the rates proposed for adoption for 2016 (based on the 2014 Study) are presented in Schedule 11-2 below.

SCHEDULE 11-2		
Fixed Asset Amortization Rates (%)		
Category	**2003-2015 (Actual)**	**2016 (Proposed)**
Charlottetown Thermal Generating Station		
▪ Structures and Improvements	2.50	9.35
▪ Boiler Plant Equipment	2.50	7.65
▪ Turbogenerator Units	2.50	8.20
▪ Accessory Electrical Equipment	2.50	5.14
▪ Miscellaneous Power Plant Equipment	2.50	6.99
Borden Generating Station	2.50	4.81
Combustion Turbine #3	2.50	2.28
Transmission Assets	2.30	2.27
Distribution Assets	3.00	3.32
General Assets	6.73	5.96
Weighted Average	**3.05**	**3.41**

Based on the actual and proposed amortization rates, the fixed asset amortization expense was $15,120,635 in 2014 and is forecast to be $15,625,500 for 2015 and $21,031,900 for 2016.

11.4 Summary

A summary of this section follows:

- The Company is proposing to adjust its fixed asset amortization rates effective January 1, 2016 in accordance with the proposals outlined in the Depreciation Study Application (IRAC Docket UE21603) filed with the Commission on July 23, 2015.
- The amortization expense for fixed assets is forecast to be $15,625,500 for 2015 using currently approved amortization rates.
- The amortization expense for fixed assets is forecast to be $21,031,900 for 2016 using the proposed new amortization rates.

12.0 FINANCIAL OBJECTIVES

12.1 Financial Objectives

To compete for financing at rates that allow the Company to continue to invest in the energy delivery infrastructure while providing service at the lowest possible cost to electricity consumers on Prince Edward Island, the following financial objectives must be met:

i. Maintain a debt ratio in the range of 57 per cent to 60 per cent and a common equity ratio in the range of 40 per cent to 43 per cent;

ii. Maintain coverage ratios on total debt interest in the range of 2.4 times to 2.6 times; and

iii. Provide a risk adjusted return to the Shareholder commensurate with that of comparable investor-owned utilities.

12.2 Capital Structure and Interest Coverage

Maritime Electric finances its investment in infrastructure with a combination of debt (short-term debt and long-term first mortgage bonds) and Shareholder equity. To minimize the total cost of this financing, a balance between the two (referred to as the target capital structure) is required.

The target capital structure provides the necessary interest coverage and flexibility to ensure the financial viability of the Company and lowest financing costs available. Under the EPA, the minimum common equity component of the Company's capital structure is set at 40 per cent. To ensure that the Company's capital structure remains flexible and able to adapt to changing market conditions, it is proposed that the common equity component of the Company's capital structure remain in the range of 40 per cent to 43 per cent with a target below the midpoint.

SECTION 12 – FINANCIAL OBJECTIVES

The target capital structure of Maritime Electric is based upon:

- The embedded and forecast cost of debt;
- The cost of common equity;
- The requirement contained in the EPA for the Company to maintain a minimum of 40 per cent common equity in its capital structure;
- Providing sufficient flexibility to allow for future external financing; and
- Maintaining adequate debt interest coverage ratios to ensure access to debt markets.

The Company recognizes that a higher common equity component in its capital structure increases its total weighted average cost of capital ("WACC") and, in turn, the financing costs to be recovered from customers. As a result, the Company has, for purposes of establishing the 2016 revenue requirement, targeted its total average common equity percentage at a forecast level of 40.5 per cent, slightly above the legislative minimum under the EPA.

The following Schedule shows the Company's average capital structure for the period 2014 - 2016.

SCHEDULE 12-1			
Average Capital Structure 2014 - 2016 (%)			
	2014 Actual	**2015 Forecast**	**2016 Forecast**
Debt	55.7	57.5	59.5
Equity*	44.3	42.5	40.5
Total	**100.0**	**100.0**	**100.0**

* *Contains non-regulated equity of 0.8 per cent in 2014 and 0.4 per cent in 2015.*

Although debt financing is usually less expensive than equity financing, a balance between these two options must be reached in order to keep the total WACC as low as possible. A larger proportion of debt leads lenders to view their investment as higher risk, requiring higher returns (interest) on the debt, thereby increasing costs. Higher proportions of debt also cause equity investors to require a higher rate of return. Conversely, while increasing equity levels will reduce the debt holders' risk (and required return) it increases the total cost of capital due to the higher return required on the thicker equity ratio. The investor return required (both debt and equity) reflects the investors' perception of business and financial risk associated with the investment.

Schedule 12-2 below shows the 2016 forecast average common equity component for the Company and the currently authorized common equity component for other Canadian utilities.

SCHEDULE 12-2	
Forecast and Authorized Common Equity Component (%)	
Utility	**Common Equity Component**
ATCO Electric Distribution	38.0
FortisAlberta	40.0
FortisBC Electric	40.0
Newfoundland Power	45.0
Nova Scotia Power	37.5*
Average	**40.1**
Maritime Electric	**40.5**

* *Nova Scotia Power also has approximately 3.8 per cent in Preferred Equity.*

If Maritime Electric is to compete for funds on a basis similar to other utilities it must maintain a similar and comparable risk profile. One basis of comparison is the ability to pay dividends. The inability to pay dividends on a consistent basis may result in considerably more restrictive covenants for new debt issues, limitations on the term for which investors are prepared to lend, and ultimately a higher cost of financing. The regular payment of dividends also assists in maintaining an appropriate balance between debt and equity.

SECTION 12 – FINANCIAL OBJECTIVES

The Company is forecasting the payment of both regulated and non-regulated dividends in 2015 and 2016. Regulated dividends represent amounts paid out of the equity retained in the Company to support the regulated operations and upon which the Company is allowed a regulated return.

Non-regulated dividends arise from a non-regulated equity contribution by the Shareholder through a tax sharing agreement between the Companies. As a non-regulated component of equity, the Company does not seek to earn a regulated return on this amount and, as a result, there is no revenue requirement to be recovered from customers. Since the Shareholder does not earn a return on this equity, it has requested that the non-regulated equity be returned.

Schedule 12-3 shows Maritime Electric's actual and forecast dividend payments for the period 2014 – 2016.

SCHEDULE 12-3 Dividends ($)			
	2014 Actual	**2015 Forecast**	**2016 Forecast**
Regulated	$ 8,000,000	$ 8,000,000	$ 8,000,000
Non-Regulated	-	3,184,271	722,500
Total	**$ 8,000,000**	**$ 11,184,271**	**$ 8,722,500**

The Corporate Credit Rating, a measure of the Company's overall credit worthiness, is based upon an independent analytical review by Standard & Poor's (S&P) of the Company's capital structure, earnings, cash flows, financial position and an analysis of Company-specific and industry-related issues. The most recent report on the Company by S&P ("S&P Report"), dated March 31, 2015, is included in Appendix 7.

As noted in the S&P Report, the Company's Corporate Credit Rating is BBB^{+}

(stable outlook); two notches above the minimum rating the markets consider being investment grade, while its long-term debt is currently rated at A (investment grade). Maritime Electric's stand-alone credit profile is only rated BBB, however, a one notch rating uplift is given to the Company by virtue of being owned by Fortis. This improved credit rating serves to lower borrowing costs and increase access to potential lenders of long-term debt.

Common equity is comprised of the Shareholder's investment in common shares and retained earnings. The level of common equity in the capital structure must be such that the resulting earnings provide for debt interest coverages within the targeted range, without undue burden on consumers.

Target interest coverages are designed to ensure that the Company's long-term debt remains competitive with that of other similarly rated companies, enabling it to compete for funds in the capital markets. Interest coverage ratios are used by credit rating agencies and debt lenders to assess the adequacy of the Company's capital structure and associated investment risk. The earnings before interest and taxes (EBIT) coverage measure is calculated by dividing operating income and allowance for funds used during construction by total interest and debt issue costs to determine the number of "times" that operating income can cover the interest costs. Management believes that the target debt interest coverage of 2.4 times to 2.6 times meets the requirements established earlier and is appropriate for supporting the Company's debt rating.

12.3 Interest Costs

This section discusses the costs associated with financing through the use of short-term and long-term debt.

12.3.1 Long-Term Debt Interest

Schedule 12-4 below shows the Company's actual and forecast long-term debt and annual long-term debt interest expense for 2014 - 2016.

SCHEDULE 12-4						
Annual Interest Expense on Long-Term Debt ($)						
Issue Date	**Maturity Date**	**Principal Amount**	**Interest Rate (%)**	**2014 Actual**	**2015 Forecast**	**2016 Forecast**
Aug. 15, 1991	Aug. 15, 2016	12,000,000	11.500	$ 1,380,000	$ 1,380,000	$ 805,000
Dec. 7, 1993	Dec. 7, 2018	15,000,000	8.550	1,282,500	1,282,500	1,282,500
Dec. 22, 2000	Dec. 22, 2025	15,000,000	7.570	1,135,500	1,135,500	1,135,500
Jan. 15, 1997	Jan. 15, 2027	15,000,000	8.625	1,293,750	1,293,750	1,293,750
Jul. 3, 1996	Jul. 3, 2031	20,000,000	8.920	1,784,000	1,784,000	1,784,000
Apr. 2, 2008	Apr. 2, 2038	60,000,000	6.054	3,632,400	3,632,400	3,632,400
Dec. 5, 2011	Dec. 5, 2061	30,000,000	4.915	1,474,500	1,474,500	1,474,500
Jul. 1, 2016*	Jul. 1, 2046	40,000,000	4.500	-	-	750,000
Total				**$ 11,982,650**	**$ 11,982,650**	**$ 12,157,650**

* *Forecast First Mortgage Bond Issue*

As shown in the table above, the Company's highest rate debt issue, $12 million at 11.50 per cent, matures on August 15, 2016. Based on forecast short-term borrowing levels for 2016, the Company expects to replace the maturing debt issue and accumulated short-term debt with a new $40 million first mortgage bond issue in July 2016 at a forecast rate of 4.50 per cent. Approval of this borrowing will be subject to a separate application submitted to the Commission in 2016 once the Company finalizes the debt issue timing and receives indicative pricing from independent capital market advisors.

Maritime Electric uses the effective interest method of accounting for the costs associated with issuing debt. The Company has estimated that the costs associated with the 2016 debt issue will be approximately $200,000. Under the effective interest method, these costs will be recorded as a deferred charge and amortized over the term of the debt in accordance with IRAC Order UE06-05. The Company has forecast $5,000 of interest expense in 2015 arising from the amortization of existing deferred debt issue costs. In 2016, the forecast expense will increase to $6,300 as a result of the expected new debt issue in that year.

12.3.2 Short-Term Debt Interest

The short-term financing requirements for Maritime Electric include, amongst other things, energy-related costs, operating and maintenance costs, tax installments, inventory purchases and payroll costs. To meet these requirements, the Company maintains a $50.0 million committed unsecured credit facility with TD Bank as well as a $5.0 million operating line with Scotiabank. Maritime Electric continues to benefit from the combined borrowing power of the Fortis group of companies as it is able to borrow funds at a lower interest rate than it would be able to negotiate on its own. The Company uses Banker's Acceptances (BAs) where appropriate, to reduce its annual borrowing costs versus the use of its operating line. BA interest rates range between 1.74 and 2.10 as compared to the operating line which bears interest at the Scotiabank prime rate.

Based on the evidence in this Application, the results of the financial forecast indicates that at December 31, 2015 and at December 31, 2016, Maritime Electric will have $29,246,000 and $15,222,900 in short-term debt outstanding, respectively with forecast short-term interest costs of $694,600 and $741,600, respectively. In addition to the day to day short-term borrowing requirements noted above, short-term borrowings and short-term interest expense in 2016 reflects the repayment of the $12.0 million long-term debt issue that matures in 2016.

12.3.3 Allowance for Funds Used During Construction

Maritime Electric provides for the cost of financing construction work in progress by including an Allowance for Funds Used During Construction (AFUDC) as an addition to the cost of property constructed. The AFUDC rate reflects the cost of the Company's debt and equity financing. This allowance is charged to operations through amortization over the service life of the related assets ensuring that the cost is paid, not just by those who are customers during the period of construction, but by those customers who benefit from the asset during its useful life. The forecast of AFUDC is $ 200,000 for both 2015 and 2016.

12.4 Return on Average Common Equity

With the expiry of the Accord and a return to cost of service regulation on March 1, 2016, Management engaged Concentric Energy Advisors ("Concentric") to perform an independent analysis of the Company's cost of capital and provide recommendations on an appropriate ROE for 2016. Their evidence is included with this Application in Appendix 8.

Maritime Electric is requesting that the Commission accept our expert's evidence indicating an average ROE range of 9.5 - 9.9 per cent as being appropriate for this Application and allow, for purposes of determining the 2016 revenue requirement, an ROE of 9.7 per cent. The requested return is based on a forecast average common equity of 40.5 per cent, just above the legislated minimum 40 per cent under the EPA and at the lower end of the Company's target equity range of 40 - 43 per cent. It is the Company's view that the proposed range of return and the target ROE in combination with the expected common equity level is reasonable for purposes of setting revenue requirement for 2016.

As recognized by the Commission in past Orders, the Company continues to have a higher overall level of risk than other Atlantic Canadian electric utilities and comparable utilities across Canada. The higher total risk assessment is driven by a number of factors which, relative to its peers, impact both the operational or business risk and the financial risk profile of the Company. The report from Concentric Energy Advisors states that business risk for a regulated utility results from variability in cash flows and earnings that impact the ability of the utility to recover its costs including the fair return on, and of, its capital in a timely manner. Business risk includes both operating risk and regulatory risk.

From an operating risk perspective, Maritime Electric is subject to greater risk from both adverse economic developments and damaging weather events due to its smaller size relative to other electric utilities and Island location resulting in a concentration of customers and assets in a restricted geographic area. The loss of a significant customer and local employer, such as the closure of the McCain processing facility in October 2014, or a significant storm can impact the Company's cash flows and ability to recover its costs in a timely manner resulting in increased debt levels and corresponding erosion in the common equity component of the capital structure. Several utilities have regulator approved deferral accounts to manage these unexpected events and provide a mechanism to address them in customer rates. Although the Commission has permitted recovery of extraordinary storm costs in the past and the Company would continue to seek relief for extraordinary storm costs, Maritime Electric does not have the relative certainty of such deferrals. In addition, the projected changes in the demographics of the customer base on PEI are expected to restrict the long term growth rate of the PEI economy and consumption of goods which could restrict sales growth, cash flow and cost recovery.

The Island location also presents unique energy supply and operating risks. With only wind generation and limited solar applications currently available as local energy supply resources, the Company is dependent upon off-island energy supply sources provided through the existing and planned submarine cables. Due to off-island transmission constraints outside the Company's control and its legislated obligation to serve its customers, the Company is therefore required to have sufficient on-island generating capacity in place to meet the supply demands of customers. Challenges operating the aging CTGS, sourcing economically priced fuel and retaining a skilled workforce at a facility with a planned retirement in the near term all present incremental business risks to Maritime Electric.

The nature of Maritime Electric's operational responsibility for integrated generation, transmission and distribution activities increases its comparable risk level in relation to other utilities which, in several cases, have minimal to no generation or transmission responsibilities. The generation function is generally regarded by investors as being higher risk than electric transmission or distribution. In Order UE10-03 dated July 12, 2010, the Commission agreed that Maritime Electric's responsibility for electricity supply was a significant difference as compared to Ontario electric distribution utilities. The Commission also stated in this Order that it:

> *"views Maritime Electric as higher risk than the benchmark BC Utility and FortisBC due to a variety of factors such as utility size, nature of operations, economic climate within which it operates and regulatory risk factors."*

Over the last twenty years, the PEI regulatory framework governing Maritime Electric's operations has been changed multiple times by the Provincial Government. Between May 1, 1994 and December 31, 2003, the Company operated in a price cap environment in accordance with the provisions of the Maritime Electric Company Limited Regulation Act. On January 1, 2004, the Company returned to cost of service regulation (the form of regulation prior to May 1, 1994) by IRAC under the terms and provisions of the EPA. As a result of these legislative changes, Maritime Electric faces higher levels of regulatory risk when comparing to utilities in other jurisdictions.

The most recent change occurred in late 2010 when legislated electricity rates were adopted under the PEI Energy Accord, effectively removing IRAC from the rate setting process until February 29, 2016. As part of the Accord, the Provincial

Government established the PEI Energy Commission to review the future of electricity on PEI. The Commission made a number of recommendations that would potentially impact the Company's electricity franchise, including taking ownership of the Company's current and future generating assets and legislatively setting a lower equity component in the Company's capital structure. In response to the recommendation with respect to ownership of generation assets, the Provincial Government has announced its intention to introduce legislation to give Government the option to own future Maritime Electric generating assets, including the proposed 50 MW Combustion Turbine #4 currently before IRAC.

The most recent S&P Report (Appendix 7) on Maritime Electric dated March 31, 2015, issued prior to Government's announcement with respect to ownership of generation assets, commented on the relatively limited independence of the Regulator on PEI caused by Government involvement. The S&P Report states:

> *"The provincial government continues to play a significant and active role in energy policy and establishing rates for island customers. We view this as generally less favorable than an independent regulator with a clear, consistent mandate and an established track record of credit-supportive policies. Due to the potential for political interference (which could negatively affect credit quality), the regulator's limited strength, and its independence, we view the Maritime Electric's regulatory environment as less favorable compared with those of regulated utilities operating in other Canadian provinces."*

The S&P Report categorizes the Company's financial risk profile as "aggressive" based upon an expectation of low but stable cash flows and a legislated minimum equity base of 40 per cent.

Schedule 12-5 below is the Business and Financial Risk Metric used by S&P in its report.

SCHEDULE 12-5						
S&P Business and Financial Risk Matrix						
	Financial Risk Profile					
Business Risk Profile	**Minimal**	**Modest**	**Intermediate**	**Significant**	**Aggressive**	**Highly leveraged**
Excellent	aaa/aa+	aa	a+/a	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

Financial risk increases as the Utility incurs higher levels of debt in financing its operations as there is a greater risk that it may not have sufficient cash flow to meet the fixed interest and debt repayment requirements. The aggressive category assigned by S&P is one level below that assigned to comparable utilities which implies a higher level of financial risk than other utilities.

Schedule 12-6 below shows the comparative S&P rankings for the Canadian and US proxy groups used by Concentric in its report.

SCHEDULE 12-6			
S&P Business Risk and Financial Risk Rankings			
	S&P Rating	**Business Risk**	**Financial Risk**
Canadian Proxy Group			
Canadian Utilities Ltd.	A	Excellent	Significant
Emera	BBB+	Excellent	Significant
Enbridge, Inc.	A-	Excellent	Significant
Valener, Inc.	BBB+	Strong	Significant
Maritime Electric	**BBB+**	**Excellent**	**Aggressive**
US Proxy Group			
ALLETE, Inc.	BBB+	Strong	Significant
Duke Energy Corporation	BBB+	Excellent	Significant
Eversource	A-	Excellent	Significant
Great Plains Energy Inc.	BBB+	Excellent	Significant
OGE Energy Corporation	A-	Strong	Intermediate
Pinnacle West Capital Corp.	A-	Excellent	Intermediate
Westar Energy, Inc.	BBB+	Excellent	Significant

The interest coverage ratio is a key measure of the Company's ability to meet its debt obligations and is a key covenant in some of its credit facilities. It is the Company's view that an Earnings Before Interest and Taxes (EBIT) coverage ratio in the range of 2.4 to 2.6 times is a reasonable target given the Company's relatively weaker financial risk profile and the need to compete for sources of financing. Schedule 12-7 below compares Maritime Electric's actual and forecast EBIT coverage ratios for 2011 – 2016 which shows that from 2011 to 2014 the ratio has been at the bottom of the target range (2.4 times) with only moderate improvement to 2.5 times forecast for 2015 and 2016.

SCHEDULE 12-7					
Interest Coverage (Times)					
2011 Actual	**2012 Actual**	**2013 Actual**	**2014 Actual**	**2015 Forecast**	**2016 Forecast**
2.4	2.4	2.4	2.4	2.5	2.5

Reductions in the allowed ROE or the related equity component of capital structure could lead to deterioration of the interest coverage ratio and potentially put downward pressure on the Corporate Credit Rating.

The S&P Report confirmed Maritime Electric's Corporate Credit Rating which reflects its stand-alone credit profile of BBB plus a one-notch upgrade to BBB+ to reflect the potential for credit support from Fortis. The Company's BBB+ corporate credit rating remains below the average A-[5] rating assigned by S&P to the universe of Canadian utilities that they rate. S&P notes in their report that a downward revision could happen if the Company's adjusted funds from operations falls and remains below 9 per cent from an expected 11 - 12 per cent for 2016. S&P notes that a lower adjusted funds from operations percentage:

> *"could happen if there were to be an adverse change in government policy, material operational difficulties, challenges in recovering deferral accounts, or a significantly adverse regulatory ruling impairing timely recovery of cash flows."*

These factors are some of the business or operational risks noted previously that differentiate Maritime Electric from neighbouring utilities.

Since the last Application filing in 2010, when economies were just beginning to recover from the global financial crisis, economic and capital market conditions have somewhat improved. However, it is recognized that the global economy is

[5] See Appendix 7 - S&P Ratings Report dated March 31, 2015.

now more interdependent than ever with disruptions in economies like China having immediate and sometimes lingering repercussions on the US and Canadian economies. Since sliding into a technical recession for the first two quarters of 2015, September data indicates that the financial system has stabilized and economic growth has resumed although still at below normal levels. The Bank of Canada has indicated that Canada, the US and other economies continue to be highly dependent on monetary stimulus through historically low interest rates which has resulted in volatile financial markets and lower yields on bonds than seen previously.

The 10 and 30-year Government of Canada bonds yields have declined from July 2010 levels of 3.22 per cent and 3.77 per cent respectively to 1.49 per cent and 2.24 per cent respectively in August 2015 which reflects the prolonged period of monetary stimulus by governments in the wake of the global financial crisis. The suppression of bond yields caused by an aggressive stimulus policy is one of the contributing reasons why many regulatory jurisdictions moved away from determining cost of capital under a formula approach tied to government or corporate bond yields.

The yields on Canadian Utility A- rated corporate bonds have also declined since 2010, although the credit spreads between the Canadian Utility A- rated corporate bonds and government bonds have actually increased by 33 basis points from 1.54 per cent in July 2010 to 1.87 per cent in August 2015. This increased credit spread is an indication that utility risk has not decreased since 2010 but has actually increased in recent months which supports a cost of equity at or near previous assessments.

In determining the appropriate cost of equity range for Maritime Electric, Concentric uses both Canadian and US proxy groups to develop and estimate utility cost of equity using the Discounted Cash Flow (“DCF”) method and the

Capital Asset Pricing Model ("CAPM"). Schedule 12-8 below shows that the Concentric analysis of the proxy groups produced a range of results from 9.0 per cent to 12.8 per cent with an average of 10.1 per cent.

SCHEDULE 12-8			
Proxy Group Cost of Equity Results (%)			
	Canadian Regulated Utilities	**US Electric Utilities**	**North American Electric Utilities**
CAPM	9.0	10.4	10.1
Constant Growth DCF	12.8	9.8	9.6
Multi-Stage DCF	10.3	9.5	9.2

The Concentric evidence also shows that in 2015, the average ROE adopted for comparable US utilities has been 9.71 per cent on an average common equity percentage of 51.11 per cent. Comparability of returns to US electric utilities is appropriate because in today's world of closely integrated economies and capital markets, investors will seek returns in multiple markets and assess investment risk between countries by comparing each country's relative economic conditions and business environments. The correlation between the various economic indicators for Canada and the US has historically been strong indicating the similarity between both countries. Over the last twenty-five years, real GDP growth has been 2.29 per cent for Canada and 2.41 per cent for the US while inflation has been 2.08 per cent in Canada and 2.63 per cent in the US.

Over the last ten years the yield on 10-year government bonds has also been very similar in Canada and the US where the average yield on 10-year Canadian government bonds was 3.17 per cent compared to 3.33 per cent in the US. In addition, in 2014 the average yield on 10-year government bonds was 2.23 per cent in Canada and 2.53 per cent in the US. The strong correlation of the average yields in the two countries suggests that the financial markets are closely integrated.

The level of trade is also an important indicator of the degree to which both economies are tied to one another. In 2014, 76.8 per cent of Canadian exports went to the US while 54.3 per cent of imports to Canada came from the US. A report by the Congressional Research Services rates that Canada is the largest single-national trading partner of the US. A further expansion of the Canada-US trade relationship is expected to occur as a result of the recently announced Trans-Pacific Partnership.

All of these indicators demonstrate that there are no fundamental differences between the Canadian and US economic and capital market environments that would cause a reasonable investor to not expect similar returns from comparable utilities in either country. Therefore, comparison to US electric utilities is considered appropriate and has been used by regulators in other Canadian jurisdictions.

In 2009 and again in 2013, the British Columbia Utilities Commission (“BCUC”) accepted the use of US proxy group data in their ROE decision, primarily due to the lack of sufficient Canadian data but also in recognition of the need for Canadian utilities to compete for capital in a global market. In addition, a 2008 decision by the National Energy Board and 2009 decision by the Ontario Energy Board and the Quebec Régie de L’Energie have also accepted the use of US data and proxy group to establish Canadian allowed ROEs and common equity ratios.

Maritime Electric’s proposed 9.7 per cent on average common equity is comparable to the US proxy group in terms of return, albeit on a much lower 40.5 per cent common equity component. A lower common equity percentage implies a higher level of risk.

In addition to the US returns, the Concentric evidence shows that the 2014 earned returns by Canadian electric utilities averaged 9.61 per cent on average equity of approximately 40.10 per cent, which is comparable to the Company's requested return and average common equity percentage, particularly considering its relative risk level.

Schedule 12-9 below shows the 2014 allowed and earned ROE and the 2015 allowed ROE for Canadian and US electric utilities.

SCHEDULE 12-9 Allowed and Earned ROE (%)			
	2014 Allowed ROE	**2014 Earned ROE**	**2015 Allowed ROE**
Maritime Electric	9.75	9.75	9.75
Canadian Electric Utilities			
Nova Scotia Power	9.00	9.25	9.00
Newfoundland Power Inc.	8.80	9.15	8.80
FortisOntario Inc.	9.36	9.82	9.30
ATCO Electric Distribution	8.30	9.74	8.30
FortisAlberta Inc.	8.30	10.50	8.30
FortisBC Inc.	9.15	9.19	9.15
Average	**8.82**	**9.61**	**8.81**
U.S. Utilities			
Electric Utilities	9.75	N/A	9.71

The difference between the allowed ROE and earned ROE occurs because of differences in the manner in which other jurisdictions establish ROE and revenue requirement as compared to PEI. Maritime Electric has traditionally been regulated by having a cap on ROE for purposes of determining revenue requirement, whereas regulators in other jurisdictions will set revenue requirement and customer rates based upon an allowed or target ROE (or return on rate base). Utilities are then permitted to earn above the allowed or target ROE or return on rates base if they experience higher than forecast sales growth, can achieve cost savings through efficiencies, or the regulator has established an allowed range of return on rate base or some other form of performance based regulation. The result has been that utilities in Ontario and Alberta, which the Commission has previously recognized as having lower risk than Maritime Electric, have been permitted to earn returns at the same level or greater than the maximum return set for the Company.

On a regional basis, the returns of Atlantic Canadian investor-owned utilities also provide a relevant benchmark for ensuring the comparable investment standard is met, recognizing Maritime Electric's higher level of business risk.

The last decision by IRAC with respect to Maritime Electric's ROE was for 2010 when it was set at 9.75 per cent, which was 0.34 per cent above the average 9.41 per cent earned by Newfoundland Power and Nova Scotia Power in that year.

In 2014, Newfoundland Power and Nova Scotia Power earned ROEs of 9.15 per cent and 9.25 per cent respectively, with an average ROE of 9.20 per cent. Maritime Electric's ROE in 2014 was set at 9.75 per cent under the PEI Energy Accord which is 0.55 per cent higher than the average for Newfoundland Power and Nova Scotia Power.

The proposed 9.7 per cent mid-point ROE for 2016, which is 0.50 per cent above the 2014 average earned ROE of Newfoundland Power and Nova Scotia Power, is a reasonable differential for purposes of establishing revenue requirement given Maritime Electric's relatively higher risk profile.

12.5 Composition of Rate Base

Section 1(1)(b) of the EPA defines "rate base" as the maximum valuation of assets fixed by the Commission pursuant to Section 21 upon which a public utility may earn a percentage of return established by the Commission. Section 21 outlines those amounts to be included in rate base as well as amounts the Commission may include or exclude from the calculation.

In addition to these provisions in the EPA, Section 48(12) and Schedule 3 of the EPA were enacted as part of the Accord legislative changes in late 2010. Section 48(12) sets out the requirement for the Company to file the calculation of its average rate base and return on average rate base for the previous year based on its audited financial information using the format and formulas in Schedule 3 of the EPA. Although Section 48(12) is repealed effective March 1, 2016, the Company proposes to continue to apply the approach for calculating and filing its average rate base in a similar manner in this Application.

Using Schedule 3 of the EPA and previous rate base filings with the Commission as the basis for calculating average rate base, the Company proposes that its rate base composition remain unchanged from previous filings and be comprised of the following:

SCHEDULE 12-10		
Composition of Rate Base		
	Component	**Notes**
	Fixed Assets	Total capital including reclassified line hardware and materials as per the audited and/or forecast financial statements
Less:	Capital Work In Progress	Capital projects not completed or available for use
Less:	Accumulated Amortization	Includes provision for future site removal and restoration
Less:	Contributions in Aid of Construction (net of Amortization)	Total CIAC as per the audited and/or forecast financial statements
Less (Add):	Future Income Tax Liability (Asset) - Net of Long-Term Receivable	Includes current and long-term future income taxes net of long-term income tax receivable
Less (Add):	Costs Payable To (Recoverable From) Customers Post 2003	Amounts deferred through ECAM
Add:	Deferred Financing Costs	Per IRAC Order
Add:	Intangible Assets	A component of capital related to in-house software and right-of-ways.
Add:	Deferred Demand Side Management Costs	Per IRAC Order
Add:	Deferred Charge (Section 47(4)(a)(ii) of the EPA	Unamortized balance of pre-2004 deferred charges related to Point Lepreau
Less (Add):	Regulatory Liability (Asset) - OPEB	Per IRAC Order
Less:	Regulatory Liability - Rebates Payable to Customers	Per IRAC Order and EPA
Less (Add):	Regulatory Liability (Asset) - As established by Commission Order	Other regulatory deferrals as may be established by the Commission.
Plus:	Working Capital Allowance - comprised of: ▪ Inventory ▪ Gross Operating Expenses x 3.6% (net of disallowed costs) ▪ Income Taxes Paid x 3.6%	Components as permitted by IRAC under historic rate base regulation. ▪ Fuel in storage to generate electricity at the Borden-Carleton and Charlottetown Generating Stations. ▪ Allowance for funds required to bridge timing between payments and receipts. ▪ Total income taxes paid during the year.

The calculation of the actual Rate Base for 2014 and forecast Rate Base for 2015 and 2016 is shown in Schedule 12-11 below.

SCHEDULE 12-11			
Calculation of Rate Base ($)			
Components	**2014 Actual**	**2015 Forecast**	**2016 Forecast**
Fixed Assets	$ 549,747,576	$ 573,895,100	$ 600,818,500
Less: Capital Work in Progress	(2,502,588)	-	-
Less: Accumulated Amortization	(184,784,475)	(196,283,900)	(212,646,400)
Less: Contributions in Aid of Construction (net of Amortization)	(26,254,677)	(25,280,700)	(24,362,100)
Less (Add): Future Income Tax Liability (Asset) - net of Long-Term Receivable	(17,297,723)	(13,367,600)	(23,802,100)
Less (Add): Costs Payable to (Recoverable from) Customers Post 2003	(5,061,928)	2,881,900	1,533,000
Add: Deferred Financing Costs	427,996	423,000	416,700
Add: Intangible Assets	4,270,784	4,500,000	4,650,000
Add: Deferred Demand Side Management Costs	113,362	100,000	1,755,900
Add: Deferred Charge (Section 47(4)(a)(ii) of the EPA)	1,961,343	1,861,800	1,768,400
Less (Add): Regulatory Liability (Asset) - OPEB	3,660,423	(4,944,300)	(3,319,500)
Less: Regulatory Liability - Rebates Payable to Customers	(13,465,192)	(16,628,200)	(11,578,800)
Less (Add): Regulatory Liability (Asset) - As established by Commission Order	-	-	-
Plus: Working Capital Allowance comprised of:			
▪ Inventory	5,709,926	5,600,000	5,700,000
▪ Gross Operating Expenses x 3.6% (net of disallowed costs)	4,708,780	4,961,000	4,899,100
▪ Income Taxes Paid x 3.6%	127,512	309,400	315,300
Total Rate Base	**$ 321,361,119**	**$ 338,027,500**	**$ 346,148,000**
Average Rate Base	**$ 312,268,689**	**$ 329,694,300**	**$ 342,087,800**

The Company proposes that the Commission determine and fix the forecast average rate base for 2016 at $342,087,800. The Company would continue to file with the Commission, its calculation of the actual rate base based upon the audited financial statement results by January 31 of each following year.

12.6 Return on Average Rate Base

Section 24 of the EPA states:

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

Section 24 sets out the Commission's obligation to determine a just and reasonable Return on Average Rate Base which is comprised of the return on debt financing and the Return on Average Common Equity. The evidence presented throughout Section 12 discusses the debt financing costs and also demonstrates that a Return on Average Common Equity of 9.70 per cent reasonable to meet the Company's financial objectives.

Schedule 12-12 shows the proposed Return on Average Rate Base calculation based on the inputs outlined in this Application and the proposed 9.70 per cent Return on Average Common Equity for the purpose of establishing the 2016 revenue requirement. For comparative purposes, the actual and forecast Return on Average Rate Base for 2014 and 2015 respectively, are also included based on the 9.75 per cent Return on Average Common Equity set under the Accord.

SCHEDULE 12-12			
Calculation of Return on Average Rate Base ($) (%)			
	2014 Actual	**2015 Forecast**	**2016 Forecast**
Total Revenue	$ 191,136,042	$ 186,859,600	$ 189,940,800
Less: Operating Expenses (net of ECAM)	(143,157,076)	(139,473,700)	(136,456,800)
Less: Amortization of Debt Issue Costs	(5,029)	(5,000)	(6,300)
	47,973,937	47,380,900	53,477,700
Less: Amortization Costs Recoverable From Customers (pre-2004)	(1,983,601)	-	-
Less: Amortization Fixed Assets	(15,120,635)	(15,625,500)	(21,031,900)
Less: Amortization Deferred Charges	(329,000)	(206,800)	(93,400)
	(17,433,236)	(15,832,300)	(21,125,300)
Earnings Before Income Taxes and Financing Costs	30,540,701	31,548,600	32,352,400
Income Taxes	(5,822,890)	(6,030,500)	(6,210,500)
Earnings on Average Rate Base (interest expense excluded)	**$ 24,717,811**	**$ 25,518,100**	**$ 26,141,900**
Rate Base - Year End Average	**$ 312,268,689**	**$ 329,694,300**	**$ 342,087,800**
Actual/Requested Return on Average Rate Base (for rate making purposes)	**7.92%**	**7.74%**	**7.64%**

The determination of the 7.64 per cent Return on Average Rate Base using the proposed Return on Average Common Equity discussed previously allows the Commission to calculate the return to the Shareholder to be included in the revenue requirement for 2016. Although this return is based upon a fixed Return on Average Common Equity, the expert evidence presented in this Application suggests that there is a range of reasonableness for the Return on Average Common Equity, both below and above the return proposed for purposes of setting customer rates. As such, it follows that there is also range of reasonableness for purposes of calculating the allowed Return on Average Rate Base.

The proposed range of Return on Average Rate base is calculated by multiplying the weighted average cost of capital (based upon the upper and lower return on average common equity limits supported by the evidence) by the ratio of the average capitalization and the average rate base at the target ROE used in determining revenue requirement.

As a formula,

$$\text{Return on Average Rate Base} = WACC_{U,L} \quad \text{x} \quad \frac{\text{Average Capitalization}}{\text{Average Rate Base}}$$

Where,

$WACC_{U,L}$ = the weighted average cost of capital at the upper (U) or lower (L) limit.

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 proposed upper and lower range of Return on Average Rate Base is included in Appendix 9.

Establishing an allowed range of return on average rate base acknowledges that the determination of the revenue requirement for 2016 is based upon a number of forecasted variables and assumptions which will likely differ from actual results, causing changes in expected revenues, costs and rate base. By establishing an allowed range of return, the Company is charged with the responsibility of operating within the parameters of the allowed range preventing it from seeking relief from the Commission unless the return falls below the lower limit while at the same time providing an incentive to seek efficiencies and savings, for the future benefit of customers, and earn a return up to the upper limit set by the Commission.

Based upon the evidence present in this Application, the Company requests that the Commission establish an allowed Return on Average Rate Base for 2016 of 7.64 per cent in an allowed range of 7.56 per cent to 7.72 per cent

12.7 Summary

A summary of this section follows:

The Company's financial objectives are as follows:

a. Maintain a debt ratio in the target range of 57 per cent to 60 per cent and a common equity ratio in the range of 40 per cent to 43 per cent;
b. Maintain coverage on total debt interest in the range of 2.4 times to 2.6 times; and
c. Provide the Shareholder with a return commensurate with that of comparable risk investor-owned utilities.

In support of these objectives, the Company proposes the following:

- Interest expense on long-term debt is forecast to be $12,157,650 in 2016;
- Short-term interest costs are forecast to be $741,600 in 2016;
- The Allowance for Funds Used During Construction is forecast to be $200,000 in 2016;
- A Return on Average Common Equity of 9.7 per cent for 2016 is just and reasonable.
- The Company requests that the Commission approve the Components of Rate Base and the forecast 2016 rate base of $342,087,800;
- Maritime Electric proposes that the Commission approve a Return on Average Rate Base of 7.64 per cent for 2016 in an allowed range of 7.56 per cent to 7.72 per cent.

13.0 COST ALLOCATION STUDY

13.1 Overview

The Company's rates, tolls and charges were established, and fixed, over the period March 1, 2011 to February 29, 2016, under the legislative requirements collectively referred to in this Application as the PEI Energy Accord.

Prior to the commencement of the PEI Energy Accord, the Commission had issued Order UE10-03 which, in part, ordered the Company to consider the issue of the continued retention of the 2,000 kWh residential declining second block structure and to provide a rate proposal with the Commission by December 31, 2011. Legislation enacting the PEI Energy Accord (for the first two of five years) was passed on December 9, 2010 and Order UE10-03 was terminated under this legislation.

Recognizing the PEI Energy Accord's end at February 29, 2016, the Company's return to cost of service regulation for rate setting purposes and the issues raised with respect to the Commission's Order UE10-03, the Company had a cost allocation study prepared as the basis for providing recommendations to the Commission regarding changes to existing rate structures.

Maritime Electric retained Chymko Consulting Ltd. ("Chymko"), a firm with expertise in performing cost allocation studies for utilities, to perform a cost allocation (or "cost of service") study to support this General Rate Application. The study was based on Maritime Electric's Statement of Earnings for the twelve months ending on December 31, 2014. The 2014 Cost Allocation Study ("2014 CA Study" or "the Study") dated September 2, 2015 prepared by Chymko is attached as Appendix 10. The following provides a summary of the background relating to the 2014 CA Study, an overview of the methodology used for the Study, analysis and conclusions from the Study and Company recommendations with respect to the adjustments of rates within customer rate classes arising from the Study.

13.2 Background and Timeline

Current Maritime Electric rate structure and rate classes are a product of a regulatory framework under which Maritime Electric, beginning in 1998, adopted the same rate schedules as New Brunswick Power.

Between May 1, 1994 and December 31, 2003, the Company operated in a price cap environment in accordance with the provisions of the Maritime Electric Company Limited Regulation Act. On January 1, 2004, the Company returned to cost of service regulation under the terms and provisions of the EPA.

On April 6, 2006, the Commission ordered (UE06-02) the Company to file a cost allocation study by October 13, 2006. The Company engaged Foster Associates Incorporated to perform this study ("the 2006 CA Study"). The 2006 CA Study was completed based on 2005 data and filed with the Commission.

In January 2006, the Accounting Standards Board announced its decision to require all Publicly Accountable Enterprises ("PAE") to report under International Financial Reporting Standards ("IFRS") for years beginning on or after January 1, 2011. The change from Canadian Generally Accepted Accounting Principles ("GAAP") to IFRS would apply to all PAE which includes listed companies and any other organizations that are responsible to large or diverse groups of stakeholders including non-listed financial institutions, securities dealers and many co-operative enterprises. While Maritime Electric was not, and is not, a PAE, it would be required to adopt these standards in its reporting to its parent Fortis Inc. which was to take effect January 1, 2011.

Subsequently, the Company advised the Commission of the impending changes announced by the Accounting Standards Board and of the potential changes in the accounting and reporting of financial results that could arise from adopting IFRS.

The Commission addressed the IFRS issue and stated its intention with respect to having Maritime Electric re-file a cost of service study as part of its Order UE09-02 dated March 5, 2009 (para. 64) addressing the Company's Application for rate adjustments effective April 1, 2009:

> *The Commission notes the Cost of Service study reference by Mr. te Raa was completed in 2006 after 10-plus years of deregulation wherein the New Brunswick rate structure was adopted. Historically, New Brunswick rates are not based on a cost of service by rate class methodology. Therefore, it is not unrealistic to find discrepancies as found in the 2006 Cost of Service Study. The Commission intends to review rates by customer class and will be requiring Maritime Electric to re-file a cost of service study with a report which outlines rate class rate implications. The Commission would like to have this study reflect changes which may occur as a result of Maritime Electric financial statement conversion to International Financial Reporting.*

In December 2009, an updated cost allocation study was completed by Chymko on behalf of the Company based on 2008 financial results ("the 2008 CA Study"). That study was to be used for the basis of a Company Application to the Commission with respect to a proposed Open Access Transmission Tariff ("OATT").

In June 2010 the Commission conducted a public hearing to address the Company's Application of January 29, 2010 (and subsequent affidavits of April 8 and 12, 2010) where the Company sought approval of the re-basing for ECAM, a return on equity of 9.75 per cent for the years 2010 and 2011 and reconsideration of Order UE08-01 which had ordered (based on the Company's Application of October 18, 2007) the elimination of the declining residential second energy block pricing (the Company had sought permission for a continuation of the existing 2,000 kWh/month residential second block pricing).

Concerns regarding the residential second block pricing were raised by a number of intervenors at the hearing including representatives of the Island farm community.

In Order UE10-03, dated July 12, 2010, the Commission found that while evidence warranting the retention of the declining residential second block rate was not presented it was recognized that the residential rate class is flawed and is out of date. Order UE10-03 ordered as follows:

> *The Company shall retain the 2,000 kWh second block reduced rate and include consideration of this issue in a rate proposal to be filed with the Commission by December 31, 2011.*

On December 9, 2010, the Provincial Government enacted the Electric Power (Electricity Rate Reduction) Amendment Act, (S.P.E.I. 2010, c. 9) and on December 7, 2012, the Provincial Government enacted the Electric Power (Energy Accord Continuation) Amendment Act, (S.P.E.I. 2012, C. 6). These two pieces of legislation established a period between March 1, 2011 and February 29, 2016, collectively referred to as the PEI Energy Accord, which among other things established input factors for the years 2011-2015 and fixed the rates, tolls and charges of Maritime Electric.

Maritime Electric, effective January 1, 2011, adopted Canadian Accounting Standards for Private Enterprises (ASPE) and has consistently applied the ASPE accounting standards since this time.

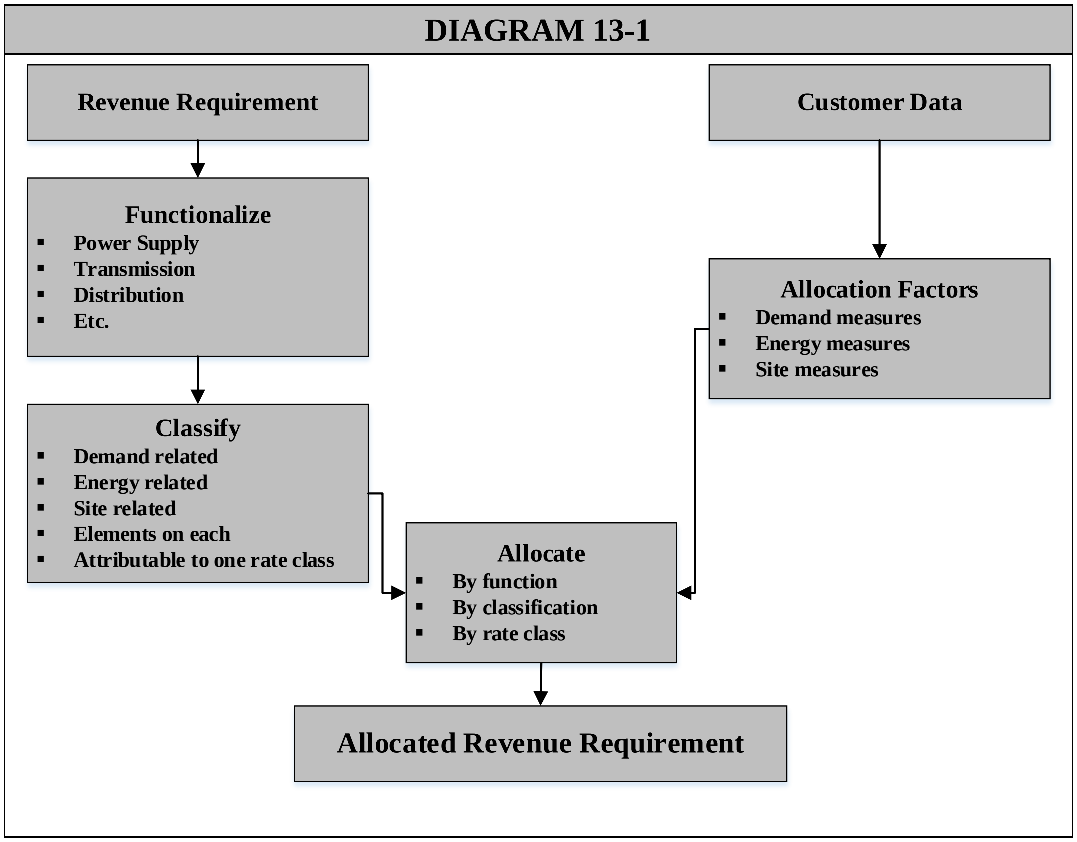
Recognizing the PEI Energy Accord's end at February 29, 2016, the Company's return to cost of service regulation for purpose of rate setting effective March 1, 2016, and the issue of a rate proposal to be brought forward by the Company under Order UE10-03 (terminated under the legislation for the Energy Accord) the Company in 2014 engaged Chymko to prepare a cost allocation study based upon financial results for the year ending December 31, 2014 (see Appendix 10 - 2014 Cost Allocation Study - prepared by Chymko Consulting Ltd. Dated September 2, 2015).

13.3 Cost Allocation Study Methodology

Generally, utilities record the revenue received from each group, or class, of customers, but the cost of providing service to each class is not tracked. The purpose of a cost allocation study is to allocate the utility's total cost of providing service among the various classes of customers so as to be able to compare the revenues to costs for each rate class as part of determining whether rates are just and reasonable. A cost allocation study also provides a benchmark to guide rate design. These studies follow a structured approach and generally accepted principles that have evolved over years of regulatory evolution.

The 2014 CA Study follows these generally accepted principles. The Study first functionalized revenue requirement (in this case, the Company's 2014 Statement of Earnings) which represent the Company's cost of providing service to its customers and attributes the full cost of service to specific purposes such as power supply, transmission, distribution network, service and metering, customer care and lighting. Next, the Study classified each function as demand, energy or site related depending upon how the cost of that function might vary with how end-use customers use the system. Finally, the Study allocated the functionalized and classified expenses to rate classes. The 2014 CA Study followed the same methodology used in the 2008 and 2006 CA Studies.

This structured process followed in conducting cost allocation studies is shown in Diagram 13-1 below.



The following provides an overview of each step of the process used by Chymko in preparing the 2014 CA Study:

a. Functionalization[6]

The process begins with the Company's Statement of Earnings for the year ended December 31, 2014 as summarized in Table 1 of the 2014 CA Study where a net revenue requirement (i.e. cost of providing service) of approximately $179 million is established.

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The 2014 Study then attributes the $179 million revenue requirement to one of sixteen functions in the areas of power supply, transmission, distribution, services and metering, customer care and lighting.

The first priority in functionalization is to attribute, or directly assign, as much as possible to a given function without the need to undertake any allocations. Approximately 66 per cent of the total net revenue requirement (including, to a large extent, energy costs and transmission costs) was directly assignable. Other costs representing approximately 29 per cent of net revenue requirement including amortization, debt financing, earnings and corporate taxes were allocated based on the same proportion as the underlying capital asset and facility infrastructure. The remaining 5 per cent of net revenue requirement was allocated based on underlying labour proportions or through professional judgement.

The functionalized revenue requirement is summarized in Schedule 13-1 below:

SCHEDULE 13-1	
Functionalized Revenue Requirement ($ millions)	
Power Supply Costs	$ 130.5
Transmission Costs	7.4
Distribution Costs	30.7
Services and Meters Costs	8.6
Customer Care Costs	1.4
Lighting Costs	.4
Functionalized Revenue Requirement	**$ 179.0**

b. Classification[7]

Functionalized revenue requirement is next classified based on the generally accepted cost drivers that are measured in terms of how customers use the system. Costs associated with upstream functions (transmission, generation and substations) are generally accepted to be driven by (or attributable to) the peak demand placed on the system. Downstream functions, such as services and metering, are generally driven by the number of sites (points of delivery) served. The following provides an overview of the methodology utilized to classify net revenue requirement into categories of demand, energy and site-related:

i. Power Supply

The Company's energy supply costs are driven by both peak demand and energy consumed. Energy purchases from NB Power and wind generated energy purchased on-Island are classified as energy related. Fixed costs associated with the Point Lepreau Generating Facility ("Point Lepreau") and the Company's on-Island generation fleet (Charlottetown Thermal Generating Station and the combustion turbines in Borden and Charlottetown) are considered demand related. In Section 13.4B(ii) there is further discussion on the methodology utilized to allocate fixed costs associated with the Point Lepreau participation.

ii. Transmission

Transmission lines are part of the bulk energy delivery system and are generally unaffected by the addition of one or more customers and the associated costs are therefore considered demand related and are allocated on the basis of coincident peak demand.

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iii. Distribution

Substations are also part of the bulk energy delivery system and are generally unaffected by the addition of one or more customers and the associated costs are accordingly classified as demand-related and are allocated on the basis of coincident peak demand.

Other functions of the distribution system including primary lines, transformers and secondary lines are designed to meet peak demand but, because the base level cost to meet peak demand will increase as more customers are added to the system there is also a site-related component for these functions.

iv. Services, Metering and Customer Care

All of these functions are classified as site related as it is generally recognized that the cost of these functions will primarily vary with the number of customers served.

The outcome of the classification process results in the classified revenue requirement and is summarized in Schedule 13-2 below:

SCHEDULE 13-2	
Classified Revenue Requirement ($ millions)	
Demand	$ 67.0
Energy	88.7
Site Related	23.3
Functionalized Revenue Requirement	**$ 179.0**

c. Allocation[8]

The final step following classification is to allocate revenue requirement to rate classes. The development of allocation factors starts with the

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collection of the Company's system load data and billing statistics. The choice of allocation factor is substantially influenced by classification. Demand related costs are allocated by the same proportion as the peak demand of each rate class. Energy costs are allocated based on energy sales (grossed up to include losses) and site related costs by the relative number of sites within each rate class.

The 4 peak demand allocators, and the summary distribution for each allocator (coincident peak (kW), non-coincident peak (kW), energy (MWh) and sites) is provided in Table 7 of the Study on Page 22.

13.4 Cost of Service Study Results, Analysis and Recommendations

A. Summary of Results[9]

The Company's fully allocated revenue requirement of $179 million, and cost of providing service by rate class, is presented in Schedule 13-3 below:

SCHEDULE 13-3							
Allocated 2014 Maritime Electric Cost of Providing Service ($,000)							
	Operating Expenses	**Financing Expenses**	**Gross Expenses**	**OATT Revenue**	**Other Revenue**	**Net Expenses**	**Per cent Share of Allocated Cost**
Residential	$ 63,884	$ 26,034	$ 89,918	$ (951)	$ (1,354)	$ 87,614	48.9 %
Residential (S)	2,156	1,965	4,121	(6)	(86)	4,028	2.3 %
Residential Farm	5,548	1,738	7,287	(87)	(26)	7,173	4.0 %
General Service I	40,323	9,698	50,021	(497)	(266)	49,258	27.5 %
General Service I (S)	805	556	1,360	(0)	(20)	1,340	0.7 %
General Service II	968	216	1,183	(11)	(4)	1,168	0.7 %
Small Industrial	9,888	2,549	12,437	(126)	(62)	12,249	6.8 %
Large Industrial	12,279	1,354	13,634	(137)	(7)	13,489	7.5 %
Lights	1,052	1,273	2,325	(13)	(23)	2,289	1.3 %
Unmetered	311	90	401	(3)	(2)	396	0.2 %
Total	**$ 137,214**	**$ 45,472**	**$ 182,686**	**$ (1,830)**	**$ (1,852)**	**$ 179,004**	**100.0 %**

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The revenue to cost (or "RTC") ratios, which compare the revenue collected from each rate class with the allocated cost of providing service to each rate class, including a comparison to the results of the 2008 and 2006 CA Studies, are presented in Schedule 13-4.

SCHEDULE 13-4					
2014 Collected Revenue and Allocated Costs and Revenue to Cost Ratios (%)					
	Revenue Collected	**Allocated Cost**	**Revenue to Cost Ratio 2014**	**2008 CA Study**	**2006 CA Study[10]**
Residential	45.0	48.9	92	91	93
Residential (S)	2.2	2.3	97	122	N/A
Residential Farm	3.3	4.0	81	N/A	N/A
General Service I	32.3	27.5	117	114	116
General Service I (S)	0.9	0.7	115	132	N/A
General Service II	0.8	0.7	120	122	124
Small Industrial	6.6	6.8	96	109	98
Large Industrial	7.5	7.5	100	86	87
Lights	1.3	1.3	103	119	111
Unmetered	0.2	0.2	103	98	111
Total	**100.0%**	**100.0%**	**100%**	**100%**	**100%**

B. Analysis, Conclusions and Recommendations from 2014 CA Study

The objective of a cost allocation study is to allocate the cost of providing service to rate classes on a cost causation basis; therefore, a revenue to cost ratio below 100 per cent indicates revenue should be increased for that rate class while a ratio above 100 per cent indicates that revenue for that rate class should be lower.

The preamble to the Electric Power Act states:

> *Whereas the rates, tolls and charges for electric power should be reasonable, publically justifiable and not discriminatory.*

[10] The 2006 CA Study combined lights and unmetered for purposes of the Study with a combined result of 111 per cent. This Study also included analysis of the wholesale rate for the City of Summerside which no longer has applicability for Maritime Electric.

One of the criteria followed to ensure fairness to all customers' is that rates must be based on the cost of providing this service.

The Company makes the following observations and conclusions as a result of the completion of the 2014 CA Study.

i. Consistency of Results

The RTC ratio results from the 2014 CA Study are reasonably consistent with the results of both the 2008 CA Study and the 2006 CA Study. The residential rate class consistently reflects a RTC ratio below 100 per cent indicating that revenue needs to be increased in this rate class and the General Service rate classes consistently show a RTC ratio above 100 per cent indicating that revenue needs to be lowered within these classes.

For purposes of the 2014 CA Study, farms which are currently part of the Residential rate class, were removed from other residential customers to determine a specific RTC ratio for farm customers. This will be discussed further in this Section.

The Large Industrial rate class RTC ratio result is 100 per cent in the 2014 CA Study which represents a significant change from results from the 2006 and 2008 studies. For purposes of the 2014 CA Study, the demand costs associated with serving this class were reduced to reflect the interruptible contracts for some of the customers in this class. This was not done in either the 2008 or 2006 studies and the Company believes the methodology used in the 2014 CA Study is proper in determining the Large Industrial RTC ratio.

The Lighting rate class RTC ratio result of 103 per cent shows a significant change compared to the results of previous studies. This is substantially attributable to the fact that the 2014 Study utilized the number of street light fixtures, as opposed to the number of street light accounts used in previous studies, in determining the allocation of site-related costs for this class.

Over the years, there has been some consolidation of street lighting fixtures into a smaller number of accounts in order to achieve efficiencies in billing. Thus the number of fixtures, rather than the number of accounts, is seen as a better indicator of the number of sites.

ii. Study Methodology

The 2014 CA Study follows the same basic principles used in previous Company cost allocation studies. The application of consistent methodology facilitates a more meaningful comparison of results over time.

The Company did conduct sensitivity analysis with respect to the classification of the annual fixed costs for the Point Lepreau participation. In the 2014 Study (as in the 2008 and 2006 studies), the annual fixed costs regarding Point Lepreau have been considered 100 per cent demand related (with no allocation to energy). The sensitivity analysis examined the impact on RTCs for each rate class if the fixed costs associated with the Point Lepreau facility were classified as energy (and not demand). The changes to the RTC ratios amongst rate classes as a result of changes to the currently used 100 per cent classification of fixed costs at Point Lepreau as 100 per cent demand did result in material changes to the RTC ratios. Schedule 13-5 summarizes the impact on RTC ratios if the fixed costs at Lepreau were classified as 100 per cent energy versus the current 100 per cent demand.

SCHEDULE 13-5			
Impact on RTC Ratios with Point Lepreau Classified 100% Energy			
Rate Class	**Existing RTC Lepreau[11] - 100% Demand***	**RTC Lepreau[11] - 100% Energy**	**Difference**
Residential (excluding Seasonal and Farms)	92	94	2
Residential - Seasonal	97	92	(5)
Residential - Farm	81	83	2
General Service I	117	115	(2)
General Service I - Seasonal	115	104	(11)
General Service II	120	116	(4)
Small Industrial	96	95	(1)
Large Industrial	100	94	(6)
Lights	103	104	1
Unmetered	103	100	(3)

* *Fixed costs only, fuel excluded*

The Point Lepreau nuclear generating facility is a base load facility that features substantially all costs as fixed long term facility costs and relatively minor fuel costs. The current classification classifies the fixed facility costs as demand and the relatively minor fuel costs as energy. An alternate classification would consider the extent to which the baseline cost of providing capacity (for example - the cost of a simple cycle combustion turbine) compared with the fixed costs of Lepreau currently incurred. The fixed costs currently incurred incremental to the cost of the base line cost of capacity could be considered costs incurred to provide lower cost energy – and therefore these costs could be classified as energy

[11] Includes fixed annual costs and excludes fuel.

related. A change in methodology would not result in a 100 per cent reallocation of demand to energy as some component of Lepreau's fixed costs will need to continue to be demand. Schedule 13-5 is meant to reflect the sensitivities between the two extremes (100 per cent demand allocation versus no demand allocation).

While the Company has consistently utilized the 100 per cent demand classification for Point Lepreau fixed costs in the 2014, 2008 and 2006 CA Studies the Company proposes, based on the material changes to RTC ratios provided above with a reclassification of Lepreau fixed costs to energy, that a change in the methodology utilized for classifying Point Lepreau fixed costs be further explored through a Lepreau Classification Study with a future recommendation to the Commission on this issue by no later than April 30, 2017.

iii. RTC Ratio Milestones

The Company has, for approximately 18 years, followed the rate schedules and regulatory policies of New Brunswick Power. The Company, over this 18 year period, has been subject to a 10 year period of price cap legislation, a transition to cost of service regulation and a 5 year period of legislatively set rates under the PEI Energy Accord. With the exception of the phase in of an increased residential second block from 1,200 kWh to 2,000 kWh over the 2008 – 2009 period, adjustments to rates within rate classes relating to the results from cost allocation studies from 2006 to the present have not been implemented.

The Company takes the position that appropriate adjustments to individual rate classes should commence, beginning in 2016, the process of rebalancing the RTC ratios derived from the 2014 CA Study as summarized in Table 13-4. The objective of achieving RTC ratios of between 90 per cent and 110 per cent is proposed to be a reasonable objective. The objective for some utilities is to achieve and maintain RTC ratios between 95 per cent and 105 per cent. In considering the background on the issue discussed above, the recognition of the rate impact in rebalancing RTC ratios for some rate classes and recognizing that some utilities and Regulators accept a 90/110 per cent RTC ratio range on an ongoing basis, the 90/110 per cent RTC ratio is a reasonable objective in balancing progress in addressing rate class cross subsidization with the rate shock associated with implementing changes.

The Company, in recognizing the same factors discussed above, proposes these changes not be implemented immediately but over a reasonable period of time. Chymko states the following in the final remarks of the 2014 CA Study:

> *The revenue to cost ratios in Table 1 indicates that some rates might need to change significantly. Pending further analysis of such change, it may well be that rate rebalancing would need to be implemented gradually over the course of multiple years.*

The following provides an analysis and discussion of the Study results by rate class and the Company's corresponding recommendations with respect to rate adjustments.

iv. Residential Rate[12] Classes

In addition to customers who use electricity for domestic living purposes (homes, apartments, etc.) the Residential rate also applies to services to farms, churches, customers who use electricity for living purposes in a dwelling other than the customer's principal residence such as summer cottages (seasonal customers) and premises provided for lodging with nine beds or less (including boarding or rooming houses, special care establishments, senior citizen homes, nursing homes, hotel and transition homes).

For purposes of the 2014 CA Study farms were extracted (based on existing Standard Industrial Classification ("SIC") codes from the Company's customer service records) and a separate RTC ratio was calculated. The Company, for purposes of providing recommendations to the Commission on potential changes to existing rate structures, wanted to better understand the revenue to cost ratio associated with farms (in isolation of other residential customers) and the potential impact of any changes in the declining block structure as it pertains to farm customers. Information used to identify farms, for purposes of the 2014 Study, were derived by isolating SIC codes the Company has within its customer account records. The Company recognizes that the SIC codes information in the Company's records will have inconsistencies unless site visits are undertaken to verify the accuracy of the existing SIC code classifications. However, the data presented with respect to those Residential customers identified as farming operations should provide a reasonable, but preliminary, revenue to cost ratio for these customers. The RTC ratio determined for farms under the 2014 Study was 81 per cent.

[12] Sections N-1 to N-2 of GRR

Schedule 13-6 provides the summary of the RTC ratios within the residential rate classes which are summarized below:

SCHEDULE 13-6	
Residential Customers - RTC Ratio Results (%)	
	RTC Ratios 2014 CA Study
Residential (excluding Seasonal and Farms)	92
Residential (Seasonal)	97
Residential (Farms)	81
On a Combined Basis	**91**

The residential rate classes, on a combined basis, achieve a 91 per cent RTC ratio and fall within the 90 per cent to 110 per cent RTC ratio objective proposed by the Company.

What follows is a discussion on three areas of the 2014 CA Study relating to certain types of customers currently within the residential rate classes: a) residential customers with second block usage, b) residential seasonal customers; and c) residential customers (operating as farms).

a. Residential Second Block

As discussed in Section 13.2, the Commission ordered (UE10-03 dated July 12, 2010) that a rate design proposal be filed with the Commission by December 31, 2011 and include consideration of the issue of the residential declining second block rate. While Order UE10-03 was terminated under the legislative provisions of the Energy Accord, the Company with the results of the 2014 CA Study completed, and recognizing the Company's return to a Regulator-based rate setting process effective March 1, 2016, proposes that it is timely and prudent to revisit this issue.

The declining block structure within a residential rate class no longer exists in other major Canadian electric utility jurisdictions. Schedule 13-7 below provides a summary of the status of residential rate structures in other major Canadian electric utility jurisdictions:

SCHEDULE 13-7 Overview of Canadian Electric Utility Residential Rate Block Structure		
Utility	**Province**	**Declining Block Structure**
BC Hydro	BC	No
EPCOR Energy	AB	No
Sask Power	SK	No
Manitoba Hydro	MB	No
Hydro One	ON	No
Hydro Quebec	QC	No
NB Power	NB	No
NS Power	NS	No
Newfoundland Power	NF	No
Maritime Electric	PE	Yes

Since Maritime Electric adopted the declining block rate structure of NB Power in 1994, NB Power has migrated from a residential declining second block structure to its current flat block structure.

The declining block rate structure came into widespread use during the early years of electrification when lighting comprised most of a utility's load. Because utilities had to maintain adequate capacity to meet increased demand during evening hours, it made sense to promote other uses of power to fill the valleys of demand - and this was accomplished through declining block rate structures.

Today declining residential second block rate structure for residential customers communicates inappropriately that the value of energy decreases with each kWh consumed. This runs contrary to a price signal that promotes energy conservation. As the number of kWhs used by a home increases so does the peak load, so a utility incurs additional energy and additional demand costs. Commercial rate structures (e.g. General Service) have demand charges to capture this cost. Residential rates do not, thus the lower second block energy charge does not send the correct price signal because it does not recover the additional demand costs incurred by the utility. As well, the cost incident pattern associated with the purchase and generation of electricity by the Company for its customers is not consistent with a declining block rate structure for residential customers.

The 2014 CA Study determined that the RTC ratio for the residential rate classes (excluding seasonal and farm customers) is 92 per cent.

While the residential rate class RTC ratio currently falls within the 90-110 per cent RTC ratio milestone objective proposed by the Company, it is only the revenue increases substantially from the residential rate class that will allow corresponding decreases in electricity rates for the General Service rate class where RTC ratios currently exceed 110.

For all of the reasons above, the Company proposes to phase in an increase in the threshold for all residential customers for the lower cost second block energy (i.e. an increase in the first block energy amount) commencing March 1, 2016 as summarized in Schedule 13-8 below:

SCHEDULE 13-8	
Proposed Second Block Energy Changes Commencing March 1, 2016 (kWh/month)	
Current Block #2 Threshold	2,000
Block #2 Threshold effective March 1, 2016	3,000
Block #2 Threshold effective March 1, 2017	3,800
Block #2 Threshold effective March 1, 2018	5,000

A 5,000 kWh (per month) threshold is deemed an appropriate threshold to capture the large majority of the highest consumption residential electricity consumers (with dwellings).

The total incremental revenue (excluding seasonal and farm customers which will be discussed separately) to be derived from this proposed increase in the second block threshold over the three year period is calculated in Table 13-1 (see Tables at the end of Section 13) to be approximately $661,000. The annual threshold changes proposed in Schedule 13-8 are expected to generate approximately one third of this total revenue in each of the three years. Table 13-1 also provides an analysis and comparison of the average demand and energy costs using the 2014 CA Study data versus the approved rates that were in effect on March 1, 2014. No adjustments to the residential rate class rate structure (other than the second block changes) are proposed at this time.

Schedule 13-9 below provides a summary of the impact on customer electricity costs for residential customers at varying total consumption Block #1 and #2 profiles following the proposed phase in of the second block threshold from 2,000 kWh to 5,000 kWh:

SCHEDULE 13-9					
Examples of Impact on Customer Bills Increasing Second Block Threshold from 2,000 kWh to 5,000 kWh					
Monthly Consumption Ranges	**Sample Customer Average kWh/Month**	**Current Monthly Bill[1]**	**Revised Monthly Bill[2]**	**% Change Total**	**% Change - 3 Year Annual Average[3]**
2,000 - 3,000 kWh	2,388	$ 330.39	$ 341.18	3.3 %	1.1 %
3,000 - 4,000 kWh	3,488	$ 444.57	$ 485.94	9.3 %	3.1 %
4,000 - 5,000 kWh	4,181	$ 516.51	$ 577.14	11.7 %	3.9 %
5,000 - 6,000 kWh	5,391	$ 642.11	$ 725.51	13.0 %	4.3 %
6,000 - 7,000 kWh	6,525	$ 759.82	$ 843.22	11.0 %	3.7 %
7,000 - 8,000 kWh	7,550	$ 866.21	$ 949.61	9.6 %	3.2 %
8,000 - 9,000 kWh	8,465	$ 961.19	$ 1,044.59	8.7 %	2.9 %
9,000 - 10,000 kWh	9,400	$ 1,058.24	$ 1,141.64	7.9 %	2.6 %
10,000 - 20,000 kWh	13,660	$ 1,500.43	$ 1,583.83	5.6 %	1.9 %
20,000 - 30,000 kWh	27,360	$ 2,922.49	$ 3,005.89	2.9 %	1.0 %
30,000 - 40,000 kWh	33,065	$ 3,514.67	$ 3,598.07	2.4 %	0.8 %
40,000 - 50,000 kWh	47,620	$ 5,025.48	$ 5,108.88	1.7 %	0.6 %
> 50,000 kWh	93,811	$ 9,820.10	$ 9,903.50	0.8 %	0.3 %

1 *Reflecting rates approved to February 29, 2016.*
2 *Reflecting only the changes in the monthly bill associated with the increase in the second block threshold from 2,000 kWh to 5,000 kWh.*
3 *Average increase for customers may vary subject to customer consumption levels and patterns.*

To better understand the number of customers that will be impacted by the proposed second block threshold increase from the current 2,000 kWh threshold, Schedule 13-10 summarizes the number of customers in various monthly consumption range blocks for the months of February 2015 and July 2015 - typical cold and warm months, respectively. In February 2015, 8,594 customers (roughly 15 per cent of customers billed) had consumption during the month in excess of 2,000 kWh and therefore accessed the lower cost second block. In July 2015, 920 customers (roughly 1.4 per cent of customers billed) had consumption that exceeded 2,000 kWh.

SCHEDULE 13-10		
Number of Residential Customers by Monthly Consumption Range February 2015 and July 2015		
Monthly Consumption Range (kWh)	**Number of Customers[13] - Monthly Consumption Range - February 2015**	**Number of Customers[13] - Monthly Consumption Range - July 2015**
1 to 416	15,170	28,692
417 to 833	17,001	25,203
834 to 1,250	9,099	7,200
1,251 to 1,667	4,816	1,688
1,668 to 2,000	2,544	447
2,001 to 2,500	2,749	314
2,501 to 3,333	2,770	235
3,334 to 4,167	1,339	122
4,168 to 8,333	1,479	168
8,334 to 16,667	203	57
16,668 to 25,000	37	12
25,001 to 33,333	9	6
33,334 to 41,666	4	2
41,667 and greater	4	4
TOTAL	**57,224**	**64,150**

Recommendations:

- No adjustments to the rate structure for residential customers (except with respect to the changes in the residential second block) are proposed.
- The current 2,000 kWh/month threshold for the lower charge residential second block in residential rate classes be increased as follows:
  - Current Block #2 Threshold - 2,000 kWh/month
  - Block #2 Threshold effective March 1, 2016 - 3,000 kWh/month

13 Includes all residential customers including farms and seasonal customers.

- Block #2 Threshold effective March 1, 2017 - 3,800 kWh/month
- Block #2 Threshold effective March 1, 2018 - 5,000 kWh/month

b. <u>Residential Seasonal Customers</u>

At July 31, 2015 the Company had 7,333 active residential seasonal customers.

Of the 7,333 customers 1,002 customers utilize the Residential Seasonal Class (Code 131) for dwellings other than a principal residence, primarily cottages (Code 131 has the same monthly service charge and energy charge structure as Residential Rural Code 130). The remaining 6,331 customers utilize the Residential Seasonal Option (Code 133) which provides for an increased monthly service charge of $37.50 (for six months) with the same energy charge structure as the other residential rate classes, however providing consumption during June 1 – October 31 does not exceed 50 per cent of annual consumption the service may remain connected year round and avoid connection related fees.

The 2014 CA Study derived a RTC ratio of 97 per cent for the seasonal residential rate classes which falls within the proposed 90/100 RTC ratio parameters proposed by the Company.

As discussed above, the Company is proposing to increase the threshold for the residential second block from the current 2,000 kWh to 5,000 kWh over a three year period. The Company proposes that Residential Seasonal customers be subject to the changes in the second block.

Table 13-2 at the end of Section 13 provides an analysis and comparison of the average demand and energy costs using the 2014 CA Study data versus the approved Residential Seasonal rates that were in effect March 1, 2014. While no changes in the Residential Seasonal rate structure are proposed, the analysis outlined in Table 13-2 estimates that an incremental $21,000 in revenue will be generated by the Company by raising the second block threshold to 5,000 kWh for Residential Seasonal customers.

Recommendations:

- No adjustment to rate structure as a result of the 2014 CA Study are proposed at this time for the Residential Seasonal rate classes.
- Residential Seasonal customers would be subject to the proposed increase in the residential second block threshold from 2,000 kWh to 5,000 kWh over a three year period.

c. Residential Customers Operating as Farms

The Company's billing records reflect approximately 2,066 Residential customers with SIC codes applicable to farming operations. As shown in Table 13-11, the range of annual consumption for these customers varies considerably.

SCHEDULE 13-11	
Farms-By Annual Consumption	
Consumption (kWh)	**Number of Accounts in Each Range**
1 - 5,000	519
5,001 - 10,000	482
10,001 - 15,000	336
15,001 - 20,000	190
20,001 - 24,000	76
24,001 - 30,000	73
30,001 - 40,000	89
40,001 - 50,000	51
50,001 - 60,000	51
60,001 - 70,000	35
70,001 - 80,000	34
80,001 - 90,000	20
90,001 - 100,000	26
100,001 - 200,000	70
200,001 - 300,000	9
300,001 - 400,000	1
400,001 - 500,000	1
Greater than 500,000	3
Total number of accounts	**2,066**

While farms fall within the Residential rate class on PEI, farms fall within different rate categories across Canadian jurisdictions as summarized below in Schedule 13-12:

SCHEDULE 13-12			
Classification of Farms Within Canadian Utility Rate Classes			
Utility	**Province**	**Included in Residential Rate Class**	**Notes**
BC Hydro	BC	In Part	Farm use in conjunction with a single family dwelling (and where the farm does not produce products from another farm, has only farming-related commercial activities and has no more than small roadside stand to sell products directly to the public) is served under the residential tariff. General Service rates apply to other farm use.
EPCOR Energy	AB	No	Farms are maintained under a separate farm rate.
Sask Power	SK	No	Farms are included in a separate and specific rate class (E34).
Manitoba Hydro	MB	In Part	Farms included in residential rate schedules if demand of 50 kW or below. Farms with demand in excess of 50 kW classified under General Service.
Hydro One	ON	In Part	Farm use in conjunction with a primary residence is served under the residential (low density) tariff. Farms without a primary residence are served under the General Service rate classification.
Hydro Quebec	QC	In Part	The residential (or domestic) rate is applicable to commercial farming given three conditions: 1) commercial activities must not exceed maximum load of 10 kW, 2) commercial and domestic use must be metered by a single meter and 3) commercial operations are carried out on a farm that is otherwise a residential farm. Farm Rate D includes fixed charge plus inclining block rate with second tier pricing applicable to consumption that is in excess of 912 kWh/month. If Rate D does not apply, the farm is billed at the appropriate commercial rate for its size.
NB Power	NB	Yes	Electricity supplied to a farm is subject to the residential rate.
NS Power	NS	No	The small industrial rate applies to farms.
Newfoundland Power	NF	No	Electricity supplied to a farm is subject to the General Service rate classification.
Maritime Electric	PE	Yes	Electricity supplied to a farm is subject to the residential rate.

In PEI and NB, farms fall within the Residential rate class. In some jurisdictions including Newfoundland and Nova Scotia farms fall exclusively within General Service or Small Industrial rate classes. Saskatchewan maintains a separate rate class for farms. In several jurisdictions, some farming operations fall within the Residential rate class while other farming operations, based on various tariff qualifications, fall within various commercial rate classes.

Larger scale farm operations could have demand and usage profiles that are inappropriate for the rate structure currently utilized in the Residential rate class and may be more appropriately included in a commercial rate in either the General Service or Small Industrial rate classes or in an individual rate class for farms. Larger scale farms currently access the lower cost residential second block (with no demand related charge).

The estimated revenue shortfall for farms indicated in the 2014 CA Study is summarized in Schedule 13-13.

SCHEDULE 13-13			
Revenue Shortfall - Farms in Residential Rate Class ($,000)			
	2014 Revenue	**2104 Allocated Cost**	**2014 Revenue Shortfall to Achieve 100% RTC**
Farms	$5,832	$7,173	$1,341

A rate design study may determine that some, or all farms, would more appropriately be included in the General Service rate categories. If that was the determination of the rate design study, the revenue over contribution in the General Service rate categories to be discussed in part (v) of this section would be materially reduced and bring the current revenue over contribution significantly closer to the 110 per cent RTC ratio milestone.

Until a determination is made with respect to the reclassification of some, or all, farms to another rate class, it is proposed changes in residential rates including changes to the residential second block discussed above apply to farms. Table 13-3 (see Tables at the end of Section 13) provides an analysis and comparison of the average demand and energy costs using the 2014 CA Study data versus the approved residential rates that apply to farms that were in effect March 1, 2014. While no changes are proposed to the residential rate (farm) structure, Table 13-3 estimates the Company would generate an estimated incremental $91,000 in revenue by raising the second block threshold to 5,000 kWh for residential customers operating as farms.

<u>Recommendations:</u>

- No adjustments to rate structure for residential customers operating as farms as a result of the 2014 CA Study are proposed at this time.
- The Company proposes to undertake a rate design study to determine the appropriate rate class for all or some farms and that the Company file the results of this Study, and related recommendations with the Commission by April 30, 2017. The Study will include consultation and discussion with key stakeholders including organizations representing various farm groups and the Provincial Government.
- Residential customers operating as farms would be subject to the proposed increase in the residential second block

threshold from 2,000 kWh to 5,000 kWh over a three year period.

v. General Service[14] Rate Classes

Results from the 2014 CA Study, as summarized in Schedule 13-4 above, reflect the General Service I (GS1), General Service Seasonal (GSS) and General Service II (GS2) rate classes with RTC ratios of 117 per cent, 115 per cent and 120 per cent respectively. These results indicate that the revenue collected from these rate classes should be decreased.

The General Service Seasonal and General Service II rate classes represent 0.7 per cent and 0.7 per cent of the Company's total allocated costs, respectively. Schedule 13-14 below reflects the combined results for the revenue reduction required to achieve a 110 per cent RTC for all 3 rate classes:

SCHEDULE 13-14				
General Rate Classes – Combined 2014 CA Study Results ($000's)				
Rate Class		**Net Expenses**	**RTC Ratios 2014 CA Study**	**Revenue Reduction Required to Achieve 110 RTC Ratio***
General Service I	(GS1)	$ 49,258	117%	$ 3,599
General Service I (S)	(GSS)	1,340	115%	68
General Service II	(GS2)	1,168	120%	115
General Service Classes Combined		**$ 51,766**	**117%**	**$ 3,782**

* *based on 2014 results. The revenue reduction required to achieve targeted results is subject to relative charges in revenue and allocated cost shifting due to several potential factors over time.*

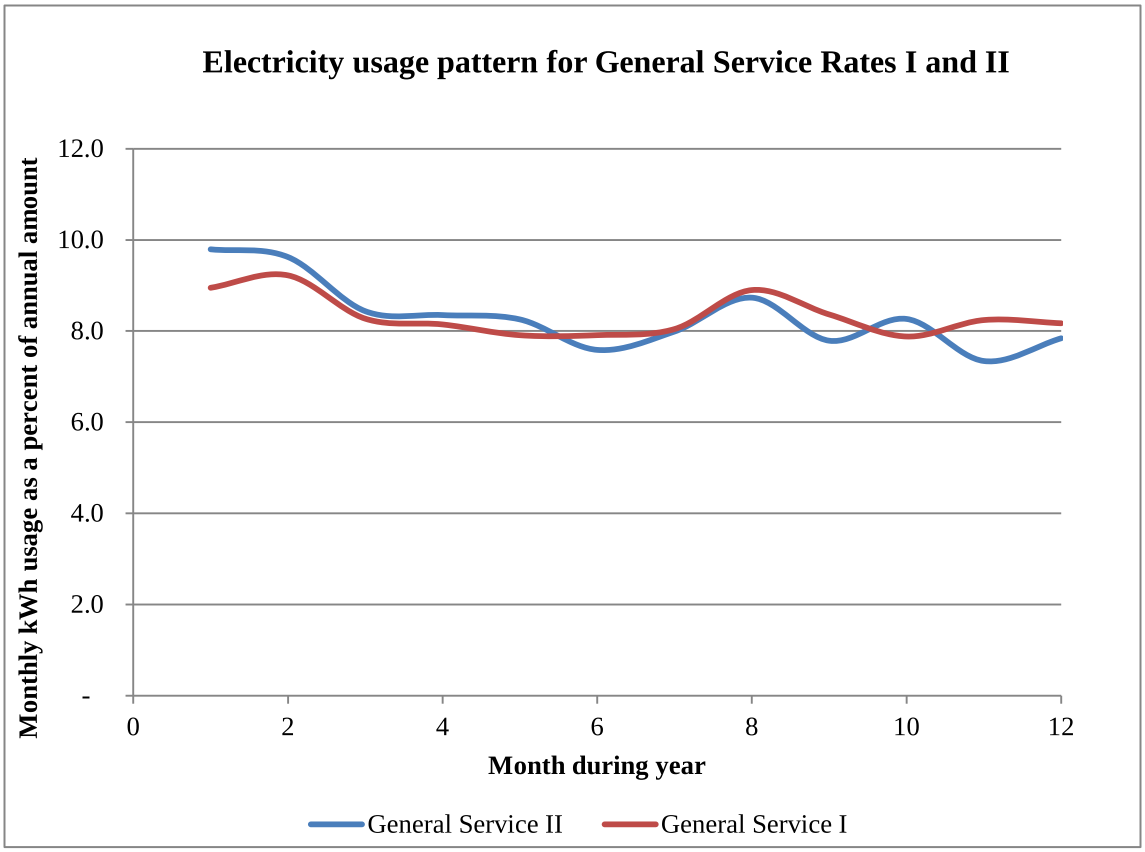
The GS2 class (which is a category for customers who use electricity for purposes other than those specifically covered under other rate classes and who use electricity as the only source of energy for cooking, space heating, water heating and all other services) has 87 customers and a net

[14] Sections N-3 to N-6 of GRR.

revenue requirement in 2014 of $1.68 million. The GS2 class is a result of adopting the NB Power rate structure in 1998. The Company expects that the GS2 class has more applicability in New Brunswick where the use of electricity for space heating is higher. The Company compared the electricity usage pattern for GS1 and GS2 customers, the results of which are summarized in Diagram 13-2.

DIAGRAM 13-2

Electricity Usage Pattern for General Service Rates 1 and 2



Given the very similar usage patterns between the two rate classes and the relatively small number of customers, and associated revenue, associated with the GS2 rate class, the Company proposes, effective March 1, 2016, that customers currently classified as GS2 customers be classified as GS1 customers and that the GS2 rate class cease to exist.

A sensitivity analysis on a sample of small, medium and large GS2 customers, that compared customer bills using GS1 rates versus GS2 rates, was undertaken and impacts on annual customer bills varied by between +2.5 per cent to -3.0 per cent.

There are two factors discussed in Section 13 that could potentially impact the $3.782 million revenue reduction required to achieve a 110 per cent RTC ratio for the combined General Service classes – a) the results of the proposed Lepreau Classification Study and b) the potential reclassification of farms (which are currently included in the Residential rate class) discussed above to the General Service rate classes.

Schedule 13-5 outlined the potential impact of reclassifying Point Lepreau fixed costs as 100 per cent energy versus the currently allocated 100 per cent demand. As Schedule 13-5 demonstrates, the General Service rate class RTC ratios, with a 100 per cent energy allocation, all decrease (GS1 to 115 per cent, GSS to 104 per cent and GS2 to 116 per cent). The revenue shortfall to achieve a 110 RTC ratio for the combined General Service classes would, under the scenario of a 100 per cent allocation of Point Lepreau fixed costs to energy, decrease from $3.782 million to approximately $2.668 million.

As discussed in part (iv)c above, (Residential Customers Operating as Farms) there are 3 potential classification options for farms proposed to be examined by the Company: a) reclassify some or all farms to General Service or Small Industrial rate categories, b) reclassify some or all farms to a new rate category, or c) retain some or all farms in the residential rate class.

If the results of the proposed rate design study for farms results in a reclassification of some or all farms to the General Service rate classes the targeted $3.782 million revenue reduction for the General Service classes could be reduced substantially.

Pending the outcome of both of these studies, it is proposed that the General Service Classes be the beneficiary of proposed increases in incremental revenue associated with changes proposed for the Residential second block energy discussed in part iv) above.

The Company has analyzed the current rate structures in the General Service classes to compare the results of the cost allocation study against the current demand and rate block structure as outlined in Tables 13-4, 13-5, 13-6 and 13-6A (see Tables at the end of Section 13) and the Company proposes adjustments in rates for each of the General Service classes that would result in a decrease in revenue estimated at $773,000 (which corresponds to the estimated additional revenue to be generated in the residential rate class from proposed changes to the second block). The summary of the proposed changes to General Service rate class rates to achieve the revenue reduction of $773,000 (over 3 years) is summarized in Schedule 13-15.

SCHEDULE 13-15				
Proposed Changes to Rates for General Service Customers (over 3 year period)				
	Increase Demand Charge		**Reduce Block 1 and 2 Rate**	
	Total 3 Years ($/kW)	**In each of 3 Years ($/kW)**	**Total 3 Years ($/kWh)**	**In each of 3 Years ($/kWh)**
General Service I*	$1.90	$.6333	$0.005	$.0016
General Service I (S)	$1.90	$.6333	$0.005	$.0016

* *General Service II customers proposed to adopt General Service I rate structure effective March 1 2016.*

Recommendations:

- The General Service rate classes are proposed to be the beneficiary of proposed increases in electricity revenue from the Residential rate classes (from proposed changes to the second block). Rates within the General Service rate classes are proposed to be adjusted as outlined in Schedule 13-15 over a three year period. See Schedule 13-17 for summary of revenue reduction impact.
- It is proposed that General Service II customers adopt the rate structure of General Service I customers effective March 1, 2016.

vi. Small Industrial[15] Rate Class

The 2014 CA Study establishes a RTC ratio of 96 per cent for the Small Industrial rate class. This result is within the 90 to 110 per cent RTC ratio parameters proposed by the Company.

Table 13-7 (see Tables at the end of Section 13) provides an analysis and comparison of the average demand and energy costs using the 2014 CA Study data versus the approved rates that were in place effective March 1, 2014. No adjustments to the Small Industrial rate structure are recommended by the Company.

Recommendations:

- No rate adjustments to the Small Industrial rate class related to the 2014 CA Study are proposed at this time.

vii. Large Industrial[16] Rate Class

The 2014 CA Study shows a RTC ratio of 100 per cent for the large industrial rate class.

[15] Sections N-7 to N-8 of GRR.
[16] Sections N-9 to N-15 of GRR.

Table 13-8 (see Tables at the end of Section 13) provides an analysis and comparison of the average demand and energy costs using the 2014 CA Study data versus the approved rates that were in effect as at March 1, 2014. No adjustments to the Large Industrial rate structure are recommended by the Company.

Recommendations:

- No adjustment to rates as a result of the 2014 CA Study are proposed at this time for the Large Industrial rate class.

viii. Unmetered[17] and Lighting[18] Rate Classes

The 2014 CA Study establishes RTC ratios for Unmetered and Lighting rate classes of 103 per cent in each rate class.

These RTC ratios fall within the proposed 90 to 110 RTC ratio parameters, and no changes to rates in these rate classes as a result of the 2014 CA Study are recommended.

The Company does propose that the Commission's approval of interim rates for LED street and area lights as established in Order UE14-01 be approved as established rates for the Company. The matter is addressed in Section 14 of this Application.

Recommendations:

- No rate adjustments as a result of the 2014 CA Study are proposed at this time for the Unmetered and Lighting rate classes.

[17] Sections N-17 to N-21 of Rates and General Rules and Regulations (GRR).
[18] Sections N-22 to N-26 of GRR.

13.5 Summary

A summary of the Company's recommendations in Section 13 are as follows:

A. Study Methodology

1. Any change in the methodology currently used for classifying Point Lepreau fixed costs as 100 per cent demand related be further explored through a Lepreau Classification Study. The Company would report back to the Commission on this matter no later than April 30, 2017.

B. RTC Ratio Milestones

2. The objective of achieving RTC ratios of between 90 per cent and 110 per cent for rate classes is proposed to be a prudent objective that should be implemented over a reasonable period of time.

C. Changes to Rates by Rate Class

3. Residential Rate Classes:

   i. Residential Second Block: The current 2,000 kWh per month threshold for the lower charge residential second block energy be increased for all residential rate classes including residential seasonal customers and farm customers, as follows:

Effective Date	kWh
Current	2,000
March 1, 2016	3,000
March 1, 2017	3,800
March 1, 2018	5,000

ii. Residential Seasonal: No adjustments to rate structure as a result of the 2014 CA Study are proposed. However, Residential Seasonal customers would be subject to the proposed change to increase the second block threshold from 2,000 kWh to 5,000 kWh.

iii. Farms: Farms will remain in the Residential rate class; however, the Company will undertake a rate design study to determine the appropriate rate class for all, or some, residential customers currently classified as farms. The Company will file the results of this study and related recommendations with the Commission no later than April 30, 2017. Residential customers operating as farms would be subject to the proposed changes to increase the second block threshold from 2,000 kWh to 5,000 kWh.

4. General Service Rate Classes - Changes to customer rates be implemented, commencing in 2016, for General Service I and General Service Seasonal customers over a 3 year period to reflect the revenue generated from the proposed changes in the residential second block threshold. General Service II customers are proposed to adopt the General Service I rate structure effective March 1, 2016. The proposed changes in rates, effective March 1, 2016, are summarized as follows:

Schedule 13-16				
Proposed Changes to Rates for General Service Customers (over 3 year period)				
	Increase Demand Charge		**Reduce Block 1 and 2 Rate**	
	Total 3 Years ($/kW)	**In each of 3 Years ($/kW)**	**Total 3 Years ($/kWh)**	**In each of 3 Years ($/kWh)**
General Service I*	$1.90	$.6333	$0.005	$.0016
General Service I (S)	$1.90	$.6333	$0.005	$.0016

* *General Service II customers proposed to adopt General Service I rate structure effective March 1, 2016*

5. Small Industrial Rate Class - No rate adjustments as a result of the 2014 CA Study are proposed.

6. Large Industrial Rate Class - No rate adjustments as a result of the 2014 CA Study are proposed.

7. Unmetered and Light Rate Classes - No rate adjustments as a result of the 2014 CA Study are proposed.

D. Other

8. The Company proposes to conduct another cost allocation study based on the Company's 2017 financial results which would be submitted with recommendations on further rate adjustments no later than June 30, 2018. The recommendations on further rate adjustments would also incorporate the Commission's determinations with respect to the Company's recommendations regarding the proposed Lepreau Classification Study and the results of the proposed rate design study with respect to farms both of which are to be filed with the Commission no later than April 30, 2017.

Schedule 13-17 below summarizes the recommendations and forecast RTC ratios at the end of the 3 year period as a result of the Company's recommendations in Section 13.

SCHEDULE 13-17						
Summary of Recommendations from 2014 CA Study and Forecast RTC Ratios						
Rate Classes	**Recommendation**	**Revenue (Shortfall) to Achieve 90/110 RTC**	**Proposed Revenue Increase (Decrease) From Proposed Rate Changes**	**Current RTC Ratio (%)**	**Forecast RTC Ratio - End of Year 3 (%)**	**Notes**
Residential						
1. Residential Customers (excluding seasonal and farms)	No changes in rates except subjectivity to changes in second block (2,000 kWh - 5,000 kWh over 3 years)	-	$661,000	92	94	1, 3
2. Seasonal	No change in rates except subjectivity to changes in second block (2,000 kWh - 5,000 kWh over 3 years)	-	$21,000	97	97	1, 2
3. Farms	No changes in rates except subjectivity to changes in second block (2,000 kWh - 5,000 kWh over 3 years)	-	$91,000	81	83	1, 3
General Service	Adjust rates over 3 years with revenue generated from proposed changes in residential second block	$3,782,000	$(773,000)	117	115.7	1, 2, 4
Small Industrial	No changes in rates	-	-	96	96	1, 2
Large Industrial	No changes in rates	-	-	100	100	1, 2
Lighting and Unmetered	No change in rates	-	-	103	103	1

NOTES:

1. Forecast RTC ratio cost end of year 3 incorporate only the changes resulting from proposed recommendations in this section. Other relative changes in allocated costs or in revenue collected in rate classes over this period could also impact the forecast RTC ratio.
2. The proposed Lepreau Reclassification Study could result in a further reduction of the forecast RTC ratio.
3. The proposed Lepreau Reclassification Study could result in an increase in the forecast RTC.
4. The proposed rate design study for farms may result in some or all farms being reclassified in the General Service rate classes and result in a further reduction in the forecast RTC for the General Service rate class.

TABLES

13-1	Residential Rate (excluding Farms and Seasonal) Analysis
13-2	Residential Rate (Seasonal Only) Analysis
13-3	Residential Rate (Farms Only) Analysis
13-4	General Service I Rate (excludes Seasonal) Analysis
13-5	General Service I Rate (Seasonal Only) Analysis
13-6	General Service II Rate Analysis
13-6A	General Service II (Billing as General Service I) Rate Analysis
13-7	Small Industrial Rate Analysis
13-8	Large Industrial Rate Analysis

TABLE 13-1						
Residential Rate (Excluding Farms and Seasonal) Analysis						
			Energy			
	Customer	**Demand**	**First Block** (first 2,000 kWh/mo)	**Second Block**	**Total**	**Total Allocated Cost**
Fully allocated costs from 2014 CA Study[1]	($ x 1,000) 16,101	($ x 1,000) 34,985			($ x 1,000) 36,528	($ x 1,000) 87,614
2014 Study[2] Billing Determinants	Number of bills 292,911 (urban) 373,449 (rural) 666,360		(MWh) 446,013	(MWh) 34,040	(MWh) 480,053	(MWh) 480,053
2014 Average Costs - as per 2014 CA Study	($/month) 24.16[3]		($/kWh) 0.1545[4]	($/kWh) 0.0761[5]	($/kWh) 0.01490[6]	($/kWh) 0.1825[7]
Approved Rates - Effective March 1, 2014	($/month) 24.57 (urban) 26.92 (rural)		($/kWh) 0.1278	($/kWh) 0.0985		
Proposed Adjustment to Rates from 2014 CA Study:	**Increase Second Block from 2,000 kWh to 5,000 kWh**					
Estimated Annual Revenue Impact:	▪ 2014 Second Block Energy in MWh (see below): - between 2,000 - 3,000 kWh per bill - between 3,000 - 4,000 kWh per bill - between 4,000 - 5,000 kWh per bill ▪ 2014 Approved Rates: - Block 1 Rate - Block 2 Rate **Estimated Annual Revenue Impact - (a) x (b)**				 8,132 9,048 5,371 $.1278 $.0985	 22,551 (a) .0293 (b) **$661,000**
Breakdown of 2014 Second Block Energy:	2,000 - 3,000 kWh per bill 3,000 - 4,000 kWh per bill 4,000 - 5,000 kWh per bill 5,000 - 6,000 kWh per bill 6,000 - 7,000 kWh per bill 7,000 - 8,000 kWh per bill 8,000 - 9,000 kWh per bill 9,000 - 10,000 kWh per bill Balance of kWh					8,132 9,048 5,371 3,084 1,751 574 240 157 306 28,663 MWh

1 Schedule 1.3.
2 Schedule 2.2.
3 Customer costs of $16,101 divided by 666,360 customer bills.
4 Demand of $34,985 divided by First Block 446,013 MWh plus Second Energy Block rate of $.0761.
5 Total allocated costs of $36,528 divided by 480,053 total MWh.
6 Total demand of $34,985 plus $36,528 total energy divided by 480,053 total MWh.
7 Total allocated costs of $87,614 divided by 480,053 total MWh.

TABLE 13-2						
Residential Rate (Seasonal Only) Analysis						
			Energy			
	Customer	**Demand**	**First Block** (first 2,000 kWh/mo)	**Second Block**	**Total**	**Total Allocated Cost**
Fully allocated costs from 2014 CA Study[1]	($ x 1,000) 2,169	($ x 1,000) 558			($ x 1,000) 1,301	($ x 1,000) 4,028
2014 Study[2] Billing Determinants	Number of bills 10,178 (Code 131) 38,970 (Code 133) 49,148		(MWh) 15,920	(MWh) 1,290	(MWh) 17,210	(MWh) 17,210
2014 Average Costs - as per 2014 CA Study	($/month) 44.13[3]		($/kWh) 0.1106[4]	($/kWh) 0.0756[5]	($/kWh) 0.01080[6]	($/kWh) 0.2340[7]
Approved Rates - Effective March 1, 2014	($/month) 26.92 (Code 131) 37.50 (Code 133)		($/kWh) 0.1278	($/kWh) 0.0985		
Proposed Adjustment to Rates from 2014 CA Study:	**Increase Second Block from 2,000 kWh to 5,000 kWh**					
Estimated Annual Revenue Impact:	▪ 2014 Second Block Energy in MWh (see below): - between 2,000 - 3,000 kWh per bill - between 3,000 - 4,000 kWh per bill - between 4,000 - 5,000 kWh per bill ▪ 2014 Approved Rates: - Block 1 Rate - Block 2 Rate **Estimated Annual Revenue Impact - (a) x (b)**				 231 269 200 $.1278 $.0985	 700 (a) .0293 (b) **$21,000**
Breakdown of 2014 Second Block Energy:	2,000 - 3,000 kWh per bill 3,000 - 4,000 kWh per bill 4,000 - 5,000 kWh per bill 5,000 - 6,000 kWh per bill 6,000 - 7,000 kWh per bill 7,000 - 8,000 kWh per bill 8,000 - 9,000 kWh per bill 9,000 - 10,000 kWh per bill Balance of kWh				231 269 200 109 111 49 65 59 197 1,290 MWh	

1. Schedule 1.3.
2. Schedule 2.2.
3. Customer costs of $2,169 divided by 49,148 customer bills.
4. Demand of $558 divided by First Block 15,920 MWh plus Second Energy Block rate of $.0756.
5. Total allocated costs of $1,301 divided by 17,210 total MWh.
6. Total demand of $558 plus total energy of $1,301 divided by 17,210 total MWh.
7. Total allocated costs of $4,028 divided by 17,210 total MWh.

TABLE 13-3

Residential Rate (Farms Only) Analysis

			Energy			
	Customer	**Demand**	**First Block** (first 2,000 kWh/mo)	**Second Block**	**Total**	**Total Allocated Cost**
Fully allocated costs from 2014 CA Study[1]	($ x 1,000) 605	($ x 1,000) 3,213			($ x 1,000) 3,355	($ x 1,000) 7,173
2014 Study[2] Billing Determinants	Number of bills 23,844 (Rural)		(MWh) 19,034	(MWh) 25,060	(MWh) 44,094	(MWh) 44,094
2014 Average Costs - as per 2014 CA Study	($/month) 25.37[3]		($/kWh) 0.2449[4]	($/kWh) 0.0761[5]	($/kWh) 0.1490[6]	($/kWh) 0.1627[7]
Approved Rates - Effective March 1, 2014	($/month) 24.57 (Urban) 26.92 (Rural)		($/kWh) 0.1278	($/kWh) 0.0985		
Proposed Adjustment to Rates from 2014 CA Study:	**Increase Second Block from 2,000 kWh to 5,000 kWh**					
Estimated Annual Revenue Impact:	▪ 2014 Second Block Energy in MWh (see below): - between 2,000 - 3,000 kWh per bill - between 3,000 - 4,000 kWh per bill - between 4,000 - 5,000 kWh per bill ▪ 2014 Approved Rates: - Block 1 Rate - Block 2 Rate **Estimated Annual Revenue Impact - (a) x (b)**				 573 1,112 1,414 $.1278 $.0985	 3,099 (a) .0293 (b) **$91,000**
Breakdown of 2014 Second Block Energy:	2,000 - 3,000 kWh per bill 3,000 - 4,000 kWh per bill 4,000 - 5,000 kWh per bill 5,000 - 6,000 kWh per bill 6,000 - 7,000 kWh per bill 7,000 - 8,000 kWh per bill 8,000 - 9,000 kWh per bill 9,000 - 10,000 kWh per bill Balance of kWh					573 1,112 1,414 1,636 1,312 1,658 1,569 1,807 19,356 30,437 MWh

1 Schedule 1.3.
2 Schedule 2.2.
3 Customer costs of $605 divided by 23,844 customer bills.
4 Demand of $3,213 divided by First Block energy of 19,034 MWh plus Second Energy Block rate of $.0761.
5 Total allocated costs of $3,355 divided by 44,094 total MWh.
6 Total demand of $3,213 plus total energy of $3,335 divided by 44,094 MWh.
7 Total allocated costs of $7,173 divided by 44,094 total MWh.

TABLE 13-4								
General Service I Rate (Excludes Seasonal) Analysis								
		Demand			**Energy**			
	Customer	**First Block** (first 20 kW/mo)	**Second Block**	**Total**	**First Block** (first 5,000 kWh/mo)	**Second Block**	**Total**	**Total Allocated Cost**
Fully allocated costs from 2014 CA Study[1]	($ x 1,000) 2,279			($ x 1,000) 18,659			($ x 1,000) 28,320	($ x 1,000) 49,258
2014 Study[2] Billing Determinants (a)	Number of bills 84,584	(kW) 338,353	(kW) 584,742	(kW) 923,095	(MWh) 130,960	(MWh) 238,268	(MWh) 369,228	(MWh) 369,228
2014 Average Costs - as per 2014 CA Study	($/month) 26.94[3]			($/kW) 20.21[4]	($/kWh) 0.1289[5]	($/kWh) 0.0767[6]	($/kWh) 0.0767[7]	($/kWh) 0.1334[8]
Approved Rates - Effective March 1, 2014	($/month) 24.57	($/kW) -	($/kW) 13.43		($/kWh) 0.1601	($/kWh) 0.0996		
Proposed Adjustment to Rates from 2014 CA Study:								
▪ **Reduce 1st Block energy charge**					**0.1551**			
▪ **Increase 2nd Block demand charge**			**15.33**					
▪ **Reduce 2nd Block energy charge**						**0.0946**		
Differential from 2014 rates (b)			1.90		0.005	0.005		
Revenue Increase (Reduction) (a) x (b)			**($ x 1,000) 1,111**		**($ x 1,000) (654)**	**($ x 1,000) (1,191)**		**($ x 1,000) (744)**

1 Schedule 1.3.
2 Schedule 2.2.
3 Customer costs of $2,279 divided by 84,584 customer bills.
4 Total demand costs of $18,659 divided by total kW demand of 923,095.
5 Second block energy rate of $.0767 plus total demand of $18,655 times First Block demand of 388,353 kW divided by total kW demand of 923,095 times 130,960 MWh First Block energy.
6,7 Total energy costs of $28,320 divided by total 369,228 MWh energy.
8 Total allocated cost of $49,258 divided by total energy of 369,228 MWh.

TABLE 13-5 General Service I Rate (Seasonal Only) Analysis								
		Demand			**Energy**			
	Customer	**First Block** (first 20 kW/mo)	**Second Block**	**Total**	**First Block** (first 5,000 kWh/mo)	**Second Block**	**Total**	**Total Allocated Cost**
Fully allocated costs from 2014 CA Study[1]	($ x 1,000) 523			($ x 1,000) 206			($ x 1,000) 611	($ x 1,000) 1,340
2014 Study[2] Billing Determinants (a)	Number of bills 10,273	(kW) 7,007	(kW) 4,265	(kW) 11,272	(MWh) 6,915	(MWh) 1,047	(MWh) 7,962	(MWh) 7,962
2014 Average Costs - as per 2014 CA Study	($/month) 50.91[3]			($/kW) 18.28[4]	($/kWh) 0.0953[5]	($/kWh) 0.0767[6]	($/kWh) 0.0767[7]	($/kWh) 0.1683[8]
Approved Rates - Effective March 1, 2014	($/month) 24.57	($/kW) -	($/kW) 13.43		($/kWh) 0.1601	($/kWh) 0.0996		
Proposed Adjustment to Rates from 2014 CA Study:								
▪ **Reduce 1st Block energy charge**					**0.1551**			
▪ **Increase 2nd Block demand charge**			**15.33**					
▪ **Reduce 2nd Block energy charge**						**0.0946**		
Differential from March 1, 2014 Rates (b)			1.90		0.005	0.005		
Revenue Increase (Reduction) (a) x (b)			**($ x 1,000) 8**		**($ x 1,000) (35)**	**($ x 1,000) (5)**		**($ x 1,000) (32)**

1 Schedule 1.3.
2 Schedule 2.2.
3 Customer costs of $523 divided by 10,273 customer bills.
4 Total demand costs of $206 divided by total kW demand of 11,272 kW.
5 Second block energy rate of $.0767 kWh plus total demand of $206 times First Block demand of 7,007 kW divided by total kW demand of 11,272 kW times 6,915 MWh First Block energy.
6,7 Total energy costs of $611 divided by total 7,962 MWh energy.
8 Total allocated cost of $1,340 divided by total energy of 7,962 MWh.

TABLE 13-6									
General Service II Rate Analysis									
		Demand			**Energy**				
	Customer	**First Block** (first 20 kW/mo)	**Second Block**	**Total**	**First Block** (first 5,000 kWh/mo)	**Second Block**	**Third Block**	**Total**	**Total Allocated Cost**
Fully allocated costs from 2014 CA Study[1]	($ x 1,000) 31			($ x 1,000) 427				($ x 1,000) 710	($ x 1,000) 1,168
2014 Study[2] Billing Determinants	Number of bills 1,040	(kW) 7,049	(kW) 14,607	(kW) 21,656	(MWh) 3,109	(MWh) 851	(MWh) 5,461	(MWh) 9,421	(MWh) 9,421
2014 Average Costs - as per 2014 CA Study	($/month) 29.81[3]			($/kW) 19.72[4]	($/kWh) 0.1201[5]	($/kWh) 0.0754[6]	($/kWh) 0.0754[7]	($/kWh) 0.0754[8]	($/kWh) 0.1240
Approved Rates - Effective March 1, 2014	($/month) 24.57	($/kW) -	($/kW) 5.68[9]		($/kWh) 0.1602	($/kWh) 0.1173	($/kWh) 0.1116		
Proposed Adjustment to Rates from 2014 CA Study: **Fold General Service Rates into General Service I Rates (see Schedule 13-6(a)[10]**									

[1] Schedule 1.3.
[2] Schedule 2.2.
[3] Customer costs of $31 divided by 1,040 customer bills.
[4] Total demand costs of $427 divided by total kW demand of 21,656 kW.
[5] Second block energy rate of $.0754/kWh plus total demand of $427 times First Block demand of 7,049 kW divided by total kW demand of 21,656 kW times first block energy of 3,109 MWh.
[6,7,8] Total energy costs of $710 divided by total 9,421 MWh energy.
[9] $.0284 times kWh (if lesser).
[10] Estimated increase in revenue from GS2 customers when billed under GS1 is approximately $21,000.

TABLE 13-6A								
General Service II (Billing Using General Service I) Rate Analysis								
		Demand			**Energy**			
	Customer	**First Block** (first 20 kW/mo)	**Second Block**	**Total**	**First Block** (first 5,000 kWh/mo)	**Second Block**	**Total**	**Total Allocated Cost**
Fully allocated costs from 2014 CA Study[1]	($ x 1,000) 31			($ x 1,000) 427			($ x 1,000) 710	($ x 1,000) 1,168
2014 Study[2] Billing Determinants	Number of bills 1,040	(kW) 7,049	(kW) 14,607	(kW) 21,656	(MWh) 3,109	(MWh) 6,312	(MWh) 9,421	(MWh) 9,421
2014 Average Costs - as per 2014 CA Study	($/month) 29.81[3]			($/kW) 19.72[4]	($/kWh) 0.1201[5]	($/kWh) 0.0754[6]	($/kWh) 0.0754[7]	($/kWh) 0.1240
Approved Rates - Effective March 1, 2014	($/month) 24.57	($/kW) -	($/kW) 13.43		($/kWh) 0.1601	($/kWh) 0.0996		
Proposed Adjustment to Rates from 2014 CA Study:								
▪ **Reduce 1st Block energy charge**					**0.1551**			
▪ **Increase 2nd Block demand charge**			**15.33**					
▪ **Reduce 2nd Block energy charge**						**0.0946**		
Differential from March 1, 2014 Rates (b)			1.90		0.005	0.005		
Revenue Increase (Reduction) (a) x (b)			**($ x 1,000) 28**		**($ x 1,000) (15)**	**($ x 1,000) (32)**		**($ x 1,000) (19)**[9]

1 Schedule 1.3.
2 Schedule 2.2.
3 Customer costs of $31 divided by 1,040 customer bills.
4 Total demand costs of $427 divided by total kW demand of 21,656 kW.
5 Second block energy rate of $.0754/kWh plus total demand of $427 times First Block demand of 7,049 kW divided by total kW demand of 21,656 kW times first block energy of 3,109 MWh.
6,7 Total energy costs of $710 divided by total 9,421 MWh energy.
8 Total allocated cost of $1,168 divided by total energy of 9.421 MWh.
9 The Company estimates that the increase in revenue from GS2 customers moving to GS1 would be approximately $21,000. Therefore, the estimated $19,000 reduction due to proposed adjustments to the GS1 is offset.

TABLE 13-7						
Small Industrial Rate Analysis						
			Energy			
	Customer	**Demand**	**First Block** (first 100 kWh/KW)	**Second Block**	**Total**	**Total Allocated Cost**
Fully allocated costs from 2014 CA Study[1]	($ x 1,000) 123	($ x 1,000) 5,320			($ x 1,000) 6,806	($ x 1,000) 12,249
2014 CA Study[2] Billing Determinants		(kW-mo) 295,833	(MWh) 28,182	(MWh) 60,748	(MWh) 88,930	(MWh) 88,930
2014 Average Costs - as per 2014 CA Study		(kW-mo) 9.41[3]	($/kWh) 0.1709[4]	($/kWh) 0.0765[5]	($/kWh) 0.0765[5]	($/kWh) 0.1377[6]
Approved Rates - Effective March 1, 2014		(kW-mo) 7.46	($/kWh) 0.1566	($/kWh) 0.0717		
Proposed Adjustment to Rates from 2014 CA Study:	**No Changes**					

1 Schedule 1.3.
2 Schedule 2.2.
3 Customer costs of $123 plus 50 per cent of $5,320 demand divided by 295,833 kW/month.
4 Second Block energy charge of $.0765/kWh plus 50 per cent of $5,320 demand divided by 28,182 MWh First Block energy.
5 Total allocated energy cost of $6,806 divided by 88,930 total MWh.
6 Total allocated cost of $12,249 divided by 88,930 MWh.

TABLE 13-8				
Large Industrial Rate Analysis				
	Customer	**Demand**	**Energy**	**Total Allocated Cost**
Fully allocated costs from 2014 CA Study[1]	($ x 1,000) 7	($ x 1,000) 3,061	($ x 1,000) 10,420	($ x 1,000) 13,488
2014 Study[2] Billing Determinants		(kW-month) 252,500	(MWh) 142,152	(MWh) 142,152
2014 Average Costs - as per 2014 CA Study		($/kW-month) 12.15[3]	($/kWh) 0.0733[4]	($/kWh) 0.0949[5]
Approved Rates - Effective March 1, 2014		($/kW-month) 14.50	($/kWh) 0.0634	
Proposed Adjustment to Rates from 2014 CA Study:	**(No Changes)**			

1 Schedule 1.3.
2 Schedule 2.2.
3 Customer costs of $7 plus demand of $3,061 divided by demand of 252,500 kW/month.
4 Energy costs of $10,420 divided by 142,152 MWh of energy.
5 Total allocated energy cost of $13,488 divided by 142,152 MWh of energy.

14.0 STREET AND AREA LIGHTING

14.1 Background

Sections N-22, N-23 and N-25 of the Maritime Electric General Rules and Regulations ("GRR") currently in effect provide rates for a number of street and area lighting categories both rented and customer-owned, predominately using high pressure sodium ("HPS") technology.

In recent years, as energy efficient light emitting diode ("LED") technology has developed and LED fixture prices decreased, the level of customer interest in adopting these new lighting options for both Maritime Electric owned and customer-owned fixtures has continued to grow. Based on favorable LED fixture test results, the increasing level of customer interest in using LED street light technology and the decrease seen in the cost of LED street light fixtures in recent years, Maritime Electric received approval from the Commission in January 2014 (UE14-01) to adopt new interim rates for four classes of rented LED street lights. In addition, the Commission authorized the Company to utilize the methodology set out in the January 2014 proposal to set the monthly rate on an interim basis for any additional LED fixtures approved for use by Maritime Electric on PEI.

14.2 Transition to LED Fixtures

The transition to LED street and area lighting is expected to yield benefits to customers and also assist the Company in its efforts to promote energy efficiency and reduce growth in peak demand. With approximately 10,000 fixtures in service, the Company has implemented a 10 year conversion plan to accommodate annual capital budget allocations and the assignment of internal resources to change out the fixtures.

To ensure the conversion of LED fixtures is achieved in a timely manner, which benefits customers and the Company, it is proposed that the existing non-LED rate classes for street and area lighting be closed to new additions and removed from the approved rate schedules once each class has been converted to LED.

Schedule 14-1 shows the number of Maritime Electric owned LED fixtures installed or converted, up to September 30, 2015 since receiving approval from IRAC for the four new LED rate classes.

SCHEDULE 14-1		
Number of LED Fixtures Installed to September 30, 2015		
Rate Class	**Wattage**	**Number of Fixtures**
619	43	377
625	50	614
666	72	138
670	100	155
Total		**1,284**

While the LED fixture classes in the table above will allow for the conversion of a significant portion of the existing fixtures in service, there are larger, brighter, yard and area lights, for which an LED fixture and rate has not been adopted to date. The Company has partnered with the City of Charlottetown to test 250 W and 400 W HPS equivalent LED fixtures to determine if they are suitable for adoption to replace the current HPS yard and area lights. Should the test results prove acceptable, the Company will develop an interim rate using the methodology previously approved by the Commission and seek approval of the class in a subsequent rate application. As LED equivalent replacements are identified and adopted, the remaining non-LED rate classes can be discontinued.

During the conversion period, the Company will continue to amortize (or depreciate) the accumulated capital costs of the existing and new street and area lighting infrastructure and retire those assets removed from service. Although there may be a residual unrecovered capital cost balance related to the old infrastructure (accumulated reserve balance) remaining after conversion, this residual will be lower than originally expected due to the new depreciation rate recommended for street and area lighting in the 2014 Depreciation Study filing (IRAC Docket UE21603).

The proposed new depreciation rate will allow for a more timely recovery of these costs, however, a definitive calculation of any residual balance cannot be completed at this time since the final amount will be dependent upon the pattern of replacement and timeframe over which the conversion is achieved. The Company proposes to continue to monitor this residual during the course of the conversion through periodic Depreciation Study filings with the Commission which will contain any recommended changes to the depreciation rates to properly recover all costs related to street and area lighting capital costs and associated cost of removal.

14.3 Summary

A summary of this section follows:

- The Company seeks approval of the interim LED Street and Area Lighting classes approved in Order UE14-01.
- The Company proposes to close all non-LED street and area lighting rate classes to new additions where comparable LED rate categories have been approved by the Commission.
- The Company proposes amortizing the street and area light assets at the new rate proposed in the 2014 Depreciation Study Application and continue to monitor the residual balance during the conversion.

15.0 FINANCIAL FORECAST

15.1 Financial Forecast Process

The components of the financial forecast process will be discussed separately.

- Energy Sales Forecast;
- Capital Expenditures;
- Operating Expenses;
- Income Taxes;
- Revenue Requirement; and
- Revenue.

The financial forecast process incorporates other variables, as discussed previously throughout the Application, such as dividend payments, short-term interest rates, inventory requirements and cash flow requirements.

15.2 Energy Sales Forecast

The results of the energy sales forecast, as discussed in Section 7, are used in the preparation of the Capital and Operating Budgets as well as the forecast of electric revenue.

15.3 Capital Expenditures

The capital expenditures forecast uses the energy sales forecast as a prime input. The projected increase in energy sales and the number of customers drive expenditures for system infrastructure. The balance of the capital expenditures is based on corporate needs in terms of ensuring the necessary infrastructure to continue to safely provide a high level of customer service. Capital expenditures are categorized according to their amortization rate and the appropriate amortization expense (½ in the first year) is calculated. The following Schedule shows the actual and forecast capital expenditures for the period 2014 - 2016.

The expenditures for 2015 reflect the Company's 2015 Capital Budget which was approved by IRAC under Order UE14-04, while the 2016 expenditures reflect the Company's 2016 Capital Budget Application filed on July 30, 2015.

SCHEDULE 15-1			
Schedule of Capital Expenditures ($)			
	2014 Actual	**2015 Forecast***	**2016 Forecast**
Generation			
Charlottetown Plant	$ 592,872	$ 927,000	$ 1,061,000
Borden-Carleton Plant	1,468,960	383,000	154,000
Transmission & Distribution			
Transmission	6,462,871	8,422,000	10,399,000
Distribution	16,974,255	16,648,000	17,538,000
Corporate	979,141	1,043,000	1,214,000
Sub-total	26,478,099	27,423,000	30,366,000
Allowance for Funds Used During Construction	368,486	200,000	200,000
General Expense Capitalized	388,730	455,000	494,000
Less: Contributions	(525,236)	(400,000)	(400,000)
Net Capital Expenditures	**$ 26,710,079**	**$ 27,678,000**	**$ 30,660,000**

* *2015 includes $ 1,649,000 of carryover expenditures (net of contributions) approved in prior years.*

15.4 Operating Expenses

Operating expenses, including the amortization of deferred charges used in the financial forecast, are taken from this Evidence and are presented in Schedule 15-2.

SCHEDULE 15-2				
Operating Expenses ($)				
	Schedule Ref.	**2014 Actual**	**2015 Forecast**	**2016 Forecast**
Energy Supply Expenses	8-3	$ 106,413,014	$ 112,839,200	$ 110,818,500
ECAM	Appendix 4	12,357,643	1,667,800	370,000
Energy Supply Expenses - Other	8-8	754,115	764,500	890,900
Distribution	9-3	3,925,204	4,635,600	4,968,800
Transmission*	9-1	7,560,200	7,224,000	7,565,200
Transmission and Distribution - Other	9-4	2,063,915	2,120,700	2,306,900
General and Administrative**	10-1	10,411,935	10,428,700	9,629,900
Total		**$ 143,486,026**	**$ 139,680,500**	**$ 136,550,200**

* *Includes OATT expenses*
** *Excludes Fortis Inc. Administrative Charges.*

15.5 Income Taxes

Maritime Electric uses the liability method of accounting for income taxes. Under this method future income taxes are recognized based on the expected future tax consequences of differences between the carrying amount of Balance Sheet items and their corresponding tax basis, using the enacted and substantively enacted income tax rates for the years in which the differences are expected to reverse. Maritime Electric maximizes its tax deductions to minimize cash taxes, reduce interest costs and minimize the impact on customers. Schedule 15-3 shows Maritime Electric's effective corporate income tax rates for the period 2014 - 2016.

SCHEDULE 15-3			
Effective Corporate Income Tax Rates (%)			
	2014 Actual	**2015 Forecast**	**2016 Forecast**
Effective Tax Rate	31.6	31.6	31.6

15.6 Revenue Requirement

The requested revenue requirement is derived from the following:

- Forecast energy sales for the year (Section 7);
- The forecast cost of generating or purchasing energy to meet energy sales (Section 8);
- The forecast cost of delivering the energy to customers (the "wires" cost) (Section 9);
- The forecast amount of general and administrative expenses (Section 10);
- Forecast fixed asset amortization expense (Section 11);
- Forecast short-term and long-term interest expense (Section 12.3);
- Income taxes (Section 15.5); and
- Return on Average Rate Base (Section 12.6).

Schedule 15-4 outlines the actual Revenue Requirement for 2014 and the forecast Revenue Requirements for 2015 and 2016 at $186,859,600 and $189,940,800 respectively. Based on the results of the financial forecast this results in a regulated Return on Average Rate Base of 7.64 per cent in 2016 (as calculated in Schedule 12-12).

SCHEDULE 15-4 Revenue Requirement ($)			
	2014 Actual	**2015 Forecast**	**2016 Forecast**
Operating Expenses (Net of ECAM)*	$ 143,157,076	$ 139,473,700	136,456,800
Amortization of Costs Recoverable From Customers	1,983,600	-	-
Interest Expense (including amortization of debt issue costs)	12,118,864	12,482,300	12,705,600
Amortization Expense - Fixed Assets	15,120,635	15,625,500	21,031,900
Amortization Expense – DSM Costs	235,600	113,400	-
Amortization Expense - Point Lepreau Writedown	93,400	93,400	93,400
Income Tax Expense	5,822,890	6,030,500	6,210,500
Return on Average Rate Base**	12,603,977	13,040,800	13,442,600
Total	**$ 191,136,042**	**$ 186,859,600**	**$ 189,940,800**

* *Excluding Fortis Inc. Administrative Charges.*
** *Before disallowable costs.*

15.7 Revenue

There are two components to the calculation of revenue. The first component is Basic Rate Revenue which is calculated using forecast energy sales at existing Basic Rates. The Basic Rate Revenue increases in 2016 reflect the continued rebasing of the ECAM, the forecast expenses for the year, and the proposals discussed in Section 13 - Cost Allocation Study. By adjusting the base rate in ECAM to the forecast unit cost for the upcoming period, there is a better match of current rates to the energy costs expensed in the current period. In addition, by adopting the changes to the rate classes proposed in Section 13, the revenue to cost ratios for the affected rate classes (Resident and General Service) begin to move closer to the target revenue-to-cost ratio range of 90 per cent to 110 per cent.

The second component is Other Revenue which is comprised of transmission revenue, connection fees, late payment charges and miscellaneous revenue. As discussed in Section 9.1 - Transmission Expenses, under Canadian ASPE the Company is required to record and disclose both the expense and offsetting revenue applicable to its participation in the OATT as well as any other costs incurred and recovered from other participants.

Schedule 15-5 below shows the components of Other Revenue for the period 2014-2016:

SCHEDULE 15-5			
Other Revenue ($)			
	2014 Actual	**2015 Forecast**	**2016 Forecast**
OATT			
Network Service	$ 5,124,080	$ 5,543,800	$ 5,681,300
Schedule 1	293,084	295,200	297,100
Schedule 2	441,849	478,300	481,200
Schedule 3C	11,104	-	-
Schedule 4	653,842	-	-
Schedule 7	270,859	270,900	270,900
Schedule 8	1,080,406	1,152,700	1,051,100
Schedule 9	326,372	328,400	328,400
Schedule 10	94,467	-	-
Sub-Total	$ 8,296,063	$ 8,069,300	$ 8,110,000
Other			
Late Payment Charges	$ 631,767	$ 634,200	$ 550,400
Connection Fees	485,078	448,900	470,300
Miscellaneous Revenue	725,826	151,900	683,400
Sub-Total	1,842,671	1,235,000	1,704,100
Total Other Revenue	**$ 10,138,734**	**$ 9,304,300**	**$ 9,814,100**

Schedule 15-6 shows the revenue derived from existing Basic Rates and Other Income for the period 2014-2016.

SCHEDULE 15-6			
Energy Sales and Revenue (Existing Basic Rates)			
	2014 Actual	**2015 Forecast**	**2016 Forecast**
Energy Sales by Class – (GWh)			
Residential	541.4	573.0	563.7
General Service I	377.2	378.1	381.0
General Service II	9.4	10.1	10.7
Large Industrial	142.2	132.6	131.3
Small Industrial	88.9	93.1	98.9
Street Lighting	6.2	6.0	5.7
Unmetered	2.4	2.4	2.5
Total Energy Sales	**1,167.7**	**1,195.3**	**1,193.8**
Gross Revenue by Class - ($)			
Residential	$ 93,697,148	$ 94,703,900	$ 93,208,500
General Service I	60,732,925	58,644,500	58,617,600
General Service II	1,432,808	1,456,600	1,550,800
Large Industrial	13,812,712	11,666,700	11,131,800
Small Industrial	12,096,771	11,980,800	12,645,000
Street Lighting	2,480,191	2,354,600	2,182,400
Unmetered	419,481	408,200	401,900
Total Gross Electric Revenue	**184,672,036**	**$ 181,215,300**	**$ 179,738,000**
Rate of Return Adjustment	(3,674,728)	(3,660,000)	-
Total Electric Revenue	**180,997,308**	**177,555,300**	**179,738,000**
Total Other Revenue	**10,138,734**	**9,304,300**	**9,814,100**
Total Revenue	**$ 191,136,042**	**$ 186,859,600**	**$ 189,552,100**

Schedule 15-7 shows the revenue derived from Basic Rates and Other Income for the period 2014-2016 as a result of the proposals in this Application.

SCHEDULE 15-7 Energy Sales and Revenue (Proposed)			
	2014 Actual	**2015 Forecast**	**2016 Forecast**
Energy Sales by Class – (GWh)			
Residential	541.4	573.0	563.7
General Service I	377.2	378.1	381.0
General Service II	9.4	10.1	10.7
Large Industrial	142.2	132.6	131.3
Small Industrial	88.9	93.1	98.9
Street Lighting	6.2	6.0	5.7
Unmetered	2.4	2.4	2.5
Total Energy Sales	**1,167.7**	**1,195.3**	**1,193.8**
Gross Revenue by Class - ($)			
Residential	$ 93,697,148	$ 94,703,900	$ 93,664,900
General Service I	60,732,925	58,644,500	58,617,200
General Service II	1,432,808	1,456,600	1,582,900
Large Industrial	13,812,712	11,666,700	10,976,200
Small Industrial	12,096,771	11,980,800	12,692,500
Street Lighting	2,480,191	2,354,600	2,189,700
Unmetered	419,481	408,200	403,300
Total Gross Electric Revenue	**184,672,036**	**181,215,300**	**180,126,700**
Rate of Return Adjustment	(3,674,728)	(3,660,000)	-
Total Electric Revenue	**180,997,308**	**177,555,300**	**180,126,700**
Total Other Revenue	**10,138,734**	**9,304,300**	**9,814,100**
Total Revenue	**$ 191,136,042**	**$ 186,859,600**	**$ 189,940,800**

15.8 Financial Forecast Results

The financial forecast uses the inputs previously outlined in this Evidence. A summary of the results (prepared in accordance with ASPE) of the Company's actual results for 2014 and its financial forecast for 2015 and 2016 is shown in Appendix 2.

15.9 Summary

A summary of the results of this section follows:

- The financial forecast is derived from the various inputs and proposals outlined in this Application.
- Total capital expenditures were $26,710,079 in 2014 and are forecast to be $27,678,000 in 2015 and $30,660,000 in 2016.
- Maritime Electric's effective corporate income tax rate for 2014 was 31.6 per cent and is forecast to be 31.6 per cent for 2015 and 2016.
- Total revenue requirement was $191,136,042 in 2014 and is forecast to be $186,859,600 in 2015 and $189,940,800 in 2016.

16.0 IMPACT OF PROPOSAL ON CUSTOMERS

16.1 Revised Customer Rates

Based upon the evidence contained in this Application, Schedule 16-1 below shows the proposed change in Residential and Commercial rates as compared to the rates in effect until February 29, 2016. Further comparisons for Street Lights and other rate classes can be found in Appendix 11.

SCHEDULE 16-1			
Comparison of Residential and Commercial Rates ($)			
Rate Code		**Effective March 1, 2015**	**Proposed March 1, 2016**
110	**Residential Urban**		
	Service Charge	$ 24.57	$ 24.57
	Energy Charge per kWh for first 3,000 kWh*	$ 0.1316	$ 0.1359
	Energy charge per kWh for balance kWh	$ 0.1038	$ 0.1080
130	**Residential Rural**		
	Service Charge	$ 26.92	$ 26.92
	Energy Charge per kWh for first 3,000 kWh*	$ 0.1316	$ 0.1359
	Energy charge per kWh for balance kWh	$ 0.1038	$ 0.1080
131	**Residential Seasonal**		
	Service Charge	$ 26.92	$ 26.92
	Energy Charge per kWh for first 3,000 kWh*	$ 0.1316	$ 0.1359
	Energy charge per kWh for balance kWh	$ 0.1038	$ 0.1080
133	**Residential Seasonal Option**		
	Service Charge	$ 37.50	$ 37.50
	Energy Charge per kWh for first 3,000 kWh*	$ 0.1316	$ 0.1359
	Energy charge per kWh for balance kWh	$ 0.1038	$ 0.1080
232	**General Service**		
	Service Charge	$ 24.57	$ 24.57
	Demand Charge - per kW for first 20 kW	$ -	$ -
	Demand Charge - per kW for balance of kW	$ 13.43	$ 14.06
	Energy Charge per kWh for first 5,000 kWh	$ 0.1625	$ 0.1654
	Energy charge per kWh for balance kWh	$ 0.1049	$ 0.1075
233	**General Service - Seasonal Operators Option**		
	Service Charge	$ 24.57	$ 24.57
	Demand Charge - per kW for first 20 kW	$ -	$ -
	Demand Charge - per kW for balance of kW	$ 13.43	$ 14.06
	Energy Charge per kWh for first 5,000 kWh	$ 0.1625	$ 0.1654
	Energy charge per kWh for balance kWh	$ 0.1049	$ 0.1075
250	**General Service II**		
	Service Charge	$ 24.57	N/A
	Demand Charge - per kW for first 20 kW	$ -	N/A
	Demand Charge - per kW for balance of kW		
	a. per kilowatt or;	$ 5.68	N/A
	b. the number of kilowatt hours consumed in the period times	$ 0.0284	N/A
	Energy Charge per kWh for first 5,000 kWh	$ 0.1626	N/A
	Energy Charge per kWh for next 5,000 kWh	$ 0.1218	N/A
	Energy charge per kWh for balance kWh	$ 0.1164	N/A
320	**Small Industrial**		
	Demand Charge per kW	$ 7.46	$ 7.46
	Energy Charge per kWh for 100 kWh per kW billing demand	$ 0.1591	$ 0.1637
	Energy Charge per kWh for balance of kWh	$ 0.0784	$ 0.0825
310	**Large Industrial**		
	Demand Charge per kW	$ 14.50	$ 14.50
	Energy Charge per kWh	$ 0.0653	$ 0.0676

* *In 2015, energy charge per kWh for first 2,000 kWh.*

16.2 Impact of Residential Second Block Changes

As shown in Schedule 13-8 of the Application, the Company is proposing to increase the residential second block from 2,000 kWh to 3,000 kWh effective March 1, 2016, then to 3,800 kWh effective March 1, 2017 and finally to 5,000 kWh effective March 1, 2018. The estimated $773,000 of incremental Residential rate class (see Schedule 13-17 of the Application) revenue generated by this change over the three year transition period will be used to lower electricity costs for General Service customers, thus making the proposal revenue neutral to the Company while beginning to rebalance the rate class revenue to cost ratios.

The impact of the proposed residential second block changes will vary from customer to customer depending upon their monthly consumption levels and patterns. The majority of residential customers will not experience any incremental increase in their electricity costs as a result of the second block changes. As illustrated in Schedule 13-10 of the Application, approximately 85 per cent of customers in February 2015 (a typical cold weather month) had consumption below the 2,000 kWh second block threshold. In July 2015 (a typical warm weather month), the percentage of customers below the 2,000 kWh second block threshold was over 98 per cent. These customers will not be impacted by the proposed block changes.

While the majority of the residential customers are not impacted by the proposed second block changes, the increase over the three years to a second block threshold of 5,000 kWh will ensure that the majority of consumption for residential customers with dwellings will be subject to the first block rate. Schedule 13-9 of the Application illustrates the estimated impact of the proposed second block changes on sample customers who do have consumption levels above 2,000 kWh. These increases are based upon fixed average kWh per month consumption and actual customer electricity cost impact will vary subject to a customer's monthly consumption level and pattern. Sample customers profile in

Schedule 13-9 who would be impacted by the proposed second block changes would experience total increases in electricity costs varying between .8 per cent and 13.0 per cent. These increases would be phased in over a three year period.

16.3 Summary

As discussed above, the majority of residential customers are not impacted by the proposed second block changes.

Schedule 16-2 illustrates the components of the estimated annual cost for a rural residential customer consuming 650 kWh per month (7,800 kWh per year) resulting in an increase of 2.5 per cent.

SCHEDULE 16-2 Annual Cost for Rural Residential Customer (650 kWh per Month/7,800 kWh per Year)			
Annual Cost ($)	**2014 Actual**	**2015 Actual**	**2016 Forecast**
Service Charge	$ 323.04	$ 323.04	$ 323.04
Basic Energy Charge	1,088.88	1,034.28	1,038.96
ECAM Charge	(129.56)	(46.44)	18.75
Provincial Costs Recoverable	40.95	41.81	41.81
Cable Contingency Fund	2.11	2.11	2.11
RORA	(5.52)	(5.52)	(41.55)
Sub-Total	$ 1,319.90	$ 1,349.28	$ 1,383.12
HST	184.78	188.89	193.63
Total Annual Cost	**$ 1,504.68**	**$ 1,538.17**	**$ 1,576.75**
Percentage Annual Increase (%)	**2.2%**	**2.2%**	**2.5%**

The adjustments to Residential rate class rates apply only to the per kWh energy charge and are not applied to the fixed monthly service charge. As a result, the impact on annual electricity costs for residential customers will vary from customer to customer based on their monthly electricity consumption level and pattern. For example, a customer utilizing 400 kWh per month would experience an increase in electricity costs of 2.2 per cent and a customer consuming 1,700 kWh per month would see an increase in electricity costs of 2.9 per cent.

The General Service rate class will be the beneficiary of the proposed residential second block change resulting in a lower increase in annual electricity cost adjustment for General Service customers (than would otherwise be incurred). The impact, however, will again vary depending upon each customer's demand and energy consumption profile. The proposed changes to General Service rates that would increase the demand charge rate while lowering the Block 1 and 2 basic energy charge rates (see Schedule 13-15) will impact customers differently (based on demand and consumption pattern).

Schedule 16-3 shows the impact of the proposals on a small General Service customer with a monthly consumption and demand profile of 1,000 kWh and 20 kW, respectively (12,000 kWh/240 kW per year).

SCHEDULE 16-3 Annual Cost for General Service Customer (1,000 kWh/20 kW per Month/12,000 kWh/240 kW per Year)			
Annual Cost ($)	**2014 Actual**	**2015 Forecast**	**2016 Forecast**
Service Charge	$ 294.84	$ 294.84	$ 294.84
Demand Charge	-	-	-
Basic Energy Charge	2,062.80	1,962.00	1,952.40
ECAM Charge	(199.32)	(71.44)	28.85
Provincial Costs Recoverable	63.00	64.32	64.32
Cable Contingency Fund	3.24	3.24	3.24
RORA	(8.49)	(8.49)	(63.92)
Sub-Total	$ 2,216.07	$ 2,244.47	$ 2,279.73
HST	310.25	314.23	319.16
Total Annual Cost	**$ 2,526.32**	**$ 2,558.70**	**$ 2,598.89**
Percentage Annual Increase (%)	**1.6%**	**1.3%**	**1.6%**

For a larger General Service customer with a monthly consumption and demand profile of 10,000 kWh and 50 kW, respectively (120,000 kWh/600 kW per year), the estimated annual increase in electricity costs is shown in Schedule 16-4 below:

SCHEDULE 16-4 Annual Cost for General Service Customer (10,000 kWh/50 kW per Month/120,000 kWh/600 kW per Year)			
Annual Cost ($)	**2014 Actual**	**2015 Forecast**	**2016 Forecast**
Service Charge	$ 294.84	$ 294.84	$ 294.84
Demand Charge	4,834.80	4,834.80	5,061.60
Basic Energy Charge	16,998.00	16,164.00	16,050.00
ECAM Charge	(1,993.23)	(714.41)	288.52
Provincial Costs Recoverable	630.00	643.20	643.20
Cable Contingency Fund	32.40	32.40	32.40
RORA	(84.87)	(84.87)	(639.17)
Sub-Total	$ 20,711.94	$ 21,169.96	$ 21,731.39
HST	2,899.67	2,963.79	3,042.39
Total Annual Cost	**$ 23,611.61**	**$ 24,133.75**	**$ 24,773.78**
Percentage Annual Increase (%)	**2.2%**	**2.2%**	**2.7%**

Typical customers in the Small and Large Industrial rate classes will also experience an increase in electricity costs of approximately 2.5 per cent and, again, the level of consumption on a customer by customer basis will determine if the increase in electricity costs is higher or lower than that of a typical customer.

17.0 PROPOSED ORDER

C A N A D A

PROVINCE OF PRINCE EDWARD ISLAND

BEFORE THE ISLAND REGULATORY
AND APPEALS COMMISSION

IN THE MATTER of Section 20 of the Electric Power Act (R.S.P.E.I. 1988, Cap. E-4) and **IN THE MATTER** of the Application of Maritime Electric Company, Limited for an order of the Commission approving rates, tolls and charges for electric service for the period beginning March 1, 2016 and for certain approvals incidental to such an order.

UPON receiving an Application by Maritime Electric Company, Limited (the "Company") for approval of proposed amendments to its rates, tolls and charges and certain approvals incidental to such an order;

AND UPON considering the Application as well as the Evidence of the Company;

NOW THEREFORE for the reasons given in the annexed Reasons for Order;
IT IS ORDERED THAT

1. The Energy Cost Adjustment Mechanism ("ECAM") formula implemented during the PEI Energy Accord as detailed in Appendix 3 shall continue effective March 1, 2016 until otherwise ordered by the Commission.

2. The base rate per kWh used in the ECAM be set as follows:

	Current	**March 1, 2016**
ECAM Base Rate per kWh ($)	0.08760	0.08605

3. The Company shall prepare an updated proposal on ECAM rebasing for inclusion in its next rate application.

4. The Basic Rates shall be adjusted to reflect the proposals contained in the Application effective March 1, 2016 as proposed in Appendix 1.

5. The Company shall refund the Rate of Return Adjustment (RORA) deferral to customers at a rate of $0.00533/kWh commencing March 1, 2016.

6. The Company shall prepare and file a proposal with respect to the refund of any remaining RORA balance for the period March 1, 2017 to February 28, 2018 for inclusion in its next rate application.

7. The Company's forecast average rate base for 2016 of $342,087,800 and the components of the Rate Base are approved.

8. The Company's requested return on average rate base for 2016 of 7.64 per cent in a range of 7.56 per cent to 7.72 per cent is approved.

9. The Weather Normalization Mechanism and Reserve account as described in the evidence and Appendix 6 are approved for adoption as of January 1, 2016.

10. The proposals in the Company's filing (UE21603) with respect to the 2014 Depreciation Study are approved.

11. The Company shall modify the current multi-block energy pricing structure for residential customers by increasing the second block threshold in accordance with the following schedule:

Rate Class	Current	March 1, 2016	March 1, 2017	March 1, 2018
Residential	2,000	3,000	3,800	5,000

12. The Company shall undertake a Rate Design Study to determine the appropriate rate class for all or some farms currently included in the Residential rate class. The Company will, as part of this process, consult with applicable stakeholders. The Study will be filed with the Commission by no later than April 30, 2017.

13. General Service II customers will adopt the rate structure of General Service I customers effective March 1, 2016.

14. The Company shall prepare and file with the Commission a Point Lepreau Cost Allocation Classification Study by April 30, 2017.

15. The Company shall file an updated Cost Allocation Study based on 2017 financial results by June 30, 2018.

16. The interim rate classes for LED street and area lights approved by the Commission in Order UE14-01 dated January 15, 2014 are approved for inclusion in the Company's rates.

17. All non-LED street and area light classes currently approved are hereby closed to new additions where comparable LED Street and Area Light rate classes have been approved by the Commission.

DATED at Charlottetown this ____ day of ____, 2015

BY THE COMMISSION:

____

_________________, Chair

____

_________________, Commissioner

____

_________________, Commissioner

____

_________________, Commissioner

Energy Cost Adjustment Mechanism

Application

The following energy cost adjustment mechanism applies to all scheduled rates applicable to the sale of energy by Maritime Electric Company, Limited.

Energy Cost Adjustment Mechanism

The energy charge applicable under all applicable rates will be subject to a rate adjustment when the cost of purchased and produced electricity increases or decreases from the base cost.

The forecast Base Rate Cost for purchased and produced electricity is $0.08605/kWh and may be adjusted as Ordered by the Commission.

Deferral of Increases or Decreases from the Base Cost

The deferral of increases or decreases in purchased and produced electricity from the Base Cost shall be calculated at the end of each month as follows:

1. Determine the total cost of purchasing and producing electricity in the month including any amounts amortized to ECAM as Ordered by the Commission;
2. Determine the net kilowatt hours of purchased and produced energy in the month;
3. Multiply the quantity of net purchased and produced energy determined in (2) above by the forecast Base Rate Cost of $0.08605/KWh to determine the base cost of electricity;
4. Subtract the base cost of electricity determined in (3) above from the total cost of purchasing and producing electricity determined in (1) above to calculate the excess or deficiency of the cost of purchased or produced electricity from the base cost;
5. Add the excess (or deficiency) of the cost of purchased or produced energy calculated in (4) above to the corresponding excess (or deficiency) costs on the Balance Sheet.

Calculation of ECAM Rate Adjustment Applied to Customers' Bills

The ECAM Rate Adjustment applied to Customers' bills shall be calculated as follows and applied to Customers' bills for not less than twelve months unless otherwise Ordered by the Commission.

6. Determine the total of the excess (or deficiency) costs on the Balance Sheet at the end of the third month proceeding the month in which the ECAM rate will be applied.
7. Determine the forecast total kilowatt hour sales for the twelve month period commencing with the month in which the ECAM rate will be applied.
8. Divide the amount calculated in (6) above by the amount calculated in (7) above to determine the ECAM rate adjustment required in cents per kilowatt hour sold and which will be applied to Customers' bills. Rate adjustment shall be calculated to the nearest three decimal places (five decimal places on the dollar).

* Application of the Energy Cost Adjustment Mechanism is subject to the terms and provisions of the Electric Power Act.

Residential Service Rate Schedule

Residential Urban That category of residential customers located in all incorporated cities, towns and villages with population over 2000 served by Maritime Electric.

Rate	***(Code 110)***
Service Charge:	$24.57 per Billing Period
Energy Charge:	13.59¢ per kWh for first 3000 kWh per Billing Period
	10.80¢ per kWh for balance kWh per Billing Period

Residential Rural That category of residential customers located in all other areas not included under Residential Urban category served by Maritime Electric.

Rate	***(Code 130)***
Service Charge:	$26.92 per Billing Period
Energy Charge:	13.59¢ per kWh for first 3000 kWh per Billing Period
	10.80¢ per kWh for balance kWh per Billing Period

Residential Seasonal That category of Residential Customers who require service to a dwelling other than a principal residence (e.g., summer cottages).

Rate	***(Code 131)***
Service Charge:	$26.92 per Billing Period
Energy Charge:	13.59¢ per kWh for first 3000 kWh per Billing Period
	10.80¢ per kWh for balance kWh per Billing Period

Residential Seasonal Option Residential seasonal customers with fully accessible outside meters may remain connected year round provided that the energy used during the period 1 November to 31 May inclusive does not exceed fifty percent (50%) of the total energy used between 1 June and 31 October of the preceding year. Residential Seasonal customers whose 1 November to 31 May consumption exceeds this fifty percent (50%) shall be billed under the applicable residential service rate for the periods connected. Meters shall be read or estimated and bills shall be rendered for May, June, July, August, September and October.

Rate	***(Code 133)***
Service Charge:	$37.50 per Billing Period
Energy Charge:	13.59¢ per kWh for first 3000 kWh per Billing Period
	10.80¢ per kWh for balance kWh per Billing Period

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Residential Service Rate Application Guidelines

Urban and Rural

Customers who use electricity for living purposes in any of the following:

- Dwellings;
- Dwelling out buildings; and
- Individually metered, self contained dwelling units within an apartment building.

In addition, the Residential Rate applies to:

- Services to farms and churches; and
- Service for the construction phase of a dwelling.

A premises providing lodging with nine (9) beds or less, including boarding and rooming houses, special care establishments, senior citizen homes, nursing homes, hostels and transition homes.

The combined usage of a dwelling and a business operation measured by one meter, where the connected load of the business operation, excluding space heating and air conditioning, is two (2) kilowatts or less.

Seasonal

Customers who use electricity for living purposes in a dwelling other than the customer's principal residence; e.g., summer cottage.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

General Service Rate Schedules

General Service

That category of customers in all areas served by Maritime Electric who use electricity for purposes other than those specifically covered under *Residential, Small and Large Industrial, Street Lighting or Unmetered* Categories.

Billing Demand

The greater of the maximum kW demand or 90% of the maximum kVA demand in the billing period.

Rate	***(Code 232)***
Service Charge:	$24.57 per Billing Period
Demand Charge:	No charge for first 20 kW or less per Billing Period $14.06 per kW for balance kW per Billing Period
Energy Charge:	16.54¢ per kWh for first 5000 kWh per Billing Period 10.75¢ per kWh for balance kWh per Billing Period

General Service – Seasonal Operators Option

General Service seasonal operators with fully accessible outside meters may remain connected year round provided that the energy used during the period 1 November to 31 May inclusive does not exceed fifty percent (50%) of the total energy used between 1 June and 31 October of the preceding year. General Service seasonal operators whose 1 November to 31 May consumption exceeds this fifty percent (50%) shall be billed under the applicable General Service rate for the periods connected. Meters shall be read or estimated and bills shall be rendered for May, June, July, August, September and October.

Rate	***(Code 233)***
Service Charge:	$24.57 per Billing Period
Demand Charge:	No charge for first 20 kW or less per Billing Period $14.06 per kW for balance kW per Billing Period
Energy Charge:	16.54¢ per kWh for first 5000 kWh per Billing Period 10.75¢ per kWh for balance kWh per Billing Period

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

General Service Rate Schedules – Cont'd

General Service II

Rate Class closed effective March 1, 2016

General Service Rate Application Guidelines

General Service

General Service rate applications include the following:

- Religious and charitable institutions, excluding churches;
- Service for the construction phase of any premises other than a dwelling;
- Dwellings providing lodging with more than nine (9) beds, including boarding and rooming houses, special care establishments, senior citizen homes, nursing homes, hostels and transition homes;
- Combined usage of a dwelling and a business operation measured by one meter, where the connected load of the business operation, excluding space heating and air conditioning, is greater than two (2) kilowatts;
- Bulk metered apartment buildings that combine the service to the dwelling units and/or the common use areas;
- Service to common areas in apartment buildings;
- Any business operation involving both manufacturing/processing and service/repair on which less than one half of the business volume is manufacturing/processing;
- Warehousing, storage and distribution centres on the same property and forming part of a manufacturing or processing operation with one meter where the warehousing, storage and distribution load is greater than one half of the total electricity consumed;
- A retail or wholesale operation on a farm must install a separate meter to measure that retail/wholesale load;

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

General Service Rate Application Guidelines – Cont'd

- Water pumping, sewage lift stations, sewage lagoons, chlorinating plants and sewage treatment plants directly related to municipally owned water supplies or waste disposal systems are normally billed at General Service Rates. At the option of the customer, an Industrial Service Rate may be applied; and
- General Service seasonal operators with fully accessible outside meters may remain connected year round provided that the energy used during the period 1 November to 31 May inclusive does not exceed fifty percent (50%) of the total energy used between 1 June and 31 October of the preceding year. Examples of eligible facilities include seasonal tourist accommodations, attractions or eateries.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Small Industrial Rate Schedule

Small Industrial That category of customers who use electricity chiefly for manufacturing or processing of goods or for the extraction of raw materials and have a minimum contracted demand of five (5) kilowatts.

Billing Demand

The greatest of:

- The monthly maximum kW demand;
- 90% of the monthly maximum kVA demand; or
- 5 kW.

As a result of installed metering, both the monthly maximum kW demand and 90% of the monthly maximum kVA demand noted above may not apply.

Rate ***(Code 320)***

Demand Charge: $7.46 per kW of billing demand per month

Energy Charge: 16.37¢ per kWh for first 100 kWh per kW of billing demand per month
8.25¢ per kWh for balance of kWh per month

To be eligible for service with a contracted demand, customers must sign the Contract for Electrical Service under Section C – Agreements and Forms.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Small Industrial Rate Application Guidelines

Industrial Rates apply to the following S.I.C. groups:

Division C Major group:
04 Logging Industry

Division D Major groups:
06 Mining Industries
07 Crude Petroleum and Natural Gas Industries
08 Quarry and Sand Pit Industries
09 Service Industries Incidental to Mineral Extraction

Division E Manufacturing Industries.

In addition:

Fish hatcheries qualify for this rate.

Any business operation involving both manufacturing/processing and service/repair in which more than one half of the business volume is manufacturing/processing.

Warehousing, storage and distribution centres on the same property and forming part of a manufacturing or processing operation with one (1) meter where the manufacturing/processing load is greater than one half of the total electricity consumed.

A processing operation on a farm must install a separate meter to measure that processing load.

Customers whose demand is above 750 kW and less than 3000 kW may choose to be billed at the Small Industrial Rate but must meet certain conditions of the Large Industrial Rate; specifically, they must be metered at a primary voltage of 69 kV and own the step-down transformation from the primary service voltage or pay an equivalent rental charge.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Large Industrial Rate Schedule

Large Industrial That category of customers in all areas served by Maritime Electric who use electricity chiefly for manufacturing or processing of goods or for the extraction of raw materials and have a minimum contracted demand of 750 kW.

Billing Demand
The greatest of:
- The monthly maximum kW demand;
- 90% of the maximum kVA demand;
- 90% of the firm amount reserved in the contract for non-curtailable customers or 100% of the total contracted amount for curtailable customers;
- 90% of the maximum demand recorded during the current calendar year excluding April through November; or
- 90% of the lesser of the average demand recorded during the previous calendar year, or the previous calendar year excluding April through November.

Rates ***(Code 310)***
Demand Charge: $14.50 per kW of the billing demand per month

Energy Charge: 6.76¢ per kWh for all kWh per month

Declining Discount Firm Rate:
New facilities coming into service after April 1, 2000 or facilities that were substantially shut down as at October 1, 2000 are eligible for a declining discount on Demand Charges for the additional firm load.

The declining discount is available for five years to Customers who meet all of the following criteria:

i) the Customer is served directly from the Maritime Electric's transmission system;
ii) the additional firm load is at least 5,000 kW; and
iii) the Customer signs a five year agreement with Maritime Electric as the electricity supplier for the total load for the Customer's account at the site.

The declining discounts are:

Year	$/kW-month	Year	$/kW-month
1	$5.39	4	$2.16
2	$4.30	5	$1.08
3	$3.23	6	$0.00

The declining discounts are not available for loads that get incentive rate credits or if the Customer is in arrears at the time of application for the declining discount.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Large Industrial Rate Schedule - Cont'd

Start-up Rate

Large Industrial customers starting new operations or expanding existing operations may request a start-up rate for a period not exceeding six (6) consecutive months.

When the new load is the result of expansion, the customer has the option to request the start-up for the total firm load at that location. The request must be submitted in writing to Maritime Electric.

To qualify, the customer must agree to reduce the load for which the start-up rate applies within ten (10) minutes of a request from Maritime Electric. The reduction will be to a level stipulated by Maritime Electric. Load reductions will normally be requested when the in-province load is expected to exceed Maritime Electric's supply capability.

Maritime Electric estimates the applicable start-up rate and makes retroactive adjustments based on the customer's actual cost per kWh, which is the aggregate of demand and energy charges, established during the six month period following the start-up period.

The start-up rate will be calculated so that the resulting cost to the customer is the higher of:

- 10.21¢ per kWh, or
- Customer's lowest monthly aggregate cost per kWh in the six months following the start-up period.

The start-up rate period may be extended up to five years for new facilities having a firm load of 5,000 kilowatts or more that are served directly off the transmission system and that Maritime Electric considers to be a new industrial technology. This provision expires on March 31, 2008. In such cases, the firm load of the Customer will not be subject to interruption and the cost of the new firm load will be the lower of (i) Customers actual cost based on usage and applicable rates, or (ii) 9.64¢ per kWh.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Large Industrial Rate Schedule - Cont'd

Interruptible Energy Charge

Maritime Electric will supply interruptible energy in excess of the demand reserved for the Customer up to the amount of the Customer's unused generation capability, if such energy is available at the Delivery Point, and can be produced with available Maritime Electric Facilities over and above the requirement of other firm commitments of Maritime Electric. The rate will be based on Maritime Electric's incremental cost of providing such energy.

Surplus Energy Charge

To qualify for new Surplus Energy, the Customer must sign a minimum three-year contract with Maritime Electric as its sole electricity supplier. Surplus Energy is supplied only if it can be provided with available Maritime Electric Facilities over and above the requirement of other firm commitments of Maritime Electric. The Customer must interrupt Surplus Energy use within ten (10) minutes of a request from Maritime Electric. Customers can purchase Surplus Energy for load additions of 2,000 kilowatts or more.

Customers will be required to interrupt Surplus Energy to meet Maritime Electric financially firm export obligations. When Surplus Energy is interrupted to meet financially firm export obligations, the Customer is reimbursed 50 percent of the cost of the replacement energy that Maritime Electric would have otherwise incurred to supply the export sales.

Customers who fail to interrupt will be billed an additional charge which is the higher of:

(i) two times the monthly demand charge per kilowatt for the Large Industrial rate classification multiplied by the kilowatts that were not interrupted plus any incremental cost of supplying the energy, or

(ii) the costs incurred by Maritime Electric for replacement energy to supply financially firm export obligations.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Large Industrial Rate Schedule - Cont'd

Surplus Energy Charge (continued)

Up to March 2001, Customers can purchase Surplus Energy for load additions of 2000 kW or more. The total annual sales are limited to 500 million kilowatthours. Because of the limited amount of available Surplus Energy, preference will be given to the Customers who sign a power purchase contract with Maritime Electric until March 2001.

This Surplus Energy is supplied only if it can be provided with available Maritime Electric Facilities. The Customer must interrupt Surplus Energy use within 10 minutes of a request from Maritime Electric. The rate will be based on Maritime Electric's incremental cost of providing such energy.

Pricing of Interruptible And Surplus Energy

The price is based on Maritime Electric's incremental cost of providing such energy. Incremental cost is defined as Maritime Electric's incremental generation or purchased power cost after supplying in-province firm load and other firm supply commitments.

Interruptible and Surplus Energy price will be:

On peak price = incremental cost during on peak hours +1.39¢/kWh.
Off peak price = incremental cost during off peak hours +0.19¢/kWh.

The on peak period is defined as 0800 to 2400 hours Atlantic Prevailing Time on all weekdays, except statutory holidays in Prince Edward Island. All other hours are considered to be off peak.

Maritime Electric will provide a week ahead forecast and day ahead firm quotes of the on and off peak prices to be paid by the customer.

Schedulable Energy

To qualify for Schedulable Energy, the Customer must sign a minimum five-year contract with Maritime Electric as its sole electricity supplier. Schedulable Energy is supplied only if it can be provided with available Maritime Electric facilities over and above the requirement of other firm commitments, including financially firm export obligations of Maritime Electric. The Customer must interrupt Schedulable Energy use within ten (10) minutes of a request from Maritime Electric, or arrange for a third party supply.

Customers, who are serviced directly from Maritime Electric's transmission system, can purchase Schedulable Energy for load additions of 10,000 kilowatts or more up to March 31, 2008.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Large Industrial Rate Schedule - Cont'd

Schedulable Energy (continued)

Customers who fail to interrupt will be billed an additional charge which is the higher of:

(i) two times the monthly demand charge per kilowatt for the Large Industrial rate classification multiplied by the kilowatts that were not interrupted plus any incremental cost of supplying the energy, or
(ii) the costs incurred by Maritime Electric for replacement energy to supply financially firm export obligations.

The price is based on Maritime Electric's incremental cost of providing such energy. Incremental cost is defined as Maritime Electric's incremental generation or purchased power costs after supplying in-province firm load and other firm supply commitments.

Pricing of Schedulable Energy

Schedulable Energy price will be:

On peak price = incremental cost during on peak hours +1.39¢/kWh.
Off peak price = incremental cost during off peak hours +0.19¢/kWh.

The on peak period is defined as 0800 to 2400 hours Atlantic Prevailing Time on all weekends, except statutory holidays in Prince Edward Island. All other hours are considered to be off peak.

Maritime Electric will provide a week ahead forecast and day ahead firm quotes of the on and off peak prices to be paid by the Customer. When Maritime Electric has insufficient generation to supply its loads, the price of Schedulable Energy will be quoted and updated on an hourly basis.

Schedulable Energy Customers can arrange for a third party outside of Prince Edward Island to supply energy to Maritime Electric. In such an event, Maritime Electric would pay the supplier 0.075¢/kWh less than the incremental cost used in determining the price of Schedulable Energy and the Customer would still pay Maritime Electric the full price of Schedulable Energy including the adders.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Large Industrial Rate Schedule - Cont'd

Rental Charges At the customer's request, Maritime Electric will supply, own and maintain the substation facilities from the high voltage switches to the low voltage terminals of the step-down transformers, provided such transformation satisfies Maritime Electric Standards. The charge for such rental facilities is $1^5/_6\%$ per month of the installed costs. The Customer will supply the low voltage switch gear, concrete substation foundation pads and necessary protective fencing.

Losses Charge At the discretion of Maritime Electric, electricity may be supplied at a primary service voltage between 4 kV and 25 kV. In such cases, the monthly demand and energy consumption will be increased by 1½% to compensate for transformation losses.

Transformation Charge When a customer is provided service at voltages less than 69 kV, the customer will also be charged an "equivalent kVA rental" charge equal to $1^5/_6\%$ per month of the costs of the equivalent substation kVA utilized by the Customer's electrical load. The equivalent kVA charge is the Customer's kVA demand multiplied by $1.25 per kVA per month.

Contracts A customer supplied at the Large Industrial Rate is required, and is deemed, to have entered a firm contract providing for the payment of the rate, for an initial term of five (5) years, in the case of a customer considered by Maritime Electric to be a new customer, and for an initial term of one year for a customer considered by Maritime Electric to be an existing customer. The contract will continue thereafter on a firm basis subject to termination by either the customer or Maritime Electric at the end of the initial term, or any date thereafter by either party giving at least twelve month's notice in writing.

When a Customer's operations are jeopardized because of a failure of its electricity generating equipment, the Customer can apply to suspend any portion of its curtailable power contract and/or firm up all or part of interruptible purchases for a period of at least six months and not more than one year.

Metering The metering point shall be at or near the transmission line terminals (69 kV).

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Large Industrial Rate Application Guidelines

Industrial Rates apply to the following S.I.C. groups:

Division C Major Group:
04 Logging Industry

Division D Major Groups:
06 Mining Industries
07 Crude Petroleum and Natural Gas Industries
08 Quarry and Sand Pit Industries
09 Service Industries Incidental to Mineral Extraction

Division E, Manufacturing Industries.

In addition:

Any business operation involving both manufacturing/processing and service/repair in which more than one half of the business volume is manufacturing/processing.

Warehousing, storage and distribution centres on the same property and forming part of a manufacturing or processing operation with one (1) meter where the manufacturing or processing load is greater than one half of the total load.

Customers whose demand is above 750 kW and less than 3000 kW may choose to be billed at the Small Industrial Rate but must meet certain conditions of the Large Industrial Rate; specifically, they must be metered at a primary service voltage of 69 kV and own the step-down transformation from the delivery voltage or pay an equivalent rental charge.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Wholesale Rate Schedule

Application The City of Summerside Electric Department.

Long Term Contract: The Wholesale Customer agrees to enter into a contract with Maritime Electric for a period not less than 10 years.

Rate	***(Code 340)***
Demand Charge:	$15.51 per kW per month
Energy Charge:	9.11¢ per kWh for all kWh in the month

Short Term Contract: The Wholesale Customer agrees to enter into a contract with Maritime Electric for a period not less than 1 year.

Rate	***(Code 330)***
Demand Charge:	$16.79 per kW per month
Energy Charge:	9.28¢ per kWh for all kWh in the first block per month 7.71¢ per kWh for balance of kWh in the month

First Energy Block Determination Set each year on 1 April based on the minimum monthly energy purchases that would have been required from Maritime Electric during the previous year period of 1 April to 31 March, assuming normalized generation from the customer's generating facilities.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Unmetered Rate Schedules

Unmetered Service

That category of customers in all areas served by Maritime Electric requiring Unmetered Service.

Rate

Minimum Charge: $11.67 per month

Energy Charge: 16.65¢ per kWh of estimated consumption

Rate Codes:

810 – 8 hour
820 – 12 hour
830 – 24 hour

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Unmetered Rate Application Guidelines

Services for which electricity consumption is uniform and easily estimated.

Services where metering is not considered practical by Maritime Electric.

Specific applications of the Unmetered Rates include:

- Traffic control lights;
- Self – contained sign lighting;
- Architectural flood lighting;
- Decorative lighting;
- Carrier repeaters;
- Radio transmitters;
- Telephone booths;
- Range lights;
- Airport runway lights;
- Highway traffic counters; and
- CATV power supply units.

Estimating Consumption

Electricity consumption is estimated by multiplying the connected load in watts times the hours of usage. For example, a photoelectrically controlled 100 watt sign light operates approximately 12 hours per day, has an estimated annual consumption calculated as follows:

100 watts x 12 hours x 365 days = 438,000 watt-hours or 438 kWh per year.

If conditions are such as to cause reasonable doubt concerning the connected load, recording equipment will be installed to determine the kW connected load.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Miscellaneous Rate Schedules

Air Raid and Fire Sirens (unmetered)

Customer is charged $4.52 per month per HP of nameplate rating.
(Code 840)

Outdoor Christmas Lighting

Customer is charged 5.77¢ per watt of connected load per week. The minimum charge is for a period of one (1) week.
(Code 850)

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Short Term Unmetered Rate Schedule

That category of customers in all areas served by Maritime Electric requiring single-phase and three-phase installations and connected for no longer than one (1) month. The installation will not be metered.

Rate

Connection Charge:	Single-Phase	Three-Phase
A. Connecting to existing Secondary voltage	$99.08	$99.08

B. Where transformer installations are required, the following connection charges will apply:

	Single-Phase	Three-Phase
(1) Up to and including 10 kVA	$148.87	$209.17
(2) 11 kVA to 15 kVA	$240.79	$301.01
(3) 16 kVA to 25 kVA	$269.20	$336.64
(4) 26 kVA to 37 kVA	$301.01	$336.64
(5) 38 kVA to 50 kVA	$336.64	$336.64
(6) 51 kVA to 75 kVA	$369.58	$523.96
(7) 76 kVA to 125 kVA	$431.07	$555.59
(8) Above 125 kVA	-	$594.94

Energy Charge:
16.65¢ per kWh of estimated consumption

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Short Term Unmetered Rate Application Guidelines

Available to serve such events as carnivals, bazaars and unmetered installations.

Connected for no longer than one (1) month.

When the service exceeds one month, the installation will be billed and the remaining time considered as a new installation.

When meters are involved, and not disconnected, a reading will be taken and the kilowatt hours noted for record purposes only.

When poles or additional equipment other than the transformer installation are required, the installation and removal charges will be estimated and collected before work commences. Customers who have a credit history, acceptable to Maritime Electric, may be billed using a Customers Contribution Estimate.

Estimating Consumption

Electricity consumption is estimated by multiplying the connected load in kW (or kVA times 0.9), times the hours of usage. For example, a carnival with a connected load of 25 kVA operates 12 hours per day for 10 days has an estimated consumption calculated as follows:

25 kVA x 0.9 power factor x 12 hours x 10 days = 2,700 kWh.

If conditions are such as to cause reasonable doubt concerning the connected load, recording equipment will be installed to determine the kVA connected load.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Rental Facility Rate Schedules

Area Lighting This rate applies to customers renting area lighting from Maritime Electric for a minimum of 12 consecutive months.

Rate

Luminaires:

Lamp Wattage	Mean Output (Lumens)	($) Rate Per Year	($) Rate Per Month	Rate Code	Annual kWhs
Mercury Vapour					
*125 Watt	5300	181.56	15.13	735	656
*175 Watt	7500	230.88	19.24	736	881
*250 Watt	11100	321.12	26.76	737	1210
*400 Watt	19800	410.28	34.19	738	1906
High Pressure Sodium					
*70 Watt	5500	183.36	15.28	730	389
*100 Watt	8500	232.68	19.39	731	553
*150 Watt	14400	333.00	27.75	732	799
*200 Watt	19800	364.44	30.37	720	1033
250 Watt	27000	452.64	37.72	733	1283
400 Watt	45000	529.56	44.13	734	1886
High Pressure Sodium Floodlight					
250 Watt	-	431.88	35.99	753	-
400 Watt	-	537.84	44.82	754	-
Metal Halide Floodlight					
250 Watt	-	455.04	37.92	755	-
400 Watt	-	539.92	46.66	756	-
1000 Watt	-	961.08	80.09	757	-

Poles:

Wood Pole			4.38	610	-
Concrete Pole			7.96	611	-

*These charges are applicable to existing fixtures only.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Rental Facility Rate Schedules - Cont'd

Street Lighting That category of customers renting street lighting from Maritime Electric.

Rate

Luminaires:

Lamp Wattage	Mean Output (Lumens)	($) Rate Per Year	($) Rate Per Month	Rate Code	Annual kWhs
Mercury Vapour					
*125 Watt	5300	181.56	15.13	635	656
*175 Watt	7500	230.88	19.24	636	881
*250 Watt	11100	321.00	26.75	637	1210
*400 Watt	19800	447.96	37.33	638	1906
High Pressure Sodium					
70 Watt Lantern	5500	674.04	56.17	639	389
*70 Watt	5500	183.36	15.28	630	389
*100 Watt	8500	233.28	19.44	631	553
*150 Watt	14400	333.00	27.75	632	799
*200 Watt	19800	398.52	33.21	620	1033
250 Watt	27000	452.64	37.72	633	1283
400 Watt	45000	529.56	44.13	634	1886
LED Lighting					
43 Watt	-	138.60	11.55	619	176
50 Watt	-	143.52	11.96	625	205
72 Watt	-	159.60	13.30	666	295
100 Watt	-	185.64	15.47	670	410

*These charges are applicable to existing fixtures only.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Rental Facility Rate Schedules - Cont'd

Pole That category of customers renting poles from Maritime Electric.

Rate

The rental rate for poles is:

	($) Rate Per Pole Per Year	Rate Code
Wood pole	52.57	610
Concrete pole	95.48	611

Customer Facility Rate Schedule

Customer Owned Street and Area Lighting

That category of customers owning street and area lighting.

Rate Lamp Wattage	($) Per Year	($) Per Month	Rate Code St. Lt.	Rate Code Yd. Lt.	Annual kWhs
Incandescent					
100 Watt	72.36	6.03	-	-	-
200 Watt	145.80	12.15	-	-	-
300 Watt	218.04	18.17	-	-	-
500 Watt	349.80	29.15	-	-	-
Mercury Vapour					
100 Watt	87.48	7.29	-	-	-
125 Watt	107.64	8.97	645 *	745	656
175 Watt	145.92	12.16	646 *	746	881
250 Watt	201.36	16.78	647 *	747	1210
400 Watt	318.72	26.56	648	748	1906
700 Watt	542.52	45.21	-	-	-
1000 Watt	770.40	64.20	-	-	-
Low Pressure Sodium					
90 Watt	83.04	6.92	752	752	-
135 Watt	118.44	9.87	751	751	-
180 Watt	148.80	12.40	749	749	869
High Pressure Sodium					
70 Watt	72.12	6.01	640 *	740 *	389
100 Watt	94.92	7.91	641 *	741 *	553
150 Watt	127.68	10.64	642 *	742	779
200 Watt	175.92	14.66	650 *	750	1033
250 Watt	202.05	16.84	643	743	1283
400 Watt	318.96	26.58	644	744	1886
1000 Watt	764.88	63.74	-	-	-
Metal Halide Lighting					
70 Watt	64.92	5.41	-	758	390
100 Watt	88.80	7.40	-	759	533
150 Watt	120.36	10.53	-	765	759
175 Watt	149.04	12.42	-	760	894
250 Watt	191.28	15.94	-	761	1148
400 Watt	312.84	26.07	-	762	1878
1000 Watt	723.96	60.33	-	763	4346
LED Lighting					
43 Watt	29.28	2.44	719	-	176
72 Watt	49.08	4.09	766	-	295
100 Watt	68.28	5.69	764	-	410
107 Watt	72.96	6.08	775	-	438
143 Watt	97.68	8.14	780	-	586
175 Watt	119.40	9.95	785	-	718

Customer Facility Rate Schedule

Customer Owned Street and Area Lighting

The above charges apply to photocontrolled lights operating from dusk to dawn. The energy charges for lights operating from dusk to 1:30 a.m. and controlled by a time switch shall be 50% of the above rates.

Customers may request service for a customer owned street and area lighting fixture other than those categories listed above provided the fixture meets current electrical standards and is approved for installation by Maritime Electric. The interim rate for these new fixtures will be calculated using the formula below, as approved by IRAC.

$$\text{Basic Rate} = \frac{4{,}100 \text{ hrs} \times W/1000 \times U}{12 \text{ months}}$$

Where:

4,100 hours	=	the number of hours the fixture is on during the year
W	=	total wattage of the fixture, ballast and any other apparatus associated with the fixture
U	=	the basic Un-metered Service energy rate from Section N-17 of the approved tariff.

These changes are applicable to existing fixtures only.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Customer Facility Rate Schedule - Cont'd

Customer Owned Outdoor Recreational Lighting

That category of customer owning metered outdoor lighting which operates only during the period April through November.

Rate

Service Charge:	$24.57 billing period
Energy Charge:	16.65¢ per kWh for first 5000 kWh per billing period
	10.22¢ per kWh for balance kWh per billing period

The above rate is available to customers with outdoor recreation lighting. Examples of customers on this rate include: baseball parks, soccer fields and tennis courts. Customers who have non-lighting requirements on the same service can also qualify for this rate if the connected non-lighting load is less than 20 kilowatts.

Customers on this rate who use electricity during December through March will be assessed demand charges for each month, including the preceding April through November, in which electricity is used. The demand charges will be assessed at the General Service I Rate. Failure to pay demand charges will result in the customer being placed on the General Service I Rate.

This rate is inclusive of the Energy Cost Adjustment Mechanism and other rates and tolls approved by the Commission and/or as authorized under the Electric Power Act.

Open Access Transmission Tariff

This rate applies to eligible customers requiring transmission services. An eligible customer is:

(i) any electric utility (including the transmission provider), wholesale customer or any person generating electric energy for sale or resale outside of Prince Edward Island.

Application Eligible customers requesting transmission services must apply in writing and request services for a minimum 12 month period.

Transmission Services Include Transmission Access and Capacity
Scheduling, System Control and Dispatch Service
Reactive Supply and Voltage Control

Billing Procedure Within a reasonable time after the first day of each month, the transmission provider or its designated agent shall submit an invoice to the transmission customer for the charges for all services furnished under the Tariff during the preceding month. The invoice shall be paid by the transmission customer within 20 calendar days of receipt. All payments shall be made in immediately available funds payable to the transmission provider.

Rate **(Code XXX)**
The rates charged will be equal to 95% of those under the New Brunswick Power Tariff as amended from time to time.

Energy Cost Adjustment Mechanism: This rate is not subject to the Energy Cost Adjustment Mechanism.

Schedule of "Adjusted Rates"

Maritime Electric Company Limited
Applied to Bills Effective March 1, 2016

Rate Code			Rates
110	**Residential Urban**		
	Service Charge	$	24.57
	Energy Charge per kWh for first 3,000 kWh	$	0.1359
	Energy Charge per kWh for balance kWh	$	0.1080
130	**Residential Rural**		
	Service Charge	$	26.92
	Energy Charge per kWh for first 3,000 kWh	$	0.1359
	Energy Charge per kWh for balance kWh	$	0.1080
131	**Residential Seasonal**		
	Service Charge	$	26.92
	Energy Charge per kWh for first 3,000 kWh	$	0.1359
	Energy Charge per kWh for balance of kWh	$	0.1080
133	**Residential Seasonal Option**		
	Service Charge	$	37.50
	Energy Charge per kWh for first 3,000 kWh	$	0.1359
	Energy Charge per kWh for balance of kWh	$	0.1080
232	**General Service**		
	Service Charge	$	24.57
	Demand Charge - per kW for first 20 kW	$	-
	Demand Charge - per kW for balance of kW	$	14.06
	Energy Charge per kWh for first 5,000 kWh	$	0.1654
	Energy Charge per kWh for balance of kWh	$	0.1075
233	**General Service - Seasonal Operators Option**		
	Service Charge	$	24.57
	Demand Charge - per kW for first 20 kW	$	-
	Demand Charge - per kW for balance of kW	$	14.06
	Energy Charge per kWh for first 5,000 kWh	$	0.1654
	Energy Charge per kWh for balance of kWh	$	0.1075
320	**Small Industrial**		
	Demand Charge - per kW	$	7.46
	Energy Charge per kWh for first 100 kWh per kW billing demand	$	0.1637
	Energy Charge per kWh for balance of kWh	$	0.0825
310	**Large Industrial**		
	Demand Charge per kW	$	14.50
	Energy Charge per kWh	$	0.0676
340	**Long Term Contract**		
	Demand Charge per kW	$	15.51
	Energy Charge per kWh	$	0.0911
330	**Short Term Contract**		
	Demand Charge - per kW	$	16.79
	Energy Charge per kWh for all kWh in the first block	$	0.0928
	Energy Charge per kWh for balance of kWh in the month	$	0.0771

Schedule of "Adjusted Rates"

Maritime Electric Company Limited
Applied to Bills Effective March 1, 2016

	Rate Code	Lamp Wattage	Type		kWh	Monthly kWh	Basic Rates
	619	43	LED	St Lights - Rented	176	15	$ 11.55
*	620	200	HPS	St Lights - Rented	1033	86	$ 33.21
	625	50	LED	St Lights - Rented	205	17	$ 11.96
*	630	70	HPS	St Lights - Rented	389	32	$ 15.28
*	631	100	HPS	St Lights - Rented	553	46	$ 19.44
*	632	150	HPS	St Lights - Rented	799	66	$ 27.75
	633	250	HPS	St Lights - Rented	1283	106	$ 37.72
	634	400	HPS	St Lights - Rented	1886	157	$ 44.13
*	635	125	MV	St Lights - Rented	656	54	$ 15.13
*	636	175	MV	St Lights - Rented	881	73	$ 19.24
*	637	250	MV	St Lights - Rented	1210	101	$ 26.75
*	638	400	MV	St Lights - Rented	1906	158	$ 37.33
	639	70	Lanterns	City Lanterns - Rented	389	32	$ 56.17
*	640	70	HPS	St Lights - Owned	389	32	$ 6.01
*	641	100	HPS	St Lights - Owned	553	46	$ 7.91
*	642	150	HPS	St Lights - Owned	779	65	$ 10.64
	643	250	HPS	St Lights - Owned	1283	107	$ 16.84
	644	400	HPS	St Lights - Owned	1886	157	$ 26.58
*	645	125	MV	St Lights - Owned	656	55	$ 8.97
*	646	175	MV	St Lights - Owned	881	73	$ 12.16
*	647	250	MV	St Lights - Owned	1210	101	$ 16.78
	648	400	MV	St Lights - Owned	1906	159	$ 26.56
*	650	200	HPS	St Lights - Owned	1033	86	$ 14.66
	666	72	LED	St Lights - Rented	295	25	$ 13.30
	670	100	LED	St Lights - Rented	410	34	$ 15.47
	719	43	LED	St Lights - Owned	176	15	$ 2.44
*	720	200	HPS	Yard Lights - Rented	1033	86	$ 30.37
*	730	70	HPS	Yard Lights - Rented	389	32	$ 15.28
*	731	100	HPS	Yard Lights - Rented	553	46	$ 19.39
*	732	150	HPS	Yard Lights - Rented	799	66	$ 27.75
	733	250	HPS	Yard Lights - Rented	1283	106	$ 37.72
	734	400	HPS	Yard Lights - Rented	1886	157	$ 44.13
*	735	125	MV	Yard Lights - Rented	656	54	$ 15.13
*	736	175	MV	Yard Lights - Rented	881	73	$ 19.24
*	737	250	MV	Yard Lights - Rented	1210	100	$ 26.76
*	738	400	MV	Yard Lights - Rented	1906	158	$ 34.19
*	740	70	HPS	Yard Lights - Owned	389	32	$ 6.01
*	741	100	HPS	Yard Lights - Owned	553	46	$ 7.91
	742	150	HPS	Yard Lights - Owned	779	65	$ 10.64
	743	250	HPS	Yard Lights - Owned	1283	107	$ 16.84
	744	400	HPS	Yard Lights - Owned	1886	157	$ 26.58
	745	125	MV	Yard Lights - Owned	656	55	$ 8.97
	746	175	MV	Yard Lights - Owned	881	73	$ 12.16
	747	250	MV	Yard Lights - Owned	1210	101	$ 16.78
	748	400	MV	Yard Lights - Owned	1906	159	$ 26.56
	749	180	LPS	Yard Lights - Owned	869	72	$ 12.40
	750	200	HPS	Yard Lights - Owned	1033	86	$ 14.66
	751	135	LPS	Yard Lights - Owned	730	61	$ 9.87
	752	90	LPS	Yard Lights - Owned	521	43	$ 6.92
	753	250	Flood	Yard Lights - Rented	1283	107	$ 35.99
	754	400	Flood	Yard Lights - Rented	1886	157	$ 44.82
	755	250	Halide	Yard Lights - Rented	1148	95	$ 37.92
	756	400	Halide	Yard Lights - Rented	1878	156	$ 46.66
	757	1000	Halide	Yard Lights - Rented	4346	362	$ 80.09
	758	70	Halide	St Lights - Owned	390	32	$ 5.41
	759	100	Halide	St Lights - Owned	533	44	$ 7.40
	760	175	Halide	St Lights - Owned	894	74	$ 12.42
	761	250	Halide	St Lights - Owned	1148	95	$ 15.94
	762	400	Halide	St Lights - Owned	1878	156	$ 26.07
	763	1000	Halide	St Lights - Owned	4346	362	$ 60.33
	764	100	LED	St Lights - Owned	410	34	$ 5.69
	765	150	Halide	St Lights - Owned	759	63	$ 10.53
	766	72	LED	St Lights - Owned	295	25	$ 4.09
	775	107	LED	St Lights - Owned	438	37	$ 6.08
	780	143	LED	St Lights - Owned	586	49	$ 8.14
	785	175	LED	St Lights - Owned	718	60	$ 9.95

* These changes are applicable to existing fixtures only

Schedule of "Adjusted Rates"

Maritime Electric Company Limited

Applied to Bills Effective March 1, 2016

			Rates
610	Pole Rental -Wood	$	4.38
611	Pole Rental -Concrete	$	7.96
	Unmetered Rates (based on 100 watt fixture)		
810	8 Hour Lighting per kWh	$	0.1665
	Minimum Charge	$	11.67
820	12 Hour Lighting per kWh	$	0.1665
	Minimum Charge	$	11.67
830	24 Hour Lighting per kWh	$	0.1665
	Minimum Charge	$	11.67
840	Air Raid & Fire Sirens	Currently no customers in this rate category	
850	Outdoor Christmas Lighting: 5.77¢ per watt of connected load per week		
234	Customer Owned Outdoor Recreational Lighting		
	Service Charge	$	24.57
	Energy Charge per kWh for first 5,000 kWh	$	0.1665
	Energy Charge per kWh for balance of kWh	$	0.1022
	Short Term Unmetered Rates	Currently no customers in this rate category	
	Energy Charge:		
	per kWh of estimated consumption	$	0.1665

Connection Charge:

	Single-Phase	Three-Phase
A. Connecting to existing secondary voltage	$99.08	$99.08

B. Where transformer installations are required, the following connection charges will apply:

	Single-Phase	Three-Phase
(1) Up to and including 10 kVA	$148.87	$209.17

APPENDIX 2
Maritime Electric
Financial Results (Actual and Forecast)
Statements of Earnings

	Actual 2014	Forecast 2015	Forecast 2016
Revenue			
Revenue Requirement	$ 191,136,042	$ 186,859,600	$ 189,940,800
Amortization - Costs Recoverable From Customers (Pre-2004)	(1,983,600)	-	-
Net Revenue	189,152,442	186,859,600	189,940,800
Operating Expenses (net of ECAM)	143,157,076	139,473,700	136,456,800
Amortization - Fixed Assets	15,120,635	15,625,500	21,031,900
Amortization - Deferred Charges	329,000	206,800	93,400
Operating Income	30,545,731	31,553,600	32,358,700
Financing Costs	12,118,864	12,482,300	12,705,600
Earnings Before Income Taxes	18,426,867	19,071,300	19,653,100
Income Taxes	5,822,890	6,030,500	6,210,500
Net Earnings - Regulated	$ 12,603,977	$ 13,040,800	$ 13,442,600
Fortis Inc Head Office Costs (net of tax) [1]	357,732	346,000	459,000
Net Earnings - Non-Regulated	12,246,245	12,694,800	12,983,600
Return on Average Common Equity (%) - Non-Regulated	9.31%	9.41%	9.37%
Return on Average Common Equity (%) - Regulated	9.75%	9.75%	9.70%

1 Costs disallowed in calculating the Annual Revenue Requirement and Regulated Return as per Order UE09-02

APPENDIX 2
Maritime Electric
Financial Results (Actual and Forecast)
Balance Sheets

	Actual 2014	Forecast 2015	Forecast 2016
ASSETS			
Fixed Assets			
Property, plant and equipment	$ 549,348,906	$ 573,895,100	$ 600,818,500
Less: Accumulated amortization	184,784,475	196,283,900	212,646,400
	364,564,431	377,611,200	388,172,100
Other Long-Term Assets			
Costs Recoverable from Customers (Post-2003)	(5,061,928)	2,881,900	1,533,000
Intangible assets	4,669,454	4,500,000	4,650,000
Deferred charges	2,074,705	1,961,800	3,524,300
	1,682,231	9,343,700	9,707,300
Current Assets			
Accounts receivable	37,076,143	40,065,600	39,998,400
Materials and supplies	5,709,926	5,600,000	5,700,000
Prepaid expenses	456,926	461,400	455,100
	43,242,994	46,127,000	46,153,500
TOTAL ASSETS	$ 409,489,656	$ 433,081,900	$ 444,032,900
SHAREHOLDER'S EQUITY AND LIABILITIES			
Shareholder's Equity			
Common shares	$ 31,100,681	$ 31,100,700	$ 31,100,700
Retained earnings	102,759,727	105,338,800	110,781,400
	133,860,408	136,439,500	141,882,100
Long-term Debt	166,572,004	166,577,000	194,383,300
Other Long-Term Liabilities			
Future income taxes	35,776,571	25,000,000	22,000,000
Contributions	26,254,677	25,280,700	24,362,100
	62,031,248	50,280,700	46,362,100
Current Liabilities			
Bank indebtedness	1,888	-	-
Short-term borrowings	2,670,000	29,246,000	15,222,900
Rebates Payable to Customers	13,465,192	16,628,200	11,578,800
Future income taxes	(5,577,461)	1,398,600	1,802,100
Regulatory Liability (Asset) - OPEB	(3,660,423)	4,944,300	3,319,500
Accounts payable and accrued liabilities	40,126,800	27,567,600	29,482,100
	47,025,996	79,784,700	61,405,400
TOTAL SHAREHOLDER'S EQUITY AND LIABILITIES	$ 409,489,656	$ 433,081,900	$ 444,032,900
Captial Structure - Year End Average			
Total Debt	55.7%	57.5%	59.5%
Common Equity	44.3%	42.5%	40.5%
	100.0%	100.0%	100.0%

APPENDIX 2
Maritime Electric
Financial Results (Actual and Forecast)
Statements of Cash Flows

	Actual 2014	Forecast 2015	Forecast 2016
Cash Flow from Operating Activities			
Net Earnings	$ 12,603,977	$ 13,040,800	$ 13,442,600
Add (deduct) non-cash items:			
Amortization - Fixed Assets	15,120,635	15,625,500	21,031,900
Amortization - Deferred Charges	334,029	211,800	99,700
Future income taxes	1,853,222	(3,800,500)	(2,596,500)
Changes in non-cash working capital	696,982	(10,896,800)	(2,714,600)
	30,608,845	14,180,800	29,263,100
Cash Flow From Financing Activities			
Issuance (Repayment) of long-term debt	-	-	28,000,000
Contributions	525,236	400,000	400,000
Financing Fees	-	-	(200,000)
Payment of dividends - Regulated	(8,000,000)	(8,000,000)	(8,000,000)
- Non-regulated	-	(3,184,300)	(722,500)
	(7,474,764)	(10,784,300)	19,477,500
Cash Flow from Investing Activities			
Expenditures for Fixed Assets (Net)	(30,024,591)	(29,876,700)	(33,061,600)
Deferred Charges	(232,811)	(93,900)	(1,655,900)
	(30,257,402)	(29,970,600)	(34,717,500)
Increase (Decrease) in Cash	(7,123,321)	(26,574,100)	14,023,100
Bank Indebtedness, Beginning of Year	4,451,433	(2,671,900)	(29,246,000)
Bank Indebtedness, End of Year	($2,671,888)	($29,246,000)	($15,222,900)

The Energy Cost Adjustment Mechanism ("ECAM") applies to approved basic rates for metering readings taken on or after March 1, 2016 as follows:

Base Cost of Purchased and Produced Electricity

The rate adjustment of ECAM will apply when the cost of purchased and produced electricity increases or decreases from the Base Cost. The forecast Base Rate Cost for purchased and produced electricity is $0.08605/KWh and may be adjusted as Ordered by the Commission.

Deferral of Increases or Decreases from the Base Cost

The deferral of increases or decreases in purchased and produced electricity from the Base Cost shall be calculated at the end of each month as follows:

1. Determine the total cost of purchasing and producing electricity in the month including any amounts amortized to ECAM as Ordered by the Commission;
2. Determine the net kilowatt hours of purchased and produced energy in the month;
3. Multiply the quantity of net purchased and produced energy determined in (2) above by the forecast Base Rate Cost of $0.08605/KWh to determine the base cost of electricity;
4. Subtract the base cost of electricity determined in (3) above from the total cost of purchasing and producing electricity determined in (1) above to calculate the excess or deficiency of the cost of purchased or produced electricity from the base cost;
5. Add the excess (or deficiency) of the cost of purchased or produced energy calculated in (4) above to the corresponding excess (or deficiency) costs on the Balance Sheet.

Calculation of ECAM Rate Adjustment Applied to Customers' Bills

The ECAM Rate Adjustment applied to Customers' bills shall be calculated as follows and applied to Customers' bills for not less than twelve months unless otherwise Ordered by the Commission.

6. Determine the total of the excess (or deficiency) costs on the Balance Sheet at the end of the third month proceeding the month in which the ECAM rate will be applied.

7. Determine the forecast total kilowatt hour sales for the twelve month period commencing with the month in which the ECAM rate will be applied.

8. Divide the amount calculated in (6) above by the amount calculated in (7) above to determine the ECAM rate adjustment required in cents per kilowatt hour sold and which will be applied to Customers' bills. Rate adjustment shall be calculated to the nearest three decimal places (five decimal places on the dollar).

APPENDIX 4
Monthly ECAM Calculation - January 1, 2016 to December 31, 2016

Energy Cost Adjustment Mechanism	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Total
Purchased Energy Costs	5,171,204	5,406,169	5,168,365	5,546,931	6,243,548	4,466,745	4,702,065	5,050,330	3,905,238	4,235,964	4,780,958	5,593,812	60,271,331
Lepreau Energy Costs	1,591,928	1,626,159	1,684,776	1,384,210	1,435,776	1,744,284	1,722,550	1,754,015	1,733,936	1,714,843	1,728,739	1,734,873	19,856,089
Generation Fuel Costs-PEI Plants	833,053	252,521	252,521	33,431	33,431	6,000	225,091	225,091	6,000	34,088	89,518	516,176	2,506,920
PEI Plant Operating Costs	406,067	406,067	406,067	406,067	406,067	406,067	406,067	406,067	406,067	406,067	406,067	406,067	4,872,808
Less: Insurance, Property Tax & Training	(74,241)	(74,241)	(74,241)	(74,241)	(74,241)	(74,241)	(74,241)	(74,241)	(74,241)	(74,241)	(74,241)	(74,241)	(890,892)
Amortization - Pt Lepreau Deferred Charge & DSM	7,783	7,783	7,783	7,783	7,783	7,783	7,783	7,783	7,783	7,783	7,783	7,783	93,400
Renewable Energy Costs	2,585,564	1,937,302	2,171,011	2,380,818	1,263,116	1,485,798	1,836,994	1,379,115	2,144,631	2,171,522	2,399,316	2,353,671	24,108,858
	10,521,359	9,561,761	9,616,283	9,685,000	9,315,480	8,042,437	8,826,309	8,748,161	8,129,414	8,496,027	9,338,141	10,538,142	110,818,514
Net Purchased & Produced Energy - kWh (NPP)	123,659,525	114,662,632	115,051,628	101,382,791	99,057,818	95,175,865	104,365,755	103,314,768	95,919,856	101,396,791	111,104,675	122,753,536	1,287,845,638
Base Rate/kWh	0.08760	0.08760	0.08605	0.08605	0.08605	0.08605	0.08605	0.08605	0.08605	0.08605	0.08605	0.08605	0.08634
Base Energy Costs	10,832,574	10,044,447	9,900,193	8,723,989	8,523,925	8,189,883	8,980,673	8,890,236	8,253,904	8,725,194	9,560,557	10,562,942	111,188,517
Difference Between Actual & Base Energy Costs	(311,216)	(482,686)	(283,909)	961,011	791,555	(147,446)	(154,364)	(142,075)	(124,489)	(229,167)	(222,416)	(24,799)	(370,003)
Opening Balance - ECAM	2,881,920	3,251,720	3,434,993	2,908,175	3,634,505	4,199,579	3,831,104	3,455,962	3,073,605	2,721,082	2,276,648	1,815,182	2,881,920
Additions/(Reductions)	(311,216)	(482,686)	(283,909)	961,011	791,555	(147,446)	(154,364)	(142,075)	(124,489)	(229,167)	(222,416)	(24,799)	(370,003)
Rebated/(Collected) From Ratepayer	681,015	665,959	(242,909)	(234,681)	(226,481)	(221,028)	(220,779)	(240,282)	(228,033)	(215,267)	(239,050)	(257,431)	(978,966)
Closing Balance - ECAM	3,251,720	3,434,993	2,908,175	3,634,505	4,199,579	3,831,104	3,455,962	3,073,605	2,721,082	2,276,648	1,815,182	1,532,952	1,532,952
Cost to Residential Customer (650 kWh/Month)	$ (3.87)	$ (3.87)	$ 1.56	$ 1.56	$ 1.56	$ 1.56	$ 1.56	$ 1.56	$ 1.56	$ 1.56	$ 1.56	$ 1.56	$ 7.89

The Conference Board of Canada   Le Conference Board du Canada

PROVINCIAL OUTLOOK EXECUTIVE SUMMARY SUMMER 2015

Another Tough Year.

At a Glance

- The Canadian economy did not perform well over the first few months of the year and is flirting with recession, but growth will pick up through the rest of 2015 and in 2016.
- The trade sector performed poorly in the first part of the year, leading to downgrades of the Quebec and Ontario economic forecast for 2015.
- Saskatchewan, along with Alberta, will see a contraction in its economy with adverse weather hurting agriculture yields and a correction in oil prices having led to a severe downturn in the energy sector.
- The near-term economic outlook is better for New Brunswick and Nova Scotia after years of sluggish growth and job losses.

NATIONAL OVERVIEW

The Canadian economy contracted slightly in the first four months of the year, posted a near-record trade deficit in May, and has been hit hard by the uncertainty in the eurozone. As a result, expectations have dimmed that the economy actually did post growth in the second quarter, fuelling speculation that the Canadian economy has dipped into recession. With four months of data available for 2015 so far, real gross domestic product has now shrunk in every month as lower oil prices and turbulence from external events—such as the Greek debt crisis—have hurt the Canadian economy. We now expect the numbers to show that economic growth tracked close to zero in the second quarter as the economy flirted with recession. However, it is not all bad news. Although employment fell by 6,400 in June, the economy has added 16,000 jobs a month on average over the first half of the year; not strong job growth, but it is positive growth and better than what we saw through most of 2014. Moreover, all the gains have been in full-time positions, more than offsetting a decline in part-time work. Finally, wage growth accelerated in May and June and should post modest gains over the near term. Consequently, even if Canada has slipped into recession, we expect it will be a mild one, with growth picking up through the rest of the year. Nonetheless, given the weak start to the year, we anticipate that growth for 2015 to come in at just 1.6 per cent, the worst showing since 2009.

Business investment will be the weakest part of the Canadian economy in 2015. Oil prices fell precipitously at the end of last year and, in late July, now dipped back to under US$50 a barrel. With weaker profits and cash flows, oil firms responded by slashing engineering projects and mineral exploration by 15 per cent in the first quarter. For 2015 and 2016 as a whole, we project that oil and gas firms will chop their capital budgets by almost one-third. Given that investment in the oil and gas sector currently represents almost one-third of total business investment, the cuts will have a sizable impact on the overall economy.

Firms have been hesitant to invest, even those outside of the energy sector. Purchases of machinery and equipment declined substantially in the first quarter. If we are to believe the recent survey of investment intentions from Statistics Canada, these declines are likely to continue throughout the year. According to this survey, businesses are planning to reduce their purchases of machinery and equipment by 5.2 per cent this year, a fall-off even more negative than our own projection. And, given the substantial erosion in the value of the loonie (which makes imported machinery and equipment more expensive), a bleak picture exists for the volume of investment. Building construction is also expected to see substantial decreases through 2015. Even with no increase in construction last year and a large drop in the first quarter of 2015, the vacancy rate has risen to its highest level since 2005. Building permits, a leading indicator for the construction industry, were down almost 15 per cent on a year-over-year basis in May, further supporting our belief that a downturn in construction activity is under way.

Although households are enjoying big savings at the gas pump and federal tax cuts, real household spending should also weaken this year. Soft employment growth, mostly weak wage gains, a high level of household debt, easing real estate markets, and job losses in oil-rich provinces will combine to take some of the steam out of real consumer spending in 2015. In addition, the economy is unlikely to get more than a small boost from government spending. Although we expect a slight increase in infrastructure spending, the federal and provincial governments were planning—even before the decline in oil prices—to maintain a significant degree of the current spending restraint. Now, with low oil prices and weak growth taking a bite out of revenue growth, an even greater level of restraint is foreseen.

The only area of the economy where we anticipate solid growth this year is the trade sector, but even here there are concerns. Trade numbers to date have been disappointing, with merchandise exports declining through the first five months of this year. In May, they were down 6.7 per cent from the same time last year. Although the Canadian dollar remains low (which should boost trade), the U.S. economy started 2015 on a weak note, as poor weather conditions and a labour strike at West Coast ports took a huge bite out of U.S. economic activity in the first quarter. On the bright side, the U.S. economy has already shown signs of bouncing back, and the expected uptick in U.S. activity over the remainder of 2015 and throughout 2016 should be good news for Canada's export sector.

Given our projection of only modest economic growth, we expect the economy to add just 150,000 jobs this year—another poor performance after 2014, which saw the weakest increase since 2009. Job growth is projected to accelerate in 2016 with 192,000 new jobs. This year, the unemployment rate will rise slightly to reach 7 per cent by the fourth quarter, before drifting back to 6.8 per cent by the end of 2016. Although conditions are weaker than we previously estimated, we expect the Bank of Canada to stand pat on further interest rate cuts following its quarter-point cut on July 15 and to begin raising rates again in late 2016 as the economy strengthens. We are looking for economic growth of 2.1 per cent in 2016.

PROVINCIAL OVERVIEW

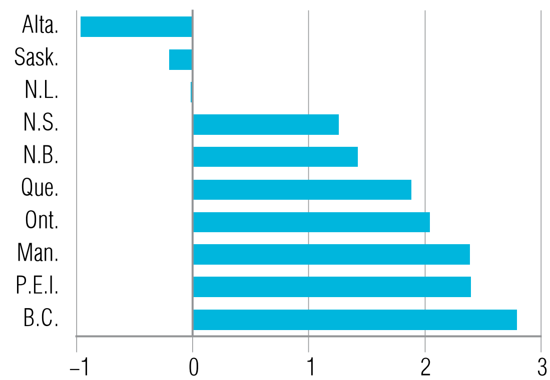
With Alberta's economy not performing well due to the lower oil prices, all eyes were on Central Canada as the lower Canadian dollar and the anticipated improvements in economic conditions south of the border were to revive growth in the Ontario and Quebec economy. But, more than midway through the year, economic forecasts are being revised down for nearly all provinces. Central Canada's economic rebound will be more moderate than first envisioned as exports failed to keep up with the acceleration that got under way in 2014. A host of factors, some temporary, some more structural, have plagued exporters in Canada's manufacturing heartland since the beginning of the year.

Difficulties in the oil sector will be hitting the Alberta, Saskatchewan, and Newfoundland and Labrador economies hard. Troubles never come alone; very dry weather conditions out west will also hamper prospects for a better harvest and that too will impact economic growth. While a lot of the weakness in the Canadian economy so far this year is due to the correction in the energy sector, economic growth outside the energy sector has been slow to pick up. It has been difficult for the metal mining sector; it is currently experiencing some turbulence as the end of the commodity boom rattles growth prospects going forward. Most projects in the mining sector have faced difficulties in securing financing and have not been able to move from proposal to development phase; this includes projects that are nearly shovel-ready. This atmosphere has softened considerably the outlook for the metal mining sector for the next few years. In addition, business investment in general remains depressed in several provinces so far this year. Although current economic conditions are far from stellar and are only slowly improving in Central and Atlantic

Canada, we do not expect the weakness to linger in the second half of the year. In fact, we are foreseeing a more normal economic performance in most of the provinces over the rest of the year and in 2016 as economic conditions stabilize in Western Canada and the stronger U.S. economy helps improve the trade outlook for Central Canada.

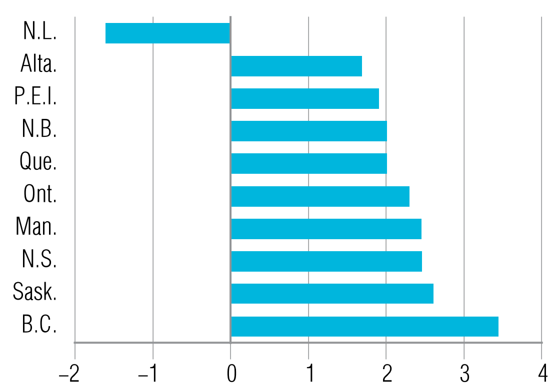
Regionally, British Columbia, Manitoba, Prince Edward Island, and Ontario will be the leaders in real GDP growth this year and the only provinces with growth of 2 per cent or more. (See Chart 1.) In 2016 (see Chart 2), while the economy is fairly stable in Manitoba despite the more volatile conditions in the resource sector, British Columbia will see the strongest real GDP growth in 2016. Recent developments have led us to include one major investment in B.C. (a liquefied natural gas [LNG] terminal) over the near term. (See Chart 2.)

Chart 1
Real GDP by Province, 2015
(percentage change*)



*based on 2007 $
Sources: The Conference Board of Canada; Statistics Canada.

Chart 2
Real GDP by Province, 2016
(percentage change*)



*based on 2007 $
Sources: The Conference Board of Canada; Statistics Canada.

PROVINCIAL ASSUMPTIONS

Newfoundland and Labrador's economy is not doing well. All key economic indicators are down in the first half of the year and weakness in the economy will persist for the next few years. The downturn in the economy is due to both cyclical and structural factors. The correction in oil, metal, and mineral prices is hurting production and investment decisions. But, even when the commodity market improves, the economy will fail to recover quickly. The aging of the population is going to hurt the ability of Newfoundland and Labrador—more than any other province in Canada—to generate the type of growth seen in the last decade. With a drop in employment, retail sales, and housing starts plus a large correction in the existing resale market, overall real GDP is not projected to grow at all in 2015 and to decline by 1.6 per cent in 2016. Some areas of the economy are expanding strongly, areas such as manufacturing where processing has begun at the Long Harbour hydromet plant.

While the economy in Canada is limping along, Prince Edward Island's seems to be in good health despite poor job creation. Following solid job gains between 2010 and 2013 (one of the strongest performances in the country), the Island's job market has stalled. Nevertheless, the economy is performing well on a number of fronts, particularly in the manufacturing and primary sectors. In addition, the retreat of the Canadian dollar should help tourism enjoy healthy growth and this will help the economy advance by 2.4 per cent in 2015 and 1.9 per cent in 2016.

Nova Scotia's economy is struggling to gain momentum and economic growth will be weaker this year than last. The new natural gas production from Encana's Deep Panuke offshore field was supposed to boost economic growth, but difficulties have hampered production to date as well as the production capacity of the field; this is weighing on growth. Aside from the petroleum industry, the economy appears to be gaining traction, mainly in the manufacturing and construction industries. However, the province has been unable to reverse a two-year trend in job creation and the job market will fail to generate any new jobs once again in 2015. The numbers are probably influenced by the downturn in the energy sector in the West; rotational workers who have lost their jobs there are counted in the workforce of their province of origin. Nevertheless, with work getting under way on the Arctic patrol vessels at Irving's newly expanded shipyard this fall, the economy should see real GDP growth accelerate from just 1.3 per cent in 2015 to 2.5 per cent in 2016.

In New Brunswick, the economic outlook is modest but much better than in recent years. Recovery in the job market remains elusive but a number of industries—such as manufacturers and industries in the forestry sector—are facing better growth prospects. The services sector should benefit from the more upbeat performance of the goods-producing sector that is helping to revive job creation and overall economic growth. New Brunswick's real GDP, after experiencing declines since 2011, is forecast to gain 1.4 per cent this year and 2 per cent in 2016.

Quebec's economic performance is being pulled down by the large contraction in exports. It will be difficult for the province's economy to gain sufficient momentum in the latter half of the year to boost economic growth to or above 2 per cent. With consumer demand that is still fairly strong, overall economic growth of 1.9 per cent is expected for 2015, a modest performance but one that still outpaces the national growth rate of just 1.6 per cent. While exports are projected to improve going forward, the aerospace industry will feel the effects of a weaker demand for business jets and the thousands of layoffs announced by Bombardier earlier this year. With stronger U.S. economic growth forecast for 2016, business investment should slowly pick up with positive growth in both non-residential and machinery and equipment investment. A number of large projects, mainly in the mining sector, could go ahead in the next few years if conditions improve; however, until then, investment in the province is forecast to advance only modestly. In 2016, the overall Quebec economy will maintain the same pace as this year, with a projected growth of 2 per cent. Fiscal restraints will continue to curb government expenditures on both programs and infrastructure. In addition, the housing market is weakening and is not expected to contribute positively to the economy.

In Ontario, the economy got off to a slow start this year as real exports fell 2 per cent in the first quarter and are very likely to contract in the second quarter as well. Ontario's disappointing trade performance will moderate its overall growth projections in 2015 to 2 per cent. Most of this growth will be concentrated in the second half of the year. The positive momentum will carry over to 2016 when real GDP is forecast to expand by 2.3 per cent. While the trade sector has faced challenges, the domestic economy in general is holding strong. Consumer demand will benefit from the sound job creation and stronger growth in household disposable income. While there are concerns of overbuilding in Toronto's condo market, the housing sector (both new and resale markets) remains very strong.

If job creation is any indication, Manitoba's economy is on solid ground. Employment is forecast to grow by 1.7 per cent in 2015 and 1.4 per cent in 2016. Real GDP growth is expected to rise by 2.4 per cent in 2015 and 2.5 per cent in 2016, keeping the province among the provincial growth leaders. Steady gains are forecast in manufacturing, agriculture, and construction. Manitoba is not facing the same pressures in the agriculture sector as are neighbouring Saskatchewan and Alberta.

Saskatchewan, along with Alberta, will face negative real GDP growth this year. The correction in oil prices has hurt the economy and now drought conditions will hamper crop yields. Overall, real GDP growth is expected to contract by 0.2 per cent in 2015 but, if the wheat harvest is more affected than expected by the adverse weather, the decline in real GDP could be steeper. The economic outlook should be stronger in 2016 as we do not foresee another major correction in the oil industry. Sound growth is also forecast for uranium and potash production and for the construction industry. All things considered, Saskatchewan's economy is projected to rebound by 2.6 per cent in 2016.

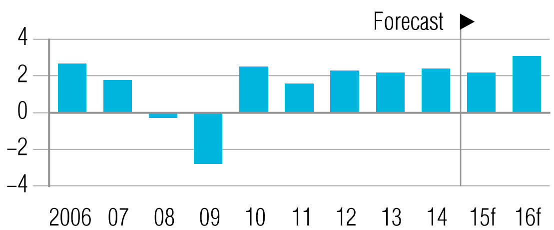
With the swift slide in crude oil prices, Alberta's economy was bracing for difficult times and it has not been smooth sailing for the province so far this year. Support activities for mining and oil and gas extraction shrank significantly over the winter drilling season as rigging and drilling services retreated by close to 35 per cent. As well, petroleum companies have announced staff layoffs and cuts to their capital plans to expand the energy sector. Employment growth is still positive but much weaker than in previous years. There is nothing more unpredictable than commodity prices, and low oil prices could likely last all of next year. The current global oversupply of oil remains a dominant factor influencing oil prices. Nonetheless, there should be more stability in the Alberta economy in 2016 and we anticipate that overall real GDP will advance by 1.7 per cent next year, following a 1 per cent decline in 2015.

There are new developments in the natural gas industry. British Columbia recently passed legislation to enter into an agreement with Petronas to build the Pacific NorthWest LNG export terminal near Prince Rupert. The project would rival the large megaprojects in Alberta's oil sands and would be the largest private investment in the province's history. If all conditions are met, construction on this first multi-billion-dollar LNG terminal could start in 2016. Meanwhile, British Columbia has been enjoying solid economic growth; no other province is facing such enviable prospects. The provincial economy is expected to advance by a solid 2.8 per cent in 2015 and by 3.4 per cent in 2016. The housing market remains hot with both new and resale markets making robust gains this year. The job market is performing well and consumers are expected to boost retail sales by a robust 7.3 per cent this year despite falling gasoline prices. Manufacturing should see a strong performance, benefiting from the rebounding U.S. economy, the lower Canadian dollar, and new shipbuilding work at North Vancouver's Seaspan shipyard for non-combat vessels.

U.S. OUTLOOK

The U.S. economy stumbled badly in the first quarter as real GDP declined. Fortunately, the economy performed better in the second quarter, as evidenced by the encouraging employment reports for May and June. However, the strong value of the greenback, among other factors, continues to restrain growth somewhat and it is only now, in the second half of the year, that economic growth is likely to hit the 3 per cent range. The weakness in the economy in the first quarter will likely delay interest rate increases until the fall, depending on how events unfold over the next few months. We expect real GDP to expand by 2.2 per cent for this year as a whole and to grow by 3.1 per cent in 2016. (See Chart 3.)

Chart 3
U.S. Economy Disappoints but the Outlook Is Robust
(U.S. real GDP, percentage change*)



*based on 2005 US$
f = forecast
Sources: The Conference Board of Canada; U.S. Bureau of Economic Analysis (BEA).

As noted, the U.S. economy slumped in the first quarter of this year. While a number of temporary factors, such as winter storms and a labour strike (now settled) at West Coast ports did hurt export growth, it would be misleading to blame the weakness in the U.S. economy on just temporary factors. Investment in energy projects is declining quickly, while the higher value of the U.S. dollar has hurt export and manufacturing activity.

In the first part of 2015, the negative effects of lower oil and gasoline prices outweighed the positives for the U.S. economy. Real investment in non-residential structures, which captures the bulk of energy investment, was down 21 per cent (at annual rates) in the first quarter, and the another decline is anticipated for the second quarter. Rig counts have dropped by more than 50 per cent since last November—evidence of the impact that world oil prices in the US$50 to US$60 range are having on this sector of the economy. However, no large correction is foreseen in energy investment in the second half of this year. Therefore, with energy investment no longer falling, overall investment in non-residential construction should expand at a slightly positive pace in the second half of this year and by 3.2 per cent in 2016.

The supposed positive effect on household spending attributable to sharply lower gasoline prices failed to materialize as many households increased their savings. During past periods of tumbling gasoline prices, it has always taken some time before Americans started to spend the money they saved from lower gasoline prices; this time is no different. However, we do expect consumer spending to increase at a faster clip in the second half of this year as households finally respond to lower prices at the pump and ramp up their purchases of goods and services. Real consumer spending is forecast to increase by 3.1 per cent this year and 3.3 per cent in 2016.

The anticipated rebound in household spending is readily apparent from the latest vehicle sales data. In May, car sales surged to 17.8 million units (seasonally adjusted at annual rates), up from 16.5 million in April. And, although the gain was weaker in June, this was widely projected, given the surge in sales in May. While some of the increase in car sales is linked to the catch-up effect following the harsh winter, there are other factors boosting sales. Labour markets are improving to the point where wages are finally starting to post some meaningful gains. In the first six months of this year, the economy created jobs at an average monthly pace well above 200,000. Also, lenders are more receptive to providing credit for more risky borrowers, while financing terms have maintained vehicle affordability at high levels.

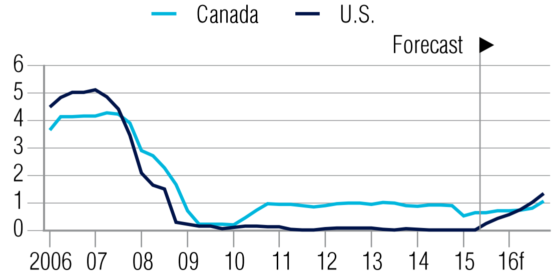
We expect the U.S. Federal Reserve to increase interest rates this autumn for the first time since 2006, as monetary authorities are confident that the economy is strong enough to handle higher rates. But future interest rate increases are projected to be modest. The Fed remains concerned about some pockets of weakness in the economy, such as the number of long-term unemployed.

MONETARY POLICY

The rapid fall in oil prices over the second half of 2014 and early 2015 drove year-over-year price growth in many countries into negative territory. As the impact of the energy price decline fades, inflation is set to return. While price growth did not turn negative in Canada, it has been restrained so far this year by the large drop in oil prices. Changes in energy prices directly affect the gasoline and fuel oil components of the consumer price index (CPI) and indirectly affect inflation through their impact on economic growth. Weak economic growth means sluggish demand, and this has helped to keep price pressures from building in the first part of this year. On the other hand, the drop in oil prices triggered a depreciation of the Canadian dollar, which is making imported goods more expensive and is adding to current price growth. Overall, headline inflation remains weak, posting growth of 1 per cent in June, while core inflation grew at a 2.1 per cent pace.

In the near term, we expect that the impact of higher import prices will continue to offset weakness stemming from sluggish demand and, therefore, that core inflation will remain at or above 2 per cent over the forecast period. However, aside from transitory impacts (such as those from exchange rate pass-through), the main factor influencing growth in trend prices is the output gap. The output gap is the difference between Canada's estimated potential and its actual output and, when the gap is negative, the economy can grow above its potential without igniting inflationary pressures. The contraction in real GDP growth in the first quarter widened the output gap but, with growth resuming in the second half of this year, the gap will continue to shrink and will fall below 1 per cent in early 2016. The steady decline in the output gap will eventually lead to inflationary pressures, but the Bank of Canada is expected to be patient about raising rates to ensure that any hikes do not derail the economic recovery. Our forecast assumes that monetary authorities will delay raising rates until at least September 2016. It also assumes that the divergence in policy between the Bank of Canada (which cut its key rate another quarter point on July 15) and the U.S. Federal Reserve (which is expected to raise rates before the end of this year) will keep the loonie around US$0.80 until the second half of next year despite a slow and steady rise in oil prices. (See Chart 4.)

Chart 4
Rate Hike in the U.S. to Take Place Sooner Rather Than Later
(U.S. and Canadian three-month T-bills spread, per cent)



f = forecast
Sources: The Conference Board of Canada; Bank of Canada.

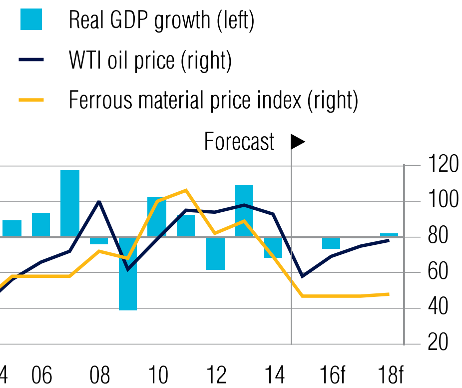
FISCAL OUTLOOK

The economy will not get much of a boost from the government sector over the forecast period. For years, most provinces—and Canada as a whole—have been waiting for a strong post-recession bounce-back in economic growth. However, with Canada's potential output growth slowing due to an aging population and lacklustre investment outside of the energy sector, we are no longer forecasting a substantial rebound in economic growth. Indeed, annual real GDP growth is not expected to exceed 2.3 per cent at any point over the next five years. This slowdown in GDP growth is moderating gains in government revenues and forcing governments to slow the pace of their spending in order to avoid a return to deficit or a sharp increase in their ongoing deficits. Despite weak spending on goods and services, total public spending looks to improve over the next few years, due mostly to a modest increase in infrastructure investment. After declining last year, real public consumption and investment spending is set to grow by a modest 0.8 per cent this year, followed by an increase of 0.9 per cent in 2016.

Most provinces are still running deficits and the federal government is expecting only small surpluses, which are predicated on continued spending restraint. For the federal government to meet its budget targets, it must continue to tightly control spending. When inflation is taken into account, federal spending on goods and services has declined in each of the last four years. And declines are anticipated again this year and in 2016. This restraint should allow the federal government to post small surpluses (unadjusted for contingency amounts) of $2.7 billion this fiscal year and $3.2 billion in fiscal 2016–17.

While the federal government looks able to handle the lower revenue outlook without returning to deficit, the provincial governments are not in as strong a fiscal position and they will have difficulty coping with this lower growth environment. Most of the provinces have tabled their 2015 budgets, and the outlook for this fiscal year is sobering. After posting a collective deficit of $13.7 billion in fiscal 2014–15, the collective provincial deficit is set to widen to $15 billion this fiscal year. Going forward, the provinces are facing slower-than-average revenue growth, a drop in resource royalties, and a growing demand for provincially funded services—a combination that will make it difficult for them to return to surplus any time soon.

Chart 5
Newfoundland and Labrador's Economy Struggles Under Lower Commodity Prices
(real GDP growth, 2007 $, per cent; WTI oil price, US$/barrel; ferrous material price index, 2002 = 100)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

NEWFOUNDLAND AND LABRADOR

SLUGGISH ECONOMIC OUTLOOK EXPECTED FOR 2015–16

Newfoundland and Labrador's economy will struggle over the next few years as major projects pass their peak investment levels and current offshore oilfields see production decline. In addition to these project-cycle factors, Newfoundland and Labrador's economy is facing the double whammy of low prices for oil and for metals. (See Chart 5.) Brent, the benchmark price for North Sea crude oil by which the province's offshore oil is priced, dropped by more than 50 per cent from its peak last summer, and prices for nickel, copper, and iron ore have all tumbled.

The weak outlook for commodity prices is having a negative impact on near-term investment and production decisions, and this will have a knock-on effect on the labour market and result in weaker economic growth.

Real GDP is not expected to grow this year and is forecast to decline by 1.6 per cent in 2016 as investments begin to slow on some of the projects currently under way.

The labour market will continue to feel the effects of the weakening economy. Year-to-date job numbers are down by more than 3,000 for the first half of this year and no reprieve is expected on that front over the medium term as major construction projects unwind. Meanwhile, the spike in the unemployment rate during the first half of this year will not get worse as the labour participation rate is expected to fall. Overall, the unemployment rate will drop from 12.7 per cent in the first half of this year to an average of 12.1 per cent in 2016 as the number of Newfoundlanders looking for work shrinks. With slack in the labour market, household consumption will be anemic over the next two years and government tax collection from households will be lower. In addition to weaker revenues from households, the provincial government has to brace for lower revenues from resource royalties for the fiscal year as crude oil and metal prices plummet. This has left the provincial government with a massive $1.1-billion deficit, thereby limiting the government's contribution to bottom-line economic growth.

But, despite this sobering litany of problems, all is not doom and gloom. Manufacturing remains one of the bright spots in the province's economy. The Long Harbour hydromet facility has begun processing nickel, copper, and cobalt ore from the Voisey's Bay mine and this will help offset some of the weakness in offshore oil production and the construction sector.

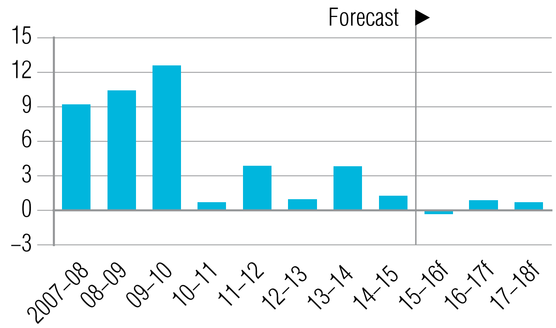
PRINCE EDWARD ISLAND

GOOD TIMES ON THE ISLAND

Prince Edward Island has finally thawed out after its record-breaking, snow-filled winter and is back on track to being one of Canada's leaders in economic growth for 2015. Thanks to the one-two punch of construction and manufacturing, as well as a surging export sector, the Island possesses solid economic prospects this year and next. The past winter saw a record amount of snowfall that postponed the opening of lobster season; however, despite the winter setback, the fishing industry is still expected to perform well this year, thanks to strong demand for lobster from China. In general, the Island's export sector will be a major positive for the province due mainly to a booming U.S. economy and the weaker Canadian dollar. As well, building construction intentions are strong 2015 and that, combined with a surge in housing starts next year, will support the construction sector over the near term. All these signs point to a healthy economy over the next two years on the Island, putting the province ahead of the national average. In particular, real GDP is expected to grow by 2.4 per cent this year and 1.9 per cent in 2016.

The recently re-elected Liberal government released its annual budget on June 19 and, as expected, the province continued its mandate of controlled spending. (See Chart 6.) Despite the frugality, the province had to push out its balanced-budget target by one year to 2016–17. Tight spending measures translate into weak growth in non-commercial services such as education and health and social services, which puts a damper on overall economic growth. This makes the positive economic outlook for the Island that much more impressive. With the combination of a strong economy and tighter spending, the province should certainly achieve its new fiscal-balance goal for 2016–17.

Chart 6
Tight Program Spending Required to Balance Books in P.E.I.
(percentage change)



f = forecast
Sources: The Conference Board of Canada; P.E.I. Budget 2015.

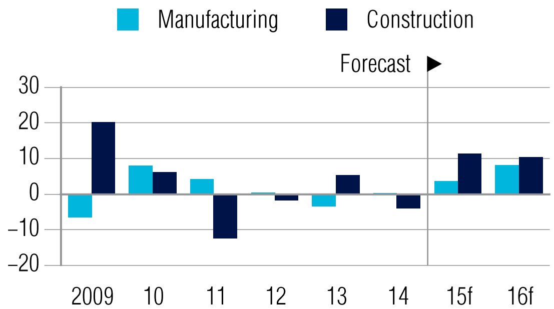
NOVA SCOTIA

NATURAL GAS PRODUCTION WEIGHS DOWN GDP GROWTH IN 2015

After modest economic growth this year, Nova Scotia's economy is forecast to post robust growth in 2016. Real GDP is expected to increase by 1.3 per cent in 2015 and 2.5 per cent in 2016. Over the near term, declines in natural gas production will take away from bottom-line growth in the province. Production at the mature Sable Island Energy project will continue to decline; ExxonMobil Canada indicated that the five fields of the project will stop producing natural gas as early as 2017 and the field will be decommissioned. In addition, Encana's Deep Panuke offshore project will now become a seasonal operation and is projected to produce natural gas for only another three years.

Despite a rather bleak outlook for mineral fuels mining, the other goods-producing industries will perform well; manufacturing and construction are forecast to post strong growth this year and next. (See Chart 7.) Manufacturing will be supported by the Irving shipbuilding contract that is expected to begin in the fall of this year. In addition, other manufacturing sectors are aiming to expand their production in the province. Construction will rebound this year and see double-digit growth this year and next. Work on the Nova Centre

Chart 7
Manufacturing and Construction Helping to Boost Nova Scotia's Economy
(percentage change)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

and King's Wharf projects in Halifax, on the Maritime Transmission, and on wind power expansion will keep construction workers busy in the province.

Employment, however, will see another disappointing year in 2015. Over the first six months of the year, total employment fell and, although it is forecast to recover somewhat over the remainder of the year, it will not be enough to offset the losses from the beginning of the year. Next year promises better employment prospects; after a 0.1 per cent decline in 2015, employment will rebound with 1 per cent growth in 2016.

NEW BRUNSWICK

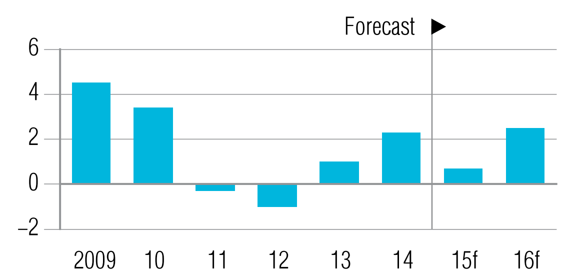
NEW BRUNSWICK'S ECONOMIC OUTLOOK IMPROVES

A rebound in the goods-producing industries and better growth in the services sector will produce an improved economic outlook for New Brunswick in the next two years. Real GDP is forecast to gain 1.4 per cent this year and 2 per cent in 2016.

Decent gains in mining, manufacturing, agriculture, and forestry will help lift growth in the goods-producing industries. Potash mining will continue to ramp up at the Picadilly mine, while metal mining will benefit from the reopening of the Trevali's Caribou mine (the company expects to more than double its zinc production). Manufacturing will also post solid gains over the next two years. Stronger economic growth in the U.S. will help drive demand for New Brunswick–produced goods, while a weaker Canadian dollar will make them more price competitive. The forestry industry will benefit from an increase in the allowable softwood cut on Crown land and stronger growth in new housing demand in the U.S. In addition, the industry will benefit from the $450-million investment by J.D. Irving in the province's lumber mill upgrades. Construction, on the other hand, will weigh down overall growth. Business residential and non-residential investment is forecast to decline this year as a number of non-residential projects are completed and housing starts are anticipated to fall off.

Transportation and warehousing plus finance, insurance, real estate, and leasing will support better growth in the services sector. On the down side, provincial retailers were hard hit by a cold and snowy winter and will not be able to recoup all the losses of the first six months of this year in the rest of 2015, leading to just a modest gain in retail trade in 2015. (See Chart 8.) Employment will see another disappointing year with a further reduction in the number of people employed; however, job prospects will improve next year.

Chart 8
Winter Takes a Toll on New Brunswick's Retailers
(percentage change)



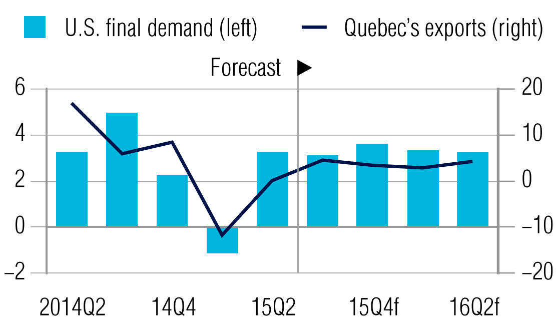
f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

QUEBEC

QUEBEC'S EXPORT RECOVERY STALLS AMIDST U.S. WINTER DOLDRUMS

Despite the weaker-than-expected performance of its trade sector, Quebec's economy will strengthen this year and advance by 1.9 per cent, compared with the 1.4 per cent gain last year. Next year, Quebec's GDP is forecast to expand by 2 per cent. The temporary slowdown in Quebec's exports is due to the exceptionally low final demand from U.S. businesses and consumers in the first quarter of 2015. (See Chart 9.) Quebec's exports of goods to other countries jumped by a solid 9.4 per cent last year but will post a meagre 0.8 per cent increase this year due to a very bad first quarter. The U.S. economy suffered a transitory setback with a port strike on the West Coast and harsh weather around the country this winter. As a result, Quebec's exports of goods and services, which posted 3.9 per cent growth in 2014, will advance by 1.1 per cent this year before rising 3.4 per cent in 2016.

Chart 9
Quebec's Export Recovery Stalls Amidst Tumbling U.S. Demand
(exports of goods and services, annualized growth rate, per cent; U.S. final demand, percentage change)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada; U.S. Bureau of Economic Analysis (BEA).

The trade slowdown this year will in turn cause Quebec's export-oriented manufacturing industry to grow by just 1.7 per cent in 2015. Weak demand south of the border will also persuade domestic businesses not to move forward with major investment projects. Non-residential construction and machinery and equipment investments will falter again this year, by 8.2 per cent and 2.1 per cent respectively, before they firm up in 2016 and post 2.4 per cent and 2.3 per cent increases, respectively.

Thanks to a 1.1 per cent increase in employment this year, stronger growth in household disposable income will help lift wholesale and retail trade by 2.6 per cent. Once again, consumer spending will support the economic performance of the province while the government holds growth on program expenditures to just 1.2 per cent in 2015–16.

ONTARIO

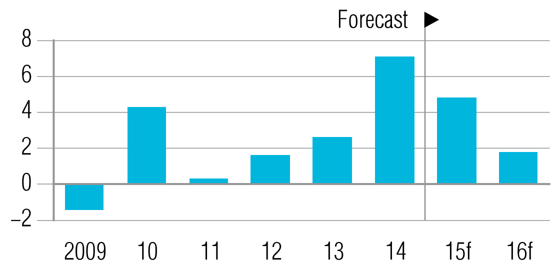
EXPORTS FAIL TO BOOST ECONOMY

Ontario's economy got off to a slow start this year as exports fell 2 per cent in the first quarter and are likely to see another decline in the second quarter. Despite strong domestic demand, the province could not overcome the first-quarter contraction in the U.S. economy, which was caused by some temporary factors including unseasonably poor weather, a port dispute that disrupted trade, and a large drop in energy investment. Ontario's disappointing trade performance will moderate its overall growth expectations in 2015 to a still-healthy 2 per cent. Most of this growth will be concentrated in the second half of the year. This positive momentum will also carry over to 2016 when real GDP is forecast to expand by 2.3 per cent.

Consumer spending has been quite robust, especially on durable goods (see Chart 10), and vehicle sales continue to set new records. Strong consumption is supported by robust consumer confidence in the province, as evidenced by the Conference Board's consumer confidence survey that shows strong intentions on the questions regarding major purchases. Household consumption will gain 2.9 per cent in 2015 and 2.4 per cent in 2016.

Although export growth has been disappointing so far this year, the weakness is expected to be temporary and better growth is forecast for the remainder of the year. Aside from the contraction in the U.S. economy, a temporary halt in production at motor vehicle plants

Chart 10
Durable Goods Consumption in Ontario Continues to Expand at a Strong Clip
(percentage change*)



*based on 2007 $
f = forecast
Sources: The Conference Board of Canada; Ontario Ministry of Finance; Statistics Canada.

in Windsor and Oakville led to a large drop in vehicle exports in the first quarter. With both plants back in full production, exports will accelerate over the remainder of the year, posting growth of 1.2 per cent. Supported by a weak Canadian dollar and stronger growth in the U.S. economy, the province's exports will enjoy strong growth of 4.2 per cent in 2016.

MANITOBA

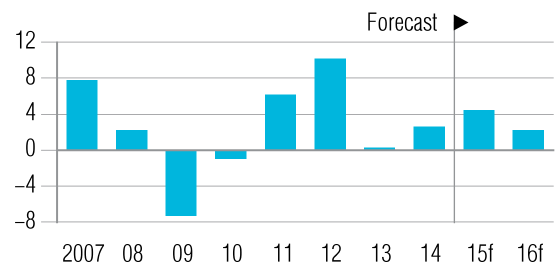
MANITOBA'S ECONOMY ON SOLID GROUND

Manitoba's economy is on solid ground with gains expected across key sectors over the next two years. Real GDP growth is expected to rise by 2.4 per cent in 2015 and 2.5 per cent in 2016, keeping Manitoba among the provincial growth leaders.

Solid gains are forecast in manufacturing, agriculture and construction. Because of the correction in oil prices, the mining sector is not expected to grow in 2015 and will advance only moderately in 2016. Metal ore production will perform better with the opening of two new mines and steady production levels in existing mines.

Increased activity is anticipated on all fronts for Manitoba's manufacturing sector, thanks to a rebounding U.S. economy. Growth in manufacturing is projected to hit 4.5 per cent in 2015 and 2.3 per cent in 2016. (See Chart 11.) The agriculture sector is expected to rebound this year with 3.8 per cent growth as the drought and dry weather in neighbouring Saskatchewan and Alberta have not affected Manitoba too much. In addition, construction is ramping up across the province with the provincial government's infrastructure plan and Manitoba Hydro projects breaking ground.

Chart 11
Manitoba's Manufacturing Sector Performing Well
(percentage change*)



*based on 2007 $
f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

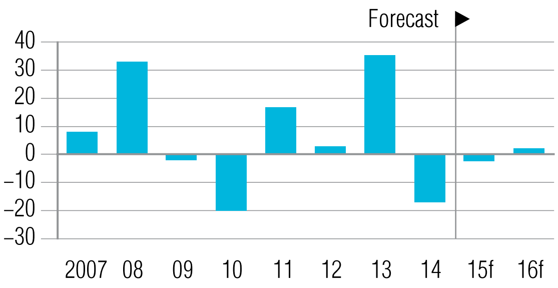
The gains in the goods-producing industries should be reflected in the services sectors. Employment is forecast to rise by an average of 1.5 per cent over the next two years. Also foreseen is a decrease in the province's unemployment rate—from 5.5 per cent in 2015 to an average of 5.1 per cent over the medium term. With stronger job creation, household disposable income will spur household consumption expenditures, boosting wholesale and retail trade in the province by 3.6 per cent in 2015 and 2.6 per cent in 2016.

SASKATCHEWAN

WEATHER WOES ADDING TO A DIFFICULT YEAR

Faced with a severe correction in the energy sector, economic growth will turn negative in Saskatchewan this year. Further weighing down economic growth are the drought conditions for the agriculture sector (see Chart 12), and rising uranium and potash production will not be enough to keep real GDP growth in positive

Chart 12
Crop Yields Are at Risk due to the Adverse Weather
(agriculture, percentage change*)



*based on 2007 $
f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

territory. Construction is also expected to cool off this year. Overall, a decline of 0.2 per cent in real GDP is foreseen this year.

Another correction in the energy sector does not appear likely in 2016 and, with uranium and potash production continuing to increase, the economy is forecast to perform better in 2016. Construction will also pick up again with projects in the mining and energy sector. Overall, Saskatchewan's economy is projected to grow by 2.6 per cent in 2016.

The weak economy slowed down job creation. Employment will rise by only 0.5 per cent this year but will expand by 0.9 per cent in 2016. The unemployment rate is expected to grow to 4.7 per cent this year, up from 3.5 per cent in 2014. Despite this rise, the unemployment rate will remain the lowest in Canada. The economic slowdown of 2015 and the rebound of 2016 will be mirrored in household consumption patterns with weakness this year and stronger growth next year.

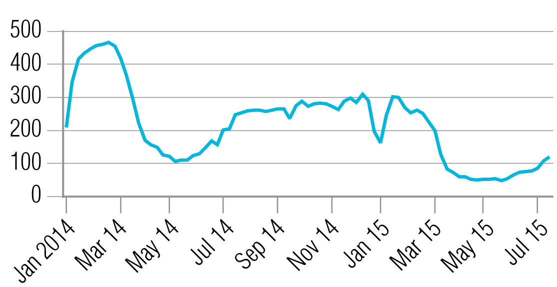
ALBERTA

ALBERTA'S ECONOMY SHIFTS TO REVERSE GEAR

After cruising in fourth speed for the last five years, Alberta's economy shifts to reverse gear this year as the economy faces headwinds stemming from the crude oil price rout. With the downturn in the energy sector, the first half of the year was difficult. The second half of this year is expected to be equally challenging as more layoffs begin to hit home and builders retreat further from breaking ground for new homes. In all, real GDP is forecast to contract by 1.0 per cent this year.

Bearish market conditions for crude stock at the onset of the summer trading season pressured crude oil prices to lose the momentum gathered during the spring. And, with crude prices still off 50 per cent from their peak in the summer of 2014, several oil firms have slashed their planned investment for this year. The steep reduction in oil-patch investment is evident in the number of oil drilling rigs in operation during the crucial peak winter season. Rig counts in the province were down 48 per cent during the first half of this year, compared with the same period a year ago. (See Chart 13.) The job losses accompanying the reduction in investment will hurt the housing market, weaken migration trends, and batter the consumer sector. Government revenues from corporate income taxes as well as resource royalties will be under severe pressure this year.

Chart 13
Alberta's Rotary Rig Counts React to Lower Crude Oil Prices
(rigs, units)



Source: www.bakerhughes.com.

Although crude oil prices seems to have stabilized in recent weeks, a return to an annual economic growth of over 4 per cent is not in the cards for Alberta since crude prices are not likely to return to the triple-digit trading range any time soon. The decline in oil prices is affecting not only the oil-patch businesses and government revenues. Consumers are having a double whammy of weak job prospects and new tax measures. With consumer confidence down, retailers are feeling the downturn.

However, the news is not all bad for Albertans. Heavy investment in recent years has helped to build a lot of capacity in the oil and gas sector, and that is paying dividends in the form of higher oil production. Even though oil prices have dropped, non-conventional oil production continues to flow south to refineries along the U.S. Gulf Coast where demand for heavy oil remains high. And, with import levels falling (due in part to the drop in machinery and equipment purchases associated with oil-patch development), net trade will remain a positive influence on the economy over the short term. Together, a positive net trade balance and more stable economic conditions will help lift real GDP by 1.7 per cent next year.

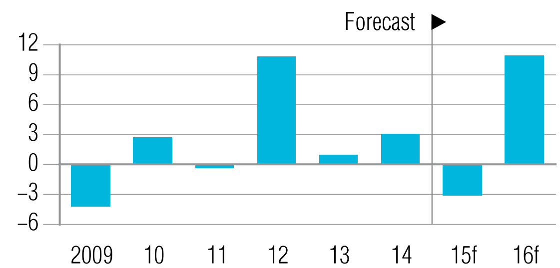
BRITISH COLUMBIA

BRITISH COLUMBIA WILL LEAD THE PROVINCES THIS YEAR AND NEXT

British Columbia's economy is firing on all cylinders. Provincial real GDP will grow the fastest among all 10 provinces in both 2015 and 2016. The economy will advance by 2.8 per cent in 2015 and 3.4 per cent in 2016.

This year, the province will benefit from strong growth in manufacturing and healthy gains in the services sector. Year-to-date (ending in June) exports of manufacturing goods have been on the rise, especially in the metal products manufacturing and transportation equipment manufacturing. Stronger economic growth in the U.S. will continue to support gains in the export categories. Construction will be a drag on the provincial bottom line this year as several projects were completed but next year will bring a strong rebound as several new projects get under way. (See Chart 14.) Metal mining is also forecast to decline in 2015 as a result of shutdowns of Endako and Mount Polley mines. However, metal mining will turn around next year as production ramps up at the Mount Milligan copper and gold mine and Red Chris gold-copper mine.

Chart 14
Construction Activity Takes a Break This Year
(percentage change*)



*based on 2007 $
f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

On the energy front, the province passed legislation to enter into an agreement with Pacific NorthWest LNG, a consortium led by Malaysian energy giant Petronas, to build an LNG export terminal near Prince Rupert. The province is now in talks to ratify this agreement. If this project goes ahead, it would be the largest private sector investment in the province's history.

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Table 1—Key Economic Indicators: Provinces
(Forecast Completed: July 16, 2015)

	Gross domestic product at market prices ($ millions)			Gross domestic product at basic prices (2007 $ millions)			Employment (000s)			Unemployment rate (per cent)			Retail sales ($ millions)		
	2014	2015	2016	2014	2015	2016	2014	2015	2016	2014	2015	2016	2014	2015	2016
Newfoundland and Labrador	34,823	33,001	34,043	26,924	26,919	26,486	238	235	234	12.0	12.6	12.1	8,881	8,835	8,994
	–2.8	*–5.2*	*3.2*	*–2.9*	*0.0*	*–1.6*	*–1.9*	*–1.3*	*–0.7*				*3.4*	*–0.5*	*1.8*
Prince Edward Island	5,971	6,235	6,475	4,644	4,755	4,845	74	74	74	10.5	10.5	10.0	2,005	2,017	2,094
	3.2	*4.4*	*3.9*	*1.3*	*2.4*	*1.9*	*–0.4*	*–0.5*	*1.0*				*3.3*	*0.6*	*3.8*
Nova Scotia	40,524	41,792	43,636	33,480	33,902	34,736	448	447	452	8.9	8.7	8.5	13,915	13,699	14,256
	3.5	*3.1*	*4.4*	*1.6*	*1.3*	*2.5*	*–1.1*	*–0.1*	*1.0*				*2.3*	*–1.6*	*4.1*
New Brunswick	32,319	33,433	34,721	26,063	26,434	26,964	354	353	357	9.9	10.0	9.5	11,528	11,650	12,155
	1.3	*3.4*	*3.9*	*0.0*	*1.4*	*2.0*	*–0.2*	*–0.1*	*1.1*				*3.8*	*1.1*	*4.3*
Quebec	374,352	384,880	399,329	311,825	317,686	324,065	4,056	4,102	4,143	7.8	7.8	8.0	108,137	110,022	114,131
	3.2	*2.8*	*3.8*	*1.4*	*1.9*	*2.0*	*–0.1*	*1.1*	*1.0*				*1.7*	*1.7*	*3.7*
Ontario	720,938	742,545	772,850	600,575	612,828	626,878	6,877	6,931	7,014	7.3	6.8	6.8	176,719	183,470	190,720
	3.6	*3.0*	*4.1*	*2.3*	*2.0*	*2.3*	*0.8*	*0.8*	*1.2*				*5.0*	*3.8*	*4.0*
Manitoba	62,957	65,679	68,311	52,874	54,137	55,465	627	638	647	5.4	5.5	5.1	18,034	18,304	18,996
	2.7	*4.3*	*4.0*	*1.1*	*2.4*	*2.5*	*0.1*	*1.7*	*1.4*				*4.3*	*1.5*	*3.8*
Saskatchewan	85,959	83,894	87,873	60,095	59,976	61,539	571	574	579	3.8	4.7	4.7	19,143	18,912	19,551
	3.3	*–2.4*	*4.7*	*1.4*	*–0.2*	*2.6*	*1.0*	*0.5*	*0.9*				*4.6*	*–1.2*	*3.4*
Alberta	365,887	353,268	370,203	305,523	302,570	307,664	2,274	2,301	2,309	4.7	5.6	5.9	78,582	76,440	78,397
	8.2	*–3.4*	*4.8*	*4.4*	*–1.0*	*1.7*	*2.2*	*1.2*	*0.3*				*7.5*	*–2.7*	*2.6*
British Columbia	240,364	251,471	263,914	203,335	209,001	216,201	2,278	2,293	2,331	6.1	6.0	5.9	66,273	71,088	74,463
	4.6	*4.6*	*4.9*	*2.6*	*2.8*	*3.4*	*0.6*	*0.7*	*1.6*				*5.6*	*7.3*	*4.7*
Canada	1,974,825	2,007,264	2,092,762	1,637,443	1,662,075	1,697,487	17,796	17,947	18,139	6.9	6.9	6.9	505,008	516,342	535,785
	4.3	*1.6*	*4.3*	*2.4*	*1.5*	*2.1*	*0.6*	*0.8*	*1.1*				*4.6*	*2.2*	*3.8*

For each indicator, the first line is the level and the second line is the percentage change from the previous year.
Shaded area represents forecast data.
Sources: The Conference Board of Canada; Statistics Canada.

Table 2—Key Economic Indicators: Provinces
(Forecast Completed: July 16, 2015)

	Gross domestic product at market prices—per capita ($ per person)			Gross domestic product at market prices—per capita (2007 $ per person)			Employment rate (per 1,000 people)			Household disposable income per capita ($ per person)			Primary household income per capita ($ per person)		
	2014	2015	2016	2014	2015	2016	2014	2015	2016	2014	2015	2016	2014	2015	2016
Newfoundland and Labrador	66,033	62,774	64,743	54,500	54,601	53,676	537	532	529	32,753	33,307	33,531	34,980	35,660	36,025
	–2.6	*–4.9*	*3.1*	*–2.7*	*0.2*	*–1.7*	*–1.7*	*–1.0*	*–0.6*	*3.8*	*1.7*	*0.7*	*4.3*	*1.9*	*1.0*
Prince Edward Island	40,889	42,564	43,988	34,721	35,438	35,938	613	609	613	26,838	27,164	27,698	28,061	28,392	29,083
	2.7	*4.1*	*3.3*	*0.8*	*2.1*	*1.4*	*–0.8*	*–0.6*	*0.6*	*1.4*	*1.2*	*2.0*	*1.5*	*1.2*	*2.4*
Nova Scotia	42,975	44,301	46,141	38,825	39,297	40,165	572	570	574	28,256	28,875	29,510	30,952	31,693	32,530
	3.6	*3.1*	*4.2*	*1.6*	*1.2*	*2.2*	*–1.2*	*–0.3*	*0.7*	*2.4*	*2.2*	*2.2*	*2.7*	*2.4*	*2.6*
New Brunswick	42,839	44,361	46,020	37,460	38,033	38,753	569	568	574	27,638	28,073	28,827	29,190	29,872	30,821
	1.5	*3.6*	*3.7*	*0.1*	*1.5*	*1.9*	*–0.1*	*–0.1*	*1.0*	*0.7*	*1.6*	*2.7*	*1.6*	*2.3*	*3.2*
Quebec	45,624	46,606	47,942	40,952	41,449	41,922	596	600	602	27,230	27,887	28,445	30,948	31,614	32,398
	2.4	*2.2*	*2.9*	*0.7*	*1.2*	*1.1*	*–0.7*	*0.6*	*0.3*	*1.6*	*2.4*	*2.0*	*1.6*	*2.2*	*2.5*
Ontario	52,754	53,804	55,284	47,276	47,736	48,219	610	608	608	31,132	32,066	32,629	35,871	36,870	37,643
	2.6	*2.0*	*2.7*	*1.2*	*1.0*	*1.0*	*–0.3*	*–0.3*	*–0.1*	*2.3*	*3.0*	*1.8*	*2.5*	*2.8*	*2.1*
Manitoba	49,203	50,731	52,104	44,635	45,167	45,701	642	646	648	28,308	28,900	29,466	31,866	32,550	33,336
	1.4	*3.1*	*2.7*	*–0.2*	*1.2*	*1.2*	*–1.1*	*0.7*	*0.3*	*1.3*	*2.1*	*2.0*	*1.4*	*2.1*	*2.4*
Saskatchewan	76,567	73,764	76,047	56,637	55,795	56,352	670	667	664	33,119	33,852	34,306	37,690	38,508	39,139
	1.5	*–3.7*	*3.1*	*–0.3*	*–1.5*	*1.0*	*–0.5*	*–0.5*	*–0.4*	*0.0*	*2.2*	*1.3*	*0.0*	*2.2*	*1.6*
Alberta	89,164	84,418	86,996	77,095	74,867	74,864	693	687	679	41,823	42,373	42,803	50,096	50,598	51,292
	5.2	*–5.3*	*3.1*	*1.5*	*–2.9*	*0.0*	*–0.7*	*–0.8*	*–1.1*	*3.3*	*1.3*	*1.0*	*3.6*	*1.0*	*1.4*
British Columbia	51,941	53,788	55,801	47,693	48,523	49,621	595	592	595	32,419	33,237	34,205	36,728	37,690	38,874
	3.5	*3.6*	*3.7*	*1.5*	*1.7*	*2.3*	*–0.5*	*–0.5*	*0.4*	*2.4*	*2.5*	*2.9*	*2.9*	*2.6*	*3.1*
Canada	55,642	55,990	57,727	49,227	49,502	49,990	614	613	613	31,492	32,262	32,883	36,136	36,967	37,814
	3.1	*0.6*	*3.1*	*1.3*	*0.6*	*1.0*	*–0.5*	*–0.2*	*0.0*	*2.3*	*2.4*	*1.9*	*2.5*	*2.3*	*2.3*

For each indicator, the first line is the level and the second line is the percentage change from the previous year.
Shaded area represents forecast data.
Sources: The Conference Board of Canada; Statistics Canada.

Insights. Understanding. Impact.

Provincial Outlook Executive Summary: Summer 2015

by Marie-Christine Bernard

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PROVINCIAL OUTLOOK

Economic Forecast.

SUMMER 2015

The Conference Board of Canada

Provincial Outlook Summer 2015: Economic Forecast
by *The Conference Board of Canada*

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Preface

The *Provincial Outlook Summer 2015* was prepared by Marie-Christine Bernard, Associate Director, under the general direction of Pedro Antunes, Deputy Chief Economist.

The report examines the economic outlook for the provinces, including gross domestic product (GDP), output by industry and labour market conditions. At the end of the report, there is a forecast for Canadian economic indicators and a comparison of GDP by province and industry.

The Provincial Outlook is updated quarterly using the Conference Board's large econometric model of the provincial economies.

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Executive Summary

Marie-Christine Bernard

Another Tough Year

At a Glance

- The Canadian economy did not perform well over the first few months of the year and is flirting with recession, but growth will pick up through the rest of 2015 and in 2016.
- The trade sector performed poorly in the first part of the year, leading to downgrades of the Quebec and Ontario economic forecast for 2015.
- Saskatchewan, along with Alberta, will see a contraction in its economy with adverse weather hurting agriculture yields and a correction in oil prices having led to a severe downturn in the energy sector.
- The near-term economic outlook is better for New Brunswick and Nova Scotia after years of sluggish growth and job losses.

NATIONAL OVERVIEW

The Canadian economy contracted slightly in the first four months of the year, posted a near-record trade deficit in May, and has been hit hard by the uncertainty in the eurozone. As a result, expectations have dimmed that the economy actually did post growth in the second quarter, fuelling speculation that the Canadian economy has dipped into recession. With four months of data available for 2015 so far, real gross domestic product has now shrunk in every month as lower oil prices and turbulence from external events—such as the Greek debt crisis—have hurt the Canadian economy. We now expect the numbers to show that economic growth tracked close to zero in the second quarter as the economy flirted with recession. However, it is not all bad news. Although employment fell by 6,400 in June, the economy has added 16,000 jobs a month on average over the first half of the year; not strong job growth, but it is positive growth and better than what we saw through most of 2014. Moreover, all the gains have been in full-time positions, more than offsetting a decline in part-time work. Finally, wage growth accelerated in May and June and should post modest gains over the near term. Consequently, even if Canada has slipped into recession, we expect it will be a mild one, with growth picking up through the rest of the year. Nonetheless, given the weak start to the year, we anticipate that growth for 2015 to come in at just 1.6 per cent, the worst showing since 2009.

Business investment will be the weakest part of the Canadian economy in 2015. Oil prices fell precipitously at the end of last year and, in late July, now dipped back to under US$50 a barrel. With weaker profits and cash flows, oil firms responded by slashing engineering projects and mineral exploration by 15 per cent in the first quarter. For 2015 and 2016 as a whole, we project that oil and gas firms will chop their capital budgets by almost one-third. Given that investment in the oil and gas sector currently represents almost one-third of total business investment, the cuts will have a sizable impact on the overall economy.

Firms have been hesitant to invest, even those outside of the energy sector. Purchases of machinery and equipment declined substantially in the first quarter. If we are to believe the recent survey of investment intentions from Statistics Canada, these declines are likely to continue throughout the year. According to this survey, businesses are planning to reduce their purchases of machinery and equipment by 5.2 per cent this year, a fall-off even more negative than our own projection. And, given the substantial erosion in the value of the loonie (which makes imported machinery and equipment more expensive), a bleak picture exists for the volume of investment. Building construction is also expected to see substantial decreases through 2015. Even with no increase in construction last year and a large drop in the first quarter of 2015, the vacancy rate has risen to its highest level since 2005. Building permits, a leading indicator for the construction industry, were down almost 15 per cent on a year-over-year basis in May, further supporting our belief that a downturn in construction activity is under way.

Although households are enjoying big savings at the gas pump and federal tax cuts, real household spending should also weaken this year. Soft employment growth, mostly weak wage gains, a high level of household debt, easing real estate markets, and job losses in oil-rich provinces will combine to take some of the steam out of real consumer spending in 2015. In addition, the economy is unlikely to get more than a small boost from government spending. Although we expect a slight increase in infrastructure spending, the federal and provincial governments were planning—even before the decline in oil prices—to maintain a significant degree of the current spending restraint. Now, with low oil prices and weak growth taking a bite out of revenue growth, an even greater level of restraint is foreseen.

The only area of the economy where we anticipate solid growth this year is the trade sector, but even here there are concerns. Trade numbers to date have been disappointing, with merchandise exports declining through the first five months of this year. In May, they were down 6.7 per cent from the same time last year. Although the Canadian dollar remains low (which should boost trade), the U.S. economy started 2015 on a weak note, as poor weather conditions and a labour strike at West Coast ports took a huge bite out of U.S. economic activity in the first quarter. On the bright side, the U.S. economy has already shown signs of bouncing back, and the expected uptick in U.S. activity over the remainder of 2015 and throughout 2016 should be good news for Canada's export sector.

Given our projection of only modest economic growth, we expect the economy to add just 150,000 jobs this year—another poor performance after 2014, which saw the weakest increase since 2009. Job growth is projected to accelerate in 2016 with 192,000 new jobs. This year, the unemployment rate will rise slightly to reach 7 per cent by the fourth quarter, before drifting back to 6.8 per cent by the end of 2016. Although conditions are weaker than we previously estimated, we expect the Bank of Canada to stand pat on further interest rate cuts following its quarter-point cut on July 15 and to begin raising rates again in late 2016 as the economy strengthens. We are looking for economic growth of 2.1 per cent in 2016.

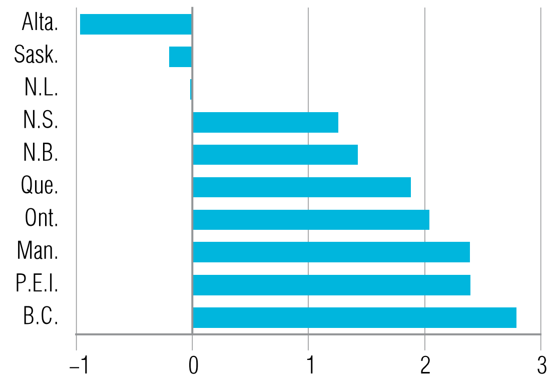
PROVINCIAL OVERVIEW

With Alberta's economy not performing well due to the lower oil prices, all eyes were on Central Canada as the lower Canadian dollar and the anticipated improvements in economic conditions south of the border were to revive growth in the Ontario and Quebec economy. But, more than midway through the year, economic forecasts are being revised down for nearly all provinces. Central Canada's economic rebound will be more moderate than first envisioned as exports failed to keep up with the acceleration that got under way in 2014. A host of factors, some temporary, some more structural, have plagued exporters in Canada's manufacturing heartland since the beginning of the year.

Difficulties in the oil sector will be hitting the Alberta, Saskatchewan, and Newfoundland and Labrador economies hard. Troubles never come alone; very dry weather conditions out west will also hamper prospects for a better harvest and that too will impact economic growth. While a lot of the weakness in the Canadian economy so far this year is due to the correction in the energy sector, economic growth outside the energy sector has been slow to pick up. It has been difficult for the metal mining sector; it is currently experiencing some turbulence as the end of the commodity boom rattles growth prospects going forward. Most projects in the mining sector have faced difficulties in securing financing and have not been able to move from proposal to development phase; this includes projects that are nearly shovel-ready. This atmosphere has softened considerably the outlook for the metal mining sector for the next few years. In addition, business investment in general remains depressed in several provinces so far this year. Although current economic conditions are far from stellar and are only slowly improving in Central and Atlantic Canada, we do not expect the weakness to linger in the second half of the year. In fact, we are foreseeing a more normal economic performance in most of the provinces over the rest of the year and in 2016 as economic conditions stabilize in Western Canada and the stronger U.S. economy helps improve the trade outlook for Central Canada.

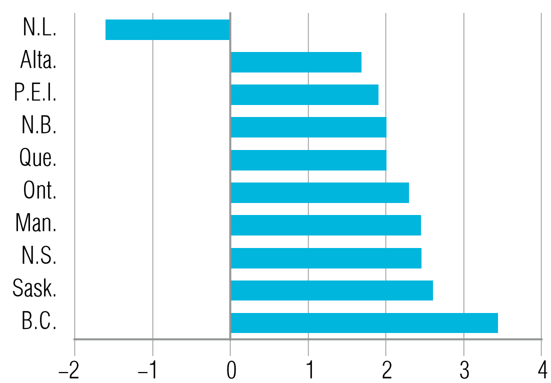
Regionally, British Columbia, Manitoba, Prince Edward Island, and Ontario will be the leaders in real GDP growth this year and the only provinces with growth of 2 per cent or more. (See Chart 1.) In 2016 (see Chart 2), while the economy is fairly stable in Manitoba despite the more volatile conditions in the resource sector, British Columbia will see the strongest real GDP growth in 2016. Recent developments have led us to include one major investment in B.C. (a liquefied natural gas [LNG] terminal) over the near term. (See Chart 2.)

Chart 1
Real GDP by Province, 2015
(percentage change*)



*based on 2007 $
Sources: The Conference Board of Canada; Statistics Canada.

Chart 2
Real GDP by Province, 2016
(percentage change*)



*based on 2007 $
Sources: The Conference Board of Canada; Statistics Canada.

PROVINCIAL ASSUMPTIONS

Newfoundland and Labrador's economy is not doing well. All key economic indicators are down in the first half of the year and weakness in the economy will persist for the next few years. The downturn in the economy is due to both cyclical and structural factors. The correction in oil, metal, and mineral prices is hurting production and investment decisions. But, even when the commodity market improves, the economy will fail to recover quickly. The aging of the population is going to hurt the ability of Newfoundland and Labrador—more than any other province in Canada—to generate the type of growth seen in the last decade. With a drop in employment, retail sales, and housing starts plus a large correction in the existing resale market, overall real GDP is not projected to grow at all in 2015 and to decline by 1.6 per cent in 2016. Some areas of the economy are expanding strongly, areas such as manufacturing where processing has begun at the Long Harbour hydromet plant.

While the economy in Canada is limping along, Prince Edward Island's seems to be in good health despite poor job creation. Following solid job gains between 2010 and 2013 (one of the strongest performances in the country), the Island's job market has stalled. Nevertheless, the economy is performing well on a number of fronts, particularly in the manufacturing and primary sectors. In addition, the retreat of the Canadian dollar should help tourism enjoy healthy growth and this will help the economy advance by 2.4 per cent in 2015 and 1.9 per cent in 2016.

Nova Scotia's economy is struggling to gain momentum and economic growth will be weaker this year than last. The new natural gas production from Encana's Deep Panuke offshore field was supposed to boost economic growth, but difficulties have hampered production to date as well as the production capacity of the field; this is weighing on growth. Aside from the petroleum industry, the economy appears to be gaining traction, mainly in the manufacturing and construction industries. However, the province has been unable to reverse a two-year trend in job creation and the job market will fail to generate any new jobs once again in 2015. The numbers are probably influenced by the downturn in the energy sector in the West; rotational workers who have lost their jobs there are counted in the workforce of their province of origin. Nevertheless, with work getting under way on the Arctic patrol vessels at Irving's newly expanded shipyard this fall, the economy should see real GDP growth accelerate from just 1.3 per cent in 2015 to 2.5 per cent in 2016.

In New Brunswick, the economic outlook is modest but much better than in recent years. Recovery in the job market remains elusive but a number of industries—such as manufacturers and industries in the forestry sector—are facing better growth prospects. The services sector should benefit from the more upbeat performance of the goods-producing sector that is helping to revive job creation and overall economic growth. New Brunswick's real GDP, after experiencing declines since 2011, is forecast to gain 1.4 per cent this year and 2 per cent in 2016.

Quebec's economic performance is being pulled down by the large contraction in exports. It will be difficult for the province's economy to gain sufficient momentum in the latter half of the year to boost economic growth to or above 2 per cent. With consumer demand that is still fairly strong, overall economic growth of 1.9 per cent is expected for 2015, a modest performance but one that still outpaces the national growth rate of just 1.6 per cent. While exports are projected to improve going forward, the aerospace industry will feel the effects of a weaker demand for business jets and the thousands of layoffs announced by Bombardier earlier this year. With stronger U.S. economic growth forecast for 2016, business investment should slowly pick up with positive growth in both non-residential and machinery and equipment investment. A number of large projects, mainly in the mining sector, could go ahead in the next few years if conditions improve; however, until then, investment in the province is forecast to advance only modestly. In 2016, the overall Quebec economy will maintain the same pace as this year, with a projected growth of 2 per cent. Fiscal restraints will continue to curb government expenditures on both programs and infrastructure. In addition, the housing market is weakening and is not expected to contribute positively to the economy.

In Ontario, the economy got off to a slow start this year as real exports fell 2 per cent in the first quarter and are very likely to contract in the second quarter as well. Ontario's disappointing trade performance will moderate its overall growth projections in 2015 to 2 per cent. Most of this growth will be concentrated in the second half of the year. The positive momentum will carry over to 2016 when real GDP is forecast to expand by 2.3 per cent. While the trade sector has faced challenges, the domestic economy in general is holding strong. Consumer demand will benefit from the sound job creation and stronger growth in household disposable income. While there are concerns of overbuilding in Toronto's condo market, the housing sector (both new and resale markets) remains very strong.

If job creation is any indication, Manitoba's economy is on solid ground. Employment is forecast to grow by 1.7 per cent in 2015 and 1.4 per cent in 2016. Real GDP growth is expected to rise by 2.4 per cent in 2015 and 2.5 per cent in 2016, keeping the province among the provincial growth leaders. Steady gains are forecast in manufacturing, agriculture, and construction.

Manitoba is not facing the same pressures in the agriculture sector as are neighbouring Saskatchewan and Alberta.

Saskatchewan, along with Alberta, will face negative real GDP growth this year. The correction in oil prices has hurt the economy and now drought conditions will hamper crop yields. Overall, real GDP growth is expected to contract by 0.2 per cent in 2015 but, if the wheat harvest is more affected than expected by the adverse weather, the decline in real GDP could be steeper. The economic outlook should be stronger in 2016 as we do not foresee another major correction in the oil industry. Sound growth is also forecast for uranium and potash production and for the construction industry. All things considered, Saskatchewan's economy is projected to rebound by 2.6 per cent in 2016.

With the swift slide in crude oil prices, Alberta's economy was bracing for difficult times and it has not been smooth sailing for the province so far this year. Support activities for mining and oil and gas extraction shrank significantly over the winter drilling season as rigging and drilling services retreated by close to 35 per cent. As well, petroleum companies have announced staff layoffs and cuts to their capital plans to expand the energy sector. Employment growth is still positive but much weaker than in previous years. There is nothing more unpredictable than commodity prices, and low oil prices could likely last all of next year. The current global oversupply of oil remains a dominant factor influencing oil prices. Nonetheless, there should be more stability in the Alberta economy in 2016 and we anticipate that overall real GDP will advance by 1.7 per cent next year, following a 1 per cent decline in 2015.

There are new developments in the natural gas industry. British Columbia recently passed legislation to enter into an agreement with Petronas to build the Pacific NorthWest LNG export terminal near Prince Rupert. The project would rival the large megaprojects in Alberta's oil sands and would be the largest private investment in the province's history. If all conditions are met, construction on this first multi-billion-dollar LNG terminal could start in 2016. Meanwhile, British Columbia has been enjoying solid economic growth; no other province is facing such enviable prospects.

The provincial economy is expected to advance by a solid 2.8 per cent in 2015 and by 3.4 per cent in 2016. The housing market remains hot with both new and resale markets making robust gains this year. The job market is performing well and consumers are expected to boost retail sales by a robust 7.3 per cent this year despite falling gasoline prices. Manufacturing should see a strong performance, benefiting from the rebounding U.S. economy, the lower Canadian dollar, and new shipbuilding work at North Vancouver's Seaspan shipyard for non-combat vessels.

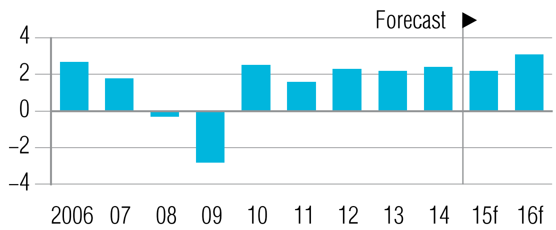
U.S. OUTLOOK

The U.S. economy stumbled badly in the first quarter as real GDP declined. Fortunately, the economy performed better in the second quarter, as evidenced by the encouraging employment reports for May and June. However, the strong value of the greenback, among other factors, continues to restrain growth somewhat and it is only now, in the second half of the year, that economic growth is likely to hit the 3 per cent range. The weakness in the economy in the first quarter will likely delay interest rate increases until the fall, depending on how events unfold over the next few months. We expect real GDP to expand by 2.2 per cent for this year as a whole and to grow by 3.1 per cent in 2016. (See Chart 3.)

As noted, the U.S. economy slumped in the first quarter of this year. While a number of temporary factors, such as winter storms and a labour strike (now settled) at West Coast ports did hurt export growth, it would be misleading to blame the weakness in the U.S. economy on just temporary factors. Investment in energy projects is declining quickly, while the higher value of the U.S. dollar has hurt export and manufacturing activity.

In the first part of 2015, the negative effects of lower oil and gasoline prices outweighed the positives for the U.S. economy. Real investment in non-residential structures, which captures the bulk of energy investment, was down 21 per cent (at annual rates) in the first quarter, and the another decline is anticipated for the second quarter. Rig counts have dropped by more than 50 per cent since last November—evidence of the impact that world oil prices in the US$50 to US$60 range are

Chart 3
U.S. Economy Disappoints but the Outlook Is Robust
(U.S. real GDP, percentage change*)



*based on 2005 US$
f = forecast
Sources: The Conference Board of Canada; U.S. Bureau of Economic Analysis (BEA).

having on this sector of the economy. However, no large correction is foreseen in energy investment in the second half of this year. Therefore, with energy investment no longer falling, overall investment in non-residential construction should expand at a slightly positive pace in the second half of this year and by 3.2 per cent in 2016.

The supposed positive effect on household spending attributable to sharply lower gasoline prices failed to materialize as many households increased their savings. During past periods of tumbling gasoline prices, it has always taken some time before Americans started to spend the money they saved from lower gasoline prices; this time is no different. However, we do expect consumer spending to increase at a faster clip in the second half of this year as households finally respond to lower prices at the pump and ramp up their purchases of goods and services. Real consumer spending is forecast to increase by 3.1 per cent this year and 3.3 per cent in 2016.

The anticipated rebound in household spending is readily apparent from the latest vehicle sales data. In May, car sales surged to 17.8 million units (seasonally adjusted at annual rates), up from 16.5 million in April. And, although the gain was weaker in June, this was widely projected, given the surge in sales in May. While some of the increase in car sales is linked to the catch-up effect following the harsh winter, there are other factors boosting sales. Labour markets are improving to the point where wages are finally starting to post some meaningful gains. In the first six months of this year, the economy created jobs at an average monthly pace well above 200,000. Also, lenders are more receptive to providing credit for more risky borrowers, while financing terms have maintained vehicle affordability at high levels.

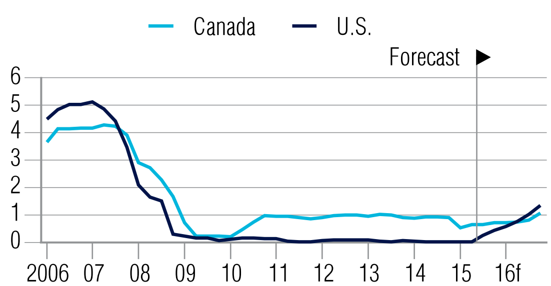
We expect the U.S. Federal Reserve to increase interest rates this autumn for the first time since 2006, as monetary authorities are confident that the economy is strong enough to handle higher rates. But future interest rate increases are projected to be modest. The Fed remains concerned about some pockets of weakness in the economy, such as the number of long-term unemployed.

MONETARY POLICY

The rapid fall in oil prices over the second half of 2014 and early 2015 drove year-over-year price growth in many countries into negative territory. As the impact of the energy price decline fades, inflation is set to return. While price growth did not turn negative in Canada, it has been restrained so far this year by the large drop in oil prices. Changes in energy prices directly affect the gasoline and fuel oil components of the consumer price index (CPI) and indirectly affect inflation through their impact on economic growth. Weak economic growth means sluggish demand, and this has helped to keep price pressures from building in the first part of this year. On the other hand, the drop in oil prices triggered a depreciation of the Canadian dollar, which is making imported goods more expensive and is adding to current price growth. Overall, headline inflation remains weak, posting growth of 1 per cent in June, while core inflation grew at a 2.1 per cent pace.

In the near term, we expect that the impact of higher import prices will continue to offset weakness stemming from sluggish demand and, therefore, that core inflation will remain at or above 2 per cent over the forecast period. However, aside from transitory impacts (such as those from exchange rate pass-through), the main factor influencing growth in trend prices is the output gap. The output gap is the difference between Canada's estimated potential and its actual output and, when the gap is negative, the economy can grow above its potential without igniting inflationary pressures. The contraction in real GDP growth in the first quarter widened the output gap but, with growth resuming in the second half of this year, the gap will continue to shrink and will fall below 1 per cent in early 2016. The steady decline in the output gap will eventually lead to inflationary pressures, but the Bank of Canada is expected to be patient about raising rates to ensure that any hikes do not derail the economic recovery. Our forecast assumes that monetary authorities will delay raising rates until at least September 2016. It also assumes that the divergence in policy between the Bank of Canada (which cut its key rate another quarter point on July 15) and the U.S. Federal Reserve (which is expected to raise rates before the end of this year) will keep the loonie around US$0.80 until the second half of next year despite a slow and steady rise in oil prices. (See Chart 4.)

Chart 4
Rate Hike in the U.S. to Take Place Sooner Rather Than Later
(U.S. and Canadian three-month T-bills spread, per cent)



f = forecast
Sources: The Conference Board of Canada; Bank of Canada.

FISCAL OUTLOOK

The economy will not get much of a boost from the government sector over the forecast period. For years, most provinces—and Canada as a whole—have been waiting for a strong post-recession bounce-back in economic growth. However, with Canada's potential output growth slowing due to an aging population and lacklustre investment outside of the energy sector, we are no longer forecasting a substantial rebound in economic growth. Indeed, annual real GDP growth is not expected to exceed 2.3 per cent at any point over the next five years. This slowdown in GDP growth is moderating gains in government revenues and forcing governments to slow the pace of their spending in order to avoid a return to deficit or a sharp increase in their ongoing deficits. Despite weak spending on goods and services, total public spending looks to improve over the next few years, due mostly to a modest increase in infrastructure investment. After declining last year, real public consumption and investment spending is set to grow by a modest 0.8 per cent this year, followed by an increase of 0.9 per cent in 2016.

Most provinces are still running deficits and the federal government is expecting only small surpluses, which are predicated on continued spending restraint. For the federal government to meet its budget targets, it must continue to tightly control spending. When inflation is taken into account, federal spending on goods and services has declined in each of the last four years. And declines are anticipated again this year and in 2016. This restraint should allow the federal government to post small surpluses (unadjusted for contingency amounts) of $2.7 billion this fiscal year and $3.2 billion in fiscal 2016–17.

While the federal government looks able to handle the lower revenue outlook without returning to deficit, the provincial governments are not in as strong a fiscal position and they will have difficulty coping with this lower growth environment. Most of the provinces have tabled their 2015 budgets, and the outlook for this fiscal year is sobering. After posting a collective deficit of $13.7 billion in fiscal 2014–15, the collective provincial deficit is set to widen to $15 billion this fiscal year. Going forward, the provinces are facing slower-than-average revenue growth, a drop in resource royalties, and a growing demand for provincially funded services—a combination that will make it difficult for them to return to surplus any time soon.

Marie-Christine Bernard

Une autre année difficile

Aperçu

- L'économie canadienne n'a pas inscrit de bons résultats dans les premiers mois de l'année et elle frôle la récession, mais la croissance sera plus forte d'ici la fin de 2015 et aussi en 2016.
- Le secteur du commerce extérieur a connu un début d'année difficile, si bien que les prévisions économiques du Québec et de l'Ontario pour 2015 ont été révisées à la baisse.
- La Saskatchewan, comme l'Alberta, subira une contraction de son économie, car le mauvais temps y perturbe les récoltes et la correction des prix du pétrole porte un dur coup au secteur de l'énergie.
- Après des années de faible croissance et de pertes d'emploi, les perspectives économiques du Nouveau-Brunswick et de la Nouvelle-Écosse sont meilleures à court terme.

VUE D'ENSEMBLE NATIONALE

L'économie canadienne s'est légèrement contractée dans les quatre premiers mois de l'année, accusant un déficit commercial quasi record en mai, et s'est nettement ressentie des incertitudes planant sur la zone euro. Cela porte à croire que l'économie aura difficilement pu progresser au deuxième trimestre et, de plus en plus, que le Canada pourrait se trouver en récession. Les données des quatre premiers mois, celles dont nous disposons pour 2015, montrent que le produit intérieur brut (PIB) a diminué pendant ces mois sous l'effet combiné de la baisse des prix réduits du pétrole et des perturbations d'origine étrangère, notamment la crise de la dette grecque. Nous croyons que les statistiques montreront que la croissance économique aura avoisiné le zéro au deuxième trimestre, l'économie frôlant la récession. Mais tout n'est pas si négatif. Ainsi, même si 6400 postes ont disparu en juin, 16 000 emplois se sont créés en moyenne par mois durant les six premiers mois de l'année. Il ne s'agit pas d'une forte progression de l'emploi, mais quand même d'une évolution positive, supérieure à celle observée généralement en 2014. De plus, les gains sont faits dans les emplois à temps plein et ils compensent amplement les pertes inscrites dans les emplois à temps partiel. Enfin la croissance des revenus de travail s'est améliorée en mai et juin et devrait s'intensifier quelque peu à court terme. Par conséquent, si le Canada est en récession, nous estimons que cela sans grande ampleur puisque la croissance sera plus importante dans les mois qui viennent. Néanmoins, compte tenu d'un lent début d'année, nous prévoyons que la croissance sera de 1,6 % à peine en 2015, le résultat le plus faible depuis 2009.

Les investissements des entreprises seront le maillon faible de l'économie canadienne en 2015. Le baril de pétrole a vu son prix dégringoler à la fin de 2014 et il était à moins de 50 $ US à la fin juillet de cette année. Avec des bénéfices et des flux de trésorerie en recul, les sociétés pétrolières ont réagi en réduisant de 15 % leurs projets d'ingénierie et d'exploration minière au premier trimestre. Pour l'ensemble de 2015 et 2016, nous estimons que ces entreprises réduiront de près du tiers leurs budgets d'immobilisations. Or, puisque les investissements dans le secteur pétrolier et gazier représentent le tiers, ou à peu près, de l'ensemble des investissements canadiens des entreprises, ces décisions auront des conséquences considérables dans toute l'économie.

Même ailleurs que dans le secteur énergétique, les entreprises hésitent à investir. Les achats de matériel et d'outillage ont beaucoup diminué au premier trimestre et, selon le récent sondage de Statistique Canada sur les intentions d'investir, ces baisses devraient se poursuivre toute l'année. Ce sondage révèle que les entreprises comptent réduire de 5,2 % leurs achats de matériel et d'outillage cette année, une réduction plus marquée que ce que nous avions prévu. Et vu l'érosion importante du huard (la perte de valeur rend le matériel et l'outillage importés plus chers), les perspectives d'investissement sont peu reluisantes. La construction d'immeubles devrait elle aussi chuter de façon importante en 2015. Et même si la construction n'a pas augmenté l'an dernier et qu'un recul marqué a été observé au premier trimestre, le taux d'inoccupation est à son plus haut niveau depuis 2005. Les permis de bâtir, un indicateur clé de l'industrie de la construction, étaient en baisse de près de 15 % en mai par rapport à mai l'an dernier, ce qui confirme notre perception quant au ralentissement de l'activité dans le secteur de la construction.

En dépit d'importantes économies à la pompe et des réductions d'impôt au palier fédéral, la croissance des dépenses réelles des ménages devrait elle aussi diminuer cette année. La croissance léthargique de l'emploi, et particulièrement la faible progression des salaires, le fort endettement des ménages et le ralentissement du marché immobilier s'ajouteront aux pertes d'emploi dans les provinces riches en pétrole pour tempérer quelque peu les dépenses de consommation en 2015.

En outre, les dépenses publiques contribueront assez peu à l'essor économique, au mieux. Nous entrevoyons une augmentation des dépenses en infrastructures, mais elle sera mince, car même avant la chute des prix du pétrole, le gouvernement fédéral et les provinces disaient vouloir sérieusement continuer à limiter les dépenses courantes. Et maintenant, les cours du pétrole agissant de façon négative sur la croissance des revenus, il faut s'attendre à de plus importantes mesures de restriction des dépenses.

Le seul secteur où l'on s'attend à une forte croissance cette année, c'est celui du commerce extérieur; mais là aussi la prudence est de mise. Les résultats dont on dispose en matière de commerce sont décevants, les exportations de marchandises accusant une baisse après les cinq premiers mois de l'année. En mai, elles étaient inférieures de 6,7 % par rapport à un an auparavant. Même si le dollar canadien demeure faible (ce qui devrait stimuler le commerce), l'économie américaine a amorcé l'année 2015 au ralenti, le mauvais temps et un conflit de travail dans les ports de la côte Ouest freinant nettement l'activité économique du pays au premier trimestre. Heureusement, l'économie américaine montre déjà des signes de reprise et la hausse de l'activité aux États-Unis d'ici la fin de 2015, puis en 2016, devrait profiter au secteur canadien du commerce extérieur.

En raison de la modeste croissance économique que nous prévoyons, nous croyons que seulement 150 000 emplois s'ajouteront cette année, un bilan de nouveau décevant après celui de 2014, alors que l'embauche fut la plus faible depuis 2009. La croissance de l'emploi devrait s'accélérer en 2016, avec la création de 192 000 postes. Cette année, le taux de chômage grimpera jusqu'à 7 % au quatrième trimestre, puis il redescendra à 6,8 % d'ici la fin de 2016. Même si la conjoncture est moins favorable que ce à quoi nous nous y attendions, nous croyons que la Banque du Canada ne réduira plus les taux d'intérêt après la baisse d'un quart de point de pourcentage annoncée le 15 juillet, et qu'elle commencera à relever les taux vers la fin de 2016, à la faveur d'une économie plus forte. Nous prévoyons une croissance économique de 2,1 % en 2016.

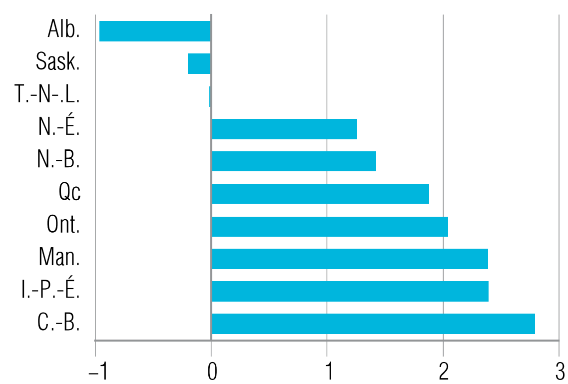
VUE D’ENSEMBLE PROVINCIALE

Alors que l’économie de l’Alberta connaissait des ratés dus au recul des prix du pétrole, tous les yeux et les espoirs se tournaient vers le Canada central, là où un dollar canadien plus faible et l’amélioration de la conjoncture américaine devaient donner de l’élan à l’économie de l’Ontario et du Québec. Mais, après un semestre, les prévisions économiques de presque toutes les provinces ont été revues à la baisse. Le regain économique du Canada central sera moins marqué qu’on l’imaginait, car les exportations n’ont pas évolué au même rythme qu’en 2014. Depuis le début de l’année, divers facteurs, certains temporaires, d’autres plus structuraux, ont nui aux exportateurs du cœur manufacturier canadien.

Les difficultés que connaît le secteur pétrolier auront de sérieux effets sur l’économie de l’Alberta, de la Saskatchewan et de Terre-Neuve-et-Labrador. Et comme un malheur ne vient jamais seul, la sécheresse qui sévit dans l’Ouest nuira aux récoltes, ce qui limitera encore la croissance économique. Si la faiblesse de l’économie canadienne, depuis le début de l’année, découle de la correction dans le secteur de l’énergie, la croissance économique ailleurs que dans l’énergie se fait attendre. Le secteur de l’extraction de minerais métalliques va mal; il est en proie à des turbulences alors que la fin du boom des produits de base entache les perspectives de croissance. La plupart des projets du secteur minier se butent à des problèmes de financement; on en reste souvent au stade de l’élaboration, sans atteindre celui de l’exploitation. C’est même le cas de projets dont la planification est assez avancée. Ce climat a fortement plombé les perspectives du secteur minier pour les prochaines années. En outre, les investissements des entreprises demeurent en général au ralenti dans plusieurs provinces depuis le début de l’année. Certes, la conjoncture économique est loin d’être emballante et ne s’améliore que lentement dans le Canada central et la région de l’Atlantique, mais nous ne croyons pas qu’il en sera ainsi jusqu’à la fin de l’année. En fait, nous prévoyons des résultats économiques plus normaux dans la plupart des provinces dans les mois qui viennent et aussi en 2016, puisque la conjoncture se stabilisera dans l’Ouest canadien et parce que le redressement de l’économie américaine éclairera les perspectives commerciales du Canada central.

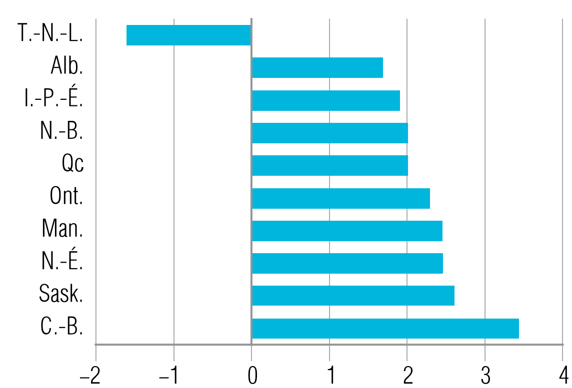
Sur le plan régional, la Colombie-Britannique, le Manitoba, l’Île-du-Prince-Édouard et l’Ontario connaîtront la meilleure croissance du PIB réel cette année, étant les seules provinces à inscrire un gain de 2 % ou plus (voir graphique 1). En 2016, si l’économie du Manitoba se montrera plutôt stable en dépit de conditions plus variables dans le secteur des ressources; c’est la Colombie-Britannique qui affichera la plus forte croissance du PIB réel. De récents développements nous ont amenés à inclure un investissement de grande envergure en C.-B. (un terminal de gaz naturel liquéfié) dans nos prévisions de court terme (voir graphique 2).

Graphique 1
PIB réel des provinces, 2015
(variation en %*)



*dollars de 2007
Sources : Le Conference Board du Canada; Statistique Canada.

Graphique 2
PIB réel des provinces, 2016
(variation en %*)



*dollars de 2007
Sources : Le Conference Board du Canada; Statistique Canada.

HYPOTHÈSES PROVINCIALES

L'économie de Terre-Neuve-et-Labrador est en difficulté. Tous les indicateurs économiques clés sont en baisse pour le premier semestre de 2015 et les faiblesses en cause joueront encore quelques années. Le ralentissement économique s'explique tant par des facteurs cycliques que structuraux. La correction des cours du pétrole, des métaux et des minéraux influe sur les décisions des producteurs et des investisseurs. Et même quand le marché des produits de base prendra du mieux, l'économie mettra du temps à se redresser. Le vieillissement de sa population limitera la capacité de Terre-Neuve-et-Labrador, plus que celle de toute autre province canadienne, à générer une croissance semblable à celle de la dernière décennie. En raison d'un recul de l'emploi, des ventes au détail et des mises en chantier, ainsi que d'une importante correction du marché de la revente, le PIB réel global ne devrait pas progresser du tout en 2015 et il devrait diminuer de 1,6 % en 2016. Certains pans de l'économie progressent rapidement, notamment l'activité manufacturière puisque la transformation a commencé aux installations hydrométallurgiques de Long Harbour.

Si l'économie canadienne est vacillante, celle de l'Île-du-Prince-Édouard semble avancer d'un bon pas même si peu d'emplois y sont créés. En effet, après une forte création d'emplois entre 2010 et 2013 (l'une des meilleures performances au pays), le marché du travail de l'Île s'est figé. Mais l'économie affiche quand même de bons résultats sur plusieurs tableaux, surtout dans le secteur manufacturier et le secteur primaire. De plus, la baisse du dollar canadien devrait aider l'industrie touristique à connaître une belle croissance, un apport qui permettra à l'économie de progresser de 2,4 % en 2015, puis de 1,9 % en 2016.

L'économie de la Nouvelle-Écosse peine à prendre son élan et cette année, la croissance économique y sera moindre que l'an dernier. La nouvelle production de gaz naturel du gisement en mer Deep Panuke d'Encana devait engendrer un essor économique, mais diverses difficultés ont jusqu'ici gêné les opérations et réduit la capacité de production du site. La croissance s'en trouve compromise. Ailleurs que dans l'industrie pétrolière, l'économie semble se solidifier, surtout l'industrie manufacturière et la construction. Mais la province n'est pas parvenue à renverser la tendance négative des deux dernières années dans l'embauche et le marché de l'emploi n'avancera pas encore en 2015. Le ralentissement du secteur de l'énergie dans l'Ouest a probablement un effet défavorable; les travailleurs en affectation par roulement ayant perdu leur poste dans l'Ouest sont en effet inclus dans la main-d'œuvre de leur province d'origine. Quand même, avec le début cet automne des travaux de construction de patrouilleurs pour l'Arctique aux chantiers d'Irving récemment agrandis, la croissance du PIB réel devrait grimper de 1,3 % seulement en 2015 et de 2,5 % en 2016.

Au Nouveau-Brunswick, les perspectives économiques sont modestes, mais bien meilleures que ces dernières années. La reprise du marché de l'emploi est mince sauf que bon nombre de secteurs, comme les fabricants et autres entreprises du secteur forestier notamment, voient le vent souffler dans la bonne direction. Le secteur des services devrait profiter de l'accélération de la production de biens, un phénomène qui relance la création d'emplois et la croissance économique dans l'ensemble. Après des reculs successifs depuis 2011, le PIB réel du Nouveau-Brunswick devrait progresser de 1,4 % cette année, puis de 2 % en 2016.

Les résultats économiques du Québec sont plombés par une importante diminution des exportations. L'économie québécoise aura du mal à s'animer suffisamment en seconde moitié d'année pour que la croissance économique atteigne les 2 %, ou les dépasse. La demande de consommation étant encore assez forte, une croissance économique totale de 1,9 % est prévue pour 2015; il s'agit d'un rendement modeste, mais supérieur à la moyenne nationale d'à peine 1,6 %. Si les exportations devraient s'intensifier au fil des mois, l'industrie aérospatiale se ressentira du recul de la demande à l'égard des jets d'affaires et des milliers de mises à pied annoncées plus tôt cette année chez Bombardier. En 2016, la croissance de l'économie américaine se faisant plus vive, les investissements des entreprises devraient augmenter lentement, évoluant positivement à la fois dans le secteur non résidentiel ainsi que dans le matériel et l'outillage. Divers grands projets devraient se concrétiser dans les années qui viennent, surtout dans le secteur minier, si la conjoncture s'améliore, mais d'ici là les investissements progresseront assez peu dans la province. En 2016, dans l'ensemble, l'économie du Québec évoluera au même rythme que cette année, donc de 2 %, selon nos prévisions. Des restrictions budgétaires limiteront encore les dépenses du gouvernement en matière de programmes et d'infrastructures. En outre, le marché de l'habitation s'affaiblit et ne devrait pas offrir un apport positif au bilan économique.

L'économie ontarienne a connu un lent début d'année. Les exportations ont baissé de 2 % au premier trimestre et semblent bien avoir encore diminué au deuxième trimestre. Les résultats décevants de l'Ontario au tableau du commerce extérieur limiteront sa croissance globale à 2 %, selon les projections. Le gros de la croissance surviendra en seconde moitié d'année. L'élan alors acquis se poursuivra en 2016, année où le PIB réel devrait gagner 2,3 %. Si le secteur du commerce extérieur a rencontré des défis, l'économie intérieure demeure en général forte. La demande des consommateurs évoluera favorablement en réaction à une bonne création d'emplois et à une croissance accrue du revenu disponible des ménages. Le marché de la copropriété de Toronto peut susciter l'inquiétude en raison d'un surplus de construction, mais le secteur de l'habitation (le neuf comme la revente) demeure très fort.

À en juger par la création d'emplois, l'économie du Manitoba est bien en selle : on y prévoit une progression de l'emploi de 1,7 % en 2015, puis de 1,4 % en 2016. Le PIB réel devrait croître de 2,4 % en 2015 et de 2,5 % en 2016, ce qui classera encore la province parmi les leaders au palmarès de la croissance. Des gains constants sont attendus dans l'activité manufacturière, l'agriculture et la construction. Le Manitoba n'est pas soumis aux mêmes pressions que ses voisines, la Saskatchewan et l'Alberta, pour ce qui est de la production agricole.

La Saskatchewan, comme l'Alberta, affichera une évolution négative de son PIB réel cette année. La correction des prix du pétrole a porté un dur coup à l'économie et la sécheresse perturbera le rendement des cultures. Ainsi, le PIB réel devrait reculer de 0,2 % en 2015, mais ce repli pourrait être plus prononcé si les récoltes de blé sont plus touchées qu'on le croyait par les conditions climatiques peu clémentes. Les perspectives économiques devraient être meilleures en 2016, car nous ne prévoyons pas d'autre forte correction dans l'industrie pétrolière. Une bonne progression est aussi prévue dans la production d'uranium et de potasse, de même que dans la construction. Tout compte fait, l'économie de la Saskatchewan devrait inscrire un gain de 2,6 % en 2016.

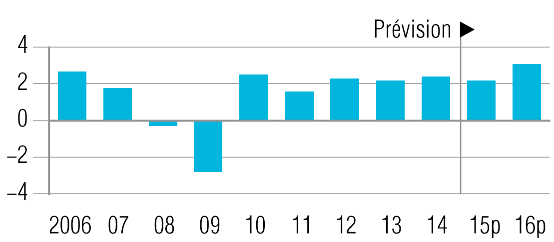
Avec la descente rapide des prix du pétrole brut, des moments douloureux s'annonçaient pour l'économie de l'Alberta; les choses n'ont pas été faciles pour la province depuis le début de l'année. Les activités de soutien à l'exploitation minière et à l'extraction de pétrole et de gaz ont considérablement diminué durant la saison de forage hivernal; les services de forage ont fléchi de quelque 35 %. De plus, les pétrolières ont annoncé des mises à pied et des réductions de leurs plans d'immobilisations dans le secteur énergétique. L'emploi continue de progresser, mais bien moins que ces dernières années. Rien n'est plus difficile à prévoir que les cours des produits de base et il est probable que les prix du pétrole demeureront bas toute l'année prochaine. L'actuel surplus de pétrole constitue encore un facteur clé dans l'établissement des prix du pétrole. Néanmoins, l'économie albertaine devrait se stabiliser un peu en 2016 et nous prévoyons que le PIB réel de la province augmentera de 1,7 % en 2016, après avoir cédé 1 % en 2015.

Du nouveau dans l'industrie du gaz naturel : la Colombie-Britannique vient de légiférer afin de conclure avec Petronas un accord pour construire le terminal d'exportation de GNL Pacific NorthWest, près de Prince Rupert. Ces installations, qui feraient concurrence aux mégaprojets des sables bitumineux de l'Alberta, représenteraient le plus important investissement privé de l'histoire de la province. Si toutes les conditions sont réunies, la construction de ce premier terminal de GNL, un projet de plusieurs milliards de dollars, pourrait s'amorcer en 2016. En même temps, la Colombie-Britannique affiche une bonne croissance économique. Aucune autre province n'offre des perspectives aussi avantageuses. L'économie de la province devrait progresser fortement, soit de 2,8 % en 2015, puis de 3,4 % en 2016. Le marché de l'habitation reste fébrile, tant pour ce qui est des marchés du neuf que de la revente, qui seront en forte hausse cette année. Le marché de l'emploi va bien et les consommateurs devraient faire grimper les ventes au détail de 7,3 % cette année, même si les prix de l'essence ont baissé. L'industrie manufacturière devrait inscrire de bons résultats, tirant profit du regain de l'économie américaine, de la faiblesse du dollar canadien et des travaux de construction de navires non destinés au combat au chantier Seaspan de North Vancouver.

PERSPECTIVES AMÉRICAINES

L'économie américaine a connu des ratés au premier trimestre, ce qui a fait reculer le PIB réel du pays. Heureusement, l'économie s'est ressaisie au trimestre suivant, comme l'indiquent des données encourageantes sur l'emploi pour les mois de mai et du juin. La force du dollar, ainsi que d'autres facteurs, continue toutefois à peser sur la croissance, et ce n'est que maintenant, en deuxième moitié d'année, que la croissance économique s'apprête à atteindre les 3 %. Le faible rendement économique du premier trimestre reportera vraisemblablement la hausse des taux d'intérêt à l'automne, tout dépendant des événements des prochains mois. Nous croyons que le PIB réel gagnera 2,2 % sur l'ensemble de 2015 et 3,1 % en 2016 (voir graphique 3).

Graphique 3
L'économie américaine déçoit, mais les perspectives sont bonnes
(PIB réel des États-Unis; variation en %*)



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*en dollars US de 2005
Sources : Le Conference Board du Canada; U.S. Bureau of Economic Analysis (BEA).

Ce fléchissement de l'économie américaine au premier trimestre résulte notamment d'un certain nombre de facteurs temporaires, comme des tempêtes hivernales et une grève (maintenant terminée) d'employés de ports de la côte Ouest, qui ont nui aux exportations. On aurait cependant tort de n'attribuer qu'à des facteurs temporaires cette piètre performance économique, car les investissements dans les projets énergétiques diminuent rapidement et la force du dollar ralentit les exportations et les activités manufacturières.

Au début de cette année, les effets négatifs de la baisse des prix du pétrole et de l'essence ont excédé les aspects positifs pour l'économie américaine. Les investissements réels dans les structures non résidentielles, secteur où se réalisent la majeure partie des investissements relatifs à l'énergie, chutaient de 21 % (taux annuel) au premier trimestre, et on s'attend à un autre repli au deuxième trimestre. Le nombre de puits actifs a reculé de plus de 50 % depuis novembre. Cela illustre comment ce secteur de l'économie est touché par le prix mondial du pétrole, qui se négocie entre 50 et 60 $ US le baril. Cela dit, nous ne prévoyons pas d'autre correction sévère des investissements liés à l'énergie dans la seconde moitié de l'année. Puisque les investissements dans les énergies cesseront de reculer, l'ensemble des investissements dans les constructions non résidentielles devrait croître modérément pendant la seconde moitié de 2015, gagnant 3,2 % en 2016.

La baisse marquée des prix de l'essence aurait pu avoir un effet positif sur les dépenses des ménages, mais cela n'a pas eu lieu, car bon nombre d'entre eux ont plutôt choisi d'épargner davantage. Lorsque le prix de l'essence baisse, il faut toujours attendre un moment avant de voir les Américains dépenser l'argent que cela leur a fait épargner, et c'est ce qui se produit en ce moment. Nous estimons toutefois que les dépenses des ménages augmenteront plus rapidement dans la deuxième moitié de l'année, lorsque ces derniers réagiront finalement aux économies réalisées à la pompe en achetant plus de biens et de services. Les dépenses de consommation réelles devraient progresser de 3,1 % cette année et de 3,3 % l'an prochain.

Le rebond attendu des dépenses des ménages s'observe déjà dans les dernières données sur les ventes de véhicules. En mai, les ventes de voitures ont grimpé à 17,8 millions d'unités (taux annuel désaisonnalisé), par rapport à 16,5 millions en avril. Les gains étaient moindres en juin, mais cela était facile à prévoir vu la flambée du mois de mai. Si une partie des ventes de véhicules est attribuable à l'effet de rattrapage suivant le rude hiver, d'autres facteurs ont motivé les acheteurs. Les marchés de l'emploi s'activent, si bien que les salaires commencent enfin à augmenter de façon significative. Dans les six premiers mois de 2015, c'est bien au-delà de 200 000 emplois qui ont été créés chaque mois, en moyenne. De plus, les créanciers prêtent plus facilement aux emprunteurs plus à risque, tandis que les modalités de financement ont gardé les véhicules à des prix très abordables.

Nous croyons que la Réserve fédérale américaine haussera son taux d'intérêt cet automne, une première depuis 2006, les autorités monétaires estimant alors que l'économie est suffisamment solide pour composer avec des taux plus élevés. Les hausses de taux à venir seront toutefois modestes. Quelques maillons faibles de l'économie, comme le chômage chronique, continuent de préoccuper la Réserve fédérale.

POLITIQUE MONÉTAIRE

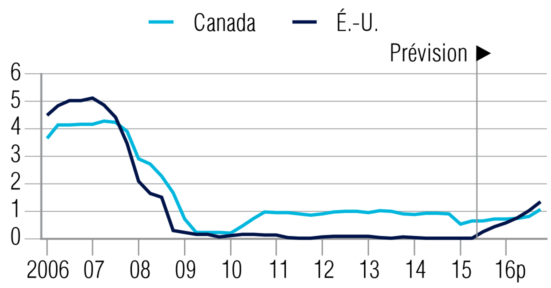
Vu la chute précipitée des cours du pétrole survenue en deuxième moitié de 2014 et au début de 2015, les prix se sont trouvés à augmenter moins qu'un an auparavant dans beaucoup de pays. Mais comme l'effet du recul des prix de l'énergie s'estompe, l'inflation pourrait reprendre. La croissance des prix n'a pas été négative au Canada, mais elle a été limitée depuis le début de l'année par la chute des prix du pétrole. Les variations des prix de l'énergie influent directement sur les composantes « essence et mazout » de l'indice des prix à la consommation (IPC) et indirectement sur l'inflation par leur effet sur la croissance économique. Lorsque la croissance économique est faible, la demande l'est aussi, et c'est ce qui a empêché les prix de monter au début de l'année. À l'opposé, la chute des prix du pétrole a fait perdre de la valeur au huard, ce qui fait augmenter le coût des importations et favorise la progression des prix. Dans l'ensemble, l'inflation totale reste faible, avec une avancée de 1 % en mai, tandis que l'inflation de base a progressé de 2,1 %.

Nous croyons qu'à court terme, l'effet de la hausse des prix à l'importation continuera de combler le manque causé par la faible demande. Ainsi, l'inflation de base restera à au moins 2 % pendant la période prévisionnelle. Mais, outre les répercussions temporaires (comme celles des variations du taux de change), le principal facteur derrière la croissance des prix sera l'écart de production. Cet écart équivaut à la différence entre la production potentielle estimée et la production réelle du Canada; lorsqu'il est négatif, l'économie peut croître au-delà de son potentiel sans exercer de pression inflationniste. La contraction du PIB réel du premier trimestre a creusé cet écart de production, mais lorsque la croissance reprendra dans la deuxième moitié de l'année, l'écart continuera de se refermer et sera de moins de 1 % au début de 2016. La réduction soutenue de l'écart de production entraînera des pressions inflationnistes, mais on s'attend à ce que la Banque du Canada se garde de hausser son taux trop rapidement, pour éviter de nuire à la reprise économique. Selon nos prévisions, les autorités monétaires attendront au moins jusqu'en septembre 2016 pour hausser leurs taux. De plus, la différence entre les politiques de la Banque du Canada (qui a encore baissé son taux directeur d'un quart de point le 15 juillet) et celles de la Réserve fédérale américaine (qui devrait hausser son taux avant la fin de l'année) maintiendra le huard autour des 0,80 $ US jusqu'à la deuxième moitié de 2016 malgré une lente, mais constante remontée du prix du pétrole (voir graphique 4).

PERSPECTIVES BUDGÉTAIRES

Le secteur gouvernemental ne stimulera pas vraiment l'activité économique durant la période de prévision. La plupart des provinces, ainsi que le Canada, espèrent depuis des années vivre un essor économique d'envergure faisant contrepoids à la récession. Mais comme la croissance de la production potentielle du Canada s'effrite en raison du vieillissement de la population et de la rareté des investissements ailleurs que dans le secteur de l'énergie, nous ne prévoyons plus un

Graphique 4
Des taux en hausse aux États-Unis plus tôt que tard
(écart des taux des bons du Trésor américain et canadien à 3 mois en %)



p = prévision
Sources : Le Conference Board du Canada; Banque du Canada.

rebond prononcé de la croissance économique. En fait, la croissance annuelle du PIB réel ne devrait pas dépasser 2,3 % dans les cinq prochaines années. Ce ralentissement de la croissance du PIB limite la progression des revenus du gouvernement et oblige les pouvoirs publics à freiner leurs dépenses afin d'éviter de se retrouver à nouveau en situation déficitaire, ou d'aggraver davantage leurs déficits actuels. Même si les dépenses en biens et services seront faibles, les dépenses publiques totales devraient s'accroître dans les années qui viennent, grâce surtout à une modeste augmentation des investissements dans les infrastructures. Les dépenses publiques réelles de consommation et d'investissement, en déclin l'an dernier, devraient augmenter un peu en 2015, soit de 0,8 %, puis de 0,9 % en 2016.

La plupart des provinces accusent encore des déficits et le gouvernement fédéral ne prévoit que de minces surplus, conditionnels au maintien des restrictions des dépenses. Si le gouvernement fédéral veut atteindre ses cibles budgétaires, il lui faut continuer de limiter sérieusement ses dépenses. Compte tenu de l'inflation, les dépenses fédérales en biens et en services ont diminué durant chacune des quatre dernières années. Des réductions sont attendues encore cette année et en 2016. Ces mesures de restriction devraient permettre au gouvernement fédéral d'afficher de légers surplus (sans tenir compte des fonds pour éventualités) de 2,7 G$ pour l'exercice en cours et de 3,2 G$ pour l'exercice 2016-2017.

Alors que le gouvernement fédéral semble pouvoir composer avec des revenus moindres que ceux prévus sans se retrouver en déficit, les gouvernements des provinces ne jouissent pas d'une situation budgétaire avantageuse et auront du mal à encaisser le coup d'une croissance moins vive. La plupart des provinces ont déposé leurs budgets de 2015 et les perspectives pour l'exercice en cours sont décevantes. Le déficit global des provinces, qui était de 13,7 G$ pour l'exercice 2014-2015, est en voie d'atteindre 15 G$ dans l'exercice en cours. Dans l'avenir prévisible, les provinces feront face à une croissance des revenus inférieure à la moyenne, à une baisse des redevances sur les ressources et à une augmentation de la demande de services financés par elles – un amalgame de facteurs qui les empêchera de renouer avec les surplus dans un avenir rapproché.

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Newfoundland and Labrador

Prince Owusu

Sluggish Economic Outlook Expected For 2015–16

Highlights

- Construction and mining are impeding bottom-line growth over the near term.
- Belt-tightening is ahead for Newfoundland and Labrador consumers as the labour market continues to shed jobs.
- Processing of nickel ore will bolster manufacturing industry growth over the medium term.

Economic Indicators

(percentage change)

	2014	2015f	2016f
Real GDP	–2.9	0.0	–1.6
Consumer Price Index	1.9	0.7	3.3
Household disposable income	3.5	1.4	0.7
Employment	–1.9	–1.3	–0.7
Unemployment rate (level)	12.0	12.6	12.1
Retail sales	3.4	–0.5	1.8
Wages and salaries per employee	6.9	2.8	1.2
Population	–0.2	–0.3	0.0

f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Government and Background Information

Premier	Paul Davis
Next election	October 2015
Population (2015Q2)	525,756
Government balance (2015–16)	–$1.1 billion

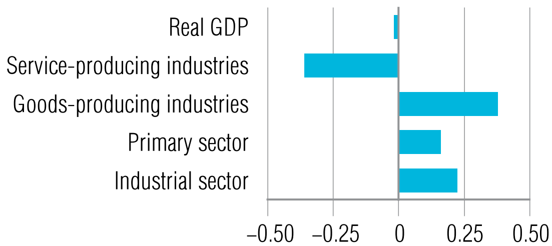
Sources: The Conference Board of Canada; Newfoundland and Labrador Finance.

Newfoundland and Labrador's economy will struggle over the next few years as major projects pass their peak investment levels and current offshore oilfields see production decline. In addition to these project-cycle factors, Newfoundland and Labrador's economy is facing the double whammy of low prices for oil and metals. Brent, the benchmark price for North Sea crude oil by which the province's offshore oil is priced, dropped by more than 50 per cent from its peak last summer, and prices for nickel, copper, and iron ore have all tumbled.

The weak outlook for commodity prices is having a negative impact on near-term investment and production decisions, and this will have a knock-on effect on the labour market and result in weaker economic growth. Real GDP is not expected to grow this year and is forecast to decline by 1.6 per cent in 2016 as investment begins to slow on some of the projects currently under way.

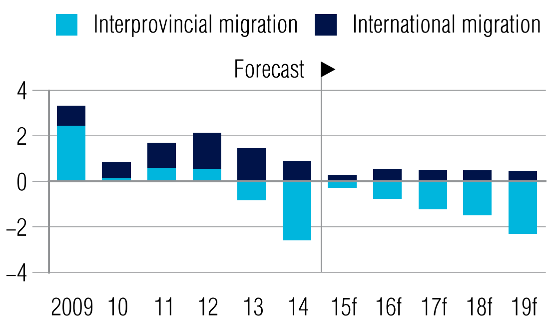
The labour market will continue to feel the effects of the weakening economy. Year-to-date job numbers are down by more than 3,000 for the first half of this year and no reprieve is expected on that front over the medium term as major construction projects unwind. Meanwhile, the spike in the unemployment rate during the first half of this year will not get worse as the labour participation rate is expected to drop. Overall, the unemployment rate will drop from 12.7 per cent in the first half of this year to an average of 12.1 per

Contributions to Newfoundland and Labrador Real GDP Growth, 2015
(by industry/sector, percentage point; GDP, per cent)



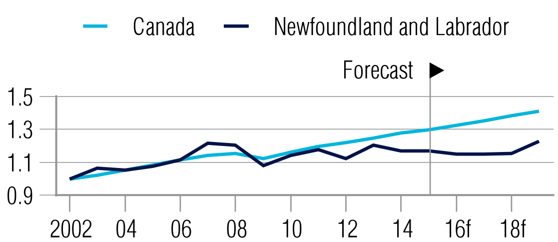
Note: "Primary" is the sum of agriculture, forestry, fishing and trapping, and mining sectors. "Industrial" is the sum of manufacturing, construction, and utilities sectors.
Sources: The Conference Board of Canada; Statistics Canada.

Sources of Migration
(net migration, 000s)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Real GDP, 2002 to 2019
(index, 2002 = 1.0)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

cent in 2016 as the number of Newfoundlanders looking for work shrinks. With slack in the labour market, household consumption will be anemic over the next two years and government tax collection from households will be lower. In addition to weaker revenues from households, the provincial government will have to brace for fewer resource royalties for the fiscal year as crude oil and metal prices plummet. This has left the provincial government with a massive $1.1-billion deficit, thereby limiting the government's contribution to bottom-line economic growth.

But, despite this sobering litany of problems, all is not doom and gloom. Manufacturing remains one of the brightest spots in the province's economy. The Long Harbour hydromet facility has begun processing nickel, copper, and cobalt ore from the Voisey's Bay mine and this will help offset some of the weakness in offshore oil production and the construction sector.

CONSTRUCTION OUTLOOK

The construction and mining industries will limit growth prospects in the province over the next four years. Many of the province's major projects have passed peak investment period and will not be contributing to growth. In addition, pressure from low metal commodity prices and difficulty in securing financing are making it more difficult for mining projects to proceed to the development phase. This is especially true for base-metal producers. Overall, real private non-residential investment is forecast to decline by an average of 10 per cent a year throughout the medium term (2015–19), bringing the level of investment to around $5.1 billion in 2019, down from $8.7 billion in 2014.

Residential investment will add to the gloom. With the domestic economy and job market cooling, homebuying activities will not return to the heady pace of the 2008–13 period. Housing starts will drop by 23 per cent this year and by a further 18.6 per cent to reach 1,300 units by next year. In fact, housing starts will continue to fall over the balance of the medium term and, as a result, real residential investment will retreat by an average of 7.5 per cent per year over the medium term.

MINING OUTLOOK

Oil production has been on a downward trajectory since 2008 as the province's offshore production fields have all matured. The downward trend will continue until the newer Hebron offshore field comes on line at the end of 2018. Hebron is currently under development at a cost of $14 billion and will be pumping about 150,000 barrels of oil per day. While the recent drop in crude oil prices has slowed global exploration activities, the impact in Newfoundland and Labrador has not been as bad as in Alberta. In fact, exploration activities at the newly discovered deep-water Flemish Pass Basin are progressing as the major players are keen to integrate Newfoundland and Labrador's offshore industry into the core and strategic part of their business in a race to stake out a piece of the potential there.

On the base-metal front, weaker market conditions over the past year have forced the Wabush and Labrador Iron Mine to close. Low prices have worsened the profit margins of producers in the province at a time when they were already dealing with cost pressures. As a result, some producers are ramping up production to maximize revenues. Tata Steel Minerals Canada (TSMC) is ramping up production at its Elross Lake iron mine while Iron Ore of Canada (IOC) is also boosting production at its mines at the Labrador Trough. The production increases will more than offset output losses from the mines that are shut down; however, output will decline next year as it is not possible to maintain that level of production. Although current market conditions and cost pressures make new mining developments difficult to undertake, we could see few projects developed beyond this year, including Phase II of Vale Inco's Voisey's Bay underground mine. Overall, we expect no growth in real metal mining output over 2015–19.

MANUFACTURING REBOUNDS, THANKS TO BASE METAL

The manufacturing industry is expected to exit the doldrums after contracting by 8.3 per cent last year due to weaker refined petroleum and other non-durable products. The Come by Chance refinery shut down for maintenance and because of unplanned equipment and weather-related outages last year. With the maintenance and outage issues resolved, we anticipate that activities will pick up at the refinery this year. In addition, a lower exchange rate and a revamp of operations at the Corner Brook Pulp and Paper mill (with the help of a $110-million loan from the provincial government) will help bolster the manufacturing industry.

While the industry will continue to benefit from seafood and newsprint production, nickel processing will help lift manufacturing out of the doldrums this year and will continue to support growth going forward. Operations at Vale's nickel processing facility in Long Harbour began in November last year. Production is expected to ramp up over the next three years before reaching full capacity—about 50,000 tonnes of processed nickel per year. This will provide a substantial boost for the manufacturing industry. Overall, a full year of production at Long Harbour will help the manufacturing industry expand by 6.5 per cent in 2015. In 2016, production from the hydromet will still be ramping up, but our forecast is for fabricated metal manufacturing to slow, with overall manufacturing growth coming in at 2.0 per cent.

DOMESTIC DEMAND REMAINS WEAK

The next five years are going to be belt-tightening for Newfoundland and Labrador consumers. The labour market has been hemorrhaging jobs since last year and we expect the losses to continue over the medium term. Investment in most of the province's megaprojects has peaked and workers are losing their jobs. On average, we expect about 1,300 positions to be eliminated each year from now until 2019. Along with weaker demand for labour, workers will see their wages slashed this year as employers try to keep costs down as they face weaker commodity prices. Wages and salaries— the industrial composite—are forecast to drop by 2 per cent this year, the first such decline in a decade after expanding at the breakneck pace of 5.6 per cent per year over 2005–14. Looking ahead, wage growth will be modest beyond next year as labour demand pressures wane.

The job losses have pushed the unemployment rate up to 12.7 per cent for the first half of this year. However, it will not remain there for long as the shrinking of the province's labour force will pull the rate down to around 12.1 per cent by next year. The slide in the unemployment rate will then continue through to 2019. The job losses, combined with lower wages, will dampen consumer spending over the next two years. Real household consumption expenditures will decline by an average of 0.4 per cent over 2015–16. Given the weak demand outlook, we expect overall consumer price inflation to average a tame 0.7 per cent this year, well below the Bank of Canada's mid-range target of 2 per cent. But consumer price inflation will shoot back up to 3.3 per cent next year with the 2 percentage point increase in the provincial sales tax, for an HST rate of 15 per cent.

Forecast Risks

Short term

- Further depreciation of the Canadian dollar should provide some upside risks for manufacturers in the province.

Medium term

- If owners of the West White Rose Extension change plans and decide to accelerate the development, it could provide relief for struggling construction workers.

Source: The Conference Board of Canada.

Key Economic Indicators: Newfoundland and Labrador
(Forecast Completed: July 16, 2015)

	2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4	2016Q1	2016Q2	2016Q3	2016Q4	2014	2015	2016
GDP at market prices ($ millions)	36,115 *1.7*	35,696 *–1.2*	35,170 *–1.5*	32,309 *–8.1*	33,221 *2.8*	32,852 *–1.1*	32,892 *0.1*	33,038 *0.4*	33,744 *2.1*	33,991 *0.7*	34,193 *0.6*	34,245 *0.2*	34,823 *–2.8*	33,001 *–5.2*	34,043 *3.2*
GDP at market prices (2007 $ millions)	29,043 *–2.0*	28,657 *–1.3*	28,301 *–1.2*	28,961 *2.3*	29,008 *0.2*	28,657 *–1.2*	28,605 *–0.2*	28,548 *–0.2*	28,305 *–0.9*	28,235 *–0.2*	28,215 *–0.1*	28,141 *–0.3*	28,740 *–2.9*	28,704 *–0.1*	28,224 *–1.7*
GDP at basic prices (2007 $ millions)	27,207 *–2.0*	26,846 *–1.3*	26,512 *–1.2*	27,130 *2.3*	27,194 *0.2*	26,872 *–1.2*	26,829 *–0.2*	26,781 *–0.2*	26,548 *–0.9*	26,490 *–0.2*	26,482 *0.0*	26,426 *–0.2*	26,924 *–2.9*	26,919 *0.0*	26,486 *–1.6*
Consumer price index (2002 = 1.0)	1.276 *0.6*	1.290 *1.1*	1.290 *0.0*	1.279 *–0.9*	1.275 *–0.3*	1.291 *1.2*	1.299 *0.6*	1.304 *0.4*	1.326 *1.7*	1.333 *0.5*	1.339 *0.5*	1.343 *0.3*	1.284 *1.9*	1.292 *0.7*	1.335 *3.3*
Implicit price deflator— **GDP at market prices** (2007 = 1.0)	1.244 *3.8*	1.246 *0.2*	1.243 *–0.2*	1.116 *–10.2*	1.145 *2.7*	1.146 *0.1*	1.150 *0.3*	1.157 *0.6*	1.192 *3.0*	1.204 *1.0*	1.212 *0.7*	1.217 *0.4*	1.212 *0.1*	1.150 *–5.1*	1.206 *4.9*
Wages and salary per employee ($ 000s)	50.102 *0.9*	51.685 *3.2*	51.886 *0.4*	52.130 *0.5*	53.087 *1.8*	52.817 *–0.5*	52.690 *–0.2*	53.028 *0.6*	53.212 *0.3*	53.422 *0.4*	53.640 *0.4*	53.848 *0.4*	51.451 *6.9*	52.905 *2.8*	53.531 *1.2*
Primary household income ($ millions)	18,248 *0.1*	18,368 *0.7*	18,516 *0.8*	18,655 *0.8*	18,836 *1.0*	18,680 *–0.8*	18,679 *0.0*	18,793 *0.6*	18,884 *0.5*	18,902 *0.1*	18,953 *0.3*	19,031 *0.4*	18,447 *4.1*	18,747 *1.6*	18,943 *1.0*
Household disposable income ($ millions)	17,138 *–0.5*	17,188 *0.3*	17,356 *1.0*	17,407 *0.3*	17,561 *0.9*	17,442 *–0.7*	17,520 *0.4*	17,517 *0.0*	17,571 *0.3*	17,596 *0.1*	17,642 *0.3*	17,716 *0.4*	17,272 *3.5*	17,510 *1.4*	17,631 *0.7*
Household net savings rate (per cent)	9.4	8.5	8.3	8.5	10.5	9.1	9.2	8.7	8.5	8.5	8.5	8.5	8.7	9.4	8.5
Population (000s)	528 *–0.1*	527 *–0.3*	527 *0.0*	527 *0.0*	526 *–0.1*	526 *–0.1*	525 *–0.1*	525 *0.0*	526 *0.1*	526 *0.0*	526 *0.0*	526 *0.0*	527 *–0.2*	526 *–0.3*	526 *0.0*
Employment (000s)	242 *–0.6*	236 *–2.1*	237 *0.5*	238 *0.4*	236 *–1.0*	236 *–0.1*	235 *–0.2*	235 *–0.1*	235 *–0.1*	234 *–0.4*	233 *–0.2*	233 *0.0*	238 *–1.9*	235 *–1.3*	234 *–0.7*
Labour force (000s)	274 *–0.3*	269 *–1.9*	271 *0.7*	270 *–0.4*	269 *–0.1*	271 *0.4*	269 *–0.5*	268 *–0.3*	268 *–0.3*	266 *–0.5*	265 *–0.4*	265 *–0.1*	271 *–1.4*	269 *–0.5*	266 *–1.3*
Labour force participation rate (per cent)	61.6	60.6	61.0	60.8	60.8	61.1	60.8	60.7	60.5	60.2	60.0	59.9	61.0	60.8	60.1
Unemployment rate (per cent)	11.9	12.1	12.3	11.6	12.4	12.9	12.6	12.5	12.2	12.2	12.0	11.9	12.0	12.6	12.1
Retail sales ($ millions)	8,737 *1.9*	8,841 *1.2*	9,022 *2.0*	8,926 *–1.1*	8,708 *–2.4*	8,842 *1.5*	8,860 *0.2*	8,930 *0.8*	8,970 *0.4*	8,979 *0.1*	9,000 *0.2*	9,029 *0.3*	8,881 *3.4*	8,835 *–0.5*	8,994 *1.8*
Housing starts (units, 000s)	2,148 *–32.4*	2,147 *0.0*	2,208 *2.8*	1,973 *–10.6*	2,204 *11.7*	1,515 *–31.3*	1,412 *–6.8*	1,397 *–1.0*	1,369 *–2.0*	1,342 *–2.0*	1,315 *–2.0*	1,289 *–2.0*	2,119 *–26.0*	1,632 *–23.0*	1,329 *–18.6*
Net interprovincial migration (000s)	–3.9	–2.3	–2.6	–1.5	–0.9	–0.1	–0.1	–0.1	–0.6	–0.8	–0.8	–0.9	–2.6	–0.3	–0.7
Net international migration (000s)	–0.9	2.1	2.4	0.0	–0.5	0.5	0.6	0.6	0.6	0.5	0.5	0.5	0.9	0.3	0.5

Shaded area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Key Economic Indicators: Newfoundland and Labrador cont'd

(Forecast Completed: July 16, 2015)

	2017Q1	2017Q2	2017Q3	2017Q4	2018Q1	2018Q2	2018Q3	2018Q4	2019Q1	2019Q2	2019Q3	2019Q4	2017	2018	2019
GDP at market prices ($ millions)	34,161	34,265	34,376	34,461	34,359	34,692	35,141	35,622	36,413	37,345	38,382	39,491	34,316	34,953	37,908
	–0.2	*0.3*	*0.3*	*0.2*	*–0.3*	*1.0*	*1.3*	*1.4*	*2.2*	*2.6*	*2.8*	*2.9*	*0.8*	*1.9*	*8.5*
GDP at market prices (2007 $ millions)	28,113	28,068	28,068	28,086	27,859	27,977	28,201	28,543	28,986	29,543	30,200	30,959	28,084	28,145	29,922
	–0.1	*–0.2*	*0.0*	*0.1*	*–0.8*	*0.4*	*0.8*	*1.2*	*1.6*	*1.9*	*2.2*	*2.5*	*–0.5*	*0.2*	*6.3*
GDP at basic prices (2007 $ millions)	26,424	26,399	26,416	26,450	26,261	26,386	26,609	26,938	27,361	27,886	28,504	29,215	26,422	26,549	28,242
	0.0	*–0.1*	*0.1*	*0.1*	*–0.7*	*0.5*	*0.8*	*1.2*	*1.6*	*1.9*	*2.2*	*2.5*	*–0.2*	*0.5*	*6.4*
Consumer price index (2002 = 1.0)	1.351	1.361	1.367	1.371	1.379	1.388	1.395	1.399	1.407	1.417	1.424	1.428	1.362	1.391	1.419
	0.6	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*2.0*	*2.1*	*2.1*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.215	1.221	1.225	1.227	1.233	1.240	1.246	1.248	1.256	1.264	1.271	1.276	1.222	1.242	1.267
	–0.1	*0.5*	*0.3*	*0.2*	*0.5*	*0.5*	*0.5*	*0.2*	*0.7*	*0.6*	*0.5*	*0.4*	*1.3*	*1.6*	*2.0*
Wages and salary per employee ($ 000s)	54.345	54.605	54.916	55.360	55.767	56.356	56.802	57.210	57.594	57.920	58.311	58.686	54.806	56.534	58.128
	0.9	*0.5*	*0.6*	*0.8*	*0.7*	*1.1*	*0.8*	*0.7*	*0.7*	*0.6*	*0.7*	*0.6*	*2.4*	*3.2*	*2.8*
Primary household income ($ millions)	19,177	19,273	19,385	19,502	19,658	19,832	19,968	20,096	20,278	20,377	20,484	20,583	19,335	19,889	20,430
	0.8	*0.5*	*0.6*	*0.6*	*0.8*	*0.9*	*0.7*	*0.6*	*0.9*	*0.5*	*0.5*	*0.5*	*2.1*	*2.9*	*2.7*
Household disposable income ($ millions)	17,895	17,985	18,086	18,189	18,317	18,463	18,574	18,687	18,848	18,947	19,045	19,126	18,039	18,510	18,991
	1.0	*0.5*	*0.6*	*0.6*	*0.7*	*0.8*	*0.6*	*0.6*	*0.9*	*0.5*	*0.5*	*0.4*	*2.3*	*2.6*	*2.6*
Household net savings rate (per cent)	8.7	8.8	8.8	8.7	8.7	8.7	8.8	8.8	8.8	8.9	9.0	9.1	8.7	8.8	8.9
Population (000s)	526	526	525	525	525	525	524	524	525	525	525	525	525	525	525
	0.0	*0.0*	*0.0*	*0.0*	*–0.1*	*–0.1*	*0.0*	*0.0*	*0.2*	*0.0*	*0.0*	*–0.1*	*–0.1*	*–0.2*	*0.1*
Employment (000s)	234	233	233	233	232	232	232	232	232	232	232	232	233	232	232
	0.1	*–0.1*	*–0.1*	*–0.3*	*–0.1*	*–0.1*	*–0.1*	*–0.1*	*0.2*	*0.0*	*–0.1*	*–0.1*	*–0.3*	*–0.5*	*0.0*
Labour force (000s)	265	265	264	263	263	262	261	260	260	260	260	259	264	261	260
	0.0	*–0.1*	*–0.1*	*–0.3*	*–0.3*	*–0.4*	*–0.4*	*–0.1*	*0.0*	*–0.1*	*–0.2*	*–0.3*	*–0.6*	*–1.1*	*–0.6*
Labour force participation rate (per cent)	60.0	59.9	59.9	59.7	59.6	59.4	59.3	59.2	59.1	59.1	59.0	58.9	59.9	59.4	59.0
Unemployment rate (per cent)	11.8	11.8	11.7	11.7	11.6	11.3	11.0	11.0	10.8	10.8	10.7	10.6	11.8	11.2	10.7
Retail sales ($ millions)	9,103	9,138	9,186	9,244	9,321	9,400	9,457	9,518	9,600	9,642	9,690	9,725	9,168	9,424	9,665
	0.8	*0.4*	*0.5*	*0.6*	*0.8*	*0.9*	*0.6*	*0.6*	*0.9*	*0.4*	*0.5*	*0.4*	*1.9*	*2.8*	*2.6*
Housing starts (units, 000s)	1,263	1,238	1,213	1,189	1,165	1,142	1,120	1,097	1,076	1,054	1,033	1,013	1,226	1,131	1,044
	–2.0	*–2.0*	*–2.0*	*–2.0*	*–2.0*	*–2.0*	*–2.0*	*–2.0*	*–1.9*	*–2.0*	*–2.0*	*–2.0*	*–7.8*	*–7.7*	*–7.7*
Net interprovincial migration (000s)	–1.1	–1.2	–1.2	–1.3	–1.3	–1.4	–1.6	–1.7	–1.9	–2.1	–2.5	–2.7	–1.2	–1.5	–2.3
Net international migration (000s)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5

Shaded area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Prince Edward Island

Daniel Fields

Good Times on the Island

Highlights

- Solid export growth is expected over the near term.
- Construction will be a major player in the province in 2015 and 2016.
- The government delayed its balanced-budget target by one year to 2016–17.

Economic Indicators
(percentage change)

	2014	2015f	2016f
Real GDP	1.3	2.4	1.9
Consumer Price Index	1.6	–0.1	2.3
Household disposable income	1.9	1.5	2.5
Employment	–0.4	–0.5	1.0
Unemployment rate (level)	10.5	10.5	10.0
Retail sales	3.3	0.6	3.8
Wages and salaries per employee	2.1	1.0	2.1
Population	0.4	0.3	0.5

f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Government and Background Information

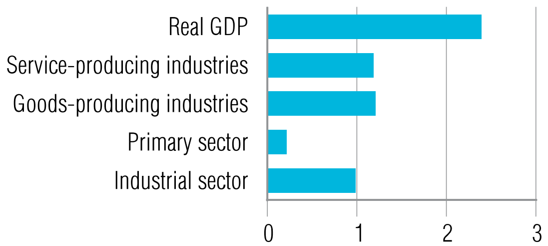
Premier	Wade MacLauchlan
Next election	2015
Population (2015Q2)	146,293
Government balance (2015–16)	–$19.9 million

Sources: The Conference Board of Canada; Prince Edward Island Finance.

Prince Edward Island has finally thawed out after its record-breaking, snow-filled winter and is back on track to being one of Canada's leaders in economic growth for 2015. Thanks to the one-two punch of construction and manufacturing, as well as a surging export sector, the Island possesses solid economic prospects this year and next. The past winter saw a record amount of snowfall that postponed the opening of lobster season; however, despite the winter setback, the fishing industry is still expected to perform well this year, thanks to strong demand for lobster from China. In general, the Island's export sector will be a major positive for the province due mainly to a booming U.S. economy and the weaker Canadian dollar. As well, there are healthy building construction intentions for 2015 and that, combined with a surge in housing starts next year, will support the construction sector over the near term. All these signs point to a healthy economy over the next two years on the Island, putting the province ahead of the national average. In particular, real GDP is expected to grow by 2.4 per cent this year and 1.9 per cent in 2016.

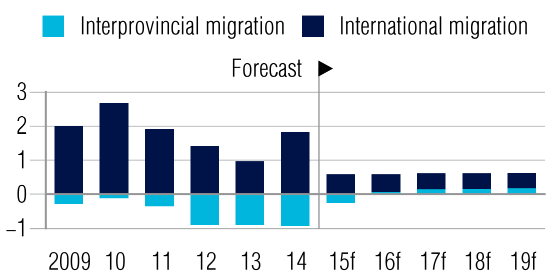
The recently re-elected Liberal government released its annual budget on June 19 and, as expected, the province continued its mandate of controlled spending. Despite the frugality, the province had to delay its target for a balanced budget by one year to 2016–17. Tight spending measures translate into weak growth in

Contributions to Prince Edward Island Real GDP Growth, 2015
(by industry/sector, percentage point; GDP, per cent)



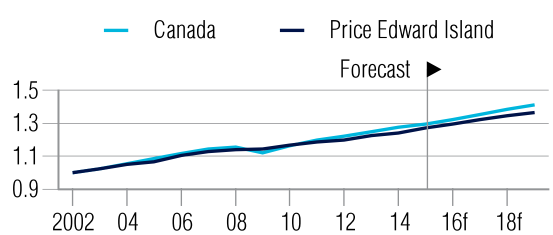
Note: "Primary" is the sum of agriculture, forestry, fishing and trapping, and mining sectors. "Industrial" is the sum of manufacturing, construction, and utilities sectors.
Sources: The Conference Board of Canada; Statistics Canada.

Sources of Migration
(net migration, 000s)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Real GDP, 2002 to 2019
(index, 2002 = 1.0)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

non-commercial services such as education and health and social services, which puts a damper on overall economic growth. This makes the positive economic outlook for the Island that much more impressive. With the combination of a strong economy and tighter spending, the province should certainly achieve its new fiscal-balance goal for 2016–17.

CONSTRUCTION AND MANUFACTURING BIG PLAYERS IN ISLAND GROWTH

The construction industry is one of the main reasons why economic growth on the Island is forecast to be strong this year and next. Real output in construction is set to rise by 9 per cent this year, thanks to robust building intentions in non-residential construction. Not to be left out, residential investment is also a healthy part of the increase in construction, growing by 19 per cent this year and 11 per cent next year in real terms. Housing starts are a big part of this increase in investment and are expected to rise next year by an impressive 23 per cent.

Manufacturing is set to grow at a more reasonable pace over the near term. The stronger U.S. dollar continues to drive up demand for P.E.I. products. Growth in the manufacturing sector should hit nearly 4 per cent this year, backed largely by a solid performance by aerospace and pharmaceutical products. Over the near term, manufacturing growth will fall back to the 2.5 per cent range as the sector is held back somewhat by modest advances in agriculture and by weakness in the fishing industry.

NEAR-TERM PROSPECTS WEAK FOR PRIMARY SECTOR

The industry got off to a slow start this year because of the poor winter weather that delayed the start of lobster season. However, as the ice thawed, so too did the fishing sector. Overall, thanks to strong demand from China, fishing and trapping should see growth of nearly 7 per cent this year. Growth in this industry goes a long way in improving the Island's primary sector, as fishing and trapping make up nearly one-third of the overall segment. With that in mind, however, the fishing sector may struggle over the near term as the industry adjusts to new labour restrictions on temporary foreign workers, a crucial input of the seasonal lobster catch. Next year, real growth in the fishing sector is expected to see a small decline.

Slow growth is anticipated in the agriculture industry over the near term as well. The industry, which makes up about two-thirds of the primary sector or about 4.5 per cent of the Island's economy, is forecast to expand by 1.7 per cent this year and 0.5 per cent next year. Increased production of potatoes in Texas is exerting downward pressure on prices and hampering the Island's agriculture prospects. Additionally, allegations of tampering with Island potatoes have raised concerns over the Island's staple product. Partially making up for this shrinking demand for potatoes is blueberry production that hit an all-time high in 2014 and should continue to be a strong source of growth for the agriculture industry. As well, other products such as barley and soybeans should continue to see production gains. However, these crops are unlikely to fill the hole left by the potato market, making overall agricultural prospects weak over the near term with average annual growth of around 1 per cent.

TOURISM IN FOR A GOOD YEAR

Last year, 2014, was a great year for tourism to the Island as the province celebrated the 150th anniversary of the Charlottetown Conference with many special events. Typically, after a once-in-a-lifetime celebration, we would expect to see a drop-off in the number of overnight visitors the following year. And, while this will still likely be the case this year, especially for domestic visitors (due to the weakness in most other provincial economies), visitors from the United States should pick up the slack thanks to robust economic growth. (More details can be seen in the Conference Board's *Travel Markets Outlook – National Focus: Spring 2015*.)

EMPLOYMENT PROSPECTS WILL IMPROVE NEXT YEAR

It has been a slow start for employment on the Island. While the second half of the year should be better for job creation, overall employment is forecast to decline by 0.5 per cent this year. This is not surprising when you consider the closure of the retail giant Target, which announced it was shutting its Charlottetown store in early 2015. The closure affected over 100 P.E.I. workers and will weigh on the year in terms of overall job growth. As well, employment growth had been exceptionally strong between 2010 and 2013 so a slowdown is not worrisome.

Next year is looking better for employment prospects on the Island. Very healthy growth in construction and manufacturing should provide plenty of work for those currently unemployed. This improvement in employment (as well as more people retiring out of the labour force) should lead to the unemployment rate falling to 10 per cent next year, which would mark the lowest level since 1978. The pickup in employment will also help boost household disposable income by 2.9 per cent next year, which will support real growth in household consumer expenditures of 2 per cent in 2016. This is good news for retailers on the Island; retail sales are forecast to gain 3.8 per cent as a result.

GOVERNMENT STILL WORKING TOWARD A BALANCED BUDGET

The P.E.I. government continues to work toward balancing its budget—an especially difficult task in a province that has posted a surplus budget in only 2 of last 14 fiscal years since 2000–01. The recently tabled provincial budget still calls for expenditure restraint to eliminate the deficit, but the province had to push out its target for balancing the budget by one fiscal year to 2016–17 with nominal program expenditures expected to decline this fiscal year. As the government holds the line on spending increases, there will be little contribution from the public sector to economic growth, which makes the positive economic outlook for the province that much more impressive.

Forecast Risks

Short term

- Weaker economic times in other provinces may reduce the number of domestic visitors to the Island more than expected.

Medium term

- Changes to the Temporary Foreign Workers Program should improve employment prospects and strengthen wage growth, as employers are forced to adjust to the new restrictions and fill more jobs locally.

Source: The Conference Board of Canada.

Key Economic Indicators: Prince Edward Island

(Forecast Completed: July 16, 2015)

	2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4	2016Q1	2016Q2	2016Q3	2016Q4	2014	2015	2016
GDP at market prices ($ millions)	5,827	5,854	6,001	6,200	6,102	6,197	6,289	6,352	6,381	6,443	6,514	6,563	5,971	6,235	6,475
	1.8	*0.5*	*2.5*	*3.3*	*−1.6*	*1.6*	*1.5*	*1.0*	*0.5*	*1.0*	*1.1*	*0.7*	*3.2*	*4.4*	*3.9*
GDP at market prices (2007 $ millions)	4,974	4,983	5,090	5,233	5,158	5,172	5,205	5,229	5,247	5,273	5,310	5,331	5,070	5,191	5,290
	−0.3	*0.2*	*2.1*	*2.8*	*−1.4*	*0.3*	*0.6*	*0.5*	*0.3*	*0.5*	*0.7*	*0.4*	*1.3*	*2.4*	*1.9*
GDP at basic prices (2007 $ millions)	4,556	4,564	4,662	4,793	4,724	4,737	4,767	4,790	4,806	4,830	4,863	4,883	4,644	4,755	4,845
	−0.3	*0.2*	*2.1*	*2.8*	*−1.4*	*0.3*	*0.6*	*0.5*	*0.3*	*0.5*	*0.7*	*0.4*	*1.3*	*2.4*	*1.9*
Consumer price index (2002 = 1.0)	1.301	1.305	1.304	1.293	1.282	1.297	1.305	1.310	1.318	1.327	1.333	1.338	1.301	1.299	1.329
	0.9	*0.4*	*−0.1*	*−0.8*	*−0.8*	*1.2*	*0.6*	*0.4*	*0.6*	*0.7*	*0.5*	*0.3*	*1.6*	*−0.1*	*2.3*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.171	1.175	1.179	1.185	1.183	1.198	1.208	1.215	1.216	1.222	1.227	1.231	1.178	1.201	1.224
	2.0	*0.3*	*0.4*	*0.5*	*−0.2*	*1.3*	*0.8*	*0.5*	*0.1*	*0.5*	*0.4*	*0.4*	*1.8*	*2.0*	*1.9*
Wages and salary per employee ($ 000s)	34.630	34.940	34.758	34.929	34.910	35.091	35.296	35.411	35.616	35.782	35.998	36.203	34.814	35.177	35.900
	0.6	*0.9*	*−0.5*	*0.5*	*−0.1*	*0.5*	*0.6*	*0.3*	*0.6*	*0.5*	*0.6*	*0.6*	*2.1*	*1.0*	*2.1*
Primary household income ($ millions)	4,078	4,087	4,101	4,123	4,151	4,114	4,170	4,202	4,236	4,263	4,296	4,329	4,097	4,159	4,281
	1.0	*0.2*	*0.3*	*0.5*	*0.7*	*−0.9*	*1.4*	*0.8*	*0.8*	*0.6*	*0.8*	*0.8*	*2.0*	*1.5*	*2.9*
Household disposable income ($ millions)	3,908	3,910	3,922	3,936	3,966	3,933	4,007	4,010	4,035	4,061	4,092	4,121	3,919	3,979	4,077
	0.9	*0.1*	*0.3*	*0.4*	*0.8*	*−0.8*	*1.9*	*0.1*	*0.6*	*0.6*	*0.8*	*0.7*	*1.9*	*1.5*	*2.5*
Household net savings rate (per cent)	−3.3	−5.4	−6.5	−5.0	−3.4	−5.5	−5.3	−6.0	−6.2	−6.2	−6.2	−6.1	−5.1	−5.1	−6.2
Population (000s)	145	146	146	147	146	146	147	147	147	147	147	148	146	146	147
	0.0	*0.2*	*0.3*	*0.2*	*0.0*	*−0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.4*	*0.3*	*0.5*
Employment (000s)	74	73	74	74	74	73	74	74	74	74	74	75	74	74	74
	0.3	*−0.7*	*1.0*	*−0.3*	*0.0*	*−1.4*	*0.9*	*0.4*	*0.3*	*0.2*	*0.2*	*0.2*	*−0.4*	*−0.5*	*1.0*
Labour force (000s)	83	83	82	82	83	82	82	82	82	83	83	83	83	82	83
	−0.3	*−0.5*	*−1.0*	*0.6*	*0.2*	*−0.9*	*0.5*	*0.2*	*0.1*	*0.1*	*0.2*	*0.1*	*−1.5*	*−0.4*	*0.4*
Labour force participation rate (per cent)	69.0	68.6	67.9	68.3	68.4	67.7	68.1	68.2	68.1	68.1	68.2	68.1	68.5	68.1	68.1
Unemployment rate (per cent)	11.1	11.2	9.4	10.2	10.5	10.9	10.5	10.3	10.2	10.0	10.0	9.8	10.5	10.5	10.0
Retail sales ($ millions)	1,954	2,004	2,058	2,004	1,961	2,006	2,043	2,060	2,075	2,087	2,101	2,112	2,005	2,017	2,094
	0.8	*2.5*	*2.7*	*−2.6*	*−2.2*	*2.3*	*1.8*	*0.8*	*0.7*	*0.6*	*0.7*	*0.5*	*3.3*	*0.6*	*3.8*
Housing starts (units, 000s)	409	649	381	605	620	357	518	571	629	631	638	646	511	517	636
	−5.6	*58.9*	*−41.3*	*58.7*	*2.5*	*−42.4*	*45.1*	*10.3*	*10.1*	*0.3*	*1.1*	*1.3*	*−19.7*	*1.1*	*23.2*
Net interprovincial migration (000s)	−0.1	−1.0	−2.1	−0.6	−1.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	−0.9	−0.3	0.1
Net international migration (000s)	1.5	2.8	2.8	0.2	0.7	0.7	0.5	0.5	0.5	0.5	0.5	0.5	1.8	0.6	0.5

Shaded area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Key Economic Indicators: Prince Edward Island cont'd

(Forecast Completed: July 16, 2015)

	2017Q1	2017Q2	2017Q3	2017Q4	2018Q1	2018Q2	2018Q3	2018Q4	2019Q1	2019Q2	2019Q3	2019Q4	2017	2018	2019
GDP at market prices ($ millions)	6,646	6,712	6,774	6,826	6,901	6,966	7,025	7,060	7,122	7,180	7,230	7,263	6,739	6,988	7,199
	1.3	*1.0*	*0.9*	*0.8*	*1.1*	*0.9*	*0.8*	*0.5*	*0.9*	*0.8*	*0.7*	*0.5*	*4.1*	*3.7*	*3.0*
GDP at market prices (2007 $ millions)	5,368	5,389	5,415	5,442	5,467	5,486	5,506	5,526	5,543	5,559	5,575	5,590	5,403	5,496	5,567
	0.7	*0.4*	*0.5*	*0.5*	*0.5*	*0.4*	*0.3*	*0.4*	*0.3*	*0.3*	*0.3*	*0.3*	*2.1*	*1.7*	*1.3*
GDP at basic prices (2007 $ millions)	4,916	4,935	4,960	4,984	5,007	5,025	5,043	5,062	5,077	5,092	5,106	5,120	4,949	5,034	5,099
	0.7	*0.4*	*0.5*	*0.5*	*0.5*	*0.4*	*0.3*	*0.4*	*0.3*	*0.3*	*0.3*	*0.3*	*2.1*	*1.7*	*1.3*
Consumer price index (2002 = 1.0)	1.346	1.355	1.362	1.366	1.374	1.383	1.390	1.394	1.402	1.412	1.419	1.423	1.357	1.385	1.414
	0.6	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*2.1*	*2.1*	*2.1*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.238	1.246	1.251	1.254	1.262	1.270	1.276	1.277	1.285	1.292	1.297	1.299	1.247	1.271	1.293
	0.6	*0.6*	*0.4*	*0.3*	*0.6*	*0.6*	*0.5*	*0.1*	*0.6*	*0.5*	*0.4*	*0.2*	*1.9*	*1.9*	*1.7*
Wages and salary per employee ($ 000s)	36.415	36.615	36.807	37.046	37.287	37.548	37.782	38.005	38.220	38.443	38.673	38.891	36.721	37.656	38.557
	0.6	*0.5*	*0.5*	*0.7*	*0.7*	*0.7*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*2.3*	*2.5*	*2.4*
Primary household income ($ millions)	4,362	4,402	4,435	4,471	4,512	4,553	4,585	4,616	4,652	4,680	4,710	4,738	4,418	4,566	4,695
	0.8	*0.9*	*0.7*	*0.8*	*0.9*	*0.9*	*0.7*	*0.7*	*0.8*	*0.6*	*0.6*	*0.6*	*3.2*	*3.4*	*2.8*
Household disposable income ($ millions)	4,165	4,199	4,227	4,260	4,298	4,337	4,368	4,398	4,433	4,463	4,492	4,520	4,213	4,350	4,477
	1.1	*0.8*	*0.7*	*0.8*	*0.9*	*0.9*	*0.7*	*0.7*	*0.8*	*0.7*	*0.7*	*0.6*	*3.3*	*3.3*	*2.9*
Household net savings rate (per cent)	-5.9	-5.8	-5.8	-5.9	-5.9	-5.8	-5.8	-5.8	-5.7	-5.6	-5.5	-5.4	-5.9	-5.8	-5.6
Population (000s)	148	148	148	148	149	149	149	149	149	150	150	150	148	149	150
	0.1	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.6*	*0.6*	*0.5*
Employment (000s)	75	75	75	75	76	76	76	76	76	76	76	76	75	76	76
	0.3	*0.4*	*0.2*	*0.2*	*0.2*	*0.2*	*0.1*	*0.1*	*0.2*	*0.1*	*0.1*	*0.1*	*1.1*	*0.8*	*0.4*
Labour force (000s)	83	83	83	83	83	83	84	84	84	84	84	84	83	84	84
	0.2	*0.1*	*0.0*	*0.2*	*0.2*	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.5*	*0.6*	*0.4*
Labour force participation rate (per cent)	68.2	68.2	68.1	68.1	68.2	68.3	68.2	68.2	68.2	68.2	68.1	68.1	68.2	68.2	68.1
Unemployment rate (per cent)	9.8	9.5	9.4	9.4	9.4	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.5	9.3	9.3
Retail sales ($ millions)	2,127	2,140	2,149	2,164	2,182	2,199	2,211	2,223	2,236	2,246	2,256	2,265	2,145	2,204	2,251
	0.7	*0.6*	*0.4*	*0.7*	*0.8*	*0.8*	*0.5*	*0.5*	*0.6*	*0.4*	*0.5*	*0.4*	*2.5*	*2.7*	*2.1*
Housing starts (units, 000s)	643	640	651	658	654	639	638	634	614	601	608	612	648	641	609
	–0.5	*–0.4*	*1.7*	*1.1*	*–0.6*	*–2.4*	*–0.1*	*–0.6*	*–3.2*	*–2.1*	*1.3*	*0.7*	*1.9*	*–1.1*	*–5.1*
Net interprovincial migration (000s)	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.2	0.2
Net international migration (000s)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.5	0.5	0.5

Shaded area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Nova Scotia

Natalia Ward

Natural Gas Production Weighs Down GDP Growth in 2015

Highlights

- The outlook for natural gas production in Nova Scotia is bleak.
- Both manufacturing and construction will see strong gains over the near term.
- Healthy growth in the goods-producing sector will bring a recovery in job creation next year.

Economic Indicators
(percentage change)

	2014	2015f	2016f
Real GDP	1.6	1.3	2.5
Consumer Price Index	1.7	0.6	2.3
Household disposable income	2.4	2.2	2.5
Employment	–1.1	–0.1	1.0
Unemployment rate (level)	8.9	8.7	8.5
Retail sales	2.3	–1.6	4.1
Wages and salaries per employee	3.4	1.7	1.8
Population	0.0	0.0	0.2

f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Government and Background Information

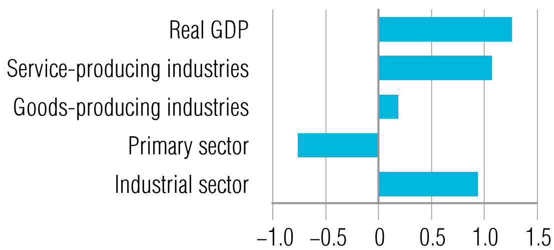
Premier	Stephen McNeil
Next election	2019
Population (2015Q2)	942,926
Government balance (2015–16)	–$97.6 million

Sources: The Conference Board of Canada; Nova Scotia Budget Documents.

After modest economic growth this year, Nova Scotia's economy is forecast to post robust growth in 2016. Real GDP is expected to increase 1.3 per cent in 2015 and 2.5 per cent in 2016. Over the near term, declines in natural gas production will take away from bottom-line growth in the province. Production at the mature Sable Island Energy Project (SOEP) will continue to decline. ExxonMobil Canada indicated that the five fields of the project will stop producing natural gas as early as 2017 and the field will be decommissioned. In addition, Encana's Deep Panuke offshore project will now become a seasonal operation and is expected to produce natural gas for only another three years.

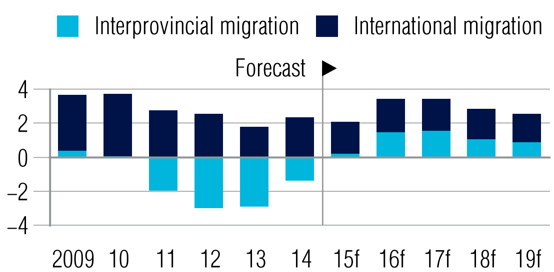
Despite a rather bleak outlook for mineral fuels mining, the other goods-producing industries will perform well; manufacturing and construction should post strong growth this year and next. Manufacturing will be supported by the Irving shipbuilding contract that is expected to begin in the fall of this year. In addition, other manufacturing sectors are aiming to expand their production in the province. Construction will rebound this year and see double-digit growth this year and next. Work on the Nova Centre and on King's Wharf projects in Halifax, the Maritime Transmission Link Project, and wind power expansion will keep construction workers busy in the province.

Contributions to Nova Scotia Real GDP Growth, 2015
(by industry/sector, percentage point; GDP, per cent)



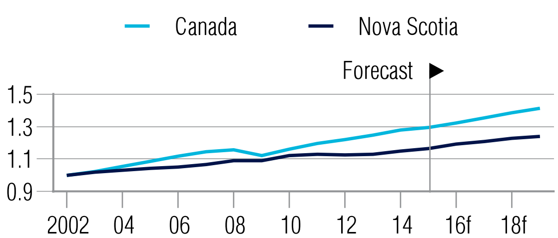
Note: "Primary" is the sum of agriculture, forestry, fishing and trapping, and mining sectors. "Industrial" is the sum of manufacturing, construction, and utilities sectors.
Sources: The Conference Board of Canada; Statistics Canada.

Sources of Migration
(net migration, 000s)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Real GDP, 2002 to 2019
(index, 2002 = 1.0)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Employment will see another disappointing year in 2015. Over the first six months of the year, total employment fell and, although it is projected to recover somewhat in the remainder of the year, it will not be enough to offset the losses from the beginning of the year. Next year promises better employment prospects; after a 0.1 per cent decline in 2015, employment will rebound with 1 per cent growth in 2016.

NATURAL GAS PROSPECTS

The outlook for natural gas production in Nova Scotia is not that good at the moment. Production at Deep Panuke offshore gas field this past winter was well below last year's levels; the field produced an average of 170 million cubic feet per day from November to March—about 50 million cubic feet fewer than the same period last year. Deep Panuke is expected to produce for only another three years and then only on a seasonal basis.

ExxonMobil will be calling for bids on work to plug wells at the SOEP; however, it may take a year before a timeline is in place to determine when the five fields will stop producing.

The Nova Scotia government has already begun planning for the end of operations at Sable Island and for the end of the royalties it provides to the province. A portion of the decommissioning costs incurred by ExxonMobil and its partners would be deducted from previous royalties paid. SOEP royalties account for a good portion of the $1.9 billion that Nova Scotia has collected from offshore energy.

All told, mineral fuels output will fall by 37.1 per cent in 2015 and another 14 per cent in 2016.

CONSTRUCTION AND MANUFACTURING DOING WELL

Both manufacturing and construction will see strong gains over the near term. Construction will be supported by a number of large-scale projects, including the $500-million Nova Centre in downtown Halifax and the King's Wharf project. These developments will include a convention centre, office towers, luxury hotels, retail outlets, restaurants, and a residential complex. The Maritime Transmission Link Project and wind power expansion projects will also help propel growth in business non-residential investment. In addition, Shell and BP will spend more than $2 billion over the next six years on exploration in Nova Scotia's offshore. Residential investment will also bolster the construction industry over the near two years, advancing an average of 14.1 per cent per year. In addition, government investment spending will improve. All told, construction will expand by 11.5 per cent in 2015 and a further 10.4 per cent in 2016.

Manufacturing will make substantial advances over the next two years. The stronger growth in the U.S. and the weaker Canadian dollar will help make Nova Scotia-produced goods more price competitive internationally. There will be a slew of contracts to keep Nova Scotia manufacturers busy: work on the Royal Canadian Navy ships is slated to commence in September. The budget for the Arctic Offshore Patrol Ships (AOPS) is expected to total $3.5 billion. The AOPS are the first of the navy's ships to be delivered under the National Shipbuilding Procurement Strategy (NSPS) and are projected to be completed around 2018. Other proposed navy ships, such as a fleet of surface combatants and supply vessels to be built under NSPS, are still years away from construction. Currently, five AOPS are planned with a potential for a sixth ship if Irving Shipbuilding meets certain incentives. To help facilitate work on the ships, Nova Scotia and British Columbia have signed an agreement to make it easier for workers to move between shipbuilding projects in the two provinces, as the Irving Shipyard in Halifax and the Seaspan shipyard in Vancouver are both slated to begin work on these new naval ships.

Other segments of the manufacturing industry are also expected to perform well. Michelin is expanding heavy-duty-tire production at its Waterville plant in the Annapolis Valley. The expansion will enable Michelin to increase output of bus, truck, and off-road tires by 2016, which will help offset the lower production levels of car tires at Michelin's plant in Granton. In addition, investment in the aerospace and biochemical industries will support manufacturing growth. Pratt & Whitney Canada is undertaking expansions at its plant near the Halifax airport to build components of its new PurePower® PW800 engines. BioVectra, a contract manufacturing organization that produces ingredients for the global pharmaceutical industry, is investing in its newly acquired Windsor facility. Overall, the manufacturing industry will gain 3.7 per cent in 2015 and 8.2 per cent in 2016.

DOMESTIC DEMAND

Nova Scotia experienced a severe winter that affected the provincial services economy. Employment fell in the first six months of the year and, although job prospects are forecast to improve over the rest of the year, it will not be enough to offset the losses in the first half of 2015. Total employment levels will fall 0.1 per cent in 2015. Strong growth in the goods-producing sector will bring a recovery in employment next year with growth of 1 per cent. Retail trade will follow a similar trajectory—after falling in the first quarter of the year, the sector will recover and enjoy healthy gains next year, helping to lift the overall domestic economy.

Forecast Risks

Short term

- If more "fly-in, fly-out" workers residing in Nova Scotia are laid off in Alberta's energy sector, provincial employment and labour income would fall.

Medium term

- If the proposed liquefied natural gas export terminals go ahead, the province will see long-term benefits across several industries.

Source: The Conference Board of Canada.

Key Economic Indicators: Nova Scotia
(Forecast Completed: July 16, 2015)

	2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4	2016Q1	2016Q2	2016Q3	2016Q4	2014	2015	2016
GDP at market prices ($ millions)	40,255 *3.0*	40,103 *–0.4*	41,190 *2.7*	40,547 *–1.6*	40,758 *0.5*	41,549 *1.9*	42,092 *1.3*	42,770 *1.6*	43,063 *0.7*	43,467 *0.9*	43,911 *1.0*	44,102 *0.4*	40,524 *3.5*	41,792 *3.1*	43,636 *4.4*
GDP at market prices (2007 $ millions)	36,441 *3.8*	36,431 *0.0*	36,698 *0.7*	36,871 *0.5*	36,708 *–0.4*	36,948 *0.7*	37,117 *0.5*	37,514 *1.1*	37,728 *0.6*	37,900 *0.5*	38,137 *0.6*	38,169 *0.1*	36,610 *1.6*	37,072 *1.3*	37,984 *2.5*
GDP at basic prices (2007 $ millions)	33,325 *3.8*	33,317 *0.0*	33,561 *0.7*	33,719 *0.5*	33,569 *–0.4*	33,789 *0.7*	33,944 *0.5*	34,307 *1.1*	34,502 *0.6*	34,660 *0.5*	34,877 *0.6*	34,906 *0.1*	33,480 *1.6*	33,902 *1.3*	34,736 *2.5*
Consumer price index (2002 = 1.0)	1.282 *1.2*	1.293 *0.8*	1.291 *–0.1*	1.285 *–0.5*	1.282 *–0.2*	1.294 *0.9*	1.302 *0.6*	1.307 *0.4*	1.314 *0.6*	1.323 *0.7*	1.330 *0.5*	1.334 *0.3*	1.288 *1.7*	1.296 *0.6*	1.325 *2.3*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.105 *–0.7*	1.101 *–0.4*	1.122 *2.0*	1.100 *–2.0*	1.110 *1.0*	1.125 *1.3*	1.134 *0.8*	1.140 *0.5*	1.141 *0.1*	1.147 *0.5*	1.151 *0.4*	1.155 *0.4*	1.107 *1.9*	1.127 *1.8*	1.149 *1.9*
Wages and salary per employee ($ 000s)	40.571 *1.5*	40.923 *0.9*	40.701 *–0.5*	40.409 *–0.7*	41.221 *2.0*	41.283 *0.2*	41.370 *0.2*	41.519 *0.4*	41.755 *0.6*	42.006 *0.6*	42.224 *0.5*	42.454 *0.5*	40.651 *3.4*	41.348 *1.7*	42.109 *1.8*
Primary household income ($ millions)	29,189 *1.9*	29,174 *–0.1*	29,122 *–0.2*	29,262 *0.5*	29,821 *1.9*	29,706 *–0.4*	29,930 *0.8*	30,134 *0.7*	30,410 *0.9*	30,655 *0.8*	30,881 *0.7*	31,109 *0.7*	29,187 *2.6*	29,898 *2.4*	30,764 *2.9*
Household disposable income ($ millions)	26,725 *1.7*	26,623 *–0.4*	26,576 *–0.2*	26,653 *0.3*	27,160 *1.9*	27,022 *–0.5*	27,376 *1.3*	27,402 *0.1*	27,585 *0.7*	27,805 *0.8*	28,015 *0.8*	28,226 *0.8*	26,644 *2.4*	27,240 *2.2*	27,908 *2.5*
Household net savings rate (per cent)	–4.2	–5.8	–6.7	–6.2	–1.9	–4.3	–4.2	–4.9	–5.1	–5.1	–5.1	–5.0	–5.7	–3.8	–5.1
Population (000s)	943 *0.0*	942 *–0.1*	943 *0.1*	944 *0.1*	944 *0.0*	943 *–0.1*	943 *0.0*	944 *0.0*	945 *0.1*	945 *0.1*	946 *0.1*	947 *0.1*	943 *0.0*	943 *0.0*	946 *0.2*
Employment (000s)	447 *–0.2*	446 *–0.3*	447 *0.2*	451 *1.0*	448 *–0.7*	445 *–0.5*	447 *0.5*	449 *0.3*	450 *0.3*	451 *0.3*	453 *0.3*	454 *0.2*	448 *–1.1*	447 *–0.1*	452 *1.0*
Labour force (000s)	491 *–0.3*	490 *–0.2*	490 *0.0*	494 *0.7*	492 *–0.4*	488 *–0.8*	490 *0.5*	491 *0.3*	492 *0.2*	493 *0.2*	495 *0.3*	496 *0.2*	491 *–1.3*	490 *–0.2*	494 *0.8*
Labour force participation rate (per cent)	62.8	62.6	62.6	63.0	62.7	62.1	62.5	62.6	62.7	62.7	62.8	62.9	62.7	62.5	62.8
Unemployment rate (per cent)	8.9	9.0	8.9	8.6	8.9	8.6	8.7	8.7	8.6	8.5	8.5	8.4	8.9	8.7	8.5
Retail sales ($ millions)	13,719 *0.6*	13,920 *1.5*	14,182 *1.9*	13,837 *–2.4*	13,222 *–4.4*	13,709 *3.7*	13,872 *1.2*	13,992 *0.9*	14,106 *0.8*	14,213 *0.8*	14,311 *0.7*	14,394 *0.6*	13,915 *2.3*	13,699 *–1.6*	14,256 *4.1*
Housing starts (units, 000s)	1,972 *–44.1*	2,577 *30.7*	4,546 *76.4*	3,128 *–31.2*	2,183 *–30.2*	6,011 *175.4*	3,069 *–48.9*	3,070 *0.0*	3,177 *3.5*	3,170 *–0.2*	3,167 *–0.1*	3,219 *1.6*	3,056 *–22.0*	3,583 *17.3*	3,183 *–11.2*
Net interprovincial migration (000s)	–4.0	0.3	–0.5	–1.3	–2.2	0.6	1.0	1.3	1.3	1.5	1.6	1.6	–1.4	0.2	1.5
Net international migration (000s)	2.3	2.3	4.6	0.2	1.5	1.9	2.0	2.0	2.0	2.0	1.9	1.9	2.4	1.9	1.9

Shaded area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Key Economic Indicators: Nova Scotia cont'd
(Forecast Completed: July 16, 2015)

	2017Q1	2017Q2	2017Q3	2017Q4	2018Q1	2018Q2	2018Q3	2018Q4	2019Q1	2019Q2	2019Q3	2019Q4	2017	2018	2019
GDP at market prices ($ millions)	44,559	44,935	45,309	45,625	46,105	46,517	46,904	47,165	47,650	48,072	48,432	48,649	45,107	46,673	48,201
	1.0	*0.8*	*0.8*	*0.7*	*1.1*	*0.9*	*0.8*	*0.6*	*1.0*	*0.9*	*0.7*	*0.4*	*3.4*	*3.5*	*3.3*
GDP at market prices (2007 $ millions)	38,351	38,442	38,590	38,745	38,900	39,008	39,121	39,267	39,411	39,520	39,619	39,676	38,532	39,074	39,556
	0.5	*0.2*	*0.4*	*0.4*	*0.4*	*0.3*	*0.3*	*0.4*	*0.4*	*0.3*	*0.2*	*0.1*	*1.4*	*1.4*	*1.2*
GDP at basic prices (2007 $ millions)	35,072	35,156	35,291	35,432	35,574	35,672	35,775	35,909	36,041	36,141	36,231	36,284	35,238	35,733	36,174
	0.5	*0.2*	*0.4*	*0.4*	*0.4*	*0.3*	*0.3*	*0.4*	*0.4*	*0.3*	*0.2*	*0.1*	*1.4*	*1.4*	*1.2*
Consumer price index (2002 = 1.0)	1.342	1.351	1.358	1.362	1.370	1.379	1.387	1.390	1.398	1.408	1.415	1.419	1.353	1.382	1.410
	0.6	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*2.1*	*2.1*	*2.1*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.162	1.169	1.174	1.178	1.185	1.193	1.199	1.201	1.209	1.216	1.222	1.226	1.171	1.194	1.219
	0.6	*0.6*	*0.4*	*0.3*	*0.6*	*0.6*	*0.5*	*0.2*	*0.7*	*0.6*	*0.5*	*0.3*	*1.9*	*2.0*	*2.0*
Wages and salary per employee ($ 000s)	42.656	42.855	43.086	43.310	43.535	43.799	44.051	44.280	44.547	44.805	45.037	45.261	42.977	43.916	44.913
	0.5	*0.5*	*0.5*	*0.5*	*0.5*	*0.6*	*0.6*	*0.5*	*0.6*	*0.6*	*0.5*	*0.5*	*2.1*	*2.2*	*2.3*
Primary household income ($ millions)	31,255	31,460	31,678	31,886	32,124	32,336	32,546	32,729	32,974	33,172	33,365	33,558	31,569	32,434	33,267
	0.5	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*	*0.6*	*0.6*	*0.8*	*0.6*	*0.6*	*0.6*	*2.6*	*2.7*	*2.6*
Household disposable income ($ millions)	28,430	28,615	28,811	28,998	29,180	29,384	29,578	29,746	29,952	30,144	30,321	30,491	28,714	29,472	30,227
	0.7	*0.7*	*0.7*	*0.6*	*0.6*	*0.7*	*0.7*	*0.6*	*0.7*	*0.6*	*0.6*	*0.6*	*2.9*	*2.6*	*2.6*
Household net savings rate (per cent)	–4.8	–4.8	–4.8	–4.8	–4.8	–4.8	–4.7	–4.8	–4.7	–4.6	–4.6	–4.5	–4.8	–4.8	–4.6
Population (000s)	948	948	949	950	951	952	952	953	953	954	955	955	949	952	954
	0.1	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.3*	*0.3*	*0.2*
Employment (000s)	454	455	455	456	456	456	456	456	456	457	457	458	455	456	457
	0.1	*0.1*	*0.1*	*0.1*	*0.1*	*0.0*	*0.1*	*0.0*	*0.1*	*0.0*	*0.1*	*0.1*	*0.6*	*0.3*	*0.2*
Labour force (000s)	496	496	496	496	496	496	496	496	496	496	496	496	496	496	496
	0.1	*0.0*	*0.0*	*0.1*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.4*	*0.0*	*0.0*
Labour force participation rate (per cent)	62.8	62.8	62.7	62.7	62.6	62.6	62.5	62.4	62.4	62.4	62.3	62.3	62.8	62.6	62.4
Unemployment rate (per cent)	8.4	8.3	8.2	8.2	8.2	8.1	8.0	8.0	8.0	7.9	7.9	7.8	8.3	8.1	7.9
Retail sales ($ millions)	14,439	14,497	14,569	14,648	14,728	14,808	14,880	14,941	15,022	15,086	15,148	15,200	14,538	14,839	15,114
	0.3	*0.4*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.4*	*0.5*	*0.4*	*0.4*	*0.3*	*2.0*	*2.1*	*1.9*
Housing starts (units, 000s)	3,256	3,223	3,177	3,144	3,097	3,064	3,018	2,985	2,940	2,906	2,860	2,827	3,200	3,041	2,883
	1.1	*–1.0*	*–1.4*	*–1.0*	*–1.5*	*–1.1*	*–1.5*	*–1.1*	*–1.5*	*–1.1*	*–1.6*	*–1.2*	*0.5*	*–5.0*	*–5.2*
Net interprovincial migration (000s)	1.6	1.6	1.6	1.5	1.2	1.1	1.0	1.0	0.9	0.9	0.8	0.8	1.6	1.1	0.9
Net international migration (000s)	1.9	1.9	1.8	1.8	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.9	1.8	1.7

Shaded area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Natalia Ward

New Brunswick's Economic Outlook Improves

Highlights

- Metal mining will benefit from the reopening of Trevali's previously closed Caribou mine.
- Investments in the forestry sector will boost domestic demand.
- Employment will see another disappointing year with another reduction in the number of people employed.

Economic Indicators
(percentage change)

	2014	2015f	2016f
Real GDP	0.0	1.4	2.0
Consumer Price Index	1.5	0.9	2.3
Household disposable income	0.6	1.5	2.8
Employment	–0.2	–0.1	1.1
Unemployment rate (level)	9.9	10.0	9.5
Retail sales	3.8	1.1	4.3
Wages and salaries per employee	1.3	1.7	2.2
Population	–0.2	–0.1	0.1

f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Government and Background Information

Premier	Brian Gallant
Next election	2019
Population (2015Q2)	753,319
Government balance (2015–16)	–$476.8 million

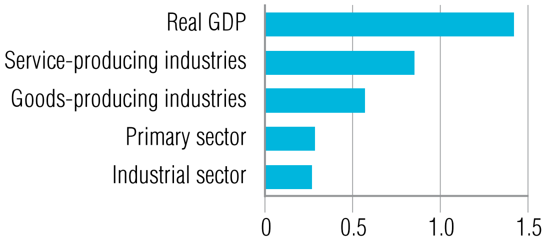
Source: The Conference Board of Canada; New Brunswick budget documents.

A rebound in the goods-producing industries and better growth in the services sector will generate an improved economic outlook for New Brunswick in the next two years. Real GDP is forecast to gain 1.4 per cent this year and 2 per cent in 2016.

Decent gains in mining, manufacturing, agriculture, and forestry will help lift growth in the goods-producing industries. Potash mining will continue to ramp up at the Picadilly mine, while metal mining will benefit from the reopening of Trevali's Caribou mine (the company expects to more than double its zinc production). Manufacturing will also post solid gains over the next two years. Stronger economic growth in the U.S. will help drive demand for New Brunswick–produced goods, while a weaker Canadian dollar will make them more price competitive. The forestry industry will benefit from an increase in the allowable softwood cut on Crown land and stronger growth in new housing demand in the U.S. In addition, the industry will benefit from the $450-million investment by J.D. Irving in the province's lumber mill upgrades. Construction, on the other hand, will weigh down overall growth. Private investment in residential and non-residential structures is forecast to decline this year as a number of non-residential projects are completed and housing starts fall off.

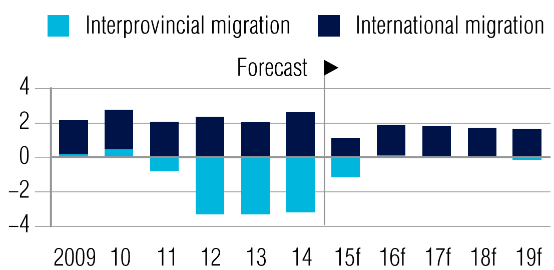
The short-term outlook for services-producing industries is somewhat weaker. Although some commercial services are experiencing solid growth, the

Contributions to New Brunswick Real GDP Growth, 2015
(by industry/sector, percentage point; GDP, per cent)



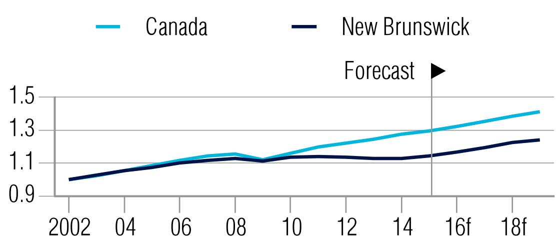
Note: "Primary" is the sum of agriculture, forestry, fishing and trapping, and mining sectors. "Industrial" is the sum of manufacturing, construction, and utilities sectors.
Sources: The Conference Board of Canada; Statistics Canada.

Sources of Migration
(net migration, 000s)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Real GDP, 2002 to 2019
(index, 2002 = 1.0)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

retail industry suffered a difficult start to the year as unseasonably cold weather kept many residents at home. Employment growth is projected to decline slightly this year, mainly due to the contraction in the construction sector.

MINING REBOUNDS

Although global metal and mineral prices have not picked up, mining in New Brunswick will perform quite well over the next two years. Metal mining will benefit from the reopening of Trevali's previously closed Caribou mine that began production this year and that will continue to ramp up production throughout the summer months. Trevali intends to increase total production more than twofold to 5,000 metric tonnes of ore per day by 2016 and will focus not only on zinc but also on copper and lead. Coming off a very low base year in 2014, metal mining will post substantial increases in 2015 and 2016.

Non-metallic mining and quarrying will perform well over the near term. After the market turmoil two years ago due to the collapse of the Russian–Belarussian cartel and the subsequent plunge in potash prices, this year's contracts with India and China have shown some price improvements. Further, there is upside potential for potash prices as Russia is facing difficulties with its Solikamsk-2 potash mine (brine inflow problems). New Brunswick's Picadilly mine will continue to increase production over the next two years, leading to a 5.2 per cent increase in non-metallic mining and quarrying in 2015 and by a 19.6 per cent gain in 2016. All told, mining will rise by 12.9 per cent in 2015 and increase a further 19.8 per cent in 2016.

FISHING, AGRICULTURE, AND FORESTRY WILL SEE DECENT GROWTH

The outlook for "other primary" industries—which include agriculture, fishing, hunting, trapping, and forestry—is also looking positive. The agriculture industry is forecast to rebound and post healthy gains this year and next. Fishing and trapping saw a 10.3 per cent increase last year and is expecting another strong year with growth of 5.8 per cent in 2015. The province and the federal government are investing in seven projects in the oyster industry—a total of $1.2 million that will support operational expansions, increased efficiencies, increased sales opportunities, and productivity improvements. On the downside, growth in the fishing industry will be limited by the recently imposed moratorium on Atlantic salmon fishing. Salmon fishing in New Brunswick (and Nova Scotia) will be limited to catch-and-release.

Output in the forestry sector will continue to enjoy strong gains over the near term. Demand for forestry products is increasing and will be supported by a robust expansion in housing starts in the U.S. This will help drive up prices for lumber and other wood products and allow some currently idle mills to restart operations. In addition, the provincial government announced a 20 per cent increase in allowable timber cuts. In response, J.D. Irving will invest about $450 million to upgrade its mills over the next two years. According to the New Brunswick's forestry association (Forest NB), almost $1 billion is expected to be spent on mills across the province to increase capacity over the medium term. The mill upgrades will be the first major new business investment in the province since 2008 and should help the forestry industry grow and generate spillover effects for the rest of the economy. All told, the forestry industry is forecast to expand by 4.9 per cent in 2015 and 3.1 per cent in 2016.

MANUFACTURING ALSO REBOUNDING

Manufacturing is expected to recover this year, supported by increasing demand for building materials south of the border. Refined crude oil product volumes are forecast to rally as the Irving refinery is once again in full operation after an unplanned shutdown last year. Food manufacturing will benefit from expanded capacity in berry processing by Oxford Frozen Foods. Finally, a weaker Canadian dollar will also help make New Brunswick–manufactured goods more price competitive on the export market and will support international demand for provincial goods. All told, manufacturing will grow by 3 per cent in 2015 and 2.7 per cent in 2016.

CONSTRUCTION FALTERS

Construction is forecast to decline this year. Cold weather and snow put the freeze on new home construction in the province. In the first six months of the year, new housing starts fell by 690 units. Although the number of starts is expected to recover toward the end of the year, overall annual residential investment spending will fall in 2015 before recovering in 2016. Non-residential business investment will also decline in 2015 as several projects are coming to an end, including the Oxford Frozen Foods berry processing facility and Phase 1 of the J.D. Irving investment in the forestry sector. Investment in machinery and equipment and government investment spending, on the other hand, will see healthy gains in 2015–16.

DOMESTIC DEMAND OUTLOOK

The services sector will benefit from healthy advances in transportation and warehousing, finance and insurance, real estate, and leasing. On the downside, provincial retailers were hard hit by a cold and snowy winter and will not be able to recoup losses of the first six months of this year; therefore, there will be only a modest gain in retail trade in 2015. Employment will see another disappointing year with a further reduction in the number of people employed (down 0.1 per cent) but job prospects will improve next year (up 1.1 per cent).

Forecast Risks

Short term

- If more "fly-in, fly-out" workers—those who are involved in the Alberta energy sector and reside in New Brunswick—are out of work for an extended period, employment and labour income could be further reduced.

Medium term

- The reconfiguration of the Canaport liquid natural gas (LNG) import terminal into an export terminal could bring huge benefits to the province.

Source: The Conference Board of Canada.

Key Economic Indicators: New Brunswick
(Forecast Completed: July 16, 2015)

	2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4	2016Q1	2016Q2	2016Q3	2016Q4	2014	2015	2016
GDP at market prices ($ millions)	31,634 *−1.8*	31,882 *0.8*	32,792 *2.9*	32,969 *0.5*	32,824 *−0.4*	33,217 *1.2*	33,666 *1.4*	34,025 *1.1*	34,193 *0.5*	34,548 *1.0*	34,928 *1.1*	35,215 *0.8*	32,319 *1.3*	33,433 *3.4*	34,721 *3.9*
GDP at market prices (2007 $ millions)	27,779 *−3.1*	27,939 *0.6*	28,652 *2.6*	28,675 *0.1*	28,567 *−0.4*	28,545 *−0.1*	28,692 *0.5*	28,849 *0.5*	28,970 *0.4*	29,138 *0.6*	29,351 *0.7*	29,496 *0.5*	28,261 *0.0*	28,663 *1.4*	29,239 *2.0*
GDP at basic prices (2007 $ millions)	25,618 *−3.1*	25,766 *0.6*	26,423 *2.6*	26,444 *0.1*	26,345 *−0.4*	26,325 *−0.1*	26,460 *0.5*	26,605 *0.5*	26,716 *0.4*	26,871 *0.6*	27,067 *0.7*	27,201 *0.5*	26,063 *0.0*	26,434 *1.4*	26,964 *2.0*
Consumer price index (2002 = 1.0)	1.243 *0.6*	1.251 *0.6*	1.250 *−0.1*	1.248 *−0.1*	1.243 *−0.5*	1.257 *1.2*	1.265 *0.6*	1.270 *0.4*	1.277 *0.6*	1.286 *0.7*	1.292 *0.5*	1.296 *0.3*	1.248 *1.5*	1.259 *0.9*	1.288 *2.3*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.139 *1.3*	1.141 *0.2*	1.145 *0.3*	1.150 *0.5*	1.149 *−0.1*	1.164 *1.3*	1.173 *0.8*	1.179 *0.5*	1.180 *0.1*	1.186 *0.5*	1.190 *0.4*	1.194 *0.3*	1.144 *1.3*	1.166 *2.0*	1.187 *1.8*
Wages and salary per employee ($ 000s)	39.739 *0.2*	40.341 *1.5*	40.709 *0.9*	40.680 *−0.1*	40.915 *0.6*	40.976 *0.2*	41.063 *0.2*	41.264 *0.5*	41.463 *0.5*	41.830 *0.9*	42.104 *0.7*	42.358 *0.6*	40.367 *1.3*	41.054 *1.7*	41.939 *2.2*
Primary household income ($ millions)	21,953 *1.0*	21,951 *0.0*	22,097 *0.7*	22,086 *0.0*	22,461 *1.7*	22,337 *−0.5*	22,523 *0.8*	22,731 *0.9*	22,906 *0.8*	23,168 *1.1*	23,371 *0.9*	23,570 *0.9*	22,022 *1.4*	22,513 *2.2*	23,254 *3.3*
Household disposable income ($ millions)	20,817 *0.4*	20,790 *−0.1*	20,910 *0.6*	20,886 *−0.1*	21,104 *1.0*	20,937 *−0.8*	21,271 *1.6*	21,318 *0.2*	21,438 *0.6*	21,677 *1.1*	21,853 *0.8*	22,029 *0.8*	20,851 *0.6*	21,158 *1.5*	21,749 *2.8*
Household net savings rate (per cent)	−0.5	−2.1	−2.9	−2.5	−0.8	−2.8	−2.6	−3.3	−3.5	−3.5	−3.5	−3.4	−2.0	−2.4	−3.5
Population (000s)	755 *0.0*	754 *−0.1*	754 *0.0*	755 *0.1*	754 *−0.1*	753 *−0.1*	753 *0.0*	754 *0.0*	754 *0.0*	754 *0.0*	755 *0.0*	755 *0.1*	754 *−0.2*	754 *−0.1*	754 *0.1*
Employment (000s)	357 *0.3*	353 *−1.1*	353 *−0.1*	352 *−0.3*	354 *0.7*	351 *−0.7*	353 *0.5*	355 *0.4*	355 *0.2*	357 *0.4*	358 *0.3*	359 *0.3*	354 *−0.2*	353 *−0.1*	357 *1.1*
Labour force (000s)	396 *0.3*	393 *−0.8*	391 *−0.5*	390 *−0.1*	394 *0.9*	391 *−0.7*	392 *0.3*	393 *0.2*	394 *0.1*	395 *0.3*	395 *0.1*	396 *0.1*	392 *−0.6*	393 *0.0*	395 *0.6*
Labour force participation rate (per cent)	63.6	63.2	62.9	62.8	63.3	62.9	63.1	63.2	63.3	63.5	63.5	63.5	63.1	63.1	63.4
Unemployment rate (per cent)	9.8	10.1	9.8	10.0	10.2	10.1	9.9	9.8	9.7	9.6	9.4	9.2	9.9	10.0	9.5
Retail sales ($ millions)	11,320 *1.3*	11,477 *1.4*	11,745 *2.3*	11,571 *−1.5*	11,343 *−2.0*	11,595 *2.2*	11,770 *1.5*	11,891 *1.0*	11,976 *0.7*	12,120 *1.2*	12,218 *0.8*	12,304 *0.7*	11,528 *3.8*	11,650 *1.1*	12,155 *4.3*
Housing starts (units, 000s)	2,218 *−24.2*	1,811 *−18.3*	2,769 *52.9*	2,306 *−16.7*	1,926 *−16.5*	1,615 *−16.1*	1,470 *−8.9*	1,641 *11.6*	1,633 *−0.5*	1,816 *11.2*	1,791 *−1.4*	1,775 *−0.9*	2,276 *−19.9*	1,663 *−26.9*	1,753 *5.4*
Net interprovincial migration (000s)	−3.1	−4.7	−3.3	−1.7	−2.5	−1.0	−0.7	−0.4	−0.1	0.1	0.2	0.3	−3.2	−1.1	0.1
Net international migration (000s)	0.9	4.2	5.2	0.2	0.1	1.0	1.7	1.7	1.7	1.7	1.7	1.7	2.6	1.1	1.7

Shaded area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Key Economic Indicators: New Brunswick cont'd

(Forecast Completed: July 16, 2015)

	2017Q1	2017Q2	2017Q3	2017Q4	2018Q1	2018Q2	2018Q3	2018Q4	2019Q1	2019Q2	2019Q3	2019Q4	2017	2018	2019
GDP at market prices ($ millions)	35,671	36,058	36,443	36,779	37,331	37,735	38,078	38,265	38,590	38,887	39,110	39,225	36,238	37,852	38,953
	1.3	*1.1*	*1.1*	*0.9*	*1.5*	*1.1*	*0.9*	*0.5*	*0.8*	*0.8*	*0.6*	*0.3*	*4.4*	*4.5*	*2.9*
GDP at market prices (2007 $ millions)	29,714	29,865	30,061	30,263	30,539	30,695	30,823	30,933	31,006	31,071	31,110	31,122	29,976	30,747	31,077
	0.7	*0.5*	*0.7*	*0.7*	*0.9*	*0.5*	*0.4*	*0.4*	*0.2*	*0.2*	*0.1*	*0.0*	*2.5*	*2.6*	*1.1*
GDP at basic prices (2007 $ millions)	27,402	27,541	27,722	27,908	28,162	28,306	28,424	28,525	28,592	28,653	28,689	28,700	27,643	28,354	28,659
	0.7	*0.5*	*0.7*	*0.7*	*0.9*	*0.5*	*0.4*	*0.4*	*0.2*	*0.2*	*0.1*	*0.0*	*2.5*	*2.6*	*1.1*
Consumer price index (2002 = 1.0)	1.304	1.313	1.319	1.323	1.331	1.340	1.347	1.351	1.359	1.368	1.375	1.379	1.315	1.342	1.370
	0.6	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*2.1*	*2.1*	*2.1*
Implicit price deflator—	1.200	1.207	1.212	1.215	1.222	1.229	1.235	1.237	1.245	1.252	1.257	1.260	1.209	1.231	1.253
GDP at market prices (2007 = 1.0)	*0.6*	*0.6*	*0.4*	*0.3*	*0.6*	*0.6*	*0.5*	*0.1*	*0.6*	*0.6*	*0.4*	*0.3*	*1.8*	*1.8*	*1.8*
Wages and salary per employee ($ 000s)	42.616	42.855	43.121	43.399	43.678	43.938	44.198	44.455	44.717	44.951	45.207	45.418	42.998	44.068	45.073
	0.6	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.5*	*0.6*	*0.5*	*2.5*	*2.5*	*2.3*
Primary household income ($ millions)	23,762	23,989	24,230	24,474	24,745	24,987	25,200	25,357	25,535	25,670	25,828	25,968	24,114	25,072	25,750
	0.8	*1.0*	*1.0*	*1.0*	*1.1*	*1.0*	*0.9*	*0.6*	*0.7*	*0.5*	*0.6*	*0.5*	*3.7*	*4.0*	*2.7*
Household disposable income ($ millions)	22,245	22,445	22,657	22,869	23,083	23,302	23,493	23,639	23,783	23,924	24,071	24,211	22,554	23,379	23,997
	1.0	*0.9*	*0.9*	*0.9*	*0.9*	*1.0*	*0.8*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*3.7*	*3.7*	*2.6*
Household net savings rate (per cent)	-3.2	-3.2	-3.2	-3.2	-3.2	-3.2	-3.1	-3.2	-3.1	-3.0	-3.0	-2.8	-3.2	-3.2	-3.0
Population (000s)	756	756	757	757	757	758	758	759	759	759	760	760	756	758	759
	0.1	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.0*	*0.1*	*0.0*	*0.0*	*0.0*	*0.2*	*0.2*	*0.2*
Employment (000s)	360	362	363	365	366	368	369	369	369	369	369	369	363	368	369
	0.4	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.3*	*0.0*	*0.0*	*0.0*	*0.1*	*0.1*	*1.5*	*1.5*	*0.3*
Labour force (000s)	396	396	398	399	400	401	401	401	400	400	400	400	397	401	400
	0.0	*0.2*	*0.3*	*0.3*	*0.3*	*0.2*	*0.1*	*0.0*	*–0.2*	*0.0*	*–0.1*	*0.1*	*0.6*	*0.9*	*–0.2*
Labour force participation rate (per cent)	63.4	63.5	63.7	63.8	63.9	64.0	64.1	64.0	63.8	63.8	63.7	63.7	63.6	64.0	63.8
Unemployment rate (per cent)	8.9	8.7	8.6	8.5	8.4	8.2	8.0	8.0	7.8	7.8	7.7	7.7	8.7	8.2	7.8
Retail sales ($ millions)	12,389	12,483	12,592	12,711	12,835	12,949	13,043	13,111	13,172	13,225	13,287	13,339	12,544	12,984	13,256
	0.7	*0.8*	*0.9*	*0.9*	*1.0*	*0.9*	*0.7*	*0.5*	*0.5*	*0.4*	*0.5*	*0.4*	*3.2*	*3.5*	*2.1*
Housing starts (units, 000s)	1,903	1,888	1,863	1,848	2,023	2,008	1,984	1,969	2,145	2,130	2,105	2,089	1,875	1,996	2,117
	7.2	*–0.8*	*–1.3*	*–0.8*	*9.5*	*–0.8*	*–1.2*	*–0.8*	*9.0*	*–0.7*	*–1.1*	*–0.8*	*7.0*	*6.4*	*6.1*
Net interprovincial migration (000s)	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	–0.1	–0.1	–0.2	–0.2	0.1	0.1	–0.1
Net international migration (000s)	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.6	1.6	1.6	1.6	1.7	1.7	1.6

Shaded area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Quebec

Elise Martin

Quebec's Export Recovery Stalls Amidst U.S. Winter Doldrums

Highlights

- Housing starts are expected to plunge by 6,400 units this year.
- A bad first quarter will slow growth in exports of goods and services to just 1.1 per cent this year.
- Real business investment is stuck in a slump and will contract by an additional 2.9 per cent this year.

Economic Indicators
(percentage change)

	2014	2015f	2016f
Real GDP	1.4	1.9	2.0
Consumer Price Index	1.4	1.3	2.2
Household disposable income	2.3	3.1	2.9
Employment	–0.1	1.1	1.0
Unemployment rate (level)	7.8	7.8	8.0
Retail sales	1.7	1.7	3.7
Wages and salaries per employee	2.0	1.3	2.0
Population	0.8	0.6	0.9

f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Government and Background Information

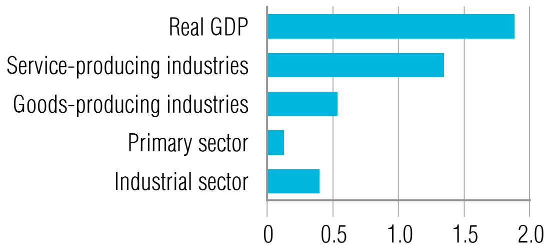
Premier	Philippe Couillard
Next election	2018
Population (2015Q2)	8,245,470
Government balance (2015–16)	0 (balanced)

Sources: Statistics Canada; Provincial budget documents.

Despite the weaker-than-expected performance of its trade sector, Quebec's economy will strengthen this year, advancing by 1.9 per cent, compared with 1.4 per cent last year. Next year, Quebec's GDP is forecast to expand by 2 per cent. The temporary slowdown in Quebec's exports is due to the exceptionally low final demand from U.S. businesses and consumers in the first quarter of 2015. Quebec's exports of goods to other countries jumped by a solid 9.4 per cent last year but will post a meagre 0.8 per cent increase this year due to a very bad first quarter. The U.S. economy suffered a transitory setback with a port strike on the West Coast and exceptionally cold weather on the East Coast this winter. As a result, Quebec's exports of goods and services, which posted 3.9 per cent growth in 2014, will advance by 1.1 per cent this year before rising 3.4 per cent in 2016.

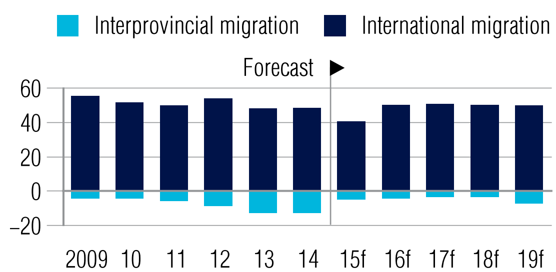
The trade slowdown this year will in turn cause Quebec's export-oriented manufacturing industry to grow by just 1.7 per cent in 2015. Weak demand south of the border will also persuade domestic businesses not to move forward with major investment projects. Non-residential construction and machinery and equipment investment will falter again this year, by 8.2 per cent and 2.1 per cent respectively, before they firm up in 2016 and post 2.4 per cent and 2.3 per cent increases, respectively.

Contributions to Quebec Real GDP Growth, 2015
(by industry/sector, percentage point; GDP, per cent)



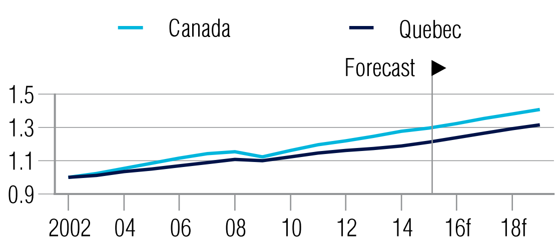
Note: "Primary" is the sum of agriculture, forestry, fishing and trapping, and mining sectors. "Industrial" is the sum of manufacturing, construction, and utilities sectors.
Sources: The Conference Board of Canada; Statistics Canada.

Sources of Migration
(net migration, 000s)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Real GDP, 2002 to 2019
(index, 2002 = 1.0)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Thanks to a 1.1 per cent increase in employment this year, stronger growth in household disposable income will help lift wholesale and retail trade by 2.6 per cent. Once again, consumer spending will support the economic performance of the province while the government holds growth on program expenditures to just 1.2 per cent in 2015–16.

THE EXPORT RECOVERY IS STALLING TEMPORARILY

With a recovery in exports, the decline in the trade deficit was responsible for half the growth in the province's real GDP in 2014, as Quebec's exports grew by 3.9 per cent. However, the U.S. economy has been hit by a bad case of winter doldrums, severely lowering U.S. final demand in the first quarter of the year and affecting Quebec's exports of goods and services, which will increase by only 1.1 per cent this year. The slump in U.S. final demand was temporary, caused by an historic strike by port workers on the West Coast and an exceptionally cold winter. However, the strength of the greenback could impose a heavier drag than expected on U.S. economic activity, as U.S. exporters sell fewer products abroad due to their high relative price. Nevertheless, solid fundamentals are in place to support stronger economic growth south of the border and, in light of encouraging employment numbers, the U.S. economy is forecast to grow by 2.2 per cent in 2015. This, together with the Canadian dollar that remains well below parity, adds optimism to the trade sector outlook.

Primary metals, aerospace products, paper and wood products, and electronics will be fuelling growth in Quebec's exports. Despite Bombardier's setbacks in developing the C Series aircraft and its recent massive waves of layoffs, other companies are faring better. Pratt & Whitney Canada motors will propel Gulfstream's new business jets with the engines being built in Mirabel. Héroux-Devtek landed the most important landing-gear contract in its history and will equip the new Boeing 777. Part of this production will take place in Laval. Quebec exports are poised to rebound and grow 3.4 per cent in 2016 and 3.2 per cent in 2017.

BUSINESS INVESTMENT TO RETREAT AGAIN

Amid the uncertainty brought about by the collapse in crude oil prices, businesses in Canada pulled back on capital plans in the first quarter of 2015. However, the Conference Board's business confidence index shows that confidence has now rebounded. Of the firms surveyed, the numbers saying the present was a bad time to invest decreased substantially, going from 27.3 per cent this winter to 12.9 per cent in the latest survey. Meanwhile, indicators of capacity pressures are emitting mixed signals. The share of firms stating that they were operating at, close to, or above capacity firmed up to 45.1 per cent in this last survey, up from 29.5 per cent in the previous survey.

Nevertheless, this recent optimistic trend will not be enough to offset the contraction in business investment that occurred in the first half of the year. Accordingly, a 2.9 per cent decline is expected in business investment this year in the province. A turnaround is anticipated next year as both investment in machinery and equipment and in non-residential construction will bounce back and grow by 2.3 and 2.4 per cent respectively. All in all, the Conference Board forecasts positive growth of 0.5 per cent in 2016 and 3.3 per cent in 2017 for real business investment.

CONSUMER SPENDING HOLDING FIRM

Indebted consumers, who are supporting economic growth with their spending, should be passing the baton to businesses. But firms are not playing along and are hesitating to expand capacity; therefore, consumer spending will continue to be a key contributor to the Quebec economy in 2015, accounting for close to 75 per cent of the increase in real GDP this year. In 2014, household final consumption expenditures were surprisingly resilient, growing by 2 per cent; this was despite the absence of job creation and an increase in household disposable income that was below the 10-year average. But, to maintain their spending, consumers have had to save less and rely more heavily on debt. The savings rate in the province, therefore, has fallen significantly and fell to 1.5 per cent in 2014, down from 2.7 per cent in 2013. This year, the labour market is generating more jobs. Employment is expected to be up by 1.1 per cent, providing a boost to households' real purchasing power. This, along with the lower gasoline prices, an increasing reliance on credit, and federal government transfers, will permit consumers to continue acting as the locomotive of Quebec's economy.

HAVOC IN THE CONSTRUCTION INDUSTRY

Hampered by a big retreat in multiple-unit housing starts, Quebec's construction industry will contract for the third year in a row, down by 1.3 percent. This will lead to about 9,400 construction workers losing their jobs in 2015. The adverse situation is expected to continue next year, with the employment level in the construction sector down by 12.2 per cent from its peak of 2013. Large infrastructure projects—such as the replacement of the Champlain Bridge and the reconstruction of the Turcot Interchange in Montréal—will not be enough to offset the plunge in housing starts and the lull in private non-residential projects.

Forecast Risks

Short term

- Large-scale mobilization of public sector unions could disrupt the economy this fall as negotiations for new collective agreements take place.

Medium term

- A U.S. economy, hampered by the rise of the greenback, could turn in a lower-than-expected performance, disrupting the export recovery experienced by Quebec's manufacturing industry.

Source: The Conference Board of Canada.

Key Economic Indicators: Quebec

(Forecast Completed: July 16, 2015)

	2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4	2016Q1	2016Q2	2016Q3	2016Q4	2014	2015	2016
GDP at market prices ($ millions)	368,971	373,037	377,049	378,351	377,417	382,743	387,809	391,551	393,402	397,453	401,694	404,766	374,352	384,880	399,329
	0.9	*1.1*	*1.1*	*0.3*	*–0.2*	*1.4*	*1.3*	*1.0*	*0.5*	*1.0*	*1.1*	*0.8*	*3.2*	*2.8*	*3.8*
GDP at market prices (2007 $ millions)	334,039	335,312	337,167	337,550	338,909	341,423	343,532	345,281	346,161	348,112	350,496	351,970	336,017	342,286	349,185
	0.2	*0.4*	*0.6*	*0.1*	*0.4*	*0.7*	*0.6*	*0.5*	*0.3*	*0.6*	*0.7*	*0.4*	*1.4*	*1.9*	*2.0*
GDP at basic prices (2007 $ millions)	309,964	311,175	312,900	313,260	314,853	316,869	318,699	320,324	321,161	322,974	325,315	326,811	311,825	317,686	324,065
	0.2	*0.4*	*0.6*	*0.1*	*0.5*	*0.6*	*0.6*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*1.4*	*1.9*	*2.0*
Consumer price index (2002 = 1.0)	1.224	1.237	1.238	1.236	1.237	1.248	1.255	1.260	1.267	1.276	1.283	1.287	1.234	1.250	1.278
	0.6	*1.1*	*0.1*	*–0.1*	*0.1*	*0.8*	*0.6*	*0.4*	*0.6*	*0.7*	*0.5*	*0.3*	*1.4*	*1.3*	*2.2*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.105	1.113	1.118	1.121	1.114	1.121	1.129	1.134	1.136	1.142	1.146	1.150	1.114	1.124	1.144
	0.7	*0.7*	*0.5*	*0.2*	*–0.6*	*0.7*	*0.7*	*0.5*	*0.2*	*0.5*	*0.4*	*0.3*	*1.7*	*0.9*	*1.7*
Wages and salary per employee ($ 000s)	40.344	40.850	41.096	41.037	40.881	41.351	41.501	41.684	41.892	42.066	42.300	42.522	40.832	41.354	42.195
	0.7	*1.3*	*0.6*	*–0.1*	*–0.4*	*1.2*	*0.4*	*0.4*	*0.5*	*0.4*	*0.6*	*0.5*	*2.0*	*1.3*	*2.0*
Primary household income ($ millions)	251,584	253,349	255,089	255,714	257,896	260,111	262,187	264,088	266,541	268,629	270,987	273,286	253,934	261,070	269,861
	0.8	*0.7*	*0.7*	*0.2*	*0.9*	*0.9*	*0.8*	*0.7*	*0.9*	*0.8*	*0.9*	*0.8*	*2.4*	*2.8*	*3.4*
Household disposable income ($ millions)	220,872	222,738	224,591	225,516	227,277	228,921	232,402	232,571	233,959	235,821	237,893	240,062	223,429	230,293	236,934
	1.0	*0.8*	*0.8*	*0.4*	*0.8*	*0.7*	*1.5*	*0.1*	*0.6*	*0.8*	*0.9*	*0.9*	*2.3*	*3.1*	*2.9*
Household net savings rate (per cent)	1.8	1.3	1.6	1.3	1.9	1.3	1.4	0.8	0.6	0.6	0.6	0.7	1.5	1.4	0.6
Population (000s)	8179	8191	8215	8236	8240	8245	8264	8283	8302	8320	8339	8357	8205	8258	8329
	0.1	*0.1*	*0.3*	*0.3*	*0.0*	*0.1*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.8*	*0.6*	*0.9*
Employment (000s)	4066	4043	4056	4060	4090	4098	4108	4112	4124	4137	4149	4161	4056	4102	4143
	–0.2	*–0.5*	*0.3*	*0.1*	*0.7*	*0.2*	*0.2*	*0.1*	*0.3*	*0.3*	*0.3*	*0.3*	*–0.1*	*1.1*	*1.0*
Labour force (000s)	4406	4390	4403	4394	4417	4440	4462	4475	4489	4499	4510	4520	4398	4449	4504
	–0.1	*–0.4*	*0.3*	*–0.2*	*0.5*	*0.5*	*0.5*	*0.3*	*0.3*	*0.2*	*0.2*	*0.2*	*0.1*	*1.1*	*1.3*
Labour force participation rate (per cent)	65.0	64.6	64.6	64.4	64.7	64.9	65.2	65.3	65.4	65.4	65.4	65.5	64.7	65.0	65.4
Unemployment rate (per cent)	7.7	7.9	7.9	7.6	7.4	7.7	7.9	8.1	8.1	8.1	8.0	8.0	7.8	7.8	8.0
Retail sales ($ millions)	106,314	108,968	109,062	108,205	107,520	109,553	111,054	111,961	112,772	113,638	114,603	115,512	108,137	110,022	114,131
	–1.1	*2.5*	*0.1*	*–0.8*	*–0.6*	*1.9*	*1.4*	*0.8*	*0.7*	*0.8*	*0.8*	*0.8*	*1.7*	*1.7*	*3.7*
Housing starts (units, 000s)	38,874	39,173	37,181	40,012	28,222	35,801	32,893	32,683	31,880	31,635	31,429	31,364	38,810	32,400	31,577
	–1.1	*0.8*	*–5.1*	*7.6*	*–29.5*	*26.9*	*–8.1*	*–0.6*	*–2.5*	*–0.8*	*–0.7*	*–0.2*	*2.8*	*–16.5*	*–2.5*
Net interprovincial migration (000s)	–10.2	–15.4	–20.1	–6.6	–10.4	–5.2	–3.0	–2.3	–3.6	–4.3	–4.5	–4.5	–13.1	–5.2	–4.2
Net international migration (000s)	40.4	83.1	69.0	2.4	25.3	37.4	50.3	50.5	50.3	50.4	50.5	50.6	48.7	40.9	50.5

Shaded area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Key Economic Indicators: Quebec cont'd
(Forecast Completed: July 16, 2015)

	2017Q1	2017Q2	2017Q3	2017Q4	2018Q1	2018Q2	2018Q3	2018Q4	2019Q1	2019Q2	2019Q3	2019Q4	2017	2018	2019
GDP at market prices ($ millions)	409,967	414,080	418,090	421,494	426,381	430,526	434,478	437,007	441,188	445,128	448,529	450,927	415,908	432,098	446,443
	1.3	*1.0*	*1.0*	*0.8*	*1.2*	*1.0*	*0.9*	*0.6*	*1.0*	*0.9*	*0.8*	*0.5*	*4.2*	*3.9*	*3.3*
GDP at market prices (2007 $ millions)	354,409	355,849	357,748	359,678	361,596	362,991	364,493	366,113	367,378	368,635	369,843	370,954	356,921	363,798	369,202
	0.7	*0.4*	*0.5*	*0.5*	*0.5*	*0.4*	*0.4*	*0.4*	*0.3*	*0.3*	*0.3*	*0.3*	*2.2*	*1.9*	*1.5*
GDP at basic prices (2007 $ millions)	329,194	330,658	332,549	334,470	336,378	337,806	339,337	340,980	342,295	343,605	344,872	346,051	331,718	338,625	344,206
	0.7	*0.4*	*0.6*	*0.6*	*0.6*	*0.4*	*0.5*	*0.5*	*0.4*	*0.4*	*0.4*	*0.3*	*2.4*	*2.1*	*1.6*
Consumer price index (2002 = 1.0)	1.294	1.304	1.310	1.314	1.321	1.331	1.337	1.341	1.349	1.358	1.365	1.369	1.305	1.333	1.360
	0.6	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*2.1*	*2.1*	*2.1*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.157	1.164	1.169	1.172	1.179	1.186	1.192	1.194	1.201	1.208	1.213	1.216	1.165	1.188	1.209
	0.6	*0.6*	*0.4*	*0.3*	*0.6*	*0.6*	*0.5*	*0.1*	*0.6*	*0.5*	*0.4*	*0.2*	*1.9*	*1.9*	*1.8*
Wages and salary per employee ($ 000s)	42.762	43.017	43.273	43.523	43.769	44.091	44.345	44.636	44.926	45.210	45.502	45.799	43.144	44.210	45.359
	0.6	*0.6*	*0.6*	*0.6*	*0.6*	*0.7*	*0.6*	*0.7*	*0.7*	*0.6*	*0.6*	*0.7*	*2.2*	*2.5*	*2.6*
Primary household income ($ millions)	275,636	278,287	280,963	283,614	286,073	288,787	291,002	293,517	296,131	298,527	300,844	303,179	279,625	289,845	299,670
	0.9	*1.0*	*1.0*	*0.9*	*0.9*	*0.9*	*0.8*	*0.9*	*0.9*	*0.8*	*0.8*	*0.8*	*3.6*	*3.7*	*3.4*
Household disposable income ($ millions)	243,203	245,460	247,713	249,948	251,890	254,278	256,267	258,447	260,470	262,665	264,721	266,730	246,581	255,220	263,647
	1.3	*0.9*	*0.9*	*0.9*	*0.8*	*0.9*	*0.8*	*0.9*	*0.8*	*0.8*	*0.8*	*0.8*	*4.1*	*3.5*	*3.3*
Household net savings rate (per cent)	0.9	0.9	0.9	0.9	0.9	0.9	1.0	0.9	1.0	1.1	1.1	1.2	0.9	0.9	1.1
Population (000s)	8,374	8,392	8,410	8,428	8,446	8,464	8,482	8,500	8,517	8,534	8,550	8,567	8,401	8,473	8,542
	0.2	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.9*	*0.9*	*0.8*
Employment (000s)	4,175	4,189	4,203	4,217	4,226	4,234	4,241	4,250	4,258	4,267	4,273	4,279	4,196	4,238	4,269
	0.3	*0.3*	*0.3*	*0.3*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.1*	*0.1*	*1.3*	*1.0*	*0.7*
Labour force (000s)	4,529	4,537	4,547	4,557	4,565	4,569	4,574	4,579	4,584	4,588	4,593	4,597	4,543	4,572	4,590
	0.2	*0.2*	*0.2*	*0.2*	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.8*	*0.6*	*0.4*
Labour force participation rate (per cent)	65.5	65.5	65.5	65.6	65.6	65.5	65.5	65.4	65.4	65.4	65.3	65.3	65.5	65.5	65.4
Unemployment rate (per cent)	7.8	7.7	7.6	7.4	7.4	7.3	7.3	7.2	7.1	7.0	7.0	6.9	7.6	7.3	7.0
Retail sales ($ millions)	116,719	117,602	118,557	119,607	120,512	121,561	122,367	123,324	124,147	124,999	125,834	126,580	118,121	121,941	125,390
	1.0	*0.8*	*0.8*	*0.9*	*0.8*	*0.9*	*0.7*	*0.8*	*0.7*	*0.7*	*0.7*	*0.6*	*3.5*	*3.2*	*2.8*
Housing starts (units, 000s)	33,525	33,468	33,265	33,207	33,403	33,346	33,147	33,089	33,102	33,046	32,848	32,787	33,366	33,246	32,946
	6.9	*–0.2*	*–0.6*	*–0.2*	*0.6*	*–0.2*	*–0.6*	*–0.2*	*0.0*	*–0.2*	*–0.6*	*–0.2*	*5.7*	*–0.4*	*–0.9*
Net interprovincial migration (000s)	–3.8	–3.8	–3.6	–3.5	–2.9	–3.3	–3.7	–4.5	–6.8	–7.4	–7.5	–7.7	–3.7	–3.6	–7.4
Net international migration (000s)	50.9	51.0	51.0	50.9	50.6	50.5	50.4	50.3	50.2	50.1	50.1	50.0	50.9	50.5	50.1

Shaded area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Elise Martin

La reprise des exportations du Québec ralentie par un hiver difficile aux États-Unis

Faits saillants

- Cette année, une baisse de 6400 unités dans les mises en chantier devrait faire perdre 9400 emplois dans l'industrie de la construction.
- Les mauvais résultats du premier trimestre limiteront à 1,1 % la hausse des exportations de biens et services.
- Les investissements réels des entreprises demeurent en déclin et diminueront cette année de 2,9 %.

Indicateurs économiques
(variation en %)

	2014	2015p	2016p
PIB réel au prix de base	1,4	1,9	2,0
IPC	1,4	1,3	2,2
Revenu disponible des ménages	2,3	3,1	2,9
Emploi	–0,1	1,1	1,0
Taux de chômage	7,8	7,8	8,0
Ventes au détail	1,7	1,7	3,7
Salaires, par employé	2,0	1,3	2,0
Population	0,8	0,6	0,9

p = prévision
Sources : Le Conference Board du Canada; Statistique Canada.

Renseignements généraux et sur le gouvernement

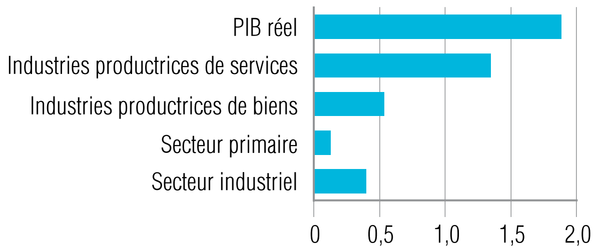
Premier ministre	Philippe Couillard
Prochaines élections	2018
Population (T2, 2015)	8 245 470
Solde budgétaire de l'État (2015–2016)	0 (équilibre)

Sources : Statistique Canada; documentation du budget provincial.

En dépit de résultats moins bons que prévu dans le commerce extérieur, l'économie du Québec se renforcera cette année, progressant de 1,9 % comparativement à 1,4 % l'an dernier. L'an prochain, le gain devrait être plus important, soit de 2 %. Le ralentissement temporaire des exportations du Québec est attribuable à la demande finale exceptionnellement faible des entreprises et des consommateurs américains au premier trimestre de 2015. Les exportations québécoises de biens vers l'étranger ont bondi de 9,4 % l'an dernier, mais elles ne progresseront cette année que de 0,8 % en raison d'un premier trimestre fort décevant. L'économie américaine s'est ressentie d'une grève dans les ports de la côte Ouest et du froid exceptionnel observé sur la côte Est cet hiver. Résultat : les exportations de biens et services du Québec, en hausse de 3,9 % en 2014, ne croîtront que de 1,1 % cette année, puis grimperont de 3,4 % en 2016.

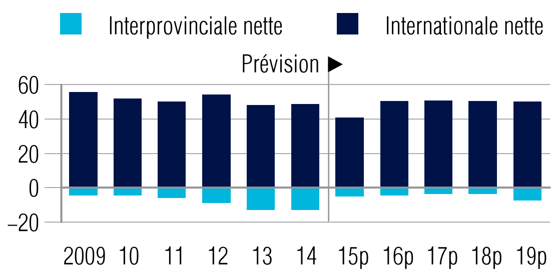
Le ralentissement des échanges commerciaux enregistré cette année se répercutera sur l'industrie manufacturière axée sur l'exportation, industrie qui ne gagnera que 1,7 % en 2015. La faible demande américaine amènera aussi les entreprises locales à retarder leurs grands projets d'investissement. La construction non résidentielle, comme les investissements liés au matériel et à l'outillage, inscriront cette année d'autres reculs de 8,2 % et 2,1 % respectivement, avant de se redresser en 2016; la première affichera une croissance de 2,4 %, l'autre de 2,3 %.

Contribution à la croissance du PIB réel du Québec
(pour 2015, industrie ou secteur, apport en points de pourcentage; PIB, en %)



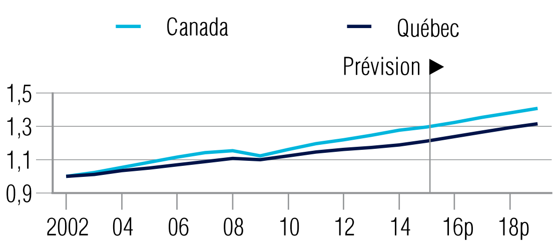
Nota : « Primaire » désigne l'ensemble des secteurs de l'agriculture, de la foresterie, de la pêche et du piégeage, et le secteur minier. « Industriel » désigne l'ensemble des secteurs de la fabrication, de la construction et des services d'utilité publics.
Sources : Le Conference Board du Canada; Statistique Canada.

Sources de migration
(migration nette, en milliers)



p = prévision
Sources : Le Conference Board du Canada; Statistique Canada.

PIB réel de 2002 à 2019
(indice, 2002 = 1,0)



p = prévision
Sources : Le Conference Board du Canada; Statistique Canada.

Par suite d'une progression de 1,1 % de l'emploi cette année, une croissance plus vive du revenu disponible des ménages aidera à stimuler le commerce de gros et de détail, qui croîtra de 2,6 %. Encore une fois, les dépenses de consommation seront déterminantes dans les résultats économiques de la province, tandis que les pouvoirs publics limitent à seulement 1,2 % la hausse des dépenses de programmes en 2015-2016.

LA REPRISE DES EXPORTATIONS CONNAÎT UNE STAGNATION TEMPORAIRE

Avec la reprise des exportations, qui ont inscrit une hausse de 3,9 %, la réduction du déficit commercial a représenté la moitié de la croissance du PIB réel de la province en 2014. Toutefois, l'hiver rigoureux a freiné l'économie américaine, de sorte que la demande finale des États-Unis a considérablement diminué au premier trimestre; de ce fait, les exportations québécoises de biens et services n'augmenteront que de 1,1 % cette année. Le repli de la demande finale des États-Unis, lié à une grève sans précédent des travailleurs portuaires de la côte Ouest et à un hiver exceptionnellement froid, sera passager. Cependant, la force du billet vert pourrait peser encore davantage que prévu sur l'activité économique américaine, les exportateurs des États-Unis vendant moins de produits à l'étranger parce que ceux-ci sont devenus relativement chers. Mais de solides facteurs économiques fondamentaux sont là pour permettre une croissance économique accrue au sud de la frontière et, à la lumière de statistiques encourageantes en matière d'emploi, l'économie américaine est en voie de progresser de 2,2 % en 2015. Cela, conjugué avec un huard assez loin de la parité, les perspectives du secteur des exportations sont encore plus favorables.

Les métaux de première transformation, les produits de l'aérospatiale, de l'électronique, du papier et du bois favoriseront la croissance des exportations québécoises. Si Bombardier connaît des difficultés dans la mise au point des appareils de la C Series et a récemment procédé à des mises à pied massives, d'autres entreprises affichent de meilleurs résultats. Ce sont des moteurs de Pratt & Whitney Canada construits à Mirabel qui équiperont les nouveaux jets d'affaires de Gulfstream et Héroux-Devtek a décroché le plus important contrat de son histoire en matière de trains d'atterrissage, ceux-là destinés aux nouveaux Boeing 777. La production se fera en partie à Laval. Les exportations du Québec devraient ainsi rebondir et croître de 3,4 % en 2016, puis de 3,2 % en 2017.

NOUVEAU RECUL DES INVESTISSEMENTS DES ENTREPRISES

Dans le contexte d'incertitude créé par l'effondrement des prix du pétrole brut, les entreprises canadiennes ont réduit leurs plans d'immobilisations au premier trimestre de 2015. Toutefois, l'indice de confiance du Conference Board du Canada montre que le climat s'est amélioré. Parmi les entreprises interrogées, le nombre de celles estimant que le moment n'est pas propice pour investir a considérablement diminué : elles étaient 27,3 % l'hiver dernier, mais seulement 12,9 % lors du dernier sondage. Parallèlement, les indicateurs relatifs aux pressions sur la capacité de production donnent des signaux mixtes : la proportion des entreprises répondant qu'elles fonctionnent à plein régime et près ou au-delà de leur capacité atteint désormais 45,1 %, contre 29,5 % dans le sondage précédent.

Le récent courant d'optimisme ne suffira cependant pas à contrebalancer la diminution des investissements des entreprises enregistrée au premier semestre de l'année. Ainsi, un repli de 2,9 % des investissements des entreprises est prévu dans la province en 2015. Un redressement est attendu l'an prochain, avec une hausse de 2,3 % des investissements en matériel et en outillage, et de 2,4 % dans la construction non résidentielle en 2016. Globalement, le Conference Board prévoit une progression de 0,5 % en 2016 et de 3,3 % des investissements réels des entreprises en 2017.

LES DÉPENSES DE CONSOMMATION SE MAINTIENNENT

Quoiqu'endettés, les consommateurs nourrissent la croissance économique par leurs dépenses. Ils devraient passer le relais aux entreprises, sauf que celles-ci ne sont pas prêtes et hésitent à accroître leur capacité. Les dépenses de consommation demeureront donc un pivot de l'économie du Québec en 2015, source de près de 75 % de la hausse du PIB réel cette année. En 2014, les dépenses de consommation finales des ménages ont fait preuve d'une surprenante résilience, affichant une hausse de 2 % malgré l'absence de création d'emploi et une progression du revenu disponible des ménages inférieure à la moyenne sur 10 ans. Mais pour continuer à dépenser, les consommateurs ont dû réduire leur épargne et recourir davantage au crédit. Le taux d'épargne dans la province a donc beaucoup baissé : 1,5 % en 2014 contre 2,7 % en 2013. Cette année, le marché du travail crée plus d'emplois. L'embauche devrait progresser de 1,1 %, ce qui devrait favoriser le pouvoir d'achat réel des ménages. De concert avec le prix peu élevé de l'essence, le recours accru au crédit et les transferts du gouvernement fédéral, cela permettra aux consommateurs de demeurer la locomotive de l'économie québécoise.

DIFFICULTÉS DANS L'INDUSTRIE DE LA CONSTRUCTION

Vu la baisse marquée des mises en chantier dans les immeubles à logements multiples, l'industrie québécoise de la construction se contractera pour une troisième année d'affilée. Ce recul de 1,3 % fera en sorte que quelque 9400 travailleurs perdront leur emploi dans le secteur de la construction en 2015. Cette conjoncture défavorable ne s'améliorera pas en 2016, si bien que le niveau d'embauche dans ce secteur aura baissé de 12,2 % par rapport au sommet de 2013. Les grands projets d'infrastructures, tels que le remplacement du pont Champlain et la reconstruction de l'échangeur Turcot, à Montréal, ne réussiront pas à faire contrepoids à la chute marquée des mises en chantier résidentielles et à la rareté des projets non résidentiels privés.

Risques conjoncturels

Court terme

- Une forte mobilisation des syndicats de la fonction publique pourrait perturber l'activité économique cet automne lors des négociations visant de nouvelles conventions collectives.

Moyen terme

- Si l'économie américaine, gênée par la hausse du billet vert, n'affiche pas les résultats escomptés, l'élan de reprise de l'industrie manufacturière du Québec pourrait être freiné.

Source : Le Conference Board du Canada.

Principaux indicateurs économiques : Québec
(Prévision en date du 16 juillet 2015)

	2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4	2016Q1	2016Q2	2016Q3	2016Q4	2014	2015	2016
PIB aux prix du marché (en millions de dollars)	368 971 *0,9*	373 037 *1,1*	377 049 *1,1*	378 351 *0,3*	377 417 *–0,2*	382 743 *1,4*	387 809 *1,3*	391 551 *1,0*	393 402 *0,5*	397 453 *1,0*	401 694 *1,1*	404 766 *0,8*	374 352 *3,2*	384 880 *2,8*	399 329 *3,8*
PIB aux prix du marché (en millions de dollars de 2007)	334 039 *0,2*	335 312 *0,4*	337 167 *0,6*	337 550 *0,1*	338 909 *0,4*	341 423 *0,7*	343 532 *0,6*	345 281 *0,5*	346 161 *0,3*	348 112 *0,6*	350 496 *0,7*	351 970 *0,4*	336 017 *1,4*	342 286 *1,9*	349 185 *2,0*
PIB aux prix de base (en millions de dollars de 2007)	309 964 *0,2*	311 175 *0,4*	312 900 *0,6*	313 260 *0,1*	314 853 *0,5*	316 869 *0,6*	318 699 *0,6*	320 324 *0,5*	321 161 *0,3*	322 974 *0,6*	325 315 *0,7*	326 811 *0,5*	311 825 *1,4*	317 686 *1,9*	324 065 *2,0*
Indice des prix à la consommation (2002 = 1,0)	1,224 *0,6*	1,237 *1,1*	1,238 *0,1*	1,236 *–0,1*	1,237 *0,1*	1,248 *0,8*	1,255 *0,6*	1,260 *0,4*	1,267 *0,6*	1,276 *0,7*	1,283 *0,5*	1,287 *0,3*	1,234 *1,4*	1,250 *1,3*	1,278 *2,2*
Déflateur implicite des prix — **PIB aux prix du marché** (2007 = 1,0)	1,105 *0,7*	1,113 *0,7*	1,118 *0,5*	1,121 *0,2*	1,114 *–0,6*	1,121 *0,7*	1,129 *0,7*	1,134 *0,5*	1,136 *0,2*	1,142 *0,5*	1,146 *0,4*	1,150 *0,3*	1,114 *1,7*	1,124 *0,9*	1,144 *1,7*
Rémunération des employés (en milliers de dollars)	40,344 *0,7*	40,850 *1,3*	41,096 *0,6*	41,037 *–0,1*	40,881 *–0,4*	41,351 *1,2*	41,501 *0,4*	41,684 *0,4*	41,892 *0,5*	42,066 *0,4*	42,300 *0,6*	42,522 *0,5*	40,832 *2,0*	41,354 *1,3*	42,195 *2,0*
Revenu primaire des ménages (en millions de dollars)	251 584 *0,8*	253 349 *0,7*	255 089 *0,7*	255 714 *0,2*	257 896 *0,9*	260 111 *0,9*	262 187 *0,8*	264 088 *0,7*	266 541 *0,9*	268 629 *0,8*	270 987 *0,9*	273 286 *0,8*	253 934 *2,4*	261 070 *2,8*	269 861 *3,4*
Revenu disponible des ménages (en millions de dollars)	220 872 *1,0*	222 738 *0,8*	224 591 *0,8*	225 516 *0,4*	227 277 *0,8*	228 921 *0,7*	232 402 *1,5*	232 571 *0,1*	233 959 *0,6*	235 821 *0,8*	237 893 *0,9*	240 062 *0,9*	223 429 *2,3*	230 293 *3,1*	236 934 *2,9*
Taux d'épargne nette des ménages (p. cent)	1,8	1,3	1,6	1,3	1,9	1,3	1,4	0,8	0,6	0,6	0,6	0,7	1,5	1,4	0,6
Population (en milliers)	8179 *0,1*	8191 *0,1*	8215 *0,3*	8236 *0,3*	8240 *0,0*	8245 *0,1*	8264 *0,2*	8283 *0,2*	8302 *0,2*	8320 *0,2*	8339 *0,2*	8357 *0,2*	8205 *0,8*	8258 *0,6*	8329 *0,9*
Emploi (en milliers)	4066 *–0,2*	4043 *–0,5*	4056 *0,3*	4060 *0,1*	4090 *0,7*	4098 *0,2*	4108 *0,2*	4112 *0,1*	4124 *0,3*	4137 *0,3*	4149 *0,3*	4161 *0,3*	4056 *–0,1*	4102 *1,1*	4143 *1,0*
Population active (en milliers)	4406 *–0,1*	4390 *–0,4*	4403 *0,3*	4394 *–0,2*	4417 *0,5*	4440 *0,5*	4462 *0,5*	4475 *0,3*	4489 *0,3*	4499 *0,2*	4510 *0,2*	4520 *0,2*	4398 *0,1*	4449 *1,1*	4504 *1,3*
Participation au marché du travail	65,0	64,6	64,6	64,4	64,7	64,9	65,2	65,3	65,4	65,4	65,4	65,5	64,7	65,0	65,4
Taux de chômage (p. cent)	7,7	7,9	7,9	7,6	7,4	7,7	7,9	8,1	8,1	8,1	8,0	8,0	7,8	7,8	8,0
Ventes au détail (en millions de dollars)	106 314 *–1,1*	108 968 *2,5*	109 062 *0,1*	108 205 *–0,8*	107 520 *–0,6*	109 553 *1,9*	111 054 *1,4*	111 961 *0,8*	112 772 *0,7*	113 638 *0,8*	114 603 *0,8*	115 512 *0,8*	108 137 *1,7*	110 022 *1,7*	114 131 *3,7*
Mises en chantier (en milliers d'unités)	38 874 *–1,1*	39 173 *0,8*	37 181 *–5,1*	40 012 *7,6*	28 222 *–29,5*	35 801 *26,9*	32 893 *–8,1*	32 683 *–0,6*	31 880 *–2,5*	31 635 *–0,8*	31 429 *–0,7*	31 364 *–0,2*	38 810 *2,8*	32 400 *–16,5*	31 577 *–2,5*
Solde migratoire interprovincial (en milliers)	–10,2	–15,4	–20,1	–6,6	–10,4	–5,2	–3,0	–2,3	–3,6	–4,3	–4,5	–4,5	–13,1	–5,2	–4,2
Solde migratoire international (en milliers)	40,4	83,1	69,0	2,4	25,3	37,4	50,3	50,5	50,3	50,4	50,5	50,6	48,7	40,9	50,5

Les prévisions se trouvent dans la partie ombragée du tableau.
À moins d'indications contraires, toutes les données sont exprimées en millions de dollars, au taux annuel désaisonnalisé.
Pour chaque indicateur, la première ligne donne le niveau, la deuxième la variation en pourcentage par rapport à la période précédente.
Sources: Le Conference Board du Canada; Statistique Canada; Répertoire des séries chronologiques de la Société canadienne d'hypothèques et de logement (SCHL).

Principaux indicateurs économiques : Québec suite
(Prévision en date du 16 juillet 2015)

	2017Q1	2017Q2	2017Q3	2017Q4	2018Q1	2018Q2	2018Q3	2018Q4	2019Q1	2019Q2	2019Q3	2019Q4	2017	2018	2019
PIB aux prix du marché	409 967	414 080	418 090	421 494	426 381	430 526	434 478	437 007	441 188	445 128	448 529	450 927	415 908	432 098	446 443
(en millions de dollars)	*1,3*	*1,0*	*1,0*	*0,8*	*1,2*	*1,0*	*0,9*	*0,6*	*1,0*	*0,9*	*0,8*	*0,5*	*4,2*	*3,9*	*3,3*
PIB aux prix du marché	354 409	355 849	357 748	359 678	361 596	362 991	364 493	366 113	367 378	368 635	369 843	370 954	356 921	363 798	369 202
(en millions de dollars de 2007)	*0,7*	*0,4*	*0,5*	*0,5*	*0,5*	*0,4*	*0,4*	*0,4*	*0,3*	*0,3*	*0,3*	*0,3*	*2,2*	*1,9*	*1,5*
PIB aux prix de base	329 194	330 658	332 549	334 470	336 378	337 806	339 337	340 980	342 295	343 605	344 872	346 051	331 718	338 625	344 206
(en millions de dollars de 2007)	*0,7*	*0,4*	*0,6*	*0,6*	*0,6*	*0,4*	*0,5*	*0,5*	*0,4*	*0,4*	*0,4*	*0,3*	*2,4*	*2,1*	*1,6*
Indice des prix à la consommation	1,294	1,304	1,310	1,314	1,321	1,331	1,337	1,341	1,349	1,358	1,365	1,369	1,305	1,333	1,360
(2002 = 1,0)	*0,6*	*0,7*	*0,5*	*0,3*	*0,6*	*0,7*	*0,5*	*0,3*	*0,6*	*0,7*	*0,5*	*0,3*	*2,1*	*2,1*	*2,1*
Déflateur implicite des prix —	1.157	1.164	1.169	1.172	1.179	1.186	1.192	1.194	1.201	1.208	1.213	1.216	1.165	1.188	1.209
PIB aux prix du marché (2007 = 1,0)	*0,6*	*0,6*	*0,4*	*0,3*	*0,6*	*0,6*	*0,5*	*0,1*	*0,6*	*0,5*	*0,4*	*0,2*	*1,9*	*1,9*	*1,8*
Rémunération des employés	42,762	43,017	43,273	43,523	43,769	44,091	44,345	44,636	44,926	45,210	45,502	45,799	43,144	44,210	45,359
(en milliers de dollars)	*0,6*	*0,6*	*0,6*	*0,6*	*0,6*	*0,7*	*0,6*	*0,7*	*0,7*	*0,6*	*0,6*	*0,7*	*2,2*	*2,5*	*2,6*
Revenu primaire des ménages	275 636	278 287	280 963	283 614	286 073	288 787	291 002	293 517	296 131	298 527	300 844	303 179	279 625	289 845	299 670
(en millions de dollars)	*0,9*	*1,0*	*1,0*	*0,9*	*0,9*	*0,9*	*0,8*	*0,9*	*0,9*	*0,8*	*0,8*	*0,8*	*3,6*	*3,7*	*3,4*
Revenu disponible des ménages	243 203	245 460	247 713	249 948	251 890	254 278	256 267	258 447	260 470	262 665	264 721	266 730	246 581	255 220	263 647
(en millions de dollars)	*1,3*	*0,9*	*0,9*	*0,9*	*0,8*	*0,9*	*0,8*	*0,9*	*0,8*	*0,8*	*0,8*	*0,8*	*4,1*	*3,5*	*3,3*
Taux d'épargne nette des ménages (p. cent)	0,9	0,9	0,9	0,9	0,9	0,9	1,0	0,9	1,0	1,1	1,1	1,2	0,9	0,9	1,1
Population	8 374	8 392	8 410	8 428	8 446	8 464	8 482	8 500	8 517	8 534	8 550	8 567	8 401	8 473	8 542
(en milliers)	*0,2*	*0,2*	*0,2*	*0,2*	*0,2*	*0,2*	*0,2*	*0,2*	*0,2*	*0,2*	*0,2*	*0,2*	*0,9*	*0,9*	*0,8*
Emploi	4 175	4 189	4 203	4 217	4 226	4 234	4 241	4 250	4 258	4 267	4 273	4 279	4 196	4 238	4 269
(en milliers)	*0,3*	*0,3*	*0,3*	*0,3*	*0,2*	*0,2*	*0,2*	*0,2*	*0,2*	*0,2*	*0,1*	*0,1*	*1,3*	*1,0*	*0,7*
Population active	4 529	4 537	4 547	4 557	4 565	4 569	4 574	4 579	4 584	4 588	4 593	4 597	4 543	4 572	4 590
(en milliers)	*0,2*	*0,2*	*0,2*	*0,2*	*0,2*	*0,1*	*0,1*	*0,1*	*0,1*	*0,1*	*0,1*	*0,1*	*0,8*	*0,6*	*0,4*
Participation au marché du travail	65,5	65,5	65,5	65,6	65,6	65,5	65,5	65,4	65,4	65,4	65,3	65,3	65,5	65,5	65,4
Taux de chômage (p. cent)	7,8	7,7	7,6	7,4	7,4	7,3	7,3	7,2	7,1	7,0	7,0	6,9	7,6	7,3	7,0
Ventes au détail	116 719	117 602	118 557	119 607	120 512	121 561	122 367	123 324	124 147	124 999	125 834	126 580	118 121	121 941	125 390
(en millions de dollars)	*1,0*	*0,8*	*0,8*	*0,9*	*0,8*	*0,9*	*0,7*	*0,8*	*0,7*	*0,7*	*0,7*	*0,6*	*3,5*	*3,2*	*2,8*
Mises en chantier	33 525	33 468	33 265	33 207	33 403	33 346	33 147	33 089	33 102	33 046	32 848	32 787	33 366	33 246	32 946
(en milliers d'unités)	*6,9*	*–0,2*	*–0,6*	*–0,2*	*0,6*	*–0,2*	*–0,6*	*–0,2*	*0,0*	*–0,2*	*–0,6*	*–0,2*	*5,7*	*–0,4*	*–0,9*
Solde migratoire interprovincial (en milliers)	–3,8	–3,8	–3,6	–3,5	–2,9	–3,3	–3,7	–4,5	–6,8	–7,4	–7,5	–7,7	–3,7	–3,6	–7,4
Solde migratoire international (en milliers)	50,9	51,0	51,0	50,9	50,6	50,5	50,4	50,3	50,2	50,1	50,1	50,0	50,9	50,5	50,1

Les prévisions se trouvent dans la partie ombragée du tableau.
À moins d'indications contraires, toutes les données sont exprimées en millions de dollars, au taux annuel désaisonnalisé.
Pour chaque indicateur, la première ligne donne le niveau, la deuxième la variation en pourcentage par rapport à la période précédente.
Sources: Le Conference Board du Canada; Statistique Canada; Répertoire des séries chronologiques de la Société canadienne d'hypothèques et de logement (SCHL).

Ontario

Fares Bounajm

Consumers Keep Economic Engine Humming

Highlights

- The contracting U.S. economy sends Ontario's economy off to a slow start this year.
- Exports will rebound in the second half of 2015 as the factors dragging them down abate.
- Tourism is experiencing a resurgence, fuelled by the low dollar and sporting events.

Economic Indicators
(percentage change)

	2014	2015f	2016f
Real GDP	2.3	2.0	2.3
Consumer Price Index	2.3	1.3	2.3
Household disposable income	3.3	4.0	3.1
Employment	0.8	0.8	1.2
Unemployment rate (level)	7.3	6.8	6.8
Retail sales	5.0	3.8	4.0
Wages and salaries per employee	2.2	2.6	2.0
Population	1.0	1.0	1.3

f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Government and Background Information

Premier	Kathleen Wynne
Next election	2018
Population (2015Q2)	13,750,073
Government balance (2015–16)	–$8.5 billion

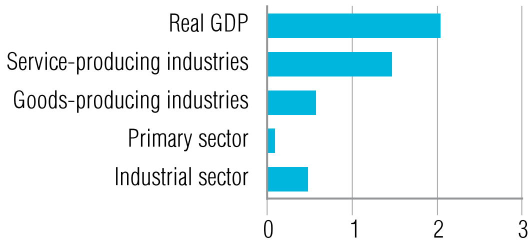
Sources: The Conference Board of Canada; Ontario Ministry of Finance; Statistics Canada.

Ontario's economy got off to a slow start this year as exports fell by an estimated 2.5 per cent in the first half of the year. Despite strong domestic demand, the province could not overcome the first-quarter contraction in the U.S. economy, which was caused by some temporary factors including a West Coast port dispute that disrupted trade and a large drop in energy investment. Ontario's disappointing trade performance will moderate the province's overall growth expectations in 2015 to a still-healthy 2 per cent. Most of this growth will be concentrated in the second half of the year as the U.S. economy shakes off the temporary factors that weighed on it earlier. This positive momentum will carry over to 2016 when real GDP is forecast to expand by 2.3 per cent.

Consumer spending has been quite robust, especially on durable goods as vehicle sales continue to set new records. Strong consumption is supported by healthy consumer confidence in the province, as evidenced by our consumer confidence survey that shows positive intentions on the questions regarding major purchases. Household consumption will gain 2.9 per cent in 2015 and 2.4 per cent in 2016.

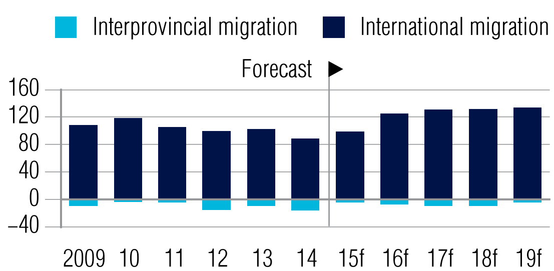
Although export growth has been disappointing so far this year, the weakness is expected to be temporary and better growth is forecast for the remainder of the year. Aside from the contraction in the U.S. economy, a temporary halt in production at motor vehicle plants in Windsor and Oakville led to a large drop in vehicle

Contributions to Ontario Real GDP Growth, 2015
(by industry/sector, percentage point; GDP, per cent)



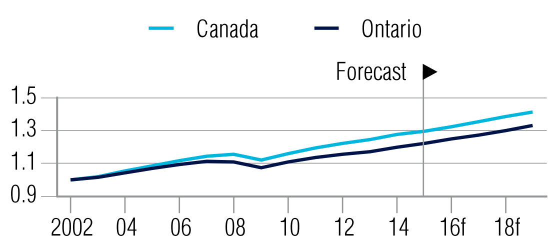
Note: "Primary" is the sum of agriculture, forestry, fishing and trapping, and mining sectors. "Industrial" is the sum of manufacturing, construction, and utilities sectors.
Sources: The Conference Board of Canada; Statistics Canada.

Sources of Migration
(net migration, 000s)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Real GDP, 2002 to 2019
(index, 2002 = 1.0)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

exports in the first quarter. With both plants back in full production, exports will accelerate over the remainder of the year, posting growth of 1.2 per cent. Buttressed by a weak Canadian dollar and stronger growth in the U.S. economy, the province's exports will enjoy strong growth of 4.2 per cent in 2015.

DOMESTIC DEMAND IS HOLDING THE FORT

Households remain the main driver of growth in Ontario's economy. Household consumption is set to grow by 2.9 per cent this year, with a 4.8 per cent increase in spending on durable goods. Motor vehicle sales continue to be outstanding. After breaking a new record in 2014, sales of new motor vehicles in Ontario are up 5.4 per cent year-over-year in the first five months of 2015 and are well on their way to posting a new all-time record. Strong sales have been fuelled in part by low interest rates and loose credit conditions.

Household consumption is forecast to remain robust in the near term. Families across Canada saw their Universal Child Care Benefit payments increase this year. Benefit increases were paid, beginning in July for benefits owed since January 2015, providing families with large retroactive lump sum payments. These tax benefits will help to keep household consumption in Ontario accelerating in the second half of the year. In 2016, household consumption is forecast to slow to a still-robust 2.4 per cent.

In addition to household consumption, domestic demand will be bolstered by substantial residential investment. Housing starts in Ontario are projected to jump by 8.5 per cent this year, encouraged by a healthy demand for housing and the two interest-rate cuts this year by the Bank of Canada. Non-residential investment will be soft, however, as weak demand from the U.S. is giving exporters little reason to invest in machinery and equipment and expand their productive capacity. In 2016, private non-residential investment is projected to grow by 2.4 per cent, as international demand improves.

EXPORTS TO ACCELERATE IN THE SECOND HALF

Despite the Canadian dollar trading at or near decade-lows in the first half of 2015, real exports have so far failed to gain any traction. In fact, they fell by an estimated 2.5 per cent over the first two quarters of the year. Exports were hurt by a slowing Chinese economy, which has reduced demand for metals, and a contracting U.S. economy, which suffered from a drop in energy investment and a labour dispute at West Coast ports that disrupted trade. In addition, a temporary halt in motor vehicle production has to shoulder much of the blame for this poor performance. According to *Automotive News*, 1.1 million vehicles were manufactured in Ontario in the first half of the year, down 6.8 per cent compared with the same period in 2014.[1] This decline was due to retooling and maintenance at both the Windsor and Oakville plants. With Ford's Oakville plant and Fiat Chrysler's Windsor plant having resumed production by the end of February and May, respectively, motor vehicle production in Ontario is back at full capacity. This, combined with a recovery in U.S. demand, will lead to a surge in the province's exports in the second half of the year, which are projected to grow by 1.2 per cent in 2015 and accelerate to 4.2 per cent in 2016.

TOURISM IS GETTING A SHOT IN THE ARM

When the Canadian dollar appreciated from a low of US$0.63 in 2002 to US$1.01 in 2011, Ontario's tourism sector was likely one of the biggest victims. The number of tourists entering Canada through Ontario dropped from 9.8 million in 2002 to 7.6 million in 2014. More dramatically, the number of tourists from the United States fell from an all-time high of 8.2 million to just 5.5 million during the same period. A report by the Canadian Tourism Research Institute (CTRI) noted that—adjusting for other factors such as travel trends, economic growth, and demographics—every 1 per cent increase in the value of the Canadian dollar has been associated with a 0.35 to 0.4 per cent drop in overnight trips from the United States.[2]

On the flip side, the tourism sector may prove to be one of the biggest winners from the loonie's recent change of fortune. Over the first five months of 2015, nearly 2.3 million tourists entered Ontario, up 7.5 per cent compared with last year. CTRI is forecasting a 4.5 per cent increase in overnight visits from the U.S. to Ontario in 2015, followed by a 1.6 per cent growth in 2016. Similarly, overnight visits from overseas to the province are projected to grow by 5.7 per cent and 4.1 per cent in 2015 and 2016, respectively. In addition to the falling loonie, tourists are being drawn by major sporting events, including the FIFA Women's World Cup and the Pan Am Games.

Forecast Risks

Short term

- Investment intentions in Statistics Canada's *Capital and Repair Expenditures Survey* showed double-digit growth in private non-residential construction in Ontario in 2015. This is much stronger than our forecast and, if it materializes, would boost the outlook.

Medium term

- Motor vehicle sales in Ontario may be reaching a saturation point, limiting growth in household consumption in the medium term.

Source: The Conference Board of Canada.

1 Automotive News Data Center.

2 *Travel Exclusive: Key Trends for the Travel Industry* (Ottawa: The Conference Board of Canada, September–October 2011).

Key Economic Indicators: Ontario
Forecast Completed: July 16, 2015)

	2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4	2016Q1	2016Q2	2016Q3	2016Q4	2014	2015	2016
GDP at market prices ($ millions)	710,346	716,847	727,960	728,600	730,727	735,552	748,433	755,467	761,937	769,815	777,265	782,381	720,938	742,545	772,850
	1.1	*0.9*	*1.6*	*0.1*	*0.3*	*0.7*	*1.8*	*0.9*	*0.9*	*1.0*	*1.0*	*0.7*	*3.6*	*3.0*	*4.1*
GDP at market prices (2007 $ millions)	638,071	642,978	649,817	653,448	653,058	655,171	661,946	665,043	668,896	672,549	676,420	678,515	646,079	658,805	674,095
	0.2	*0.8*	*1.1*	*0.6*	*−0.1*	*0.3*	*1.0*	*0.5*	*0.6*	*0.5*	*0.6*	*0.3*	*2.2*	*2.0*	*2.3*
GDP at basic prices (2007 $ millions)	593,082	597,675	604,081	607,461	607,941	609,300	615,598	618,475	622,052	625,444	629,037	630,978	600,575	612,828	626,878
	0.3	*0.8*	*1.1*	*0.6*	*0.1*	*0.2*	*1.0*	*0.5*	*0.6*	*0.5*	*0.6*	*0.3*	*2.3*	*2.0*	*2.3*
Consumer price index (2002 = 1.0)	1.243	1.264	1.266	1.262	1.262	1.273	1.280	1.286	1.293	1.302	1.308	1.313	1.259	1.275	1.304
	0.9	*1.7*	*0.1*	*−0.3*	*0.0*	*0.8*	*0.6*	*0.4*	*0.6*	*0.7*	*0.5*	*0.3*	*2.3*	*1.3*	*2.3*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.113	1.115	1.120	1.115	1.119	1.123	1.131	1.136	1.139	1.145	1.149	1.153	1.116	1.127	1.146
	1.0	*0.1*	*0.5*	*−0.5*	*0.4*	*0.3*	*0.7*	*0.5*	*0.3*	*0.5*	*0.4*	*0.3*	*1.4*	*1.0*	*1.7*
Wages and salary per employee ($ 000s)	47.337	47.752	48.164	48.145	48.924	48.900	49.123	49.418	49.664	49.929	50.179	50.446	47.849	49.091	50.055
	0.8	*0.9*	*0.9*	*0.0*	*1.6*	*0.0*	*0.5*	*0.6*	*0.5*	*0.5*	*0.5*	*0.5*	*2.2*	*2.6*	*2.0*
Primary household income ($ millions)	484,241	488,400	492,617	495,586	504,173	506,149	510,432	514,590	519,471	524,103	528,448	532,908	490,211	508,836	526,233
	1.2	*0.9*	*0.9*	*0.6*	*1.7*	*0.4*	*0.8*	*0.8*	*0.9*	*0.9*	*0.8*	*0.8*	*3.5*	*3.8*	*3.4*
Household disposable income ($ millions)	420,990	423,679	427,575	429,557	438,420	439,358	445,490	446,918	450,716	454,581	457,973	461,294	425,450	442,547	456,141
	1.1	*0.6*	*0.9*	*0.5*	*2.1*	*0.2*	*1.4*	*0.3*	*0.8*	*0.9*	*0.7*	*0.7*	*3.3*	*4.0*	*3.1*
Household net savings rate (per cent)	4.2	2.9	2.7	2.4	3.9	2.7	2.8	2.2	2.0	2.0	2.1	2.1	3.0	2.9	2.1
Population (000s)	13615	13640	13679	13730	13734	13750	13840	13880	13920	13960	13999	14040	13666	13801	13980
	0.1	*0.2*	*0.3*	*0.4*	*0.0*	*0.1*	*0.7*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.0*	*1.0*	*1.3*
Employment (000s)	6856	6869	6879	6904	6896	6922	6946	6960	6981	7004	7025	7046	6877	6931	7014
	0.1	*0.2*	*0.1*	*0.4*	*−0.1*	*0.4*	*0.4*	*0.2*	*0.3*	*0.3*	*0.3*	*0.3*	*0.8*	*0.8*	*1.2*
Labour force (000s)	7406	7410	7426	7419	7406	7411	7447	7476	7494	7520	7540	7561	7415	7435	7529
	0.0	*0.1*	*0.2*	*−0.1*	*−0.2*	*0.1*	*0.5*	*0.4*	*0.2*	*0.3*	*0.3*	*0.3*	*0.4*	*0.3*	*1.3*
Labour force participation rate (per cent)	66.0	65.8	65.8	65.6	65.3	65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.8	65.2	65.2
Unemployment rate (per cent)	7.4	7.3	7.4	6.9	6.9	6.6	6.7	6.9	6.8	6.9	6.8	6.8	7.3	6.8	6.8
Retail sales ($ millions)	170,948	176,477	179,160	180,290	178,572	183,179	185,072	187,057	188,846	190,283	191,426	192,323	176,719	183,470	190,720
	0.6	*3.2*	*1.5*	*0.6*	*−1.0*	*2.6*	*1.0*	*1.1*	*1.0*	*0.8*	*0.6*	*0.5*	*5.0*	*3.8*	*4.0*
Housing starts (units, 000s)	54,113	64,522	58,629	59,272	55,610	67,721	66,833	66,448	64,630	64,522	64,328	64,418	59,134	64,153	64,475
	−15.1	*19.2*	*−9.1*	*1.1*	*−6.2*	*21.8*	*−1.3*	*−0.6*	*−2.7*	*−0.2*	*−0.3*	*0.1*	*−3.2*	*8.5*	*0.5*
Net interprovincial migration (000s)	−18.6	−31.8	−2.4	−9.7	−13.8	3.1	−2.8	−4.7	−6.7	−7.5	−7.7	−8.0	−15.6	−4.5	−7.5
Net international migration (000s)	89.3	138.3	147.1	−19.2	53.4	105.4	118.2	120.7	122.4	124.4	126.2	127.8	88.9	99.4	125.2

Shaded area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Key Economic Indicators: Ontario cont'd
Forecast Completed: July 16, 2015)

	2017Q1	2017Q2	2017Q3	2017Q4	2018Q1	2018Q2	2018Q3	2018Q4	2019Q1	2019Q2	2019Q3	2019Q4	2017	2018	2019
GDP at market prices ($ millions)	790,396	798,556	806,416	813,200	823,341	832,161	840,623	846,555	856,386	865,880	874,553	881,520	802,142	835,670	869,585
	1.0	*1.0*	*1.0*	*0.8*	*1.2*	*1.1*	*1.0*	*0.7*	*1.2*	*1.1*	*1.0*	*0.8*	*3.8*	*4.2*	*4.1*
GDP at market prices (2007 $ millions)	681,572	684,551	688,324	692,232	696,535	699,918	703,513	707,518	711,407	715,375	719,422	723,474	686,670	701,871	717,420
	0.5	*0.4*	*0.6*	*0.6*	*0.6*	*0.5*	*0.5*	*0.6*	*0.5*	*0.6*	*0.6*	*0.6*	*1.9*	*2.2*	*2.2*
GDP at basic prices (2007 $ millions)	633,811	636,572	640,073	643,700	647,689	650,831	654,171	657,895	661,514	665,208	668,978	672,754	638,539	652,647	667,114
	0.4	*0.4*	*0.5*	*0.6*	*0.6*	*0.5*	*0.5*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*1.9*	*2.2*	*2.2*
Consumer price index (2002 = 1.0)	1.320	1.330	1.336	1.340	1.348	1.357	1.364	1.368	1.376	1.386	1.392	1.397	1.331	1.359	1.388
	0.6	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*2.1*	*2.1*	*2.1*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.160	1.167	1.172	1.175	1.182	1.189	1.195	1.197	1.204	1.210	1.216	1.218	1.168	1.191	1.212
	0.6	*0.6*	*0.4*	*0.3*	*0.6*	*0.6*	*0.5*	*0.1*	*0.6*	*0.5*	*0.4*	*0.2*	*1.9*	*1.9*	*1.8*
Wages and salary per employee ($ 000s)	50.752	51.110	51.434	51.727	52.014	52.296	52.609	52.939	53.292	53.671	54.021	54.379	51.256	52.465	53.841
	0.6	*0.7*	*0.6*	*0.6*	*0.6*	*0.5*	*0.6*	*0.6*	*0.7*	*0.7*	*0.7*	*0.7*	*2.4*	*2.4*	*2.6*
Primary household income ($ millions)	536,968	542,544	547,638	552,456	558,027	562,990	568,358	574,087	580,473	586,520	592,590	598,730	544,902	565,865	589,578
	0.8	*1.0*	*0.9*	*0.9*	*1.0*	*0.9*	*1.0*	*1.0*	*1.1*	*1.0*	*1.0*	*1.0*	*3.5*	*3.8*	*4.2*
Household disposable income ($ millions)	464,355	468,475	472,220	475,695	479,460	483,353	487,646	492,167	497,122	502,350	507,581	512,856	470,186	485,656	504,977
	0.7	*0.9*	*0.8*	*0.7*	*0.8*	*0.8*	*0.9*	*0.9*	*1.0*	*1.1*	*1.0*	*1.0*	*3.1*	*3.3*	*4.0*
Household net savings rate (per cent)	2.3	2.4	2.4	2.3	2.3	2.4	2.4	2.4	2.4	2.5	2.6	2.7	2.3	2.4	2.6
Population (000s)	14,081	14,122	14,163	14,204	14,247	14,288	14,330	14,372	14,412	14,454	14,497	14,540	14,142	14,309	14,476
	0.3	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.2*	*1.2*	*1.2*
Employment (000s)	7,063	7,086	7,105	7,123	7,146	7,170	7,196	7,225	7,253	7,280	7,310	7,341	7,094	7,184	7,296
	0.3	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*1.1*	*1.3*	*1.6*
Labour force (000s)	7,581	7,604	7,625	7,640	7,655	7,663	7,675	7,690	7,711	7,734	7,761	7,786	7,612	7,671	7,748
	0.3	*0.3*	*0.3*	*0.2*	*0.2*	*0.1*	*0.2*	*0.2*	*0.3*	*0.3*	*0.3*	*0.3*	*1.1*	*0.8*	*1.0*
Labour force participation rate (per cent)	65.2	65.2	65.2	65.1	65.1	64.9	64.8	64.8	64.8	64.8	64.8	64.8	65.2	64.9	64.8
Unemployment rate (per cent)	6.8	6.8	6.8	6.8	6.7	6.4	6.2	6.0	5.9	5.9	5.8	5.7	6.8	6.3	5.8
Retail sales ($ millions)	192,624	193,777	194,864	196,019	197,365	198,583	199,985	201,546	203,248	204,953	206,750	208,452	194,321	199,370	205,850
	0.2	*0.6*	*0.6*	*0.6*	*0.7*	*0.6*	*0.7*	*0.8*	*0.8*	*0.8*	*0.9*	*0.8*	*1.9*	*2.6*	*3.3*
Housing starts (units, 000s)	58,875	60,948	62,218	65,406	66,800	68,416	69,750	73,008	77,177	80,574	82,905	85,313	61,862	69,493	81,492
	–8.6	*3.5*	*2.1*	*5.1*	*2.1*	*2.4*	*2.0*	*4.7*	*5.7*	*4.4*	*2.9*	*2.9*	*–4.1*	*12.3*	*17.3*
Net interprovincial migration (000s)	–8.8	–9.1	–9.1	–9.2	–9.9	–9.9	–9.2	–8.3	–5.8	–4.7	–3.9	–3.2	–9.1	–9.3	–4.4
Net international migration (000s)	129.8	130.9	131.6	132.0	130.8	130.9	131.3	131.8	133.0	133.5	134.0	134.4	131.1	131.2	133.7

Shaded area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Lois Mainville

Manitoba's Economy on Solid Ground

Highlights

- All key sectors of Manitoba's economy are experiencing sound growth.
- Strong gains are expected in manufacturing sector.
- The healthy economy is expected to boost employment and consumer spending.

Economic Indicators
(percentage change)

	2014	2015f	2016f
Real GDP	1.1	2.4	2.5
Consumer Price Index	1.8	1.4	2.3
Household disposable income	2.6	3.3	3.2
Employment	0.1	1.7	1.4
Unemployment rate (level)	5.4	5.5	5.1
Retail sales	4.3	1.5	3.8
Wages and salaries per employee	2.9	0.9	2.2
Population	1.3	1.2	1.3

f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Government and Background Information

Premier	Greg Selinger
Next election	April 19, 2016
Population (2015Q2)	1,292,151
Government balance (2015–16)	–$422 million

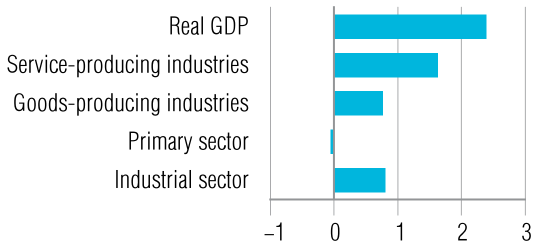
Sources: The Conference Board of Canada; Manitoba Budget Documents.

Manitoba's economy is on solid ground with gains expected across key sectors over the next two years. Real GDP growth is projected to rise by 2.4 per cent in 2015 and 2.5 per cent in 2016, keeping Manitoba among the provincial growth leaders.

Solid gains are forecast in manufacturing, agriculture and construction. Because of the correction in oil prices, the mining sector is not expected to grow in 2015 and will advance only moderately in 2016. Metal ore production will perform better with the opening of two new mines and steady production levels in existing mines.

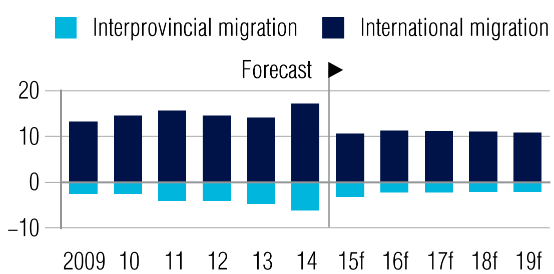
Increased activity is anticipated on all fronts for Manitoba's manufacturing sector, thanks to a rebounding U.S. economy. Growth in manufacturing is projected to hit 4.5 per cent in 2015 and 2.3 per cent in 2016. The agriculture sector is expected to rebound this year with 3.9 per cent growth as the drought and dry weather in neighbouring Saskatchewan and Alberta have not affected Manitoba too much. In addition, construction is ramping up across the province with the provincial government's infrastructure plan and Manitoba Hydro projects breaking ground

Contributions to Manitoba Real GDP Growth, 2015
(by industry/sector, percentage point; GDP, per cent)



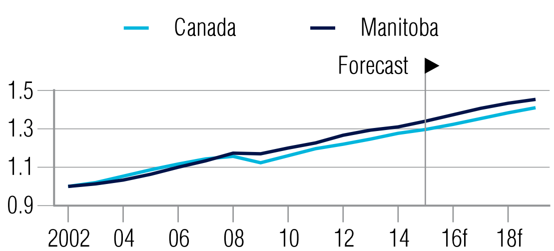
Note: "Primary" is the sum of agriculture, forestry, fishing and trapping, and mining sectors. "Industrial" is the sum of manufacturing, construction, and utilities sectors.
Sources: The Conference Board of Canada; Statistics Canada.

Sources of Migration
(net migration, 000s)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Real GDP, 2002 to 2019
(index, 2002 = 1.0)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

The gains in the goods-producing industries are expected to be reflected in the services sectors. Employment is forecast to rise by an average of 1.4 per cent over the next two years. Also foreseen is a decrease in the province's unemployment rate—from 5.5 per cent in 2015 to an average of 5.1 per cent over the medium term. With stronger job creation, household disposable income will spur household consumption expenditures, boosting wholesale and retail trade in the province by 3.6 per cent in 2016 and 2.9 per cent in 2016.

METAL MINING REACHING TARGET PRODUCTION LEVELS

Metal mining is expected to grow 8.4 per cent in 2015 as production is ramping up at two new mines in the province, the Reed copper mine (a joint venture between Hudbay Minerals and VMS Ventures) and the Lalor copper-zinc-gold mine (Hudbay Minerals). Growth in the sector is projected to slow to 0.7 per cent in 2016 as the two new mines reach steady production levels.

MANUFACTURING GROWING ON ALL FRONTS

The manufacturing sector is projected to be one of the strongest performers in Manitoba in 2015 with growth of 4.5 per cent, followed by a 2.3 per cent increase in 2016.

U.S. demand for heavy-duty buses is helping boost output in manufacturing. New Flyer Industries have recently announced orders of 218 buses for Orange County and 138 buses for King County (Seattle Metro Area). The Winnipeg-based company is also working on a large order for the New York City Transit Authority. As well, Motor Coach Industries recently made a $395-million deal to deliver 772 commuter coaches to New Jersey Transit over the next six years.

In the aerospace industry, StandardAero recently announced that it will expand its Winnipeg operations by adding new strategic business lines. The multi-million-dollar investment will offer engine repair services that are currently unavailable on the market and that will not duplicate work now being done south of the border. Operations on certain lines are expected to begin production at the end of the year with the expansion slated to be completed in 2016.

CONSTRUCTION BOOST ACROSS THE PROVINCE

Construction should keep the province's economy on a solid track with growth in the sector anticipated at 3.1 per cent for 2015, 6 per cent for 2016, and 5.3 per cent for 2017. The province's five-year infrastructure plan is currently in full swing. The completion of the $5.5-billion investment in roads and bridges, municipal infrastructure, public transit, and flood protection is projected in about four years (2019). Two large Manitoba Hydro projects are also contributing positively to the sector's outlook over the medium term. Construction on the Keeyask Generating Station began last summer; this $6.5-billion project has a target in-service date of 2019. Work is forecast to break ground this year on the Bipole III Transmission Reliability Project. This project, expected to improve the reliability of Manitoba's power system, has an in-service date of 2018.

Housing starts are projected to decline this year but to pick up again in 2016 when the housing market levels off. In Winnipeg, strong population growth has recently spurred quite a bit of building activity. However, there is a high inventory of unsold units and suppliers are working on clearing the backlog. Over the medium term, demand for housing is expected to increase due to strong population growth, especially from international migration, as well as historically low interest rates.

AGRICULTURE ON THE REBOUND

Following a difficult 2014 due to bad weather conditions, agriculture is projected to rebound in Manitoba with growth expected at 3.8 per cent for 2015 and 1.9 per cent for 2016. The drought currently affecting Saskatchewan and Alberta has not hit Manitoba. Good weather conditions so far this year should set the stage for a great crop year in Manitoba. The province will also benefit from higher commodity prices due to extreme weather conditions affecting crops in various markets. The grain transportation backlog on the railways from the bumper crop of 2013 has for the most part been cleared and that will help producers move products more easily than in the past few years.

Various developments on international markets may affect the medium-term outlook for agriculture. Although the U.S. House of Representatives has voted to repeal Country of Origin Labelling (COOL) regulations, the Senate has introduced a bill calling for voluntary labelling at the dissatisfaction of Canadian stakeholders. Unless COOL is fully repealed, the Canadian government is threatening to impose retaliatory tariffs against the U.S. If COOL is repealed, Canadian producers should become more competitive on the U.S. market as production costs will be lower for agricultural producers venturing on that market.

Forecast Risks

Short term

- Weather conditions across North America may cause commodity prices to rise due to supply constraints, benefiting Manitoba's agricultural sector that might experience a bumper crop year.

Medium term

- If Hudbay Minerals refurbishes the recently acquired New Britannia mill, metal mining output could increase further.

Source: The Conference Board of Canada.

The Canada–Korea Free Trade Agreement, which came into effect earlier this year, is expected to have positive supply-chain effects in Asia. On the downside, the Russian ban on Canadian agricultural imports (related to the Ukrainian conflict) probably will be extended past its August expiry date.

SERVICES AND DOMESTIC DEMAND

The healthy gains in the province's goods-producing industries are forecast to be reflected in the services sectors over the next two years. Looked-for expansions include the following: transportation and warehousing, 3.9 per cent in 2015 and 3.1 per cent in 2016; wholesale and retail trade, 3.6 per cent and 2.9 per cent in 2015 and 2016, respectively.

Labour demand will be strong. Growth in employment is projected to average 1.4 percent annually over the next two years. The growth in employment and household disposable income will support increases of 0.9 per cent in 2015 and 2.4 per cent in 2016 in real household consumption with the fastest growth in the consumption of semi-durable goods.

Key Economic Indicators: Manitoba
(Forecast Completed: July 16, 2015)

	2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4	2016Q1	2016Q2	2016Q3	2016Q4	2014	2015	2016
GDP at market prices ($ millions)	62,275	62,371	63,761	63,420	64,160	65,329	66,247	66,979	67,318	67,986	68,721	69,218	62,957	65,679	68,311
	0.5	*0.2*	*2.2*	*–0.5*	*1.2*	*1.8*	*1.4*	*1.1*	*0.5*	*1.0*	*1.1*	*0.7*	*2.7*	*4.3*	*4.0*
GDP at market prices (2007 $ millions)	56,745	56,699	57,784	57,216	57,947	58,282	58,647	59,027	59,338	59,699	60,170	60,456	57,111	58,476	59,916
	0.1	*–0.1*	*1.9*	*–1.0*	*1.3*	*0.6*	*0.6*	*0.6*	*0.5*	*0.6*	*0.8*	*0.5*	*1.1*	*2.4*	*2.5*
GDP at basic prices (2007 $ millions)	52,535	52,492	53,496	52,971	53,648	53,959	54,295	54,647	54,933	55,266	55,700	55,962	52,874	54,137	55,465
	0.1	*–0.1*	*1.9*	*–1.0*	*1.3*	*0.6*	*0.6*	*0.6*	*0.5*	*0.6*	*0.8*	*0.5*	*1.1*	*2.4*	*2.5*
Consumer price index (2002 = 1.0)	1.243	1.259	1.257	1.252	1.254	1.269	1.277	1.282	1.289	1.298	1.305	1.309	1.253	1.271	1.300
	0.6	*1.3*	*–0.1*	*–0.5*	*0.2*	*1.2*	*0.6*	*0.4*	*0.6*	*0.7*	*0.5*	*0.3*	*1.8*	*1.4*	*2.3*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.097	1.100	1.103	1.108	1.107	1.121	1.130	1.135	1.134	1.139	1.142	1.145	1.102	1.123	1.140
	0.3	*0.2*	*0.3*	*0.5*	*–0.1*	*1.2*	*0.8*	*0.5*	*0.0*	*0.4*	*0.3*	*0.2*	*1.5*	*1.9*	*1.5*
Wages and salary per employee ($ 000s)	42.918	43.539	43.668	43.100	43.436	43.608	43.803	43.993	44.235	44.518	44.810	45.087	43.306	43.710	44.662
	–0.2	*1.4*	*0.3*	*–1.3*	*0.8*	*0.4*	*0.4*	*0.4*	*0.5*	*0.6*	*0.7*	*0.6*	*2.9*	*0.9*	*2.2*
Primary household income ($ millions)	40,248	40,717	41,077	41,050	41,826	41,944	42,234	42,563	43,013	43,470	43,933	44,402	40,773	42,141	43,705
	0.0	*1.2*	*0.9*	*–0.1*	*1.9*	*0.3*	*0.7*	*0.8*	*1.1*	*1.1*	*1.1*	*1.1*	*2.6*	*3.4*	*3.7*
Household disposable income ($ millions)	35,862	36,192	36,456	36,374	37,130	37,171	37,642	37,721	38,031	38,425	38,827	39,240	36,221	37,416	38,631
	0.1	*0.9*	*0.7*	*–0.2*	*2.1*	*0.1*	*1.3*	*0.2*	*0.8*	*1.0*	*1.0*	*1.1*	*2.6*	*3.3*	*3.2*
Household net savings rate (per cent)	0.2	–0.3	–0.4	–1.4	1.3	0.0	0.2	–0.5	–0.7	–0.7	–0.6	–0.6	–0.5	0.3	–0.6
Population (000s)	1273	1277	1282	1286	1290	1292	1296	1300	1305	1309	1313	1317	1280	1295	1311
	0.3	*0.3*	*0.4*	*0.3*	*0.3*	*0.2*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.3*	*1.2*	*1.3*
Employment (000s)	623	623	627	634	637	637	637	639	642	645	648	652	627	638	647
	0.3	*–0.1*	*0.7*	*1.1*	*0.5*	*0.0*	*0.1*	*0.3*	*0.4*	*0.5*	*0.5*	*0.5*	*0.1*	*1.7*	*1.4*
Labour force (000s)	659	659	663	668	675	674	674	675	678	680	682	686	662	674	681
	0.0	*–0.1*	*0.6*	*0.8*	*1.0*	*–0.2*	*0.0*	*0.2*	*0.4*	*0.3*	*0.4*	*0.5*	*0.1*	*1.8*	*1.0*
Labour force participation rate (per cent)	67.9	67.6	67.8	68.2	68.6	68.4	68.3	68.2	68.2	68.2	68.3	68.4	67.8	68.4	68.3
Unemployment rate (per cent)	5.5	5.5	5.4	5.2	5.6	5.5	5.4	5.3	5.3	5.1	5.0	5.0	5.4	5.5	5.1
Retail sales ($ millions)	17,774	17,990	18,172	18,201	17,936	18,261	18,431	18,588	18,746	18,916	19,085	19,239	18,034	18,304	18,996
	2.2	*1.2*	*1.0*	*0.2*	*–1.5*	*1.8*	*0.9*	*0.8*	*0.8*	*0.9*	*0.9*	*0.8*	*4.3*	*1.5*	*3.8*
Housing starts (units, 000s)	4,077	7,162	8,488	5,153	5,080	5,128	6,387	6,658	6,595	6,650	6,675	6,731	6,220	5,813	6,663
	–44.8	*75.7*	*18.5*	*–39.3*	*–1.4*	*0.9*	*24.6*	*4.2*	*–1.0*	*0.8*	*0.4*	*0.8*	*–16.7*	*–6.5*	*14.6*
Net interprovincial migration (000s)	–5.7	–5.5	–9.5	–4.2	–6.2	–2.5	–2.3	–2.3	–2.4	–2.4	–2.3	–2.3	–6.2	–3.3	–2.3
Net international migration (000s)	15.1	21.1	19.5	12.7	11.4	7.7	11.6	11.5	11.3	11.3	11.2	11.1	17.1	10.5	11.2

Shaded area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Key Economic Indicators: Manitoba cont'd
(Forecast Completed: July 16, 2015)

	2017Q1	2017Q2	2017Q3	2017Q4	2018Q1	2018Q2	2018Q3	2018Q4	2019Q1	2019Q2	2019Q3	2019Q4	2017	2018	2019
GDP at market prices ($ millions)	70,068	70,771	71,458	72,062	73,067	73,780	74,405	74,751	75,354	75,926	76,357	76,593	71,090	74,001	76,058
	1.2	*1.0*	*1.0*	*0.8*	*1.4*	*1.0*	*0.8*	*0.5*	*0.8*	*0.8*	*0.6*	*0.3*	*4.1*	*4.1*	*2.8*
GDP at market prices (2007 $ millions)	60,991	61,270	61,602	61,926	62,189	62,407	62,629	62,873	63,067	63,299	63,516	63,727	61,447	62,525	63,402
	0.9	*0.5*	*0.5*	*0.5*	*0.4*	*0.4*	*0.4*	*0.4*	*0.3*	*0.4*	*0.3*	*0.3*	*2.6*	*1.8*	*1.4*
GDP at basic prices (2007 $ millions)	56,454	56,711	57,016	57,314	57,555	57,755	57,960	58,186	58,366	58,583	58,785	58,984	56,874	57,864	58,679
	0.9	*0.5*	*0.5*	*0.5*	*0.4*	*0.3*	*0.4*	*0.4*	*0.3*	*0.4*	*0.3*	*0.3*	*2.5*	*1.7*	*1.4*
Consumer price index (2002 = 1.0)	1.316	1.326	1.332	1.336	1.344	1.353	1.360	1.364	1.372	1.381	1.388	1.392	1.328	1.355	1.383
	0.6	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*2.1*	*2.1*	*2.1*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.149	1.155	1.160	1.164	1.175	1.182	1.188	1.189	1.195	1.199	1.202	1.202	1.157	1.184	1.200
	0.3	*0.5*	*0.4*	*0.3*	*1.0*	*0.6*	*0.5*	*0.1*	*0.5*	*0.4*	*0.2*	*0.0*	*1.5*	*2.3*	*1.4*
Wages and salary per employee ($ 000s)	45.350	45.645	45.914	46.179	46.440	46.723	46.987	47.243	47.521	47.808	48.093	48.386	45.772	46.848	47.952
	0.6	*0.7*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.5*	*0.6*	*0.6*	*0.6*	*0.6*	*2.5*	*2.4*	*2.4*
Primary household income ($ millions)	44,807	45,309	45,711	46,102	46,509	46,868	47,227	47,583	47,957	48,325	48,700	49,081	45,482	47,047	48,516
	0.9	*1.1*	*0.9*	*0.9*	*0.9*	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*4.1*	*3.4*	*3.1*
Household disposable income ($ millions)	39,667	40,112	40,461	40,801	41,114	41,450	41,780	42,101	42,406	42,753	43,095	43,435	40,261	41,611	42,922
	1.1	*1.1*	*0.9*	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*0.7*	*0.8*	*0.8*	*0.8*	*4.2*	*3.4*	*3.1*
Household net savings rate (per cent)	-0.4	-0.3	-0.3	-0.4	-0.4	-0.3	-0.3	-0.3	-0.3	-0.2	-0.1	0.0	-0.4	-0.3	-0.1
Population (000s)	1,321	1,326	1,330	1,334	1,338	1,342	1,346	1,351	1,355	1,359	1,363	1,367	1,328	1,344	1,361
	0.3	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.3*	*1.3*	*1.2*
Employment (000s)	655	658	659	661	661	662	663	664	664	664	665	666	658	662	665
	0.5	*0.5*	*0.2*	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.0*	*0.1*	*0.1*	*0.1*	*1.7*	*0.7*	*0.4*
Labour force (000s)	689	693	694	696	697	698	699	700	700	701	702	703	693	698	702
	0.5	*0.5*	*0.2*	*0.2*	*0.2*	*0.1*	*0.1*	*0.2*	*0.0*	*0.1*	*0.1*	*0.2*	*1.7*	*0.8*	*0.5*
Labour force participation rate (per cent)	68.5	68.7	68.6	68.6	68.5	68.4	68.3	68.2	68.0	67.9	67.8	67.7	68.6	68.4	67.9
Unemployment rate (per cent)	5.0	5.1	5.1	5.1	5.1	5.1	5.2	5.2	5.2	5.2	5.3	5.3	5.0	5.1	5.2
Retail sales ($ millions)	19,354	19,510	19,620	19,745	19,858	19,965	20,066	20,167	20,250	20,347	20,452	20,545	19,557	20,014	20,399
	0.6	*0.8*	*0.6*	*0.6*	*0.6*	*0.5*	*0.5*	*0.5*	*0.4*	*0.5*	*0.5*	*0.5*	*3.0*	*2.3*	*1.9*
Housing starts (units, 000s)	6,754	6,810	6,733	6,688	6,713	6,669	6,592	6,548	6,574	6,632	6,554	6,612	6,746	6,630	6,593
	0.3	*0.8*	*–1.1*	*–0.7*	*0.4*	*–0.7*	*–1.1*	*–0.7*	*0.4*	*0.9*	*–1.2*	*0.9*	*1.3*	*–1.7*	*–0.6*
Net interprovincial migration (000s)	–2.3	–2.3	–2.3	–2.2	–2.2	–2.2	–2.2	–2.2	–2.1	–2.1	–2.1	–2.1	–2.3	–2.2	–2.1
Net international migration (000s)	11.1	11.1	11.1	11.0	11.0	11.0	11.0	10.9	10.9	10.8	10.8	10.8	11.1	11.0	10.8

Shaded area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Lois Mainville

Weather Woes Adding to a Difficult Year

Highlights

- The economy is expected to contract in 2015, due to a bad year for the oil industry and the agriculture sector.
- The construction sector is set to do well next year.
- A better outlook exists for the economy for 2016.

Economic Indicators
(percentage change)

	2014	2015f	2016f
Real GDP	1.4	–0.2	2.6
Consumer Price Index	2.4	1.7	2.3
Household disposable income	1.7	3.5	3.0
Employment	1.0	0.5	0.9
Unemployment rate (level)	3.8	4.7	4.7
Retail sales	4.6	–1.2	3.4
Wages and salaries per employee	3.3	2.4	1.9
Population	1.7	1.3	1.6

f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Government and Background Information

Premier	Brad Wall
Next election	April 4, 2016
Population (2015Q2)	1,134,402
Government balance (2015–16)	$107 million

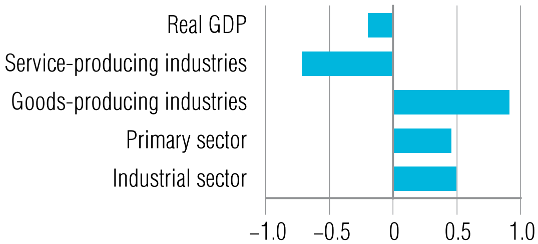
Sources: Saskatchewan Budget Documents.

Faced with a severe correction in the energy sector, economic growth will turn negative in Saskatchewan this year. Further weighing down economic growth are the drought conditions for the agriculture sector, and rising uranium and potash production will not be enough to keep real GDP growth in positive territory. Construction is also expected to cool off this year. Overall, a decline of 0.2 per cent in real GDP is foreseen this year.

Another correction in the energy sector does not appear likely in 2016 and, with uranium and potash production continuing to increase, the economy is forecast to perform better in 2016. Construction will also pick up again with projects in the mining and energy sector. Overall, Saskatchewan's economy is projected to grow by 2.6 per cent in 2016.

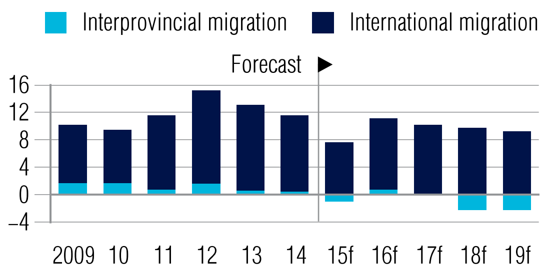
The weak economy slowed down job creation. Employment will rise by only 0.5 per cent this year but will expand by 0.9 per cent in 2016. The unemployment rate is expected to increase to 4.7 per cent, up from 3.5 per cent in 2014. Despite this rise, the province's unemployment rate will remain the lowest in Canada. The economic slowdown of 2015 and the rebound of 2016 will be mirrored in household consumption patterns: weakness this year and stronger growth next year.

Contributions to Saskatchewan Real GDP Growth, 2015
(by industry/sector, percentage point; GDP, per cent)



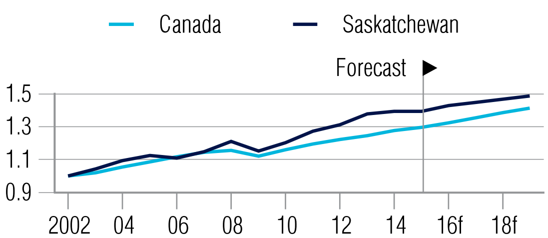
Note: "Primary" is the sum of agriculture, forestry, fishing and trapping, and mining sectors. "Industrial" is the sum of manufacturing, construction, and utilities sectors.
Sources: The Conference Board of Canada; Statistics Canada.

Sources of Migration
(net migration, 000s)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Real GDP, 2002 to 2019
(index, 2002 = 1.0)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

POTASH AND URANIUM TO TEMPER OIL PRICE IMPACTS

The outlook for the mining sector remains mixed with potash and uranium tempering the effects of the drop in oil prices. Overall, mining is expected to contract by 1.4 per cent this year.

Metal mining however, is looking for an increase of 12.8 per cent this year and 9.6 per cent in 2016. Increased supply from Cameco's Cigar Lake uranium mine, in addition to demand from China, India, and Japan, is contributing to the bright outlook for the sector. Non-metal mining is also forecast to perform well with growth of 11.1 per cent this year and 6.1 per cent in 2016, thanks to increased production from recent expansions at Agrium's Vanscoy and PotashCorp's Rocanville mines. Production at the K+S Legacy mine is expected to begin at the end of 2016.

But mineral fuels are weighing down the mining outlook for 2015, due to the steep decline in oil prices. As the number of wells drilled during the winter drilling season was down, oil production will slow this year and the effects will be felt throughout the industry's supply chain. Although it is not anticipated that oil prices will return to their previous three-digit levels, a slight increase in prices appears to be in the cards. Growth in mineral fuels should be 1.3 per cent in 2016 while overall growth in the mining sector is expected to reach 2.4 per cent in 2016.

DROUGHT CAUSING LOSSES IN AGRICULTURE

Seeding is currently well above the five-year average, as producers took advantage of the ideal favourable spring weather. However, hot and dry weather has thrown parts of Saskatchewan and Alberta into a drought. The anticipation of lower crop yields is not only affecting crop production but is also creating ripple effects throughout the agricultural sector. For example, as a cost-cutting measure, livestock producers might have to start selling off animals as feed is now more expensive because supply constraints are expected to lift commodity prices.

The highly anticipated rebound in agriculture, following a difficult 2014, is now projected to become a 2.4 per cent loss for 2015.

But the agriculture sector is expected to bounce back next year with a 2.1 per cent growth if, of course, more normal weather occurs. International trade should also contribute to the sector's recovery over the medium term. The U.S. House of Representatives has voted to repeal Country of Origin Labelling (COOL) and Senate approval is pending. If COOL is repealed, Canadian products should become more competitive on the U.S. market as production costs will be lower for Canadian agricultural producers venturing into the American market. It is anticipated that the Canada–Korea Free Trade Agreement, which came into effect earlier this year, will have positive supply-chain effects in Asia.

CONSTRUCTION OUTCOME DEPENDENT ON MINING INVESTMENT DECISIONS

Construction is forecast to decline by 7.6 per cent this year as work on the Cigar Lake uranium mine and the Rocanville and Vanscoy potash mine expansions are now complete and investment in the energy sector is much weaker. Although work is ongoing on the K+S Legacy potash mine, this project is not enough to lift growth in the construction sector into positive territory. Projects currently in the feasibility stage or different stages of approval—such as the Orion diamond mine (Star Gold), Kronau potash mine (Vale), Jansen potash mine (BHP Billiton), and Energy East pipeline project (Enbridge)—are expected to determine the outcome of the construction sector over the medium term and could boost growth above what we are currently forecasting.

Housing starts are projected to decline this year as Regina's and Saskatoon's hot housing markets are expected to level off. Strong pent-up demand has occasioned a lot of building in the two cities, resulting in a high inventory of unsold units. Housing starts are forecast to pick up again in 2016 as the housing market should be more balanced with the uptick in the economy.

Government investment is expected to contribute positively to the construction outlook over the next few years. In the most recent budget, the provincial government presented a four-year, $5.8-billion infrastructure plan to sustain growth in the province. The largest infrastructure plan in the province's history includes investments in transportation infrastructure (including the Regina Bypass), municipal infrastructure, education, health care, and government services. Overall, the construction sector is looking for an increase of 7.4 per cent in 2016.

DOMESTIC DEMAND MIRRORS THE ECONOMY'S STATUS

The downturn in the province's major sectors will cause employment growth to slow this year to just 0.5 per cent. With activity picking up again in major sectors in 2016, employment is expected to grow by 0.9 per cent. The unemployment rate will increase to 4.7 per cent this year (up from 3.5 per cent in 2014) and remain there over the medium term but, despite the rise, it will continue to be the lowest in Canada.

The slowdown in the economic outlook will also decrease household consumption by 0.8 per cent this year. Retail trade will feel the slight drop in consumption with losses of 3.8 per cent this year. However, in 2016, with the economy picking up again and job growth improving, household consumption and retail trade are both expected to increase by 1.9 per cent.

Forecast Risks

Short term

- Forest fires in the northern areas of the province might result in a further contraction of the economy in 2015.

Medium term

- If COOL legislation is modified into voluntary labelling requirements rather than repealed completely, retaliatory tariffs against the U.S. might be imposed resulting in a damaged relationship between the two countries at the expense of the agriculture sector.

Source: The Conference Board of Canada.

Key Economic Indicators: Saskatchewan
(Forecast Completed: July 16, 2015)

	2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4	2016Q1	2016Q2	2016Q3	2016Q4	2014	2015	2016
GDP at market prices ($ millions)	85,515 *1.8*	85,852 *0.4*	85,883 *0.0*	86,587 *0.8*	83,397 *–3.7*	83,399 *0.0*	84,033 *0.8*	84,746 *0.8*	86,656 *2.3*	87,549 *1.0*	88,390 *1.0*	88,897 *0.6*	85,959 *3.3*	83,894 *–2.4*	87,873 *4.7*
GDP at market prices (2007 $ millions)	63,108 *0.1*	63,531 *0.7*	63,219 *–0.5*	64,481 *2.0*	63,485 *–1.5*	63,159 *–0.5*	63,423 *0.4*	63,766 *0.5*	64,595 *1.3*	64,949 *0.5*	65,353 *0.6*	65,564 *0.3*	63,585 *1.4*	63,458 *–0.2*	65,115 *2.6*
GDP at basic prices (2007 $ millions)	59,644 *0.1*	60,045 *0.7*	59,750 *–0.5*	60,942 *2.0*	60,001 *–1.5*	59,693 *–0.5*	59,943 *0.4*	60,266 *0.5*	61,049 *1.3*	61,383 *0.5*	61,764 *0.6*	61,961 *0.3*	60,095 *1.4*	59,976 *–0.2*	61,539 *2.6*
Consumer price index (2002 = 1.0)	1.276 *1.0*	1.290 *1.1*	1.291 *0.1*	1.291 *0.0*	1.293 *0.2*	1.306 *1.0*	1.314 *0.6*	1.320 *0.4*	1.327 *0.6*	1.336 *0.7*	1.343 *0.5*	1.347 *0.3*	1.287 *2.4*	1.308 *1.7*	1.338 *2.3*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.355 *1.6*	1.351 *–0.3*	1.359 *0.5*	1.343 *–1.2*	1.314 *–2.2*	1.320 *0.5*	1.325 *0.3*	1.329 *0.3*	1.342 *0.9*	1.348 *0.5*	1.353 *0.3*	1.356 *0.2*	1.352 *1.9*	1.322 *–2.2*	1.349 *2.1*
Wages and salary per employee ($ 000s)	48.815 *1.4*	49.380 *1.2*	49.319 *–0.1*	49.389 *0.1*	50.254 *1.8*	50.298 *0.1*	50.379 *0.2*	50.611 *0.5*	50.887 *0.5*	51.148 *0.5*	51.484 *0.7*	51.800 *0.6*	49.226 *3.3*	50.385 *2.4*	51.330 *1.9*
Primary household income ($ millions)	41,529 *–0.9*	42,345 *2.0*	42,648 *0.7*	42,734 *0.2*	43,309 *1.3*	43,740 *1.0*	43,922 *0.4*	44,213 *0.7*	44,651 *1.0*	45,009 *0.8*	45,435 *0.9*	45,805 *0.8*	42,314 *1.7*	43,796 *3.5*	45,225 *3.3*
Household disposable income ($ millions)	36,599 *–0.5*	37,184 *1.6*	37,478 *0.8*	37,467 *0.0*	38,056 *1.6*	38,372 *0.8*	38,758 *1.0*	38,819 *0.2*	39,116 *0.8*	39,444 *0.8*	39,833 *1.0*	40,172 *0.9*	37,182 *1.7*	38,501 *3.5*	39,641 *3.0*
Household net savings rate (per cent)	5.5	6.2	6.2	6.6	8.8	7.7	7.8	7.2	7.1	7.0	7.1	7.1	6.2	7.9	7.1
Population (000s)	1,115 *0.3*	1,120 *0.4*	1,125 *0.5*	1,130 *0.4*	1,133 *0.2*	1,134 *0.2*	1,139 *0.4*	1,143 *0.4*	1,148 *0.4*	1,153 *0.4*	1,158 *0.4*	1,163 *0.4*	1,123 *1.7*	1,137 *1.3*	1,156 *1.6*
Employment (000s)	566 *0.0*	569 *0.5*	573 *0.7*	575 *0.5*	568 *–1.2*	576 *1.3*	575 *0.0*	576 *0.1*	577 *0.3*	578 *0.2*	580 *0.2*	580 *0.1*	571 *1.0*	574 *0.5*	579 *0.9*
Labour force (000s)	592 *0.4*	591 *–0.1*	594 *0.5*	597 *0.5*	596 *–0.2*	604 *1.3*	604 *0.0*	604 *0.1*	605 *0.2*	606 *0.2*	608 *0.3*	609 *0.1*	593 *0.7*	602 *1.4*	607 *0.9*
Labour force participation rate (per cent)	69.8	69.4	69.6	69.7	69.4	70.2	70.1	69.9	69.8	69.7	69.6	69.5	69.6	69.9	69.6
Unemployment rate (per cent)	4.3	3.7	3.6	3.6	4.6	4.7	4.7	4.7	4.6	4.6	4.7	4.7	3.8	4.7	4.7
Retail sales ($ millions)	19,216 *3.9*	19,186 *–0.2*	19,276 *0.5*	18,894 *–2.0*	18,380 *–2.7*	18,971 *3.2*	19,079 *0.6*	19,219 *0.7*	19,360 *0.7*	19,480 *0.6*	19,633 *0.8*	19,732 *0.5*	19,143 *4.6*	18,912 *–1.2*	19,551 *3.4*
Housing starts (units, 000s)	6,995 *–14.1*	8,942 *27.8*	9,585 *7.2*	7,506 *–21.7*	5,256 *–30.0*	5,705 *8.5*	7,283 *27.7*	7,074 *–2.9*	6,750 *–4.6*	6,642 *–1.6*	6,603 *–0.6*	6,597 *–0.1*	8,257 *–0.4*	6,329 *–23.3*	6,648 *5.0*
Net interprovincial migration (000s)	3.2	–0.3	–1.5	0.6	–3.7	0.0	–0.2	–0.3	1.0	0.9	0.7	0.5	0.5	–1.0	0.8
Net international migration (000s)	11.5	15.0	12.3	5.6	5.7	4.0	10.6	10.5	10.4	10.3	10.3	10.2	11.1	7.7	10.3

Shaded area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Key Economic Indicators: Saskatchewan cont'd
(Forecast Completed: July 16, 2015)

	2017Q1	2017Q2	2017Q3	2017Q4	2018Q1	2018Q2	2018Q3	2018Q4	2019Q1	2019Q2	2019Q3	2019Q4	2017	2018	2019
GDP at market prices ($ millions)	89,011	89,730	90,536	91,343	93,041	94,142	95,137	95,778	96,784	97,758	98,557	99,116	90,155	94,525	98,054
	0.1	*0.8*	*0.9*	*0.9*	*1.9*	*1.2*	*1.1*	*0.7*	*1.1*	*1.0*	*0.8*	*0.6*	*2.6*	*4.8*	*3.7*
GDP at market prices (2007 $ millions)	65,639	65,791	66,030	66,292	66,620	66,826	67,031	67,254	67,440	67,665	67,867	68,064	65,938	66,932	67,759
	0.1	*0.2*	*0.4*	*0.4*	*0.5*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.3*	*1.5*	*1.2*
GDP at basic prices (2007 $ millions)	62,030	62,173	62,398	62,644	62,952	63,145	63,339	63,549	63,725	63,939	64,131	64,318	62,311	63,246	64,028
	0.1	*0.2*	*0.4*	*0.4*	*0.5*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.3*	*1.5*	*1.2*
Consumer price index (2002 = 1.0)	1.355	1.365	1.371	1.375	1.383	1.393	1.400	1.404	1.412	1.422	1.429	1.433	1.367	1.395	1.424
	0.6	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*2.1*	*2.1*	*2.1*
Implicit price deflator— **GDP at market prices** (2007 = 1.0)	1.356	1.364	1.371	1.378	1.397	1.409	1.419	1.424	1.435	1.445	1.452	1.456	1.367	1.412	1.447
	0.0	*0.6*	*0.5*	*0.5*	*1.4*	*0.9*	*0.7*	*0.3*	*0.8*	*0.7*	*0.5*	*0.3*	*1.3*	*3.3*	*2.5*
Wages and salary per employee ($ 000s)	52.097	52.349	52.671	53.004	53.337	53.636	53.971	54.290	54.637	54.977	55.332	55.710	52.530	53.809	55.164
	0.6	*0.5*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.7*	*2.3*	*2.4*	*2.5*
Primary household income ($ millions)	46,125	46,469	46,857	47,250	47,680	48,048	48,445	48,840	49,284	49,695	50,124	50,564	46,675	48,253	49,917
	0.7	*0.7*	*0.8*	*0.8*	*0.9*	*0.8*	*0.8*	*0.8*	*0.9*	*0.8*	*0.9*	*0.9*	*3.2*	*3.4*	*3.4*
Household disposable income ($ millions)	40,544	40,856	41,203	41,550	41,880	42,223	42,584	42,933	43,294	43,672	44,054	44,437	41,038	42,405	43,864
	0.9	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*0.9*	*0.8*	*0.8*	*0.9*	*0.9*	*0.9*	*3.5*	*3.3*	*3.4*
Household net savings rate (per cent)	7.3	7.3	7.3	7.3	7.3	7.3	7.4	7.3	7.4	7.5	7.5	7.6	7.3	7.3	7.5
Population (000s)	1,167	1,172	1,177	1,181	1,186	1,190	1,194	1,198	1,202	1,205	1,209	1,213	1,174	1,192	1,207
	0.4	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.6*	*1.5*	*1.3*
Employment (000s)	581	581	582	583	583	584	585	585	586	587	588	588	582	584	587
	0.1	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.5*	*0.5*	*0.5*
Labour force (000s)	609	610	611	611	612	613	614	615	616	617	618	619	610	614	617
	0.1	*0.1*	*0.1*	*0.1*	*0.2*	*0.1*	*0.1*	*0.1*	*0.2*	*0.2*	*0.1*	*0.2*	*0.5*	*0.5*	*0.6*
Labour force participation rate (per cent)	69.3	69.1	69.0	68.8	68.7	68.6	68.5	68.3	68.3	68.2	68.1	68.0	69.0	68.5	68.1
Unemployment rate (per cent)	4.7	4.7	4.7	4.7	4.8	4.8	4.8	4.8	4.8	4.9	4.9	4.9	4.7	4.8	4.9
Retail sales ($ millions)	19,804	19,872	19,974	20,095	20,211	20,317	20,432	20,546	20,663	20,777	20,905	21,024	19,936	20,376	20,842
	0.4	*0.3*	*0.5*	*0.6*	*0.6*	*0.5*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*0.6*	*2.0*	*2.2*	*2.3*
Housing starts (units, 000s)	6,671	6,795	6,748	6,628	6,242	6,096	6,030	6,024	5,990	5,984	5,948	5,941	6,710	6,098	5,966
	1.1	*1.9*	*−0.7*	*−1.8*	*−5.8*	*−2.3*	*−1.1*	*−0.1*	*−0.6*	*−0.1*	*−0.6*	*−0.1*	*0.9*	*−9.1*	*−2.2*
Net interprovincial migration (000s)	0.6	0.3	−0.1	−0.6	−1.7	−2.1	−2.4	−2.5	−2.2	−2.2	−2.2	−2.2	0.0	−2.2	−2.2
Net international migration (000s)	10.3	10.2	10.1	10.0	9.9	9.7	9.6	9.5	9.4	9.3	9.2	9.1	10.1	9.7	9.3

Shaded area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Prince Owusu

Alberta's Economy Shifts to Reverse Gear

Highlights

- Lower crude oil prices are moderating the demand for new homes in 2015–16.
- Cuts to capital budgets and the workforce in the energy sector will push up the jobless rate over the next nine months.
- Increased bitumen production will bolster exports and help minimize the impact of lower investment on the economy.

Economic Indicators

(percentage change)

	2014	2015f	2016f
Real GDP	4.4	–1.0	1.7
Consumer Price Index	2.6	0.9	2.2
Household disposable income	6.3	3.3	2.7
Employment	2.2	1.2	0.3
Unemployment rate (level)	4.7	5.6	5.9
Retail sales	7.5	–2.7	2.6
Wages and salaries per employee	4.5	0.7	2.2
Population	2.9	2.0	1.7

f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Government and Background Information

Premier	Rachel Notley
Next election	Before June 1, 2019
Population (2015Q2)	4,175,409
Government balance (2015–16)	–$5 billion

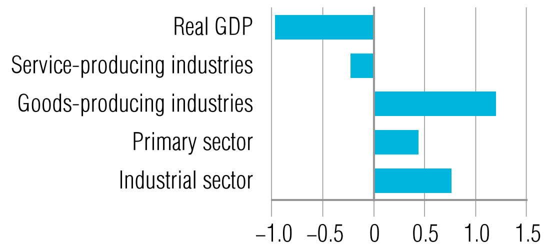
Sources: The Conference Board of Canada; Alberta Budget Documents.

After cruising in fourth speed for the last five years, Alberta's economy shifts to reverse gear this year as the economy faces headwinds stemming from the crude oil price rout. With the downturn in the energy sector, the first half of the year was difficult. The second half of the year is expected to be equally challenging as more layoffs begin to hit home and builders retreat further from breaking ground for new homes. In all, real GDP is forecast to contract by 1.0 per cent this year.

Bearish market conditions for crude stock at the onset of the summer trading season pressured crude oil prices to lose the momentum gathered during the spring. And, with crude prices still off by 50 per cent from their peak in the summer of 2014, several oil firms have slashed their planned investment for this year. The steep reduction in oil-patch investment is evident in the number of oil drilling rigs in operation during the crucial peak winter season. Rig counts in the province were down by 48 per cent during the first half of this year, compared with the same period a year ago. The job losses accompanying the reduction in investment will hurt the housing market, weaken migration trends, and batter the consumer sector. Government revenues from corporate income taxes as well as resource royalties will be under severe pressure this year.

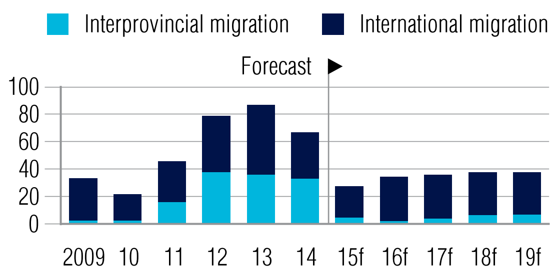
A return to annual economic growth of over 4 per cent is not in the cards for Alberta since crude prices are not likely to return to the triple-digit trading range any time soon. The decline in oil prices is affecting not

Contributions to Alberta Real GDP Growth, 2015
(by industry/sector, percentage point; GDP, per cent)



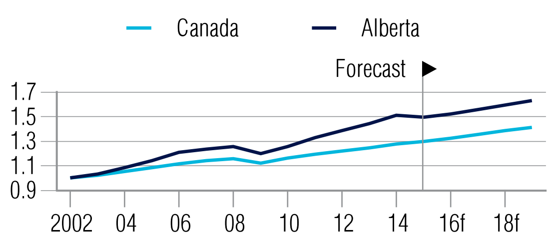
Note: "Primary" is the sum of agriculture, forestry, fishing and trapping, and mining sectors. "Industrial" is the sum of manufacturing, construction, and utilities sectors.
Sources: The Conference Board of Canada; Statistics Canada.

Sources of Migration
(net migration, 000s)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Real GDP, 2002 to 2019
(index, 2002 = 1.0)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

only oil-patch businesses and government revenues. Consumers are having a double whammy of weak job prospects and new tax measures. With consumer confidence down, retailers are feeling the downturn.

However, the news is not all bad for Albertans. Heavy investment in recent years has helped to build a lot of capacity in the oil and gas sector, and that is paying dividends in the form of higher oil production. Even though oil prices have dropped, non-conventional oil production continues to flow south to refineries along the U.S. Gulf Coast where demand for heavy oil remains high. And, with import levels falling (due in part to the drop in machinery and equipment purchases associated with oil-patch development), net trade will remain a positive influence on the economy over the short term. Together, a positive net trade balance and more stable economic conditions will help lift real GDP by 1.7 per cent next year.

LOWER OIL PRICE HITS OIL-PATCH INVESTMENT

The drop of more than 50 per cent in crude oil prices is having a predictable impact on Alberta's oil patch. Drilling activities plummeted in the first quarter—considered the peak of the drilling season—as rotary oil rigs were idled. In fact, several oil firms have reduced their investments to align with the weak pricing outlook brought on by the oil glut. Energy investment in nominal terms is expected to fall by 15.8 per cent this year, pulling more than $8 billion out of the economy, and it will not recover before next year. And, even then, recovery will be slow and a return to the level of investment before crude prices collapsed will not occur in the medium term, since crude prices are not likely to return to triple-digit levels any time soon.

The plunge in crude oil prices is hitting not only oil-patch investment but is also putting a severe damper on Alberta's red-hot housing market. The oil patch acted as a magnet to pull in migrants from different parts of the country and from abroad, generating a lot of residential construction activities to accommodate the influx of immigrants. However, with oil firms slamming the brakes on investment and on hiring in response to lower crude oil prices, we project that net annual inflows of immigrants will drop to around 31,000 over the next two years (down from an average of 78,000 for the last three years). Slower immigrant inflows, combined with job losses from the oil rout, will stifle demand for new housing. Housing starts are expected to average around 33,000 units over 2015–16 and, with that, real residential construction investment is anticipated to contract by an average of 7.6 per cent over that period.

DOMESTIC ECONOMY EXPECTED TO REMAIN WEAK

After benefiting from years of wage premiums and hiring blitzes that helped boost household consumption expenditures, Albertans are now taking a break from their prolific spending as the oil rout hits their paycheques.

Oil and gas companies are reducing their capital plans and renegotiating labour and supply contracts. Layoffs have begun and paycheques slashed[1] as lower oil prices hit the bottom lines of energy firms. Our forecast calls for employment to contract in the second half of this year, particularly in the construction and resource sectors as many energy firms have started a second round of capital and labour retrenchment. Job seekers will struggle next year to find employment in these sectors as employers continue to adjust to the impact of lower crude prices. The slowdown in demand for workers, plus the increase in the available labour pool as migrants from other provinces and abroad continue to move to Alberta, will push the unemployment rate up to 5.9 per cent next year, up from 4.4 per cent in November last year when OPEC decided to let the market correct itself.

On the wage front, our forecast calls for only a modest gain of 1.7 per cent for average weekly wages (industrial composite) compared with the average annual gains of 4.4 per cent over the past decade. A new progressive personal income tax rate that is going into effect on October 1 will hit some 7 per cent of tax filers and rake in about $1 billion for government coffers in this fiscal year along with the extra $530 million from the fuel tax increase. The new tax measures along with weaker job prospects and slower net inflow of migrants will put a damper on consumer demand. Retail sales contracted sharply in the first quarter of this year and we expect sales to slide by 2.7 per cent in 2015 with only a modest recovery slated for next year.

The slowdown in consumer spending will take the steam out of inflation in the province. We anticipate that the increase in the overall consumer price index will fall from 2.6 per cent last year to around 1.5 per cent in each of the next two years.

BITUMEN EXPORTS CONTINUE STRONG

One thing that has remained positive as the provincial economy struggles to cope with lower crude oil prices is the exports of bitumen from the massive oil sands deposits. Energy firms continue to add new capacities to their operations. ConocoPhillips Canada began production in June at its Surmont project south of Fort McMurray, adding 118,000 barrels per day to oil sands output. It is the largest steam-assisted gravity drainage (SADG) facility ever built in Canada. Imperial Oil, Husky, China National Offshore Oil Corporation, and several others are also expected to add new capacity to oil sands production this year. Increased production will help minimize the impact of lower investment on Alberta's economy as exports of crude oil continue to flow to the United States. Refineries along the U.S. Gulf Coast, which are configured to process heavy oil, are taking advantage of weak crude oil prices by running at full capacity.

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1 Carrie Tait, "Trinidad Drilling Slashes Jobs, Wages Amid Oil Slump," *The Globe and Mail*, February 17, 2015. www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/trinidad-drilling-slashes-jobs-wages-amid-oil-slump/article23035939/.

Our forecast calls for non-conventional oil production to increase by an average of 6.9 per cent in each of the next five years in response to favourable refinery demand conditions south of the border (although that is down from around 10 per cent over 2010–14). At the same time, conventional oil production, which is more price-sensitive than non-conventional oil, will take a much bigger hit from the drop in crude prices and that will result in lower production going forward. All things considered, total crude production is projected to advance over the medium term.

Forecast Risks

Short term

- Oil prices could stay lower for a longer period as oil markets are still oversupplied.

Medium term

- New export capacity for crude oil is still needed, but political wrangling has left the future of this issue cloudy. Without the new capacity, exports of oil could be constrained at the beginning of the next decade.

Source: The Conference Board of Canada.

Key Economic Indicators: Alberta
(Forecast Completed: July 16, 2015)

	2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4	2016Q1	2016Q2	2016Q3	2016Q4	2014	2015	2016
GDP at market prices ($ millions)	362,853	367,266	367,642	365,787	351,970	350,226	354,174	356,704	363,637	367,928	372,607	376,639	365,887	353,268	370,203
	4.5	*1.2*	*0.1*	*–0.5*	*–3.8*	*–0.5*	*1.1*	*0.7*	*1.9*	*1.2*	*1.3*	*1.1*	*8.2*	*–3.4*	*4.8*
GDP at market prices (2007 $ millions)	311,678	316,422	316,362	320,970	314,402	311,226	313,408	314,167	316,143	317,501	319,518	321,139	316,358	313,301	318,575
	0.8	*1.5*	*0.0*	*1.5*	*–2.0*	*–1.0*	*0.7*	*0.2*	*0.6*	*0.4*	*0.6*	*0.5*	*4.4*	*–1.0*	*1.7*
GDP at basic prices (2007 $ millions)	301,003	305,585	305,527	309,977	303,634	300,567	302,674	303,407	305,315	306,627	308,575	310,140	305,523	302,570	307,664
	0.8	*1.5*	*0.0*	*1.5*	*–2.0*	*–1.0*	*0.7*	*0.2*	*0.6*	*0.4*	*0.6*	*0.5*	*4.4*	*–1.0*	*1.7*
Consumer price index (2002 = 1.0)	1.313	1.324	1.328	1.323	1.320	1.331	1.340	1.345	1.351	1.361	1.368	1.372	1.322	1.334	1.363
	1.5	*0.9*	*0.3*	*–0.4*	*–0.2*	*0.9*	*0.6*	*0.4*	*0.5*	*0.7*	*0.5*	*0.3*	*2.6*	*0.9*	*2.2*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.164	1.161	1.162	1.140	1.119	1.125	1.130	1.135	1.150	1.159	1.166	1.173	1.157	1.128	1.162
	3.7	*–0.3*	*0.1*	*–1.9*	*–1.8*	*0.5*	*0.4*	*0.5*	*1.3*	*0.7*	*0.6*	*0.6*	*3.6*	*–2.5*	*3.1*
Wages and salary per employee ($ 000s)	66.176	66.813	67.804	67.755	67.390	67.492	67.532	67.943	68.281	68.821	69.362	69.870	67.137	67.589	69.084
	0.4	*1.0*	*1.5*	*–0.1*	*–0.5*	*0.2*	*0.1*	*0.6*	*0.5*	*0.8*	*0.8*	*0.7*	*4.5*	*0.7*	*2.2*
Primary household income ($ millions)	200,885	204,163	207,454	209,772	210,737	211,828	211,883	212,511	214,490	216,931	219,537	222,118	205,568	211,740	218,269
	1.3	*1.6*	*1.6*	*1.1*	*0.5*	*0.5*	*0.0*	*0.3*	*0.9*	*1.1*	*1.2*	*1.2*	*6.6*	*3.0*	*3.1*
Household disposable income ($ millions)	168,373	170,335	173,103	174,678	176,635	177,226	177,707	177,718	179,036	181,050	183,200	185,280	171,622	177,321	182,142
	1.1	*1.2*	*1.6*	*0.9*	*1.1*	*0.3*	*0.3*	*0.0*	*0.7*	*1.1*	*1.2*	*1.1*	*6.3*	*3.3*	*2.7*
Household net savings rate (per cent)	15.8	15.8	16.0	16.4	18.4	18.0	18.1	17.6	17.4	17.4	17.4	17.4	16.0	18.0	17.4
Population (000s)	4,060	4,087	4,122	4,146	4,160	4,175	4,193	4,211	4,228	4,246	4,265	4,283	4,104	4,185	4,255
	0.5	*0.7*	*0.9*	*0.6*	*0.3*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*2.9*	*2.0*	*1.7*
Employment (000s)	2,256	2,270	2,274	2,294	2,305	2,308	2,301	2,290	2,297	2,304	2,313	2,322	2,274	2,301	2,309
	0.7	*0.6*	*0.2*	*0.9*	*0.5*	*0.1*	*–0.3*	*–0.5*	*0.3*	*0.3*	*0.4*	*0.4*	*2.2*	*1.2*	*0.3*
Labour force (000s)	2,367	2,386	2,388	2,402	2,429	2,446	2,440	2,436	2,443	2,449	2,457	2,462	2,386	2,438	2,453
	0.7	*0.8*	*0.1*	*0.6*	*1.1*	*0.7*	*–0.3*	*–0.1*	*0.3*	*0.2*	*0.3*	*0.2*	*2.3*	*2.2*	*0.6*
Labour force participation rate (per cent)	72.9	72.9	72.5	72.5	73.0	73.2	72.7	72.4	72.3	72.2	72.2	72.0	72.7	72.8	72.2
Unemployment rate (per cent)	4.7	4.9	4.8	4.5	5.1	5.6	5.7	6.0	6.0	5.9	5.9	5.7	4.7	5.6	5.9
Retail sales ($ millions)	77,699	78,100	79,625	78,904	76,029	76,638	76,347	76,745	77,272	78,012	78,813	79,493	78,582	76,440	78,397
	4.0	*0.5*	*2.0*	*–0.9*	*–3.6*	*0.8*	*–0.4*	*0.5*	*0.7*	*1.0*	*1.0*	*0.9*	*7.5*	*–2.7*	*2.6*
Housing starts (units, 000s)	37,830	42,585	42,999	38,945	45,306	35,784	30,928	28,665	28,682	29,594	30,507	31,419	40,590	35,171	30,050
	–3.8	*12.6*	*1.0*	*–9.4*	*16.3*	*–21.0*	*–13.6*	*–7.3*	*0.1*	*3.2*	*3.1*	*3.0*	*12.7*	*–13.4*	*–14.6*
Net interprovincial migration (000s)	38.3	52.8	25.3	16.7	26.9	–5.1	–1.5	–1.0	1.1	2.5	2.7	3.0	33.3	4.8	2.3
Net international migration (000s)	39.0	50.2	35.4	9.4	4.0	19.6	33.5	33.1	32.5	32.2	31.9	31.8	33.5	22.5	32.1

Shaded area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Key Economic Indicators: Alberta cont'd
(Forecast Completed: July 16, 2015)

	2017Q1	2017Q2	2017Q3	2017Q4	2018Q1	2018Q2	2018Q3	2018Q4	2019Q1	2019Q2	2019Q3	2019Q4	2017	2018	2019
GDP at market prices ($ millions)	383,168	388,081	392,704	396,653	401,094	405,682	410,164	413,382	418,405	423,369	427,896	431,546	390,151	407,581	425,304
	1.7	*1.3*	*1.2*	*1.0*	*1.1*	*1.1*	*1.1*	*0.8*	*1.2*	*1.2*	*1.1*	*0.9*	*5.4*	*4.5*	*4.3*
GDP at market prices (2007 $ millions)	324,039	325,700	327,715	329,767	331,419	333,028	334,792	336,724	338,519	340,435	342,355	344,242	326,805	333,991	341,388
	0.9	*0.5*	*0.6*	*0.6*	*0.5*	*0.5*	*0.5*	*0.6*	*0.5*	*0.6*	*0.6*	*0.6*	*2.6*	*2.2*	*2.2*
GDP at basic prices (2007 $ millions)	312,941	314,545	316,490	318,473	320,068	321,622	323,325	325,191	326,925	328,775	330,630	332,452	315,612	322,552	329,695
	0.9	*0.5*	*0.6*	*0.6*	*0.5*	*0.5*	*0.5*	*0.6*	*0.5*	*0.6*	*0.6*	*0.6*	*2.6*	*2.2*	*2.2*
Consumer price index (2002 = 1.0)	1.380	1.390	1.397	1.401	1.409	1.419	1.426	1.430	1.438	1.448	1.456	1.460	1.392	1.421	1.451
	0.6	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*2.1*	*2.1*	*2.1*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.182	1.192	1.198	1.203	1.210	1.218	1.225	1.228	1.236	1.244	1.250	1.254	1.194	1.220	1.246
	0.8	*0.8*	*0.6*	*0.4*	*0.6*	*0.7*	*0.6*	*0.2*	*0.7*	*0.6*	*0.5*	*0.3*	*2.7*	*2.2*	*2.1*
Wages and salary per employee ($ 000s)	70.342	70.762	71.215	71.689	72.155	72.649	73.170	73.683	74.179	74.751	75.338	75.952	71.002	72.914	75.055
	0.7	*0.6*	*0.6*	*0.7*	*0.6*	*0.7*	*0.7*	*0.7*	*0.7*	*0.8*	*0.8*	*0.8*	*2.8*	*2.7*	*2.9*
Primary household income ($ millions)	224,473	226,924	229,395	231,886	234,280	236,469	239,035	241,552	244,335	247,314	250,326	253,385	228,170	237,834	248,840
	1.1	*1.1*	*1.1*	*1.1*	*1.0*	*0.9*	*1.1*	*1.1*	*1.2*	*1.2*	*1.2*	*1.2*	*4.5*	*4.2*	*4.6*
Household disposable income ($ millions)	187,469	189,413	191,353	193,333	195,167	196,990	199,095	201,145	203,372	205,809	208,266	210,723	190,392	198,099	207,042
	1.2	*1.0*	*1.0*	*1.0*	*0.9*	*0.9*	*1.1*	*1.0*	*1.1*	*1.2*	*1.2*	*1.2*	*4.5*	*4.0*	*4.5*
Household net savings rate (per cent)	17.6	17.6	17.6	17.6	17.6	17.6	17.7	17.6	17.7	17.7	17.8	17.9	17.6	17.6	17.8
Population (000s)	4,302	4,321	4,340	4,359	4,377	4,396	4,415	4,435	4,454	4,473	4,493	4,512	4,331	4,406	4,483
	0.4	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*1.8*	*1.7*	*1.7*
Employment (000s)	2,331	2,340	2,349	2,357	2,363	2,367	2,375	2,381	2,389	2,398	2,407	2,416	2,345	2,371	2,403
	0.4	*0.4*	*0.4*	*0.4*	*0.2*	*0.2*	*0.3*	*0.3*	*0.3*	*0.4*	*0.4*	*0.4*	*1.6*	*1.1*	*1.3*
Labour force (000s)	2,468	2,473	2,477	2,483	2,487	2,492	2,498	2,505	2,514	2,522	2,532	2,540	2,476	2,495	2,527
	0.3	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.3*	*0.3*	*0.3*	*0.3*	*0.4*	*0.4*	*0.9*	*0.8*	*1.3*
Labour force participation rate (per cent)	71.9	71.8	71.7	71.6	71.4	71.3	71.2	71.1	71.0	71.0	71.0	71.0	71.7	71.2	71.0
Unemployment rate (per cent)	5.5	5.4	5.2	5.1	5.0	5.0	4.9	5.0	5.0	4.9	4.9	4.9	5.3	5.0	4.9
Retail sales ($ millions)	80,040	80,590	81,190	81,897	82,548	83,110	83,809	84,499	85,245	86,051	86,908	87,721	80,929	83,492	86,481
	0.7	*0.7*	*0.7*	*0.9*	*0.8*	*0.7*	*0.8*	*0.8*	*0.9*	*0.9*	*1.0*	*0.9*	*3.2*	*3.2*	*3.6*
Housing starts (units, 000s)	28,806	29,722	30,635	31,551	29,390	30,308	31,223	32,141	33,088	33,165	33,237	33,310	30,179	30,766	33,200
	–8.3	*3.2*	*3.1*	*3.0*	*–6.8*	*3.1*	*3.0*	*2.9*	*2.9*	*0.2*	*0.2*	*0.2*	*0.4*	*1.9*	*7.9*
Net interprovincial migration (000s)	3.7	4.1	4.1	4.5	5.5	6.5	6.7	7.0	7.1	7.2	7.3	7.4	4.1	6.4	7.3
Net international migration (000s)	31.8	31.7	31.5	31.4	31.3	31.2	31.1	30.9	30.7	30.6	30.5	30.3	31.6	31.1	30.5

Shaded area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Elise Martin

British Columbia Will Lead the Provinces This Year and Next

Highlights

- British Columbia's economy will grow by 2.8 per cent in 2015, the fastest pace of all the provinces.
- The residential housing market is still hot, with 31,580 units breaking ground this year.
- Metal mining will be a drag on the overall bottom line this year.

Economic Indicators
(percentage change)

	2014	2015f	2016f
Real GDP	2.6	2.8	3.4
Consumer Price Index	1.0	1.3	2.3
Household disposable income	3.4	3.6	4.1
Employment	0.6	0.7	1.6
Unemployment rate (level)	6.1	6.0	5.9
Retail sales	5.6	7.3	4.7
Wages and salaries per employee	3.1	2.4	2.4
Population	1.1	1.0	1.2

f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Government and Background Information

Premier	Christy Clark
Next election	May 2017
Population (2015Q2)	4,666,892
Government balance (2015–16)	$284 million

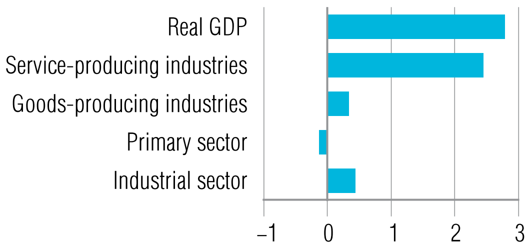
Sources: The Conference Board of Canada; B.C. Finance.

British Columbia's economy is firing on all cylinders. Provincial real GDP will grow at the fastest rate of all 10 provinces in both 2015 and 2016. The economy will advance by 2.8 per cent in 2015 and 3.5 per cent in 2016.

This year, the province will benefit from strong growth in manufacturing and healthy gains in the services sector. Year-to-date (ending in June) exports of manufacturing goods have been on the rise, especially in the metal products manufacturing and transportation equipment manufacturing. Stronger economic growth in the U.S. will continue to support gains in the export categories. Construction will be a drag on the provincial bottom line this year as several projects were completed but next year will bring a substantial rebound as several new projects get under way. Metal mining is also forecast to decline in 2015 as a result of the shutdown of both the Endako and Mount Polley mines. However, metal mining will turn around next year as production ramps up at the Mount Milligan and the Red Chris gold-copper mines.

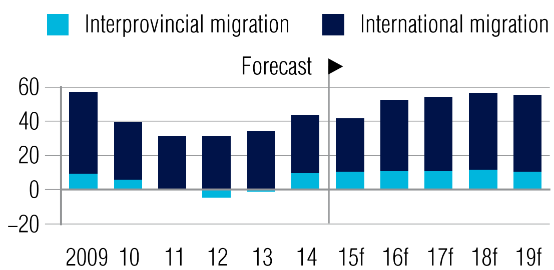
On the energy front, the province passed legislation on July 21st, to enter into an agreement with Pacific NorthWest LNG, a consortium led by Malaysian energy giant Petronas, to build an LNG export terminal near Prince Rupert. The two remaining barriers to this $36-billion project include First Nation's rights and the

Contributions to British Columbia Real GDP Growth, 2015
(by industry/sector, percentage point; GDP, per cent)



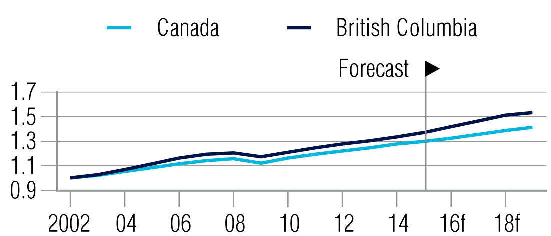
Note: "Primary" is the sum of agriculture, forestry, fishing and trapping, and mining sectors. "Industrial" is the sum of manufacturing, construction, and utilities sectors.
Sources: The Conference Board of Canada; Statistics Canada.

Sources of Migration
(net migration, 000s)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

Real GDP, 2002 to 2019
(index, 2002 = 1.0)



f = forecast
Sources: The Conference Board of Canada; Statistics Canada.

environmental assessment approval. If it goes ahead, it would be the largest private sector investment in the province's history.

EXPORTS GAINS LIFTS THE PROVINCE TO NUMBER ONE IN GDP GROWTH

Over the first five months of 2015, British Columbia saw gains across a wide range of export categories, including aircraft products and services, motor vehicles, and machinery and equipment. Provincial exports are expected to do well as the United States, B.C.'s main trading partner, is gaining economic momentum.

Total housing starts in the U.S. will grow by an average of 25.7 per cent per year over the next two years. However, despite rising demand by the new housing sector in the U.S., growth in the province's forestry industry will dip this year. Because of the mountain pine beetle infestation, a much more limited timber supply is available as many of the hardest-hit areas have already been harvested. As a result, output in the forestry sector will decline by 2.4 per cent in 2015 and 1.5 per cent next year.

After remarkable 29.1 per cent growth last year, metal mining will be a drag on the economy in 2015 as production is expected to decline. The slump comes partly as a result of Thompson Creek's shutting down its Endako mine due to low molybdenum prices. The shutdown was originally announced as temporary in December 2014; however, the mine was put on a care and maintenance footing on July 1. In addition, the shutdown of the Mount Polley mine due to the tailing pond collapse in August 2014 will continue to weigh on the province's metal mining production. The B.C. government has now given the go-ahead for the Mount Polley mine to restart at half capacity and activities could resume as soon as mid-August. Overall, total mining will fall by 1.9 per cent in 2015 but is forecast to rebound in 2016 by 3 per cent.

MANUFACTURING TO DO WELL

Manufacturing is expected to provide a solid base for the provincial economy over the next few years. B.C.'s shipbuilding industry, which has struggled to survive for decades, has had new life breathed into it by the federal government. At the end of June, Seaspan Shipyards started working on an enormous $8-billion federal shipbuilding contract for the construction of non-combat vessels for the Canadian Coast Guard and the Royal Canadian Navy. All told, manufacturing will advance by 8.8 per cent this year and 3.7 per cent in 2016.

CONSTRUCTION WILL DECLINE THIS YEAR BUT PICK UP AGAIN IN 2016

Construction growth will fall into negative territory in 2015 after expanding by 3.1 per cent in 2014, the decrease coming from a slump in non-residential construction. Two large mining projects (Mount Milligan and Red Chris), which boosted construction output over the past several years, have been moved into production. However, the construction decline will not last long; other projects are set to get under way shortly, including the expansion of the Prince Rupert port and construction of a number of energy projects. This investment will spur a 21.4 per cent rebound in the non-residential construction sector in 2016.

No liquid natural gas (LNG) terminals are yet under construction, but work on the Pacific NorthWest LNG, LNG Canada, Kitimat LNG, and Douglas Channel LNG terminals could start before the end of 2018. No fewer than 19 LNG project proposals are on the table in British Columbia. However, only a handful of terminals are likely to take advantage of the window of opportunity before the gap closes between the price of natural gas in North America and Asia. The Malaysian energy producer Petronas is expected to put shovels in the ground as soon as the federal government issues a positive regulatory decision on the project's environmental assessment. The Lax Kw'alaams, an Indigenous band in northern British Columbia, is spearheading the opposition movement to the Pacific NorthWest LNG terminal near Prince Rupert. They turned down a $1.15-billion deal with Petronas over concerns that the LNG terminal will harm an essential juvenile salmon habitat.

Residential construction will post strong growth this year as housing starts are projected to continue increasing, defying the national trend. But, all told, construction will decrease by 3.1 per cent in 2015 and then jump up by 10.9 per cent in 2016.

DOMESTIC DEMAND

Labour markets will continue to increase slightly in British Columbia. Strong growth in manufacturing, as well as a respectable performance by the services industry, will help support labour market growth in the near term. The unemployment rate will continue to edge down to 5.9 per cent by the end of 2016, well below the national average of 6.9 per cent. Healthy advances in wages and salaries will provide support for consumer spending. High prices, historically low interest rates, and steady demand for housing will be behind the elevated levels of buying and selling activity this year, lifting the financial services sector. All told, the services sector will expand by 3.3 per cent in 2015 and 2.8 per cent in 2016.

Forecast Risks

Short term

- Prolonged or permanent mine shutdowns could lower mining output.

Medium term

- A subdued Chinese economy could cool offshore demand for Vancouver real estate.

Source: The Conference Board of Canada.

Key Economic Indicators: British Columbia
(Forecast Completed: July 16, 2015)

	2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4	2016Q1	2016Q2	2016Q3	2016Q4	2014	2015	2016
GDP at market prices ($ millions)	235,592	238,644	241,326	245,895	245,561	249,826	253,735	256,760	258,684	261,957	265,887	269,127	240,364	251,471	263,914
	0.5	*1.3*	*1.1*	*1.9*	*–0.1*	*1.7*	*1.6*	*1.2*	*0.7*	*1.3*	*1.5*	*1.2*	*4.6*	*4.6*	*4.9*
GDP at market prices (2007 $ millions)	217,494	219,609	221,287	224,437	224,648	225,808	227,625	229,343	231,665	233,519	235,937	237,610	220,707	226,856	234,683
	–0.7	*1.0*	*0.8*	*1.4*	*0.1*	*0.5*	*0.8*	*0.8*	*1.0*	*0.8*	*1.0*	*0.7*	*2.6*	*2.8*	*3.5*
GDP at basic prices (2007 $ millions)	200,374	202,323	203,869	206,771	206,968	208,036	209,709	211,290	213,427	215,131	217,355	218,891	203,335	209,001	216,201
	–0.7	*1.0*	*0.8*	*1.4*	*0.1*	*0.5*	*0.8*	*0.8*	*1.0*	*0.8*	*1.0*	*0.7*	*2.6*	*2.8*	*3.4*
Consumer price index (2002 = 1.0)	1.179	1.195	1.196	1.186	1.189	1.204	1.211	1.216	1.223	1.231	1.237	1.241	1.189	1.205	1.233
	0.5	*1.4*	*0.1*	*–0.8*	*0.2*	*1.2*	*0.6*	*0.4*	*0.6*	*0.7*	*0.5*	*0.3*	*1.0*	*1.3*	*2.3*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.083	1.087	1.091	1.096	1.093	1.106	1.115	1.120	1.117	1.122	1.127	1.133	1.089	1.108	1.124
	1.2	*0.3*	*0.4*	*0.5*	*–0.2*	*1.2*	*0.8*	*0.4*	*–0.3*	*0.5*	*0.5*	*0.5*	*2.0*	*1.8*	*1.4*
Wages and salary per employee ($ 000s)	45.061	44.742	45.140	45.573	45.877	46.083	46.371	46.593	46.865	47.165	47.514	47.887	45.129	46.231	47.358
	1.0	*–0.7*	*0.9*	*1.0*	*0.7*	*0.4*	*0.6*	*0.5*	*0.6*	*0.6*	*0.7*	*0.8*	*3.1*	*2.4*	*2.4*
Primary household income ($ millions)	169,170	168,741	169,729	172,218	174,525	174,877	176,837	178,587	180,583	182,665	184,911	187,266	169,964	176,206	183,856
	1.6	*–0.3*	*0.6*	*1.5*	*1.3*	*0.2*	*1.1*	*1.0*	*1.1*	*1.2*	*1.2*	*1.3*	*4.0*	*3.7*	*4.3*
Household disposable income ($ millions)	149,769	148,945	149,772	151,602	153,849	154,013	156,450	157,250	158,923	160,730	162,697	164,744	150,022	155,390	161,774
	1.3	*–0.6*	*0.6*	*1.2*	*1.5*	*0.1*	*1.6*	*0.5*	*1.1*	*1.1*	*1.2*	*1.3*	*3.4*	*3.6*	*4.1*
Household net savings rate (per cent)	1.1	–1.5	–2.0	–2.1	–1.8	–3.0	–2.9	–3.5	–3.7	–3.7	–3.7	–3.6	–1.1	–2.8	–3.7
Population (000s)	4,605	4,617	4,631	4,658	4,659	4,667	4,680	4,694	4,708	4,722	4,737	4,751	4,628	4,675	4,730
	0.0	*0.3*	*0.3*	*0.6*	*0.0*	*0.2*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.1*	*1.0*	*1.2*
Employment (000s)	2,277	2,280	2,274	2,282	2,288	2,286	2,295	2,303	2,313	2,325	2,336	2,348	2,278	2,293	2,331
	0.6	*0.1*	*–0.3*	*0.4*	*0.3*	*–0.1*	*0.4*	*0.4*	*0.4*	*0.5*	*0.5*	*0.5*	*0.6*	*0.7*	*1.6*
Labour force (000s)	2,429	2,428	2,424	2,422	2,429	2,434	2,443	2,452	2,460	2,470	2,482	2,493	2,426	2,439	2,476
	0.2	*–0.1*	*–0.2*	*–0.1*	*0.3*	*0.2*	*0.4*	*0.4*	*0.3*	*0.4*	*0.5*	*0.4*	*0.0*	*0.6*	*1.5*
Labour force participation rate (per cent)	63.7	63.5	63.2	63.0	63.0	62.9	63.0	63.0	63.1	63.1	63.2	63.3	63.3	63.0	63.2
Unemployment rate (per cent)	6.3	6.1	6.2	5.8	5.8	6.1	6.1	6.1	6.0	5.9	5.9	5.8	6.1	6.0	5.9
Retail sales ($ millions)	64,056	66,033	67,124	67,880	69,223	70,840	71,728	72,562	73,352	74,065	74,848	75,586	66,273	71,088	74,463
	0.2	*3.1*	*1.7*	*1.1*	*2.0*	*2.3*	*1.3*	*1.2*	*1.1*	*1.0*	*1.1*	*1.0*	*5.6*	*7.3*	*4.7*
Housing starts (units, 000s)	27,199	27,640	29,403	29,182	30,128	33,129	31,726	31,339	31,200	31,259	31,570	31,993	28,356	31,580	31,505
	–8.3	*1.6*	*6.4*	*–0.7*	*3.2*	*10.0*	*–4.2*	*–1.2*	*–0.4*	*0.2*	*1.0*	*1.3*	*4.8*	*11.4*	*–0.2*
Net interprovincial migration (000s)	5.2	7.9	16.9	10.2	15.2	9.5	8.8	9.2	10.4	10.6	11.0	11.2	10.0	10.7	10.8
Net international migration (000s)	34.8	38.4	75.0	–12.6	9.3	35.3	39.0	39.7	40.5	41.2	41.8	42.3	33.9	30.8	41.4

Shaded area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Key Economic Indicators: British Columbia cont'd
(Forecast Completed: July 16, 2015)

	2017Q1	2017Q2	2017Q3	2017Q4	2018Q1	2018Q2	2018Q3	2018Q4	2019Q1	2019Q2	2019Q3	2019Q4	2017	2018	2019
GDP at market prices ($ millions)	274,666 *2.1*	278,708 *1.5*	282,474 *1.4*	285,877 *1.2*	290,614 *1.7*	294,255 *1.3*	297,448 *1.1*	299,273 *0.6*	302,130 *1.0*	304,645 *0.8*	306,467 *0.6*	307,332 *0.3*	280,431 *6.3*	295,398 *5.3*	305,144 *3.3*
GDP at market prices (2007 $ millions)	239,705 *0.9*	241,340 *0.7*	243,214 *0.8*	245,258 *0.8*	248,002 *1.1*	249,548 *0.6*	250,887 *0.5*	251,964 *0.4*	252,706 *0.3*	253,290 *0.2*	253,566 *0.1*	253,548 *0.0*	242,379 *3.3*	250,100 *3.2*	253,277 *1.3*
GDP at basic prices (2007 $ millions)	220,815 *0.9*	222,315 *0.7*	224,036 *0.8*	225,912 *0.8*	228,426 *1.1*	229,846 *0.6*	231,077 *0.5*	232,071 *0.4*	232,757 *0.3*	233,302 *0.2*	233,565 *0.1*	233,559 *0.0*	223,270 *3.3*	230,355 *3.2*	233,296 *1.3*
Consumer price index (2002 = 1.0)	1.249 *0.6*	1.257 *0.7*	1.263 *0.5*	1.267 *0.3*	1.275 *0.6*	1.283 *0.7*	1.290 *0.5*	1.293 *0.3*	1.301 *0.6*	1.310 *0.7*	1.316 *0.5*	1.321 *0.3*	1.259 *2.1*	1.285 *2.1*	1.312 *2.1*
Implicit price deflator— **GDP at market prices** (2007 = 1.0)	1.146 *1.2*	1.155 *0.8*	1.161 *0.6*	1.166 *0.4*	1.172 *0.5*	1.179 *0.6*	1.186 *0.5*	1.188 *0.2*	1.196 *0.7*	1.203 *0.6*	1.209 *0.5*	1.212 *0.3*	1.157 *2.9*	1.181 *2.1*	1.205 *2.0*
Wages and salary per employee ($ 000s)	48 *0.7*	49 *0.6*	49 *0.8*	49 *0.8*	50 *0.9*	50 *0.8*	51 *0.8*	51 *0.8*	51 *0.7*	52 *0.5*	52 *0.7*	52 *0.7*	49 *2.9*	50 *3.3*	52 *2.8*
Primary household income ($ millions)	189,571 *1.2*	191,802 *1.2*	194,330 *1.3*	196,927 *1.3*	199,705 *1.4*	202,443 *1.4*	205,169 *1.3*	207,543 *1.2*	209,725 *1.1*	211,552 *0.9*	213,530 *0.9*	215,517 *0.9*	193,157 *5.1*	203,715 *5.5*	212,581 *4.4*
Household disposable income ($ millions)	167,074 *1.4*	168,976 *1.1*	171,086 *1.2*	173,226 *1.3*	175,332 *1.2*	177,739 *1.4*	180,111 *1.3*	182,143 *1.1*	183,946 *1.0*	185,595 *0.9*	187,338 *0.9*	189,068 *0.9*	170,091 *5.1*	178,831 *5.1*	186,487 *4.3*
Household net savings rate (per cent)	–3.4	–3.4	–3.4	–3.4	–3.4	–3.4	–3.3	–3.3	–3.2	–3.1	–3.1	–2.9	–3.4	–3.3	–3.1
Population (000s)	4,767 *0.3*	4,782 *0.3*	4,797 *0.3*	4,813 *0.3*	4,828 *0.3*	4,844 *0.3*	4,860 *0.3*	4,876 *0.3*	4,892 *0.3*	4,908 *0.3*	4,924 *0.3*	4,940 *0.3*	4,790 *1.3*	4,852 *1.3*	4,916 *1.3*
Employment (000s)	2,360 *0.5*	2,372 *0.5*	2,384 *0.5*	2,395 *0.5*	2,408 *0.5*	2,420 *0.5*	2,432 *0.5*	2,440 *0.3*	2,445 *0.2*	2,449 *0.2*	2,453 *0.2*	2,457 *0.2*	2,378 *2.0*	2,425 *2.0*	2,451 *1.1*
Labour force (000s)	2,502 *0.4*	2,512 *0.4*	2,520 *0.3*	2,526 *0.3*	2,533 *0.3*	2,547 *0.5*	2,559 *0.5*	2,565 *0.2*	2,571 *0.2*	2,577 *0.2*	2,581 *0.2*	2,586 *0.2*	2,515 *1.6*	2,551 *1.4*	2,579 *1.1*
Labour force participation rate (per cent)	63.3	63.4	63.4	63.3	63.3	63.4	63.5	63.5	63.4	63.4	63.3	63.2	63.4	63.4	63.3
Unemployment rate (per cent)	5.7	5.6	5.4	5.2	4.9	5.0	4.9	4.9	4.9	4.9	5.0	5.0	5.5	4.9	4.9
Retail sales ($ millions)	76,294 *0.9*	76,873 *0.8*	77,615 *1.0*	78,460 *1.1*	79,306 *1.1*	80,240 *1.2*	81,140 *1.1*	81,857 *0.9*	82,404 *0.7*	82,820 *0.5*	83,335 *0.6*	83,807 *0.6*	77,310 *3.8*	80,636 *4.3*	83,092 *3.0*
Housing starts (units, 000s)	31,738 *–0.8*	31,899 *0.5*	32,246 *1.1*	32,703 *1.4*	32,486 *–0.7*	32,266 *–0.7*	32,332 *0.2*	31,739 *–1.8*	32,197 *1.4*	32,335 *0.4*	32,464 *0.4*	32,797 *1.0*	32,147 *2.0*	32,206 *0.2*	32,448 *0.8*
Net interprovincial migration (000s)	10.8	10.9	11.2	11.3	11.7	11.7	11.7	11.5	11.2	10.9	10.6	10.2	11.0	11.6	10.7
Net international migration (000s)	42.5	43.0	43.4	43.9	44.6	44.9	45.1	45.1	44.8	44.7	44.6	44.6	43.2	44.9	44.7

Shaded area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Key Economic Indicators: Canada
(Forecast Completed: July 16, 2015)

	2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4	2016Q1	2016Q2	2016Q3	2016Q4	2014	2015	2016
GDP at market prices ($ millions)	1,949,952	1,968,220	1,989,532	1,991,596	1,977,028	1,991,904	2,020,504	2,039,621	2,060,259	2,082,485	2,105,580	2,122,723	1,974,825	2,007,264	2,092,762
	1.6	*0.9*	*1.1*	*0.1*	*–0.7*	*0.8*	*1.4*	*0.9*	*1.0*	*1.1*	*1.1*	*0.8*	*4.3*	*1.6*	*4.3*
GDP at market prices (2007 $ millions)	1,726,814	1,741,505	1,755,344	1,765,019	1,762,406	1,767,769	1,780,262	1,788,118	1,796,986	1,806,431	1,819,117	1,826,662	1,747,171	1,774,639	1,812,299
	0.3	*0.9*	*0.8*	*0.6*	*–0.1*	*0.3*	*0.7*	*0.4*	*0.5*	*0.5*	*0.7*	*0.4*	*2.4*	*1.6*	*2.1*
GDP at basic prices (2007 $ millions)	1,619,106	1,633,316	1,644,035	1,653,314	1,650,171	1,655,792	1,667,490	1,674,845	1,683,149	1,691,993	1,703,871	1,710,934	1,637,443	1,662,075	1,697,487
	0.3	*0.9*	*0.7*	*0.6*	*–0.2*	*0.3*	*0.7*	*0.4*	*0.5*	*0.5*	*0.7*	*0.4*	*2.4*	*1.5*	*2.1*
Consumer price index (2002 = 1.0)	1.240	1.256	1.257	1.253	1.253	1.269	1.277	1.282	1.289	1.298	1.304	1.309	1.252	1.270	1.300
	0.9	*1.3*	*0.1*	*–0.4*	*0.1*	*1.2*	*0.6*	*0.4*	*0.6*	*0.7*	*0.5*	*0.3*	*1.9*	*1.5*	*2.3*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.129	1.130	1.133	1.128	1.122	1.127	1.135	1.141	1.147	1.153	1.157	1.162	1.130	1.131	1.155
	1.4	*0.1*	*0.3*	*–0.4*	*–0.6*	*0.4*	*0.7*	*0.5*	*0.5*	*0.6*	*0.4*	*0.4*	*1.8*	*0.1*	*2.1*
Wages and salary per employee ($ 000s)	47.675	48.103	48.503	48.525	48.853	49.015	49.167	49.417	49.671	49.957	50.260	50.566	48.202	49.113	50.114
	0.7	*0.9*	*0.8*	*0.0*	*0.7*	*0.3*	*0.3*	*0.5*	*0.5*	*0.6*	*0.6*	*0.6*	*2.9*	*1.9*	*2.0*
Primary household income ($ millions)	1,267,068	1,277,288	1,288,484	1,297,264	1,313,792	1,319,631	1,328,981	1,338,651	1,351,524	1,364,221	1,377,267	1,390,433	1,282,526	1,325,264	1,370,861
	1.1	*0.8*	*0.9*	*0.7*	*1.3*	*0.4*	*0.7*	*0.7*	*1.0*	*0.9*	*1.0*	*1.0*	*3.7*	*3.3*	*3.4*
Household disposable income ($ millions)	1,106,124	1,112,676	1,122,860	1,129,208	1,146,308	1,149,608	1,163,890	1,166,535	1,175,775	1,186,630	1,197,542	1,208,477	1,117,717	1,156,585	1,192,106
	1.0	*0.6*	*0.9*	*0.6*	*1.5*	*0.3*	*1.2*	*0.2*	*0.8*	*0.9*	*0.9*	*0.9*	*3.4*	*3.5*	*3.1*
Household net savings rate (per cent)	4.8	3.8	3.7	3.6	5.0	4.0	4.1	3.5	3.3	3.3	3.3	3.4	4.0	4.1	3.3
Population (000s)	35,335	35,416	35,540	35,676	35,703	35,800	35,899	35,999	36,101	36,202	36,304	36,406	35,492	35,850	36,253
	0.1	*0.2*	*0.4*	*0.4*	*0.1*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.1*	*1.0*	*1.1*
Employment (000s)	17,764	17,763	17,794	17,864	17,896	17,928	17,973	17,992	18,049	18,110	18,170	18,229	17,796	17,947	18,139
	0.2	*0.0*	*0.2*	*0.4*	*0.2*	*0.2*	*0.3*	*0.1*	*0.3*	*0.3*	*0.3*	*0.3*	*0.6*	*0.8*	*1.1*
Labour force (000s)	19,104	19,098	19,131	19,139	19,190	19,264	19,302	19,354	19,406	19,461	19,516	19,568	19,118	19,278	19,488
	0.1	*0.0*	*0.2*	*0.0*	*0.3*	*0.4*	*0.2*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.4*	*0.8*	*1.1*
Labour force participation rate (per cent)	66.2	66.0	65.9	65.8	65.8	65.9	65.9	65.9	65.9	65.9	65.9	65.9	66.0	65.9	65.9
Unemployment rate (per cent)	7.0	7.0	7.0	6.7	6.7	6.9	6.9	7.0	7.0	6.9	6.9	6.8	6.9	6.9	6.9
Retail sales ($ millions)	493,515	504,790	511,211	510,514	504,723	515,508	520,185	524,953	529,458	533,804	538,081	541,797	505,008	516,342	535,785
	0.9	*2.3*	*1.3*	*–0.1*	*–1.1*	*2.1*	*0.9*	*0.9*	*0.9*	*0.8*	*0.8*	*0.7*	*4.6*	*2.2*	*3.8*
Housing starts (units)	175,834	197,210	196,190	188,082	176,554	189,782	182,520	179,547	176,546	177,261	178,023	179,451	189,329	182,101	177,820
	–11.1	*12.2*	*–0.5*	*–4.1*	*–6.1*	*7.5*	*–3.8*	*–1.6*	*–1.7*	*0.4*	*0.4*	*0.8*	*0.7*	*–3.8*	*–2.4*

Shaded area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Key Economic Indicators: Canada cont'd
(Forecast Completed: July 16, 2015)

	2017Q1	2017Q2	2017Q3	2017Q4	2018Q1	2018Q2	2018Q3	2018Q4	2019Q1	2019Q2	2019Q3	2019Q4	2017	2018	2019
GDP at market prices ($ millions)	2,150,037	2,173,774	2,196,623	2,216,531	2,244,696	2,269,125	2,292,277	2,307,898	2,333,297	2,357,681	2,379,208	2,395,531	2,184,241	2,278,499	2,366,429
	1.3	*1.1*	*1.1*	*0.9*	*1.3*	*1.1*	*1.0*	*0.7*	*1.1*	*1.0*	*0.9*	*0.7*	*4.4*	*4.3*	*3.9*
GDP at market prices (2007 $ millions)	1,838,736	1,846,891	1,857,580	1,868,930	1,880,596	1,889,666	1,899,080	1,909,152	1,918,032	1,927,301	1,936,360	1,945,035	1,853,034	1,894,624	1,931,682
	0.7	*0.4*	*0.6*	*0.6*	*0.6*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.4*	*2.2*	*2.2*	*2.0*
GDP at basic prices (2007 $ millions)	1,722,239	1,729,876	1,739,884	1,750,512	1,761,434	1,769,926	1,778,740	1,788,172	1,796,486	1,805,165	1,813,647	1,821,770	1,735,628	1,774,568	1,809,267
	0.7	*0.4*	*0.6*	*0.6*	*0.6*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.4*	*2.2*	*2.2*	*2.0*
Consumer price index (2002 = 1.0)	1.316	1.325	1.332	1.336	1.344	1.353	1.360	1.363	1.371	1.381	1.388	1.392	1.327	1.355	1.383
	0.6	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*2.1*	*2.1*	*2.1*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.169	1.177	1.183	1.186	1.194	1.201	1.207	1.209	1.217	1.223	1.229	1.232	1.179	1.203	1.225
	0.6	*0.7*	*0.5*	*0.3*	*0.6*	*0.6*	*0.5*	*0.2*	*0.6*	*0.6*	*0.4*	*0.2*	*2.1*	*2.0*	*1.9*
Wages and salary per employee ($ 000s)	50.886	51.209	51.538	51.863	52.188	52.531	52.875	53.227	53.586	53.950	54.319	54.695	51.374	52.705	54.137
	0.6	*0.6*	*0.6*	*0.6*	*0.6*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*	*2.5*	*2.6*	*2.7*
Primary household income ($ millions)	1,402,824	1,417,249	1,431,521	1,445,577	1,460,473	1,474,581	1,488,917	1,503,413	1,518,965	1,533,560	1,548,324	1,563,215	1,424,293	1,481,846	1,541,016
	0.9	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*3.9*	*4.0*	*4.0*
Household disposable income ($ millions)	1,220,718	1,232,293	1,243,658	1,254,803	1,265,771	1,277,658	1,289,728	1,301,729	1,314,054	1,326,837	1,339,579	1,352,262	1,237,868	1,283,722	1,333,183
	1.0	*0.9*	*0.9*	*0.9*	*0.9*	*0.9*	*0.9*	*0.9*	*0.9*	*1.0*	*1.0*	*0.9*	*3.8*	*3.7*	*3.9*
Household net savings rate (per cent)	3.6	3.6	3.6	3.6	3.6	3.6	3.7	3.7	3.7	3.8	3.9	4.0	3.6	3.6	3.8
Population (000s)	36,509	36,612	36,716	36,820	36,925	37,029	37,133	37,237	37,341	37,444	37,548	37,651	36,664	37,081	37,496
	0.3	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.1*	*1.1*	*1.1*
Employment (000s)	18,288	18,351	18,408	18,465	18,517	18,569	18,624	18,677	18,729	18,779	18,830	18,882	18,378	18,597	18,805
	0.3	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.3*	*1.2*	*1.1*
Labour force (000s)	19,617	19,669	19,715	19,755	19,792	19,823	19,860	19,895	19,936	19,979	20,025	20,071	19,689	19,843	20,003
	0.2	*0.3*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*1.0*	*0.8*	*0.8*
Labour force participation rate (per cent)	65.9	65.9	65.8	65.8	65.8	65.7	65.6	65.6	65.5	65.5	65.5	65.5	65.8	65.7	65.5
Unemployment rate (per cent)	6.8	6.7	]	6.5	6.4	6.3	6.2	6.1	6.1	6.0	6.0	5.9	5.0	6.3	6.0
Retail sales ($ millions)	544,993	548,612	552,481	556,796	561,126	565,426	569,722	574,100	578,398	582,590	587,038	591,155	550,720	567,593	584,795
	0.6	*0.7*	*0.7*	*0.8*	*0.8*	*0.8*	*0.8*	*0.8*	*0.7*	*0.7*	*0.8*	*0.7*	*2.8*	*3.1*	*3.0*
Housing starts (units)	173,433	176,633	178,749	183,024	181,974	183,954	185,834	189,234	194,903	198,426	200,564	203,301	177,960	185,249	199,298
	–3.4	*1.8*	*1.2*	*2.4*	*–0.6*	*1.1*	*1.0*	*1.8*	*3.0*	*1.8*	*1.1*	*1.4*	*0.1*	*4.1*	*7.6*

Shaded area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Gross Domestic Product by Province and Industry
(Forecast Completed: July 16, 2015)

	Newfoundland and Labrador			Prince Edward Island			Nova Scotia			New Brunswick			Quebec		
	2014	2015	2016	2014	2015	2016	2014	2015	2016	2014	2015	2016	2014	2015	2016
Agriculture	85	88	89	201	204	205	225	231	232	255	262	265	3,562	3,746	3,801
	–3.3	*3.5*	*0.9*	*3.7*	*1.7*	*0.5*	*–5.7*	*2.6*	*0.6*	*–3.2*	*2.8*	*1.1*	*–1.3*	*5.2*	*1.5*
Forestry	67	71	67	4	4	4	57	57	63	260	273	281	929	929	1,005
	–2.3	*6.2*	*–5.8*	*–12.2*	*3.9*	*–1.8*	*12.7*	*0.7*	*9.7*	*7.6*	*4.9*	*3.1*	*1.4*	*–0.1*	*8.2*
Agriculture and forestry support services	16	18	18	8	8	8	48	53	54	69	74	75	467	500	511
	–6.4	*10.3*	*2.6*	*23.8*	*4.5*	*2.2*	*5.5*	*8.7*	*2.6*	*7.7*	*7.3*	*2.2*	*10.3*	*7.1*	*2.2*
Fishing and trapping	229	242	243	91	97	96	479	507	503	151	160	158	83	96	96
	–8.2	*5.9*	*0.5*	*2.7*	*6.9*	*–0.7*	*11.0*	*5.8*	*–0.7*	*10.3*	*5.8*	*–1.2*	*16.9*	*15.6*	*–0.5*
Mining	8,258	8,194	8,104	2	2	2	1,262	972	909	354	400	479	4,273	4,473	4,632
	–7.2	*–0.8*	*–1.1*	*0.0*	*2.9*	*0.2*	*56.3*	*–23.0*	*–6.5*	*–10.0*	*12.9*	*19.8*	*19.4*	*4.7*	*3.6*
Manufacturing	992	1,057	1,078	459	477	488	2,704	2,805	3,035	2,899	2,985	3,066	44,631	45,370	46,574
	–8.4	*6.5*	*2.0*	*9.1*	*3.7*	*2.4*	*0.2*	*3.7*	*8.2*	*–3.6*	*3.0*	*2.7*	*3.1*	*1.7*	*2.7*
Construction	2,553	2,372	1,922	256	279	297	1,725	1,923	2,122	1,241	1,199	1,217	20,486	20,226	20,092
	–4.7	*–7.1*	*–18.9*	*–6.0*	*9.0*	*6.5*	*–4.0*	*11.5*	*10.4*	*–1.6*	*–3.4*	*1.5*	*–2.2*	*–1.3*	*–0.7*
Utilities	637	693	700	49	55	58	652	666	675	995	1,020	1,032	13,543	14,302	14,631
	–4.1	*8.8*	*1.1*	*–2.2*	*11.9*	*5.4*	*–2.3*	*2.1*	*1.3*	*4.8*	*2.5*	*1.2*	*–1.1*	*5.6*	*2.3*
Goods producing-industries	13,195	13,093	12,580	1,049	1,106	1,138	7,176	7,238	7,617	6,116	6,265	6,466	88,482	90,150	91,848
	–4.3	*–0.8*	*–3.9*	*1.7*	*5.3*	*3.0*	*4.0*	*0.9*	*5.2*	*–1.2*	*2.4*	*3.2*	*1.9*	*1.9*	*1.9*
Wholesale and retail trade	2,124	2,104	2,091	429	443	452	3,687	3,721	3,841	3,089	3,128	3,209	35,528	36,448	37,361
	2.6	*–1.0*	*–0.6*	*2.5*	*3.3*	*2.1*	*1.5*	*0.9*	*3.2*	*–0.6*	*1.3*	*2.6*	*1.2*	*2.6*	*2.5*
Transportation and warehousing	676	677	666	122	127	130	1,063	1,106	1,146	1,238	1,279	1,312	12,434	12,728	12,987
	–0.3	*0.1*	*–1.7*	*1.3*	*4.2*	*2.4*	*1.0*	*4.1*	*3.6*	*2.3*	*3.3*	*2.6*	*2.4*	*2.4*	*2.0*
Information and culture	588	585	588	132	131	133	1,077	1,074	1,079	807	804	807	10,168	10,133	10,217
	–2.2	*–0.5*	*0.5*	*–1.3*	*–0.3*	*0.9*	*–1.5*	*–0.3*	*0.5*	*–1.9*	*–0.4*	*0.4*	*–1.0*	*–0.3*	*0.8*
Finance, insurance, and real estate	3,270	3,358	3,425	939	964	985	7,398	7,546	7,716	4,914	4,998	5,105	56,973	58,785	60,478
	2.3	*2.7*	*2.0*	*1.5*	*2.6*	*2.2*	*2.7*	*2.0*	*2.2*	*1.1*	*1.7*	*2.1*	*1.8*	*3.2*	*2.9*
Community, business, and personal services	1,803	1,820	1,851	548	550	564	3,677	3,720	3,801	2,980	3,020	3,108	40,604	41,626	43,031
	1.0	*1.0*	*1.7*	*1.8*	*0.3*	*2.6*	*1.0*	*1.2*	*2.2*	*0.8*	*1.3*	*2.9*	*1.0*	*2.5*	*3.4*
Education	1,417	1,419	1,399	342	345	349	2,150	2,177	2,157	1,599	1,601	1,579	18,604	18,645	18,663
	0.5	*0.2*	*–1.4*	*0.3*	*0.8*	*1.2*	*–0.7*	*1.2*	*–0.9*	*–0.5*	*0.1*	*–1.3*	*0.9*	*0.2*	*0.1*
Health and social assistance	2,358	2,378	2,396	454	455	457	3,127	3,166	3,200	2,372	2,376	2,402	25,689	25,747	26,035
	0.8	*0.9*	*0.8*	*0.7*	*0.2*	*0.4*	*0.7*	*1.3*	*1.1*	*0.8*	*0.2*	*1.1*	*1.2*	*0.2*	*1.1*
Public administration and defence	1,979	1,969	1,976	615	621	625	4,122	4,150	4,175	2,953	2,969	2,981	23,287	23,369	23,390
	–0.5	*–0.5*	*0.4*	*–1.8*	*1.0*	*0.6*	*–0.2*	*0.7*	*0.6*	*1.0*	*0.5*	*0.4*	*1.7*	*0.4*	*0.1*
Service-producing industries	14,312	14,408	14,489	3,602	3,657	3,715	26,328	26,688	27,143	19,892	20,114	20,443	223,183	227,378	232,058
	1.6	*0.7*	*0.6*	*1.4*	*1.5*	*1.6*	*1.2*	*1.4*	*1.7*	*0.2*	*1.1*	*1.6*	*1.3*	*1.9*	*2.1*
All industries	26,924	26,919	26,486	4,644	4,755	4,845	33,480	33,902	34,736	26,063	26,434	26,964	311,825	317,686	324,065
	–2.9	*0.0*	*–1.6*	*1.3*	*2.4*	*1.9*	*1.6*	*1.3*	*2.5*	*0.0*	*1.4*	*2.0*	*1.4*	*1.9*	*2.0*

Shaded area represents forecast data.
All data are in millions of 2007 dollars.
For each industry, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada.

Gross Domestic Product by Province and Industry cont'd
(Forecast Completed: July 16, 2015)

	Newfoundland and Labrador			Prince Edward Island			Nova Scotia			New Brunswick			Quebec		
	2017	2018	2019	2017	2018	2019	2017	2018	2019	2017	2018	2019	2017	2018	2019
Agriculture	89	90	90	207	211	212	235	240	243	269	275	279	3,877	3,955	4,041
	0.8	*0.7*	*0.4*	*1.2*	*1.5*	*0.6*	*1.1*	*2.1*	*1.3*	*1.7*	*2.3*	*1.4*	*2.0*	*2.0*	*2.2*
Forestry	66	66	66	4	4	4	66	66	66	291	304	303	1,084	1,108	1,131
	–1.6	*0.9*	*–0.7*	*–0.7*	*0.9*	*–0.8*	*5.8*	*0.1*	*–0.7*	*3.6*	*4.3*	*–0.4*	*7.9*	*2.2*	*2.0*
Agriculture and forestry support services	19	31	34	8	9	8	55	56	56	77	78	79	520	527	502
	2.1	*65.3*	*11.7*	*1.7*	*1.4*	*–5.3*	*2.1*	*1.8*	*0.0*	*1.7*	*1.4*	*2.2*	*1.7*	*1.4*	*–4.7*
Fishing and trapping	245	246	248	96	96	96	506	509	512	158	158	158	97	97	98
	0.6	*0.6*	*0.5*	*0.0*	*0.0*	*–0.2*	*0.6*	*0.6*	*0.6*	*–0.1*	*0.0*	*0.1*	*0.6*	*0.6*	*0.6*
Mining	7,993	8,027	9,576	2	2	2	864	864	841	522	526	531	4,723	5,151	5,556
	–1.4	*0.4*	*19.3*	*1.1*	*1.1*	*1.1*	*–5.0*	*0.0*	*–2.6*	*9.0*	*0.7*	*1.0*	*2.0*	*9.1*	*7.9*
Manufacturing	1,102	1,126	1,144	500	513	522	3,099	3,206	3,294	3,134	3,195	3,246	47,631	48,609	49,440
	2.2	*2.1*	*1.6*	*2.6*	*2.4*	*1.9*	*2.1*	*3.5*	*2.7*	*2.2*	*2.0*	*1.6*	*2.3*	*2.1*	*1.7*
Construction	1,719	1,554	1,479	311	320	326	2,155	2,160	2,187	1,375	1,637	1,644	20,623	21,104	21,021
	–10.6	*–9.6*	*–4.8*	*4.6*	*3.0*	*1.8*	*1.5*	*0.3*	*1.2*	*13.0*	*19.0*	*0.4*	*2.6*	*2.3*	*–0.4*
Utilities	723	761	769	61	63	64	684	692	701	1,048	1,062	1,074	14,963	15,264	15,539
	3.3	*5.3*	*1.0*	*5.6*	*2.6*	*1.7*	*1.4*	*1.2*	*1.3*	*1.5*	*1.3*	*1.1*	*2.3*	*2.0*	*1.8*
Goods-producing industries	12,315	12,248	13,753	1,170	1,197	1,214	7,688	7,818	7,925	6,767	7,128	7,207	94,026	96,324	97,836
	–2.1	*–0.5*	*12.3*	*2.8*	*2.3*	*1.4*	*0.9*	*1.7*	*1.4*	*4.6*	*5.3*	*1.1*	*2.4*	*2.4*	*1.6*
Wholesale and retail trade	2,114	2,148	2,175	459	466	470	3,880	3,913	3,931	3,284	3,361	3,387	38,393	39,242	39,871
	1.1	*1.6*	*1.2*	*1.5*	*1.5*	*0.8*	*1.0*	*0.8*	*0.5*	*2.3*	*2.4*	*0.8*	*2.8*	*2.2*	*1.6*
Transportation and warehousing	654	643	704	132	133	136	1,154	1,166	1,185	1,370	1,447	1,496	13,224	13,460	13,711
	–1.8	*–1.5*	*9.4*	*1.1*	*1.3*	*1.7*	*0.7*	*1.0*	*1.6*	*4.4*	*5.6*	*3.4*	*1.8*	*1.8*	*1.9*
Information and culture	592	598	597	134	135	136	1,084	1,088	1,084	809	811	808	10,305	10,372	10,395
	0.5	*1.1*	*–0.3*	*0.9*	*0.8*	*0.6*	*0.4*	*0.4*	*–0.3*	*0.3*	*0.3*	*–0.4*	*0.9*	*0.7*	*0.2*
Finance, insurance, and real estate	3,499	3,552	3,600	1,008	1,028	1,046	7,900	8,033	8,141	5,211	5,292	5,364	62,230	63,713	64,988
	2.2	*1.5*	*1.3*	*2.3*	*2.0*	*1.7*	*2.4*	*1.7*	*1.3*	*2.1*	*1.6*	*1.4*	*2.9*	*2.4*	*2.0*
Community, business, and personal services	1,881	1,920	1,930	578	591	599	3,885	3,963	4,061	3,172	3,217	3,236	44,266	45,348	46,453
	1.6	*2.1*	*0.5*	*2.5*	*2.3*	*1.4*	*2.2*	*2.0*	*2.5*	*2.1*	*1.4*	*0.6*	*2.9*	*2.4*	*2.4*
Education	1,385	1,387	1,393	354	354	354	2,132	2,130	2,120	1,561	1,560	1,556	18,977	19,140	19,298
	–1.0	*0.2*	*0.4*	*1.4*	*0.1*	*–0.1*	*–1.2*	*–0.1*	*–0.5*	*–1.2*	*–0.1*	*–0.3*	*1.7*	*0.9*	*0.8*
Health and social assistance	2,475	2,525	2,560	471	480	487	3,292	3,350	3,400	2,470	2,513	2,548	26,563	27,016	27,418
	3.3	*2.0*	*1.4*	*3.0*	*1.9*	*1.5*	*2.9*	*1.8*	*1.5*	*2.8*	*1.7*	*1.4*	*2.0*	*1.7*	*1.5*
Public administration and defence	1,994	2,012	2,016	631	637	645	4,220	4,267	4,323	3,006	3,032	3,062	23,678	23,954	24,180
	0.9	*0.9*	*0.2*	*1.0*	*1.0*	*1.2*	*1.1*	*1.1*	*1.3*	*0.8*	*0.9*	*1.0*	*1.2*	*1.2*	*0.9*
Service-producing industries	14,690	14,883	15,070	3,786	3,845	3,892	27,574	27,939	28,274	20,822	21,172	21,397	237,533	242,142	246,211
	1.4	*1.3*	*1.3*	*1.9*	*1.5*	*1.2*	*1.6*	*1.3*	*1.2*	*1.9*	*1.7*	*1.1*	*2.4*	*1.9*	*1.7*
All industries	26,422	26,549	28,242	4,949	5,034	5,099	35,238	35,733	36,174	27,643	28,354	28,659	331,718	338,625	344,206
	–0.2	*0.5*	*6.4*	*2.1*	*1.7*	*1.3*	*1.4*	*1.4*	*1.2*	*2.5*	*2.6*	*1.1*	*2.4*	*2.1*	*1.6*

Shaded area represents forecast data.
All data are in millions of 2007 dollars.
For each industry, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada.

Gross Domestic Product by Province and Industry
(Forecast Completed: July 16, 2015)

	Ontario			Manitoba			Saskatchewan			Alberta			British Columbia		
	2014	2015	2016	2014	2015	2016	2014	2015	2016	2014	2015	2016	2014	2015	2016
Agriculture	3,975	4,088	4,148	1,571	1,631	1,663	3,674	3,584	3,659	3,811	3,756	3,837	1,161	1,200	1,220
	–5.1	*2.8*	*1.4*	*–13.1*	*3.9*	*1.9*	*–17.1*	*–2.4*	*2.1*	*–9.1*	*–1.5*	*2.2*	*–1.9*	*3.3*	*1.7*
Forestry	389	488	538	29	30	35	57	60	70	423	451	509	1,654	1,614	1,591
	3.2	*25.4*	*10.3*	*–2.4*	*6.2*	*15.4*	*6.5*	*4.8*	*16.5*	*0.4*	*6.6*	*13.1*	*–8.1*	*–2.4*	*–1.5*
Agriculture and forestry support services	541	588	602	77	83	85	170	190	196	281	306	313	706	770	787
	14.0	*8.8*	*2.2*	*3.6*	*7.6*	*2.2*	*9.0*	*12.2*	*3.0*	*6.4*	*8.8*	*2.2*	*1.9*	*9.0*	*2.2*
Fishing and trapping	29	31	30	6	8	7	0	1	1	7	7	6	137	102	101
	16.8	*5.2*	*–1.1*	*0.0*	*19.6*	*–1.1*	*–75.0*	*383.0*	*–0.7*	*–61.8*	*0.4*	*–0.4*	*17.6*	*–25.9*	*–0.6*
Mining	8,634	8,920	9,227	3,038	2,947	2,966	13,170	12,982	13,290	83,791	82,482	84,442	12,266	12,039	12,392
	2.4	*3.3*	*3.4*	*–7.8*	*–3.0*	*0.7*	*7.2*	*–1.4*	*2.4*	*7.9*	*–1.6*	*2.4*	*4.6*	*–1.9*	*2.9*
Manufacturing	77,852	79,067	80,817	5,924	6,189	6,332	3,916	3,943	4,042	19,297	19,598	20,084	14,719	16,009	16,599
	3.8	*1.6*	*2.2*	*2.6*	*4.5*	*2.3*	*1.5*	*0.7*	*2.5*	*3.4*	*1.6*	*2.5*	*3.0*	*8.8*	*3.7*
Construction	32,626	33,622	34,479	3,710	3,826	4,057	4,733	4,371	4,696	32,930	30,493	28,998	16,483	15,969	17,703
	0.6	*3.1*	*2.6*	*1.8*	*3.1*	*6.0*	*–2.6*	*–7.6*	*7.4*	*2.2*	*–7.4*	*–4.9*	*3.1*	*–3.1*	*10.9*
Utilities	11,815	12,490	12,782	1,383	1,427	1,459	1,278	1,316	1,351	5,170	4,973	5,166	3,839	3,956	4,029
	0.9	*5.7*	*2.3*	*–0.2*	*3.2*	*2.2*	*3.8*	*3.0*	*2.7*	*4.1*	*–3.8*	*3.9*	*–1.4*	*3.0*	*1.9*
Goods-producing industries	136,253	139,686	143,016	15,519	15,921	16,385	26,927	26,378	27,235	145,106	141,461	142,751	50,554	51,247	54,011
	2.3	*2.5*	*2.4*	*–2.6*	*2.6*	*2.9*	*0.2*	*–2.0*	*3.2*	*4.4*	*–2.5*	*0.9*	*2.0*	*1.4*	*5.4*
Wholesale and retail trade	72,880	74,309	76,327	6,057	6,276	6,458	6,801	6,861	6,989	27,991	27,212	27,779	21,095	22,100	22,832
	4.3	*2.0*	*2.7*	*5.3*	*3.6*	*2.9*	*3.7*	*0.9*	*1.9*	*6.0*	*–2.8*	*2.1*	*4.4*	*4.8*	*3.3*
Transportation and warehousing	22,825	23,213	23,840	3,375	3,507	3,615	2,896	2,910	2,980	12,003	11,796	11,812	11,173	11,544	12,152
	3.9	*1.7*	*2.7*	*4.4*	*3.9*	*3.1*	*6.0*	*0.5*	*2.4*	*6.5*	*–1.7*	*0.1*	*3.6*	*3.3*	*5.3*
Information and culture	22,691	22,587	22,707	1,607	1,602	1,614	1,171	1,172	1,185	6,859	6,895	6,994	7,034	7,002	7,038
	0.4	*–0.5*	*0.5*	*–0.1*	*–0.3*	*0.7*	*0.0*	*0.1*	*1.1*	*0.7*	*0.5*	*1.4*	*–0.2*	*–0.5*	*0.5*
Finance, insurance, and real estate	143,664	148,183	152,976	9,866	10,157	10,476	8,231	8,420	8,699	43,143	44,307	45,939	49,683	51,618	53,269
	3.0	*3.1*	*3.2*	*2.9*	*2.9*	*3.1*	*3.0*	*2.3*	*3.3*	*3.9*	*2.7*	*3.7*	*3.7*	*3.9*	*3.2*
Community, business, and personal services	84,001	85,862	87,795	4,757	4,856	5,016	4,805	4,876	4,987	35,103	35,190	36,138	27,672	28,599	29,463
	2.1	*2.2*	*2.3*	*0.7*	*2.1*	*3.3*	*1.4*	*1.5*	*2.3*	*3.4*	*0.2*	*2.7*	*3.4*	*3.3*	*3.0*
Education	34,127	34,372	34,673	2,787	2,801	2,776	2,688	2,689	2,680	10,012	10,100	10,081	10,326	10,809	10,972
	0.5	*0.7*	*0.9*	*1.0*	*0.5*	*–0.9*	*2.8*	*0.0*	*–0.3*	*2.4*	*0.9*	*–0.2*	*–4.0*	*4.7*	*1.5*
Health and social assistance	41,048	41,421	42,117	4,315	4,412	4,474	3,455	3,528	3,604	13,518	13,816	14,340	13,753	13,997	14,286
	1.6	*0.9*	*1.7*	*2.0*	*2.3*	*1.4*	*1.3*	*2.1*	*2.2*	*3.6*	*2.2*	*3.8*	*2.1*	*1.8*	*2.1*
Public administration and defence	43,086	43,195	43,427	4,458	4,473	4,519	3,336	3,358	3,395	12,032	12,039	12,073	11,970	12,012	12,102
	0.5	*0.3*	*0.5*	*–0.8*	*0.4*	*1.0*	*1.0*	*0.6*	*1.1*	*1.7*	*0.1*	*0.3*	*0.4*	*0.4*	*0.8*
Service-producing industries	463,805	472,625	483,345	37,140	38,001	38,865	33,300	33,730	34,436	160,567	161,259	165,063	152,927	157,900	162,336
	2.3	*1.9*	*2.3*	*2.0*	*2.3*	*2.3*	*2.7*	*1.3*	*2.1*	*3.9*	*0.4*	*2.4*	*2.7*	*3.3*	*2.8*
All industries	600,575	612,828	626,878	52,874	54,137	55,465	60,095	59,976	61,539	305,523	302,570	307,664	203,335	209,001	216,201
	2.3	*2.0*	*2.3*	*1.1*	*2.4*	*2.5*	*1.4*	*–0.2*	*2.6*	*4.4*	*–1.0*	*1.7*	*2.6*	*2.8*	*3.4*

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Sources: The Conference Board of Canada; Statistics Canada.

Gross Domestic Product by Province and Industry cont'd
(Forecast Completed: July 16, 2015)

	Ontario			Manitoba			Saskatchewan			Alberta			British Columbia		
	2017	2018	2019	2017	2018	2019	2017	2018	2019	2017	2018	2019	2017	2018	2019
Agriculture	4,225	4,312	4,387	1,690	1,728	1,766	3,721	3,799	3,890	3,897	3,989	4,085	1,238	1,255	1,272
	1.9	*2.0*	*1.8*	*1.6*	*2.2*	*2.2*	*1.7*	*2.1*	*2.4*	*1.6*	*2.4*	*2.4*	*1.5*	*1.4*	*1.3*
Forestry	570	600	635	39	40	40	76	74	74	557	570	581	1,564	1,559	1,570
	6.0	*5.1*	*5.9*	*12.2*	*0.8*	*0.3*	*8.4*	*–2.6*	*–0.5*	*9.4*	*2.2*	*1.9*	*–1.7*	*–0.3*	*0.7*
Agriculture and forestry support services	612	613	607	86	87	90	201	205	222	318	323	332	801	812	857
	1.7	*0.2*	*–1.1*	*1.7*	*1.4*	*3.5*	*2.6*	*2.2*	*8.0*	*1.7*	*1.4*	*3.0*	*1.7*	*1.4*	*5.5*
Fishing and trapping	30	30	30	7	8	8	1	1	1	7	7	7	101	102	102
	–0.9	*0.3*	*–0.6*	*0.2*	*0.4*	*0.6*	*0.6*	*0.6*	*0.6*	*1.6*	*1.8*	*1.7*	*0.3*	*0.3*	*0.7*
Mining	9,391	9,444	9,566	3,061	3,024	2,950	13,276	13,155	12,878	85,921	87,371	88,720	13,029	14,265	14,185
	1.8	*0.6*	*1.3*	*3.2*	*–1.2*	*–2.5*	*–0.1*	*–0.9*	*–2.1*	*1.8*	*1.7*	*1.5*	*5.1*	*9.5*	*–0.6*
Manufacturing	81,844	83,532	85,206	6,441	6,551	6,640	4,136	4,230	4,317	20,561	21,019	21,432	17,030	17,513	18,061
	1.3	*2.1*	*2.0*	*1.7*	*1.7*	*1.4*	*2.3*	*2.3*	*2.1*	*2.4*	*2.2*	*2.0*	*2.6*	*2.8*	*3.1*
Construction	35,371	36,905	38,416	4,272	4,333	4,269	4,537	4,653	4,705	30,265	30,751	31,190	19,032	19,551	18,995
	2.6	*4.3*	*4.1*	*5.3*	*1.4*	*–1.5*	*–3.4*	*2.5*	*1.1*	*4.4*	*1.6*	*1.4*	*7.5*	*2.7*	*–2.8*
Utilities	13,068	13,332	13,581	1,488	1,517	1,580	1,387	1,420	1,454	5,300	5,427	5,553	4,131	4,228	4,323
	2.2	*2.0*	*1.9*	*2.0*	*2.0*	*4.1*	*2.7*	*2.4*	*2.3*	*2.6*	*2.4*	*2.3*	*2.5*	*2.4*	*2.2*
Goods-producing industries	145,504	149,167	152,822	16,867	17,069	17,124	27,265	27,467	27,470	146,222	148,852	151,296	56,515	58,873	58,954
	1.7	*2.5*	*2.5*	*2.9*	*1.2*	*0.3*	*0.1*	*0.7*	*0.0*	*2.4*	*1.8*	*1.6*	*4.6*	*4.2*	*0.1*
Wholesale and retail trade	77,285	78,579	80,236	6,603	6,692	6,741	7,149	7,275	7,399	28,547	29,230	29,988	23,550	24,334	24,796
	1.3	*1.7*	*2.1*	*2.3*	*1.3*	*0.7*	*2.3*	*1.8*	*1.7*	*2.8*	*2.4*	*2.6*	*3.1*	*3.3*	*1.9*
Transportation and warehousing	24,191	24,732	25,184	3,725	3,750	3,836	2,971	2,986	3,056	12,083	12,256	12,512	12,717	13,223	13,438
	1.5	*2.2*	*1.8*	*3.0*	*0.7*	*2.3*	*–0.3*	*0.5*	*2.3*	*2.3*	*1.4*	*2.1*	*4.7*	*4.0*	*1.6*
Information and culture	22,835	22,921	23,018	1,626	1,636	1,639	1,197	1,206	1,208	7,095	7,177	7,225	7,078	7,111	7,126
	0.6	*0.4*	*0.4*	*0.8*	*0.6*	*0.2*	*1.0*	*0.7*	*0.2*	*1.4*	*1.2*	*0.7*	*0.6*	*0.5*	*0.2*
Finance, insurance, and real estate	157,648	162,437	167,377	10,814	11,161	11,492	8,986	9,286	9,564	47,563	49,227	50,972	54,741	56,296	57,774
	3.1	*3.0*	*3.0*	*3.2*	*3.2*	*3.0*	*3.3*	*3.3*	*3.0*	*3.5*	*3.5*	*3.5*	*2.8*	*2.8*	*2.6*
Community, business, and personal services	90,076	92,174	94,487	5,160	5,320	5,469	5,096	5,239	5,399	37,166	38,134	39,276	30,627	31,784	31,880
	2.6	*2.3*	*2.5*	*2.9*	*3.1*	*2.8*	*2.2*	*2.8*	*3.1*	*2.8*	*2.6*	*3.0*	*3.9*	*3.8*	*0.3*
Education	34,700	34,786	34,793	2,774	2,805	2,831	2,693	2,737	2,777	10,146	10,339	10,554	11,149	11,295	11,403
	0.1	*0.2*	*0.0*	*–0.1*	*1.1*	*0.9*	*0.5*	*1.6*	*1.5*	*0.6*	*1.9*	*2.1*	*1.6*	*1.3*	*1.0*
Health and social assistance	42,599	43,587	44,488	4,610	4,697	4,778	3,700	3,761	3,817	14,916	15,363	15,799	14,571	14,940	15,280
	1.1	*2.3*	*2.1*	*3.0*	*1.9*	*1.7*	*2.7*	*1.6*	*1.5*	*4.0*	*3.0*	*2.8*	*2.0*	*2.5*	*2.3*
Public administration and defence	43,702	44,264	44,708	4,563	4,600	4,637	3,470	3,505	3,554	12,120	12,219	12,317	12,247	12,424	12,572
	0.6	*1.3*	*1.0*	*1.0*	*0.8*	*0.8*	*2.2*	*1.0*	*1.4*	*0.4*	*0.8*	*0.8*	*1.2*	*1.4*	*1.2*
Service-producing industries	492,518	502,963	513,774	39,792	40,580	41,341	35,178	35,911	36,690	169,540	173,850	178,549	166,901	171,628	174,488
	1.9	*2.1*	*2.1*	*2.4*	*2.0*	*1.9*	*2.2*	*2.1*	*2.2*	*2.7*	*2.5*	*2.7*	*2.8*	*2.8*	*1.7*
All industries	638,539	652,647	667,114	56,874	57,864	58,679	62,311	63,246	64,028	315,612	322,552	329,695	223,270	230,355	233,296
	1.9	*2.2*	*2.2*	*2.5*	*1.7*	*1.4*	*1.3*	*1.5*	*1.2*	*2.6*	*2.2*	*2.2*	*3.3*	*3.2*	*1.3*

Shaded area represents forecast data.
All data are in millions of 2007 dollars.
For each industry, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada.

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APPENDIX 6 - SCHEDULE 1
Illustration of Annual Change in Weather Normalization Reserve

	Heating Degree Days (below 18 deg C)		Space heating load			Weather Normalization Reserve	
Year	Actual HDD	Variation from Average (4,339 days)	Coefficient (MWh/HDD)	Variation from Average (MWh)	Marginal Net Revenue ($/MWh)	Increase (Decrease) ($)	Balance Owing (Recoverable) ($)
2005	4,448	109	41.73	4,553	50.42	229,577	229,577
2006	3,996	(343)	41.73	(14,310)	50.42	(721,558)	(491,981)
2007	4,677	338	41.73	14,110	50.42	711,458	219,477
2008	4,389	50	41.73	2,091	50.42	105,425	324,901
2009	4,559	220	41.73	9,186	50.42	463,153	788,054
2010	3,968	(371)	41.73	(15,479)	50.42	(780,478)	7,575
2011	4,231	(108)	41.73	(4,503)	50.42	(227,052)	(219,477)
2012	4,055	(284)	41.73	(11,848)	50.42	(597,406)	(816,882)
2013	4,519	180	41.73	7,516	50.42	378,981	(437,901)
2014	4,547	208	41.73	8,685	50.42	437,901	(0)
		(0)		(0)			

APPENDIX 6 - SCHEDULE 2
Calculation of 10-Year Average HDD

Month	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	10 year average (2005 - 2014)
Jan	854	626	737	728	866	686	744	715	812	771	754
Feb	698	677	763	686	664	608	697	700	672	717	688
Mar	654	594	643	694	675	556	621	572	603	760	637
Apr	406	411	491	418	420	367	420	379	441	453	421
May	314	204	308	286	245	262	259	224	235	308	265
Jun	117	55	121	95	102	114	150	119	107	120	110
Jul	29	5	29	0	42	13	21	12	13	1	17
Aug	17	52	38	20	30	21	14	5	17	28	24
Sep	82	116	120	121	135	107	90	76	106	118	107
Oct	247	290	248	300	345	290	249	240	291	228	273
Nov	402	374	446	421	392	429	397	424	472	461	422
Dec	628	592	733	620	643	515	569	589	750	582	622
	4,448	3,996	4,677	4,389	4,559	3,968	4,231	4,055	4,519	4,547	**4,339**
										Standard Deviation	258

APPENDIX 6 - SCHEDULE 3
Calculation of MWh/HDD Coefficient

Year	Month	Days in month	Actual HDD	HDD per day	Reported sales (MWh)	Fewer hours of daylight	Average HDD per day	Average MWh per day
2014	Jul	31	1	0.0	70,921			
	Aug	31	28	0.9	79,973			
	Sep	30	118	3.9	74,136			
	Oct	31	228	7.4	72,767	2.52	5.6	2,426
	Nov	30	461	15.4	84,725	4.07	11.4	2,733
	Dec	31	582	18.8	88,471	5.21	17.1	2,949
2015	Jan	31	829	26.7	103,575	5.40	22.8	3,341
	Feb	28	858	30.6	107,097	4.53	28.7	3,455
	Mar	31	743	24.0	95,132	3.11	27.3	3,398
	Apr	30	537	17.9	90,109	1.53	20.9	2,907
	May	31	233	7.5	78,424	0.00	12.7	2,614
	Jun	30		-	72,384			

Linear regression results:
(Oct 2014 - May 2015)

HDD	Daylight hrs	b	
41.73	50.89	2045.89	coefficients
3.43	14.71	69.33	standard error coefficients
0.98	68.90	#N/A	R^2, standard error y
106.89	5.00	#N/A	F, degrees of freedom
1014942	23737.67	#N/A	Regression SS, residual SS
12.17	3.46	29.51	t values

APPENDIX 6 - SCHEDULE 4
Calculation of Forecast Marginal Net Revenue Rate for 2016

Rate Class	2016 (Forecast) Revenue ($)	Sales (MWh)	Unit Revenue ($/MWh)	
Residential	70,955,849	545,578		*
General Service I	55,143,280	372,955		*
General Service II	1,530,913	10,751		
Small Industrial	12,692,471	98,933		
Total	140,322,513	1,028,217	$ 136.47	
ECAM Base Rate (Proposed)			$ (86.05)	
Marginal Net Revenue Rate			$ 50.42	

* Excludes revenue and kWh sales from seasonal customers

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Research

Summary:

Maritime Electric Co. Ltd.

Primary Credit Analyst:
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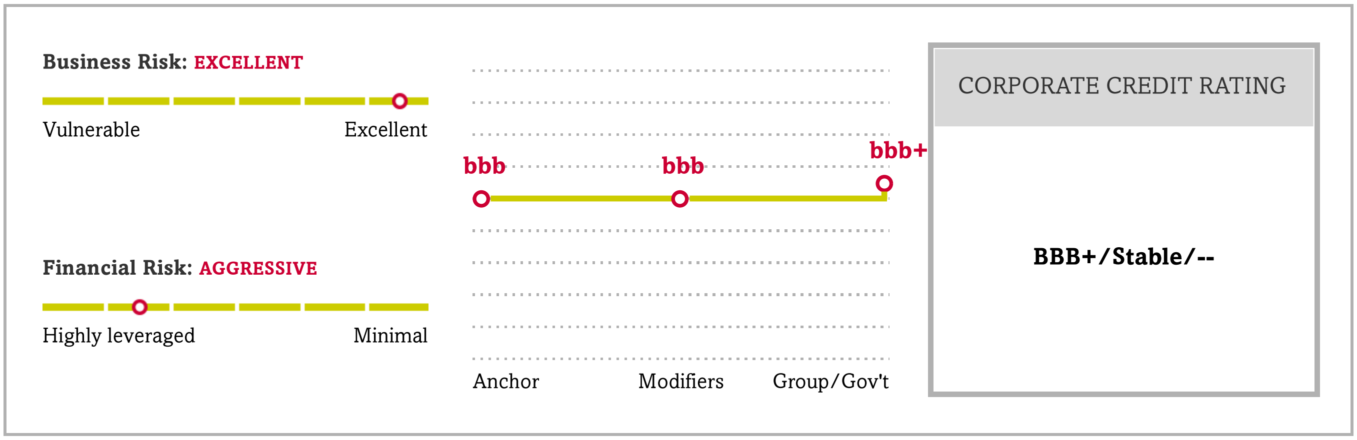
Maritime Electric Co. Ltd.



Rationale

Business Risk: Excellent	Financial Risk: Aggressive
• Low-risk monopoly operations in the Province of Prince Edward Island (PEI) • Electricity input cost that remains a pass-thru to customers via the Energy Cost Adjustment Mechanism (ECAM) • The limited independence of Island Regulatory and Appeals Commission (IRAC), the regulator. There is potential for political intervention despite the broadly supportive regulation	• Stable and predictable cash flows

Outlook: Stable

The stable outlook reflects Standard & Poor's Ratings Services' expectation that Maritime Electric Co. Ltd. (MECL) will continue to generate stable cash flow during our two-year outlook horizon with no adverse regulatory or governmental rulings.

Downside Scenario

We believe MECL will continue to generate stable regulated cash flows during our outlook horizon. Although we don't expect it in that period, a downward revision in the stand-alone credit profile (SACP) could happen if we see the utility's adjusted funds from operations (AFFO)-to-debt ratio fall and stay below 9%. This could happen should there be an adverse change in government policy, material operational difficulties, challenges in recovering deferral accounts, or a significantly adverse regulatory ruling impairing timely recovery of cash flows. A downward revision in the SACP could lead to a downward revision in the corporate credit rating (CCR) given no change in the rating on parent Fortis Inc. and our assessment of MECL as "moderately strategic" to the Fortis group. Alternatively, a negative rating action on Fortis will also have a negative rating impact on MECL.

Upside Scenario

A material change in MECL's financial policy resulting in reduced leverage (adjusted funds from operations [AFFO]-to-debt increases and stay above 13%) could lead to an upward revision in the SACP, but we consider this unlikely during our two-year outlook horizon. Although we do not foresee it in the next two years, an SACP that is equal to or higher than the group credit profile would result in a higher CCR on the company.

Standard & Poor's Base-Case Scenario

Assumptions

- There will be no material changes to the return on equity (ROE) and capital structure of 40% equity and 60% debt in MECL's next rate setting in 2016
- The company will have a new PPA contract in place before the current one expires to ensure adequate electricity supply and stable electricity pricing
- PEI will continue to support the regulatory framework, although there is the potential for political intervention
- The utility will continue to earn a return on net regulatory assets and liabilities, including deferral accounts
- Capital expenditures will be about C$30 million and C$50 million for 2015 and 2016, respectively
- Total depreciation rates will not change significantly

Key Metrics

	2014A	2015E	2016E
FFO-to-debt	17.4%	12%-13%	11%-12%
Debt-to-EBITDA	3.9x	4x-5x	4x-5x

FFO--Funds from operations. A--Actual. E--Estimate.

Business Risk: Excellent

In our view, MECL's business risk profile is "excellent," reflecting our assessment of the regulatory framework that supports a stable and predictable cash flow model, which we view as key credit strength. The IRAC continues to administer a regulatory framework that allows full recovery of prudently incurred operating, capital and commodity costs. Under the current framework, which expires in February 2016, MECL's maximum allowed ROE is 9.75% and is required to maintain a minimum equity base of 40%. This forms the cornerstone of its financial policies and provides a floor on a key cash-flow driver. We expect there will be no material changes to both the ROE and equity base in the company's next rate setting in 2016. In addition, under the existing framework, MECL has a power purchase agreement (PPA) with NB Power, an electricity provider in the province of New Brunswick, which also expires in February 2016. We expect MECL will re-new this agreement in a timely manner to ensure adequate supply of electricity at a reasonable cost so that electricity cost will remain a flow-through to customers.

Further supporting the excellent business risk profile is that MECL is the legislated monopoly provider of electricity to about 77,000 customers on PEI, which we believe provides the company with a stable market position. The province has a mature-but-stable economy that relies primarily on the public sector, fishing, agriculture, and tourism. We believe that the company's limited diversification is an offsetting factor, given the relatively small market, a limited number of sources of generation, and some customer concentration (with the largest customer accounting for 5%-6% of sales).

The provincial government continues to play a significant and active role in energy policy and establishing rates for island customers. We view this as generally less favorable than an independent regulator with a clear, consistent mandate and an established track record of credit-supportive policies. Due to the potential for political interference (which could negatively affect credit quality), the regulator's limited strength, and its independence, we view the

MECL's regulatory environment as less favorable compared with those of regulated utilities operating in other Canadian provinces.

We believe that the company will continue to benefit from the PEI Energy Accord, an agreement between MECL and the province. The accord addressed cost pressures and related rate increases from replacement power needs and operations and maintenance (O&M) costs associated with a prolonged outage at the base load Point Lepreau nuclear power station. Point Lepreau, which is again operational, supplies about 20% of the power the utility requires. The accord reduces the company's risk primarily by transferring the costs of replacement energy and O&M charges to PEI. In turn, the province has financed these costs at its lower cost of capital and plans to recover the costs over Point Lepreau's remaining life.

Financial Risk: Aggressive

MECL's "aggressive" financial risk profile reflects our expectation of low-but-stable cash flows and a legislated minimum equity base of 40%. We use the medial cash flow volatility table to assess the credit metrics. We expect forecast metrics to remain relatively stable. We expect the AFFO-to-debt ratio to be in the 11%-13% range during our outlook horizon. We base this on the assumption that the key components of FFO -- ROE, equity base, and depreciation -- remain highly stable, with FFO fluctuations coming from the difference between current and cash taxes.

Liquidity: Adequate

We have assessed MECL's liquidity as "adequate." We expect that liquidity sources will exceed uses by more than 1.1x in the next 12 months and that sources will exceed uses even in case of a 10% decline in EBITDA. Although the company has sources over uses of greater than 1.5x, which would qualify for strong treatment, qualitative factors such as a limited ability to absorb high-impact and low-probability events in the near term constrain our liquidity assessment. The company continues to have sufficient headroom under its existing covenants.

Principal Liquidity Sources	Principal Liquidity Uses
• Projected cash FFO of about C$25.1 million in 2015 • Available capacity under committed revolving facilities of about C$48 million; the facilities expire in 2019	• Projected capital expenditure of about C$30 million in 2015 • Projected dividend payment of about C$8 million in 2015

Other Modifiers

Modifiers have no impact on the ratings.

Group Influence

MECL is an indirect wholly-owned subsidiary of Fortis. Based on our Group Rating Methodology (GRM), we view MECL as "moderately strategic" to the Fortis group. We believe that although MECL represents a small proportion of the parent's business, it provides a very stable cash flow that is aligned to the parent's overall business strategy. In our view, MECL is unlikely to be sold, has the support of management, and is reasonably successful at what it does. As a result, this provides a one-notch rating uplift to MECL.

Ratings Score Snapshot

Corporate Credit Rating

BBB+/Stable/--

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Strong

Financial risk: Aggressive

- **Cash flow/Leverage:** Aggressive

Anchor: bbb

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Fair (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : bbb

- **Group credit profile:** a-
- **Entity status within group:** Moderately strategic (+1 notch from SACP)

Recovery Analysis

MECL's first mortgage bonds benefit from a first-priority lien on the majority of the utility's real property owned or subsequently acquired. Based on our criteria, collateral coverage of more than 1.5x supports a recovery rating of '1+' and an issue rating of 'A', two notches above the corporate credit rating for a 'BBB' category company. We base the recovery rating on the maximum amount of secured utility bonds outstanding at the time of the recovery analysis.

Related Criteria And Research

Related Criteria

- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Corporate Methodology, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013
- Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	Intermediate	Significant	**Aggressive**	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	a-	**bbb**	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

REPORT:
COST OF CAPITAL

PREPARED FOR:
MARITIME ELECTRIC COMPANY, LIMITED

BEFORE THE:
ISLAND REGULATORY AND APPEALS COMMISSION

OCTOBER 16, 2015

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I. INTRODUCTION

A. Qualifications

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

I am among Concentric's professionals who provide expert testimony before federal, state and Canadian provincial agencies on matters pertaining to economics, finance, and public policy in the energy industry. Concentric provides financial, economic and regulatory advisory services to clients across North America, including utility companies, regulatory and public agencies, and utility sector investors. I regularly advise utilities, generating companies, public agencies and private equity investors on business issues pertaining to the utilities industry. This work includes calculating the cost of capital for the purpose of ratemaking, and providing expert testimony and studies on matters pertaining to incentive regulation, rate policy, valuation, capital costs, demand side management, low-income programs, fuels and power markets. I have testified or provided expert evidence in state, provincial and federal jurisdictions in Canada and the U.S. This work has been provided on behalf of utilities, regulatory commissions, and staff.

I am also a frequent speaker and author of articles and white papers on the energy industry. Recently, on behalf of the Canadian Gas Association and the Canadian Electric Association, I prepared a discussion paper for utility executives and provincial regulators that examined the roles that Canada's utilities and regulators can play to promote innovation. In addition, I facilitated workshops between Canadian regulators and utility executives on regulatory and utility responses to a low carbon world, and drafted follow-up white papers to facilitate further discussion on emerging industry issues. In collaboration with the Canadian Gas and Canadian Electricity Associations, I also publish a newsletter summarizing allowed ROEs and capital structures for gas and electric utilities in Canada and the U.S. I have been an invited speaker for several CAMPUT events, including the recent Energy Regulation Course at Queen's University where I spoke on "Innovations in Utility Business Models and Regulation".

Prior to joining Concentric, I was Senior Managing Director in the Corporate Economics Practice for FTI/Lexecon, and Managing Director for Arthur Andersen's Energy & Utilities Corporate Finance Practice. In those positions, I provided expert testimony and advisory services on mergers, acquisitions, divestitures and capital markets for clients in the energy industry. In addition to the foregoing positions, I was also Managing Director for Navigant Consulting, with responsibility for the firm's Financial Services practice, Director in DRI's Electric and Natural Gas practices, and Senior Economist for the Massachusetts Energy Facilities Siting Council, where I analyzed the supply plans and facilities proposals from the state's electric and gas utilities. I also served as State Energy Economist for the Maine Office of Energy Resources. I hold a B.S. in Business Administration from Georgetown University and a M.S. in Resource Economics from the University of New Hampshire. My qualifications are detailed more fully in Attachment 1.

B. Executive Summary

I have been asked to provide an estimate of the cost of capital for Maritime Electric Company, Limited ("Maritime Electric"), for the purpose of establishing the return on equity ("ROE") and capital structure for the 2016 year to go into effect March 1, 2016. In order to estimate the cost of capital, I have relied upon analytical tools and data sources normally used for such purposes before regulators in Canada and the U.S. I have also reviewed past decisions of the Island Regulatory and Appeals Commission (the "Commission") in consideration of such matters. The analysis provided in this report supports my overall recommendation on the cost of equity and capital structure. That analysis includes the following:

1) examination of the legal and regulatory requirements for determination of a fair rate of return;

2) selection of Canadian, U.S. and North American proxy groups with companies comparable to Maritime Electric with respect to business and financial risks;

3) estimation of the cost of common equity for the proxy group companies using the Discounted Cash Flow ("DCF") method and the Capital Asset Pricing Model ("CAPM");

4) examination of authorized and earned returns on equity for other investor-owned electric utilities in Canada and the U.S.;

5) development of a range of results for the Canadian, U.S. and North American proxy groups; and

6) an assessment of the appropriateness of Maritime Electric's proposed capital structure based on an examination of the Company's business and financial risks relative to the respective proxy groups.

As shown in Figure 1, the various ROE estimation models produce a range of results for the proxy group companies from 9.0 percent to 12.8 percent. The average of all methods is 10.1 percent. Because the utilities selected in the North American Electric Utilities proxy group are most representative of Maritime Electric, I place greater weight on those results.

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

	Canadian Regulated Utilities	US Electric Utilities	North American Electric Utilities	Average
CAPM	9.0%	10.4%	10.1%	9.8%
Constant Growth DCF	12.8%	9.8%	9.6%	10.7%
Multi-Stage DCF	10.3%	9.5%	9.2%	9.6%
Average	10.7%	9.9%	9.7%	10.1%

Based on the range of results for the North American proxy group, I believe that Maritime Electric's proposed ROE of 9.7 percent within a range of 9.5 to 9.9 percent is a reasonable estimate of the Company's required cost of equity. Maritime Electric's proposed ROE of 9.7 percent is equal to the average of 9.7 percent across all three methods for the North American proxy group. In addition, the Company's forecasted average common equity ratio of 40.5 percent is reasonable,

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

if not somewhat conservative, given the relative business risks of Maritime Electric and the legislatively set minimum common equity requirement of 40 percent.

C. Report Organization

The remainder of the report is organized as follows: Section II discusses the legal requirements and regulatory precedents for the determination of a fair rate of return; Section III provides an overview of economic and capital market conditions and their impact on the allowed ROE and capital structure for Maritime Electric; Section IV describes the selection of proxy group companies to estimate the cost of equity for Maritime Electric and discusses the precedent in Canada for considering the use of U.S. data; Section V discusses the methods used to estimate the cost of equity and summarizes the results of the DCF and CAPM analyses, as well as allowed and earned ROEs for other investor-owned electric utilities; Section VI provides an assessment of Maritime Electric's business and financial risks relative to the proxy group companies and a recommendation on the appropriate equity ratio for the Company. Finally, Section VII summarizes my overall conclusions and recommendations.

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

A. The Fair Return Standard

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

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

[2] *Northwestern*, at p. 186.

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

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

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

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

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

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

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

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

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

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

> [59] The Commission in determining a fair return must try to assess the risk associated with the capital invested and the comments provided in the Northwestern Utilities case. Those comments make reference to the fact that the company will be allowed as large a return on the capital invested in its enterprise as it would receive if it were investing the same amount in other

[3] National Energy Board RH-2-2004 Reasons for Decision, TransCanada PipeLines Ltd, Phase II, April 2005, at p. 17.
[4] Ontario Energy Board, EB-2009-084, Report of the Board on the cost of Capital for Ontario's Regulated Utilities, December 11, 2009, at i.
[5] *Ibid*, at p. 19.

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

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

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

B. The Stand-Alone Principle

The Stand-Alone Principle provides that the utility must be regulated as if it were a stand-alone entity, raising capital on the merits of its own business and financial characteristics. In this way, capital may be efficiently allocated, with each business segment earning a return based on its own unique set of risks and business characteristics regardless of affiliations within the holding company structure. In order to establish a fair return and satisfy the Stand-Alone Principle, the

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

utility must be allowed a return sufficient to meet all three requirements of the Fair Return Standard on the basis of the utility's individual merits.

C. The Relationship between Capital Structure and ROE

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

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

III. ECONOMIC AND CAPITAL MARKET CONDITIONS

A. Changes in Economic and Capital Market Conditions since 2010

Globally, economic and capital market conditions today are generally more favorable than in January 2010 when the Company's last General Rate Application ("GRA") was filed, although the outlook is somewhat mixed. At the time of the Commission's July 2010 decision, the Canadian and U.S. economies were just starting to recover from the global financial crisis. As of September 2015, the financial system has stabilized, economic growth had resumed albeit at somewhat lower than normal levels prior to sliding into a technical recession for the first two quarters of 2015, and unemployment rates have declined in Canada.

The global economy has become increasingly interdependent. It is nearly impossible for a disruption in one major economy not to have a ripple effect throughout the global economy. This has been underscored by the recent weakness in the Chinese economy and its reverberations throughout global economies and capital markets. Beginning from that global perspective, the Bank of Canada rates the key risks to the Canadian financial system to range from "moderate" to "elevated,"[7] and projects a modest pickup in global economic growth for 2015 and 2016, as investor confidence increases and consumers and businesses realize the benefits of recent deleveraging, accommodative monetary policy, low oil prices and financial repair.

The U.S. was identified as leading the global recovery. The Bank of Canada predicts that monetary policy will begin to normalize in advanced economies and interest rates are projected to rise. Financial market volatility will begin to reflect two-sided interest rate risk. The Bank of Canada sees challenges to the global economic outlook arising from the repercussions of rising interest rates on emerging market economies, the significant challenges faced by the Chinese economy due to its sharp slow-down in economic growth, a real estate market correction and slower growth in investment spending, and the impact of low oil prices on the Canadian economy. Prolonged low oil prices in Canada will increase the vulnerability of the Canadian financial system to adverse shocks to employment and income.[8]

The Bank of Canada predicts that the U.S. economic recovery will continue to strengthen despite a weaker than expected start to the year, attributed to a harsh winter. The stalled growth in China and the euro area may serve as a drag on the Canadian economy. The Canadian economy is currently in a technical recession, with two consecutive quarters of negative GDP growth. The Bank of Canada acknowledges that much of the world, including Canada and the U.S., continues to be highly dependent on stimulative monetary conditions which have resulted in interest rates near historic lows, equity indexes near all-time highs, and volatility in financial markets. These stimulative monetary policies cause certain vulnerabilities in the Canadian financial system.[9]

The Conference Board of Canada ("Conference Board") adopts a similar view. Economic conditions in Canada are expected to weaken in 2015 as plummeting oil prices have a significant negative impact on the Canadian economy. In addition to low oil prices, economic growth will also be affected by weaker growth in household spending, a result of high debt levels and ongoing

7 Bank of Canada, Financial System Review June 2015, at 3.
8 *Ibid*, at 1-3.
9 *Ibid*.

fiscal restraint at both the national and provincial levels.[10] Though low oil prices provide a benefit to Canadian consumers, the negative impact on the Canadian oil industry more than offsets these gains. Commodity prices have risen modestly from recent lows, but remain well below levels of a year ago. Weak oil prices and the weaker-than-expected U.S. recovery in the first quarter of 2015 led to a contraction in the Canadian economy in the beginning of 2015.

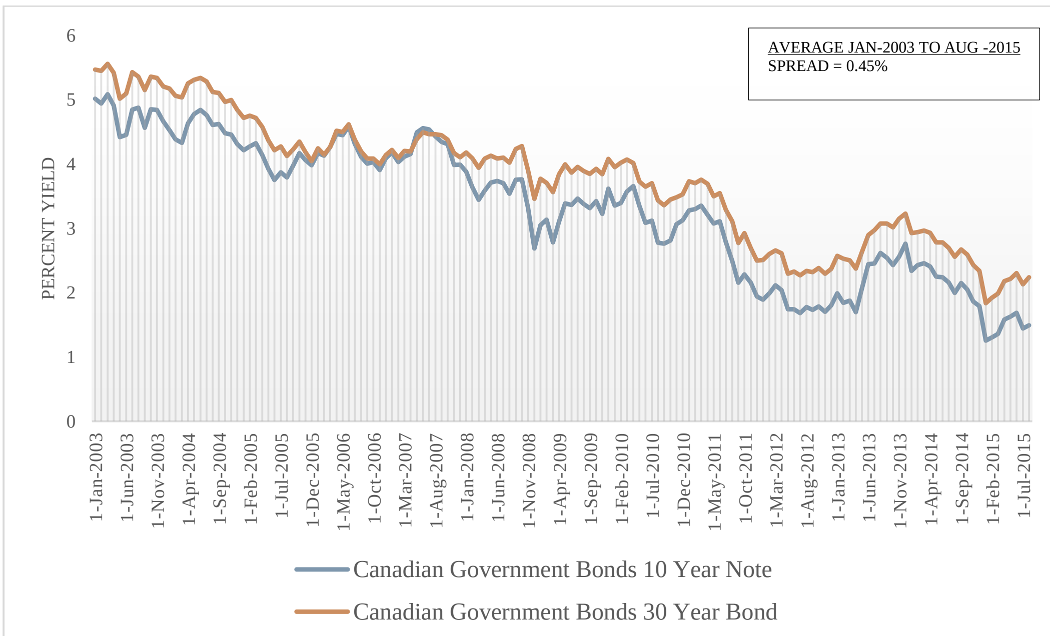
The Bank of Canada projects the Canadian economy will continue to strengthen despite lower oil prices due to the anticipated strengthening of the U.S. economy and supportive financial conditions.[11] The U.S. continues its economic recovery at a steady, but uneven pace. Based on recently revised data, U.S. GDP growth for Q1 2015 was 0.6 percent, and rebounded in Q2 2015 to an annual rate of 3.7 percent. With consumer confidence reaching the highest point in the last five years, the U.S. economy is on track to continue its strengthening trend with expectations of 3 percent real GDP growth for 2015 and 2016.[12] U.S. consumer spending has benefited from a drop in fuel prices, with the price of West Texas Intermediate now in the mid $40/barrel range, after dropping from over $100/barrel. The U.S. economic recovery is also fueled by an improving job market, with unemployment rates dropping to 5.3 percent in August 2015, and projected to continue to decline to 5.0 percent in 2016.[13] The strong U.S. dollar and a European economic downturn may negatively affect U.S. exports, but the loss from declining exports has thus far been more than offset by the savings on oil imports due to lower oil prices.

As shown in Figure 2, the 30-day average yields on 10- and 30-year long-term Canadian government bonds of 1.49 percent and 2.24 percent, respectively, in August 2015 are significantly lower than the levels of 3.22 percent and 3.77 percent as of July 2010. Despite an uptick in the second half of 2012 and the first half of 2013, government bond yields remain near all-time lows and reflect the prolonged period of accommodative monetary policy in Canada and the U.S. following the financial crisis. Although the Canadian economy is currently in a technical recession, the Bank of Canada projects a return to economic growth in the third quarter of 2015, led by improvement in the non-resources sectors of the economy. According to Blue Chip Financial Forecast, 96 percent of those surveyed expect the U.S. Federal Reserve to begin raising short-term

10 The Conference Board of Canada, "Provincial Outlook 2015, Long-Term Economic Forecast," April 2015, at i.
11 Bank of Canada, Financial System Review June 2015, at 5.
12 *Ibid.*
13 *Ibid.*

interest rates before the end of 2015.[14] These plans, however, may be tempered by the recent disruptions in global stock markets amid uncertainty regarding the impacts of a slowdown in the Chinese economy.

Figure 2: Canadian Government Bond Yields - 10-Year and 30-Year

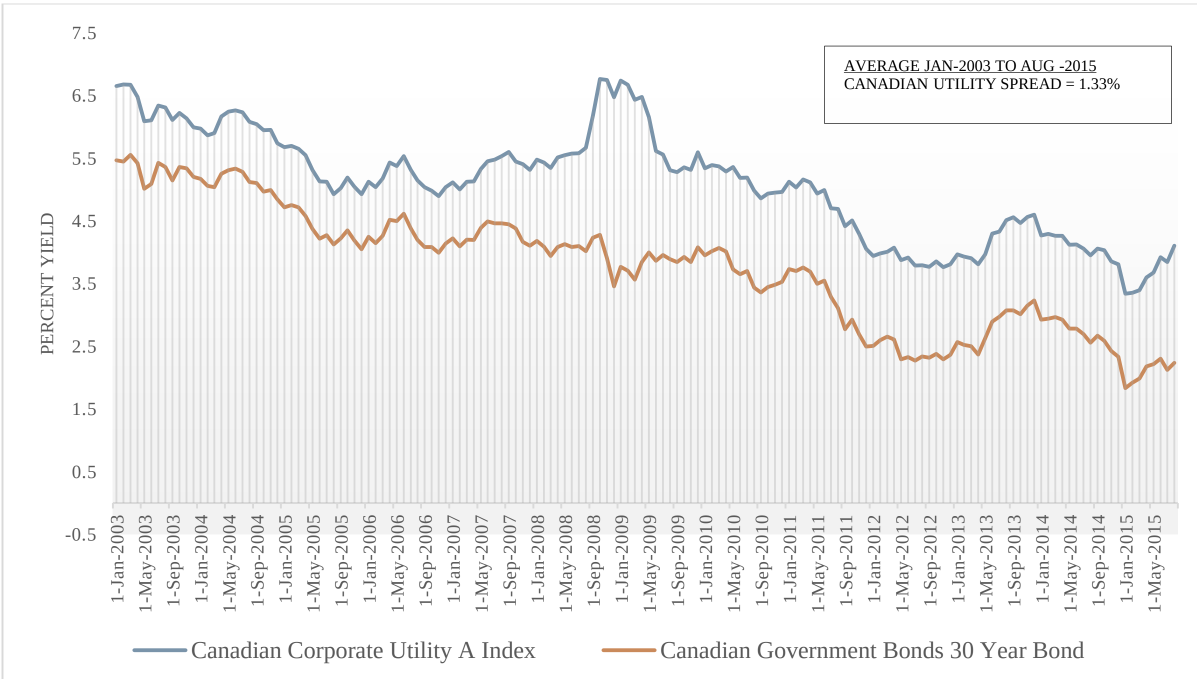


Source: Bloomberg series C29530Y

Corporate bond yields have decreased less than government bond yields since July 2010, and credit spreads have widened. As Figure 3 shows, the Canadian Utility A-rated bond index yield decreased from 5.18 percent in July 2010 to 4.10 percent in August 2015. Figure 4 shows that the Canadian Utility A-rated spread was 1.54 percent in July 2010 versus 1.87 percent in August 2015, or an increase of 33 basis points, suggesting that corporate and utility risk have not declined since 2010 in the eyes of debt investors, but have actually widened over the past several months.

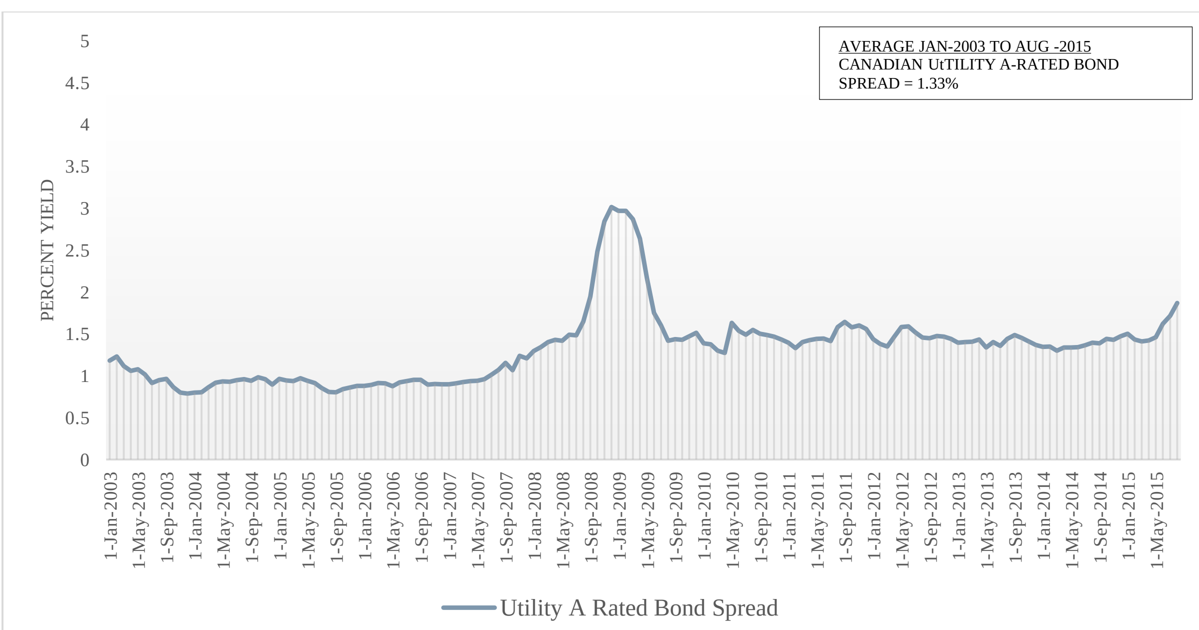
14 Blue Chip Financial Forecast, Volume 34, No. 9, September 1, 2015, at 14.

Figure 3: Canadian Utility A-Rated Bond vs. 30-Year Canada Long Bond



Source: Bloomberg series C29530Y

Figure 4: Canadian Utility A-Rated Bond Spread vs 30-Year Canada Long Bond



Source: Bloomberg series C29530Y

Conditions in the Canadian equity market have also evolved since 2010, as the prolonged period of low interest rates has encouraged investors to move out of low yielding investments such as government bonds into higher return investments such as equities. This has caused valuation levels of Canadian stocks (as measured by the Price/Earnings ratio) to increase over the past five years, as share prices have risen faster than earnings. The same phenomenon has occurred among shares of regulated utility companies, with valuations for these companies at elevated levels compared to historical norms, as investors seek out the dividend yields that utilities offer.

Overall, capital market conditions in Canada and the U.S. have generally improved since July 2010. Equity valuations have increased, most likely to unsustainable levels in this low interest rate environment. However, investor expectations call for tighter monetary policy in the upcoming year leading to higher interest rates in both the U.S. and Canada. Corporate and utility debt costs have already moved modestly higher. Recent volatility in equity markets is a reminder that global forces are at play in the Canadian and U.S. economies that can cause unanticipated market disruptions.

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

In a world of increasingly linked economies and capital markets, investors seek returns from a global basket of investment options, and they distinguish between risks on a country-to-country basis, factoring in the comparability of the economies and the business environments. Country-specific economic and business conditions that affect investment risk may be measured through a variety of qualitative and quantitative metrics.

As shown in Exhibit JMC-1, the correlation between real GDP growth rates in Canada and the U.S. has been strong, as has the correlation between the consumer price indices for each country, indicating that these metrics have tended to move together over time. Over the 25-year period, real GDP growth has been 2.29 percent in Canada and 2.41 percent in the U.S., while consumer inflation has been 2.08 percent in Canada and 2.63 percent in the U.S. Unemployment rates over the 25 year period have averaged higher in Canada (e.g., 7.40 percent in Canada vs. 6.12 percent in the U.S. since 1990), but that trend reversed in 2008 when U.S. unemployment exceeded that in Canada. The U.S. was harder hit and initially slower to recover from the recent recession than its Canadian neighbors, but the U.S. continues its economic recovery, the gap in unemployment rates between the two countries has closed, and current U.S. unemployment of 5.3 percent is now lower than that in Canada.

The average yield on 10-year government bonds has also been very similar in Canada and the U.S. Over the past decade, the average yield on 10-year Canadian government bonds was 3.17 percent, compared to 3.33 percent in the U.S. The 5-year averages for the Canadian and U.S. 10-year government bond yields are very close at 2.46 percent for Canada and 2.54 percent for the U.S. The average yield on 10-year government bonds for 2014 was 2.23 percent in Canada and 2.53 percent in the U.S. The correlation between average yields on 10-year government bonds in Canada and the U.S. since 1990 has been very strong at 0.97, the highest of all macroeconomic indicators compared. Correlations of this degree are reflective of closely integrated financial markets.

The magnitude and significance of trade between the two countries reflects the high degree of integration between the two economies. In 2014, in terms of trade in goods, 76.8 percent of Canada's total exports went to the U.S., and imports from the U.S. accounted for 54.3 percent of Canada's total imports.[15] According to a report by the Congressional Research Service ("CRS"), Canada is the largest single-nation trading partner of the U.S. The CRS observes:

> That the United States and Canada trade substantial volumes of the same goods bespeaks the economic integration of the two economies. This integration has been assisted by trade liberalization over the past 40 years, beginning with the Automotive Agreement of 1965 (which eliminated tariffs on shipments of autos and auto parts between the two countries), through the Canada-U.S. Free Trade Agreement of 1989, and NAFTA [the North American Free Trade Agreement of 1994].[16]

The recently announced Trans-Pacific Partnership is expected to further expand Canadian-U.S. trade with the other members of the 12-nation group. Of this group, Canada is the largest trade partner of the U.S. at $685 billion, with only Mexico at $534 billion near this level of combined import/export trade.[17]

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15 Source: Trade Data Online – Canadian Trade Industry, Industry Canada.

16 Ian F. Fergusson, "United States – Canada Trade and Economic Relationship: Prospects and Challenges," Congressional Research Service, September 14, 2011, at 3.

17 The New York Times, October 6, 2015.

On balance, the economic and business environments of Canada and the U.S. are highly integrated and exhibit strong correlation across a variety of metrics, including GDP growth and government bond yields. Based on these macroeconomic indicators, there are no fundamental dissimilarities between Canada and the U.S. (*i.e.*, in terms of economic growth, inflation, unemployment, or government bond yields) that would cause a reasonable investor to have materially different return expectations for a group of comparably situated utilities in the two countries.

IV. SELECTION OF PROXY COMPANIES

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

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

Figure 5: Canadian Utility Proxy Group

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

The second proxy group is comprised of U.S. electric utility companies that would be considered by investors as generally comparable in risk to Maritime Electric. To obtain companies of like-risk, I performed a number of screens to develop a group of companies that is primarily engaged in the provision of regulated electric utility service. Starting with the 46 companies Value Line classifies as Electric Utilities, I further screened for companies that meet the following criteria:

1) Credit ratings of at least BBB+ from S&P or Baa1 from Moody's;
2) Consistently pay quarterly cash dividends;
3) Positive earnings growth rate projections from at least two sources;
4) At least 70 percent of their operating income was derived from regulated operations in the period from 2012-2014;
5) At least 90 percent of their regulated operating income was derived from electric utility service in the period from 2012-2014; and
6) Not involved in a merger or other significant transformative transaction during the evaluation period.

I also considered whether each company that passed the screening criteria was, in fact, generally comparable to Maritime Electric in terms of business and financial risk. On that basis, two additional companies were excluded: Edison International and ITC Holdings Corp.

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

Figure 6: U.S. Electric Proxy Group

Company	Ticker
ALLETE, Inc.	ALE
Duke Energy Corporation	DUK
Eversource	EV
Great Plains Energy Inc.	GXP
OGE Energy Corporation	OGE
Pinnacle West Capital Corp.	PNW
Westar Energy, Inc.	WR

The third proxy group is comprised of all seven U.S. electric utilities in Figure 7 plus the two Canadian investor-owned utilities that are primarily engaged in the provision of electricity (i.e., Canadian Utilities Limited and Emera). This group is referred to as the North American Electric proxy group.

Figure 7: North American Electric Proxy Group

Company	Ticker
ALLETE, Inc.	ALE
Canadian Utilities Limited	CU
Duke Energy Corporation	DUK
Emera, Inc.	EMA
Eversource	EV
Great Plains Energy Inc.	GXP
OGE Energy Corporation	OGE
Pinnacle West Capital Corp.	PNW
Westar Energy, Inc.	WR

Profiles of each Canadian and U.S. proxy group company are provided in Exhibit JMC-2.

A. Use of U.S. Data and Proxy Groups

Canadian regulators have accepted the use of U.S. data and proxy groups to estimate the allowed ROE for Canadian regulated utilities. The development of a proxy group comprised entirely of Canadian electric utilities is compromised by the small number of publicly traded utilities in Canada and the fact that many of those Canadian companies derive a significant percentage of revenues and net income from operations other than regulated electric utility service. This problem has been exacerbated by the continuing trend toward mergers and acquisitions in the utility industry, both within Canada and across the border with U.S. utility companies.

The British Columbia Utilities Commission ("BCUC"), for example, has accepted the use of U.S. proxy group data in Canadian ROE analysis, primarily due to the lack of sufficient Canadian data, but also in recognition of the need for Canadian utilities to compete for capital in a global marketplace.[18] In 2013, the BCUC reaffirmed its position on the use of U.S. data.[19] Similarly, the NEB, the OEB and the Régie de L'Energie (Quebec) have also accepted the use of U.S. data and

[18] British Columbia Utilities Commission, In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc., Return on Equity and Capital Structure, Decision G-158-09, December 16, 2009, at 15-16.

[19] British Columbia Utilities Commission, Generic Cost of Capital Proceeding (Stage 1), Decision May 10, 2013, at 19.

proxy groups for purposes of establishing the allowed ROE and common equity ratio for Canadian electric and gas utilities.[20]

In summary, multiple regulatory authorities in Canada have recognized that Canadian utility companies are competing for capital in global financial markets and that Canadian data are limited by the small number of publicly traded utilities. Regulators have also recognized the integrated nature of Canadian and U.S. financial markets, and the similarity of the utility regulatory regimes.

V. METHODS FOR ESTIMATING THE COST OF EQUITY

A. Financial Models to Estimate the Cost of Equity

Analysts use multiple approaches to estimate the cost of common equity. The required ROE can be estimated using one or more analytical techniques that rely on market-based data to quantify investor expectations regarding required equity returns, adjusted for certain incremental costs and risks. Quantitative models produce a range of results from which the market-required ROE is determined. A consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' forward views of financial markets in general, and the subject company (in the context of the proxy group) in particular.

No financial model can exactly pinpoint the correct return on equity; rather, each test brings its own perspective and set of inputs that inform the estimate of the ROE. Consistent with the *Hope* standard, it is "the result reached, not the method employed, which is controlling."[21] Although each model brings a different perspective and adds depth to the analysis, each model also has its own inherent weaknesses and should not be relied upon individually without corroboration from other approaches. Regardless of which analyses are used to estimate the investor's required ROE, the analyst must apply informed judgment to assess the reasonableness of results and to determine the appropriate weighting to apply to results under prevailing capital market conditions.

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20 National Energy Board, Reasons for Decision, TQM RH-1-2008 (March 2009), at 66-72; Ontario Energy Board, EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, at 23; and English translation of Régie de l'Energie, Decision 2009-156 (R-3690-2009), Gaz Metro, December 7, 2009, at paragraph [249].

21 See *Hope Natural Gas v. Federal Power Commission*.

1. Discounted Cash Flow ("DCF") Model

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

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

where:

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

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

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

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

a. Constant Growth DCF Model Assumptions

The Constant Growth DCF model requires the following assumptions: (1) a constant average growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings multiple; and (4) a discount rate greater than the expected growth rate. As discussed later in the report, other forms of the DCF model do not rely on the assumption of constant growth in perpetuity.

b. Dividend Yield

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

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

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

The dividend yields were calculated for each company in the respective proxy groups by dividing the current annualized dividend by the average stock price for each company for the 90-trading days ended August 31, 2015. Those dividend yields are multiplied by one-half the growth rate to reflect expected future dividend increases.

c. Growth Rate Estimates

In considering the appropriate growth rate for the DCF model, the most relied upon indicator of investors' expectations is analysts' estimates of future earnings growth. I have relied on earnings growth estimates from SNL Financial, Value Line, Zacks and Thomson First Call for the companies in the respective proxy groups as of August 31, 2015. Those growth rates are shown on Exhibit JMC-3.

Investors typically rely on projected earnings growth rates rather than dividend growth rates for several reasons. First, although the DCF model is based on dividend growth rates, a company's dividend growth is derived from and can only be sustained by earnings growth. Second, in order to reduce the long-term growth rate to a single measure, as required in the Constant Growth DCF model, it is necessary to assume a constant payout ratio, and that earnings per share, dividends per share and book value per share grow at a constant rate. Third, earnings growth rates are less influenced by dividend decisions that companies may make in response to near-term changes in the business environment. Finally, analysts' forecasts of earnings growth are widely available, whereas dividend and book value growth rates are generally available only from Value Line.[22]

Some utility regulators have expressed concern that analyst's earnings growth rates may be overly optimistic. If optimism bias were present in analysts' earnings forecasts, it could create an upward bias in the estimated cost of capital that results from the DCF approach. However, several changes have been implemented by financial regulators that are designed to provide fair disclosure and to reduce or eliminate the possibility of analysts' bias. For example, on August 15, 2000, the U.S. Securities and Exchange Commission ("SEC") adopted Regulation FD to address the selective disclosure of information by publicly traded companies. Regulation FD provides that when an issuer discloses material nonpublic information, the issuer must publicly disclose that information to all investors at the same time. In this way, the rule aims to promote full and fair disclosure.

Also, in 2002 the SEC, the New York Stock Exchange, the New York Attorney General, and other state regulators introduced guidelines regarding the interaction between analysts and investment banks that became known as the "Global Settlement." The Global Settlement outlined several structural reforms that limit the interaction between analysts and investment banks, thus removing any incentive for analysts to produce upwardly biased growth forecasts.

In Canada, regulators took a parallel set of actions, with Policy 11 as the core framework. On April 12, 2001, the Securities Industry Committee on Analyst Standards released a draft report containing recommendations aimed at improving the independence of research and ensuring the professional practice of Canadian securities industry analysts. The Investment Dealers Association ("IDA") published the initial proposed Policy 11 on July 5, 2002, a revised version on April 25, 2003, and a summary of comments on August 8, 2003. Policy 11 requires more disclosures from analysts and independence of research departments. Also, in a letter dated August 15, 2002, the Ontario Securities Commission ("OSC") requested information from financial institutions about current practices to address conflicts of interest relating to equity

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

analysts. Accordingly, in September 2002, most financial institutions had adjusted their practice and replied to OSC.

A 2010 article in Financial Analyst Journal found that analyst forecast bias had declined significantly or disappeared entirely since the Global Settlement:

> Introduced in 2002, the Global Settlement and related regulations had an even bigger impact than Reg FD on analyst behavior. After the Global Settlement, the mean forecast bias declined significantly, whereas the median forecast bias essentially disappeared. Although disentangling the impact of the Global Settlement from that or related rules and regulations aimed at mitigating analysts' conflicts of interest is impossible, forecast bias clearly declined around the time the Global Settlement was announced. These results suggest that the recent efforts of regulators have helped neutralize analysts' conflicts of interest.[23]

2. Multi-Stage DCF Model

In order to address some of the limiting assumptions underlying the Constant Growth form of the DCF model, I also considered the results of a multi-period (three-stage) DCF Model. The Multi-stage DCF model tempers the assumption of constant growth in perpetuity with a three-stage approach based on near-term, transitional and long-term growth rates.

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

[23] Armen Hovakimian and Ekkachai Saenyasiri, *Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation*, Financial Analysts Journal, Volume 66, Number 4, July/August 2010, at p. 105.

a. Long-Term Growth Rate

Nominal GDP growth rates for both proxy groups were developed using data for each country as reported by Consensus Economics, Inc. for the period from 2021-2025. These forecasts are based on real (constant dollar) growth rates and estimates for inflation. The inflation estimate was applied to the estimate of real GDP growth to develop the nominal (post-inflation) GDP growth rate. The estimates of nominal GDP growth are summarized in Figure 8.

Figure 8: Estimates of Nominal GDP Growth [24]

Source	Canada	U.S.
Real GDP Growth	1.9%	2.3%
Inflation	2.0%	2.2%
Nominal GDP Growth	3.94%	4.55%

3. DCF Results

The DCF results are shown in Figure 9 and in Exhibits JMC-3 and JMC-4. As shown in Figure 9, the DCF analyses produce an average cost of common equity of 11.55 percent for the Canadian Utility proxy group, 9.61 percent for the U.S. Electric proxy group, and 9.44 percent of the North American Electric Utility proxy group, including an adjustment for flotation costs and financial flexibility.

[24] Consensus Forecasts, for 2021-2025, April 13, 2015, at 3 (U.S.) and 28 (Canada).

Figure 9: DCF Results (including flotation costs)

DCF Model			
Market Averaging Period	Constant Growth	Multi-Stage	Average
Canadian Utility Proxy Group			
90-day	12.84%	10.26%	11.55%
U.S. Electric Utility Proxy Group			
90-day	9.77%	9.45%	9.61%
North American Electric Utility Proxy Group			
90-day	9.64%	9.24%	9.44%

I do not believe that any adjustment to the DCF results for the U.S. proxy group is necessary in this proceeding. As discussed in more detail Section VI of this report, the U.S. electric utility proxy group is more comparable to Maritime Electric than the Canadian utility proxy group companies, many of which have significant non-electric operations and unregulated operations. Conversely, the U.S. electric utility proxy group is comprised of companies that derive almost 100 percent of net operating income and operating revenues from electric utility operations, and dedicate almost 100 percent of assets to regulated electric utility service. For that reason, I have not adjusted the DCF results for the U.S. electric utility proxy group, or the North American proxy group.

4. Capital Asset Pricing Model ("CAPM")

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

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

where:

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

The term (rm – rf) represents the Market Risk Premium ("MRP"). According to the theory underlying the CAPM, since unsystematic risk can be diversified away, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by Beta, which is defined as:

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

where:

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

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

a. Risk Free Rate

Current bond yields remain near historical lows; consequently, adjustments are necessary to better reflect forward-looking circumstances. Use of forecast bond yields, as opposed to the current risk free rate, reflects the current market reality that while bond yields remain near all-time lows, investors are factoring higher interest rates into their longer-term expectations and required returns.

My CAPM analysis relies on the 2016 through 2018 average *Consensus Economics* forecast of the Canadian 10-year government bond (shown in Figure 10) plus the historical spread between 10-year and 30-year government debt.

Figure 10: Long Term Forecast for 10-Year Government Bond Yields 2016-2018[25]

	2016	2017	2018	Average
Canada	2.1	3.2	3.6	**2.97**
U.S.	2.8	3.9	4.1	**3.60**

With an average spread between 10-year and 30-year Government bond yields of 71 basis points in Canada and 69 basis points in the U.S.,[26] the corresponding longer-term yield on 30-year government bonds over the period 2016 – 2018 is shown in Figure 11.

Figure 11: Risk Free Rate

30-Year Risk Free Yield	Canada	U.S.
April 2015 Consensus Forecast Average 2016-2018 Forecasts	2.97%	3.60%
Average Daily Spread between 10-year and 30-year government bonds (August 2015)	0.71%	0.69%
Sum	**3.68%**	**4.29%**

b. <u>Beta</u>

I have employed several methods of measuring the Beta coefficient for the Canadian and U.S. proxy groups using estimates from both Value Line and Bloomberg.[27] Value Line publishes the historical Beta for each company based on five years of weekly stock returns and uses the New York Stock Exchange as the market index.[28] Bloomberg produces Beta estimates based on parameters entered by the user. I have computed Bloomberg betas based on five years of weekly stock returns and use the S&P 500 or the S&P/TSX Composite as the market index. Both Value Line and Bloomberg report adjusted betas to compensate for the tendency of beta to revert towards the market average of 1.0 over time. The betas used in my CAPM analyses are shown in Figure 12.

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25 Consensus Forecasts by Consensus Economics Inc., Survey Date April 30, 2015, at 28 and 3.
26 Historical spreads were calculated using daily bond yields from August 1, 2015 through August 31, 2015.
27 I have used Bloomberg betas for the Canadian proxy group and both Value Line and Bloomberg betas for the U.S. proxy group.
28 http://www.valueline.com/sup_glossb.html.

Figure 12: Value Line and Bloomberg Betas

	Value Line	Bloomberg
Canadian Group	N/A	0.64
U.S. Electric Utility Group	0.76	0.70
North American Electric Group	0.76	0.69

There are two primary reasons to adjust raw betas. First, numerous empirical studies have provided evidence that an individual company beta is more likely than not to move toward the market average of 1.0 over time. Second, adjusting beta serves a statistical purpose. Because betas are statistically estimated and have associated error terms, betas that are greater than 1.0 tend to have positive estimated errors and thus tend to overestimate future returns. Betas that are below the market average of 1.0 tend to have negative error terms and underestimate future returns. Consequently, it is necessary to adjust forecasted betas toward 1.0 in an effort to improve forecasts.[29] Because current stock prices reflect expected risk, one must use an expected beta to appropriately reflect investors' expectations. A raw beta reflects only where the stock price has been relative to the market historically and is an inferior proxy for the expected returns when compared to the adjusted beta.

The betas I have used in my analysis are supported by the Brattle study conducted for the BCUC on cost of capital methodologies.

> Beta estimates are provided by many data services for Canadian, American and other traded companies. The most common methodology to estimate betas is to use the most recent five years of weekly or monthly return data. These betas may then be adjusted towards one as an adjustment for sampling reversion that was first identified by Professor Marshall Blume (1971, 1975).[30]

c. Market Risk Premium (MRP)

Estimates of the MRP generally fall into two categories, *ex-post* (historical arithmetic average) and *ex-ante* (forward looking). The historical MRP is based on the arithmetic mean of the equity market returns over the income only return on long-term government bonds, based on data from Morningstar and Duff & Phelps. The forward-looking MRP is calculated by subtracting the risk-

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

free rate for each country from the estimated total return for the overall market, as calculated using the DCF methodology for the S&P/TSX Composite Index in Canada and the S&P 500 Index in the U.S.

Because the U.S. and Canadian economies are highly integrated and capital flows freely across the border, the risk premiums for each country are highly correlated. Accordingly, it is reasonable to derive a single forward-looking estimate. Figure 13 provides the historical and forward-looking MRP for Canada and the U.S. Exhibits JMC-5 and JMC-6 show the derivation of the forward-looking MRP for Canada and the U.S.

Figure 13: Market Risk Premia – Canada and U.S.

	Canadian MRP	U.S. MRP
Historical	5.6%	7.0%
Forward-Looking	9.8%	8.1%
Average	7.6%	

As shown in Figure 13, forward-looking MRPs currently are greater than historical MRPs, reflecting the fact that the historical MRP is based on much higher government bond yields than are available in the current low interest rate environment. There is an inverse relationship between interest rates and the MRP, meaning that as interest rates increase (decrease), the MRP decreases (increases). Historic MRPs would therefore underestimate MRPs in the current low bond yield environment.

Another way to illustrate this point is by analyzing the historic relationship between the equity risk premium and bond yields. I have separately examined these MRP estimates by conducting a regression analysis on bond yields and annual market risk premiums calculated by Morningstar Ibbotson through 2011 and by Duff & Phelps thereafter. As shown in Exhibit JMC-7, I have isolated the effects of the global financial crisis in 2008 as an anomalous event that did not align with the normal relationship between government bond yields and market risk premiums. I have set this period aside by assigning a dummy variable to it. My analysis yielded a statistically significant value at the 95 percent confidence for the Y-intercept and also the dummy variable for the global financial crisis. However, the coefficient for the 30-year bond yield had a slightly weaker confidence at roughly 80 percent, but in my opinion is still informative for the relationship between bond yields and market risk premiums. Using the 30-year Canadian bond yield forecast from Figure 11 of 3.68 percent, the regression formula produced by my analysis yields a market risk premium of 10.09 percent. Accordingly, my estimate of the forward-looking market risk premium is reasonable and is more reflective of the current low interest rate environment than the long term historical average. I have nonetheless used the more conservative average of both historic and forward looking MRP's in my analysis.

5. CAPM Results

The results of the CAPM analysis, including flotation costs, are provided in Figure 14 and in Exhibit JMC-8.

Figure 14: CAPM Results (including flotation costs)

	Mean Result
Canadian Utilities	9.04%
U.S. Electric Utilities	10.37%
North American Utilities	10.12%

6. Flotation Costs and Financing Flexibility

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

B. Comparison to Other Authorized ROEs and Earned ROEs

Regulators also consider authorized ROEs for other investor-owned electric utilities in Canada and the U.S when setting allowed returns. Given the "opportunity cost" concept underlying a fair return, this is appropriate, as an investor would shift capital to a higher return for the same level of risk, if available. As shown in Figure 15, the average allowed ROE for Canadian investor-owned electric utilities in 2014 was approximately 8.82 percent and in 2015 is approximately 8.81 percent, while in the U.S., the average allowed ROE for electric utilities in 2014 and 2015 has been 9.91 percent and 9.71 percent, respectively. Furthermore, Figure 15 shows that the actual earned ROE for the investor-owned electric utilities in Canada in 2014 was 9.61 percent. This variation between the allowed and earned ROE is due to the fact that other investor-owned electric utility companies in Canada do not have a hard cap on the authorized ROE (as Maritime Electric does), but rather are allowed to earn above the authorized ROE either within a specified band or without any specific limitations.

Figure 15: Allowed ROEs and Earned ROEs[31]

	2014 Allowed ROE	2014 Earned ROE	2015 Allowed ROE
Maritime Electric	9.75%	9.75%	9.75%
Canadian Electric Utilities			
Nova Scotia Power	9.00%	9.25%	9.00%
Newfoundland Power, Inc.	8.80%	9.15%	8.80%
FortisOntario	9.36%	9.82%	9.30%
ATCO Electric Distribution	8.30%	9.74%	8.30%
FortisAlberta Inc.	8.30%	10.50%	8.30%
FortisBC Inc.	9.15%	9.19%	9.15%
Average	**8.82%**	**9.61%**	**8.81%**
U.S. Utilities[32]			
Electric Utilities	9.91%	N/A	9.71%

The current allowed ROE for Nova Scotia Power is 9.0 percent on 37.5 percent common equity, and for Newfoundland Power is 8.8 percent on 45.0 percent common equity. Nova Scotia Power also has 3.8 percent preferred stock in its regulatory capital structure. Preferred shares are generally considered to be a hybrid between equity and debt, suggesting that Nova Scotia Power's equity ratio is approximately 39.4 percent. The Commission has previously considered this information relevant in setting the allowed ROE and equity ratio for Maritime Electric.[33]

In terms of relative generation risk, Maritime Electric has somewhat more generation risk than Newfoundland Power, which purchases approximately 93 percent of its electricity supply from Newfoundland and Labrador Hydro while generating the remaining seven percent from company-owned hydro-electric plants, primarily for peaking purposes. Nova Scotia Power owns substantial generation assets, and has significantly higher generation risk than Maritime Electric. In addition, Maritime Electric is more risky than electric utilities in Ontario and Alberta because Maritime

[31] The Alberta Utilities Commission's 2015 decision in the Generic Cost of Capital proceeding was retroactive. The allowed ROE for FortisAlberta Inc. and ATCO Electric Distribution for 2014 was originally 8.75%.
[32] Source: SNL Financial. Figures are from January 1, 2014 through August 31, 2015.
[33] The Island Regulatory and Appeals Commission, Docket UE20940, Order UE10-03, July 12, 2010, at paragraph [101].

Electric owns generation assets, while electric utilities in those provinces do not. The generation function is generally regarded by investors as being higher risk than electric transmission or distribution. The Commission has previously accepted that Maritime Electric, with its responsibilities for electricity supply, is different than Ontario's electric distribution utilities. The Commission has stated that it "views this difference as significant."[34] Furthermore, the Commission has stated that it "views Maritime Electric as higher risk than the benchmark BC utility and FortisBC due to a variety of factors such as utility size, nature of operations, economic climate within which it operates, and regulatory risk factors."[35]

VI. BUSINESS RISK

The risk for any company, including utilities, has two principal sources, business risk and financial risk. Business risk is the risk inherent in the company's operations, absent the use of debt. Business risk for a regulated utility results from variability in cash flows and earnings that impact the ability of the utility to recover its costs including the fair return on, and of, its capital in a timely manner. Both operating risk and regulatory risk are included under this broad definition of business risk for regulated utilities. Financial risk exists to the extent a company incurs debt obligations in financing its operations. These risks also have a time dimension. For a utility, short-term risks are those that will reverse or resolve themselves within a year or two, either through regulatory intervention or the normal ebb and flow of earnings. Examples include storms, supply or financial market disruptions. Long term risks, on the other hand, are those that cannot be easily weathered and resolved in a year or two, but represent an actual shift in the business risk profile of the company for which there is no foreseeable mitigation. Examples of long term risks would include: the risk of stranded assets due to loss of competitive market share; or governmental policies that could substantially impact the profitability of a company's operations, such as asset ownership or environmental policies.

Because utilities are generally regulated on the basis of annual revenue requirements, the longer-term risks are sometimes downplayed, essentially under the assumption that the regulatory framework will allow the regulator to compensate investors as risks materialize, through higher

[34] *Ibid*, at paragraph [99].
[35] *Ibid*, at paragraph [104].

ROEs and/or assurance of return of capital. This premise, however, may not always be true. If the utility is losing customers and/or load, competitive limits on regulated prices may constrain a utility's ability to earn higher returns or recover the invested capital when the risk materializes. Further, utility assets are long-lived. Utility regulators cannot bind its successors and thereby guarantee that investors will be adequately compensated in the future for risks as they materialize. In the following sections, I examine the risks of Maritime Electric from several perspectives. First, I examine the business risk of the Company based on the macroeconomic and business environment of its service area. I then compare the Company's business risks against both its Canadian and U.S. peer groups; and I conclude with an examination of the Company's financial risks against these same comparators.

A. Business Risk of Maritime Electric

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

1. Small Size of Maritime Electric

As shown in Figure 16, Maritime Electric is significantly smaller than other electric utilities in the Canadian and U.S. proxy groups, both in terms of 2014 retail electric customers and 2014 net property, plant and equipment. As such, Maritime Electric has greater risk associated with adverse economic conditions, as well as risk that customer demand could decrease significantly due to a major employer or industry experiencing a downturn or deciding to relocate. For example, in October 2014, a potato processing facility owned by McCain announced it was closing. A small utility cannot diversify its risks to the same extent as larger utilities whose assets, geography and economic bases are less concentrated. Negative events are likely to have greater impact on the earnings and cash flows of a smaller utility. The credit ratings of smaller utilities are often lower despite financial parameters that are stronger than their larger peers. Maritime Electric's small size and island location give rise to the concentration of the Company's assets in a limited geographic area. The concentration of its assets means that a major incident is more likely to negatively impact the entire Maritime Electric system than it would for a more geographically dispersed system.

Figure 16: Small Size of Maritime Electric

Retail Electric Customers and Net Property, Plant and Equipment

Company	Retail Electric Customers	2014 Net PP&E ($ millions)
Maritime Electric	78,000	362.5
Canadian Investor Owned Electrics		C$
ATCO Electric Distribution	251,800	2,091.1
FortisAlberta	530,000	2,866.9
FortisBC Electric	166,000	1,419.2
Newfoundland Power	259,000	984.3
Nova Scotia Power	503,700	3,276.4
U.S. Electric Proxy Group		US$
Minnesota Power	145,000	2,995.6
Duke Energy Florida	1,700,000	9,955.0
Duke Energy Indiana	810,000	8,815.0
Duke Energy Kentucky	140,000	1,029.1
Duke Energy Carolinas – NC	3,200,000	20,089.2
Duke Energy Ohio	700,000	4,937.0
Duke Energy Carolinas – SC	730,000	4,582.8
Connecticut Light and Power	1,223,700	6,809.7
NSTAR Electric	1,179,900	5,335.4
Public Service of New Hampshire	504,000	2,635.8
Western Mass Electric	207,900	1,461.3
Kansas City Power and Light – KS	247,000	1,724.0
Kansas City Power and Light – MO	589,100	4,111.7
Oklahoma Gas and Electric - OK	811,200	6,941.5
Arizona Public Service	1,163,100	11,074.4
Kansas Gas and Electric	321,500	3,899.3
Westar Energy	374,500	4,542.1

The Commission has previously recognized that the small size of Maritime Electric makes it more risky than other electric utilities in Canada.[36] This finding has been used to support an above

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

average ROE. Nothing has changed in this regard since the previous GRA filing, with the exception that current forecasts show an equity ratio lower than past equity ratios for Maritime Electric, which contributes to higher financial risk. Based on the small size of Maritime Electric, the analysis could support an equity ratio higher than 40.5 percent.

2. Macroeconomic and Demographic Trends

Maritime Electric's service territory is largely rural; Charlottetown is the only major population center. The economy on Prince Edward Island is concentrated in the following industries: agriculture, fishing, tourism, aerospace and government. According to the Conference Board's Long-Term Economic Forecast, PEI is expected to lead the Atlantic Provinces (i.e., Nova Scotia, New Brunswick, and Newfoundland and Labrador) in economic growth over the long-term, with GDP advancing at a compound annual growth rate of 1.4 percent between 2014 and 2035.[37] However, this long-term GDP growth rate is lower than the overall Canadian compound annual growth rate of 2.0 percent.

The Conference Board projects that PEI will post the highest rate of population growth in the Atlantic region and will be the only province in the region where population growth will remain positive over the long-term.[38] While strong population migration will benefit the Island's service sector, many of these migrants will be of retirement age, so the impact will be less favorable in terms of consumption of goods. Real economic growth is expected to advance at 1.5 percent per year from 2014 to 2020, but then decelerate to 1.3 percent per year from 2021-2035 as the population ages.[39] Figure 17 compares PEI to Canada as a whole and other Canadian provinces on a number of key macroeconomic indicators over the period from 2014-2035. It is notable that over the long-term all of PEI's key economic indicators are projected to be weaker than Canada overall, especially in terms of employment growth and housing starts.

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[37] The Conference Board of Canada, Provincial Outlook 2015, Long-Term Economic Forecast, at 14.
[38] *Ibid.*
[39] *Ibid*, at 15.

Figure 17: Key Economic Indicators – 2014-2035[40]

	PEI	CAN	ALB	BC	NL	NS	ONT	QC
GDP Growth at Market Prices	1.4%	2.0%	2.0%	2.1%	0.9%	1.1%	2.1%	1.6%
Labor Force Growth	0.1%	0.8%	1.1%	0.8%	(0.8%)	(0.3%)	0.9%	0.4%
Population Growth	0.4%	1.0%	1.4%	1.0%	(0.2%)	0.0%	1.1%	0.7%
Employment Growth	0.2%	0.9%	1.2%	0.9%	(0.6%)	(0.1%)	1.0%	0.5%
Disposable Income	2.8%	3.6%	4.0%	3.9%	1.8%	2.4%	3.8%	3.0%
Retail Sales	3.3%	3.6%	3.8%	3.7%	2.3%	2.8%	3.7%	3.3%
Housing Starts	(3.3%)	(0.5%)	(1.3%)	(0.8%)	(7.7%)	(3.5%)	1.2%	(2.1%)

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

40 The Conference Board of Canada, Provincial Outlook 2015, Long-Term Economic Forecast.

3. Operating Risks

Maritime Electric is an integrated electric utility serving approximately 78,000 residential, commercial and industrial customers on PEI. Figure 18 presents the sources of the Company's electricity supply in 2014.

Figure 18: Maritime Electric Electricity Supply in 2014[41]

	MWh	%
On-Island oil-fired generation	8,300	0.6%
On-island wind generation	291,400	23.1%
Point Lepreau participation (nuclear)	208,000	16.5%
System purchases from NB Power	753,000	59.8%

Due to its island location, Maritime Electric is exposed to relatively high supply and operating risks. As of 2014, Maritime Electric remains dependent on New Brunswick Power for approximately 76 percent of its energy requirements. My understanding is that the off-island energy supply is delivered from the mainland grid via two provincially-owned submarine cables, which are approximately 38 years old and whose capacity is already less than peak demand. Maritime Electric has a responsibility to operate and maintain these cables. In 2012, a leak in the cable under the Northumberland Strait required a sophisticated response to undertake repairs which cost approximately $6.0 million (including the cost of replacement energy when the cables were removed from service to complete the repairs). Based on conversations with Maritime Electric, my understanding is that in 2016, Maritime Electric will act as Construction Agent to install two new 180 MW cables between New Brunswick and PEI and will have the additional responsibility to operate and maintain these cables when put into service in late 2016.

[41] In the Matter of the Application of Maritime Electric Company, Ltd. for approval of capital expenditures to be made over a four year period (2015 to 2018) for the design, construction, and commissioning of a combustion turbine generator with a nominal rating of 50 MW (the "Project") to be located at the Charlottetown Generating Station, filed June 5, 2015, at 12.

Maritime Electric's dependence on mainland power supplies means that, for reliability purposes, the Company owns on-island generation capacity (150 MW) to serve as back-up in case of supply interruption. While this generation capacity is not intended to be operated on a regular basis, as it is relatively high cost compared to off-island production, Maritime Electric has an obligation to ensure that back-up capability is maintained and available. In this regard, the Company faces several significant challenges, including availability of bunker oil for the Charlottetown Generation Station ("CTGS") and staffing CTGS given its planned retirement in the near-term. Generation assets, which inherently face higher operating and capital cost recovery risks than T&D assets, comprise approximately 18 percent of Maritime Electric's net utility property, plant and equipment.

Certain aspects of the current electricity supply situation on Prince Edward Island are viewed as favorable by rating agencies. For example, in March 2015, S&P commented on the PEI Energy Accord as follows:

> We believe the company will continue to benefit from the PEI Energy Accord, an agreement between MECL and the province. The accord addressed cost pressures and related rate increases from replacement power needs and operations and maintenance (O&M) costs associated with a prolonged outage at the base load Point Lepreau nuclear power station. Point Lepreau, which is again operational, supplies about 20% of the power the utility requires. The accord reduces the company's risk primarily by transferring the costs of replacement energy and O&M Charges to PEI. In turn, the province has financed these costs at its lower cost of capital and plans to recover the costs over Point Lepreau's remaining life.[42]

However, my understanding is that Maritime Electric has filed an application with the Commission for approval to spend $68 million to construct a new 50 MW combustion turbine at the CTGS location that will serve as necessary generation capacity in the event of energy supply disruptions and will eventually replace the generation units at the CTGS which are near the end of their useful lives. Rather than refurbishing the CTGS units, Maritime Electric has determined that it would be more cost effective to design and construct a new combustion turbine. When the provincial government learned of Maritime Electric's planned application, the government decided to act on

[42] Standard and Poor's Rating Service, Summary: Maritime Electric Co. Ltd., March 31, 2015, at 5.

a recommendation made by the PEI Energy Commission in September 2012 and sent a letter in June 2015 to the Company's regulator indicating its intention to introduce legislation to allow the option to own all future Maritime Electric generation assets on PEI. This level of government involvement in the regulatory process introduces a new level of business/regulatory uncertainty for Maritime Electric. Even before the issuance of this letter, S&P had expressed some degree of caution with the extent of regulatory intervention by the provincial government, stating:

> The provincial government continues to play a significant and active role in energy policy and establishing rates for island customers. We view this as generally less favorable than an independent regulator with a clear, consistent mandate and an established track record of credit-supportive policies. Due to the potential for political interference (which could negatively affect credit quality), the regulator's limited strength, and its independence, we view the MECL's regulatory environment as less favorable compared with those of regulated utilities operating in other Canadian provinces.[43]

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

Lastly, my understanding is that all of Maritime Electric's renewable energy supply is generated by on-island wind generation facilities. Future renewable energy supply sources are also expected to be largely from wind generation facilities. Given the intermittent nature of wind as a source of generation, there are additional operational and contractual complexities for Maritime Electric which distribution utilities in other provinces do not face to the same degree.

[43] *Ibid*, at 4.

4. Deferral and Variance Accounts

Maritime Electric has very limited protection against costs that tend to fluctuate significantly from year to year, are material in nature, and over which management of the utility has no control. While several utilities in Canada have deferral and variance accounts to mitigate the risk associated with various operating and capital costs, Maritime Electric does not. (See Figure 19.) The only accounts that Maritime Electric has implemented are 1) the Energy Cost Adjustment Mechanism ("ECAM"), which allows the Company to recover the actual cost of fuel and purchased power compared to the forecasted amount, 2) a variance account for the recovery of costs related to energy efficiency, which are recovered through the ECAM, and 3) a variance account for OPEB costs. On this basis, the Company's cost recovery risk is high relative to other electric utilities in Canada.

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

5. Alternative Fuel Risk

Maritime Electric does face competition from alternative fuel sources. The majority of the Company's residential customers are oil-based heating customers. While Maritime Electric has experienced higher than normal sales growth due to an increase in the use of electric-based heating (primarily heat pumps), the recent drop in crude oil prices is expected to keep downward pressure on fuel oil prices and will represent a new competitive dynamic for the Company.

6. Political and Regulatory Uncertainty

With respect to the political environment and regulatory framework, a change in provincial legislation in the mid-1990s greatly altered the regulatory model for Maritime Electric. The legislation replaced rate of return/rate base regulation with price cap regulation that limited the Company's regulated prices to those of NB Power plus 10 percent, thereby exposing Maritime Electric to significant financial pressures. Pursuant to the 2004 Electric Power Act, Maritime Electric was returned to rate of return/rate base regulation and allowed to recover approximately $21 million of costs that had been incurred and deferred pursuant to the prior regulatory framework.

Maritime Electric and the Provincial Government entered into a five-year Energy Accord Agreement between March 1, 2011 and February 29, 2016 which, among other things, fixed customer rates and the Company's ROE during this period. As part of the Energy Accord, the government appointed the PEI Energy Commission to undertake a review of PEI's electricity sector. The PEI Energy Commission made several recommendations, including the following: 1) government ownership of Maritime Electric's existing and future generation assets; and 2) a legislatively set reduction in the Company's allowed equity. These recommendations introduced material political risk to the Company. As discussed previously, the government acted on the recommendation regarding ownership of Maritime Electric's future generation assets by announcing their policy which gives them the option to own and finance future generation on PEI.

The Energy Accord also provided benefits to both Maritime Electric and its customers. Nevertheless, the active role of government, as demonstrated by past changes in legislation as well as by the broad mandate of the PEI Energy Commission, contributes to a higher degree of political/regulatory risk for the Company and its investors.

7. Summary of Maritime Electric's Business Risk

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

B. Comparison to other Canadian Electric and Gas Utilities

Maritime Electric derives 100 percent of its operating income and revenues from electric utility service. By contrast, several companies in the Canadian Utility proxy group are engaged in either non-electric utility operations (such as gas distribution or gas transmission) or in non-regulated operations. See Exhibit JMC-2 for profiles of the Canadian proxy group companies. Among the four companies in the Canadian proxy group, Emera derived approximately 69 percent of its operating revenues from electric utility service in 2014, but only 48 percent of its net income came from regulated electric operations. Canadian Utilities Ltd. ("CU Ltd.") provides gas distribution service, electric distribution and transmission service, and gas transmission service in Alberta through its ATCO Gas, ATCO Electric, and ATCO Pipeline subsidiaries. CU Ltd. derived approximately 62 percent of its operating revenues and 71 percent of its net income from regulated utility services in 2014 (electric, gas distribution, and gas transportation). CU Ltd. also owns unregulated electric generation plants in western Canada and Ontario, operates unregulated natural gas gathering, processing, storage and transmission businesses, and has regulated and unregulated operations in Australia and Mexico. Enbridge, Inc. is primarily engaged in the oil and gas pipeline business and the gas distribution business, while Valener, Inc. owns Gaz Metro, the natural gas distribution company in Quebec, as well as several natural gas and electric distribution utilities in Vermont. Both Enbridge and Valener have different business risks than the regulated electric utility operations of Maritime Electric.

1. Macro-economic Conditions

Macro-economic conditions on PEI are projected by the Conference Board to be generally weaker than other Canadian provinces for the period from 2014-2035. Figure 17 provides a comparison of the key economic indicators for PEI to those in the provinces where the other five investor-owned electric utilities are located, as well as Ontario and Quebec. As shown on Figure 17, PEI's key economic indicators are generally stronger than Newfoundland and Labrador and Nova Scotia, but weaker than the other Canadian provinces over the period from 2014-2035.

2. Capital Cost Recovery

Maritime Electric files a capital budget with the Commission on an annual basis, which includes the Company's capital budget for the upcoming year, as well as a ten-year comparative history. The Commission reviews Maritime Electric's capital plan and either provides an Order approving the capital budget or modifying it. Similarly, Nova Scotia Power, Newfoundland Power and FortisBC Electric also file for pre-approval of capital expenditures. The Alberta Utilities Commission does not pre-approve capital-spending plans for electric utilities, but it has allowed ATCO Electric and FortisAlberta to implement capital-tracking mechanisms to recover significant capital expenditures that are made between rate cases under the performance-based regulation (PBR) plan. In summary, Maritime Electric has similar risk associated with capital spending as other investor-owned electric utilities in Canada.

3. Operating Cost Recovery

For my analysis of operating cost recovery risk, I focused on five categories that tend to distinguish specific areas of operating costs where cost recovery mechanisms vary between jurisdictions. These are costs that (1) tend to fluctuate substantially from year to year, (2) are significant in magnitude, and (3) are generally beyond the control of utility management. Among those cost categories for regulated electric utilities, I considered the following: (1) pension expenses; (2) bad debt expense; (3) storm cost recovery; (4) changes in interest rates; and (5) energy efficiency and demand side management costs. Some Canadian regulators have used variance and deferral accounts to mitigate the risks associated with these types of costs.

Figure 19: Operating Cost Recovery Mechanisms

Cost	Pension/OPEB Expense	Bad Debt Expense	Storm Costs	Change in Interest Rates	Energy Efficiency and DSM
Maritime Electric	Yes	No	No	No	Yes
Newfoundland Power	Yes	No	No	No	Yes
ATCO Electric	Yes	No	Yes	Yes	No
FortisBC Electric	Yes	No	Yes	Yes	Yes
FortisAlberta	No	No	No	No	No
Nova Scotia Power	No	No	No	No	Yes

As shown in Figure 19, unlike most other investor-owned electric utilities in Canada, Maritime Electric does not have deferral/variance accounts to protect against the operating risks that are commonly faced by regulated utilities. For that reason, Maritime Electric has higher operating cost risk than the other investor-owned electric utilities in Canada.

4. Summary

Based on the information in this section, my conclusion is that Maritime Electric has higher business risk than other Canadian investor-owned electric utilities. In particular, while the regulatory framework on PEI is generally supportive of maintaining credit quality, there are certain aspects of the economic and operating environment where Maritime Electric has higher business risk than other Canadian investor-owned electric utilities.

C. Comparison to U.S. Electric Utility Proxy Group

In this section of the report, I compare Maritime Electric to the companies in the U.S. Electric Utility Proxy Group on the following factors: (1) percentage of regulated electric utility operations; (2) supportiveness of the regulatory environment in which the operating company provides electric utility service; and (3) investment risk as measured by the business and financial rankings from S&P. On that basis, I draw conclusions regarding whether it is reasonable to use the DCF and CAPM results for the U.S. Electric Utility Proxy Group to establish the range of ROE results for Maritime Electric, without making any adjustments to account for differences in business and financial risk between the U.S. proxy group and Maritime Electric.

1. Comparison of Regulated Electric Utility Operations

Maritime Electric is a pure-play electric utility that derives 100 percent of its operating income and revenues from regulated electric utility service. As shown in Exhibit JMC-9, the U.S. Electric Utility proxy group companies derive approximately 98 percent of regulated income and 97 percent of regulated revenues from electric utility service, and approximately 96 percent of regulated assets are dedicated to electric utility operations. For this reason, I believe that the U.S. Electric Utility proxy group is more representative of Maritime Electric than the Canadian proxy group, which as noted previously is engaged in other regulated utility business, as well as non-regulated activities. Exhibit JMC-10 provides relevant operating statistics for the Canadian and U.S. proxy group companies at the operating company level, including S&P credit ratings, 2014 regulated revenue, and 2014 retail customers.

2. Assessment of Regulatory Environment

It has been argued by some observers before Canadian regulators that the U.S. regulatory environment for utilities is higher risk than the regulatory environment in Canada. In September 2013, however, Moody's issued a report discussing its evolving view of U.S. utility regulation. In that report, Moody's stated:

> Based on our observations of trends and events, we propose to adopt a generally more favorable view of the relative credit supportiveness of the U.S. utility regulatory environment. Our updated view considers improving regulatory trends that include the increased prevalence of automatic cost recovery provisions, reduced regulatory lag, and generally fair and open relationships between utilities and regulators.
>
> ***
>
> Our revised view that the regulatory environment and timely recovery of costs is in most cases more reliable than we previously believed is expected to lead to a one notch upgrade of most regulated utilities in the U.S., with some exceptions. This evolving view is independent of the proposed changes in the methodology that are highlighted in the Summary section that follows, and would have taken place even if the 2009 methodology were to remain in place without modification.[44]

Exhibit JMC-11, Schedules 1-6 provide an assessment of the regulatory environment for Maritime Electric compared to the operating companies in the Canadian and U.S. proxy groups.

3. Using Credit Ratings to Measure Investment Risk

Maritime Electric is rated BBB+ by S&P, while the average S&P credit rating for the U.S. proxy group of electric utility companies is between BBB+/A-. The credit rating screen that I used to select my U.S. proxy group is based on the utility's business risk (including an assessment of the regulatory environment in which the utility operates) and its financial risk. Companies with similar credit ratings have been determined by the rating agency to have similar levels of business and financial risk. Various regulatory agencies have used credit ratings to assess overall investment risk. For example, in the U.S., the Federal Energy Regulatory Commission ("FERC") has found that "it is reasonable to use the proxy companies' corporate credit rating as a good measure of investment risk, since this rating considers both financial and business risk."[45]

I compared the investment risk of Maritime Electric to that of the U.S. Electric Utility proxy group by analyzing the business and financial risk rankings used by S&P in the development of its credit

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

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

ratings. As shown in Figure 20, Maritime Electric's business risk ranking is "Excellent" and its financial risk ranking is "Aggressive." On that basis, Maritime Electric has comparable business risk as most companies in the U.S. Electric Utility proxy group, but higher financial risk due to its more leveraged capital structure and weaker credit metrics.

Figure 20: U.S. Electric Proxy Group – S&P Rankings

Company	S&P Rating	Business Risk	Financial Risk
ALLETE, Inc.	BBB+	Strong	Significant
Duke Energy Corporation	BBB+	Excellent	Significant
Eversource	A-	Excellent	Significant
Great Plains Energy Inc.	BBB+	Excellent	Significant
OGE Energy Corporation	A-	Strong	Intermediate
Pinnacle West Capital Corp.	A-	Excellent	Intermediate
Westar Energy, Inc.	BBB+	Excellent	Significant
Maritime Electric Co. Ltd.	**BBB+**	**Excellent**	**Aggressive**

In addition, Maritime Electric faces higher long-term business risk than the U.S. proxy group companies due to unfavorable demographic trends (e.g., Maritime Electric serves an island where population growth is limited). In addition, PEI is known for severe weather conditions, especially wind and ice storms that create significant risk that Maritime Electric will incur substantial capital and operating costs to restore service in any given year. On a more favorable note, Maritime Electric has lower business risk than operating companies in the U.S. proxy group as it relates to competition from alternative fuel sources such as natural gas, but faces competition from fuel oil for space heating needs due to the significant decrease in the price of crude oil in recent months.

Based on the risk analysis, my conclusion is that Maritime Electric has comparable to higher business risk and higher financial risk compared to the U.S. electric utility proxy group.

D. Financial Risk

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

The capital structure relates to a company's financial risk, which represents the risk that a company may not have adequate cash flows to meet its financial obligations, and is a function of the percentage of debt (or financial leverage) in the capital structure. As the percentage of debt and preferred equity in the capital structure increases, so do the fixed obligations for the repayment of that debt. Consequently, as the degree of financial leverage increases, the risk of financial distress for common equity holders (i.e., financial risk) also increases.[46] Since the capital structure can affect the Company's overall level of risk, it is an important consideration in establishing a fair return.

Under the provisions of the Electric Power Act, Maritime Electric is required to maintain a minimum of 40 percent common equity in its capital structure.

1. Comparison to Other Investor-Owned Utilities

One way to assess the reasonableness of Maritime Electric's equity ratio is by comparison to other investor-owned electric utilities. As shown in Figure 21, Maritime Electric's forecasted average common equity ratio of 40.5 percent is comparable to the other Canadian investor-owned electric utilities, with the exception of Newfoundland Power, which has a common equity ratio of 45 percent. As discussed previously, Nova Scotia Power has 37.5 percent common equity and 3.8 percent preferred stock in its regulatory capital structure.

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

Figure 21: Comparison of Authorized Equity Ratios

Operating Utility	Equity Ratio
ATCO Electric Distribution	38.0%
FortisAlberta	40.0%
FortisBC Electric	40.0%
Newfoundland Power	45.0%
Nova Scotia Power	37.5%
Average	**40.1%**

As shown in Figure 22, the average authorized common equity ratio for the operating companies in the U.S. electric utility proxy group is approximately 51.1 percent, or more than 9 percent higher than Maritime Electric's forecasted average common equity ratio of 40.5 percent. Maritime Electric would be at the low end of this range.

Figure 22: U.S. Electric Utility Proxy Group

Average Authorized Common Equity Ratio[47]

Company	Authorized Common Equity Ratio
Minnesota Power	54.29%
Duke Energy Florida	46.74%
Duke Energy Indiana	44.44%
Duke Energy Kentucky	N/A
Duke Energy Carolinas – NC	53.00%
Duke Energy Ohio	53.30%
Duke Energy Carolinas – SC	53.00%
Connecticut Light and Power	50.38%
NSTAR Electric	N/A
Public Service of New Hampshire	52.40%
Western Mass Electric	50.70%
Kansas City Power and Light – KS	50.48%
Kansas City Power and Light – MO	50.09%
Oklahoma Gas and Electric - OK	N/A
Arizona Public Service	53.94%
Kansas Gas and Electric	50.13%
Westar Energy	52.63%
Mean	**51.11%**

2. Assessment of Credit Metrics

Financial risk is also measured through credit metrics, such as the ratio of Funds From Operations ("FFO") to debt, as well as interest coverage ratios that compare Earnings Before Interest and Taxes ("EBITDA") and FFO to interest payments on long-term debt. As shown I Exhibit JMC-12, the S&P adjusted credit metrics for Maritime Electric in 2014 were generally weaker than the companies in the Canadian utility proxy group and much weaker than the average for the U.S. electric proxy group, especially with respect to interest coverage ratios and debt to capital ratios.

[47] For utilities with operations in multiple jurisdictions, the authorized equity ratios shown are those for the jurisdiction in which the utility predominantly operates. Those utilities marked "N/A" did not have an authorized common equity ratio in their most recent rate case decision. In most instances, those cases were resolved through a settlement agreement that did not specify the authorized equity ratio.

In particular, compared to the Canadian utility proxy group, Maritime Electric has a lower debt to capital ratio, a weaker EBIDTA to interest coverage ratio and a much weaker FFO to interest coverage ratio, a weaker FFO to debt ratio, and a lower debt to EBITDA ratio. As compared to the U.S. electric utility proxy group, Maritime Electric has a higher debt to capital ratio, a weaker EBIDTA to interest coverage ratio, a much weaker FFO to interest coverage ratio, a much weaker FFO to debt ratio, and a slightly weaker debt to EBITDA ratio.

Based on a comparison of the equity ratios and the credit metrics of Maritime Electric to the companies in the Canadian and U.S. proxy groups, my conclusion is that Maritime Electric has somewhat higher financial risk than the Canadian proxy group and significantly higher financial risk than the U.S. Electric Utility proxy group.

3. Credit Rating Agency View

Maritime Electric has consistently maintained a long-term issuer rating from S&P of "BBB+" since January 2004. A March 2015 S&P report reaffirmed the current ratings for Maritime Electric, noting the supportive regulatory and business environment on PEI. However, as discussed previously, S&P expressed some degree of caution with respect to the extent of government involvement in the business of Maritime Electric. In terms of Financial Risk, S&P characterizes Maritime Electric as having "Aggressive" financial risk, whereas the companies in the U.S. Electric Utility proxy group have "Significant" or "Intermediate" financial risk rankings from S&P. As shown in Figure 23, all of the companies in the Canadian peer group have "Significant" financial risk rankings, while Maritime Electric has "Aggressive" financial risk, representing higher financial risk due to a more leveraged capital structure and weaker cash flow metrics.

Figure 23: Canadian Proxy Group – S&P Rankings

Company	S&P Rating	Business Risk	Financial Risk
Canadian Utilities Ld.	A	Excellent	Significant
Emera	BBB+	Excellent	Significant
Enbridge, Inc.	A-	Excellent	Significant
Valener, Inc.	BBB+	Strong	Significant
Maritime Electric Co. Ltd.	**BBB+**	**Excellent**	**Aggressive**

4. Conclusions on Proposed Equity Ratio

Maritime Electric is proposing a capital structure in 2016 consisting of 40.5 percent average common equity and 59.5 percent average long-term debt. Maritime Electric's proposed equity ratio is consistent with the relative risk of the Company compared to the Canadian proxy group, and is substantially lower than the authorized equity ratios of the electric utility companies in the U.S. proxy group. For those reasons, my conclusion is that Maritime Electric's forecasted average common equity ratio of 40.5 percent is reasonable and should be adopted by the Commission. Maritime Electric's forecasted average common equity ratio is very close to the legislative minimum equity ratio requirement of 40 percent.

VII. OVERALL CONCLUSIONS AND RECOMMENDATIONS

Based on the analysis discussed throughout this report, Maritime Electric's proposed ROE of 9.7 percent within a range of 9.5-9.9 percent is consistent with the allowed ROEs for other investor-owned electric utilities across Canada, especially those in Atlantic Canada (Nova Scotia Power and Newfoundland Power), given the relative risk of Maritime Electric to those companies.

In addition, for the reasons discussed throughout this report, it is appropriate to consider both the DCF and CAPM results when establishing the authorized ROE for Maritime Electric. The results of my DCF and CAPM analyses are summarized in Figure 24.

Figure 24: Summary of Results (including flotation costs)

	Canadian Regulated Utilities	US Electric Utilities	North American Electric Utilities	Average
CAPM	9.0%	10.4%	10.1%	9.8%
Constant Growth DCF	12.8%	9.8%	9.6%	10.7%
Multi-Stage DCF	10.3%	9.5%	9.2%	9.6%
Average	10.7%	9.9%	9.7%	10.1%

The Constant Growth and Multi-Stage DCF methods produce fairly tight ranges of 9.5 percent to 9.8 percent for the U.S. Electric Utilities proxy group and 9.2 percent to 9.6 percent for the North American Electric Utilities proxy group, and a wide range for the Canadian proxy group of 10.3 percent to 12.8 percent.

I have concerns with the ability of the CAPM to produce reasonable results without adjustments for the current market environment. Bond yields in Canada and the U.S. have been driven to all-time lows, and most would agree below sustainable levels in the longer term. The historical MRP is also impacted by the current low level of interest rates. There is a substantial gap between historic equity returns and the higher returns implied in current stock market data. These are problems with the CAPM, and in general, in the current market environment.

I have attempted to compensate for these concerns by using forward-looking inputs, including a forecasted Canadian risk-free rate, an MRP that combines both Canadian and U.S. market inputs, including both historic and forward-looking estimates, and the adjusted beta coefficient for the Canadian and U.S. proxy companies. Flotation costs are included, consistent with regulatory practice across Canada. The CAPM analysis produces results of 9.0 percent for the Canadian proxy group, 10.4 percent for the U.S. Electric Utility proxy group, and 10.1 percent for the North American Electric proxy group.

Taking into consideration the results of both the DCF and CAPM methods for the Canadian and U.S. proxy companies, giving more weight to the North American proxy group results, the estimated cost of equity for Maritime Electric is between 9.5 percent and 9.9 percent. Based on this range of results, and taking into consideration the business and financial risks of Maritime Electric relative to the proxy group companies, the Company's proposed ROE of 9.7 percent is reasonable and appropriate. This is equal to the average of the North American Electric proxy group of 9.7 percent. In addition, a forecast average common equity ratio of 40.5 percent is reasonable, and taken together are conservative, given the relative business risks of Maritime Electric.

James M. Coyne
Senior Vice President

Mr. Coyne provides financial, regulatory, strategic, and litigation support services to clients in the natural gas, power, and utilities industries. Drawing upon his industry and regulatory expertise, he regularly advises utilities, public agencies and investors on business strategies, investment evaluations, and matters pertaining to rate and regulatory policy. Prior to Concentric, Mr. Coyne worked in senior consulting positions focused on North American utilities industries, in corporate planning for an integrated energy company, and in regulatory and policy positions in Maine and Massachusetts. He has authored numerous articles on the energy industry and provided testimony and expert reports before the Federal Energy Regulatory Commission and numerous jurisdictions in the U.S. and Canada. Mr. Coyne holds a B.S. in Business from Georgetown University with honors and an M.S. in Resource Economics from the University of New Hampshire.

REPRESENTATIVE PROJECT EXPERIENCE

Expert Testimony Experience

- FortisBC Energy Inc.: Before the British Columbia Utilities Commission, provided expert testimony on the cost of capital and business risk for the Company's BC gas distribution operations. (Docket No._)
- Green Mountain Power Company: Before the Vermont Public Service Board, provided expert testimony on the cost of capital for the Company's Vermont Electric Utility Business. (Docket No. 8191)
- Northern States Power Company: Before the Public Service Commission of Wisconsin, provided expert testimony on the cost of capital for the company's Wisconsin electric and natural gas utility operations. (Docket No. 4220-UR-119)
- Hydro Quebec: Before the Régie de l'énergie, filed expert testimony on the cost of capital and business risk for the Company's Québec electric transmission and distribution businesses, with John Trogonoski. (R-3842-2013)
- Enbridge: Before the Ontario Energy Board, filed expert testimony with Jim Simpson and Melissa Bartos in support of the Company's proposed 2nd Generation Incentive Regulation plan. Our work focused on development of a proposed plan consistent with the OEB's objectives for such plans, while recognizing the Company's operating environment and business objectives, and capitalizing on the experience with other IR programs. Concentric conducted a series of analyses, including industry benchmarking, and productivity analyses for the industry and Enbridge using both total factor productivity "TFP" analysis and partial factor productivity ("PFP") analysis. These analyses produced productivity measures ("X factors") for both Enbridge and the industry peer group that were utilized to test parameters for the proposed IR plan. Concentric also evaluated alternative measures of inflation ("I factors") for utility inputs. Lastly, we examined Enbridge's anticipated 2014 to 2016 costs, and evaluated the ability of a traditional I-X framework to accommodate the Company's cost profile. (EB-2012-0459)
- Gaz Métro: Before the Régie de l'énergie, filed expert testimony on the cost of capital, business risk, and capital structure for the Company's Québec gas distribution operations. (R-3809-2012)
- Startrans IO, LLC: Before the Federal Energy Regulatory Commission, filed expert testimony on the appropriate cost of equity for the Startrans transmission facilities in Nevada and California, and the economic and business environment for transmission investments. (FERC Dockets Nos. ER13-272-000, and EL13-26-000)

- Nova Scotia Power: Before the Nova Scotia Utility and Review Board, provided direct and rebuttal evidence on the business risk of Nova Scotia Power in relation to its North American peers for purposes of determining the appropriate cost of capital. (Docket No. 2013 GRA)
- FortisBC Utilities: Before the British Columbia Utilities Commission, provided direct evidence and a supporting study on formulaic approaches to the determination of the cost of capital. (BCUC 2012 Generic Cost of Capital Proceeding)
- Northern States Power Company: Before the South Dakota Public Utilities Commission provided expert testimony on the appropriate cost of capital for the company's South Dakota electric utility operations. (Docket No. EL12 -)
- Vermont Gas Systems, Inc: Before the Vermont Public Service Board, filed expert testimony on the appropriate cost of equity and capital structure. (Docket No. 7803A)
- Northern States Power Company: Before the South Dakota Public Utilities Commission, provided expert testimony on the appropriate cost of capital for the company's South Dakota electric utility operations. (Docket No. EL11-019)
- Public Service Commission of Wisconsin: Provided expert testimony on the cost of capital for the company's Wisconsin electric and natural gas utility operations. (Docket No. 4220-UR-117)
- Atlantic Path 15, LLC: Before the Federal Energy Regulatory Commission, filed expert testimony on the appropriate rate of return for the Path 15 transmission facilities in California, and the economic and business environment for transmission investments. (FERC Dockets Nos. ER11-2909 and EL11-29)
- Enbridge: Cost of capital witness for the company's 2013 rate filing, providing testimony on recommended ROE and capital structure for the company's Ontario gas distribution business, and a separate benchmarking analysis designed to illustrate the efficiency of the company's operations in relation to its' North American peers. (EB-2011-0354)
- Northern States Power Company: Before the Public Service Commission of Wisconsin, provided expert testimony on the cost of capital for the company's Wisconsin electric and natural gas utility operations. (Docket No. 4220-UR-117)
- FortisBC Energy, Inc: Provided a detailed study of alternative automatic adjustment mechanisms for setting the cost of equity, filed with the British Columbia Public Utilities Commission, December, 2010. (In response to BCUC Order No. G-158-09)
- Commonwealth of Massachusetts, Superior Court, Central Water District vs. Burncoat Pond Watershed District: Provided expert testimony on the appropriate method for computing interest in an eminent domain taking. (Civil Action No. WDCV2001-01051, May 2010)
- Retained by the Ontario Energy Board to evaluate the existing DSM regulatory framework and guidelines for gas distributors, and based on research on best practices in other jurisdictions, make recommendations and lead a stakeholder conference on proposed changes. (2009-2010)
- ATCO Utilities: Primary cost of capital witness on behalf of ATCO Utilities in the 2009 Alberta Generic Cost of Capital proceeding, for the establishment of the return on equity and capital structure for each of Alberta's gas and electric utilities. (AUC Proceeding ID. 85)
- Enbridge: Primary cost of capital witness before the Ontario Energy Board in its Consultative Process on the Board's policy for determination of the cost of capital. (EB-2009-0084)
- Provided written comments to the Ontario Energy Board on behalf of Enbridge Gas Distribution, and separately for Hydro One Networks and the Coalition of Large Distributors in response to the Board's invitation to interested stakeholders to provide comments to help the Board better understand whether current economic and financial market conditions have an impact on the reasonableness of the Cost of Capital parameter values calculated in accordance with the Board's established Cost of Capital methodology; and to help the Board determine if, when, and how to make any appropriate adjustments to those parameter values. (2009)

- Atlantic Path 15, LLC: Before the Federal Energy Regulatory Commission, provided expert testimony on the appropriate rate of return, capital structure, and rate incentives for the development and operation of the Path 15 transmission facilities in California. (FERC Docket ER08-374-000)
- Wisconsin Power and Light Company: Before the Public Service Commission of Wisconsin, on establishing ratemaking principles for the company's proposed wind and coal electric generation facility additions, providing expert testimony on the appropriate return on equity. (PSCW Docket Nos. 6680-CE-170 and 6680-CE-171, 2007)
- Aquarion Water Company: Before the Connecticut Department of Public Utility Control, providing expert testimony on establishing the appropriate return on equity for the Company's Connecticut operations. (DPUC Docket No. 07-05-19, 2007)
- Central Maine Power Company: Before the Maine Public Utilities Commission, provided expert testimony on the theoretical and analytical soundness of the Company's sales forecast for ratemaking purposes. (MPUC Docket No. 2007-215, 2007)
- Vermont Gas Systems, Inc.: Before the State of Vermont Public Board, on the company's petition for approval of an alternative regulation plan, provided expert testimony on models of incentive regulation and their relative benefits for VGS and its ratepayers. (VPSB Docket No. 7109, 2006)
- Texas New Mexico Power Company: Before the Public Utility Commission of Texas, on the approval of the company's stranded cost recovery associated with the auction of the company's generating assets. (PUC Docket No. 29206, 2004)
- TransCanada Corporation: Provided an independent expert valuation of a natural gas pipeline, filed with the American Arbitration Association. (AAA Case No. 50T 1810018804, 2004)
- Advised the Board of Directors of El Paso Corporation on settlement matters pertaining to western power and gas markets before FERC. (2003)
- Conectiv: Before the New Jersey Board of Public Utilities, on the approval of the proposed sale of Atlantic City Electric Company's fossil and nuclear generating assets. (NJBPU Docket No. EM00020106, 2000-2001)
- Bangor Hydro Electric Company: Before the Maine Public Utilities Commission, on the approval of the proposed sale of the company's hydroelectric and fossil generation assets. (MPUC Docket No. 98-820, 1998)
- Maine Office of Energy Resources: Before the Maine Public Utilities Commission on behalf of the Maine Office of Energy on the establishment of avoided costs rates for generators under PURPA. (1981-1982)

Regulatory Support Experience

- Retained by Gaz Métro to provide an independent assessment of the comprehensive incentive rate mechanism designed to improve the performance of Gaz Métro, and evaluate the proposed mechanism resulting from the Company's collaboration with a stakeholder working group. (R-3693-2009, 2011)
- For the Canadian Gas Association, facilitated workshops between Canadian regulators and utility executives on regulatory and utility responses to a low carbon world, and drafted follow-up white paper to facilitate further discussion on emerging industry issues. (2010-2013)
- Retained by Ontario's Coalition of Large Distributors (Enersource Hydro, Horizon Utilities, Hydro Ottawa, PowerStream, Toronto Hydro, and Veridian Connections) to examine the cost of capital for Ontario's electric utilities in relation to those in other provinces and in the U.S. (2008)
- Retained by the Ontario Energy Board to analyze ROE awards for the past two years in Ontario, and compare against other jurisdictions in Canada, the U.S., the U.K., and select other European jurisdictions. Differences in awarded ROEs were examined for underlying factors, including ROE methodology, company size, business risks, tax issues, subsidiary vs. parent, and sources of capital. The

analysis also addressed the question of whether Canadian utilities compete for capital on the same basis as U.S. utilities. (2007)

- Retained by the Nantucket Planning and Economic Development Commission to educate government officials and island residents on the wind industry, and provide analysis leading to constructive input to the Army Corps of Engineers and the Minerals Management Service on the siting of proposed wind projects. (2004-2007)
- Interim manager of Government and Regulatory affairs for Boston Generating, LLC. Coordinate activities and interventions before FERC, NE-ISO, state regulatory agencies, and local communities hosting Boston Generating power plants. (2004)
- Facilitated the development of an Alternative Regulation Plan with the Department of Public Service and Vermont Gas Systems providing research and advice leading to a rate proposal for the Vermont Public Service Board. Conducted several workshops including the major stakeholders and regulatory agencies to develop solutions satisfying both public policy and utility objectives. (2004-2005)
- For an independent power company, perform market analysis and annual audits of its utility power contract. Services provided include verification of the contract price as a function of its index components, surveys of regional competitive energy suppliers, and analysis of regional spot prices for an independent benchmark. Meet with PUC staff to discuss and represent the company in its annual adjustment process, and report results to the company and its creditors. (2003-2004)

Areas of Expertise

- **Energy Regulation**
  - Rate policy
  - Cost of capital
  - Incentive regulation
  - Fuels and power markets
- **Management and Business Strategy**
  - Fuels and power market assessments
  - Investment feasibility
  - Corporate and business unit planning
  - Benchmarking and productivity analysis
- **Financial and Economic Advisory**
  - Valuation analysis
  - Due diligence
  - Buy and sell-side advisory

PUBLICATIONS AND RESEARCH

- "Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Consumers" (with Robert Yardley), prepared for the Canadian Gas Association and Canadian Electricity Association, May, 2015.
- "Autopilot Error: Why Similar U.S. and Canadian Risk Profiles Yield Varied Rate-making Results" (with John Trogonoski), Public Utilities Fortnightly, May 2010
- "A Comparative Analysis of Return on Equity of Natural Gas Utilities" (with Dan Dane and Julie Lieberman), prepared for the Ontario Energy Board, June, 2007
- "Do Utilities Mergers Deliver?" (with Prescott Hartshorne), Public Utilities Fortnightly, June 2006
- "Winners and Losers: Utility Strategy and Shareholder Return" (with Prescott Hartshorne), Public Utilities Fortnightly, October 2004
- "Winners and Losers in Restructuring: Assessing Electric and Gas Company Financial Performance" (with Prescott Hartshorne), white paper distributed to clients and press, August 2003

- "The New Generation Business," commissioned by the Electric Power Research Institute (EPRI) and distributed to EPRI members to contribute to a series on the changes in the Power Industry, December 2001
- Potential for Natural Gas in the United States, Volume V, Regulatory and Policy Issues (co-author), National Petroleum Council, December 1992
- "Natural Gas Outlook," articles on U.S. natural gas markets, published quarterly in the Data Resources Energy Review and Natural Gas Review, 1984-1989

SELECTED SPEAKING ENGAGEMENTS

- "Innovations in Utility Business Models and Regulation", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2015 Energy Regulation Course, Queens University, Kingston, Ontario, June 2015
- "M&A and Valuations," Panelist at Infocast Utility Scale Solar Summit, September 2010
- "The Use of Expert Evidence," The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2010 Energy Regulation Course, Queens University, Kingston, Ontario, June 2010
- "A Comparative Analysis of Return on Equity for Utilities in Canada and the U.S.", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) Annual Conference, Banff, Alberta, April 22, 2008
- "Nuclear Power on the Verge of a New Era," moderator for a client event co-hosted by Sutherland Asbill & Brennan and Lexecon, Washington D.C., October 2005
- "The Investment Implications of the Repeal of PUCHA," Skadden Arps Client Conference, New York, NY, October 2005
- "Anatomy of the Deal," First Annual Energy Transactions Conference, Newport, RI, May 2005
- "The Outlook for Wind Power," Skadden Arps Annual Energy and Project Finance Seminar, Naples, FL, March 2005
- "Direction of U.S. M&A Activity for Utilities," Energy and Mineral Law Foundation Conference, Sanibel Island, FL, February 2002
- "Outlook for U.S. Merger & Acquisition Activity," Utility Mergers & Acquisitions Conference, San Antonio, TX, October 2001
- "Investor Perspectives on Emerging Energy Companies," Panel Moderator at Energy Venture Conference, Boston, MA, June 2001
- "Electric Generation Asset Transactions: A Practical Guide," workshop conducted at the 1999 Thai Electricity and Gas Investment Briefing, Bangkok, Thailand, July 1999
- "New Strategic Options for the Power Sector," Electric Utility Business Environment Conference, Denver, CO, May 1999
- "Electric and Gas Industries: Moving Forward Together," New England Gas Association Annual Meeting, November 1998
- "Opportunities and Challenges in the Electric Marketplace," Electric Power Research Institute, July 1998

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2006 – Present)
Senior Vice President
Vice President

FTI Consulting (Lexecon) (2002 – 2006)
Senior Managing Director – Energy Practice

Arthur Andersen LLP (2000 – 2002)
Managing Director, Andersen Corporate Finance – Energy and Utilities

Navigant Consulting, Inc. (1996 – 2000)
Managing Director, Financial Services Practice
Senior Vice President, Strategy Practice

TotalFinaElf (1990 – 1996)
Manager, Corporate Planning and Development
Manager, Investor Relations
Manager of Strategic Planning and Vice President, Natural Gas Division

Arthur D. Little, Inc. (1989 – 1990)
Senior Consultant – International Energy Practice

DRI/McGraw-Hill (1984 – 1989)
Director, North American Natural Gas Consulting
Senior Economist, U.S. Electricity Service

Massachusetts Energy Facilities Siting Council (1982 – 1984)
Senior Economist – Gas and Electric Utilities

Maine Office of Energy Resources (1981 – 1982)
State Energy Economist

EDUCATION

M.S., Resource Economics, University of New Hampshire, with Honors, 1981
B.S., Business Administration and Economics, Georgetown University, Cum Laude, 1975

DESIGNATIONS AND AFFILIATIONS

NASD General Securities Representative and Managing Principal (Series 7, 63 and 24 Certifications), 2001
NARUC, Advanced Regulatory Studies Program, Michigan State University, 1984
American Petroleum Institute, CEO's Liaison to Management and Policy Committees, 1994-1996
National Petroleum Council, Regulatory and Policy Task Forces, 1992
President, International Association for Energy Economics, Dallas Chapter, 1995
Gas Research Institute, Economics Advisory Committee, 1990-1993
Georgetown University, Alumni Admissions Interviewer, 1988 – current

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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Alberta Utilities Commission				
ATCO Utilities Group	2008	ATCO Gas; ATCO Pipelines Ltd.; ATCO Electric Ltd.	Application No. 1578571 / Proceeding ID. 85	2009 Generic Cost of Capital Proceeding (Gas & Electric)
American Arbitration Association				
TransCanada Corporation	2004	TransCanada Corporation	AAA Case No. 50T 1810018804	Valuation of Natural Gas Pipeline
British Columbia Utilities Commission				
FortisBC	2012	FortisBC Utilities	G-20-12	Cost of Capital Adjustment Mechanisms
FortisBC	2015	FortisBC Utilities		Return on Equity (Gas)
Connecticut Department of Public Utility Control				
Aquarion Water Company of CT/ Macquarie Securities	2007	Aquarion Water Company of CT	DPUC Docket No. 07-05-19	Return on Equity (Water)
Federal Energy Regulatory Commission				
Atlantic Power Corporation	2007	Atlantic Path 15, LLC	ER08-374-000	Return on Equity (Electric)
Atlantic Power Corporation	2010	Atlantic Path 15, LLC	Docket No. ER11-2909-000	Return on Equity (Electric)
Atlantic Power Corporation	2011	Atlantic Path 15, LLC	Docket Nos. ER11-2909 and EL11-29	Rate of Return (Electric Transmission)
Startrans IO, LLC	2012	Startrans IO, LLC	ER-13-272-000	Cost of Capital (Electric Transmission)
Maine Public Utility Commission				
Bangor Hydro Electric Company	1998	Bangor Hydro Electric Company	MPUC Docket No. 98-820	Transaction-Related Financial Advisory Services, valuation
Central Maine Power Company	2007	Central Maine Power Company	MPUC Docket No. 2007-215	Sales Forecast

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Massachusetts Superior Court				
Burncoat Pond Watershed District	2010	Central Water District v. Burncoat Pond Watershed District	WDCV 2001-0105	Valuation / Eminent Domain
New Jersey Board of Public Utilities				
Conectiv	2000-2001	Atlantic City Electric Company	NJBPU Docket No. EM00020106	Transaction-Related Financial Advisory Services
Nova Scotia Utility and Review Board				
Nova Scotia Power Inc.	2012	Nova Scotia Power Inc.	2013 GRA	Return on Equity/Business Risk (Electric)
Ontario Energy Board				
Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	2009	Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	EB-2009-0084	Ontario Energy Board's 2009 Consultative Process on Cost of Capital Review (Gas & Electric)
Enbridge Gas Distribution	2012	Enbridge Gas Distribution	EB-2011-0354	Industry Benchmarking Study and Cost of Capital (Gas Distribution)
Enbridge Gas Distribution	2014	Enbridge Gas Distribution	EB-2012-0459	Incentive Regulation Plan and Industry Productivity Study
Régie de l'énergie du Québec				
Gaz Métro	2012	Gaz Métro	R-3809-2012	Return on Equity/Business Risk/ Capital Structure (Gas Distribution)
Hydro-Québec Distribution and Hydro- Québec TransÉnergie	2013	Hydro-Québec Distribution and Hydro-Québec TransÉnergie	R-3842-2013	Return on Equity/Business Risk (Electric)
Hydro-Québec Distribution	2014	Hydro-Québec Distribution	R-3905-2014	Remuneration of Deferral Accounts
South Dakota Public Service Commission				
Northern States Power Company-MN	2012	Northern States Power Company-MN	EL 11-019	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Texas Public Utility Commission				
Texas New Mexico Power Company	2004	Texas New Mexico Power Company	PUC Docket No. 29206	Auction Process and Stranded Cost Recovery
Vermont Public Service Board				
Vermont Gas Systems, Inc.	2006	Vermont Gas Systems, Inc.	VPSB Docket No. 7109	Models of Incentive Regulation
Vermont Gas Systems, Inc.	2012	Vermont Gas Systems	Docket No. 7803A	Cost of Capital (Gas Distribution)
Green Mountain Power Corporation	2013	Green Mountain Power Corporation	Docket No. 8191	Return on Equity (Electric)
Wisconsin Public Service Commission				
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-170	Return on Equity (Electric)
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-171	Return on Equity (Electric)
Northern States Power Company	2011	Northern States Power Company	PSCW Docket No. 4220-UR-117	Return on Equity (Electric)
Northern States Power Company	2013	Northern States Power Company	PSCW Docket No. 4220-UR-119	Return on Equity (Gas & Electric)
Northern States Power Company	2015	Northern States Power Company	PSCW Docket No. 4220-UR-121	Return on Equity (Gas & Electric)

Canadian & U.S. Macroeconomic Factors

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[11]	[12]	[13]	[14]
	Total Return on:		Total Return on:		Real GDP Growth		CPI		10-year Gov't Bond		Exports		Unemployment		Currency
	S&P/TSX	S&P 500	S&P/TSX Utilities	S&P 500 Utilities	Canada	U.S.	Canada	U.S.	Canada	U.S.	Canada to U.S./ Canadian GDP	U.S. to Canada / U.S. GDP	Canada	U.S.	Exchange Rate (CAD / USD)
1990	-14.8	-3.11	--	--	0.1	1.9	4.8	5.4	10.76	8.55	16.12	1.96	7.7	5.6	1.17
1991	12.02	30.47	--	--	-2.1	-0.2	5.6	4.2	9.42	7.86	15.55	1.86	9.8	6.8	1.15
1992	-1.43	7.62	--	--	0.9	3.4	1.4	3.0	8.05	7.01	17.28	2.10	10.7	7.5	1.21
1993	32.55	10.08	--	--	2.6	2.9	1.9	3.0	7.22	5.87	20.04	2.51	10.8	6.9	1.29
1994	-0.18	1.32	--	--	4.6	4.1	0.1	2.6	8.42	7.09	22.95	3.00	9.6	6.1	1.37
1995	14.53	37.58	--	--	2.7	2.5	2.2	2.8	8.08	6.57	24.82	3.19	8.6	5.6	1.37
1996	28.35	22.96	--	--	1.7	3.7	1.5	3.0	7.20	6.44	25.94	3.13	8.8	5.4	1.36
1997	14.98	33.36	--	--	4.3	4.5	1.7	2.3	6.11	6.35	26.82	3.51	8.4	4.9	1.38
1998	-1.58	28.58	--	--	4.2	4.4	1.0	1.6	5.30	5.26	28.67	3.94	7.7	4.5	1.48
1999	31.71	21.04	--	--	5.2	4.8	1.8	2.2	5.55	5.65	30.75	3.96	7.0	4.2	1.49
2000	7.41	-9.11	--	--	5.1	4.1	2.7	3.4	5.89	6.03	32.57	3.97	6.1	4.0	1.49
2001	-12.57	-11.89	--	--	1.7	1.1	2.5	2.8	5.47	5.02	30.90	3.82	6.5	4.7	1.55
2002	-12.44	-22.10	--	--	2.8	1.8	2.2	1.6	5.29	4.61	29.26	3.76	7.0	5.8	1.57
2003	26.72	28.68	24.96	26.27	2.0	2.5	2.8	2.3	4.79	4.01	26.34	3.02	6.9	6.0	1.40
2004	14.48	10.88	9.42	24.28	3.2	3.5	1.8	2.7	4.59	4.27	26.36	2.74	6.4	5.5	1.30
2005	24.13	4.91	38.30	16.83	3.1	3.1	2.2	3.4	4.05	4.29	26.01	2.49	6.0	5.1	1.21
2006	17.26	15.79	7.01	21.00	2.7	2.7	2.0	3.2	4.22	4.80	24.23	2.25	5.5	4.6	1.13
2007	9.83	5.49	11.80	19.38	2.1	1.9	2.2	2.8	4.28	4.63	22.64	2.07	5.2	4.6	1.07
2008	-33.00	-37.00	-20.46	-28.98	1.1	-0.3	2.3	3.8	3.58	3.66	22.41	2.10	5.3	5.8	1.07
2009	35.05	26.46	19.00	11.92	-2.8	-3.1	0.3	-0.4	3.29	3.26	17.25	1.93	7.3	9.3	1.14
2010	17.61	15.06	18.42	5.46	3.2	2.4	1.8	1.6	3.20	3.22	17.75	1.85	7.1	9.6	1.03
2011	-8.71	2.10	6.47	19.95	2.6	1.8	2.9	3.2	2.78	2.78	18.72	1.84	6.5	8.9	0.99
2012	7.19	16.00	4.00	0.47	1.8	2.2	1.5	2.1	1.85	1.80	18.59	1.89	6.3	8.1	1.00
2013	12.98	32.39	-3.71	14.79	2.0	2.2	0.9	1.5	2.26	2.35	19.63	1.79	7.1	7.4	1.03
2014	10.55	13.68	16.08	28.98	2.5	2.4	2.0	1.6	2.23	2.53	22.37	1.79	6.7	6.2	1.10
25-year Avg.	9.31	11.25	--	--	2.29	2.41	2.08	2.63	5.36	4.96	23.36	2.66	7.40	6.12	1.25
10-year Avg.	9.29	9.49	9.69	10.98	1.83	1.53	1.81	2.28	3.17	3.33	20.96	2.00	6.30	6.95	1.08
5-year Avg.	7.92	15.85	8.25	13.93	2.42	2.20	1.82	2.00	2.46	2.54	19.41	1.83	6.74	8.02	1.03
Correlation	0.71		0.64		0.86		0.72		0.97		0.90		0.21		--
Consensus Forecasts [15]															
2015					2.00	2.90	1.00	0.10	1.60	2.20			6.80	5.40	1.28
2016					2.10	2.80	2.10	2.20	2.10	2.80			6.60	5.00	1.26
2017					2.30	2.60	2.10	2.30	3.20	3.90					1.20

Notes:
[1] Source: Morningstar and Bloomberg Professional; includes price appreciation and dividend yield
[2] Source: Morningstar and Bloomberg Professional; includes price appreciation and dividend yield
[3] Source: Bloomberg Professional; includes price appreciation and dividend yield, however dividend data for S&P/TSX Utilities not available prior to 2003
[4] Source: Bloomberg Professional; includes price appreciation and dividend yield
[5] Source: Statistics Canada; expenditure-based GDP at market prices, chained 2007 prices, seasonally adjusted
[6] Source: U.S. Bureau of Economic Analysis
[7] Source: Statistics Canada; not seasonally adjusted
[8] Source: U.S. Bureau of Labor Statistics; not seasonally adjusted, U.S. city average, all items
[9] Source: Bank of Canada
[10] Source: Bloomberg Professional
[11] Source: Government of Canada (exports to United States, merchandise only), Office of the United States Trade Representative (exports to Canada, merchan
United States Census Bureau (Trade in Goods with Canada), The World Bank (Total GDP), U.S. Bureau of Economic Analysis (U.S. GDP)
[12] Source: 1989-2012: U.S. Bureau of Labor Statistics, International Unemployment Rates and Employment Indexes, Seasonally Adjusted, 2013: Statistics Canada
[13] Source: U.S. Bureau of Labor Statistics, International Unemployment Rates and Employment Indexes, Seasonally Adjusted
[14] Source: Federal Reserve Economic Data
[15] Source: Consensus Forecasts, Survey Date April 13, 2015

Canadian Proxy Group Company Profiles

Canadian Utilities, Ltd.

Canadian Utilities provides electric transmission and distribution service, gas distribution service and gas transportation service through its Utilities segment. The Utilities segment accounted for 62% of operating revenues and 71% of operating income for Canadian Utilities in 2014, and 80% of total assets were dedicated to the Utilities segment. ATCO Electric accounted for 67% of operating income, ATCO Gas for 24% of operating income, and ATCO Pipelines for 9% of operating income in 2014. Canadian Utilities also has a business segment called "Energy" that conducts its activities through ATCO Power and ATCO Energy Solutions. ATCO Power's business involves the regulated and unregulated supply of electricity from generating plants in western Canada and Ontario. ATCO Energy Solutions is involved in non-regulated natural gas gathering, processing, storage and transmission, natural gas liquids extraction, electricity transmission, and industrial water services. The Energy segment accounted for 29% of operating revenues and 17% of operating income in 2014, and 10% of total assets were dedicated to this business unit. ATCO also owns a regulated gas distribution utility in Western Australia and supplies electricity from three gas-fired generation plants in Australia. The Australian operations accounted for slightly less than 10% of operating revenues, income and total assets in 2014.

		Utilities	Energy	ATCO Australia	Corporate and Other	Intersegment Eliminations	Consolidated
2014	Revenues	62%	29%	7%	6%	-4%	100%
2014	Income	71%	17%	9%	3%	0%	100%
2014	Assets	80%	10%	8%	3%	-1%	100%
2013	Revenues	60%	30%	8%	7%	-5%	100%
2013	Income	59%	26%	8%	7%	0%	100%
2013	Assets	77%	11%	9%	4%	-1%	100%

Canadian Proxy Group Company Profiles

Emera, Inc.

Emera provides electric generation, transmission and distribution service through subsidiaries including Nova Scotia Power, Emera Maine (formerly Bangor Hydro), and Emera Caribbean. In 2014, Emera derived 69% of its operating revenues and 48% of operating income from electric utility service, and 69% of total assets were dedicated to the provision of electric utility service. Emera recently announced plans to acquire TECO Energy, which provides electric utility service in Florida and gas distribution service in New Mexico. Emera Energy Inc. is an unregulated subsidiary that purchases and sells natural gas and electricity and provides related energy asset management services, and owns various electricity generating facilities in Canada and the U.S. Emera Energy Services accounted for 27% of operating revenues and 46% of operating income in 2014. Emera also owns the New Brunswick pipeline, which transports re-gasified LNG from New Brunswick to the U.S. The pipeline segment represented 8% of operating income and 8% of total assets in 2014.

		Nova Scotia Power	Emera Maine	Emera Carribean	Pipelines	Emera Energy	Corporate and Other	Total
2014	Revenues	45%	8%	16%	2%	27%	2%	100%
2014	Income	31%	10%	7%	8%	46%	-2%	100%
2014	Assets	44%	13%	12%	8%	16%	7%	100%
2013	Revenues	60%	10%	20%	2%	6%	2%	100%
2013	Income	58%	18%	15%	14%	1%	-6%	100%
2013	Assets	47%	12%	12%	7%	14%	8%	100%

Canadian Proxy Group Company Profiles

Enbridge, Inc.

Enbridge is primarily a natural gas transmission and distribution company with operations in Canada and the U.S. Through its Liquid Pipelines segment, it owns various pipelines (including the Canadian Mainline, the Regional Oil Sands System, Seaway Pipeline, Flanagan South, Southern Lights, and Spearhead) through which it ships crude oil, natural gas liquids and refined products. Enbridge Gas Distribution provides gas distribution service to customers in central and eastern Ontario, as well as upstate New York. Enbridge owns interests in Vector Pipeline and transmission and gathering systems in the Gulf of Mexico. Enbridge also owns economic interests in Enbridge Energy Partners LP and Enbridge Income Fund. The energy services businesses undertake physical commodity marketing activity and logistical services, oversee refinery supply services and manage the Company's volume commitments on the Alliance, Vector and other pipeline systems. Enbridge Gas Distribution 9% of operating revenues and 18% of operating income in 2014, and 13% of total company assets were devoted to gas distribution service. Liquid and gas pipelines represented 67% of operating revenues and 48% of total assets in 2014, while Sponsored Investments accounted for 24% of operating revenues, 36% of operating income and 32% of total assets. Enbridge does not provide regulated electric utility service.

		Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
2014	Revenues	6%	9%	61%	24%	0%	100%
2014	Income	40%	18%	53%	36%	-48%	100%
2014	Assets	38%	13%	10%	32%	7%	100%
2013	Revenues	7%	8%	62%	23%	0%	100%
2013	Income	96%	29%	-14%	60%	-70%	100%
2013	Assets	36%	14%	12%	32%	5%	100%

Canadian Proxy Group Company Profiles

Valener, Inc.

Valener is organized as a limited partnership that primarily owns various interests in regulated gas distribution utilities (such as Gaz Metro QDA and Vermont Gas Systems) and regulated electric utilities (such as Green Mountain Power in Vermont). Valener also owns subsidiaries that are engaged in natural gas transportation, energy production and energy services. Valener derives the vast majority of its operating revenues and operating income from Gaz Metro (62% and 64%, respectively, in 2014), which provides gas distribution service in Quebec. Green Mountain Power and Vermont Gas accounted for 34% of operating revenues and 33% of operating income in 2014. Valener also derives a small percentage of revenue and net income from gas transportation service.

		Gaz Metro QDA	GMP and Vermont Gas	Natural Gas Transportation	Energy Production	Energy Services	Corp Affairs	Consolidated
2014	Revenues	62%	34%	2%	1%	2%	-1%	100%
2014	Income	64%	33%	9%	0%	-2%	-4%	100%
2014	Assets	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2013	Revenues	62%	35%	2%	0%	3%	-1%	100%
2013	Income	64%	28%	10%	-1%	4%	-5%	100%
2013	Assets	N/A	N/A	N/A	N/A	N/A	N/A	N/A

U.S. Proxy Group Company Profiles

ALLETE, Inc.

Allete's operations are broken into two business segments: regulated operations, and other investments. Regulated operations represents the majority of ALLETE's business, and is made up of their regulated utilities, Minnesota Power, Superior Water, Light & Power (SWL&P), and an ownership interest in American Transmission Company (ATC). Minnesota Power provides electric utility electric in northeastern Minnesota to approximately 144,000 retail customers. SWL&P provides electric, natural gas and water service in northwestern Wisconsin and serves approximately 15,000 electric, 12,000 natural gas, and 10,000 water customers. ATC is a Wisconsin based utility that owns and operates electric transmission assets in Wisconsin, Michigan, Minnesota and Illinois. Allete serves a large residential population; however, they also have a large industrial customer base representing 54% of total Regulated Utility kilowatt-hour sales in 2014.

Allete's business also includes non-regulated investments, and other operations. This is comprised primarily of Energy Infrastructure and Related Service businesses. Companies include: Allete Clean Energy, which owns four wind energy facilities and is developing one to be sold; and BNI Coal, representing Allete's coal mining operations in North Dakota.

		Regulated Operations	Investments and Other	Consolidated
2014	Revenues	88%	12%	100%
2014	Income	99%	1%	100%
2014	Assets	85%	15%	100%
2013	Revenues	91%	9%	100%
2013	Income	100%	0%	100%
2013	Assets	91%	9%	100%

U.S. Proxy Group Company Profiles

Duke Energy

Duke Energy conducts their operations in three business segments: Regulated Utilities, International Energy and Commercial Power.

The Regulated Utilities segment primarily operates through Duke Energy Carolinas, Duke Energy Progress, Duke Energy Florida, Duke Energy Indiana, and Duke Energy Ohio. These utilities provide electric utility service in six states in the Southeast and Midwest regions of the U.S. to approximately 7.3 million retail customers. In addition to providing retail electricity, electricity is also sold wholesale to incorporated municipalities, electric cooperative utilities and other load-serving entities. Duke also provides natural gas distribution service to 500,000 retail customers in southwestern Ohio and northern Kentucky.

The International Energy segment operates and manages power generation facilities and performs sales and marketing of electric power, natural gas, and natural gas liquids outside of the U.S., primarily in Latin America. Customers include retail distributors, electric utilities, independent power producers, marketers, and industrial and commercial companies.

The Commercial Power business segment, which is regulated at the federal level by the FERC, builds, develops and operates wind and solar renewable generation and energy transmission projects throughout the continental U.S.

		Regulated Utilities	International Energy	Commercial Power	Other	Eliminations
2014	Revenues	93%	6%	1%	0%	-1%
2014	Income	100%	8%	-4%	-4%	0%
2014	Assets	88%	4%	5%	2%	0%
2013	Revenues	92%	7%	1%	1%	-1%
2013	Income	98%	11%	-4%	-6%	0%
2013	Assets	87%	4%	6%	2%	0%

U.S. Proxy Group Company Profiles

Eversource Energy

Eversource Energy (formerly Northeast Utilities) is a public utility holding company primarily engaged in the delivery of energy through multiple wholly-owned, regulated utility subsidiaries in three segments: Electric Distribution, Electric Transmission, and Natural Gas Distribution

The Electric Distribution segment consists of a few wholly owned subsidiaries: Connecticut Light and Power Company (CL&P), which provides service to approximately 1.2 million residential, commercial and industrial customers in parts of Connecticut; NSTAR Electric Company (NSTAR Electric), which serves approximately 1.2 million residential, commercial and industrial customers in parts of Massachusetts; Western Massachusetts Electric Company (WMECO), which serves 208,000 residential, commercial and industrial customers in parts of western Massachusetts and owns solar generating assets; and Public Service Company of New Hampshire (PSNH), an electric utility that serves approximately 504,000 residential, commercial and industrial customers in parts of New Hampshire and owns generation assets used to serve customers.

Within the Electric Transmission segment, CL&P, NSTAR Electric, PSNH and WMECO own and maintain transmission facilities that are part of an interstate power transmission grid over which electricity is transmitted throughout New England.

The Natural Gas Distribution segment consists of NSTAR Gas Company, and Yankee Gas Services Company. NSTAR Gas Company is a regulated natural gas distribution utility that serves approximately 282,000 residential, commercial and industrial customers in 51 communities in central and eastern of Massachusetts. Yankee Gas Services Company is a natural gas utility that serves residential, commercial and industrial customers in parts of Connecticut.

		Electric Distribution	Natural Gas Distribution	Electric Transmission	Other	Eliminations	Total
2014	Revenues	73%	13%	13%	1%	0%	100%
2014	Income	56%	9%	35%	0%	0%	100%
2014	Assets	59%	10%	26%	43%	-37%	100%
2013	Revenues	73%	12%	13%	11%	-9%	100%
2013	Income	54%	8%	37%	0%	1%	100%
2013	Assets	62%	10%	24%	43%	-39%	100%

U.S. Proxy Group Company Profiles

Great Plains Energy

Great Plains Energy is a public utility holding company operating Kansas City Power & Light, and KCP&L Greater Missouri Operations (GMO), two wholly owned subsidiaries in the electric utilities segment.

Kansas City Power & Light (KCP&L), is a regulated electric utility that provides service primarily in Missouri and Kansas. KCP&L serves approximately 520,700 residential, commercial, industrial, municipal and other utility customers. Retail revenues accounted for an average of approximately 87% of its total operating revenues over the last three years.

GMO is a regulated electric utility that provides electricity service to customers in Missouri. Additionally, they provide regulated steam service to certain customers in the St. Joseph, Missouri area. GMO's business also includes two wholly owned subsidiaries, GMO Receivables Company and MPS Merchant Services, Inc.

Additionally, Great Plains Energy owns GPE Transmission Holding Company, LLC.

		Electric Utility	Other	Eliminations	Consolidated
2014	Revenues	100%	0%	0%	100%
2014	Income	100%	0%	0%	100%
2014	Assets	103%	0%	-3%	100%
2013	Revenues	100%	0%	0%	100%
2013	Income	103%	-3%	0%	100%
2013	Assets	102%	1%	-3%	100%

U.S. Proxy Group Company Profiles

OG&E Corp

OG&E conducts operations in two business segments: electric utilities, and natural gas midstream operations.

OG&E's electric utility segment generates, transmits, distributes and sells energy in Oklahoma and western Arkansas to approximately 815,000 customers. They are the largest electric utility in Oklahoma and also provide service in Fort Smith, Arkansas. OG&E derived 90 percent of its total electric operating revenue in 2014 from sales in Oklahoma.

Through OG&E's wholly-owned subsidiary, OGE Holdings, they own 26.3% of Enable Midstream Partners, representing their natural gas midstream operations. Enable is in the business of gathering, processing, transporting and storing natural gas. Enable is located in 4 states and serve natural gas production from shale developments in the Anadarko, Arkoma and Ark-La basins. Their natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois.

		Electric Utility	Natural Gas Midstream	Consolidated
2014	Revenues	73%	27%	100%
2014	Income	74%	26%	100%
2014	Assets	69%	31%	100%
2013	Revenues	78%	22%	100%
2013	Income	75%	25%	100%
2013	Assets	67%	33%	100%

U.S. Proxy Group Company Profiles

Pinnacle West Capital Corp.

Pinnacle West Capital is a holding company that operates through their wholly owned subsidiaries. Arizona Public Service Company (APS) represents their largest subsidiary and is where PNW derives the majority of revenues and net income. APS is a vertically integrated electric utility that provides both retail and wholesale electric service to approximately 1.2 million customers in the State of Arizona.

Other smaller subsidiaries are El Dorado and Bright Canyon Energy (BCE). El Dorado owns minority interests in energy related investments and Arizona community backed ventures. BCE is a wholly owned subsidiary and focuses on new growth opportunities that leverage the company's expertise in the electric energy industry.

		Regulated Electricity	Consolidated
2014	Revenues	100%	100%
2014	Income	100%	100%
2014	Assets	100%	100%
2013	Revenues	100%	100%
2013	Income	100%	100%
2013	Assets	100%	100%

U.S. Proxy Group Company Profiles

Westar Energy

Wester Energy is the largest electric utility in Kansas providing electric generation, transmission and distribution services to approximately 698,000 residential, commercial, and industrial customers in Kansas as well as wholesale service to municipalities and electric cooperatives in Kansas. Westar Energy provides service in central and northeastern Kansas, including the cities of Topeka, Lawrence, Manhattan, Salina and Hutchinson. Kansas Gas and Electric (KGE), Westar's wholly owned subsidiary, provides services in south central and southeastern Kansas, including Wichita. Both Westar Energy and KGE operate under the name Westar Energy.

		Regulated Electricity	Consolidated
2014	Revenues	100%	100%
2014	Income	100%	100%
2014	Assets	100%	100%
2013	Revenues	100%	100%
2013	Income	100%	100%
2013	Assets	100%	100%

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

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks EPS Growth	[6] SNL EPS Growth	[7] Value Line EPS Growth	[8] First Call Growth	[9] Average Growth Rate	[10] Low DCF ROE	[11] Mean DCF ROE	[12] High DCF ROE
ALLETE, Inc.	ALE	$2.02	$48.88	4.13%	4.26%	N/A	6.00%	6.50%	6.00%	6.17%	10.26%	10.43%	10.77%
Duke Energy Corp	DUK	$3.18	$74.39	4.27%	4.38%	4.70%	4.84%	5.00%	4.60%	4.79%	8.97%	9.16%	9.38%
Eversource Energy	ES	$1.68	$48.25	3.48%	3.60%	6.80%	5.97%	8.50%	6.21%	6.87%	9.56%	10.47%	12.13%
Great Plains Energy Inc.	GXP	$0.98	$25.61	3.83%	3.94%	6.10%	6.78%	5.00%	6.43%	6.08%	8.92%	10.02%	10.74%
OGE Energy Corp.	OGE	$1.00	$30.03	3.33%	3.40%	5.00%	5.30%	3.00%	3.34%	4.16%	6.38%	7.56%	8.72%
Pinnacle West Capital Corp	PNW	$2.38	$60.22	3.95%	4.05%	5.20%	5.28%	4.00%	5.37%	4.96%	8.03%	9.01%	9.43%
Westar Energy Inc.	WR	$1.44	$36.55	3.94%	4.02%	3.90%	3.55%	6.00%	3.40%	4.21%	7.41%	8.24%	10.06%
MEAN				3.85%	3.95%	5.28%	5.39%	5.43%	5.05%	5.32%	8.50%	9.27%	10.17%
Flotation Costs											0.50%	0.50%	0.50%
											9.00%	9.77%	10.67%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of August 31, 2015
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [9])
[5] Source: Zacks at August 31, 2015
[6] Source: SNL Financial Median Long-Term EPS Growth Rate as of September 21, 2015
[7] Source: Value Line
[8] Source: Yahoo! Finance at August 31, 2015
[9] Equals Average([5], [6], [7], [8])
[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])
[11] Equals [4] + [9]
[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])

90-DAY CONSTANT GROWTH DCF -- CANADIAN PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	SNL EPS Growth	Value Line EPS Growth	First Call Growth	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
Canadian Utilities Limited	CU	$1.18	$35.79	3.30%	3.37%	N/A	3.60%	N/A	4.78%	4.19%	6.96%	7.56%	8.16%
Emera Incorporated	EMA	$1.60	$43.69	3.66%	3.78%	N/A	6.60%	N/A	5.99%	6.30%	9.76%	10.07%	10.38%
Enbridge Inc.	ENB	$1.86	$54.98	3.38%	3.61%	12.00%	N/A	10.50%	18.40%	13.63%	14.06%	17.25%	22.09%
Valener Inc.	VNR	$1.04	$16.73	6.22%	6.47%	N/A	N/A	N/A	8.00%	8.00%	14.47%	14.47%	14.47%
MEAN				4.14%	4.31%	12.00%	5.10%	10.50%	9.29%	8.03%	11.31%	12.34%	13.77%
Flotation Costs											0.50%	0.50%	0.50%
											11.81%	12.84%	14.27%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of August 31, 2015
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [9])
[5] Source: Zacks at August 31, 2015
[6] Source: SNL Financial Median Long-Term EPS Growth Rate as of September 21, 2015
[7] Source: Value Line
[8] Source: Yahoo! Finance at August 31, 2015
[9] Equals Average([5], [6], [7], [8])
[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])
[11] Equals [4] + [9]
[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])

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

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	SNL EPS Growth	Value Line EPS Growth	First Call Growth	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
Canadian Utilities Limited	CU	$1.18	$35.79	3.30%	3.36%	N/A	2.90%	N/A	4.78%	3.84%	6.24%	7.20%	8.16%
Emera Incorporated	EMA	$1.60	$43.69	3.66%	3.78%	N/A	6.50%	N/A	5.99%	6.25%	9.76%	10.02%	10.28%
ALLETE, Inc.	ALE	$2.02	$49.06	4.12%	4.24%	N/A	6.00%	6.50%	6.00%	6.17%	10.24%	10.41%	10.75%
Duke Energy Corp	DUK	$3.18	$73.94	4.30%	4.40%	4.70%	4.92%	5.00%	4.60%	4.81%	9.00%	9.21%	9.41%
Eversource Energy	ES	$1.68	$49.31	3.41%	3.53%	6.80%	7.00%	8.50%	6.21%	7.13%	9.72%	10.66%	12.05%
Great Plains Energy Inc.	GXP	$0.98	$25.92	3.78%	3.89%	6.10%	5.88%	5.00%	6.43%	5.85%	8.88%	9.74%	10.33%
OGE Energy Corp.	OGE	$1.00	$29.36	3.41%	3.48%	5.00%	5.15%	3.00%	3.34%	4.12%	6.46%	7.60%	8.64%
Pinnacle West Capital Corp	PNW	$2.38	$61.85	3.85%	3.94%	5.20%	5.00%	4.00%	5.37%	4.89%	7.93%	8.83%	9.32%
Westar Energy Inc.	WR	$1.44	$35.72	4.03%	4.12%	3.90%	4.65%	6.00%	3.40%	4.49%	7.50%	8.61%	10.15%
MEAN				3.76%	3.86%	5.28%	5.33%	5.43%	5.12%	5.28%	8.41%	9.14%	9.90%
Flotation Costs											0.50%	0.50%	0.50%
											8.91%	9.64%	10.40%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of August 31, 2015
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [9])
[5] Source: Zacks at August 31, 2015
[6] Source: SNL Financial Median Long-Term EPS Growth Rate as of September 21, 2015
[7] Source: Value Line
[8] Source: Yahoo! Finance at August 31, 2015
[9] Equals Average([5], [6], [7], [8])
[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])
[11] Equals [4] + [9]
[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])

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

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Annualized Dividend	Stock Price	Growth Rate, Years 1-5	Year 6	Year 7	Year 8	Year 9	Year 10	GDP Growth (perpetuity)	ROE
ALLETE, Inc.	ALE	$2.02	$48.88	6.17%	5.90%	5.63%	5.36%	5.09%	4.82%	4.55%	9.53%
Duke Energy Corp	DUK	$3.18	$74.39	4.79%	4.75%	4.71%	4.67%	4.63%	4.59%	4.55%	9.28%
Eversource Energy	ES	$1.68	$48.25	6.87%	6.48%	6.10%	5.71%	5.32%	4.94%	4.55%	8.93%
Great Plains Energy Inc.	GXP	$0.98	$25.61	6.08%	5.82%	5.57%	5.31%	5.06%	4.81%	4.55%	9.14%
OGE Energy Corp.	OGE	$1.00	$30.03	4.16%	4.23%	4.29%	4.36%	4.42%	4.49%	4.55%	8.07%
Pinnacle West Capital Corp	PNW	$2.38	$60.22	4.96%	4.89%	4.83%	4.76%	4.69%	4.62%	4.55%	8.97%
Westar Energy Inc.	WR	$1.44	$36.55	4.21%	4.27%	4.33%	4.38%	4.44%	4.49%	4.55%	8.75%
MEAN				5.32%	5.19%	5.06%	4.93%	4.81%	4.68%	4.55%	8.95%
Flotation Costs											0.50%
											9.45%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of August 31, 2015
[3] Source: Constant Growth DCF
[4] Equals [3] – ([3] – [9]) / 6
[5] Equals [4] – ([3] – [9]) / 6
[6] Equals [5] – ([3] – [9]) / 6
[7] Equals [6] – ([3] – [9]) / 6
[8] Equals [7] – ([3] – [9]) / 6
[9] Consensus Economics Inc., Consensus Forecasts, April 13, 2015, at 3.
[10] Internal rate of return

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

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Annualized Dividend	Stock Price	Growth Rate, Years 1-5	Year 6	Year 7	Year 8	Year 9	Year 10	GDP Growth (perpetuity)	ROE
Canadian Utilities Limited	CU	$1.18	$35.79	4.19%	4.15%	4.11%	4.06%	4.02%	3.98%	3.94%	7.54%
Emera Incorporated	EMA	$1.60	$43.69	6.30%	5.90%	5.51%	5.12%	4.72%	4.33%	3.94%	8.52%
Enbridge Inc.	ENB	$1.86	$54.98	13.63%	12.02%	10.40%	8.79%	7.17%	5.55%	3.94%	10.45%
Valener Inc.	VNR	$1.04	$16.73	8.00%	7.32%	6.65%	5.97%	5.29%	4.62%	3.94%	12.53%
MEAN				8.03%	7.35%	6.67%	5.98%	5.30%	4.62%	3.94%	9.76%
Flotation Costs											0.50%
											10.26%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of August 31, 2015
[3] Source: Constant Growth DCF
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Consensus Economics Inc., Consensus Forecasts, April 13, 2015, at 28.
[10] Internal rate of return

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

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Annualized Dividend	Stock Price	Growth Rate, Years 1-5	Year 6	Year 7	Year 8	Year 9	Year 10	GDP Growth (perpetuity)	ROE
Canadian Utilities Limited	CU	$1.18	$35.79	3.84%	3.86%	3.87%	3.89%	3.91%	3.92%	3.94%	7.46%
Emera Incorporated	EMA	$1.60	$43.69	6.25%	5.86%	5.48%	5.09%	4.71%	4.32%	3.94%	8.51%
ALLETE, Inc.	ALE	$2.02	$49.06	6.17%	5.90%	5.63%	5.36%	5.09%	4.82%	4.55%	9.52%
Duke Energy Corp	DUK	$3.18	$73.94	4.81%	4.76%	4.72%	4.68%	4.64%	4.59%	4.55%	9.32%
Eversource Energy	ES	$1.68	$49.31	7.13%	6.70%	6.27%	5.84%	5.41%	4.98%	4.55%	8.91%
Great Plains Energy Inc.	GXP	$0.98	$25.92	5.85%	5.64%	5.42%	5.20%	4.98%	4.77%	4.55%	9.02%
OGE Energy Corp.	OGE	$1.00	$29.36	4.12%	4.19%	4.27%	4.34%	4.41%	4.48%	4.55%	8.14%
Pinnacle West Capital Corp	PNW	$2.38	$61.85	4.89%	4.84%	4.78%	4.72%	4.66%	4.61%	4.55%	8.83%
Westar Energy Inc.	WR	$1.44	$35.72	4.49%	4.50%	4.51%	4.52%	4.53%	4.54%	4.55%	8.92%
MEAN				5.28%	5.14%	4.99%	4.85%	4.70%	4.56%	4.41%	8.74%
Flotation Costs											0.50%
											9.24%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of August 31, 2015
[3] Source: Constant Growth DCF
[4] Equals [3] − ([3] − [9]) / 6
[5] Equals [4] − ([3] − [9]) / 6
[6] Equals [5] − ([3] − [9]) / 6
[7] Equals [6] − ([3] − [9]) / 6
[8] Equals [7] − ([3] − [9]) / 6
[9] Consensus Economics Inc., Consensus Forecasts, April 13, 2015, at 3 and 28.
[10] Internal rate of return

Market DCF Calculation as of August 31, 2015

	[1] Dividend Yield	[2] Dividend Yield x (1 + 0.50g)	[3] Expected Growth Rate (g)	[4] Secondary Market Investor Required Return	[13] Forecast Canadian Government Bond 30 Year	[14] Equity Risk Premium
S&P/TSX UTILITIES INDEX	**3.28%**	**3.44%**	**10.02%**	**13.46%**	3.68%	9.78%

Company	Ticker	[5] Shares Outstanding (million)	[6] Price	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] BEst Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Long-Term Growth Estimate
Sun Life Financial Inc	SLF	612.078	41.700	25,524	1.8010%	3.65%	8.50%	0.0656%	0.1531%
Enghouse Systems Ltd	ESL	26.285	48.690	1,280	0.0000%	0.99%	n/a	0.0000%	n/a
H&R Real Estate Investment Trust	HR-U	276.087	22.440	6,195	0.0000%	6.02%	n/a	0.0000%	n/a
West Fraser Timber Co Ltd	WFT	81.248	68.630	5,576	0.0000%	0.41%	n/a	0.0000%	n/a
Brookfield Asset Management Inc	BAM/A	980.619	43.640	42,794	3.0197%	1.37%	13.00%	0.0415%	0.3926%
Enbridge Income Fund Holdings Inc	ENF	70.351	34.530	2,429	0.0000%	4.47%	n/a	0.0000%	n/a
Saputo Inc	SAP	392.510	30.210	11,858	0.8367%	1.72%	6.67%	0.0144%	0.0558%
Pembina Pipeline Corp	PPL	332.338	40.370	13,416	0.9467%	4.53%	6.60%	0.0429%	0.0625%
Secure Energy Services Inc	SES	136.107	12.780	1,739	0.0000%	1.88%	n/a	0.0000%	n/a
Ritchie Bros Auctioneers Inc	RBA	106.045	34.850	3,696	0.2608%	2.01%	13.22%	0.0052%	0.0345%
Seven Generations Energy Ltd	VII	245.153	16.320	4,001	0.0000%	n/a	n/a	n/a	n/a
Performance Sports Group Ltd	PSG	45.526	22.480	1,023	0.0000%	n/a	13.69%	n/a	0.0000%
Gildan Activewear Inc	GIL	242.394	41.490	10,057	0.7097%	0.77%	17.15%	0.0055%	0.1217%
Descartes Systems Group Inc/The	DSG	75.495	20.050	1,514	0.0000%	n/a	15.00%	n/a	0.0000%
Industrial Alliance Insurance & Financial Servi	IAG	101.174	42.010	4,250	0.2999%	2.67%	3.40%	0.0080%	0.0102%
Innergex Renewable Energy Inc	INE	101.269	10.620	1,075	0.0000%	5.84%	n/a	0.0000%	n/a
Manulife Financial Corp	MFC	1,970.270	23.210	45,730	3.2269%	2.93%	7.10%	0.0945%	0.2291%
Element Financial Corp	EFN	264.204	19.750	5,218	0.0000%	n/a	n/a	n/a	n/a
FirstService Corp	FSV	34.645	34.720	1,203	0.0849%	1.42%	15.00%	0.0012%	0.0127%
Canadian Pacific Railway Ltd	CP	164.062	200.020	32,816	2.3156%	0.70%	15.30%	0.0162%	0.3544%
Husky Energy Inc	HSE	983.840	23.890	23,504	1.6585%	5.02%	17.30%	0.0833%	0.2869%
Bonavista Energy Corp	BNP	206.603	6.790	1,403	0.0000%	6.19%	n/a	0.0000%	n/a
Baytex Energy Corp	BTE	205.599	19.430	3,995	0.2819%	6.18%	-101.42%	0.0174%	-0.2859%
Crescent Point Energy Corp	CPG	452.279	25.630	11,592	0.8180%	10.77%	-14.60%	0.0881%	-0.1194%
Centerra Gold Inc	CG	236.475	7.100	1,679	0.1185%	2.25%	0.50%	0.0027%	0.0006%
Newalta Corp	NAL	56.237	14.220	800	0.0000%	3.52%	n/a	0.0000%	n/a
Alaris Royalty Corp	AD	31.996	30.490	976	0.0000%	5.31%	n/a	0.0000%	n/a
Intact Financial Corp	IFC	131.543	86.790	11,417	0.0000%	2.44%	n/a	0.0000%	n/a
George Weston Ltd	WN	127.919	98.110	12,550	0.8856%	1.73%	36.10%	0.0153%	0.3197%
MEG Energy Corp	MEG	223.847	20.400	4,566	0.0000%	n/a	n/a	n/a	n/a
DREAM Unlimited Corp	DRM	75.993	9.690	736	0.0000%	n/a	n/a	n/a	n/a
PrairieSky Royalty Ltd	PSK	149.409	31.510	4,708	0.0000%	4.13%	n/a	0.0000%	n/a
Cameco Corp	CCO	395.793	17.870	7,073	0.4991%	2.24%	40.91%	0.0112%	0.2042%
Turquoise Hill Resources Ltd	TRQ	2,012.309	4.750	9,558	0.0000%	n/a	n/a	n/a	n/a
Canfor Corp	CFP	134.155	27.200	3,649	0.0000%	n/a	n/a	n/a	n/a
ProMetic Life Sciences Inc	PLI	574.974	2.350	1,351	0.0000%	n/a	n/a	n/a	n/a
Interfor Corp	IFP	70.030	20.490	1,435	0.0000%	n/a	n/a	n/a	n/a
Cott Corp	BCB	109.375	12.210	1,335	0.0000%	2.45%	n/a	0.0000%	n/a
Franco-Nevada Corp	FNV	156.480	59.570	9,322	0.6578%	1.74%	5.00%	0.0114%	0.0329%
Cenovus Energy Inc	CVE	828.436	19.970	16,544	1.1674%	5.33%	20.40%	0.0622%	0.2381%
AutoCanada Inc	ACQ	24.510	41.300	1,012	0.0000%	2.42%	n/a	0.0000%	n/a
Athabasca Oil Corp	ATH	402.944	2.040	822	0.0000%	n/a	n/a	n/a	n/a
Pretium Resources Inc	PVG	133.422	6.760	902	0.0000%	n/a	n/a	n/a	n/a
Empire Co Ltd	EMP/A	58.049	87.970	5,107	0.3603%	1.36%	7.00%	0.0049%	0.0252%
Loblaw Cos Ltd	L	412.628	63.080	26,029	1.8367%	1.59%	14.28%	0.0291%	0.2623%
Metro Inc	MRU	248.891	33.520	8,343	0.5887%	1.39%	11.10%	0.0082%	0.0653%
Tourmaline Oil Corp	TOU	216.063	37.520	8,107	0.0000%	n/a	n/a	n/a	n/a
Bank of Montreal	BMO	644.256	74.010	47,681	3.3646%	4.43%	4.40%	0.1491%	0.1480%
Bank of Nova Scotia/The	BNS	1,209.962	64.470	78,006	5.5044%	4.22%	5.73%	0.2322%	0.3156%
Canadian Imperial Bank of Commerce/Canc	CM	397.276	92.070	36,577	2.5810%	4.74%	8.80%	0.1222%	0.2271%
Canadian Western Bank	CWB	80.451	28.770	2,315	0.0000%	3.06%	n/a	0.0000%	n/a
Laurentian Bank of Canada	LB	28.945	48.140	1,393	0.0000%	4.65%	n/a	0.0000%	n/a
Concordia Healthcare Corp	CXR	33.265	90.250	3,002	0.0000%	0.42%	n/a	0.0000%	n/a
National Bank of Canada	NA	329.390	46.920	15,455	1.0906%	4.43%	8.30%	0.0483%	0.0905%
Toronto-Dominion Bank/The	TD	1,851.851	53.040	98,222	6.9309%	3.85%	12.00%	0.2666%	0.8317%
Amaya Inc	AYA	133.384	34.220	4,564	0.0000%	n/a	n/a	n/a	n/a
Osisko Gold Royalties Ltd	OR	94.142	15.720	1,480	0.1044%	0.76%	50.00%	0.0008%	0.0522%
Sherritt International Corp	S	297.300	2.090	621	0.0000%	1.91%	n/a	0.0000%	n/a
TORC Oil & Gas Ltd	TOG	156.916	8.700	1,365	0.0963%	6.21%	26.00%	0.0060%	0.0250%
TMX Group Ltd	X	54.172	53.150	2,879	0.0000%	3.01%	n/a	0.0000%	n/a
Ensign Energy Services Inc	ESI	153.060	12.240	1,873	0.0000%	3.92%	n/a	0.0000%	n/a
Parex Resources Inc	PXT	149.828	10.470	1,569	0.0000%	n/a	n/a	n/a	n/a
Trican Well Service Ltd	TCW	148.918	4.150	618	0.0000%	n/a	10.05%	n/a	0.0000%
Aimia Inc	AIM	164.724	13.600	2,240	0.0000%	5.59%	n/a	0.0000%	n/a
Pure Industrial Real Estate Trust	AAR-U	189.411	4.710	892	0.0000%	6.62%	n/a	0.0000%	n/a
Computer Modelling Group Ltd	CMG	78.543	12.660	994	0.0702%	3.16%	32.70%	0.0022%	0.0229%
Genworth MI Canada Inc	MIC	93.172	32.800	3,056	0.0000%	4.76%	n/a	0.0000%	n/a
Chemtrade Logistics Income Fund	CHE-U	68.275	20.300	1,386	0.0000%	5.91%	n/a	0.0000%	n/a

Market DCF Calculation as of August 31, 2015

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast Canadian Government Bond 30 Year	Equity Risk Premium
S&P/TSX UTILITIES INDEX	**3.28%**	**3.44%**	**10.02%**	**13.46%**	3.68%	9.78%

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Manitoba Telecom Services Inc	MBT	78.935	27.910	2,203	0.1555%	4.66%	0.70%	0.0072%	0.0011%
Methanex Corp	MX	91.085	69.720	6,350	0.0000%	1.94%	n/a	0.0000%	n/a
Restaurant Brands International Inc	QSR	202.304	47.870	9,684	0.6834%	1.04%	18.52%	0.0071%	0.1265%
Constellation Software Inc/Canada	CSU	21.192	495.860	10,508	0.0000%	0.99%	n/a	0.0000%	n/a
Suncor Energy Inc	SU	1,445.656	34.400	49,731	3.5092%	3.26%	16.90%	0.1143%	0.5930%
Parkland Fuel Corp	PKI	89.708	24.880	2,232	0.0000%	4.34%	n/a	0.0000%	n/a
Lundin Mining Corp	LUN	719.326	5.130	3,690	0.0000%	n/a	22.58%	n/a	0.0000%
Novagold Resources Inc	NG	317.862	4.290	1,364	0.0000%	n/a	n/a	n/a	n/a
Kelt Exploration Ltd	KEL	158.424	8.440	1,337	0.0000%	n/a	n/a	n/a	n/a
Aecon Group Inc	ARE	56.448	12.750	720	0.0508%	3.14%	-4.00%	0.0016%	-0.0020%
Atco Ltd/Canada	ACO/X	101.502	39.490	4,008	0.0000%	2.51%	n/a	0.0000%	n/a
Intertain Group Ltd/The	IT	72.353	17.230	1,247	0.0000%	n/a	n/a	n/a	n/a
TransForce Inc	TFI	101.212	25.330	2,564	0.0000%	2.68%	n/a	0.0000%	n/a
Bonterra Energy Corp	BNE	32.170	31.490	1,013	0.0000%	5.72%	n/a	0.0000%	n/a
Calfrac Well Services Ltd	CFW	95.868	7.710	739	0.0000%	3.24%	n/a	0.0000%	n/a
Dorel Industries Inc	DII/B	28.127	33.410	940	0.0663%	4.39%	10.00%	0.0029%	0.0066%
Royal Bank of Canada	RY	1,443.102	76.380	110,224	7.7778%	4.03%	9.05%	0.3136%	0.7039%
Crombie Real Estate Investment Trust	CRR-U	77.248	12.470	963	0.0000%	7.14%	n/a	0.0000%	n/a
Russel Metals Inc	RUS	61.702	22.730	1,402	0.0990%	6.69%	4.50%	0.0066%	0.0045%
Stantec Inc	STN	93.976	36.500	3,430	0.2420%	1.15%	18.00%	0.0028%	0.0436%
Transcontinental Inc	TCL/A	63.246	15.390	973	0.0687%	4.42%	-2.00%	0.0030%	-0.0014%
Bankers Petroleum Ltd	BNK	261.394	3.100	810	0.0000%	n/a	n/a	n/a	n/a
Home Capital Group Inc	HCG	70.226	43.280	3,039	0.0000%	2.03%	n/a	0.0000%	n/a
Gran Tierra Energy Inc	GTE	277.211	3.740	1,037	0.0000%	n/a	n/a	n/a	n/a
Fortuna Silver Mines Inc	FVI	128.846	4.550	586	0.0000%	n/a	n/a	n/a	n/a
Hudson's Bay Co	HBC	182.100	27.750	5,053	0.3566%	0.72%	14.64%	0.0026%	0.0522%
Painted Pony Petroleum Ltd	PPY	99.651	7.960	793	0.0000%	n/a	n/a	n/a	n/a
Linamar Corp	LNR	65.112	81.120	5,282	0.0000%	0.49%	n/a	0.0000%	n/a
Nevsun Resources Ltd	NSU	199.658	4.700	938	0.0000%	4.20%	n/a	0.0000%	n/a
North West Co Inc/The	NWC	48.499	24.760	1,201	0.0000%	4.69%	n/a	0.0000%	n/a
Celestica Inc	CLS	150.238	14.540	2,184	0.0000%	n/a	n/a	n/a	n/a
SEMAFO Inc	SMF	294.086	3.360	988	0.0000%	n/a	-10.00%	n/a	0.0000%
ShawCor Ltd	SCL	64.499	36.590	2,360	0.0000%	1.64%	n/a	0.0000%	n/a
RONA Inc	RON	108.037	15.180	1,640	0.1157%	0.92%	0.38%	0.0011%	0.0004%
Silver Standard Resources Inc	SSO	80.754	7.850	634	0.0000%	n/a	3.00%	n/a	0.0000%
BlackBerry Ltd	BB	529.431	10.210	5,405	0.0000%	n/a	-17.60%	n/a	0.0000%
Granite Real Estate Investment Trust	GRT-U	47.014	42.960	2,020	0.0000%	5.36%	n/a	0.0000%	n/a
Toromont Industries Ltd	TIH	77.577	31.240	2,424	0.1710%	2.18%	7.26%	0.0037%	0.0124%
First Majestic Silver Corp	FR	122.215	6.050	739	0.0000%	n/a	n/a	n/a	n/a
Advantage Oil & Gas Ltd	AAV	170.666	7.900	1,348	0.0000%	n/a	n/a	n/a	n/a
Colliers International Group Inc	CIG	36.643	47.800	1,752	0.1236%	1.05%	20.00%	0.0013%	0.0247%
Dominion Diamond Corp	DDC	85.206	17.500	1,491	0.0000%	2.75%	n/a	0.0000%	n/a
Cogeco Cable Inc	CCA	33.532	72.240	2,422	0.1709%	1.94%	13.37%	0.0033%	0.0229%
Canadian Real Estate Investment Trust	REF-U	71.964	42.450	3,055	0.0000%	4.24%	n/a	0.0000%	n/a
First Capital Realty Inc	FCR	222.046	17.880	3,970	0.0000%	4.81%	n/a	0.0000%	n/a
First Quantum Minerals Ltd	FM	688.967	16.330	11,251	0.7939%	0.60%	52.31%	0.0047%	0.4153%
Pason Systems Inc	PSI	83.609	22.350	1,869	0.0000%	3.04%	n/a	0.0000%	n/a
Rogers Communications Inc	RCI/B	402.304	44.300	17,822	1.2576%	4.33%	3.67%	0.0545%	0.0462%
Jean Coutu Group PJC Inc/The	PJC/A	83.566	23.200	1,939	0.1368%	1.90%	6.40%	0.0026%	0.0088%
Major Drilling Group International Inc	MDI	80.137	6.250	501	0.0000%	0.64%	n/a	0.0000%	n/a
Mullen Group Ltd	MTL	91.654	20.410	1,871	0.0000%	5.88%	n/a	0.0000%	n/a
Maple Leaf Foods Inc	MFI	142.956	23.690	3,387	0.0000%	1.35%	n/a	0.0000%	n/a
HudBay Minerals Inc	HBM	235.054	10.400	2,445	0.1725%	0.19%	43.00%	0.0003%	0.0742%
Labrador Iron Ore Royalty Corp	LIF	64.000	14.260	913	0.0644%	7.01%	15.20%	0.0045%	0.0098%
Dream Office Real Estate Investment Trust	D-U	108.123	24.540	2,653	0.0000%	9.13%	n/a	0.0000%	n/a
CCL Industries Inc	CCL/B	32.436	153.200	4,969	0.0000%	0.98%	n/a	0.0000%	n/a
Extendicare Inc	EXE	87.530	7.570	663	0.0000%	6.34%	n/a	0.0000%	n/a
Superior Plus Corp	SPB	126.185	12.560	1,585	0.0000%	5.73%	n/a	0.0000%	n/a
Freehold Royalties Ltd	FRU	97.990	16.140	1,582	0.0000%	6.69%	n/a	0.0000%	n/a
Encana Corp	ECA	840.818	13.770	11,578	0.8170%	2.51%	-9.50%	0.0205%	-0.0776%
Westshore Terminals Investment Corp	WTE	74.250	30.410	2,258	0.0000%	4.34%	n/a	0.0000%	n/a
Northland Power Inc	NPI	167.951	15.820	2,657	0.0000%	6.83%	n/a	0.0000%	n/a
Canadian Apartment Properties REIT	CAR-U	116.433	27.600	3,214	0.0000%	4.42%	n/a	0.0000%	n/a
Inter Pipeline Ltd	IPL	334.580	28.700	9,602	0.0000%	5.12%	n/a	0.0000%	n/a
Peyto Exploration & Development Corp	PEY	158.958	30.530	4,853	0.0000%	4.32%	n/a	0.0000%	n/a
Avigilon Corp	AVO	46.638	16.840	785	0.0000%	n/a	n/a	n/a	n/a
Algonquin Power & Utilities Corp	AQN	238.132	9.360	2,229	0.0000%	5.08%	n/a	0.0000%	n/a
Veresen Inc	VSN	289.167	16.890	4,884	0.0000%	5.92%	n/a	0.0000%	n/a

Market DCF Calculation as of August 31, 2015

	[1] Dividend Yield	[2] Dividend Yield x (1 + 0.50g)	[3] Expected Growth Rate (g)	[4] Secondary Market Investor Required Return	[13] Forecast Canadian Government Bond 30 Year	[14] Equity Risk Premium
S&P/TSX UTILITIES INDEX	**3.28%**	**3.44%**	**10.02%**	**13.46%**	3.68%	9.78%

Company	Ticker	[5] Shares Outstanding (million)	[6] Price	[7] Market Capitalizatio n ($million)	[8] Percent of Total Market Capitalizatio n	[9] Current Dividend Yield	[10] BEst Long-Term Growth Estimate	[11] Market Capitalizatio n-Weighted Dividend Yield	[12] Market Capitalizatio n-Weighted Long-Term Growth Estimate
Dream Global Real Estate Investment Trust	DRG-U	109.015	9.930	1,083	0.0000%	8.06%	n/a	0.0000%	n/a
Smart Real Estate Investment Trust	SRU-U	124.504	28.920	3,601	0.0000%	5.54%	n/a	0.0000%	n/a
Alacer Gold Corp	ASR	290.918	2.930	852	0.0000%	n/a	-0.18%	n/a	0.0000%
Pan American Silver Corp	PAA	151.643	10.740	1,629	0.1149%	2.27%	4.00%	0.0026%	0.0046%
AltaGas Ltd	ALA	134.833	38.040	5,129	0.0000%	5.05%	n/a	0.0000%	n/a
Cominar Real Estate Investment Trust	CUF-U	167.877	17.730	2,976	0.0000%	8.29%	n/a	0.0000%	n/a
DH Corp	DH	105.568	39.920	4,214	0.0000%	3.21%	n/a	0.0000%	n/a
WestJet Airlines Ltd	WJA	107.674	26.360	2,838	0.2003%	2.12%	12.98%	0.0043%	0.0260%
Corus Entertainment Inc	CJR/B	83.343	16.670	1,389	0.0000%	6.84%	n/a	0.0000%	n/a
Emera Inc	EMA	142.101	39.340	5,590	0.0000%	4.07%	n/a	0.0000%	n/a
Birchcliff Energy Ltd	BIR	152.290	6.970	1,061	0.0000%	n/a	n/a	n/a	n/a
MacDonald Dettwiler & Associates Ltd	MDA	36.133	91.270	3,298	0.0000%	1.62%	n/a	0.0000%	n/a
Torex Gold Resources Inc	TXG	785.372	1.130	887	0.0000%	n/a	n/a	n/a	n/a
Trinidad Drilling Ltd	TDG	133.425	4.040	539	0.0000%	4.95%	n/a	0.0000%	n/a
Just Energy Group Inc	JE	146.559	6.510	954	0.0000%	7.68%	n/a	0.0000%	n/a
Progressive Waste Solutions Ltd	BIN	115.180	33.500	3,859	0.2723%	1.91%	9.40%	0.0052%	0.0256%
Northern Property Real Estate Investment Trust	NPR-U	31.822	22.380	712	0.0000%	7.28%	n/a	0.0000%	n/a
Allied Properties Real Estate Investment Trust	AP-U	77.283	35.440	2,739	0.0000%	4.12%	n/a	0.0000%	n/a
Keyera Corp	KEY	168.832	41.700	7,040	0.0000%	3.31%	n/a	0.0000%	n/a
Power Financial Corp	PWF	711.174	35.870	25,510	1.8001%	4.15%	12.60%	0.0748%	0.2268%
NuVista Energy Ltd	NVA	152.992	6.690	1,024	0.0000%	n/a	n/a	n/a	n/a
Canadian Energy Services & Technology Corp	CEU	217.007	7.200	1,562	0.0000%	4.58%	n/a	0.0000%	n/a
Barrick Gold Corp	ABX	1,164.670	13.350	15,548	1.0971%	1.87%	-1.93%	0.0205%	-0.0212%
Crew Energy Inc	CR	140.984	5.710	805	0.0000%	n/a	n/a	n/a	n/a
Cineplex Inc	CGX	63.067	47.020	2,965	0.0000%	3.32%	n/a	0.0000%	n/a
BCE Inc	BCE	847.646	53.060	44,976	3.1737%	4.90%	5.07%	0.1555%	0.1609%
Chartwell Retirement Residences	CSH-U	174.165	11.480	1,999	0.0000%	4.80%	n/a	0.0000%	n/a
Trilogy Energy Corp	TET	105.240	5.650	595	0.0000%	n/a	n/a	n/a	n/a
Black Diamond Group Ltd	BDI	41.086	17.510	719	0.0000%	5.48%	n/a	0.0000%	n/a
Surge Energy Inc	SGY	220.060	3.540	779	0.0000%	8.47%	n/a	0.0000%	n/a
Artis Real Estate Investment Trust	AX-U	134.866	13.710	1,849	0.0000%	7.88%	n/a	0.0000%	n/a
Potash Corp of Saskatchewan Inc	POT	834.228	38.680	32,268	2.2769%	5.01%	6.00%	0.1141%	0.1366%
Detour Gold Corp	DGC	170.563	14.370	2,451	0.0000%	n/a	7.00%	n/a	0.0000%
TransCanada Corp	TRP	708.941	50.760	35,986	0.0000%	4.10%	n/a	0.0000%	n/a
OceanaGold Corp	OGC	303.255	3.090	937	0.0661%	1.62%	-3.00%	0.0011%	-0.0020%
Enerflex Ltd	EFX	78.999	13.500	1,066	0.0000%	2.52%	n/a	0.0000%	n/a
B2Gold Corp	BTO	921.483	1.910	1,760	0.0000%	n/a	51.43%	n/a	0.0000%
Valeant Pharmaceuticals International Inc	VRX	340.859	277.070	94,442	0.0000%	n/a	16.10%	n/a	0.0000%
Dollarama Inc	DOL	129.356	75.700	9,792	0.6910%	0.48%	16.78%	0.0033%	0.1159%
Capital Power Corp	CPX	103.219	21.540	2,223	0.0000%	6.31%	n/a	0.0000%	n/a
Eldorado Gold Corp	ELD	716.587	5.180	3,712	0.2619%	0.39%	13.90%	0.0010%	0.0364%
Onex Corp	OCX	111.049	69.110	7,675	0.0000%	0.36%	n/a	0.0000%	n/a
Tahoe Resources Inc	THO	224.000	15.140	3,391	0.2393%	1.96%	4.77%	0.0047%	0.0114%
Imperial Oil Ltd	IMO	847.599	48.250	40,897	0.0000%	1.08%	n/a	0.0000%	n/a
Air Canada	AC	286.835	13.210	3,789	0.0000%	n/a	40.13%	n/a	0.0000%
ATS Automation Tooling Systems Inc	ATA	91.630	15.290	1,401	0.0000%	n/a	n/a	n/a	n/a
Brookfield Renewable Energy Partners LP/CA	BEP-U	143.401	37.140	5,326	0.0000%	5.58%	n/a	0.0000%	n/a
Alimentation Couche-Tard Inc	ATD/B	419.263	53.430	22,401	1.5807%	0.34%	17.98%	0.0053%	0.2841%
Pacific Exploration and Production Corp	PRE	316.095	4.710	1,489	0.0000%	n/a	n/a	n/a	n/a
Brookfield Property Partners LP	BPY-U	255.863	27.620	7,067	0.0000%	4.79%	n/a	0.0000%	n/a
Agnico Eagle Mines Ltd	AEM	216.202	35.460	7,667	0.5410%	1.12%	4.40%	0.0061%	0.0238%
Bombardier Inc	BBD/B	1,932.014	2.250	4,347	0.0000%	n/a	6.44%	n/a	0.0000%
TELUS Corp	T	605.501	43.030	26,055	1.8385%	3.90%	8.00%	0.0718%	0.1471%
Penn West Petroleum Ltd	PWT	502.163	2.150	1,080	0.0000%	1.86%	n/a	0.0000%	n/a
CAE Inc	CAE	267.181	14.870	3,973	0.2803%	1.88%	10.85%	0.0053%	0.0304%
Canadian Natural Resources Ltd	CNQ	1,094.180	33.900	37,093	2.6174%	2.71%	9.20%	0.0710%	0.2408%
DHX Media Ltd	DHX/B	79.885	9.340	746	0.0000%	0.60%	n/a	0.0000%	n/a
Canadian Tire Corp Ltd	CTC/A	73.603	133.580	9,832	0.6938%	1.57%	8.41%	0.0109%	0.0583%
Primero Mining Corp	P	162.264	4.870	790	0.0000%	n/a	48.78%	n/a	0.0000%
Canadian Utilities Ltd	CU	189.373	35.970	6,812	0.0000%	3.28%	n/a	0.0000%	n/a
Western Forest Products Inc	WEF	395.065	2.230	881	0.0000%	3.59%	n/a	0.0000%	n/a
CGI Group Inc	GIB/A	281.744	48.850	13,763	0.0000%	n/a	11.55%	n/a	0.0000%
EnerCare Inc	ECI	91.941	13.300	1,223	0.0000%	6.32%	n/a	0.0000%	n/a
New Gold Inc	NGD	509.083	3.350	1,705	0.0000%	n/a	3.50%	n/a	0.0000%
Fairfax Financial Holdings Ltd	FFH	22.016	615.880	13,559	0.0000%	1.95%	n/a	0.0000%	n/a

Market DCF Calculation as of August 31, 2015

	[1] Dividend Yield	[2] Dividend Yield x (1 + 0.50g)	[3] Expected Growth Rate (g)	[4] Secondary Market Investor Required Return	[13] Forecast Canadian Government Bond 30 Year	[14] Equity Risk Premium
S&P/TSX UTILITIES INDEX	**3.28%**	**3.44%**	**10.02%**	**13.46%**	3.68%	9.78%

Company	Ticker	[5] Shares Outstanding (million)	[6] Price	[7] Market Capitalizatio n ($million)	[8] Percent of Total Market Capitalizatio n	[9] Current Dividend Yield	[10] BEst Long-Term Growth Estimate	[11] Market Capitalizatio n-Weighted Dividend Yield	[12] Market Capitalizatio n-Weighted Long-Term Growth Estimate
Finning International Inc	FTT	172.374	23.490	4,049	0.2857%	3.11%	10.00%	0.0089%	0.0286%
Badger Daylighting Ltd	BAD	37.046	26.190	970	0.0000%	1.37%	n/a	0.0000%	n/a
Canaccord Genuity Group Inc	CF	102.621	7.780	798	0.0000%	2.57%	n/a	0.0000%	n/a
Fortis Inc/Canada	FTS	277.493	35.080	9,734	0.0000%	3.88%	n/a	0.0000%	n/a
Goldcorp Inc	G	829.793	20.270	16,820	1.1869%	3.65%	14.20%	0.0433%	0.1685%
Great-West Lifeco Inc	GWO	996.699	36.360	36,240	2.5572%	3.59%	10.00%	0.0917%	0.2557%
BRP Inc/CA	DOO	39.215	29.190	1,145	0.0000%	n/a	10.00%	n/a	0.0000%
Enbridge Inc	ENB	856.713	58.410	50,041	3.5310%	3.18%	5.50%	0.1124%	0.1942%
IGM Financial Inc	IGM	249.490	39.780	9,925	0.7003%	5.66%	5.30%	0.0396%	0.0371%
Magna International Inc	MG	410.776	70.100	28,795	2.0319%	1.57%	10.18%	0.0319%	0.2068%
Great Canadian Gaming Corp	GC	69.782	24.010	1,675	0.0000%	n/a	n/a	n/a	n/a
Precision Drilling Corp	PD	292.823	8.400	2,460	0.1736%	3.33%	-27.28%	0.0058%	-0.0473%
Paramount Resources Ltd	POU	106.188	28.700	3,048	0.0000%	n/a	-5.00%	n/a	0.0000%
Shaw Communications Inc	SJR/B	448.986	27.200	12,212	0.8618%	4.36%	5.71%	0.0375%	0.0492%
SNC-Lavalin Group Inc	SNC	152.142	41.960	6,384	0.0000%	2.38%	n/a	0.0000%	n/a
Martinrea International Inc	MRE	85.756	13.350	1,145	0.0808%	0.90%	22.10%	0.0007%	0.0179%
Teck Resources Ltd	TCK/B	566.863	12.380	7,018	0.4952%	2.42%	23.49%	0.0120%	0.1163%
Boardwalk Real Estate Investment Trust	BEI-U	47.479	56.630	2,689	0.0000%	3.60%	n/a	0.0000%	n/a
Thomson Reuters Corp	TRI	784.473	47.560	37,310	2.6327%	3.44%	8.35%	0.0907%	0.2198%
Whitecap Resources Inc	WCP	298.023	13.180	3,928	0.0000%	5.69%	n/a	0.0000%	n/a
Agrium Inc	AGU	143.250	132.370	18,962	1.3380%	3.26%	20.90%	0.0437%	0.2796%
Norbord Inc	NBD	85.323	26.210	2,236	0.0000%	3.82%	n/a	0.0000%	n/a
Pengrowth Energy Corp	PGF	539.684	3.120	1,684	0.0000%	7.69%	n/a	0.0000%	n/a
Kinross Gold Corp	K	1,146.211	2.910	3,335	0.0000%	n/a	-4.80%	n/a	0.0000%
RioCan Real Estate Investment Trust	REI-U	317.127	26.770	8,489	0.0000%	5.27%	n/a	0.0000%	n/a
TransAlta Corp	TA	278.670	9.680	2,698	0.1903%	7.44%	31.60%	0.0142%	0.0601%
Bellatrix Exploration Ltd	BXE	191.957	2.910	559	0.0000%	n/a	n/a	n/a	n/a
Gibson Energy Inc	GEI	125.616	22.550	2,833	0.0000%	5.68%	n/a	0.0000%	n/a
Vermilion Energy Inc	VET	109.261	53.950	5,895	0.4159%	4.78%	3.14%	0.0199%	0.0131%
CI Financial Corp	CIX	283.439	33.600	9,524	0.6720%	3.93%	12.69%	0.0264%	0.0853%
Yamana Gold Inc	YRI	941.575	3.760	3,540	0.2498%	1.97%	9.70%	0.0049%	0.0242%
Silver Wheaton Corp	SLW	404.098	21.650	8,749	0.6173%	1.11%	14.50%	0.0069%	0.0895%
Mitel Networks Corp	MNW	119.915	11.080	1,329	0.0000%	n/a	15.00%	n/a	0.0000%
WSP Global Inc	WSP	89.632	39.310	3,523	0.0000%	3.82%	n/a	0.0000%	n/a
Quebecor Inc	QBR/B	83.900	31.220	2,619	0.1848%	0.45%	6.87%	0.0008%	0.0127%
Intertape Polymer Group Inc	ITP	59.587	18.720	1,115	0.0000%	3.16%	n/a	0.0000%	n/a
Power Corp of Canada	POW	412.437	31.940	13,173	0.0000%	3.90%	n/a	0.0000%	n/a
Alamos Gold Inc	AGI	n/a	n/a	n/a	0.0000%	n/a	33.00%	n/a	0.0000%
Open Text Corp	OTC	122.224	50.730	6,200	0.0000%	1.97%	n/a	0.0000%	n/a
Canadian National Railway Co	CNR	802.701	72.060	57,843	4.0816%	1.73%	11.30%	0.0708%	0.4612%
Canadian Oil Sands Ltd	COS	484.614	10.100	4,895	0.3454%	1.98%	5.37%	0.0068%	0.0185%
IAMGOLD Corp	IMG	391.336	2.500	978	0.0000%	n/a	0.50%	n/a	0.0000%
Sierra Wireless Inc	SW	32.134	31.030	997	0.0000%	n/a	n/a	n/a	n/a
ARC Resources Ltd	ARX	340.028	21.400	7,277	0.5135%	5.61%	3.60%	0.0288%	0.0185%
Enerplus Corp	ERF	206.215	10.960	2,260	0.1595%	5.47%	-19.62%	0.0087%	-0.0313%
Raging River Exploration Inc	RRX	197.666	8.730	1,726	0.0000%	n/a	n/a	n/a	n/a
Average for Companies Paying Dividends with Positive Long-Term Growth Estimates						**2.80%**	**13.15%**	**3.28%**	**10.02%**

Notes:
[1] Equals sum of Column [11]
[2] Equals Column [1] x (1 + 0.5 x Column [3])
[3] Equals sum of Column [12]
[4] Equals Column [2] + Column [3]
[5] Source: Bloomberg Finance L.P., as of September 2, 2015
[6] Source: Bloomberg Finance L.P., as of September 2, 2015
[7] Equals Column [5] x Column [6]
[8] Equals percent of sum of Column [7] if Current Dividend Yield does not equal "n/a" and Best Long-Term Growth Estimate does not equal "n/a" and is greater than (
[9] Source: Bloomberg Finance L.P., as of September 2, 2015
[10] Source: Bloomberg Finance L.P., as of September 2, 2015
[11] Equals Column [8] x Column [9]
[12] Equals Column [8] x Column [10]
[13] Source: April 2015 Consensus Forecast Average 2016-2018 Forecasts 10-Year bond yield plus Average Daily Spread between 10-year and 30-year government b
[14] Equals Column [4] - (Column [13]/100)

Market DCF Calculation as of August 31, 2015

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast US Government 30 Year Yield	Equity Risk Premium
S&P 500	**2.58%**	**2.71%**	**9.66%**	**12.37%**	4.29%	8.08%

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Alcoa Inc	AA	1,309.818	9.450	12,378	0.0804%	1.27%	5.00%	0.0010%	0.0040%
LyondellBasell Industries NV	LYB	465.875	85.380	39,776	0.2583%	3.65%	5.67%	0.0094%	0.0146%
American Express Co	AXP	1,001.283	76.720	76,818	0.4988%	1.51%	9.62%	0.0075%	0.0480%
Verizon Communications Inc	VZ	4,065.691	46.010	187,062	1.2146%	4.78%	7.42%	0.0581%	0.0902%
Avago Technologies Ltd	AVGO	259.730	125.970	32,718	0.2124%	1.27%	21.18%	0.0027%	0.0450%
Boeing Co/The	BA	679.495	130.680	88,796	0.5765%	2.79%	11.28%	0.0161%	0.0651%
Caterpillar Inc	CAT	602.633	76.440	46,065	0.2991%	4.03%	9.00%	0.0121%	0.0269%
JPMorgan Chase & Co	JPM	3,698.100	64.100	237,048	1.5391%	2.75%	6.70%	0.0423%	0.1031%
Chevron Corp	CVX	1,881.735	80.990	152,402	0.9895%	5.28%	-2.02%	0.0523%	-0.0200%
Coca-Cola Co/The	KO	4,350.004	39.320	171,042	1.1105%	3.36%	6.40%	0.0373%	0.0710%
AbbVie Inc	ABBV	1,655.276	62.410	103,306	0.6707%	3.27%	8.55%	0.0219%	0.0573%
Walt Disney Co/The	DIS	1,687.858	101.880	171,959	1.1165%	1.30%	11.43%	0.0145%	0.1276%
EI du Pont de Nemours & Co	DD	904.838	51.500	46,599	0.3026%	2.95%	3.40%	0.0089%	0.0103%
Exxon Mobil Corp	XOM	4,169.449	75.240	313,709	2.0368%	3.88%	11.36%	0.0790%	0.2313%
Phillips 66	PSX	537.660	79.070	42,513	0.2760%	2.83%	3.54%	0.0078%	0.0098%
General Electric Co	GE	10,096.429	24.820	250,593	1.6270%	3.71%	7.92%	0.0603%	0.1289%
Hewlett-Packard Co	HPQ	1,806.415	28.060	50,688	0.3291%	2.51%	4.01%	0.0083%	0.0132%
Home Depot Inc/The	HD	1,284.103	116.460	149,547	0.9710%	2.03%	13.64%	0.0197%	0.1324%
International Business Machines Corp	IBM	979.530	147.890	144,863	0.9406%	3.52%	6.65%	0.0331%	0.0625%
Johnson & Johnson	JNJ	2,769.106	93.980	260,241	1.6897%	3.19%	5.97%	0.0539%	0.1009%
McDonald's Corp	MCD	941.810	95.020	89,491	0.5810%	3.58%	7.89%	0.0208%	0.0459%
Merck & Co Inc	MRK	2,816.635	53.850	151,676	0.9848%	3.34%	6.33%	0.0329%	0.0624%
3M Co	MMM	624.745	142.140	88,801	0.5766%	2.88%	8.90%	0.0166%	0.0513%
Bank of America Corp	BAC	10,438.420	16.340	170,564	1.1074%	1.22%	6.65%	0.0136%	0.0736%
Pfizer Inc	PFE	6,167.348	32.220	198,712	1.2902%	3.48%	2.05%	0.0448%	0.0264%
Procter & Gamble Co/The	PG	2,713.146	70.670	191,738	1.2449%	3.75%	6.70%	0.0467%	0.0834%
AT&T Inc	T	6,151.000	33.200	204,213	1.3259%	5.66%	3.72%	0.0751%	0.0493%
Travelers Cos Inc/The	TRV	311.206	99.550	30,981	0.2011%	2.45%	8.62%	0.0049%	0.0173%
United Technologies Corp	UTX	890.598	91.610	81,588	0.5297%	2.79%	8.71%	0.0148%	0.0461%
Analog Devices Inc	ADI	313.675	55.860	17,522	0.1138%	2.86%	11.38%	0.0033%	0.0129%
Wal-Mart Stores Inc	WMT	3,220.549	64.730	208,466	1.3535%	3.03%	5.23%	0.0410%	0.0708%
Cisco Systems Inc	CSCO	5,085.889	25.880	131,623	0.8546%	3.25%	8.36%	0.0277%	0.0714%
Intel Corp	INTC	4,754.000	28.540	135,679	0.8809%	3.36%	7.99%	0.0296%	0.0704%
General Motors Co	GM	1,583.997	29.440	46,633	0.3028%	4.89%	11.86%	0.0148%	0.0359%
Microsoft Corp	MSFT	7,997.981	43.520	348,072	2.2599%	2.85%	10.47%	0.0644%	0.2366%
Dollar General Corp	DG	294.660	74.490	21,949	0.1425%	1.18%	11.85%	0.0017%	0.0169%
Kinder Morgan Inc/DE	KMI	2,191.937	32.410	71,041	0.4612%	6.05%	9.33%	0.0279%	0.0430%
Citigroup Inc	C	3,009.845	53.480	160,967	1.0451%	0.37%	20.61%	0.0039%	0.2154%
American International Group Inc	AIG	1,293.887	60.340	78,073	0.5069%	1.86%	9.04%	0.0094%	0.0458%
Honeywell International Inc	HON	781.762	99.270	77,606	0.5039%	2.09%	9.51%	0.0105%	0.0479%
Altria Group Inc	MO	1,960.695	53.580	105,054	0.6821%	4.22%	7.59%	0.0288%	0.0518%
HCA Holdings Inc	HCA	415.192	86.620	35,964	0.0000%	n/a	10.75%	n/a	0.0000%

Market DCF Calculation as of August 31, 2015

	[1] Dividend Yield	[2] Dividend Yield x (1 + 0.50g)	[3] Expected Growth Rate (g)	[4] Secondary Market Investor Required Return	[13] Forecast US Government 30 Year Yield	[14] Equity Risk Premium
S&P 500	**2.58%**	**2.71%**	**9.66%**	**12.37%**	4.29%	8.08%

Company	Ticker	[5] Shares Outstanding (million)	[6] Price	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] BEst Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Long-Term Growth Estimate
Under Armour Inc	UA	179.962	95.530	17,192	0.0000%	n/a	22.75%	n/a	0.0000%
International Paper Co	IP	417.741	43.140	18,021	0.1170%	3.71%	8.28%	0.0043%	0.0097%
Abbott Laboratories	ABT	1,490.441	45.290	67,502	0.4383%	2.12%	12.28%	0.0093%	0.0538%
Aflac Inc	AFL	430.694	58.600	25,239	0.1639%	2.66%	8.79%	0.0044%	0.0144%
Air Products & Chemicals Inc	APD	214.982	139.530	29,996	0.1948%	2.32%	9.10%	0.0045%	0.0177%
Airgas Inc	ARG	74.654	96.520	7,206	0.0468%	2.49%	9.08%	0.0012%	0.0042%
Royal Caribbean Cruises Ltd	RCL	219.944	88.160	19,390	0.1259%	1.36%	20.54%	0.0017%	0.0259%
American Electric Power Co Inc	AEP	490.560	54.290	26,633	0.1729%	3.91%	5.10%	0.0068%	0.0088%
Hess Corp	HES	287.058	59.450	17,066	0.1108%	1.68%	-3.78%	0.0019%	-0.0042%
Anadarko Petroleum Corp	APC	508.012	71.580	36,363	0.2361%	1.51%	8.33%	0.0036%	0.0197%
Aon PLC	AON	280.043	93.440	26,167	0.1699%	1.28%	11.04%	0.0022%	0.0188%
Apache Corp	APA	377.987	45.240	17,100	0.1110%	2.21%	8.50%	0.0025%	0.0094%
Archer-Daniels-Midland Co	ADM	608.940	44.990	27,396	0.1779%	2.49%	4.21%	0.0044%	0.0075%
AGL Resources Inc	GAS	120.088	60.990	7,324	0.0476%	3.34%	6.50%	0.0016%	0.0031%
Automatic Data Processing Inc	ADP	465.810	77.320	36,016	0.2338%	2.53%	10.40%	0.0059%	0.0243%
AutoZone Inc	AZO	30.872	715.990	22,104	0.0000%	n/a	13.79%	n/a	0.0000%
Avery Dennison Corp	AVY	91.438	58.080	5,311	0.0345%	2.55%	7.35%	0.0009%	0.0025%
Baker Hughes Inc	BHI	435.882	56.000	24,409	0.1585%	1.21%	8.15%	0.0019%	0.0129%
Ball Corp	BLL	137.328	65.910	9,051	0.0588%	0.79%	9.07%	0.0005%	0.0053%
Bank of New York Mellon Corp/The	BK	1,106.518	39.800	44,039	0.2859%	1.71%	12.10%	0.0049%	0.0346%
CR Bard Inc	BCR	74.199	193.790	14,379	0.0934%	0.50%	10.00%	0.0005%	0.0093%
Baxter International Inc	BAX	545.539	38.450	20,976	0.1362%	1.20%	5.62%	0.0016%	0.0076%
Becton Dickinson and Co	BDX	210.254	141.020	29,650	0.1925%	1.70%	11.09%	0.0033%	0.0213%
Berkshire Hathaway Inc	BRK/B	1,247.366	134.040	167,197	0.0000%	n/a	5.80%	n/a	0.0000%
Best Buy Co Inc	BBY	352.771	36.740	12,961	0.0842%	2.50%	10.69%	0.0021%	0.0090%
H&R Block Inc	HRB	276.285	34.020	9,399	0.0610%	2.35%	11.00%	0.0014%	0.0067%
Boston Scientific Corp	BSX	1,343.957	16.740	22,498	0.0000%	n/a	9.72%	n/a	0.0000%
Bristol-Myers Squibb Co	BMY	1,667.503	59.470	99,166	0.6439%	2.49%	13.58%	0.0160%	0.0875%
Brown-Forman Corp	BF/B	121.963	98.100	11,965	0.0777%	1.28%	8.80%	0.0010%	0.0068%
Cabot Oil & Gas Corp	COG	413.808	23.670	9,795	0.0636%	0.34%	42.75%	0.0002%	0.0272%
Campbell Soup Co	CPB	310.521	47.990	14,902	0.0968%	2.60%	3.64%	0.0025%	0.0035%
Kansas City Southern	KSU	110.360	92.740	10,235	0.0665%	1.42%	11.38%	0.0009%	0.0076%
Carnival Corp	CCL	593.457	49.230	29,216	0.1897%	2.44%	17.12%	0.0046%	0.0325%
Qorvo Inc	QRVO	149.531	55.510	8,300	0.0000%	n/a	16.84%	n/a	0.0000%
CenturyLink Inc	CTL	562.986	27.040	15,223	0.0988%	7.99%	-1.74%	0.0079%	-0.0017%
Chubb Corp/The	CB	226.977	120.810	27,421	0.1780%	1.89%	7.73%	0.0034%	0.0138%
Cigna Corp	CI	257.495	140.790	36,253	0.2354%	0.03%	11.36%	0.0001%	0.0267%
Frontier Communications Corp	FTR	1,168.207	5.070	5,923	0.0385%	8.28%	3.00%	0.0032%	0.0012%
Clorox Co/The	CLX	128.644	111.170	14,301	0.0929%	2.77%	7.05%	0.0026%	0.0065%
CMS Energy Corp	CMS	276.668	32.780	9,069	0.0589%	3.54%	6.03%	0.0021%	0.0036%
Coca-Cola Enterprises Inc	CCE	229.086	51.490	11,796	0.0766%	2.18%	6.19%	0.0017%	0.0047%
Colgate-Palmolive Co	CL	900.132	62.810	56,537	0.3671%	2.42%	8.41%	0.0089%	0.0309%
Comerica Inc	CMA	177.929	44.000	7,829	0.0508%	1.91%	9.41%	0.0010%	0.0048%
CA Inc	CA	441.305	27.290	12,043	0.0782%	3.66%	5.70%	0.0029%	0.0045%
Computer Sciences Corp	CSC	138.332	61.990	8,575	0.0557%	1.48%	9.30%	0.0008%	0.0052%
ConAgra Foods Inc	CAG	431.735	41.680	17,995	0.1168%	2.40%	-3.05%	0.0028%	-0.0036%
Consolidated Edison Inc	ED	292.872	62.910	18,425	0.1196%	4.13%	3.33%	0.0049%	0.0040%
SL Green Realty Corp	SLG	99.707	103.510	10,321	0.0670%	2.32%	5.78%	0.0016%	0.0039%
Corning Inc	GLW	1,225.935	17.210	21,098	0.1370%	2.79%	1.28%	0.0038%	0.0018%
CSX Corp	CSX	983.737	27.380	26,935	0.1749%	2.63%	9.53%	0.0046%	0.0167%
Cummins Inc	CMI	178.650	121.750	21,751	0.1412%	3.20%	9.99%	0.0045%	0.0141%
Danaher Corp	DHR	683.488	87.020	59,477	0.3862%	0.62%	12.73%	0.0024%	0.0491%

Market DCF Calculation as of August 31, 2015

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast US Government 30 Year Yield	Equity Risk Premium
S&P 500	**2.58%**	**2.71%**	**9.66%**	**12.37%**	4.29%	8.08%

Company	Ticker	[5] Shares Outstanding (million)	[6] Price	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] BEst Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Long-Term Growth Estimate
Target Corp	TGT	628.430	77.710	48,835	0.3171%	2.88%	9.25%	0.0091%	0.0293%
Deere & Co	DE	328.166	81.780	26,837	0.1742%	2.93%	5.27%	0.0051%	0.0092%
Dominion Resources Inc/VA	D	594.322	69.750	41,454	0.2692%	3.71%	6.40%	0.0100%	0.0172%
Dover Corp	DOV	156.465	61.950	9,693	0.0629%	2.71%	12.00%	0.0017%	0.0076%
Dow Chemical Co/The	DOW	1,158.102	43.760	50,679	0.3290%	3.84%	6.93%	0.0126%	0.0228%
Duke Energy Corp	DUK	688.330	70.910	48,809	0.3169%	4.65%	4.84%	0.0147%	0.0153%
Eaton Corp PLC	ETN	467.500	57.060	26,676	0.1732%	3.86%	8.51%	0.0067%	0.0147%
Ecolab Inc	ECL	295.092	109.140	32,206	0.2091%	1.21%	13.17%	0.0025%	0.0275%
PerkinElmer Inc	PKI	113.383	48.680	5,519	0.0358%	0.58%	8.54%	0.0002%	0.0031%
EMC Corp/MA	EMC	1,924.726	24.870	47,868	0.3108%	1.85%	10.66%	0.0057%	0.0331%
Emerson Electric Co	EMR	657.140	47.720	31,359	0.2036%	3.94%	5.83%	0.0080%	0.0119%
EOG Resources Inc	EOG	549.171	78.310	43,006	0.2792%	0.86%	-4.17%	0.0024%	-0.0116%
Entergy Corp	ETR	179.528	65.330	11,729	0.0762%	5.08%	4.73%	0.0039%	0.0036%
Equifax Inc	EFX	118.244	97.900	11,576	0.0752%	1.18%	12.67%	0.0009%	0.0095%
EQT Corp	EQT	152.404	77.820	11,860	0.0770%	0.15%	25.00%	0.0001%	0.0193%
XL Group PLC	XL	302.314	37.290	11,273	0.0732%	2.15%	9.50%	0.0016%	0.0070%
FedEx Corp	FDX	282.501	150.610	42,547	0.2763%	0.66%	14.80%	0.0018%	0.0409%
Macy's Inc	M	330.983	58.610	19,399	0.1260%	2.46%	8.78%	0.0031%	0.0111%
FMC Corp	FMC	133.615	42.310	5,653	0.0367%	1.56%	6.75%	0.0006%	0.0025%
Ford Motor Co	F	3,896.986	13.870	54,051	0.3509%	4.33%	15.44%	0.0152%	0.0542%
NextEra Energy Inc	NEE	452.104	98.410	44,492	0.2889%	3.13%	6.01%	0.0090%	0.0174%
Franklin Resources Inc	BEN	613.818	40.580	24,909	0.1617%	1.48%	8.87%	0.0024%	0.0143%
Freeport-McMoRan Inc	FCX	1,040.228	10.640	11,068	0.0719%	1.88%	-16.19%	0.0014%	-0.0116%
TEGNA Inc	TGNA	226.472	23.790	5,388	0.0350%	2.35%	4.08%	0.0008%	0.0014%
Gap Inc/The	GPS	417.355	32.810	13,693	0.0889%	2.80%	10.60%	0.0025%	0.0094%
General Dynamics Corp	GD	322.727	142.030	45,837	0.2976%	1.94%	10.64%	0.0058%	0.0317%
General Mills Inc	GIS	598.738	56.760	33,984	0.2207%	3.10%	7.25%	0.0068%	0.0160%
Genuine Parts Co	GPC	151.597	83.490	12,657	0.0822%	2.95%	9.17%	0.0024%	0.0075%
WW Grainger Inc	GWW	65.975	223.440	14,741	0.0957%	2.09%	11.87%	0.0020%	0.0114%
Halliburton Co	HAL	854.749	39.350	33,634	0.2184%	1.83%	12.60%	0.0040%	0.0275%
Harley-Davidson Inc	HOG	205.967	56.050	11,544	0.0750%	2.21%	11.33%	0.0017%	0.0085%
Harman International Industries Inc	HAR	71.172	97.740	6,956	0.0452%	1.43%	17.00%	0.0006%	0.0077%
Joy Global Inc	JOY	97.454	24.220	2,360	0.0153%	3.30%	13.60%	0.0005%	0.0021%
Harris Corp	HRS	123.592	76.820	9,494	0.0000%	2.60%	n/a	0.0000%	n/a
HCP Inc	HCP	462.587	37.060	17,143	0.1113%	6.10%	3.02%	0.0068%	0.0034%
Helmerich & Payne Inc	HP	107.751	59.010	6,358	0.0413%	4.66%	27.51%	0.0019%	0.0114%
Hershey Co/The	HSY	158.765	89.520	14,213	0.0923%	2.61%	8.20%	0.0024%	0.0076%
Hormel Foods Corp	HRL	264.275	61.100	16,147	0.1048%	1.64%	6.60%	0.0017%	0.0069%
Starwood Hotels & Resorts Worldwide Inc	HOT	170.379	71.470	12,177	0.0791%	2.10%	9.55%	0.0017%	0.0076%
Mondelez International Inc	MDLZ	1,611.307	42.360	68,255	0.4432%	1.61%	10.86%	0.0071%	0.0481%
CenterPoint Energy Inc	CNP	430.262	18.620	8,011	0.0520%	5.32%	4.25%	0.0028%	0.0022%
Humana Inc	HUM	148.215	182.790	27,092	0.1759%	0.63%	12.55%	0.0011%	0.0221%
Illinois Tool Works Inc	ITW	366.089	84.530	30,946	0.2009%	2.60%	9.08%	0.0052%	0.0182%
Ingersoll-Rand PLC	IR	265.353	55.290	14,671	0.0953%	2.10%	10.22%	0.0020%	0.0097%
Interpublic Group of Cos Inc/The	IPG	410.401	18.880	7,748	0.0503%	2.54%	3.90%	0.0013%	0.0020%
International Flavors & Fragrances Inc	IFF	80.586	109.550	8,828	0.0573%	2.04%	9.20%	0.0012%	0.0053%
Jacobs Engineering Group Inc	JEC	123.799	40.410	5,003	0.0000%	n/a	8.42%	n/a	0.0000%
Johnson Controls Inc	JCI	654.069	41.140	26,908	0.1747%	2.53%	10.50%	0.0044%	0.0183%
Hanesbrands Inc	HBI	402.477	30.110	12,119	0.0787%	1.33%	11.25%	0.0010%	0.0089%
Kellogg Co	K	353.581	66.280	23,435	0.1522%	3.02%	5.07%	0.0046%	0.0077%
Perrigo Co PLC	PRGO	146.279	182.970	26,765	0.1738%	0.27%	12.29%	0.0005%	0.0214%
Kimberly-Clark Corp	KMB	364.275	106.530	38,806	0.2520%	3.30%	7.68%	0.0083%	0.0193%

Market DCF Calculation as of August 31, 2015

	[1] Dividend Yield	[2] Dividend Yield x (1 + 0.50g)	[3] Expected Growth Rate (g)	[4] Secondary Market Investor Required Return	[13] Forecast US Government 30 Year Yield	[14] Equity Risk Premium
S&P 500	**2.58%**	**2.71%**	**9.66%**	**12.37%**	4.29%	8.08%

Company	Ticker	[5] Shares Outstanding (million)	[6] Price	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] BEst Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Long-Term Growth Estimate
Kimco Realty Corp	KIM	413.135	23.050	9,523	0.0618%	4.16%	4.69%	0.0026%	0.0029%
Kohl's Corp	KSS	197.876	51.030	10,098	0.0656%	3.53%	8.28%	0.0023%	0.0054%
Oracle Corp	ORCL	4,336.077	37.090	160,825	1.0442%	1.62%	7.89%	0.0169%	0.0824%
Kroger Co/The	KR	971.423	34.500	33,514	0.2176%	1.22%	10.42%	0.0026%	0.0227%
Legg Mason Inc	LM	109.708	44.330	4,863	0.0316%	1.80%	15.50%	0.0006%	0.0049%
Leggett & Platt Inc	LEG	136.829	44.420	6,078	0.0000%	2.88%	n/a	0.0000%	n/a
Lennar Corp	LEN	173.937	50.900	8,853	0.0575%	0.31%	20.20%	0.0002%	0.0116%
Leucadia National Corp	LUK	366.603	21.460	7,867	0.0000%	1.17%	n/a	0.0000%	n/a
Eli Lilly & Co	LLY	1,108.541	82.350	91,288	0.5927%	2.43%	10.45%	0.0144%	0.0619%
L Brands Inc	LB	291.964	83.900	24,496	0.1590%	2.38%	10.50%	0.0038%	0.0167%
Lincoln National Corp	LNC	250.952	50.790	12,746	0.0828%	1.58%	10.06%	0.0013%	0.0083%
Loews Corp	L	363.082	36.450	13,234	0.0000%	0.69%	n/a	0.0000%	n/a
Lowe's Cos Inc	LOW	932.686	69.170	64,514	0.4189%	1.62%	16.67%	0.0068%	0.0698%
Host Hotels & Resorts Inc	HST	751.123	17.730	13,317	0.0865%	4.51%	5.00%	0.0039%	0.0043%
Marsh & McLennan Cos Inc	MMC	529.993	53.730	28,477	0.1849%	2.31%	11.53%	0.0043%	0.0213%
Masco Corp	MAS	343.950	26.230	9,022	0.0586%	1.37%	15.39%	0.0008%	0.0090%
Mattel Inc	MAT	338.613	23.430	7,934	0.0515%	6.49%	9.65%	0.0033%	0.0050%
McGraw Hill Financial Inc	MHFI	272.500	96.990	26,430	0.1716%	1.36%	11.83%	0.0023%	0.0203%
Medtronic PLC	MDT	1,414.189	72.290	102,232	0.6638%	2.10%	9.10%	0.0140%	0.0604%
CVS Health Corp	CVS	1,114.486	102.400	114,123	0.7410%	1.37%	14.68%	0.0101%	0.1088%
Micron Technology Inc	MU	1,083.436	16.410	17,779	0.0000%	n/a	6.49%	n/a	0.0000%
Motorola Solutions Inc	MSI	206.777	64.820	13,403	0.0870%	2.10%	8.80%	0.0018%	0.0077%
Murphy Oil Corp	MUR	172.752	31.000	5,355	0.0348%	4.52%	13.00%	0.0016%	0.0045%
Mylan NV	MYL	491.554	49.590	24,376	0.0000%	n/a	11.00%	n/a	0.0000%
Laboratory Corp of America Holdings	LH	101.100	117.810	11,911	0.0000%	n/a	10.27%	n/a	0.0000%
Tenet Healthcare Corp	THC	99.564	49.230	4,902	0.0000%	n/a	12.33%	n/a	0.0000%
Newell Rubbermaid Inc	NWL	267.800	42.130	11,282	0.0733%	1.80%	9.52%	0.0013%	0.0070%
Newmont Mining Corp	NEM	529.055	17.070	9,031	0.0586%	0.59%	2.10%	0.0003%	0.0012%
Twenty-First Century Fox Inc	FOXA	1,220.940	27.390	33,442	0.2171%	1.10%	15.58%	0.0024%	0.0338%
NIKE Inc	NKE	677.926	111.750	75,758	0.4919%	1.00%	11.21%	0.0049%	0.0552%
NiSource Inc	NI	317.859	16.790	5,337	0.0347%	3.69%	-0.30%	0.0013%	-0.0001%
Noble Energy Inc	NBL	428.034	33.410	14,301	0.0929%	2.16%	3.53%	0.0020%	0.0033%
Norfolk Southern Corp	NSC	301.387	77.910	23,481	0.1525%	3.03%	9.37%	0.0046%	0.0143%
Eversource Energy	ES	317.173	47.240	14,983	0.0973%	3.54%	6.50%	0.0034%	0.0063%
Northrop Grumman Corp	NOC	187.393	163.740	30,684	0.1992%	1.95%	6.57%	0.0039%	0.0131%
Wells Fargo & Co	WFC	5,133.359	53.330	273,762	1.7775%	2.81%	11.71%	0.0500%	0.2081%
Nucor Corp	NUE	319.600	43.290	13,835	0.0898%	3.44%	12.43%	0.0031%	0.0112%
PVH Corp	PVH	82.692	118.980	9,839	0.0639%	0.13%	9.61%	0.0001%	0.0061%
Occidental Petroleum Corp	OXY	763.951	73.010	55,776	0.3621%	4.11%	7.00%	0.0149%	0.0253%
Omnicom Group Inc	OMC	242.948	66.980	16,273	0.1057%	2.99%	5.33%	0.0032%	0.0056%
ONEOK Inc	OKE	209.167	36.010	7,532	0.0489%	6.72%	9.63%	0.0033%	0.0047%
Owens-Illinois Inc	OI	160.768	20.850	3,352	0.0000%	n/a	2.37%	n/a	0.0000%
PG&E Corp	PCG	489.166	49.580	24,253	0.1575%	3.67%	6.00%	0.0058%	0.0094%
Parker-Hannifin Corp	PH	138.419	107.660	14,902	0.0968%	2.34%	8.95%	0.0023%	0.0087%
PPL Corp	PPL	669.970	30.990	20,762	0.1348%	4.87%	2.85%	0.0066%	0.0038%
PepsiCo Inc	PEP	1,468.993	92.930	136,514	0.8863%	3.02%	5.96%	0.0268%	0.0528%
Exelon Corp	EXC	861.618	30.760	26,503	0.1721%	4.03%	6.69%	0.0069%	0.0115%
ConocoPhillips	COP	1,233.459	49.150	60,625	0.3936%	6.02%	1.82%	0.0237%	0.0072%
PulteGroup Inc	PHM	352.790	20.690	7,299	0.0474%	1.55%	14.00%	0.0007%	0.0066%
Pinnacle West Capital Corp	PNW	110.814	59.530	6,597	0.0428%	4.00%	5.54%	0.0017%	0.0024%
Pitney Bowes Inc	PBI	201.919	19.810	4,000	0.0260%	3.79%	14.00%	0.0010%	0.0036%
Plum Creek Timber Co Inc	PCL	174.729	38.490	6,725	0.0437%	4.57%	11.45%	0.0020%	0.0050%

Market DCF Calculation as of August 31, 2015

	[1]	[2]	[3]	[4]	[13]	[14]
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S&P 500	**2.58%**	**2.71%**	**9.66%**	**12.37%**	4.29%	8.08%

Company	Ticker	[5] Shares Outstanding (million)	[6] Price	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] BEst Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Long-Term Growth Estimate
PNC Financial Services Group Inc/The	PNC	513.600	91.120	46,799	0.3039%	2.24%	7.80%	0.0068%	0.0237%
PPG Industries Inc	PPG	270.721	95.290	25,797	0.1675%	1.51%	7.10%	0.0025%	0.0119%
Praxair Inc	PX	286.472	105.750	30,294	0.1967%	2.70%	9.00%	0.0053%	0.0177%
Precision Castparts Corp	PCP	137.498	230.250	31,659	0.2056%	0.05%	10.56%	0.0001%	0.0217%
Progressive Corp/The	PGR	585.932	29.960	17,555	0.1140%	2.29%	7.92%	0.0026%	0.0090%
Public Service Enterprise Group Inc	PEG	505.875	40.250	20,361	0.1322%	3.88%	5.67%	0.0051%	0.0075%
Raytheon Co	RTN	303.548	102.560	31,132	0.2021%	2.61%	8.35%	0.0053%	0.0169%
Robert Half International Inc	RHI	134.500	51.030	6,864	0.0446%	1.57%	14.10%	0.0007%	0.0063%
Ryder System Inc	R	53.374	81.970	4,375	0.0284%	2.00%	12.75%	0.0006%	0.0036%
SCANA Corp	SCG	142.917	52.890	7,559	0.0491%	4.12%	5.90%	0.0020%	0.0029%
Edison International	EIX	325.811	58.480	19,053	0.1237%	2.86%	5.68%	0.0035%	0.0070%
Schlumberger Ltd	SLB	1,265.449	77.370	97,908	0.6357%	2.59%	10.12%	0.0164%	0.0643%
Charles Schwab Corp/The	SCHW	1,315.624	30.380	39,969	0.2595%	0.79%	22.39%	0.0021%	0.0581%
Sherwin-Williams Co/The	SHW	93.211	255.810	23,844	0.1548%	1.05%	19.65%	0.0016%	0.0304%
JM Smucker Co/The	SJM	119.667	117.720	14,087	0.0915%	2.28%	8.83%	0.0021%	0.0081%
Snap-on Inc	SNA	58.172	159.770	9,294	0.0603%	1.33%	3.90%	0.0008%	0.0024%
AMETEK Inc	AME	242.164	53.820	13,033	0.0846%	0.67%	10.84%	0.0006%	0.0092%
Southern Co/The	SO	908.425	43.410	39,435	0.2560%	5.00%	4.16%	0.0128%	0.0107%
BB&T Corp	BBT	779.607	36.920	28,783	0.1869%	2.93%	8.37%	0.0055%	0.0156%
Southwest Airlines Co	LUV	659.356	36.700	24,198	0.1571%	0.82%	18.02%	0.0013%	0.0283%
Southwestern Energy Co	SWN	384.488	16.240	6,244	0.0000%	n/a	9.29%	n/a	0.0000%
Stanley Black & Decker Inc	SWK	153.239	101.520	15,557	0.1010%	2.17%	10.67%	0.0022%	0.0108%
Public Storage	PSA	172.967	201.270	34,813	0.2260%	3.38%	4.60%	0.0076%	0.0104%
SunTrust Banks Inc	STI	514.047	40.370	20,752	0.1347%	2.38%	6.59%	0.0032%	0.0089%
Sysco Corp	SYY	586.766	39.870	23,394	0.1519%	3.01%	8.25%	0.0046%	0.0125%
TECO Energy Inc	TE	235.216	21.070	4,956	0.0322%	4.27%	5.00%	0.0014%	0.0016%
Tesoro Corp	TSO	123.097	92.010	11,326	0.0735%	2.17%	16.42%	0.0016%	0.0121%
Texas Instruments Inc	TXN	1,026.386	47.840	49,102	0.3188%	2.84%	9.23%	0.0091%	0.0294%
Textron Inc	TXT	276.422	38.800	10,725	0.0696%	0.21%	9.26%	0.0001%	0.0064%
Thermo Fisher Scientific Inc	TMO	398.488	125.370	49,958	0.3244%	0.48%	11.30%	0.0016%	0.0367%
Tiffany & Co	TIF	128.947	82.250	10,606	0.0689%	1.95%	11.57%	0.0013%	0.0080%
TJX Cos Inc/The	TJX	674.371	70.320	47,422	0.3079%	1.19%	10.92%	0.0037%	0.0336%
Torchmark Corp	TMK	125.115	58.460	7,314	0.0475%	0.92%	8.04%	0.0004%	0.0038%
Total System Services Inc	TSS	183.950	45.830	8,430	0.0547%	0.87%	11.75%	0.0005%	0.0064%
Tyco International Plc	TYC	421.516	36.290	15,297	0.0993%	2.26%	11.03%	0.0022%	0.0110%
Union Pacific Corp	UNP	867.692	85.740	74,396	0.4830%	2.57%	9.03%	0.0124%	0.0436%
UnitedHealth Group Inc	UNH	953.563	115.700	110,327	0.7163%	1.73%	12.53%	0.0124%	0.0897%
Unum Group	UNM	246.681	33.540	8,274	0.0537%	2.21%	8.50%	0.0012%	0.0046%
Marathon Oil Corp	MRO	677.185	17.290	11,709	0.0760%	4.86%	-20.11%	0.0037%	-0.0153%
Varian Medical Systems Inc	VAR	98.717	81.250	8,021	0.0000%	n/a	12.75%	n/a	0.0000%
Ventas Inc	VTR	332.502	55.020	18,294	0.1188%	5.74%	2.89%	0.0068%	0.0034%
VF Corp	VFC	425.642	72.430	30,829	0.2002%	1.77%	12.12%	0.0035%	0.0243%
Vornado Realty Trust	VNO	188.497	87.190	16,435	0.1067%	2.89%	6.26%	0.0031%	0.0067%
ADT Corp/The	ADT	169.933	32.780	5,570	0.0362%	2.56%	6.33%	0.0009%	0.0023%
Vulcan Materials Co	VMC	133.186	93.620	12,469	0.0810%	0.43%	41.23%	0.0003%	0.0334%
Weyerhaeuser Co	WY	514.194	27.940	14,367	0.0933%	4.44%	3.50%	0.0041%	0.0033%
Whirlpool Corp	WHR	78.418	168.100	13,182	0.0856%	2.14%	19.24%	0.0018%	0.0165%
Williams Cos Inc/The	WMB	749.711	48.200	36,136	0.2346%	4.90%	3.75%	0.0115%	0.0088%
WEC Energy Group Inc	WEC	315.684	47.650	15,042	0.0977%	1.96%	4.07%	0.0019%	0.0040%
Xerox Corp	XRX	1,068.795	10.170	10,870	0.0706%	2.75%	9.00%	0.0019%	0.0064%
Adobe Systems Inc	ADBE	497.645	78.570	39,100	0.0000%	n/a	16.25%	n/a	0.0000%
AES Corp/VA	AES	682.827	12.000	8,194	0.0532%	3.33%	5.20%	0.0018%	0.0028%

Market DCF Calculation as of August 31, 2015

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast US Government 30 Year Yield	Equity Risk Premium
S&P 500	**2.58%**	**2.71%**	**9.66%**	**12.37%**	4.29%	8.08%

Company	Ticker	[5] Shares Outstanding (million)	[6] Price	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] BEst Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Long-Term Growth Estimate
Amgen Inc	AMGN	758.250	151.780	115,087	0.7472%	2.08%	8.63%	0.0156%	0.0645%
Apple Inc	AAPL	5,702.722	112.760	643,039	4.1751%	1.84%	16.92%	0.0770%	0.7064%
Autodesk Inc	ADSK	226.199	46.750	10,575	0.0000%	n/a	13.74%	n/a	0.0000%
Cintas Corp	CTAS	110.211	84.990	9,367	0.0608%	1.00%	11.70%	0.0006%	0.0071%
Comcast Corp	CMCSA	2,114.785	56.330	119,126	0.7735%	1.78%	12.68%	0.0137%	0.0981%
Molson Coors Brewing Co	TAP	162.774	68.090	11,083	0.0720%	2.41%	1.55%	0.0017%	0.0011%
KLA-Tencor Corp	KLAC	157.531	50.110	7,894	0.0513%	4.15%	17.27%	0.0021%	0.0089%
Marriott International Inc/MD	MAR	265.888	70.660	18,788	0.1220%	1.42%	14.42%	0.0017%	0.0176%
McCormick & Co Inc/MD	MKC	115.965	79.280	9,194	0.0000%	2.02%	n/a	0.0000%	n/a
Nordstrom Inc	JWN	190.534	72.880	13,886	0.0902%	2.03%	10.12%	0.0018%	0.0091%
PACCAR Inc	PCAR	354.968	58.970	20,932	0.1359%	1.63%	7.70%	0.0022%	0.0105%
Costco Wholesale Corp	COST	439.488	140.050	61,550	0.3996%	1.14%	9.79%	0.0046%	0.0391%
Sigma-Aldrich Corp	SIAL	119.804	139.410	16,702	0.1084%	0.66%	5.13%	0.0007%	0.0056%
St Jude Medical Inc	STJ	281.745	70.810	19,950	0.1295%	1.64%	11.40%	0.0021%	0.0148%
Stryker Corp	SYK	376.558	98.650	37,147	0.2412%	1.40%	10.97%	0.0034%	0.0265%
Tyson Foods Inc	TSN	304.359	42.280	12,868	0.0836%	0.95%	6.00%	0.0008%	0.0050%
Altera Corp	ALTR	302.836	48.550	14,703	0.0955%	1.48%	12.27%	0.0014%	0.0117%
Applied Materials Inc	AMAT	1,200.619	16.085	19,312	0.1254%	2.49%	11.96%	0.0031%	0.0150%
Time Warner Inc	TWX	815.581	71.100	57,988	0.3765%	1.97%	15.14%	0.0074%	0.0570%
Bed Bath & Beyond Inc	BBBY	169.596	62.110	10,534	0.0000%	n/a	6.61%	n/a	0.0000%
American Airlines Group Inc	AAL	671.821	38.980	26,188	0.1700%	1.03%	17.78%	0.0017%	0.0302%
Cardinal Health Inc	CAH	327.359	82.270	26,932	0.1749%	1.88%	10.40%	0.0033%	0.0182%
Celgene Corp	CELG	790.540	118.080	93,347	0.0000%	n/a	23.83%	n/a	0.0000%
Cerner Corp	CERN	345.074	61.760	21,312	0.0000%	n/a	16.78%	n/a	0.0000%
Cincinnati Financial Corp	CINF	164.093	52.330	8,587	0.0000%	3.52%	n/a	0.0000%	n/a
Cablevision Systems Corp	CVC	222.337	25.170	5,596	0.0363%	2.38%	1.84%	0.0009%	0.0007%
DR Horton Inc	DHI	366.778	30.370	11,139	0.0723%	0.82%	21.50%	0.0006%	0.0155%
Flowserve Corp	FLS	133.368	45.130	6,019	0.0391%	1.60%	7.04%	0.0006%	0.0028%
Electronic Arts Inc	EA	311.746	66.150	20,622	0.0000%	n/a	11.68%	n/a	0.0000%
Express Scripts Holding Co	ESRX	675.731	83.600	56,491	0.0000%	n/a	12.12%	n/a	0.0000%
Expeditors International of Washington Inc	EXPD	189.160	48.970	9,263	0.0601%	1.47%	11.58%	0.0009%	0.0070%
Fastenal Co	FAST	290.165	38.540	11,183	0.0726%	2.91%	15.60%	0.0021%	0.0113%
M&T Bank Corp	MTB	133.238	118.240	15,754	0.1023%	2.37%	8.09%	0.0024%	0.0083%
Fiserv Inc	FISV	234.578	85.270	20,002	0.0000%	n/a	12.80%	n/a	0.0000%
Fifth Third Bancorp	FITB	809.290	19.920	16,121	0.1047%	2.61%	4.20%	0.0027%	0.0044%
Gilead Sciences Inc	GILD	1,467.606	105.070	154,201	1.0012%	1.64%	4.40%	0.0164%	0.0440%
Hasbro Inc	HAS	124.903	74.590	9,317	0.0605%	2.47%	10.20%	0.0015%	0.0062%
Huntington Bancshares Inc/OH	HBAN	803.066	10.910	8,761	0.0569%	2.20%	8.64%	0.0013%	0.0049%
Health Care REIT Inc	HCN	351.885	63.350	22,292	0.1447%	5.21%	4.55%	0.0075%	0.0066%
Biogen Inc	BIIB	235.169	297.300	69,916	0.0000%	n/a	14.45%	n/a	0.0000%
Linear Technology Corp	LLTC	239.758	40.280	9,657	0.0627%	2.98%	7.20%	0.0019%	0.0045%
Range Resources Corp	RRC	169.362	38.620	6,541	0.0425%	0.41%	10.45%	0.0002%	0.0044%
Northern Trust Corp	NTRS	232.853	69.840	16,262	0.1056%	2.06%	13.79%	0.0022%	0.0146%
Paychex Inc	PAYX	361.206	44.660	16,131	0.1047%	3.76%	9.89%	0.0039%	0.0104%
People's United Financial Inc	PBCT	309.993	15.500	4,805	0.0000%	4.32%	n/a	0.0000%	n/a
Patterson Cos Inc	PDCO	103.376	45.830	4,738	0.0308%	1.92%	8.62%	0.0006%	0.0027%
QUALCOMM Inc	QCOM	1,571.202	56.580	88,899	0.5772%	3.39%	10.80%	0.0196%	0.0623%
Roper Technologies Inc	ROP	100.666	162.090	16,317	0.1059%	0.62%	13.20%	0.0007%	0.0140%
Ross Stores Inc	ROST	411.357	48.620	20,000	0.1299%	0.97%	10.67%	0.0013%	0.0139%
AutoNation Inc	AN	113.441	59.840	6,788	0.0000%	n/a	13.16%	n/a	0.0000%
Starbucks Corp	SBUX	1,484.200	54.710	81,201	0.5272%	1.17%	18.35%	0.0062%	0.0967%
KeyCorp	KEY	840.861	13.740	11,553	0.0750%	2.18%	7.10%	0.0016%	0.0053%

Market DCF Calculation as of August 31, 2015

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast US Government 30 Year Yield	Equity Risk Premium
S&P 500	**2.58%**	**2.71%**	**9.66%**	**12.37%**	4.29%	8.08%

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Staples Inc	SPLS	643.566	14.210	9,145	0.0594%	3.38%	0.89%	0.0020%	0.0005%
State Street Corp	STT	408.113	71.920	29,351	0.1906%	1.89%	9.01%	0.0036%	0.0172%
US Bancorp	USB	1,761.004	42.350	74,579	0.4842%	2.41%	8.12%	0.0117%	0.0393%
Symantec Corp	SYMC	684.173	20.490	14,019	0.0910%	2.93%	8.35%	0.0027%	0.0076%
T Rowe Price Group Inc	TROW	256.213	71.880	18,417	0.1196%	2.89%	11.26%	0.0035%	0.0135%
Waste Management Inc	WM	452.250	50.060	22,640	0.1470%	3.08%	7.88%	0.0045%	0.0116%
CBS Corp	CBS	444.408	45.240	20,105	0.1305%	1.33%	15.02%	0.0017%	0.0196%
Allergan plc	AGN	393.636	303.740	119,563	0.0000%	n/a	12.35%	n/a	0.0000%
Whole Foods Market Inc	WFM	357.858	32.760	11,723	0.0761%	1.59%	12.30%	0.0012%	0.0094%
Constellation Brands Inc	STZ	171.987	128.000	22,014	0.1429%	0.97%	12.21%	0.0014%	0.0175%
Xilinx Inc	XLNX	258.658	41.890	10,835	0.0704%	2.96%	8.58%	0.0021%	0.0060%
DENTSPLY International Inc	XRAY	139.808	52.410	7,327	0.0476%	0.55%	9.36%	0.0003%	0.0045%
Zions Bancorporation	ZION	204.170	29.000	5,921	0.0384%	0.83%	8.47%	0.0003%	0.0033%
Invesco Ltd	IVZ	428.719	34.110	14,624	0.0949%	3.17%	11.21%	0.0030%	0.0106%
Intuit Inc	INTU	275.669	85.750	23,639	0.1535%	1.40%	17.06%	0.0021%	0.0262%
Morgan Stanley	MS	1,953.385	34.450	67,294	0.4369%	1.74%	11.93%	0.0076%	0.0521%
Microchip Technology Inc	MCHP	211.091	42.500	8,971	0.0582%	3.37%	4.60%	0.0020%	0.0027%
ACE Ltd	ACE	323.805	102.160	33,080	0.2148%	2.62%	8.16%	0.0056%	0.0175%
Chesapeake Energy Corp	CHK	665.367	7.810	5,197	0.0000%	n/a	7.98%	n/a	0.0000%
O'Reilly Automotive Inc	ORLY	99.403	240.070	23,864	0.0000%	n/a	18.05%	n/a	0.0000%
Allstate Corp/The	ALL	400.390	58.280	23,335	0.1515%	2.06%	9.70%	0.0031%	0.0147%
FLIR Systems Inc	FLIR	140.248	28.630	4,015	0.0261%	1.54%	13.50%	0.0004%	0.0035%
Equity Residential	EQR	364.082	71.250	25,941	0.1684%	3.10%	8.52%	0.0052%	0.0143%
BorgWarner Inc	BWA	226.315	43.640	9,876	0.0641%	1.19%	11.03%	0.0008%	0.0071%
Newfield Exploration Co	NFX	162.989	33.310	5,429	0.0000%	n/a	7.21%	n/a	0.0000%
Urban Outfitters Inc	URBN	125.126	30.860	3,861	0.0000%	n/a	15.79%	n/a	0.0000%
Simon Property Group Inc	SPG	309.410	179.320	55,483	0.3602%	3.46%	7.55%	0.0125%	0.0272%
Eastman Chemical Co	EMN	148.664	72.460	10,772	0.0699%	2.21%	7.17%	0.0015%	0.0050%
AvalonBay Communities Inc	AVB	132.902	165.060	21,937	0.1424%	3.03%	7.40%	0.0043%	0.0105%
Prudential Financial Inc	PRU	451.000	80.700	36,396	0.2363%	2.87%	15.78%	0.0068%	0.0373%
United Parcel Service Inc	UPS	698.448	97.650	68,203	0.4428%	2.99%	11.49%	0.0132%	0.0509%
Apartment Investment & Management Co	AIV	156.282	36.030	5,631	0.0366%	3.33%	7.21%	0.0012%	0.0026%
Walgreens Boots Alliance Inc	WBA	1,092.283	86.550	94,537	0.6138%	1.66%	14.00%	0.0102%	0.0859%
McKesson Corp	MCK	232.403	197.580	45,918	0.2981%	0.57%	10.80%	0.0017%	0.0322%
Lockheed Martin Corp	LMT	310.535	201.180	62,473	0.4056%	2.98%	8.13%	0.0121%	0.0330%
AmerisourceBergen Corp	ABC	216.202	100.040	21,629	0.1404%	1.16%	17.79%	0.0016%	0.0250%
Cameron International Corp	CAM	191.514	66.760	12,785	0.0000%	n/a	2.27%	n/a	0.0000%
Capital One Financial Corp	COF	542.429	77.750	42,174	0.2738%	2.06%	6.42%	0.0056%	0.0176%
Waters Corp	WAT	82.270	121.380	9,986	0.0000%	n/a	9.69%	n/a	0.0000%
Dollar Tree Inc	DLTR	234.637	76.260	17,893	0.0000%	n/a	15.00%	n/a	0.0000%
Darden Restaurants Inc	DRI	127.683	68.010	8,684	0.0564%	3.23%	12.11%	0.0018%	0.0068%
SanDisk Corp	SNDK	204.439	54.560	11,154	0.0724%	2.20%	0.38%	0.0016%	0.0003%
Diamond Offshore Drilling Inc	DO	137.159	23.710	3,252	0.0000%	2.11%	n/a	0.0000%	n/a
NetApp Inc	NTAP	300.083	31.960	9,591	0.0623%	2.25%	10.02%	0.0014%	0.0062%
Citrix Systems Inc	CTXS	160.701	68.110	10,945	0.0000%	n/a	14.38%	n/a	0.0000%
Goodyear Tire & Rubber Co/The	GT	269.399	29.770	8,020	0.0521%	0.81%	7.00%	0.0004%	0.0036%
DaVita HealthCare Partners Inc	DVA	215.500	75.640	16,300	0.0000%	n/a	10.26%	n/a	0.0000%
Hartford Financial Services Group Inc/The	HIG	414.845	45.950	19,062	0.1238%	1.83%	9.25%	0.0023%	0.0114%
Iron Mountain Inc	IRM	210.826	28.340	5,975	0.0388%	6.70%	4.60%	0.0026%	0.0018%
Estee Lauder Cos Inc/The	EL	225.861	79.770	18,017	0.1170%	1.20%	11.49%	0.0014%	0.0134%
Yahoo! Inc	YHOO	941.391	32.240	30,350	0.0000%	n/a	13.33%	n/a	0.0000%
Principal Financial Group Inc	PFG	294.745	50.350	14,840	0.0964%	3.02%	10.17%	0.0029%	0.0098%

Market DCF Calculation as of August 31, 2015

	[1] Dividend Yield	[2] Dividend Yield x (1 + 0.50g)	[3] Expected Growth Rate (g)	[4] Secondary Market Investor Required Return	[13] Forecast US Government 30 Year Yield	[14] Equity Risk Premium
S&P 500	**2.58%**	**2.71%**	**9.66%**	**12.37%**	4.29%	8.08%

Company	Ticker	[5] Shares Outstanding (million)	[6] Price	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] BEst Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Long-Term Growth Estimate
Stericycle Inc	SRCL	84.833	141.140	11,973	0.0000%	n/a	15.37%	n/a	0.0000%
Universal Health Services Inc	UHS	91.736	137.140	12,581	0.0817%	0.29%	10.19%	0.0002%	0.0083%
E*TRADE Financial Corp	ETFC	290.307	26.290	7,632	0.0000%	n/a	17.42%	n/a	0.0000%
Skyworks Solutions Inc	SWKS	190.738	87.350	16,661	0.1082%	1.19%	21.08%	0.0013%	0.0228%
National Oilwell Varco Inc	NOV	383.809	42.330	16,247	0.1055%	4.35%	-14.01%	0.0046%	-0.0148%
Quest Diagnostics Inc	DGX	143.553	67.800	9,733	0.0632%	2.24%	11.30%	0.0014%	0.0071%
Activision Blizzard Inc	ATVI	729.020	28.630	20,872	0.1355%	0.80%	9.78%	0.0011%	0.0133%
Rockwell Automation Inc	ROK	134.106	111.830	14,997	0.0974%	2.33%	8.40%	0.0023%	0.0082%
Kraft Heinz Co/The	KHC	1,212.833	72.660	88,124	0.5722%	3.03%	12.30%	0.0173%	0.0704%
American Tower Corp	AMT	423.279	92.190	39,022	0.2534%	1.91%	14.48%	0.0048%	0.0367%
Regeneron Pharmaceuticals Inc	REGN	101.737	513.500	52,242	0.0000%	n/a	21.33%	n/a	0.0000%
Amazon.com Inc	AMZN	467.710	512.890	239,884	0.0000%	n/a	47.77%	n/a	0.0000%
Ralph Lauren Corp	RL	59.767	111.190	6,645	0.0431%	1.80%	11.09%	0.0008%	0.0048%
Boston Properties Inc	BXP	153.574	113.380	17,412	0.1131%	2.29%	6.35%	0.0026%	0.0072%
Amphenol Corp	APH	309.147	52.360	16,187	0.1051%	1.07%	6.69%	0.0011%	0.0070%
Pioneer Natural Resources Co	PXD	149.308	123.060	18,374	0.1193%	0.07%	8.73%	0.0001%	0.0104%
Valero Energy Corp	VLO	497.112	59.340	29,499	0.1915%	2.70%	-1.23%	0.0052%	-0.0023%
L-3 Communications Holdings Inc	LLL	80.332	105.470	8,473	0.0550%	2.47%	6.79%	0.0014%	0.0037%
Western Union Co/The	WU	511.432	18.440	9,431	0.0612%	3.36%	9.03%	0.0021%	0.0055%
CH Robinson Worldwide Inc	CHRW	141.801	67.430	9,562	0.0621%	2.25%	10.63%	0.0014%	0.0066%
Accenture PLC	ACN	624.135	94.270	58,837	0.3820%	2.16%	10.33%	0.0083%	0.0395%
Yum! Brands Inc	YUM	431.206	79.770	34,397	0.2233%	2.06%	11.82%	0.0046%	0.0264%
Prologis Inc	PLD	524.047	38.000	19,914	0.1293%	4.21%	4.99%	0.0054%	0.0064%
FirstEnergy Corp	FE	422.453	31.960	13,502	0.0877%	4.51%	-0.68%	0.0039%	-0.0006%
VeriSign Inc	VRSN	113.493	68.940	7,824	0.0000%	n/a	10.40%	n/a	0.0000%
Quanta Services Inc	PWR	196.832	24.240	4,771	0.0000%	n/a	7.45%	n/a	0.0000%
Ameren Corp	AEE	242.635	40.290	9,776	0.0635%	4.07%	6.77%	0.0026%	0.0043%
Henry Schein Inc	HSIC	83.397	136.810	11,410	0.0000%	n/a	11.12%	n/a	0.0000%
Broadcom Corp	BRCM	559.000	51.670	28,884	0.1875%	1.08%	12.24%	0.0020%	0.0230%
NVIDIA Corp	NVDA	539.000	22.480	12,117	0.0787%	1.73%	8.80%	0.0014%	0.0069%
Sealed Air Corp	SEE	205.842	51.450	10,591	0.0688%	1.01%	10.11%	0.0007%	0.0069%
Cognizant Technology Solutions Corp	CTSH	609.529	62.940	38,364	0.0000%	n/a	15.50%	n/a	0.0000%
Intuitive Surgical Inc	ISRG	37.019	510.950	18,915	0.0000%	n/a	15.36%	n/a	0.0000%
CONSOL Energy Inc	CNX	229.004	15.230	3,488	0.0226%	0.26%	12.40%	0.0001%	0.0028%
Aetna Inc	AET	348.688	114.520	39,932	0.2593%	0.87%	12.06%	0.0023%	0.0313%
Affiliated Managers Group Inc	AMG	54.284	186.440	10,121	0.0000%	n/a	14.71%	n/a	0.0000%
Republic Services Inc	RSG	348.917	40.980	14,299	0.0928%	2.93%	4.85%	0.0027%	0.0045%
eBay Inc	EBAY	1,218.228	27.110	33,026	0.0000%	n/a	9.71%	n/a	0.0000%
Goldman Sachs Group Inc/The	GS	432.871	188.600	81,639	0.5301%	1.38%	18.98%	0.0073%	0.1006%
Sempra Energy	SRE	247.580	94.850	23,483	0.1525%	2.95%	7.75%	0.0045%	0.0118%
Moody's Corp	MCO	200.300	102.310	20,493	0.1331%	1.33%	13.50%	0.0018%	0.0180%
Priceline Group Inc/The	PCLN	50.702	1,248.640	63,309	0.0000%	n/a	18.97%	n/a	0.0000%
F5 Networks Inc	FFIV	71.004	121.410	8,621	0.0000%	n/a	15.41%	n/a	0.0000%
Akamai Technologies Inc	AKAM	178.595	71.310	12,736	0.0000%	n/a	15.80%	n/a	0.0000%
Reynolds American Inc	RAI	714.551	83.750	59,844	0.3886%	3.44%	11.08%	0.0134%	0.0431%
Devon Energy Corp	DVN	411.000	42.660	17,533	0.1138%	2.25%	6.24%	0.0026%	0.0071%
Google Inc	GOOGL	289.886	647.820	187,794	0.0000%	n/a	17.33%	n/a	0.0000%
Red Hat Inc	RHT	183.483	72.210	13,249	0.0000%	n/a	17.86%	n/a	0.0000%
Hudson City Bancorp Inc	HCBK	529.529	9.300	4,925	0.0320%	1.72%	-3.00%	0.0006%	-0.0010%
Netflix Inc	NFLX	424.363	115.030	48,814	0.0000%	n/a	32.49%	n/a	0.0000%
Allegion PLC	ALLE	95.812	59.610	5,711	0.0371%	0.67%	14.70%	0.0002%	0.0055%
Agilent Technologies Inc	A	333.192	36.310	12,098	0.0786%	1.10%	5.90%	0.0009%	0.0046%

Market DCF Calculation as of August 31, 2015

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast US Government 30 Year Yield	Equity Risk Premium
S&P 500	**2.58%**	**2.71%**	**9.66%**	**12.37%**	4.29%	8.08%

		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	BEst Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Anthem Inc	ANTM	261.587	141.050	36,897	0.2396%	1.77%	9.61%	0.0042%	0.0230%
CME Group Inc/IL	CME	337.756	94.440	31,898	0.2071%	2.12%	12.36%	0.0044%	0.0256%
Juniper Networks Inc	JNPR	384.427	25.710	9,884	0.0642%	1.56%	11.84%	0.0010%	0.0076%
BlackRock Inc	BLK	163.636	302.470	49,495	0.3214%	2.88%	14.62%	0.0093%	0.0470%
DTE Energy Co	DTE	179.330	78.060	13,998	0.0909%	3.74%	5.15%	0.0034%	0.0047%
NASDAQ OMX Group Inc/The	NDAQ	168.930	51.190	8,648	0.0561%	1.95%	6.88%	0.0011%	0.0039%
Philip Morris International Inc	PM	1,549.186	79.800	123,625	0.8027%	5.01%	5.87%	0.0402%	0.0471%
Time Warner Cable Inc	TWC	282.974	186.020	52,639	0.3418%	1.61%	9.75%	0.0055%	0.0333%
salesforce.com inc	CRM	660.000	69.360	45,778	0.0000%	n/a	25.57%	n/a	0.0000%
MetLife Inc	MET	1,116.881	50.100	55,956	0.3633%	2.99%	7.25%	0.0109%	0.0264%
Monsanto Co	MON	467.835	97.650	45,684	0.2966%	2.21%	10.90%	0.0066%	0.0323%
Coach Inc	COH	276.627	30.250	8,368	0.0543%	4.46%	10.88%	0.0024%	0.0059%
Fluor Corp	FLR	144.943	45.620	6,612	0.0429%	1.84%	2.49%	0.0008%	0.0011%
Dun & Bradstreet Corp/The	DNB	36.111	105.970	3,827	0.0248%	1.75%	10.15%	0.0004%	0.0025%
Edwards Lifesciences Corp	EW	107.516	140.880	15,147	0.0000%	n/a	15.20%	n/a	0.0000%
Ameriprise Financial Inc	AMP	178.221	112.670	20,080	0.1304%	2.38%	11.65%	0.0031%	0.0152%
Xcel Energy Inc	XEL	507.211	33.730	17,108	0.1111%	3.79%	5.05%	0.0042%	0.0056%
Rockwell Collins Inc	COL	131.770	81.850	10,785	0.0700%	1.61%	9.88%	0.0011%	0.0069%
FMC Technologies Inc	FTI	229.474	34.780	7,981	0.0000%	n/a	7.58%	n/a	0.0000%
Zimmer Biomet Holdings Inc	ZBH	203.365	103.560	21,060	0.1367%	0.85%	10.87%	0.0012%	0.0149%
CBRE Group Inc	CBG	333.180	32.020	10,668	0.0000%	n/a	10.50%	n/a	0.0000%
Signet Jewelers Ltd	SIG	80.127	138.000	11,058	0.0718%	0.64%	8.00%	0.0005%	0.0057%
MasterCard Inc	MA	1,108.884	92.370	102,428	0.6650%	0.69%	16.58%	0.0046%	0.1103%
GameStop Corp	GME	106.720	42.480	4,533	0.0294%	3.39%	14.43%	0.0010%	0.0042%
CarMax Inc	KMX	208.042	61.000	12,691	0.0000%	n/a	14.98%	n/a	0.0000%
Intercontinental Exchange Inc	ICE	110.489	228.410	25,237	0.1639%	1.31%	15.55%	0.0022%	0.0255%
Fidelity National Information Services Inc	FIS	281.583	69.060	19,446	0.1263%	1.51%	12.62%	0.0019%	0.0159%
Chipotle Mexican Grill Inc	CMG	31.142	710.010	22,111	0.0000%	n/a	21.24%	n/a	0.0000%
Pepco Holdings Inc	POM	253.072	22.980	5,816	0.0378%	4.70%	4.70%	0.0018%	0.0018%
Wynn Resorts Ltd	WYNN	101.537	75.050	7,620	0.0495%	2.66%	7.90%	0.0013%	0.0039%
Hospira Inc	HSP	172.934	89.970	15,559	0.0000%	n/a	14.30%	n/a	0.0000%
Assurant Inc	AIZ	66.818	74.350	4,968	0.0323%	1.61%	8.14%	0.0005%	0.0026%
NRG Energy Inc	NRG	330.655	19.920	6,587	0.0428%	2.91%	23.90%	0.0012%	0.0102%
Genworth Financial Inc	GNW	497.419	5.180	2,577	0.0000%	n/a	5.00%	n/a	0.0000%
Monster Beverage Corp	MNST	204.193	138.460	28,273	0.0000%	n/a	20.50%	n/a	0.0000%
Regions Financial Corp	RF	1,324.907	9.590	12,706	0.0825%	2.50%	2.86%	0.0021%	0.0024%
Teradata Corp	TDC	141.600	29.230	4,139	0.0000%	n/a	8.11%	n/a	0.0000%
Mosaic Co/The	MOS	337.159	40.830	13,766	0.0894%	2.69%	9.30%	0.0024%	0.0083%
Expedia Inc	EXPE	116.334	114.990	13,377	0.0869%	0.83%	13.75%	0.0007%	0.0119%
Discovery Communications Inc	DISCA	149.302	26.600	3,971	0.0000%	n/a	13.57%	n/a	0.0000%
CF Industries Holdings Inc	CF	233.048	57.380	13,372	0.0868%	2.09%	12.00%	0.0018%	0.0104%
Viacom Inc	VIAB	347.460	40.770	14,166	0.0920%	3.92%	9.25%	0.0036%	0.0085%
Google Inc	GOOG	343.929	618.250	212,634	0.0000%	n/a	17.33%	n/a	0.0000%
Wyndham Worldwide Corp	WYN	118.111	76.480	9,033	0.0586%	2.20%	10.00%	0.0013%	0.0059%
Spectra Energy Corp	SE	671.363	29.070	19,517	0.1267%	5.09%	3.85%	0.0065%	0.0049%
First Solar Inc	FSLR	100.903	47.840	4,827	0.0000%	n/a	-2.95%	n/a	0.0000%
Ensco PLC	ESV	235.679	18.110	4,268	0.0000%	3.31%	n/a	0.0000%	n/a
Mead Johnson Nutrition Co	MJN	202.739	78.340	15,883	0.1031%	2.11%	8.80%	0.0022%	0.0091%
TE Connectivity Ltd	TEL	402.384	59.290	23,857	0.1549%	2.23%	10.45%	0.0034%	0.0162%

Market DCF Calculation as of August 31, 2015

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast US Government 30 Year Yield	Equity Risk Premium
S&P 500	**2.58%**	**2.71%**	**9.66%**	**12.37%**	4.29%	8.08%

Company	Ticker	[5] Shares Outstanding (million)	[6] Price	[7] Market Capitalization ($million)	[8] Percent of Total Market Capitalization	[9] Current Dividend Yield	[10] BEst Long-Term Growth Estimate	[11] Market Capitalization-Weighted Dividend Yield	[12] Market Capitalization-Weighted Long-Term Growth Estimate
Discover Financial Services	DFS	435.307	53.730	23,389	0.1519%	2.08%	9.22%	0.0032%	0.0140%
TripAdvisor Inc	TRIP	131.296	69.900	9,178	0.0000%	n/a	20.05%	n/a	0.0000%
Dr Pepper Snapple Group Inc	DPS	190.886	76.730	14,647	0.0951%	2.50%	7.26%	0.0024%	0.0069%
Scripps Networks Interactive Inc	SNI	94.201	53.090	5,001	0.0325%	1.73%	11.45%	0.0006%	0.0037%
Visa Inc	V	1,951.387	71.300	139,134	0.9034%	0.67%	18.08%	0.0061%	0.1634%
Xylem Inc/NY	XYL	181.499	32.450	5,890	0.0382%	1.74%	9.87%	0.0007%	0.0038%
Marathon Petroleum Corp	MPC	536.157	47.310	25,366	0.1647%	2.71%	2.58%	0.0045%	0.0043%
Tractor Supply Co	TSCO	135.819	85.310	11,587	0.0752%	0.94%	15.33%	0.0007%	0.0115%
Level 3 Communications Inc	LVLT	355.833	44.730	15,916	0.0000%	n/a	26.99%	n/a	0.0000%
Transocean Ltd	RIG	363.554	14.230	5,173	0.0336%	4.22%	-25.40%	0.0014%	-0.0085%
Essex Property Trust Inc	ESS	65.744	214.620	14,110	0.0916%	2.68%	8.18%	0.0025%	0.0075%
General Growth Properties Inc	GGP	885.657	25.380	22,478	0.1459%	2.68%	7.91%	0.0039%	0.0115%
Realty Income Corp	O	234.869	44.690	10,496	0.0681%	5.10%	3.92%	0.0035%	0.0027%
Seagate Technology PLC	STX	302.034	51.400	15,525	0.1008%	4.20%	8.30%	0.0042%	0.0084%
WestRock Co	WRK	261.848	59.350	15,541	0.1009%	2.53%	7.46%	0.0026%	0.0075%
Western Digital Corp	WDC	230.403	81.960	18,884	0.1226%	2.44%	5.00%	0.0030%	0.0061%
Fossil Group Inc	FOSL	48.147	61.580	2,965	0.0000%	n/a	11.13%	n/a	0.0000%
JB Hunt Transport Services Inc	JBHT	116.251	72.780	8,461	0.0549%	1.15%	14.83%	0.0006%	0.0081%
Lam Research Corp	LRCX	158.187	72.770	11,511	0.0747%	1.65%	6.41%	0.0012%	0.0048%
Mohawk Industries Inc	MHK	73.913	196.970	14,559	0.0000%	n/a	12.05%	n/a	0.0000%
Pentair PLC	PNR	180.056	55.290	9,955	0.0646%	2.32%	14.40%	0.0015%	0.0093%
Vertex Pharmaceuticals Inc	VRTX	244.656	127.520	31,199	0.0000%	n/a	25.67%	n/a	0.0000%
Facebook Inc	FB	2,259.737	89.430	202,088	0.0000%	n/a	24.17%	n/a	0.0000%
United Rentals Inc	URI	95.370	69.330	6,612	0.0000%	n/a	12.20%	n/a	0.0000%
Navient Corp	NAVI	374.033	12.790	4,784	0.0000%	5.00%	n/a	0.0000%	n/a
Delta Air Lines Inc	DAL	795.398	43.780	34,823	0.2261%	1.23%	22.14%	0.0028%	0.0501%
Baxalta Inc	BXLT	676.969	35.150	23,795	0.1545%	0.80%	4.55%	0.0012%	0.0070%
Mallinckrodt PLC	MNK	117.343	86.240	10,120	0.0000%	n/a	13.05%	n/a	0.0000%
Keurig Green Mountain Inc	GMCR	154.058	56.600	8,720	0.0566%	2.03%	14.20%	0.0012%	0.0080%
Macerich Co/The	MAC	158.321	76.180	12,061	0.0783%	3.41%	6.31%	0.0027%	0.0049%
Martin Marietta Materials Inc	MLM	67.001	167.800	11,243	0.0730%	0.95%	24.07%	0.0007%	0.0176%
PayPal Holdings Inc	PYPL	1,218.736	35.000	42,656	0.0000%	n/a	16.75%	n/a	0.0000%
Alexion Pharmaceuticals Inc	ALXN	226.155	172.190	38,942	0.0000%	n/a	23.19%	n/a	0.0000%
Columbia Pipeline Group Inc	CPGX	317.615	25.360	8,055	0.0523%	1.97%	36.00%	0.0010%	0.0188%
Endo International PLC	ENDP	208.251	77.000	16,035	0.0000%	n/a	8.97%	n/a	0.0000%
News Corp	NWSA	380.999	13.630	5,193	0.0337%	1.47%	10.35%	0.0005%	0.0035%
Crown Castle International Corp	CCI	333.762	83.390	27,832	0.1807%	3.93%	22.67%	0.0071%	0.0410%
Delphi Automotive PLC	DLPH	284.349	75.520	21,474	0.1394%	1.32%	13.73%	0.0018%	0.0191%
Advance Auto Parts Inc	AAP	73.217	175.250	12,831	0.0833%	0.14%	13.68%	0.0001%	0.0114%
Michael Kors Holdings Ltd	KORS	193.422	43.460	8,406	0.0000%	n/a	27.34%	n/a	0.0000%
Alliance Data Systems Corp	ADS	61.433	257.190	15,800	0.0000%	n/a	14.60%	n/a	0.0000%
Nielsen Holdings PLC	NLSN	366.860	45.230	16,593	0.1077%	2.48%	14.00%	0.0027%	0.0151%
Garmin Ltd	GRMN	190.936	37.610	7,181	0.0466%	5.42%	7.95%	0.0025%	0.0037%
Cimarex Energy Co	XEC	94.456	110.510	10,438	0.0678%	0.58%	-4.37%	0.0004%	-0.0030%
Zoetis Inc	ZTS	498.944	44.870	22,388	0.1454%	0.74%	12.50%	0.0011%	0.0182%
Equinix Inc	EQIX	56.958	269.770	15,366	0.0998%	2.51%	38.74%	0.0025%	0.0386%
Discovery Communications Inc	DISCK	274.284	25.360	6,956	0.0000%	n/a	13.57%	n/a	0.0000%
Average for Companies Paying Dividends with Positive Long-Term Growth Estimates						**2.39%**	**10.00%**	**2.58%**	**9.66%**

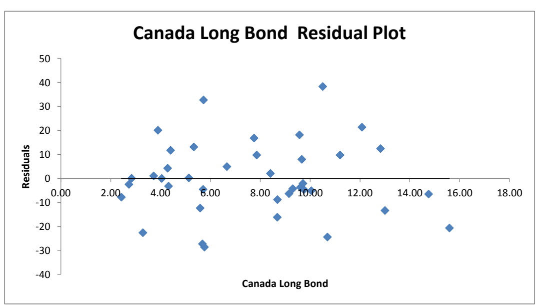
Notes:
[1] Equals sum of Column [11]
[2] Equals Column [1] x (1 + 0.5 x Column [3])
[3] Equals sum of Column [12]
[4] Equals Column [2] + Column [3]
[5] Source: Bloomberg Finance L.P., as of August 31, 2015
[6] Source: Bloomberg Finance L.P., as of August 31, 2015
[7] Equals Column [5] x Column [6]
[8] Equals percent of sum of Column [7] if Current Dividend Yield does not equal "n/a" and Best Long-Term Growth Estimate does not equal "n/a" and is greater tha
[9] Source: Bloomberg Finance L.P., as of August 31, 2015
[10] Source: Bloomberg Finance L.P., as of August 31, 2015
[11] Equals Column [8] x Column [9]
[12] Equals Column [8] x Column [10]
[13] Source: April 2015 Consensus Forecast Average 2016-2018 Forecasts 10-Year bond yield plus Average Daily Spread between 10-year and 30-year government b
[14] Equals Column [4] - (Column [13]/100)

Regression Analysis of MRP to GOC Long-term Bond Yields from 1976 - 2014

Year	[1] Canada Long Bond	[2] Dummy	[3] MRP
###	9.61	0	-0.2
###	9.15	0	-2.3
###	9.57	0	21.7
###	10.50	0	40.8
###	12.82	0	12.4
###	15.59	0	-23.8
###	14.75	0	-8.7
###	12.08	0	22.1
###	13.00	0	-13.6
###	11.20	0	11.5
###	9.30	0	-0.4
###	9.75	0	-1.3
###	10.05	0	-2.1
###	9.66	0	11.4
###	10.69	0	-22.1
###	9.72	0	1.3
###	8.68	0	-11.6
###	7.86	0	15.2
###	8.69	0	-4.3
###	8.41	0	6.9
###	7.75	0	22.4
###	6.66	0	11.7
###	5.59	0	-4.4
###	5.72	0	40.5
###	5.71	0	3.3
###	5.76	0	-20.8
###	5.68	0	-19.4
###	5.34	0	21.4
###	5.14	0	8.7
###	4.40	0	21
###	4.28	0	13.7
###	4.32	0	6.2
###	4.05	1	-35.5
###	3.90	0	29.9
###	3.73	0	11.1
###	3.29	0	-12.1
###	2.43	0	3.7
###	2.84	0	11.1
###	2.73	0	8.7

Notes and Results of Analysis:
[1] Bank of Canada, Data and Statistics Office, Selected Government of Canada Benchmark
[2] Dummy Variable for Global Economic Crisis in 2008
[3] MRP from Morningstar Ibbotson through 2011, and Duff & Phelps from 2011-2014

		Forecast 30-Yr. Bond Yield Scenario	August 31, 2015 Spot 30-Yr. Bond Yield Scenario
[4]	Intercept	14.18%	14.18%
[5]	Coefficient for Canadian Long Bond	-1.11%	-1.11%
[6]	Coefficient for Global Economic Crisis	-45.18%	-45.18%
[7]	Lower Bound of Confidence Interval for Canadian Long Bond Y	-2.62%	-2.62%
[8]	Upper Bound of Confidence Interval for Canadian Long Bond Y	0.40%	0.40%
[9]	30-year Bond Yield, Forecast and Spot as of August 31, 2015	3.68	2.23
[10]	Canadian Proxy Group Beta	0.62	0.62
[11]	**Calculation of Market Risk Premium = [4] +([9] x [5])+ (0 x [6])**	**10.09%**	**11.70%**
	Calculation of Canadian Utility ROE = [9] + ([10]*[11])	**9.97%**	**9.52%**



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.4457109
R Square	0.19865821
Adjusted R Square	0.15413922
Standard Error	15.6325895
Observations	39

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	2180.986958	1090.493479	4.46233	0.018566083
Residual	36	8797.602785	244.3778551		
Total	38	10978.58974			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Ipper 95%*	*ower 95.0*	*pper 95.0%*
Intercept	14.1770905	6.345553584	2.234177095	0.03177	1.307711408	27.0465	1.30771	27.0465
Canada Long Bond	-1.1105949	0.745857732	-1.48901713	0.14519	-2.623264523	0.40207	-2.6233	0.40207
Dummy	-45.184734	16.0825281	-2.809554174	0.00797	-77.80161247	-12.568	-77.802	-12.568

RESIDUAL OUTPUT

Observation	*redicted MR*	*Residuals*	*andard Residuals*
1	3.5033476	-3.703347603	-0.243390768
2	4.01237028	-6.312370284	-0.414860504
3	3.54592041	18.15407959	1.193119266
4	2.51121612	38.28878388	2.516408805
5	-0.0644386	12.46443864	0.819185672
6	-3.1370846	-20.66291536	-1.358004535
7	-2.2060359	-6.493964114	-0.426795182
8	0.76295459	21.33704541	1.402309593
9	-0.2624947	-13.33750526	-0.876565205
10	1.73842714	9.761572857	0.641548396
11	3.84393005	-4.243930051	-0.278918834
12	3.34693882	-4.646938815	-0.305405306
13	3.01931331	-5.119313308	-0.33645062
14	3.44596686	7.954033136	0.522753584
15	2.30205408	-24.40205408	-1.60374756
16	3.38766063	-2.08766063	-0.137204869
17	4.5352754	-16.1352754	-1.060439768
18	5.45059073	9.749409269	0.640748983
19	4.52972243	-8.829722427	-0.580305484
20	4.84068901	2.05931099	0.135341679
21	5.57183068	16.82816932	1.105978022
22	6.77960268	4.920397324	0.323377498
23	7.96793926	-12.36793926	-0.812843556
24	7.82263642	32.67736358	2.147616014
25	7.83651886	-4.536518861	-0.298148305
26	7.78006362	-28.58006362	-1.878333978
27	7.86891121	-27.26891121	-1.792162647
28	8.25114097	13.14885903	0.86416703
29	8.47418546	0.225814544	0.014840944
30	9.28862175	11.71137825	0.769693168
31	9.42004215	4.279957853	0.281286647
32	9.37469285	-3.174692854	-0.208646612
33	-35.5	-1.42109E-14	-9.33963E-16
34	9.85132318	20.04867682	1.317635656
35	10.0391988	1.060801174	0.069717791
36	10.5232331	-22.62323312	-1.486840199
37	11.4764938	-7.776493778	-0.511085374
38	11.0230008	0.076999156	0.005060525
39	11.1442408	-2.444240792	-0.160639969

PROBABILITY OUTPUT

Percentile	*MRP*
1.282051282	-35.5
3.846153846	-23.8
6.41025641	-22.1
8.974358974	-20.8
11.53846154	-19.4
14.1025641	-13.6
16.66666667	-12.1
19.23076923	-11.6
21.79487179	-8.7
24.35897436	-4.4
26.92307692	-4.3
29.48717949	-2.3
32.05128205	-2.1
34.61538462	-1.3
37.17948718	-0.4
39.74358974	-0.2
42.30769231	1.3
44.87179487	3.3
47.43589744	3.7
50	6.2
52.56410256	6.9
55.12820513	8.7
57.69230769	8.7
60.25641026	11.1
62.82051282	11.1
65.38461538	11.4
67.94871795	11.5
70.51282051	11.7
73.07692308	12.4
75.64102564	13.7
78.20512821	15.2
80.76923077	21
83.33333333	21.4
85.8974359	21.7
88.46153846	22.1
91.02564103	22.4
93.58974359	29.9
96.15384615	40.5
98.71794872	40.8

Capital Asset Pricing Model

US Proxy Group	Ticker	[1] Bloomberg	[2] Value Line	[3] Average Beta	[4] Risk Free Rate	[5] Average Market Risk Premium	[6] Basic CAPM Calculation	[7] Flotation Cost	[8] Total CAPM
ALLETE, Inc.	ALE	0.75	0.80	0.78	4.29%	7.62%	10.20%	0.50%	10.70%
Duke Energy	DUK	0.55	0.60	0.58	4.29%	7.62%	8.68%	0.50%	9.18%
Eversource Energy	ES	0.68	0.75	0.71	4.29%	7.62%	9.72%	0.50%	10.22%
Great Plains	GXP	0.76	0.85	0.80	4.29%	7.62%	10.41%	0.50%	10.91%
OG&E Corp	OGE	0.78	0.90	0.84	4.29%	7.62%	10.70%	0.50%	11.20%
Pinnacle West Capital	PNW	0.72	0.70	0.71	4.29%	7.62%	9.68%	0.50%	10.18%
Westar	WR	0.67	0.75	0.71	4.29%	7.62%	9.71%	0.50%	10.21%
MEAN		0.70	0.76	0.73			9.87%		10.37%

Canada Proxy Group	Ticker	[1] Bloomberg	[2] Value Line	[3] Average Beta	[4] Risk Free Rate	[5] Average Market Risk Premium	[6] Basic CAPM Calculation	[7] Flotation Cost	[8] Total CAPM
Canadian Utilities Limited	CU	0.62	N/A	0.62	3.68%	7.62%	8.37%	0.50%	8.87%
Emera Inc.	EMA	0.71	N/A	0.71	3.68%	7.62%	9.08%	0.50%	9.58%
Enbridge Inc.	ENB	0.79	N/A	0.79	3.68%	7.62%	9.71%	0.50%	10.21%
Valener Inc.	VNR	0.43	N/A	0.43	3.68%	7.62%	6.98%	0.50%	7.48%
MEAN		0.64	N/A	0.64			8.54%		9.04%

North American Electric Proxy Group	Ticker	[1] Bloomberg	[2] Value Line	[3] Average Beta	[4] Risk Free Rate	[5] Average Market Risk Premium	[6] Basic CAPM Calculation	[7] Flotation Cost	[8] Total CAPM
ALLETE, Inc.	ALE	0.75	0.80	0.78	4.29%	7.62%	10.20%	0.50%	10.70%
Canadian Utilities Limited	CU	0.62	N/A	0.62	3.68%	7.62%	8.37%	0.50%	8.87%
Duke Energy	DUK	0.55	0.60	0.58	4.29%	7.62%	8.68%	0.50%	9.18%
Emera Inc.	EMA	0.71	N/A	0.71	3.68%	7.62%	9.08%	0.50%	9.58%
Eversource Energy	ES	0.68	0.75	0.71	4.29%	7.62%	9.72%	0.50%	10.22%
Great Plains	GXP	0.76	0.85	0.80	4.29%	7.62%	10.41%	0.50%	10.91%
OG&E Corp	OGE	0.78	0.90	0.84	4.29%	7.62%	10.70%	0.50%	11.20%
Pinnacle West Capital	PNW	0.72	0.70	0.71	4.29%	7.62%	9.68%	0.50%	10.18%
Westar	WR	0.67	0.75	0.71	4.29%	7.62%	9.71%	0.50%	10.21%
MEAN		0.69	0.76	0.72			9.62%		10.12%

Notes:
[1] Source: Bloomberg Professional; average of five years of weekly market-adjusted betas
[2] Source: Value Line as of August 31, 2015
[3] Equals mean of [1] and [2]
[4] Source: Equals average long-term Consensus Forecast of 10-year government bond yields for the period 2016-2018 as of April 13, 2015. (Pg. plus the 30-day average spread between 10- and 30-year bond ending August 31, 2015.
[5] Source: Average of the Duff and Phelps Canada historical risk premium (1936-2013),
Duff and Phelps US historical risk premium (1926-2013),
Bloomberg; TSX total return less [4] as of August 31, 2015
Bloomberg; S&P 500 total return less [4] as of August 31, 2015
[6] Equals [4] + ([5] x [6])
[7] Flotation Costs
[8] Equals [6] + [8]

2014 % Regulated				
Utility	**% Regulated Income**	**% Electric Revenues**	**% Electric Income**	**% Electric Assets**
ALLETE, Inc.	97%	97%	97%	99%
Duke Energy Corporation	100%	98%	97%	97%
Eversource Energy	100%	87%	91%	89%
Great Plains Energy, Inc.	100%	100%	100%	100%
OG&E Energy Corp	100%	100%	100%	85%
Pinnacle West Capital	100%	100%	100%	100%
Westar Energy	100%	100%	100%	100%
U.S. Proxy Group Average	**100%**	**97%**	**98%**	**96%**

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

Operating Stats

U.S. Proxy Group	Ticker	Operating Utility	State	S&P Credit Rating (Operating Utility)	2014 Regulated Electric Revenues US$	2014 Retail Customers	Notes
ALLETE, Inc.	ALE	Minnesota Power	MN	BBB+	956,416,000	145,033	[1]
Duke Energy Corporation	DUK	Duke Energy Florida	FL	A-	4,975,000,000	1,700,000	
		Duke Energy Indiana	IN	A-	3,175,000,000	810,000	
		Duke Energy Kentucky	KY	A-	368,894,000	140,000	
		Duke Energy Carolinas - NC	NC	A-	5,985,551,750	3,200,000	[2]
		Duke Energy Carolinas - SC	SC	A-	1,365,448,250	730,000	[2]
		Duke Energy Ohio	OH	A-	1,316,000,000	700,000	
Eversource Energy	ES	Connecticut Light and Power	CT	A	2,649,531,000	1,223,743	
		NSTAR Electric	MA	A	2,536,677,000	1,179,867	
		Public Service of New Hampshire	NH	A	959,500,000	504,000	
		Western Mass. Electric	MA	A	417,449,000	207,877	
Great Plains Energy Inc.	GXP	Kansas City Power and Light - KS	KS	BBB+	758,695,076	247,000	[2]
		Kansas City Power and Light - MO	MO	BBB+	1,809,504,924	589,100	[2]
OG&E Energy Corporation	OGE	Oklahoma Gas and Electric - OK	OK	A-	2,453,100,000	811,190	
Pinnacle West Capital Corp.	PNW	Arizona Public Service	AZ	A-	3,488,946,000	1,163,079	
Westar Energy, Inc.	WR	Kansas Gas and Electric	KS	BBB+	771,687,000	321,501	
		Westar Energy	KS	BBB+	1,014,778,000	374,472	

Canadian Proxy Group	Ticker	Operating Utility	Province	S&P Credit Rating (Operating Utility)	C$ 2014 Regulated Revenue	2014 Retail Customers	
Canadian Utilities Ltd.	CU	ATCO Electric Ltd.	AB	A	1,061,006,000	251,755	[1]
Emera, Inc.	EMA	Nova Scotia Power	NS	BBB+	1,319,200,000	503,676	
Enbridge	ENB	Enbridge Gas Distribution	ON	BBB+	3,200,000,000	2,098,145	[3]
Valener, Inc.	VNR	Gaz Metro QDA	QC	A	1,561,700,000	195,617	[3]
Fortis, Inc		Maritime Electric	NL	BBB+	180,997,000	78,000	[1]

Notes
[1] S&P credit rating is for ALLETE Inc., Canadian Utilities Ltd., and Fortis, Inc.
[2] Regulated electric revenues allocated between states based on percentage of retail customers.
[2] Regulated revenues and number of customers are from gas distribution operations.

* Revenue for U.S. utilities shown in US$; Revenue for Canadian utilities shown in CAN$

Regulated Generation

U.S. Proxy Group		Operating Utility	State	Regulated Generation	Fuel/PP Costs	Customers
ALLETE, Inc.	ALE	Minnesota Power	MN	Yes	Monthly	144,000
Duke Energy Corporation	DUK	Duke Energy Florida	FL	Yes	Annually	1,700,000
		Duke Energy Indiana	IN	Yes	Quarterly	810,000
		Duke Energy Kentucky	KY	Yes	Monthly	140,000
		Duke Energy Carolinas - NC	NC	Yes	Annually	3,200,000
		Duke Energy Carolinas - SC	SC	Yes	Monthly	730,000
		Duke Energy Ohio	OH	No	N/A	700,000
Eversource Energy	ES	Connecticut Light and Power	CT	No	Bi-Annual	1,223,743
		NSTAR Electric	MA	No	Bi-Annual	1,179,867
		Public Service of New Hampshire	NH	Yes	Annually	504,000
		Western Mass. Electric	MA	Limited	Bi-Annual	207,877
Great Plains Energy Inc.	GXP	Kansas City Power and Light - KS	KS	Yes	Monthly	316,800
		Kansas City Power and Light - MO	MO	Yes	Bi-Annual	519,100
OG&E Energy Corporation	OGE	Oklahoma Gas and Electric - OK	OK	Yes	Bi-Annual	814,982
Pinnacle West Capital Corp.	PNW	Arizona Public Service	AZ	Yes	Annually	1,163,079
Westar Energy, Inc.	WR	Kansas Gas and Electric	KS	Yes	Quarterly	321,501
		Westar Energy	KS	Yes	Quarterly	374,472

Canadian Proxy Group		Utility	Province			
Canadian Utilities Ltd.	CU	ATCO Electric Distribution	AB	No	N/A	251,755
Emera, Inc.	EMA	Nova Scotia Power	NS	Yes	Annually	503,676
Enbridge	ENB	Enbridge Gas Distribution	ON	N/A	Quarterly	2,098,145
Valener, Inc.	VNR	Gaz Metro	QC	N/A	Monthly	195,617

Fortis, Inc		Maritime Electric	PEI	Yes	Annually	78,000

	U.S.	Canada
Total Number of Customers	12,886,342	755,431
Own Regulated Generation	74.30%	66.67%
Own Limited Generation	1.61%	0.00%
Do not own Generation	24.08%	33.33%

Volume/Demand Risk

U.S. Proxy Group		Operating Utility	State	Full Decoupling	Partial Decoupling or LRAM	Weather Norm	Customers
ALLETE, Inc.	ALE	Minnesota Power	MN	No	No	No	144,000
Duke Energy Corporation	DUK	Duke Energy Florida	FL	No	No	No	1,700,000
		Duke Energy Indiana	IN	No	Yes	No	810,000
		Duke Energy Kentucky	KY	No	Yes	No	140,000
		Duke Energy Carolinas - NC	NC	No	No	No	3,200,000
		Duke Energy Carolinas - SC	SC	No	No	No	730,000
		Duke Energy Ohio	OH	Yes	No	No	700,000
Eversource Energy	ES	Connecticut Light and Power	CT	Yes	No	No	1,223,743
		NSTAR Electric	MA	No	No	No	1,179,867
		Public Service of New Hampshire	NH	No	No	No	504,000
		Western Mass. Electric	MA	Yes	No	No	207,877
Great Plains Energy Inc.	GXP	Kansas City Power and Light - KS	KS	No	No	No	316,800
		Kansas City Power and Light - MO	MO	No	Yes	No	519,100
OG&E Energy Corp	OGE	Oklahoma Gas and Electric	OK	No	Yes	No	814,982
Pinnacle West Capital	PNW	Arizona Public Service	AZ	No	Yes	No	1,163,079
Westar Energy, Inc.	WR	Kansas Gas and Electric	KS	No	Yes	No	321,501
		Westar Energy	KS	No	Yes	No	374,472
Canadian Proxy Group		**Utility**	**Province**				
Canadian Utilities Ltd.	CU	ATCO Electric Distribution	AB	No	No	No	251,755
Emera, Inc.	EMA	Nova Scotia Power	NS	No	Yes	No	503,676
Enbridge	ENB	Enbridge Gas Distribution	ON	No	Yes	No	2,098,145
Valener, Inc.	VNR	Gaz Metro	QC	No	No	Yes	195,617
Fortis, Inc.		Maritime Electric	PEI	No	No	Proposing	78,000

	U.S.	Canada
Total Number of Customers	12,886,342	3,049,193
Full Decoupling	16.54%	0.00%
Partial Decoupling or LRAM	23.13%	85.33%
Weather Normalization	0.00%	6.42%

Capital Cost Recovery Risk

U.S. Proxy Group		Operating Utility	State	Pre-Approval	CWIP	AFUDC	Cost Tracking Mechanism	Customers
ALLETE, Inc.	ALE	Minnesota Power	MN	No	Limited	Yes	Yes	144,000
Duke Energy Corporation	DUK	Duke Energy Florida	FL	Yes	Yes	Yes	Yes	1,700,000
		Duke Energy Indiana	IN	No	Yes	Yes	Yes	810,000
		Duke Energy Kentucky	KY	No	Yes	Yes	No	140,000
		Duke Energy Carolinas - NC	NC	Yes	Yes	Yes	No	3,200,000
		Duke Energy Carolinas - SC	SC	Yes	Yes	Yes	No	730,000
		Duke Energy Ohio	OH	No	Yes	Yes	Yes	700,000
Eversource Energy	ES	Connecticut Light and Power	CT	No	No	Yes	No	1,223,743
		NSTAR Electric	MA	No	No	Yes	Yes	1,179,867
		Public Service of New Hampshire	NH	No	No	Yes	Yes	504,000
		Western Mass. Electric	MA	No	No	Yes	Yes	207,877
Great Plains Energy Inc.	GXP	Kansas City Power and Light - KS	KS	No	Yes	Yes	No	316,800
		Kansas City Power and Light - MO	MO	No	No	Yes	No	519,100
OG&E Energy Corp	OGE	Oklahoma Gas and Electric	OK	Yes	Yes	Yes	Yes	814,982
Pinnacle West Capital	PNW	Arizona Public Service	AZ	No	No	Yes	Yes	1,163,079
Westar Energy, Inc.	WR	Kansas Gas and Electric	KS	No	Yes	Yes	Yes	321,501
		Westar Energy	KS	No	Yes	Yes	Yes	374,472
Canadian Proxy Group		**Utility**	**Province**					
Canadian Utilities Ltd.	CU	ATCO Electric Distribution	AB	No	No	Yes	Yes	251,755
Emera, Inc.	EMA	Nova Scotia Power	NS	No	No	Yes	No	503,676
Enbridge	ENB	Enbridge Gas Distribution	ON	Yes	No	Yes	Yes	2,098,145
Valener, Inc.	VNR	Gaz Metro	QC	Yes	No	Yes	No	195,617
Fortis, Inc.		Maritime Electric	PEI	Yes	No	Yes	No	78,000

	U.S.	Canada
Total Number of Customers	12,886,342	3,049,193
Pre-Approval of Capital Projects	50.01%	75.23%
CWIP in Rate Base	70.68%	0.00%
AFUDC	100.00%	100.00%
Cost Tracking Mechanism	52.43%	77.07%

Rate Regulation and Earnings Sharing

U.S. Proxy Group		Operating Utility	State	Cost of Svc	Incentive Reg	ESM	Customers
ALLETE, Inc.	ALE	Minnesota Power	MN	Yes	No	No	144,000
Duke Energy Corporation	DUK	Duke Energy Florida	FL	Yes	No	No	1,700,000
		Duke Energy Indiana	IN	Yes	No	Yes	810,000
		Duke Energy Kentucky	KY	Yes	No	No	140,000
		Duke Energy Carolinas - NC	NC	Yes	No	No	3,200,000
		Duke Energy Carolinas - SC	SC	Yes	No	No	730,000
		Duke Energy Ohio	OH	Yes	No	No	700,000
Eversource Energy	ES	Connecticut Light and Power	CT	Yes	No	Yes	1,223,743
		NSTAR Electric	MA	Yes	No	Yes	1,179,867
		Public Service of New Hampshire	NH	Yes	No	Yes	504,000
		Western Mass. Electric	MA	Yes	No	No	207,877
Great Plains Energy Inc.	GXP	Kansas City Power and Light - KS	KS	Yes	No	No	316,800
		Kansas City Power and Light - MO	MO	Yes	No	No	519,100
OG&E Energy Corp	OGE	Oklahoma Gas and Electric	OK	Yes	No	No	814,982
Pinnacle West Capital	PNW	Arizona Public Service	AZ	Yes	No	No	1,163,079
Westar Energy, Inc.	WR	Kansas Gas and Electric	KS	Yes	No	No	321,501
		Westar Energy	KS	Yes	No	No	374,472
Canadian Proxy Group		**Utility**	**Province**				
Canadian Utilities Ltd.	CU	ATCO Electric Distribution	AB	No	Yes	No	251,755
Emera, Inc.	EMA	Nova Scotia Power	NS	Yes	No	No	503,676
Enbridge	ENB	Enbridge Gas Distribution	ON	No	Yes	Yes	2,098,145
Valener, Inc.	VNR	Gaz Metro	QC	Yes	No	Yes	195,617
Fortis, Inc.		Maritime Electric	PEI	Yes	No	Yes	78,000

	U.S.	Canada
Total Number of Customers	12,886,342	3,049,193
Cost of Service Regulation	100.00%	22.93%
Incentive Regulation Plan	0.00%	77.07%
Earnings Sharing Mechanism	28.85%	75.23%

Incentive Regulation includes performance-based, multi-year, and formula rate plans.

Regulatory Lag

U.S. Proxy Group		Operating Utility	State	Test Year	Interim Rates	Rate Base	Rate Case Lag (months)	Customers
ALLETE, Inc.	ALE	Minnesota Power	MN	Partial Forecast	Yes	Average	12	144,000
Duke Energy Corporation	DUK	Duke Energy Florida	FL	Forecast	Yes	Average	11	1,700,000
		Duke Energy Indiana	IN	Historical	Yes	Year-end	16	810,000
		Duke Energy Kentucky	KY	Historical	Emergency	Year-end	6	140,000
		Duke Energy Carolinas - NC	NC	Historical	Emergency	Year-end	7	3,200,000
		Duke Energy Carolinas - SC	SC	Historical	Yes	Year-end	5	730,000
		Duke Energy Ohio	OH	Historical	Emergency	Year-end	9	700,000
Eversource Energy	ES	Connecticut Light and Power	CT	Historical	Emergency	Year-end	6	1,223,743
		NSTAR Electric	MA	Historical	Emergency	Year-end	6	1,179,867
		Public Service of New Hampshire	NH	Historical	Yes	Average	12	504,000
		Western Mass. Electric	MA	Historical	Emergency	Year-end	6	207,877
Great Plains Energy Inc.	GXP	Kansas City Power and Light - KS	KS	Historical	Yes	Year-end	7	316,800
		Kansas City Power and Light - MO	MO	Partial Forecast	Emergency	Year-end	10	519,100
OG&E Energy Corp	OGE	Oklahoma Gas and Electric	OK	Historical	Yes	Year-end	11	814,982
Pinnacle West Capital	PNW	Arizona Public Service	AZ	Historical	Yes	Year-end	11	1,163,079
Westar Energy, Inc.	WR	Kansas Gas and Electric	KS	Historical	Yes	Year-end	7	321,501
		Westar Energy	KS	Historical	Yes	Year-end	7	374,472
Canadian Proxy Group		**Utility**	**Province**					
Canadian Utilities Ltd.	CU	ATCO Electric Distribution	AB	Forecast	Yes	Average	N/A	251,755
Emera, Inc.	EMA	Nova Scotia Power	NS	Forecast	No	Average	6.5	503,676
Enbridge	ENB	Enbridge Gas Distribution	ON	Forecast	N/A	Average	N/A	2,098,145
Valener, Inc.	VNR	Gaz Metro	QC	Forecast	Yes	Average	7	195,617
Fortis, Inc		Maritime Electric	PEI	Forecast	No	Average	5	78,000

	U.S.	Canada
Total Number of Customers	12,886,342	3,049,193
Forecasted Test Year	13.19%	100.00%
Partially Forecasted Test Year	5.15%	0.00%
Historical Adjusted Test Year	81.66%	0.00%
Interim Rates	44.36%	14.67%
Interim Rates in Financial Emergency	55.64%	0.00%
Average Rate Base	18.22%	100.00%
Year End Rate Base	81.78%	0.00%
Rate Case Lag in Months	8.76	6.75

Other Cost Recovery

U.S. Proxy Group		Operating Utility	State	Pension/ OPEB Expense	Bad Debt Expense	Storm Cost Recovery	Interest Rate Tracker	Energy Efficiency Cost	Customers
ALLETE, Inc.	ALE	Minnesota Power	MN	No	No	No	No	Yes	144,000
Duke Energy Corporation	DUK	Duke Energy Florida	FL	No	No	Yes	Yes	No	1,700,000
		Duke Energy Indiana	IN	No	No	No	No	Yes	810,000
		Duke Energy Kentucky	KY	No	No	No	No	Yes	140,000
		Duke Energy Carolinas - NC	NC	No	No	Yes	No	Yes	3,200,000
		Duke Energy Caorlinas - SC	SC	No	No	No	No	No	730,000
		Duke Energy Ohio	OH	No	No	No	No	No	700,000
Eversource Energy	ES	Connecticut Light and Power	CT	No	No	Yes	No	Yes	1,223,743
		NSTAR Electric	MA	Yes	Yes	Yes	No	Yes	1,179,867
		Public Service of New Hampshire	NH	No	No	Yes	No	Yes	504,000
		Western Mass. Electric	MA	Yes	Yes	Yes	No	Yes	207,877
Great Plains Energy Inc.	GXP	Kansas City Power and Light - KS	KS	Yes	No	No	No	Yes	316,800
		Kansas City Power and Light - MO	MO	Yes	No	No	No	Yes	519,100
OG&E Energy Corp	OGE	Oklahoma Gas and Electric	OK	Yes	No	Yes	No	Yes	814,982
Pinnacle West Capital	PNW	Arizona Public Service	AZ	Yes	No	No	No	Yes	1,163,079
Westar Energy, Inc.	WR	Kansas Gas and Electric	KS	Yes	No	No	No	Yes	321,501
		Westar Energy	KS	Yes	No	No	No	Yes	374,472
Canadian Proxy Group		**Utility**	**Province**						
Canadian Utilities Ltd.	CU	ATCO Electric Distribution	AB	Yes	No	Yes	Yes	No	251,755
Emera, Inc.	EMA	Nova Scotia Power	NS	Yes	No	No	No	Yes	503,676
Enbridge	ENB	Enbridge Gas Distribution	ON	Yes	No	No	No	Yes	2,098,145
Valener, Inc.	VNR	Gaz Metro	QC	Yes	Yes	Yes	No	Yes	195,617
Fortis, Inc.		Maritime Electric	PEI	Yes	No	No	No	Yes	78,000

	U.S.	Canada
Total Number of Customers	12,886,342	3,049,193
Pension Expense Cost Recovery	28.98%	100.00%
Bad Debt Expense Cost Recovery	10.77%	6.42%
Storm Cost Recovery	68.53%	14.67%
Interest Rate Tracker for Change in Interest Rates	13.19%	8.26%
Energy Efficiency and DSM Cost Recovery	75.71%	91.74%

2014 Credit Metrics - U.S. and Canadian Proxy Groups and Maritime Electric Company Ltd.

Company Name	Ticker		Debt to Capital Ratio	EBITDA to Interest Coverage	FFO to Interest Coverage	FFO / Debt (%)	Debt to EBITDA
Maritime Electric		[1]	58%	3.53	2.43	17.4%	3.95
U.S. Proxy Group							
ALLETE, Inc.	ALE		49%	4.92	3.90	18.9%	4.19
Duke Energy Corporation	DUK		53%	4.42	3.95	18.4%	4.86
Eversource Energy	ES		53%	5.18	4.07	16.5%	4.75
Great Plains Energy Inc	GXP		57%	4.13	3.15	16.5%	4.60
OG&E Energy Corp	OGE		49%	5.78	4.86	25.8%	3.26
Pinnacle West Capital Corp	PNW		48%	5.12	3.89	25.7%	2.95
Westar Energy, Inc	WR		56%	4.68	3.67	19.4%	4.04
U.S. Proxy Group			52%	4.89	3.92	20.2%	4.09
Canadian Proxy Group							
Canadian Utilities Limited	CU		63%	3.69	4.48	13.4%	5.18
Emera Incorporated	EMA		59%	5.13	5.13	17.8%	4.19
Enbridge Inc.	ENB		69%	3.55	2.57	10.0%	7.25
Valener, Inc.	VNR	[2]	68%	N/A	N/A	33.6%	2.30
Canadian Proxy Group			65%	4.12	4.06	18.7%	4.73

APPENDIX 9
Maritime Electric
Proposed Range of Return on Average Rate Base

		Debt	Common	Total	Rate of Return on Average Rate Base
2014					
Percent of Capital		56.17%	43.83%	100.00%	
Cost of Capital		7.31	9.75		
		4.11	4.27	8.38	
Conversion of Return on Average Capitalization to Return on Average Rate Base					
	Average Capitalization	294,953,733	X	8.38	7.92
	Average Rate Base	312,268,689			
2015					
Percent of Capital		57.74%	42.26%	100.00%	
Cost of Capital		6.83	9.75		
		3.94	4.12	8.06	
Conversion of Return on Average Capitalization to Return on Average Rate Base					
	Average Capitalization	$ 316,452,487	X	8.06	7.74
	Average Rate Base	$ 329,694,300			
2016					
Percent of Capital		59.46%	40.54%	100.00%	
Cost of Capital		6.25	9.90		
		3.71	4.01	7.73	
Conversion of Return on Average Capitalization to Return on Average Rate Base					**Upper Limit**
	Average Capitalization	$ 341,875,300	X	7.73	7.72
	Average Rate Base	$ 342,087,800			
Percent of Capital		59.46%	40.54%	100.00%	
Cost of Capital		6.25	9.50		
		3.71	3.85	7.57	
Conversion of Return on Average Capitalization to Return on Average Rate Base					**Lower Limit**
	Average Capitalization	$ 341,875,300	X	7.57	7.56
	Average Rate Base	$ 342,087,800			

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September 2, 2015

Jason Roberts
Maritime Electric Company, Ltd.
180 Kent Street
Charlottetown, PE C1A 7N2

Dear Mr. Roberts

SUBJECT: 2014 Cost Allocation Study

Please find attached the findings of Chymko Consulting's Electric Utility cost allocation study to assist Maritime Electric with a its upcoming rate proposal to the Island Regulatory and Appeals Commission.

We appreciate the time and effort of Maritime Electric staff to provide us with the necessary data and information to conduct this study. Should you have any questions or comments on this report, please contact me at (403) 781-7691.

Yours truly,

Michael Turner
President

cc: Gloria Crockett

Attachment

2014 Cost Allocation Study

Maritime Electric

September 2, 2015

www.chymko.com

EXECUTIVE SUMMARY

1. Maritime Electric Company Ltd. (MECL) retained Chymko Consulting Ltd. to perform a comprehensive cost allocation study to support a future rate proposal to the Island Regulatory and Appeals Commission (IRAC). The following report provides the results of this study, which is based on MECL's Statement of Earnings for twelve months ending on December 31, 2014.

2. A cost allocation study first functionalizes revenue requirement (in this case, the Statement of Earnings), essentially seeking to attribute the full cost of service to a specific purpose, such as power supply, transmission, distribution network, services and metering, customer care, and lighting. Next, the cost allocation study classifies each function as demand, energy, or site related depending upon how the cost of that function might vary with how end-use customers use the system. Finally, the cost allocation study will allocate the functionalized and classified expenses to rate classes.

3. Table A below summarizes MECL's allocated revenue requirement.

Table A
Allocated 2014 Net Revenue Requirement from Rates ($,000)

	Revenue Collected	Allocated Cost	Revenue to Cost Ratio	2008 Study
Residential	45.0 %	48.9 %	92 %	91 %
Residential (S)	2.2 %	2.3 %	97 %	122 %
Farm	3.3 %	4.0 %	81 %	N/A
General Service 1	32.3 %	27.5 %	117 %	114 %
General Service 1 (S)	0.9 %	0.7 %	115 %	132 %
General Service 2	0.8 %	0.7 %	120 %	122 %
Small Industrial	6.6 %	6.8 %	96 %	109 %
Large Industrial	7.5 %	7.5 %	100 %	86 %
Lights	1.3 %	1.3 %	103 %	119 %
Unmetered	0.2 %	0.2 %	103 %	98 %
Total	100.0 %	100.0 %	100 %	100 %

4. Allocated cost is one bookend for a 2016 rate proposal, representing the cost to provide electric utility service for each rate class. If cost causation were the only consideration, for instance, Table A indicates that 2016 rates should seek to recover 48.9 percent of 2016 revenue requirement from the Residential rate class, 2.3 percent from the Seasonal Residential rate class, and so on.

5. Another consideration is how much the rate for each class of customer would have to change to recover allocated cost. By the current revenue to cost ratios shown in Table A above, some rates would need to change significantly. Subject to full consideration of all rate design principles and further analysis of any such change, it may well be that rate rebalancing would need to be implemented gradually over the course of multiple years.

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1 INTRODUCTION

6. Maritime Electric Company Ltd. (MECL) retained Chymko Consulting Ltd. to perform a comprehensive cost allocation study to support a future rate proposal to the Island Regulatory and Appeals Commission (IRAC). Based on the assumptions discussed in this report, Chymko Consulting's cost allocation study takes as a starting point MECL's Statement of Earnings for twelve months ending on December 31, 2014. Contained in MECL's December 2014 monthly financial report submitted to IRAC, the Statement of Earnings represents the total cost of providing electric utility service at a rate of return determined by the 2012 PEI Energy Accord.

7. A cost allocation study will typically begin with "revenue requirement," which represents the forecast cost of providing electric utility service based on a regulator-approved rate of return. MECL's 2014 Statement of Earnings is similarly based on a rate of return deemed to be in the public interest insofar as it is compliant with the 2012 PEI Energy Accord. Therefore, the principle difference between the Statement of Earnings and revenue requirement is that the Statement of Earnings is calculated after-the-fact and revenue requirement is typically forward-looking. MECL has traditionally filed cost allocation studies based on actual expenses from the previous calendar year, and in using the 2014 Statement of Earnings this study is no different.

8. This study examines the detailed expenses underlying the Statement of Earnings and assigns, attributes, or allocates expenses to each of MECL's rate classes. The fully-allocated 2014 Statement of Earnings by rate class then becomes an important benchmark to inform MECL's anticipated 2016 rate proposal. If the residential rate class is attributed fifty percent of 2014 expenses, for instance, then this information can serve as a target or objective for designing 2016 residential rates.

9. The first step of a cost allocation model is to group similar types of expenses that make up revenue requirement into elements of service, or functions. For each function, the user of the cost allocation model must consider:

- Is the function incurred for the purpose of servicing all rate classes, a sub-set of rate classes, or a single rate class?

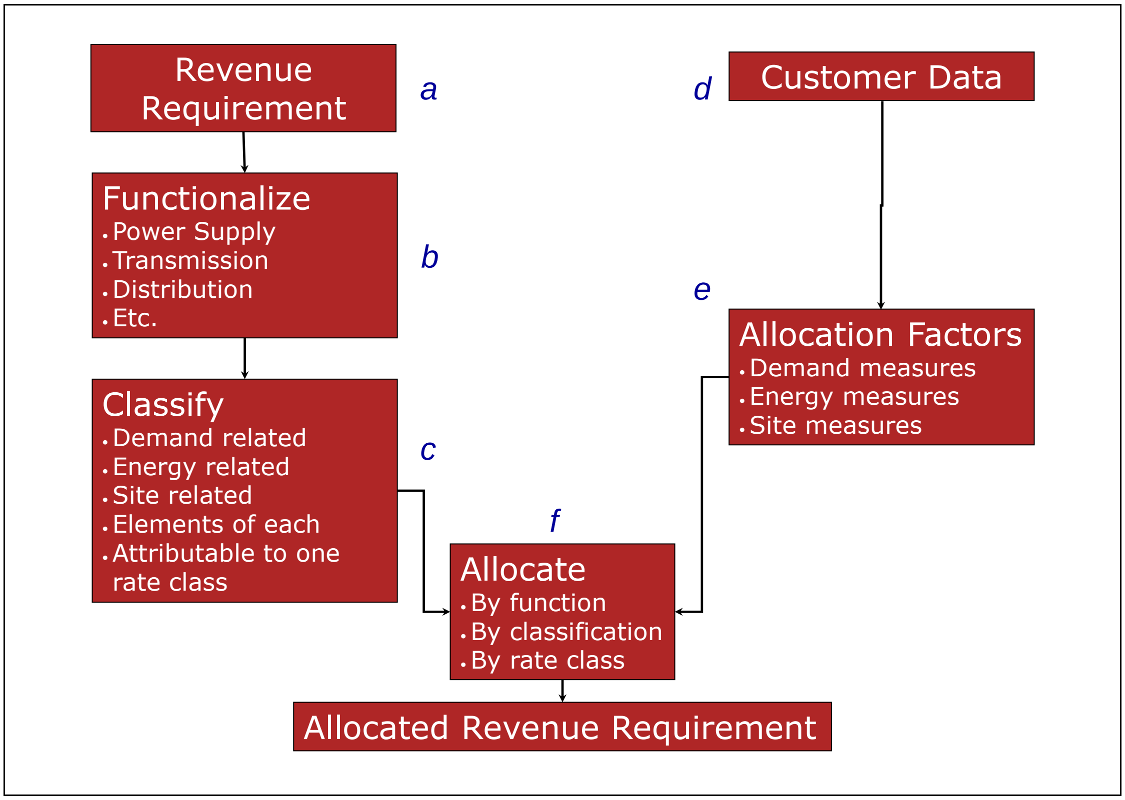
- If the function is attributable to more than one rate class, how might the cost of that function vary depending upon how end-use customers use the distribution system? For example, does the cost vary with peak daily demand changes? Does it vary with the total amount of energy delivered? Does it vary with the number of distribution sites served?

- How does each rate class contribute to the use of distribution infrastructure? For example, how does each rate class contribute to total peak demand and total energy delivered? How many sites are served in each rate class?

10. In order to answer the above questions, cost allocation studies follow a structured process, which can be explained with the aid of Figure 1 below. Taking revenue requirement (labelled

as a) as a given, the first step is known as functionalization (labelled as b), which begins with attributing each line item in the study by its purpose or function.

Figure 1: Process of a cost allocation study



11. The next step in a cost allocation study is called classification (c). The purpose of classification is to determine how each function might vary based on how end-use customers use the system. Sometimes, a function exists solely for the purpose of serving a subset of rate classes, perhaps only a single rate class. However, as long as the function is attributable to more than one rate class, it is necessary to explore further as to whether the expense will vary with peak demand on the system, the amount of energy consumed, or the number of sites served by the system. Thus, each function is classified as demand-related, energy-related, site-related, or a combination of the three.

12. The final step of a cost allocation study is to allocate the functionalized and classified revenue requirement to rate classes. The choice of allocation factor is to a large degree influenced by the classification of each functionalized detail of revenue requirement. For example, demand related costs are generally allocated by the same proportions as the peak demand of each rate class. Similarly, energy related costs are allocated by the same proportions as energy sales and site related costs are allocated by the relative size of each rate class.

13. The development of allocation factors starts with the collection of MECL's system load data and billing statistics (d). From this foundation along with any associated load research data, it is possible to calculate allocation factors based on each rate classes' peak demand, energy consumption, and the number of sites per rate class.

14. As suggested by the overview above, the process of a cost allocation study is relatively uncomplicated given there is agreement upon how a cost is to be functionalized, classified, and allocated. Thus, generally accepted principles and methods have evolved out of a number of years of regulatory experience. Regulated distribution utilities must file cost allocation studies to demonstrate that its tariffs are just and reasonable. Generally accepted methods typically evolve out of the regulatory process, but even these continue to evolve with industry changes and provincial government policy. Furthermore, every utility is different and every utility service area has its own unique characteristics and issues that may justify a different method. Therefore, it is important to justify the rationale for every cost functionalization, classification, and allocation decision, regardless of whether it is a commonly accepted standard or not.

2 FUNCTIONALIZATION

15. The starting point for cost allocation is the 2014 MECL Statement of Earnings. This is summarized in Table 1 below.

Table 1[1]
MECL 2014 Statement of Earnings (Revenue Requirement)
$,000

	Twelve Months ending December 31, 2014
Operating Expenses	
Energy Costs	106,818
ECAM Adjustment	12,358
Net Energy Costs	119,176
Distribution	3,925
Transmission	922
Transmission and Distribution - Other	1,994
Transmission - OATT	172
General	11,025
Total Operating Expenses	137,214
Amortization	
Amortization Other	688
Amortization Plant And Equipment	14,761
Total Amortization	15,450
Total Operating Income	159,130
Financing Expenses	
Long-Term Debt	11,983
Short-Term Debt	500
Interest Charged To Construction	(368)
Amortization of Financing Costs	5
Total Financing Expenses	12,119
Earnings before Income Taxes	164,782
Income Taxes	5,658
Net Earnings	12,246
Gross Revenue Requirement	182,686
OATT Revenue	(1,830)
Other Revenue[2]	(1,852)
Net Revenue Requirement	179,004

16. Net earnings identified is equivalent to the allowed return on equity for a prospective revenue requirement. This is because MECL has already adjusted 2014 net earnings to account for customer refunds associated with ECAM 2003 and the maximum rate of return allowed by the 2012 PEI Energy Accord.

17. Note that the Statement of Earnings in Table 1, subject to two exceptions, is the same format as previous IRAC filings. Both Open Access Transmission Tariff (OATT) Revenue and Other Revenue are explicitly identified in Table 1. If not for these sources of revenue, end-user

[1] Table totals in this report may not reconcile due to rounding.
[2] Inclusive of pole rental revenue.

rates would need to recover $182.7 Million, which is labelled as Gross Revenue Requirement. Net of these revenue sources, the Net Revenue Requirement is $179.0 Million. Subject to ECAM and rate of return adjustments noted above (see paragraph 16), $179.0 Million was recovered from end-user rates in 2014.

2.1 METHOD

18. Chymko Consulting's cost allocation study fully attributes revenue requirement in Table 1 to one of sixteen functions discussed below. For purposes of summary, the sixteen functions are also discussed under six general categories: power supply, transmission, distribution network, services and metering, customer care, and lighting.

Power Supply

- Generation: MECL's Borden and Charlottetown generating facilities, which are typically dispatched for peak demand and backup purposes.

- Purchased Power: Energy supply purchases from NB Power, which are typically dispatched for base load and ancillary service requirements.

Transmission

- High-voltage transmission facilities operating at a voltage of 69 kV or greater.

Distribution Network

- Substations: Facilities used to regulate and step-down voltages from transmission facilities to distribution lines.

- Primary Lines: Bulk distribution lines used to deliver energy from substations to localized distribution transformers.

- Transformers: Facilities used to regulate and step-down voltages from primary distribution lines to a voltage more suitable for the end-use consumer.

- Secondary Lines: Local distribution lines operating at a consumer-level voltage that service multiple end-use customers.

Services and Metering

- Service Lines: Local distribution lines operating at a consumer-level voltage that connect the distribution network to the meter of a single, end-use customer.

- Meter Assets: Metering infrastructure used to measure and record energy consumed by each end-use customer.

- Meter Reading: The process of collecting and processing end-use customer metering data, primarily for the purpose of billing.

Customer Care

- Billing: The process of preparing and delivering invoices to end-use customers for power supply and use of the MECL system.

- Remittance & Collection: The accounts receivable process of collecting and processing end-use customer bill payments.

- Uncollectibles & Damage Claims: Uncollectibles are associated with the cost of outstanding customer invoices (e.g. bad debts), whereas damage claims represent claims against MECL for damage to customers' property.

- Service Connections: Activities related to the connection or re-connection of customers, which may include off-cycle meter reads as well as modifications or additions to secondary lines, service lines, and meters. MECL recovers the cost of these activities under sections O-1 and O-2 of its tariff.

- Late Payments: Penalty revenues associated with consumer accounts in arrears, as recovered under section O-3 of the MECL tariff.

Lighting

- Facilities dedicated to the use of providing electric service to street and area lighting, as defined under sections N-22, N-23, N-25, and N-26 of the MECL tariff.

19. Chymko Consulting functionalizes revenue requirement as per a series of methods and assumptions summarized in Table 2 below. Overall, this table demonstrates that 66% of revenue requirement is directly assigned to a function. An additional 29% is functionalized according to the same proportions as the underlying facilities and assets, the majority of which are also directly assignable because of detailed asset records. A further 3% is allocated by the same proportions by which labour cost is functionalized, which leaves 2% to be allocated by various methods involving professional judgement.

Table 2 Methods to Functionalize 2014 MECL Revenue Requirement					
	Direct Assign	Assets & Facilities	Labour	Profes-sional Judgment	Total
Operating Expenses					
Energy Costs	99 %	1 %	0 %	1 %	100 %
ECAM Adjustment	100 %	0 %	0 %	0 %	100 %
Net Energy Costs	99 %	1 %	0 %	1 %	100 %
Distribution	17 %	77 %	0 %	7 %	100 %
Transmission	100 %	0 %	0 %	0 %	100 %
Transmission and Distribution - Other	5 %	95 %	0 %	0 %	100 %
Transmission - OATT	100 %	0 %	0 %	0 %	100 %
General	6 %	15 %	52 %	26 %	100 %
Total Operating Expenses	88 %	5 %	4 %	3 %	100 %
Amortization					
Amortization Other	48 %	16 %	36 %	0 %	100 %
Amortization Plant And Equipment	0 %	100 %	0 %	0 %	100 %
Total Amortization	2 %	96 %	2 %	0 %	100 %
Total Operating Income	79 %	15 %	4 %	3 %	100 %
Financing Expenses					
Long-Term Debt	0 %	100 %	0 %	0 %	100 %
Short-Term Debt	0 %	100 %	0 %	0 %	100 %
Interest Charged To Construction	0 %	100 %	0 %	0 %	100 %
Amortization of Financing Costs	0 %	100 %	0 %	0 %	100 %
Total Financing Expenses	0 %	100 %	0 %	0 %	100 %
Earnings before Income Taxes	73 %	21 %	4 %	2 %	100 %
Income Taxes	0 %	100 %	0 %	0 %	100 %
Net Earnings	0 %	100 %	0 %	0 %	100 %
Gross Revenue Requirement	66 %	29 %	3 %	2 %	100 %
OATT Revenue	100 %	0 %	0 %	0 %	100 %
Other Revenue	60 %	39 %	0 %	0 %	100 %
Net Revenue Requirement	66 %	29 %	3 %	2 %	100 %

20. To the extent that the information exists and it is practical to do so, the first priority in functionalization is to directly attribute as much as possible to a given function without the need to allocate. Indeed, MECL provided Chymko Consulting with detailed financial accounting records that allowed it to directly assign two thirds of revenue requirement to one of the sixteen functions.

21. That which cannot be directly assigned is allocated. Amortization, debt financing, return, and income tax are the most important examples of a functional allocation. These expenses comprise more than one fifth of the MECL revenue requirement and only indirectly are they associated with the sixteen functions. Amortization, debt financing, and return are all calculated based on MECL's infrastructure investment and therefore the underlying infrastructure becomes a determining factor as to how these expenses should be functionalized. Moreover, MECL pays income tax only if it earns a positive return and therefore, tax is also indirectly associated with utility infrastructure.

22. Chymko Consulting allocates these expenses by the same proportions as the underlying capital infrastructure, which means that gross plant and depreciation must also be fully attributed to each of the sixteen functions. MECL's detailed plant records facilitate a relatively straightforward functionalization process: two-thirds of gross plant in service is directly attributable to a single function and an additional thirty percent is attributable to a narrow subset of the sixteen functions.

23. The next-most important functionalization method as it affects total revenue requirement is general operating expenses that are non-specific to any particular utility function. For instance, over two-thirds of general operating costs are mostly related to corporate supervisory salaries and employment benefits. Because these corporate overheads exist for the purpose of all other personnel, Chymko Consulting allocated such expenses by the same proportions as all other labour expenses already attributed to the sixteen functions.

24. The final category of functionalization method used is broadly described as professional judgement in Table 2. This actually describes seven different methods that are applied on a case-by-case basis depending upon the nature of the expense. The two most important methods, as measured by total expense allocated, are used for the allocation of energy control centre expenses and the allocation of finance administration costs. In the case of the former, this and previous studies rely on the professional judgement of MECL staff to functionalize energy control centre: one-quarter to power supply, one-quarter to transmission, and the remaining amount to the distribution network. In the case of financial administration, approximately half of the annual expense is postage and stationary associated with billing and the other half is labour cost. For the half that is labour, expenses are functionalized according to the work responsibilities of the seven personnel in that department.

2.2 RESULT

25. The outcome of the functionalization process is summarized in Table 3 below.

Table 3 Functionalized MECL Revenue Requirement ($,000)							
	Power Supply	Trans'n	Distrib'n Network	Services and Metering	Customer Care	Lighting	Total
Operating Expenses							
Energy Costs	105,188	1,209	419	2	0	0	106,818
ECAM Adjustment	12,358	0	0	0	0	0	12,358
Net Energy Costs	117,545	1,209	419	2	0	0	119,176
Distribution	65	65	3,257	512	0	26	3,925
Transmission	0	922	0	0	0	0	922
T&D - Other	0	0	1,994	0	0	0	1,994
Transmission - OATT	0	172	0	0	0	0	172
General	2,701	1,324	3,597	1,063	2,320	20	11,025
Total Operating Expenses	120,312	3,693	9,266	1,577	2,320	46	137,214
Amortization							
Other	429	145	109	6	0	0	688
Plant And Equipment	3,241	1,777	7,225	2,319	61	138	14,761
Total Amortization	3,670	1,922	7,334	2,324	61	138	15,450
Total Operating Income	123,981	5,615	16,601	3,902	2,381	184	152,663
Financing Expenses							
Long-Term Debt	2,630	1,429	5,910	1,881	49	84	11,983
Short-Term Debt	110	60	246	78	2	4	500
Charged To Construction	(81)	(44)	(182)	(58)	(2)	(3)	(368)
Amortization of Financing	1	1	2	1	0	0	5
Total Financing Expenses	2,660	1,445	5,977	1,902	50	85	12,119
Earnings before Tax	126,641	7,060	22,578	5,804	2,431	269	164,782
Income Taxes	1,242	675	2,790	888	23	40	5,658
Net Earnings	2,688	1,460	6,040	1,922	51	86	12,246
Gross Revenue Requirement	130,570	9,194	31,409	8,614	2,505	394	182,686
OATT Revenue	0	(1,830)	0	0	0	0	(1,830)
Other Revenue	(35)	(19)	(652)	(25)	(1,120)	(1)	(1,852)
Net Revenue Requirement	130,535	7,345	30,757	8,589	1,385	393	179,004

26. The results in Table 3 are consistent with previous studies to the extent that Chymko Consulting has as much generally followed the same methods of previous studies.[3] Compared to Chymko Consulting's 2008 cost allocation study for MECL, the largest shift in functionalized expense is related to power supply, which has dropped from eighty one percent to seventy three percent of the total functionalized cost (see Table 4 below). Chymko Consulting attributes this result to reduced power import costs compared to 2008 as the result of a five-year Power Purchase Agreement effective March 1, 2011.

27. Excluding power supply from the analysis, Table 4 also demonstrates that there is a shift in functionalized expenses from service lines and meters toward transmission and distribution networks. Chymko Consulting attributes this outcome to MECL's infrastructure investments since 2008, which ultimately affect how amortization, debt financing, return, and income tax are all functionalized.

[3] Exceptions are minor and are noted in paragraph 28.

Table 4 Functionalized MECL Revenue Requirement ($,000)							
	Power Supply	Trans'n	Distrib'n Network	Services and Metering	Customer Care	Lighting	Total
Percent of total							
2014 Revenue Requirement	73 %	4 %	17 %	5 %	1 %	0 %	100 %
2008 Revenue Requirement	81 %	4 %	10 %	5 %	1 %	0 %	100 %
Excluding Power Supply							
2014 Revenue Requirement	N/A	15 %	63 %	18 %	3 %	1 %	100 %
2008 Revenue Requirement	N/A	19 %	52 %	23 %	5 %	1 %	100 %

28. Also as part of MECL's improved cost reporting processes, the utility is more accurately identifying general operating expenses, administration, and supervision attributable to customer care, thus reducing the dependence on allocations. Chymko Consulting therefore views this internal improvement to have the added benefit of improving the accuracy of the cost allocation study.

3 CLASSIFICATION

29. Functionalized revenue requirement is next classified based on the generally accepted cost drivers that can be measured in terms of how customers use the system. Costs associated with upstream functions are generally accepted to be a function of the peak demand placed on the system and are classified accordingly. At the other extreme, downstream functions, such as services and metering, are generally a function of the number of sites served.[4]

3.1 METHOD

Power Supply

30. In the context of a vertically integrated and regulated electric utility, power supply requirements are generally considered to be a function of both peak demand and total energy consumed. Power supply is a function of total energy consumed because all else equal, a utility with 50,000 GWh of annual sales would incur higher power supply costs than a utility with 1,000 GWh of annual sales. However, even among two utilities with the same annual sales, generation resource planning (and therefore, cost) will differ based on the peak hourly demand. While a consistently flat electrical load may be better served by larger generating facilities suited for full-on production, a variable and peaking load will require a different mix of generating resources. Options for meeting variable peak demand may include smaller scale facilities, technologies that are able to ramp-up production on relatively short notice, or a combination of the two.

31. MECL's objective for this study is to apply methods that are consistent with previous studies. Therefore, this study continues with the same basic principles followed in previous MECL cost allocation studies in which power supply is classified as a combination of demand and energy related.[5] Purchases from NB Power and wind farms are classified as energy related because they are used to supply MECL's base load requirements. However, MECL's fixed annual payments for the capital cost of NB Power's Point Lepreau generating facilities is considered demand related.

32. Capital and operating costs associated with MECL's on-island generation resources are classified as demand related because on-island generation sources are called upon when supply from NB Power is insufficient to meet MECL demand. On the other hand, MECL's Energy Control Centre (ECC) is classified as ninety five percent energy related because the main purpose of the ECC is to manage and coordinate the delivery of energy supply. Because

[4] Note that Chymko Consulting's report often uses the term "sites" as opposed to "customers" in the context of a cost allocation study. The purpose of this terminology is to be clear that a cost allocation study is concerned with attributing revenue requirement to distribution points of delivery or "sites." Some customers may actually be served by multiple sites.
[5] A refinement to this study is to further differentiate demand-related capacity costs required for firm load such that they may be allocated to rate classes based on peak demand of firm load.

at least a portion of ECC activities must ultimately feed into long term resource planning, five percent of the ECC expenses are classified as demand related.[6]

Transmission

33. Transmission lines are part of a bulk delivery system that ultimately services all utility customers, including wholesale customers. Transmission infrastructure is unaffected by the addition of one more customer, unless the addition of that customer is expected to materially affect peak system demand. Chymko Consulting therefore considers transmission lines to be demand related and allocates these functions on the basis of coincident peak demand.[7] Coincident peak demand is appropriate for this allocation because transmission facilities must be capable of providing service during the time of system peak. PEI's demand for electricity is at its highest during the winter, and therefore MECL's backbone delivery system must be designed to accommodate peak demand at this time.

Distribution Network

34. Substations are part of a bulk delivery system that services virtually all of MECL customers. Also similar to transmission infrastructure, substations are generally unaffected by the addition of one more customer, unless the addition of that customer is expected to materially affect peak system demand. Thus, substations are classified as demand related and allocated on the basis of coincident peak demand.[8]

35. Functions such as primary lines, transformers, and secondary lines also form MECL's distribution network. These facilities must also be designed to meet peak demand, but it is also true that the cost of these functions will increase as more customers are added to the system. Expanding the distribution system to service new customers will require MECL to extend distribution lines and install new transformers, and so there will be a base level cost regardless of the capacity that these facilities will be required to carry.

36. This cost allocation study continues with the same basic principles followed in previous MECL cost allocation studies. MECL considers that circumstances have not materially changed and the Company's objective for this study is to apply consistent methods to previous studies and facilitate a more meaningful comparison of results over time. Thus, lines are classified as 50% demand related and 50% site related[9] whereas transformers are classified as 60% demand related and 40% site related.

[6] Prior to 1994, previous cost studies have also classified fuel and a portion of variable O&M expenditures related to on-island generation as energy related. Chymko Consulting understands that MECL generating resources are used more sparingly in recent years, thus only increasing the likelihood that they will be used for periods of peak demand.
[7] For transmission lines, peak demand is measured at the transmission system level including losses, which as noted earlier are not evenly distributed between rate classes.
[8] The allocator for substations is also adjusted to recognize that some large industrial customers are serviced at a transmission voltage and do not use substation facilities.
[9] For the allocation of distribution network functions, allocators are adjusted to recognize that some distribution customers are serviced at a primary voltage and do not use a MECL transformer or secondary line.

Services, Metering, and Customer Care

37. Functions such as service lines, metering, meter reading, billing, remittance & collection, and uncollectibles & damage claims are all classified as site related. It is generally recognized that the cost of these functions will primarily vary with the number of customers served. Factors other than demand, energy or sites also play a role in cost causation, but these adjustments are made by the choice of allocation and are discussed further in Section 4.

38. Finally, functions associated with service connections and late payments are also classified as site related. From a cost causation perspective, MECL tracks cost by rate class and so classification of these functions is mainly for presentation purposes. In Section 4, these functions are allocated to rate classes in the exact same proportion as actual revenue.

3.2 RESULT

39. MECL's classified revenue requirement is summarized in Table 5 below.

Table 5 Classified 2014 MECL Revenue Requirement ($,000)				
	Demand	Energy	Site	Total
Operating Expenses				
Energy Costs	28,982	77,734	101	106,818
ECAM Adjustment	2,715	9,643	0	12,358
Net Energy Costs	31,697	87,377	101	119,176
Distribution	1,987	6	1,932	3,925
Transmission	922	0	0	922
T&D - Other	1,163	0	831	1,994
Transmission - OATT	172	0	0	172
General	5,869	337	4,820	11,025
Total Operating Expenses	41,810	87,720	7,684	137,214
Amortization	0	0	0	
Other	370	270	48	688
Plant And Equipment	8,853	304	5,604	14,761
Total Amortization	9,223	575	5,652	15,450
Total Operating Income	51,033	88,294	13,336	152,663
Financing Expenses	0	0	0	
Long-Term Debt	7,247	169	4,567	11,983
Short-Term Debt	302	7	190	500
Charged To Construction	(223)	(5)	(140)	(368)
Amortization of Financing	3	0	2	5
Total Financing Expenses	7,329	171	4,619	12,119
Earnings before Tax	58,362	88,466	17,955	164,782
Income Taxes	3,422	80	2,156	5,658
Net Earnings	7,406	173	4,667	12,246
Gross Revenue Requirement	69,189	88,719	24,778	182,686
OATT Revenue	(1,830)	0	0	(1,830)
Other Revenue	(384)	(2)	(1,467)	(1,852)
Net Revenue Requirement	66,976	88,716	23,311	179,004

40. Chymko Consulting has applied the same methods as previous studies, and to the extent that the results in Table 5 vary from previous studies it is because different parts of revenue requirement will change at varying rates of growth. For instance, expenses related to power supply have dropped materially (see Section 3.2) and because most of power supply is classified as energy related, energy related revenue requirement also decreases. In Table 6 below, energy related revenue requirement decreases from sixty percent in the 2008 study to fifty percent in the current study.

41. Excluding power supply from the analysis, Table 6 also demonstrates the effect of shifts noted in functionalization. As per Section 2.2, the shift in functionalized expenses toward the transmission and distribution networks means that more of revenue requirement is classified as demand related.

Table 6 Classified MECL Revenue Requirement ($,000)				
	Demand	Energy	Site	Total
Percent of total				
2014 Revenue Requirement	37 %	50 %	13 %	100 %
2008 Revenue Requirement	30 %	60 %	10 %	100 %
Excluding Power Supply				
2014 Revenue Requirement	52 %	0 %	48 %	100 %
2008 Revenue Requirement	49 %	0 %	51 %	100 %

4 ALLOCATION

42. Once revenue requirement is classified between demand, energy, and site related, the next step is to allocate revenue requirement to rate classes. This requires some consideration of how customers should be grouped into rate classes for purposes of allocation as well as choosing the appropriate allocator for each expense.

4.1 RATE CLASSES

43. As a general principle, cost recovery and cost causation are the two basic reasons or rationales for grouping distribution sites into rate classes. Cost recovery is a matter of fairness because a significant portion of fixed infrastructure costs are recovered through usage-based rates. Usage and infrastructure cost are positively correlated, but because usage tends to increase at a faster rate than cost, a single rate class would unfairly recover a disproportionate amount of cost from higher-usage customers. In other words, an end-use customer that uses twice the energy does not necessarily cause the utility to incur two times the infrastructure cost. In fact, it is entirely possible that the two customers could require exactly the same infrastructure, but one customer will pay much more because rates are often usage-based. Separating customers into rate classes allows the utility to set different rates for each rate class so as to reduce this disparity.

44. Cost causation is the other reason or rationale for rate classes. Given that the objective of cost allocation is to fairly apportion revenue requirement to end-use distribution customers, then it is necessary to group customers by similar infrastructure cost characteristics. It is important to note that distribution infrastructure characteristics need not be identical within a rate class and infrastructure itself is not necessarily sufficient justification to create a new rate class. In fact, distribution infrastructure characteristics will never be identical within any group of any material size. In addition to being administratively impractical to administer dozens of rate classes, it is not a theoretical imperative for all customers within a rate class to be perfectly homogenous.[10] Nevertheless, creating rate classes of similar cost characteristics allows the utility to allocate or assign cost in a way that acknowledges the infrastructure used by each rate class.

45. MECL rate classes and rate structure is a product of a 1990s regulatory framework that obliged MECL to adopt the same rate schedules as New Brunswick Power. As MECL returns to a more traditional cost-of-service regulatory framework, its long-term intention is to fully rationalize the definition of rate classes and the rate structure within each rate class. This process will be gradual so as to minimize customer impacts.

[10] In practice, there are a number of other factors that will mitigate differences in distribution infrastructure. For instance, the utility's contribution policy helps to levelize construction costs before they are added to rate base. In addition, higher costs not addressed by the contribution policy are often associated with greater usage and higher revenue since a large portion of utility costs is recovered from an energy charge.

46. MECL's immediate and primary concern to be addressed in an upcoming tariff application is the composition of the residential rate class and the declining two-block rate structure.[11] The benefit of a declining block rate structure is the ability to fairly recover fixed cost when there is a wide range of low and high use customers in one rate class. From a purely cost-causation perspective, revenue from high-use customers tends to increase at a faster rate than the cost to serve so a declining per-kWh rate is one method (among several) to address this issue. The downside of a declining blocked rate is that it also communicates to the customer that the *value* of energy is decreasing with every kWh consumed. This is also contrary to the long run view that the utility's cost per-kWh is actually increasing because increased consumption accelerates the need for major infrastructure upgrades.

47. MECL is intending to phase out the residential declining block rate structure, subject to managing the transitional impacts. In this regard, one area of concern for MECL is the fact that the current residential rate class includes farm customers. Specifically, MECL has observed that farms consume twice the energy per customer than the average residential customer. Whereas the second energy block would rarely apply to the average (non-farm) residential customer, approximately fifty percent of the farm customers' energy charges are associated with the second energy block.[12] Thus, eliminating the declining block structure would have a disproportionate impact on farm customers.

48. Eliminating the declining block rate is more easily managed if farm customers are first separated from the residential rate class. Thus, Chymko Consulting modified its cost allocation model to accommodate an additional farm rate class separate from residential. This preparatory work for rate design will allow MECL to calculate two different per-kWh rates for each rate class with due regard for the impact on each group. For this study, Chymko Consulting assumed the same service line cost and pro-rated peak demand (based on energy sales). Although not modelled in this cost allocation study, further analysis might establish differences in the cost of a service line (due to distances involved) and a different peak demand profile. Depending upon the conclusions of that analysis, farm customers might be better justified to be part of a small general service rate class, or left as its own unique rate class.

4.2 ALLOCATORS

49. The final step of the cost allocation study is to allocate the utility's classified revenue requirement to rate classes. The choice of allocation factor is to a large degree influenced by classification. For example, demand related costs are generally allocated by the same proportions as the peak demand of each rate class. Similarly, energy related costs are allocated by the same proportions as energy sales and site related costs are allocated by the

[11] As of March 1, 2014, the residential per-kWh rate was $0.1278 / kWh for the first 2,000 kWh and $0.0985 / kWh thereafter.
[12] The exception to this rule is seasonal farm customers, which are much more similar to equivalent seasonal residential customers. In the conclusions of Section 5, Chymko Consulting recommends that these customers remain in the residential seasonal rate class.

relative number of sites within each rate class. Below are some common measures of customer usage that are often used as the basis for allocation to rate classes.

Coincident Peak Demand (CP)

50. Coincident peak represents each rate class's contribution to the utility's peak demand day. This is typically measured over the period of one year, but other variants include the sum of peak summer and peak winter demands as well as the sum of daily peak demand for twelve consecutive months. This type of allocator is often paired with demand-related costs associated with high-voltage transmission. The MECL system peak occurs during the winter because lighting and heating demand.

51. While the coincident peak demand allocator recognizes customers are collectively peaking, it also recognizes that that individual customers use energy at different times of the day. For example, a transmission line servicing one 1 MW customer is likely to require higher capacity than a line that services one thousand 1 kW customers who collectively add up to 1 MW. Given that individual customers do not necessarily peak at the same time, this diversity can be factored into transmission system design. The calculation of coincident peak demand also reflects this diversity, making it an appropriate allocator for transmission facilities.

Non-Coincident Peak Demand (NCP)

52. Non-coincident peak demand (NCP) represents the peak demand for each rate class without regard for when the peak occurs for other rate classes. Therefore, the sum of all rate class NCPs is by definition equal to or greater than the system peak. This type of allocator is typically paired with demand-related costs associated with more localized distribution facilities. NCP is widely recognized as an appropriate allocator for components of the distribution system that must be designed and built to handle local peak demand situations that do not necessarily correspond to the overall system peak.

53. Distribution network functions classified as demand related are allocated on the basis of non-coincident peak demand. As facilities become more localized, the needs of specific local customers play a more important role in network design. Individual customers served by a distribution feeder are still diverse, but compared to a bulk transmission system that services a greater number and a broader mix of customers, diversity is less of a factor. Thus, local distribution customers are more likely to peak at the same time compared to a random collection of residential, commercial, and industrial customers. Given that local distribution facilities are more likely to serve one particular rate class, an allocation based on non-coincident rate class peak demand is appropriate. The calculation of non-coincident peak demand reflects diversity within a rate class, but not between rate classes.

Energy Use

54. An energy allocator is calculated from rate class kWh sales, grossed-up for losses. This allocator is used for power supply classified as energy related, but is not otherwise used for the other, wires-related functions.

Number of Sites

55. The number of sites within each rate class is used to allocate site-related costs. Depending upon the function to be allocated, a number of adjustments are required. For instance, the allocation of the secondary lines function should exclude distribution sites that are just served at the primary voltage. Another adjustment is necessary for lighting fixtures and other unmetered points of delivery, which are high in number but the addition of one more fixture should not cause distribution cost to increase as much as the addition of one more residential customer, for example.[13]

56. Furthermore, site counts are sometimes weighted if the per-site cost is known to differ between rate classes and neither a demand nor an energy based allocation is a reasonable alternative. This situation often occurs when a number of factors either directly or indirectly affect the per-site cost and the net impact is material. This is a generally accepted cost allocation practice and in its cost allocation model, Chymko Consulting weights the site-based allocations of functions such as service lines, meter assets, meter reading, billing, and remittance & collection.

57. While the functions for service connection and late payment revenue are classified as site related, this is mainly for completeness. This revenue is directly assigned to rate classes according the same proportions as it was collected.

Summary of Allocators

58. Detailed calculations of all allocators appear in Appendix A and a summary is provided below in Table 7.

[13] In this study, Chymko Consulting discounted the number of lighting fixtures and unmetered points of delivery by a factor of 0.40. Chymko Consulting selected 0.40 such that the allocated secondary distribution voltage cost per fixture is approximately one fifth of a residential customer.

Table 7 Summary of 2014 Peak Demand Allocators				
	Coincident Peak[14] (kW)	Non-Coincident Peak[15] (kW)	Energy Including Losses[14] (MWh)	Sites
Residential	119,190	142,428	515,510	55,530
Residential (S)	738	7,449	18,359	7,328
Farm	10,948	13,082	47,351	1,987
General Service 1	62,272	83,244	399,673	7,049
General Service 1 (S)	0	3,958	8,620	1,711
General Service 2	1,319	2,349	10,023	87
Small Industrial	15,778	32,095	96,049	268
Large Industrial	17,241	2,770	147,055	4
Lights	1,579	1,552	6,772	4,447
Unmetered	359	349	2,612	269
Total	229,423	289,275	1,252,023	78,679

4.3 RESULT

59. MECL's allocated revenue requirement is shown in detail in Appendix A while a simplified version is shown in Table 8 below.

Table 8 Allocated 2014 MECL Revenue Requirement ($,000)						
	Operating Expenses	Capital Expenses	Gross Revenue Require-ment	OATT Revenue	Other Revenue	Net Revenue Require-ment
Residential	63,884	26,034	89,918	(951)	(1,354)	87,614
Residential (S)	2,156	1,965	4,121	(6)	(86)	4,028
Farm	5,548	1,738	7,287	(87)	(26)	7,173
General Service 1	40,323	9,698	50,021	(497)	(266)	49,258
General Service 1 (S)	805	556	1,360	(0)	(20)	1,340
General Service 2	968	216	1,183	(11)	(4)	1,168
Small Industrial	9,888	2,549	12,437	(126)	(62)	12,249
Large Industrial	12,279	1,354	13,634	(137)	(7)	13,489
Lights	1,052	1,273	2,325	(13)	(23)	2,289
Unmetered	311	90	401	(3)	(2)	396
Total	137,214	45,472	182,686	(1,830)	(1,852)	179,004

60. Again, results are consistent with prior studies and differences from the 2008 study are largely caused by how MECL's revenue requirement and customer base has evolved since 2008. A comparison appears below in Table 9.

[14] Calculated at input voltage.
[15] Calculated at primary voltage.

Table 9 Allocated MECL Revenue Requirement ($,000)				
	Total Revenue Requirement		Excluding Power Supply	
	2014	2008	2014	2008
Residential[16]	53 %	50 %	63 %	68 %
Residential (S)[16]	2 %	2 %	5 %	3 %
General Service 1	28 %	30 %	19 %	19 %
General Service 1 (S)	1 %	1 %	2 %	1 %
General Service 2	1 %	0 %	0 %	0 %
Small Industrial	7 %	5 %	5 %	3 %
Large Industrial	8 %	11 %	2 %	2 %
Lights	1 %	1 %	3 %	3 %
Unmetered	0 %	0 %	0 %	0 %
Total	100 %	100 %	100 %	100 %

61. Overall, the Residential rate class as well as General Service 2 and Small Industrial are allocated a greater share of total revenue requirement compared to the 2008 study. Although it has decreased in weight since 2008, the power supply function still represents two thirds of revenue requirement and is mostly allocated on the basis of energy. Residential, General Service 2, and Small Industrial kWh sales per customer all increased from 2008 and consequently, these rate classes receive a larger allocation of power supply cost.

62. When the effects of power supply are excluded, expenses allocated to the Residential rate class actually decrease from the previous study. Section 2.2 noted that expenses related to delivery are shifting toward transmission, which is classified as demand related in Section 3.2. General Service and Industrial sites contribute more to peak demand on a per-customer basis and the end result is that these rate classes are allocated a larger share of delivery compared to 2008.

[16] Including farm for purposes of comparison to 2008.

5 CONCLUSIONS

63. Chymko Consulting's cost allocation study is based on MECL's 2014 Statement of Earnings. To use these results as a yardstick for a 2016 rate proposal, it is necessary to express the allocated net revenue requirement as a percentage share. This adjustment is shown in Table 10.

Table 10
Allocated 2014 Net Revenue Requirement from Rates ($,000)

	Net Revenue Requirement	Percent Share
Residential	87,614	48.9 %
Residential (S)[17]	4,028	2.3 %
Farm	7,173	4.0 %
General Service 1	49,258	27.5 %
General Service 1 (S)	1,340	0.7 %
General Service 2	1,168	0.7 %
Small Industrial	12,249	6.8 %
Large Industrial	13,489	7.5 %
Lights	2,289	1.3 %
Unmetered	396	0.2 %
Total	179,004	100.0 %

64. Allocated cost in Table 10 is only one yardstick or guideline for designing 2016 rates. Other rate design considerations are equally important and one such consideration is the current structure and level of rates. If the desired change is too significant and would cause rate shock (i.e. an increase greater than ten percent of the total bill), then it may be necessary to adopt additional strategies to implement change gradually. One such indicator of the possibility of rate shock is the revenue-to-cost ratio. Table 11 below calculates revenue to cost ratios on current rates as well as providing similarly calculated revenue to cost ratios from the 2008 study.

[17] Of note is the very small allocation to farm customers that are currently billed as Seasonal Residential; this is primarily due to the fact that MECL identified only fifteen such sites in its 2014 data. Chymko Consulting considers there to be too few customers and too few sales to create an administratively feasible rate. Not only is this too small of a sample to depend on consistent cost allocation results over time, but 2014 usage appears very similar to Seasonal Residential and the administration of such a rate class is likely to be burdensome. Thus, Chymko Consulting recommends that these two groups remain in the same Seasonal rate class.

Table 11 Allocated 2014 Net Revenue Requirement from Rates ($,000)				
	Revenue Collected	Allocated Cost	Revenue to Cost Ratio	2008 Study
Residential	45.0 %	48.9 %	92 %	91 %
Residential (S)[18]	2.2 %	2.3 %	97 %	122 %
Farm	3.3 %	4.0 %	81 %	N/A
General Service 1	32.3 %	27.5 %	117 %	114 %
General Service 1 (S)[18]	0.9 %	0.7 %	115 %	132 %
General Service 2	0.8 %	0.7 %	120 %	122 %
Small Industrial	6.6 %	6.8 %	96 %	109 %
Large Industrial	7.5 %	7.5 %	100 %	86 %
Lights[19]	1.3 %	1.3 %	103 %	119 %
Unmetered[19]	0.2 %	0.2 %	103 %	98 %
Total	100.0 %	100.0 %	100 %	100 %

65. Given that the objective of a cost allocation study is to fairly allocate revenue requirement to rate classes on a cost causation basis, a ratio below 100% in Table 11 indicate that (all else equal) rate revenues should be raised for that rate class. Similarly, a ratio above 100% indicates that current rate revenues are above cost and should (all else equal) be lowered.

66. What is generally accepted to be a reasonable revenue to cost ratio will vary among Canadian provinces and regulators. For MECL's specific circumstances, Chymko Consulting considers 100% to be a long term objective, but variances in any given year would be expected and reasonable. Actual rate impacts will depend upon MECL's rate design proposal, and MECL's proposal will need to make such other considerations such as rate shock and whether an overall general rate increase is required for 2016. Moreover, one must take into account that rates are set prospectively and that normal forecast variances in cost, load, and revenue will mean that the intended revenue to cost ratio will rarely be achieved. Pending further rate design analysis, it may be necessary to compromise revenue to cost ratio objectives in the short run so as to mitigate rate shock for one or more rate classes or even subsets of customers within rate classes. In this situation, a short to medium term objective of transitioning customer rates toward a revenue to cost ratio between 90% and 110% may be more reasonable.

67. Unit cost is another output from the cost allocation study with potential use for rate design. Unit cost is calculated by dividing billing units into allocated cost for each rate class. In Table 12 below, Chymko Consulting divides billing demand (i.e. peak demand on the customers' bills) into allocated demand-related cost and number of bills into allocated site-related cost.

[18] The 2008 study underestimated the number of seasonal sites reported in MECL's billing system. This had the effect of understating cost allocated to seasonal rate classes, resulting in an overstated revenue to cost ratio.
[19] The 2008 study allocated lighting and unmetered cost based on number of customer accounts, rather than points of distribution delivery (see paragraph 55).

Table 12 Unit Cost Results for Consideration in Rate Design		
	Demand Related ($/kW/Mo Billing Demand)	Site Related ($/Bill/Mo)
Residential	N/A	24.16
Residential (S)	N/A	44.14
Farm	N/A	25.34
General Service 1	20.21	26.94
General Service 1 (S)	18.26	50.79
General Service 2	19.73	29.87
Small Industrial	17.98	38.40
Large Industrial	12.14	151.77
Lights	N/A	444.72
Unmetered	73.35	62.57
Total	0.00	898.70

68. Site related unit cost gives some indication for an appropriate monthly service charge. Given that the service line, meter, and billing costs are all considered site related, a monthly service charge equal to unit cost would at least ensure the utility is recovering the localized fixed costs from every customer regardless of their consumption. One such application is the seasonal rate, which requires just as much local distribution infrastructure to serve but is billed for only half the year. From a cost-causation perspective, it would be fair for the seasonal rate class to have a higher monthly service charge to ensure these local infrastructure costs are recovered from each site.[20]

69. Similar to the site related unit cost, the demand related unit cost in Table 12 is calculated as the demand related cost divided by the kilowatts billed to customers in that rate class. This only applies to rate classes that are metered and billed for peak demand and unit cost also provides useful information for a potential demand charge. Demand related costs are predominantly related to reserve power supply, transmission, and primary voltage distribution and flowing through the demand related unit cost in the monthly demand charge helps communicate to these customers the value of reducing peak demand.

Final Remarks

70. The overall purpose of a cost allocation study is to develop a benchmark to guide rate design. Rates that reflect the full cost of electric utility service are generally accepted as a worthwhile objective, subject to a number of other considerations that must be taken into account. MECL's existing rate structure presents a number of challenges simply because the basic form and structure has not changed for approximately twenty years. Customer acceptance is an important consideration in rate design and the longevity of the existing structure may make some changes, regardless of their merit, more difficult to accept. It is for this reason that cost allocation results alone should not be the determining factor for rates. The revenue to cost ratios in Table 11 indicates that some rates might need to change significantly. Pending

[20] Note that there is an offsetting effect in which seasonal rate classes are allocated fewer demand related costs because they contribute little to system peak by virtue of being less active in the winter.

further analysis of any such change, it may well be that rate rebalancing would need to be implemented gradually over the course of multiple years.

APPENDIX A: DETAILED SCHEDULES

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Schedule 1.0											
Summary of Cost Allocation Results											
Revenue Requirement ($,000)											
	Residenti al	Residenti al (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmeter ed	Total
Revenue Collected	83,555	4,090	6,052	59,134	1,598	1,433	12,097	13,813	2,470	419	184,662
less Rate of Return Adjustment	(2,110)	(160)	(140)	(782)	(45)	(17)	(205)	(106)	(101)	(7)	(3,675)
less ECAM 2003 Recovery	(872)	(24)	(80)	(616)	(11)	(15)	(150)	(200)	(11)	(4)	(1,984)
Base Revenue, Comparable for 20:	80,573	3,905	5,832	57,737	1,542	1,400	11,741	13,506	2,358	408	179,004
Revenue Share	45 %	2 %	3 %	32 %	1 %	1 %	7 %	8 %	1 %	0 %	100 %
Allocated Cost (net of Other Reven	87,614	4,028	7,173	49,258	1,340	1,168	12,249	13,489	2,289	396	179,004
Allocated Share	49 %	2 %	4 %	28 %	1 %	1 %	7 %	8 %	1 %	0 %	100 %
Revenue to Cost Ratio	92 %	97 %	81 %	117 %	115 %	120 %	96 %	100 %	103 %	103 %	100 %
Revenue to Cost Ratio (2008 Stud	91 %	122 %	N/A	114 %	132 %	122 %	109 %	86 %	119 %	98 %	100 %
Unit Cost											
Demand Related ($/kW/Mo Billing	N/A	N/A	N/A	20.21	18.26	19.73	17.98	12.14	N/A	73.35	0.00
Site Related ($/Bill/Mo)	24.16	44.14	25.34	26.94	50.79	29.87	38.40	151.77	444.72	62.57	898.70

Schedule 1.1											
Unit Cost Summary											
Full Revenue Requirement (¢/kWh Sales)											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Operating Expenses											
Energy Costs	9.91	7.25	9.90	8.90	6.77	8.43	9.02	7.44	10.12	8.70	9.15
ECAM Adjustment	1.13	0.87	1.13	1.04	0.83	0.99	1.05	0.88	1.15	1.02	1.06
Net Energy Costs	11.04	8.12	11.03	9.94	7.60	9.42	10.07	8.31	11.27	9.72	10.21
Distribution	0.49	1.28	0.32	0.20	0.80	0.19	0.24	0.02	2.08	0.34	0.34
Transmission	0.10	0.02	0.10	0.07	0.00	0.06	0.07	0.05	0.10	0.06	0.08
Transmission and Distribution -	0.24	0.60	0.17	0.11	0.39	0.11	0.14	0.01	0.86	0.18	0.17
Transmission - OATT	0.02	0.00	0.02	0.01	0.00	0.01	0.01	0.01	0.02	0.01	0.01
General	1.41	2.50	0.94	0.59	1.31	0.49	0.59	0.24	2.53	2.63	0.94
Total Operating Expenses	13.31	12.53	12.58	10.92	10.10	10.27	11.12	8.64	16.87	12.94	11.75
Amortization											
Amortization Other	0.07	0.06	0.07	0.05	0.04	0.05	0.05	0.04	0.11	0.05	0.06
Amortization Plant And Equipme	1.76	3.74	1.28	0.84	2.28	0.74	0.92	0.30	7.12	1.22	1.26
Total Amortization	1.83	3.80	1.34	0.90	2.32	0.78	0.98	0.34	7.23	1.27	1.32
Total Operating Income	15.14	16.33	13.93	11.82	12.43	11.06	12.10	8.98	24.09	14.22	13.07
Financing Expenses											
Long-Term Debt	1.43	3.04	1.04	0.69	1.86	0.60	0.75	0.24	5.26	0.98	1.03
Short-Term Debt	0.06	0.13	0.04	0.03	0.08	0.03	0.03	0.01	0.22	0.04	0.04
Interest Charged To Constructio	(0.04)	(0.09)	(0.03)	(0.02)	(0.06)	(0.02)	(0.02)	(0.01)	(0.16)	(0.03)	(0.03)
Amortization of Financing Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Financing Expenses	1.45	3.07	1.05	0.70	1.88	0.61	0.76	0.25	5.32	0.99	1.04
Earnings before Income Taxes	16.59	19.40	14.98	12.52	14.31	11.66	12.86	9.23	29.41	15.21	14.11
Income Taxes	0.68	1.44	0.49	0.33	0.88	0.28	0.36	0.12	2.48	0.46	0.48
Net Earnings	1.46	3.11	1.06	0.71	1.90	0.61	0.77	0.25	5.38	1.00	1.05
Gross Revenue Requirement	18.73	23.94	16.53	13.55	17.08	12.56	13.99	9.59	37.28	16.66	15.65
OATT Revenue	(0.20)	(0.03)	(0.20)	(0.13)	(0.00)	(0.11)	(0.14)	(0.10)	(0.20)	(0.12)	(0.16)
Other Revenue	(0.28)	(0.50)	(0.06)	(0.07)	(0.25)	(0.05)	(0.07)	(0.01)	(0.38)	(0.09)	(0.16)
Net Revenue Requirement	18.25	23.41	16.27	13.34	16.83	12.40	13.77	9.49	36.70	16.45	15.33

Schedule 1.1										
Unit Cost Summary										
Demand Related Revenue Requirement ($/kW/Mo Billing Demand)										
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered
Operating Expenses										
Energy Costs	N/A	N/A	N/A	8.72	0.14	7.93	6.95	5.71	N/A	33.80
ECAM Adjustment	N/A	N/A	N/A	0.82	0.00	0.75	0.66	0.45	N/A	3.20
Net Energy Costs	0.00	0.00	0.00	9.54	0.14	8.68	7.61	6.16	0.00	37.00
Distribution	N/A	N/A	N/A	0.62	1.95	0.71	0.70	0.11	N/A	1.86
Transmission	N/A	N/A	N/A	0.27	0.00	0.24	0.21	0.27	N/A	1.05
Transmission and Distribution -	N/A	N/A	N/A	0.36	1.15	0.42	0.41	0.05	N/A	1.09
Transmission - OATT	N/A	N/A	N/A	0.05	0.00	0.05	0.04	0.05	N/A	0.20
General	N/A	N/A	N/A	1.76	2.03	1.75	1.61	1.18	N/A	6.27
Total Operating Expenses	N/A	N/A	N/A	12.60	5.27	11.84	10.58	7.83	N/A	47.45
Amortization										
Amortization Other	N/A	N/A	N/A	0.11	0.06	0.10	0.09	0.08	N/A	0.41
Amortization Plant And Equipme	N/A	N/A	N/A	2.67	4.31	2.75	2.57	1.57	N/A	9.17
Total Amortization	N/A	N/A	N/A	2.78	4.37	2.86	2.67	1.65	N/A	9.58
Total Operating Income	N/A	N/A	N/A	15.39	9.64	14.70	13.25	9.48	N/A	57.03
Financing Expenses										
Long-Term Debt	N/A	N/A	N/A	2.19	3.60	2.26	2.11	1.29	N/A	7.48
Short-Term Debt	N/A	N/A	N/A	0.09	0.15	0.09	0.09	0.05	N/A	0.31
Interest Charged To Constructio	N/A	N/A	N/A	(0.07)	(0.11)	(0.07)	(0.07)	(0.04)	N/A	(0.23)
Amortization of Financing Costs	N/A	N/A	N/A	0.00	0.00	0.00	0.00	0.00	N/A	0.00
Total Financing Expenses	N/A	N/A	N/A	2.21	3.64	2.28	2.14	1.31	N/A	7.57
Earnings before Income Taxes	N/A	N/A	N/A	17.60	13.28	16.98	15.38	10.78	N/A	64.60
Income Taxes	N/A	N/A	N/A	1.03	1.70	1.07	1.00	0.61	N/A	3.53
Net Earnings	N/A	N/A	N/A	2.24	3.68	2.31	2.16	1.32	N/A	7.64
Gross Revenue Requirement	N/A	N/A	N/A	20.87	18.65	20.35	18.54	12.71	N/A	75.77
OATT Revenue	N/A	N/A	N/A	(0.54)	(0.00)	(0.49)	(0.43)	(0.55)	N/A	(2.08)
Other Revenue	N/A	N/A	N/A	(0.12)	(0.40)	(0.14)	(0.14)	(0.03)	N/A	(0.35)
Net Revenue Requirement	N/A	N/A	N/A	20.21	18.26	19.73	17.98	12.14	N/A	73.35

Schedule 1.1											
Unit Cost Summary											
Energy Related Revenue Requirement (¢/kWh)											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Operating Expenses											
Energy Costs	6.67	6.62	6.67	6.72	6.72	6.61	6.71	6.42	6.74	6.74	6.66
ECAM Adjustment	0.83	0.82	0.83	0.83	0.83	0.82	0.83	0.80	0.84	0.84	0.83
Net Energy Costs	7.49	7.45	7.49	7.55	7.56	7.42	7.54	7.22	7.58	7.58	7.48
Distribution	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transmission	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transmission and Distribution -	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transmission - OATT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
General	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Total Operating Expenses	7.52	7.47	7.52	7.58	7.59	7.45	7.57	7.25	7.61	7.61	7.51
Amortization											
Amortization Other	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Amortization Plant And Equipme	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Total Amortization	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Total Operating Income	7.57	7.52	7.57	7.63	7.63	7.50	7.62	7.30	7.66	7.66	7.56
Financing Expenses											
Long-Term Debt	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Short-Term Debt	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Interest Charged To Constructi	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
Amortization of Financing Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Financing Expenses	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Earnings before Income Taxes	7.59	7.54	7.59	7.65	7.65	7.52	7.63	7.31	7.67	7.67	7.58
Income Taxes	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Net Earnings	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.01
Gross Revenue Requirement	15.20	15.10	15.20	15.32	15.32	15.06	15.28	14.64	15.37	15.37	15.17
OATT Revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Revenue	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
Net Revenue Requirement	15.20	15.10	15.20	15.32	15.32	15.06	15.28	14.64	15.37	15.37	15.17

Schedule 1.1											
Unit Cost Summary											
Site Related Revenue Requirement ($/Bill)											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Operating Expenses											
Energy Costs	0.11	0.19	0.11	0.11	0.21	0.11	0.11	0.05	1.89	0.20	3.08
ECAM Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net Energy Costs	0.11	0.19	0.11	0.11	0.21	0.11	0.11	0.05	1.89	0.20	3.08
Distribution	2.04	3.62	2.04	2.00	4.04	2.16	2.72	5.13	38.61	3.20	65.56
Transmission	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transmission and Distribution -	0.88	1.57	0.88	0.88	1.75	0.88	0.88	0.23	15.33	1.62	24.92
Transmission - OATT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
General	5.42	7.51	5.25	5.14	7.70	5.50	5.61	37.03	38.52	30.89	148.57
Total Operating Expenses	8.45	12.90	8.28	8.13	13.70	8.65	9.32	42.44	94.34	35.92	242.13
Amortization											
Amortization Other	0.05	0.09	0.05	0.05	0.10	0.05	0.06	0.05	0.84	0.09	1.43
Amortization Plant And Equipme	5.71	10.79	5.71	6.52	12.67	7.11	11.26	33.11	126.16	9.20	228.24
Total Amortization	5.77	10.88	5.76	6.57	12.77	7.17	11.31	33.16	127.00	9.28	229.67
Total Operating Income	14.22	23.77	14.04	14.70	26.47	15.82	20.63	75.61	221.35	45.20	471.80
Financing Expenses											
Long-Term Debt	4.67	8.76	4.66	5.62	10.32	6.13	9.79	30.61	91.93	7.33	179.81
Short-Term Debt	0.19	0.37	0.19	0.23	0.43	0.26	0.41	1.28	3.83	0.31	7.50
Interest Charged To Constructi	(0.14)	(0.27)	(0.14)	(0.17)	(0.32)	(0.19)	(0.30)	(0.94)	(2.83)	(0.23)	(5.53)
Amortization of Financing Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.04	0.00	0.08
Total Financing Expenses	4.72	8.86	4.71	5.69	10.43	6.20	9.90	30.96	92.97	7.41	181.85
Earnings before Income Taxes	18.94	32.63	18.75	20.39	36.90	22.02	30.53	106.57	314.32	52.61	653.65
Income Taxes	2.20	4.14	2.20	2.65	4.87	2.89	4.62	14.45	43.40	3.46	84.90
Net Earnings	4.77	8.95	4.76	5.74	10.54	6.26	10.00	31.29	93.95	7.49	183.76
Gross Revenue Requirement	25.91	45.72	25.71	28.78	52.31	31.17	45.15	152.31	451.67	63.56	922.31
OATT Revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Revenue	(1.74)	(1.58)	(0.37)	(1.84)	(1.53)	(1.30)	(6.76)	(0.54)	(6.96)	(0.99)	(23.61)
Net Revenue Requirement	24.16	44.14	25.34	26.94	50.79	29.87	38.40	151.77	444.72	62.57	898.70

Schedule 1.2											
Unit Cost by Function											
Full Revenue Requirement (¢/kWh Sales)											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	2.02	0.47	2.02	1.42	0.14	1.20	1.48	1.05	2.05	1.27	1.62
Purchased Power	10.22	7.89	10.22	9.38	7.53	8.95	9.48	7.92	10.36	9.21	9.55
Transmission	0.79	0.14	0.79	0.54	0.00	0.45	0.57	0.39	0.81	0.48	0.63
Substations	0.32	0.06	0.32	0.21	0.00	0.18	0.23	0.02	0.33	0.19	0.24
Primary Lines	1.61	4.47	1.03	0.66	2.88	0.63	0.83	0.04	6.42	1.24	1.11
Transformers	1.26	3.21	0.89	0.59	2.23	0.59	0.80	0.04	4.34	0.91	0.90
Secondary Lines	0.57	1.58	0.36	0.23	1.01	0.22	0.29	0.02	2.26	0.44	0.39
Service Lines	0.86	3.77	0.34	0.16	2.13	0.09	0.06	0.00	3.72	0.58	0.52
Meter Assets	0.21	0.79	0.08	0.10	0.48	0.05	0.04	0.00	0.00	0.00	0.14
Meter Reading	0.16	0.33	0.06	0.02	0.09	0.01	0.00	0.00	0.00	0.00	0.08
Billing	0.15	0.32	0.06	0.03	0.14	0.01	0.00	0.00	0.05	2.02	0.08
Remittance & Collection	0.13	0.27	0.05	0.02	0.12	0.01	0.00	0.00	0.07	0.12	0.07
Uncollectibles & Damage Claims	0.09	0.34	0.04	0.02	0.17	0.01	0.00	0.00	0.00	0.00	0.05
Service Connections	(0.06)	(0.13)	0.00	(0.00)	(0.02)	0.00	(0.00)	0.00	(0.00)	0.00	(0.03)
Late Payments	(0.10)	(0.07)	0.00	(0.03)	(0.07)	(0.01)	(0.02)	0.00	(0.02)	(0.02)	(0.05)
Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.30	0.00	0.03
Total	18.25	23.41	16.27	13.34	16.83	12.40	13.77	9.49	36.70	16.45	15.33
Demand Related Revenue Requirement ($/kW/Mo Billing Demand)											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	0.00	0.00	0.00	5.09	0.00	4.59	4.02	5.16	0.00	19.64	11.50
Purchased Power	0.00	0.00	0.00	7.42	0.00	6.75	5.91	4.09	0.00	28.86	16.28
Transmission	0.00	0.00	0.00	2.16	0.00	1.95	1.71	2.19	0.00	8.33	4.88
Substations	0.00	0.00	0.00	0.85	0.00	0.79	0.70	0.13	0.00	3.39	1.84
Primary Lines	0.00	0.00	0.00	2.02	7.85	2.43	2.43	0.25	0.00	5.65	4.30
Transformers	0.00	0.00	0.00	1.96	7.64	2.36	2.36	0.24	0.00	5.49	4.18
Secondary Lines	0.00	0.00	0.00	0.71	2.77	0.85	0.86	0.09	0.00	1.99	1.51
Service Lines	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meter Assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meter Reading	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Billing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Remittance & Collection	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Uncollectibles & Damage Claims	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Service Connections	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Late Payments	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	0.00	0.00	0.00	20.21	18.26	19.73	17.98	12.14	0.00	73.35	44.49

Schedule 1.2											
Unit Cost by Function											
Energy Related Revenue Requirement (¢/kWh)											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Purchased Power	7.47	7.42	7.47	7.53	7.53	7.40	7.51	7.19	7.55	7.55	7.46
Transmission	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Substations	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Primary Lines	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transformers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Secondary Lines	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Service Lines	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meter Assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meter Reading	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Billing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Remittance & Collection	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Uncollectibles & Damage Claims	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Service Connections	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Late Payments	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	7.61	7.56	7.61	7.67	7.67	7.54	7.65	7.33	7.69	7.69	7.60
Site Related Revenue Requirement ($/Bill)											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Purchased Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transmission	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Substations	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Primary Lines	6.85	12.26	6.85	6.85	13.65	6.85	6.85	3.43	119.33	12.65	195.57
Transformers	4.44	7.95	4.44	4.44	8.85	4.44	4.44	0.00	77.36	8.20	124.57
Secondary Lines	2.42	4.32	2.42	2.42	4.81	2.42	2.42	0.00	42.06	4.46	67.73
Service Lines	6.23	13.19	6.23	6.88	16.44	8.25	17.72	63.60	75.65	8.02	222.21
Meter Assets	1.54	2.76	1.54	4.33	3.69	4.96	10.02	50.17	0.00	0.00	79.02
Meter Reading	1.16	1.16	1.16	0.71	0.71	1.16	1.16	5.80	0.00	0.00	13.02
Billing	1.11	1.11	1.11	1.11	1.11	1.11	1.11	27.84	1.11	27.84	64.58
Remittance & Collection	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	1.35	1.72	10.51
Uncollectibles & Damage Claims	0.66	1.18	0.66	0.66	1.31	0.66	0.00	0.00	0.00	0.00	5.11
Service Connections	(0.45)	(0.46)	0.00	(0.18)	(0.18)	0.00	(0.14)	0.00	(0.01)	0.00	(1.42)
Late Payments	(0.73)	(0.26)	0.00	(1.20)	(0.53)	(0.91)	(6.13)	0.00	(0.43)	(0.31)	(10.50)
Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	128.29	0.00	128.29
Total	24.16	44.14	25.34	26.94	50.79	29.87	38.40	151.77	444.72	62.57	898.70

Schedule 1.3											
Allocated Revenue Requirement ($,000)											
Full Revenue Requirement											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Operating Expenses											
Energy Costs	47,570	1,248	4,365	32,871	539	794	8,020	10,570	631	209	106,818
ECAM Adjustment	5,434	150	499	3,837	66	93	934	1,247	72	25	12,358
Net Energy Costs	53,004	1,398	4,865	36,708	605	887	8,953	11,817	703	234	119,176
Distribution	2,361	221	141	740	64	18	215	29	130	8	3,925
Transmission	479	3	44	250	0	5	63	69	6	1	922
Transmission and Distribution -	1,174	103	75	408	31	10	124	12	54	4	1,994
Transmission - OATT	89	1	8	47	0	1	12	13	1	0	172
General	6,777	431	416	2,169	105	46	521	339	158	63	11,025
Total Operating Expenses	63,884	2,156	5,548	40,323	805	968	9,888	12,279	1,052	311	137,214
Amortization											
Amortization Other	339	11	29	193	4	4	49	53	7	1	688
Amortization Plant And Equipme	8,460	643	563	3,117	181	69	821	432	444	29	14,761
Total Amortization	8,799	654	593	3,310	185	74	870	485	451	31	15,450
Total Operating Income	72,683	2,810	6,141	43,632	989	1,042	10,759	12,764	1,502	342	152,663
Financing Expenses											
Long-Term Debt	6,879	523	457	2,550	148	57	670	347	328	23	11,983
Short-Term Debt	287	22	19	106	6	2	28	14	14	1	500
Interest Charged To Constructi	(212)	(16)	(14)	(78)	(5)	(2)	(21)	(11)	(10)	(1)	(368)
Amortization of Financing Costs	3	0	0	1	0	0	0	0	0	0	5
Total Financing Expenses	6,957	529	463	2,579	150	57	678	351	332	24	12,119
Earnings before Income Taxes	79,640	3,339	6,603	46,211	1,139	1,099	11,436	13,115	1,834	366	164,782
Income Taxes	3,248	247	216	1,204	70	27	316	164	155	11	5,658
Net Earnings	7,030	535	467	2,606	151	58	685	355	335	24	12,246
Gross Revenue Requirement	89,918	4,121	7,287	50,021	1,360	1,183	12,437	13,634	2,325	401	182,686
OATT Revenue	(951)	(6)	(87)	(497)	(0)	(11)	(126)	(137)	(13)	(3)	(1,830)
Other Revenue	(1,354)	(86)	(26)	(266)	(20)	(4)	(62)	(7)	(23)	(2)	(1,852)
Net Revenue Requirement	87,614	4,028	7,173	49,258	1,340	1,168	12,249	13,489	2,289	396	179,004

Schedule 1.3											
Allocated Revenue Requirement ($,000)											
Demand Related Revenue Requirement											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Operating Expenses											
Energy Costs	15,492	98	1,423	8,048	2	172	2,056	1,440	205	47	28,982
ECAM Adjustment	1,464	9	134	759	0	16	194	114	19	4	2,715
Net Energy Costs	16,956	107	1,557	8,807	2	188	2,250	1,555	224	51	31,697
Distribution	999	43	92	569	22	15	206	28	11	3	1,987
Transmission	479	3	44	250	0	5	63	69	6	1	922
Transmission and Distribution -	587	25	54	334	13	9	121	12	7	2	1,163
Transmission - OATT	89	1	8	47	0	1	12	13	1	0	172
General	3,025	57	278	1,627	23	38	477	298	38	9	5,869
Total Operating Expenses	22,135	236	2,033	11,633	59	256	3,129	1,974	288	66	41,810
Amortization											
Amortization Other	193	2	18	102	1	2	28	21	2	1	370
Amortization Plant And Equipme	4,527	109	416	2,468	49	60	762	395	56	13	8,853
Total Amortization	4,720	111	434	2,570	49	62	790	416	58	13	9,223
Total Operating Income	26,856	347	2,467	14,204	109	318	3,919	2,390	347	79	51,033
Financing Expenses											
Long-Term Debt	3,700	90	340	2,020	41	49	625	326	46	10	7,247
Short-Term Debt	154	4	14	84	2	2	26	14	2	0	302
Interest Charged To Constructi	(114)	(3)	(10)	(62)	(1)	(2)	(19)	(10)	(1)	(0)	(223)
Amortization of Financing Costs	2	0	0	1	0	0	0	0	0	0	3
Total Financing Expenses	3,742	91	344	2,043	41	49	633	329	46	10	7,329
Earnings before Income Taxes	30,598	438	2,810	16,247	150	368	4,551	2,719	393	89	58,362
Income Taxes	1,747	43	160	954	19	23	295	154	22	5	3,422
Net Earnings	3,781	92	347	2,065	41	50	639	333	47	11	7,406
Gross Revenue Requirement	36,126	572	3,318	19,265	210	441	5,486	3,206	461	105	69,189
OATT Revenue	(951)	(6)	(87)	(497)	(0)	(11)	(126)	(137)	(13)	(3)	(1,830)
Other Revenue	(191)	(9)	(18)	(109)	(4)	(3)	(40)	(7)	(2)	(0)	(384)
Net Revenue Requirement	34,985	558	3,213	18,659	206	427	5,320	3,061	446	101	66,976

Schedule 1.3											
Allocated Revenue Requirement ($,000)											
Energy Related Revenue Requirement											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Operating Expenses											
Energy Costs	32,006	1,140	2,940	24,814	535	622	5,963	9,130	420	162	77,734
ECAM Adjustment	3,970	141	365	3,078	66	77	740	1,133	52	20	9,643
Net Energy Costs	35,977	1,281	3,305	27,893	602	699	6,703	10,263	473	182	87,377
Distribution	2	0	0	2	0	0	0	1	0	0	6
Transmission	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0
General	139	5	13	107	2	3	26	40	2	1	337
Total Operating Expenses	36,118	1,286	3,317	28,002	604	702	6,729	10,303	474	183	87,720
Amortization											
Amortization Other	111	4	10	86	2	2	21	32	1	1	270
Amortization Plant And Equipme	125	4	12	97	2	2	23	36	2	1	304
Total Amortization	237	8	22	183	4	5	44	67	3	1	575
Total Operating Income	36,354	1,295	3,339	28,185	608	707	6,774	10,371	478	184	88,294
Financing Expenses											
Long-Term Debt	70	2	6	54	1	1	13	20	1	0	169
Short-Term Debt	3	0	0	2	0	0	1	1	0	0	7
Interest Charged To Constructi	(2)	(0)	(0)	(2)	(0)	(0)	(0)	(1)	(0)	(0)	(5)
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	71	3	6	55	1	1	13	20	1	0	171
Earnings before Income Taxes	36,425	1,297	3,346	28,240	609	708	6,787	10,391	478	185	88,466
Income Taxes	33	1	3	26	1	1	6	9	0	0	80
Net Earnings	71	3	7	55	1	1	13	20	1	0	173
Gross Revenue Requirement	36,529	1,301	3,355	28,321	611	710	6,806	10,420	480	185	88,719
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	(1)	(0)	(0)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(2)
Net Revenue Requirement	36,528	1,301	3,355	28,320	611	710	6,806	10,420	480	185	88,716

Schedule 1.3											
Allocated Revenue Requirement ($,000)											
Site Related Revenue Requirement											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Operating Expenses											
Energy Costs	71	9	3	9	2	0	0	0	6	0	101
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	71	9	3	9	2	0	0	0	6	0	101
Distribution	1,359	178	49	169	42	2	9	0	118	6	1,932
Transmission	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	587	77	21	74	18	1	3	0	47	3	831
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0
General	3,614	369	125	435	79	6	18	2	118	54	4,820
Total Operating Expenses	5,631	634	197	688	141	9	30	2	289	63	7,684
Amortization											
Amortization Other	34	4	1	4	1	0	0	0	3	0	48
Amortization Plant And Equipm	3,807	530	136	551	131	7	36	2	387	16	5,604
Total Amortization	3,842	535	137	556	132	7	36	2	389	16	5,652
Total Operating Income	9,473	1,168	335	1,243	273	16	66	4	678	79	13,336
Financing Expenses											
Long-Term Debt	3,109	431	111	475	106	6	31	1	282	13	4,567
Short-Term Debt	130	18	5	20	4	0	1	0	12	1	190
Interest Charged To Constructi	(96)	(13)	(3)	(15)	(3)	(0)	(1)	(0)	(9)	(0)	(140)
Amortization of Financing Costs	1	0	0	0	0	0	0	0	0	0	2
Total Financing Expenses	3,145	435	112	481	108	6	32	1	285	13	4,619
Earnings before Income Taxes	12,618	1,604	447	1,724	380	23	98	5	963	92	17,955
Income Taxes	1,468	203	52	224	50	3	15	1	133	6	2,156
Net Earnings	3,178	440	114	486	109	7	32	2	288	13	4,667
Gross Revenue Requirement	17,263	2,247	613	2,435	539	32	145	7	1,384	111	24,778
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	(1,162)	(78)	(9)	(156)	(16)	(1)	(22)	(0)	(21)	(2)	(1,467)
Net Revenue Requirement	16,101	2,169	604	2,279	523	31	123	7	1,363	109	23,311

Schedule 1.4											
Allocated Revenue Requirement ($,000)											
Full Revenue Requirement											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	9,679	80	889	5,230	11	113	1,318	1,496	128	31	18,975
Purchased Power	49,060	1,358	4,506	34,640	599	843	8,428	11,258	646	221	111,560
Transmission	3,815	24	350	1,993	0	42	505	552	51	12	7,343
Substations	1,554	10	143	788	0	17	206	32	21	5	2,774
Primary Lines	7,751	769	456	2,441	229	60	740	62	400	30	12,939
Transformers	6,058	553	390	2,186	177	56	712	60	271	22	10,485
Secondary Lines	2,732	271	161	861	81	21	261	22	141	11	4,561
Service Lines	4,151	648	149	582	169	9	57	3	232	14	6,014
Meter Assets	1,028	136	37	366	38	5	32	2	0	0	1,645
Meter Reading	773	57	28	60	7	1	4	0	0	0	931
Billing	742	55	27	94	11	1	4	1	3	49	987
Remittance & Collection	620	46	22	79	10	1	3	0	4	3	787
Uncollectibles & Damage Claims	438	58	16	56	13	1	0	0	0	0	581
Service Connections	(298)	(23)	0	(16)	(2)	0	(0)	0	(0)	0	(338)
Late Payments	(490)	(13)	0	(101)	(5)	(1)	(20)	0	(1)	(1)	(632)
Lighting	0	0	0	0	0	0	0	0	393	0	393
Total	87,614	4,028	7,173	49,258	1,340	1,168	12,249	13,489	2,289	396	179,004
Demand Related Revenue Requirement											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	8,994	56	826	4,699	0	99	1,191	1,301	119	27	17,312
Purchased Power	13,216	82	1,214	6,851	0	146	1,750	1,033	175	40	24,506
Transmission	3,815	24	350	1,993	0	42	505	552	51	12	7,343
Substations	1,554	10	143	788	0	17	206	32	21	5	2,774
Primary Lines	3,185	167	293	1,862	89	53	718	62	35	8	6,469
Transformers	3,097	162	285	1,810	86	51	698	60	34	8	6,291
Secondary Lines	1,123	59	103	656	31	19	253	22	12	3	2,280
Service Lines	0	0	0	0	0	0	0	0	0	0	0
Meter Assets	0	0	0	0	0	0	0	0	0	0	0
Meter Reading	0	0	0	0	0	0	0	0	0	0	0
Billing	0	0	0	0	0	0	0	0	0	0	0
Remittance & Collection	0	0	0	0	0	0	0	0	0	0	0
Uncollectibles & Damage Claims	0	0	0	0	0	0	0	0	0	0	0
Service Connections	0	0	0	0	0	0	0	0	0	0	0
Late Payments	0	0	0	0	0	0	0	0	0	0	0
Lighting	0	0	0	0	0	0	0	0	0	0	0
Total	34,985	558	3,213	18,659	206	427	5,320	3,061	446	101	66,976

Schedule 1.4

Allocated Revenue Requirement ($,000)

Energy Related Revenue Requirement

	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	685	24	63	531	11	13	128	195	9	3	1,663
Purchased Power	35,844	1,277	3,292	27,789	599	697	6,678	10,225	471	182	87,054
Transmission	0	0	0	0	0	0	0	0	0	0	0
Substations	0	0	0	0	0	0	0	0	0	0	0
Primary Lines	0	0	0	0	0	0	0	0	0	0	0
Transformers	0	0	0	0	0	0	0	0	0	0	0
Secondary Lines	0	0	0	0	0	0	0	0	0	0	0
Service Lines	0	0	0	0	0	0	0	0	0	0	0
Meter Assets	0	0	0	0	0	0	0	0	0	0	0
Meter Reading	0	0	0	0	0	0	0	0	0	0	0
Billing	0	0	0	0	0	0	0	0	0	0	0
Remittance & Collection	0	0	0	0	0	0	0	0	0	0	0
Uncollectibles & Damage Claims	0	0	0	0	0	0	0	0	0	0	0
Service Connections	0	0	0	0	0	0	0	0	0	0	0
Late Payments	0	0	0	0	0	0	0	0	0	0	0
Lighting	0	0	0	0	0	0	0	0	0	0	0
Total	36,528	1,301	3,355	28,320	611	710	6,806	10,420	480	185	88,716

Site Related Revenue Requirement

	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	0	0	0	0	0	0	0	0	0	0	0
Purchased Power	0	0	0	0	0	0	0	0	0	0	0
Transmission	0	0	0	0	0	0	0	0	0	0	0
Substations	0	0	0	0	0	0	0	0	0	0	0
Primary Lines	4,566	603	163	580	141	7	22	0	366	22	6,469
Transformers	2,960	391	106	376	91	5	14	0	237	14	4,194
Secondary Lines	1,610	212	58	204	50	3	8	0	129	8	2,280
Service Lines	4,151	648	149	582	169	9	57	3	232	14	6,014
Meter Assets	1,028	136	37	366	38	5	32	2	0	0	1,645
Meter Reading	773	57	28	60	7	1	4	0	0	0	931
Billing	742	55	27	94	11	1	4	1	3	49	987
Remittance & Collection	620	46	22	79	10	1	3	0	4	3	787
Uncollectibles & Damage Claims	438	58	16	56	13	1	0	0	0	0	581
Service Connections	(298)	(23)	0	(16)	(2)	0	(0)	0	(0)	0	(338)
Late Payments	(490)	(13)	0	(101)	(5)	(1)	(20)	0	(1)	(1)	(632)
Lighting	0	0	0	0	0	0	0	0	393	0	393
Total	16,101	2,169	604	2,279	523	31	123	7	1,363	109	23,311

Schedule 2.0											
Allocators by Function											
Allocators											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	51.0 %	0.4 %	4.7 %	27.6 %	0.1 %	0.6 %	6.9 %	7.9 %	0.7 %	0.2 %	100.0 %
Purchased Power	44.0 %	1.2 %	4.0 %	31.1 %	0.5 %	0.8 %	7.6 %	10.1 %	0.6 %	0.2 %	100.0 %
Transmission	52.0 %	0.3 %	4.8 %	27.1 %	0.0 %	0.6 %	6.9 %	7.5 %	0.7 %	0.2 %	100.0 %
Substations	56.0 %	0.3 %	5.1 %	28.4 %	0.0 %	0.6 %	7.4 %	1.1 %	0.7 %	0.2 %	100.0 %
Primary Lines	59.9 %	5.9 %	3.5 %	18.9 %	1.8 %	0.5 %	5.7 %	0.5 %	3.1 %	0.2 %	100.0 %
Transformers	57.8 %	5.3 %	3.7 %	20.8 %	1.7 %	0.5 %	6.8 %	0.6 %	2.6 %	0.2 %	100.0 %
Secondary Lines	59.9 %	5.9 %	3.5 %	18.9 %	1.8 %	0.5 %	5.7 %	0.5 %	3.1 %	0.2 %	100.0 %
Service Lines	69.0 %	10.8 %	2.5 %	9.7 %	2.8 %	0.1 %	0.9 %	0.1 %	3.9 %	0.2 %	100.0 %
Meter Assets	62.5 %	8.3 %	2.2 %	22.3 %	2.3 %	0.3 %	2.0 %	0.1 %	0.0 %	0.0 %	100.0 %
Meter Reading	83.1 %	6.1 %	3.0 %	6.4 %	0.8 %	0.1 %	0.4 %	0.0 %	0.0 %	0.0 %	100.0 %
Billing	75.2 %	5.5 %	2.7 %	9.5 %	1.2 %	0.1 %	0.4 %	0.1 %	0.3 %	4.9 %	100.0 %
Remittance & Collection	78.7 %	5.8 %	2.8 %	10.0 %	1.2 %	0.1 %	0.4 %	0.0 %	0.5 %	0.4 %	100.0 %
Uncollectibles & Damage Claims	75.4 %	9.9 %	2.7 %	9.6 %	2.3 %	0.1 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Service Connections	88.0 %	6.7 %	0.0 %	4.6 %	0.5 %	0.0 %	0.1 %	0.0 %	0.0 %	0.0 %	100.0 %
Late Payments	77.5 %	2.0 %	0.0 %	16.0 %	0.9 %	0.2 %	3.1 %	0.0 %	0.2 %	0.1 %	100.0 %
Lighting	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %	0.0 %	100.0 %
Demand Allocators, Isolated (%)											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	52.0 %	0.3 %	4.8 %	27.1 %	0.0 %	0.6 %	6.9 %	7.5 %	0.7 %	0.2 %	100.0 %
Purchased Power	53.9 %	0.3 %	5.0 %	28.0 %	0.0 %	0.6 %	7.1 %	4.2 %	0.7 %	0.2 %	100.0 %
Transmission	52.0 %	0.3 %	4.8 %	27.1 %	0.0 %	0.6 %	6.9 %	7.5 %	0.7 %	0.2 %	100.0 %
Substations	56.0 %	0.3 %	5.1 %	28.4 %	0.0 %	0.6 %	7.4 %	1.1 %	0.7 %	0.2 %	100.0 %
Primary Lines	49.2 %	2.6 %	4.5 %	28.8 %	1.4 %	0.8 %	11.1 %	1.0 %	0.5 %	0.1 %	100.0 %
Transformers	49.2 %	2.6 %	4.5 %	28.8 %	1.4 %	0.8 %	11.1 %	1.0 %	0.5 %	0.1 %	100.0 %
Secondary Lines	49.2 %	2.6 %	4.5 %	28.8 %	1.4 %	0.8 %	11.1 %	1.0 %	0.5 %	0.1 %	100.0 %
Service Lines	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Meter Assets	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Meter Reading	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Billing	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Remittance & Collection	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Uncollectibles & Damage Claims	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Service Connections	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Late Payments	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Lighting	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %

Schedule 2.0											
Allocators by Function											
Energy Allocators, Isolated (%)											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	41.2 %	1.5 %	3.8 %	31.9 %	0.7 %	0.8 %	7.7 %	11.7 %	0.5 %	0.2 %	100.0 %
Purchased Power	41.2 %	1.5 %	3.8 %	31.9 %	0.7 %	0.8 %	7.7 %	11.7 %	0.5 %	0.2 %	100.0 %
Transmission	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Substations	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Primary Lines	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Transformers	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Secondary Lines	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Service Lines	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Meter Assets	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Meter Reading	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Billing	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Remittance & Collection	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Uncollectibles & Damage Claims	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Service Connections	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Late Payments	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Lighting	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Site Allocators, Isolated (%)											
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Purchased Power	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Transmission	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Substations	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Primary Lines	70.6 %	9.3 %	2.5 %	9.0 %	2.2 %	0.1 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %
Transformers	70.6 %	9.3 %	2.5 %	9.0 %	2.2 %	0.1 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %
Secondary Lines	70.6 %	9.3 %	2.5 %	9.0 %	2.2 %	0.1 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %
Service Lines	69.0 %	10.8 %	2.5 %	9.7 %	2.8 %	0.1 %	0.9 %	0.1 %	3.9 %	0.2 %	100.0 %
Meter Assets	62.5 %	8.3 %	2.2 %	22.3 %	2.3 %	0.3 %	2.0 %	0.1 %	0.0 %	0.0 %	100.0 %
Meter Reading	83.1 %	6.1 %	3.0 %	6.4 %	0.8 %	0.1 %	0.4 %	0.0 %	0.0 %	0.0 %	100.0 %
Billing	75.2 %	5.5 %	2.7 %	9.5 %	1.2 %	0.1 %	0.4 %	0.1 %	0.3 %	4.9 %	100.0 %
Remittance & Collection	78.7 %	5.8 %	2.8 %	10.0 %	1.2 %	0.1 %	0.4 %	0.0 %	0.5 %	0.4 %	100.0 %
Uncollectibles & Damage Claims	75.4 %	9.9 %	2.7 %	9.6 %	2.3 %	0.1 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Service Connections	88.0 %	6.7 %	0.0 %	4.6 %	0.5 %	0.0 %	0.1 %	0.0 %	0.0 %	0.0 %	100.0 %
Late Payments	77.5 %	2.0 %	0.0 %	16.0 %	0.9 %	0.2 %	3.1 %	0.0 %	0.2 %	0.1 %	100.0 %
Lighting	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %	0.0 %	100.0 %

Schedule 2.1												
Allocators												
Allocators												
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total	
1CP - Input	52.0 %	0.3 %	4.8 %	27.1 %	0.0 %	0.6 %	6.9 %	7.5 %	0.7 %	0.2 %	100.0 %	
1CP - Input Firm	56.2 %	0.3 %	5.2 %	28.9 %	0.0 %	0.6 %	7.4 %	0.4 %	0.7 %	0.2 %	100.0 %	
1CP - Transmission	52.0 %	0.3 %	4.8 %	27.1 %	0.0 %	0.6 %	6.9 %	7.5 %	0.7 %	0.2 %	100.0 %	
1CP - Distribution Primary	56.0 %	0.3 %	5.1 %	28.4 %	0.0 %	0.6 %	7.4 %	1.1 %	0.7 %	0.2 %	100.0 %	
NCP - Distribution Primary	49.2 %	2.6 %	4.5 %	28.8 %	1.4 %	0.8 %	11.1 %	1.0 %	0.5 %	0.1 %	100.0 %	
NCP - Distribution Secondary	49.2 %	2.6 %	4.5 %	28.8 %	1.4 %	0.8 %	11.1 %	1.0 %	0.5 %	0.1 %	100.0 %	
Energy - Input	41.2 %	1.5 %	3.8 %	31.9 %	0.7 %	0.8 %	7.7 %	11.7 %	0.5 %	0.2 %	100.0 %	
Sites	70.6 %	9.3 %	2.5 %	9.0 %	2.2 %	0.1 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %	
Sites - Distribution Primary	70.6 %	9.3 %	2.5 %	9.0 %	2.2 %	0.1 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %	
Sites - Distribution Secondary	70.6 %	9.3 %	2.5 %	9.0 %	2.2 %	0.1 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %	
Sites - Mass Market	75.4 %	9.9 %	2.7 %	9.6 %	2.3 %	0.1 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %	
Service Lines	69.0 %	10.8 %	2.5 %	9.7 %	2.8 %	0.1 %	0.9 %	0.1 %	3.9 %	0.2 %	100.0 %	
Meter Assets	62.5 %	8.3 %	2.2 %	22.3 %	2.3 %	0.3 %	2.0 %	0.1 %	0.0 %	0.0 %	100.0 %	
Meter Reading	83.1 %	6.1 %	3.0 %	6.4 %	0.8 %	0.1 %	0.4 %	0.0 %	0.0 %	0.0 %	100.0 %	
Billing	75.2 %	5.5 %	2.7 %	9.5 %	1.2 %	0.1 %	0.4 %	0.1 %	0.3 %	4.9 %	100.0 %	
Remittance & Collection	78.7 %	5.8 %	2.8 %	10.0 %	1.2 %	0.1 %	0.4 %	0.0 %	0.5 %	0.4 %	100.0 %	
Service Connection Revenue	88.0 %	6.7 %	0.0 %	4.6 %	0.5 %	0.0 %	0.1 %	0.0 %	0.0 %	0.0 %	100.0 %	
Penalty Revenue	77.5 %	2.0 %	0.0 %	16.0 %	0.9 %	0.2 %	3.1 %	0.0 %	0.2 %	0.1 %	100.0 %	
Lighting Direct Assign	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %	0.0 %	100.0 %	
MECL Generation	51.0 %	0.4 %	4.7 %	27.6 %	0.1 %	0.6 %	6.9 %	7.9 %	0.7 %	0.2 %	100.0 %	
MECL Purchases	44.0 %	1.2 %	4.0 %	31.1 %	0.5 %	0.8 %	7.6 %	10.1 %	0.6 %	0.2 %	100.0 %	
Primary System	59.9 %	5.9 %	3.5 %	18.9 %	1.8 %	0.5 %	5.7 %	0.5 %	3.1 %	0.2 %	100.0 %	
Distribution Transformers	57.8 %	5.3 %	3.7 %	20.8 %	1.7 %	0.5 %	6.8 %	0.6 %	2.6 %	0.2 %	100.0 %	
Secondary System	59.9 %	5.9 %	3.5 %	18.9 %	1.8 %	0.5 %	5.7 %	0.5 %	3.1 %	0.2 %	100.0 %	

Schedule 2.1												
Allocators												
Demand Allocators, Isolated (%)												
	Residenti al	Residenti al (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmeter ed	Total	Weight
1CP - Input	52.0 %	0.3 %	4.8 %	27.1 %	0.0 %	0.6 %	6.9 %	7.5 %	0.7 %	0.2 %	100.0 %	100.0 %
1CP - Input Firm	56.2 %	0.3 %	5.2 %	28.9 %	0.0 %	0.6 %	7.4 %	0.4 %	0.7 %	0.2 %	100.0 %	100.0 %
1CP - Transmission	52.0 %	0.3 %	4.8 %	27.1 %	0.0 %	0.6 %	6.9 %	7.5 %	0.7 %	0.2 %	100.0 %	100.0 %
1CP - Distribution Primary	56.0 %	0.3 %	5.1 %	28.4 %	0.0 %	0.6 %	7.4 %	1.1 %	0.7 %	0.2 %	100.0 %	100.0 %
NCP - Distribution Primary	49.2 %	2.6 %	4.5 %	28.8 %	1.4 %	0.8 %	11.1 %	1.0 %	0.5 %	0.1 %	100.0 %	100.0 %
NCP - Distribution Secondary	49.2 %	2.6 %	4.5 %	28.8 %	1.4 %	0.8 %	11.1 %	1.0 %	0.5 %	0.1 %	100.0 %	100.0 %
Energy - Input	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Sites	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Sites - Distribution Primary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Sites - Distribution Secondary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Sites - Mass Market	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Service Lines	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Meter Assets	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Meter Reading	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Billing	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Remittance & Collection	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Service Connection Revenue	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Penalty Revenue	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Lighting Direct Assign	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
MECL Generation	52.0 %	0.3 %	4.8 %	27.1 %	0.0 %	0.6 %	6.9 %	7.5 %	0.7 %	0.2 %	100.0 %	91.2 %
MECL Purchases	53.9 %	0.3 %	5.0 %	28.0 %	0.0 %	0.6 %	7.1 %	4.2 %	0.7 %	0.2 %	100.0 %	22.0 %
Primary System	49.2 %	2.6 %	4.5 %	28.8 %	1.4 %	0.8 %	11.1 %	1.0 %	0.5 %	0.1 %	100.0 %	50.0 %
Distribution Transformers	49.2 %	2.6 %	4.5 %	28.8 %	1.4 %	0.8 %	11.1 %	1.0 %	0.5 %	0.1 %	100.0 %	60.0 %
Secondary System	49.2 %	2.6 %	4.5 %	28.8 %	1.4 %	0.8 %	11.1 %	1.0 %	0.5 %	0.1 %	100.0 %	50.0 %

Schedule 2.1												
Allocators												
Energy Allocators, Isolated (%)												
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total	Weight
1CP - Input	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
1CP - Input Firm	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
1CP - Transmission	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
1CP - Distribution Primary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
NCP - Distribution Primary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
NCP - Distribution Secondary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Energy - Input	41.2 %	1.5 %	3.8 %	31.9 %	0.7 %	0.8 %	7.7 %	11.7 %	0.5 %	0.2 %	100.0 %	100.0 %
Sites	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Sites - Distribution Primary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Sites - Distribution Secondary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Sites - Mass Market	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Service Lines	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Meter Assets	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Meter Reading	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Billing	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Remittance & Collection	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Service Connection Revenue	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Penalty Revenue	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Lighting Direct Assign	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
MECL Generation	41.2 %	1.5 %	3.8 %	31.9 %	0.7 %	0.8 %	7.7 %	11.7 %	0.5 %	0.2 %	100.0 %	8.8 %
MECL Purchases	41.2 %	1.5 %	3.8 %	31.9 %	0.7 %	0.8 %	7.7 %	11.7 %	0.5 %	0.2 %	100.0 %	78.0 %
Primary System	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Distribution Transformers	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Secondary System	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %

Schedule 2.1												
Allocators												
Site Allocators, Isolated (%)												
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmetered	Total	Weight
1CP - Input	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
1CP - Input Firm	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
1CP - Transmission	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
1CP - Distribution Primary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
NCP - Distribution Primary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
NCP - Distribution Secondary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Energy - Input	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Sites	70.6 %	9.3 %	2.5 %	9.0 %	2.2 %	0.1 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %	100.0 %
Sites - Distribution Primary	70.6 %	9.3 %	2.5 %	9.0 %	2.2 %	0.1 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %	100.0 %
Sites - Distribution Secondary	70.6 %	9.3 %	2.5 %	9.0 %	2.2 %	0.1 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %	100.0 %
Sites - Mass Market	75.4 %	9.9 %	2.7 %	9.6 %	2.3 %	0.1 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %	100.0 %
Service Lines	69.0 %	10.8 %	2.5 %	9.7 %	2.8 %	0.1 %	0.9 %	0.1 %	3.9 %	0.2 %	100.0 %	100.0 %
Meter Assets	62.5 %	8.3 %	2.2 %	22.3 %	2.3 %	0.3 %	2.0 %	0.1 %	0.0 %	0.0 %	100.0 %	100.0 %
Meter Reading	83.1 %	6.1 %	3.0 %	6.4 %	0.8 %	0.1 %	0.4 %	0.0 %	0.0 %	0.0 %	100.0 %	100.0 %
Billing	75.2 %	5.5 %	2.7 %	9.5 %	1.2 %	0.1 %	0.4 %	0.1 %	0.3 %	4.9 %	100.0 %	100.0 %
Remittance & Collection	78.7 %	5.8 %	2.8 %	10.0 %	1.2 %	0.1 %	0.4 %	0.0 %	0.5 %	0.4 %	100.0 %	100.0 %
Service Connection Revenue	88.0 %	6.7 %	0.0 %	4.6 %	0.5 %	0.0 %	0.1 %	0.0 %	0.0 %	0.0 %	100.0 %	100.0 %
Penalty Revenue	77.5 %	2.0 %	0.0 %	16.0 %	0.9 %	0.2 %	3.1 %	0.0 %	0.2 %	0.1 %	100.0 %	100.0 %
Lighting Direct Assign	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %	0.0 %	100.0 %	100.0 %
MECL Generation	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
MECL Purchases	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Primary System	70.6 %	9.3 %	2.5 %	9.0 %	2.2 %	0.1 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %	50.0 %
Distribution Transformers	70.6 %	9.3 %	2.5 %	9.0 %	2.2 %	0.1 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %	40.0 %
Secondary System	70.6 %	9.3 %	2.5 %	9.0 %	2.2 %	0.1 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %	50.0 %

Schedule 2.2											
Allocator Assumptions											
Site Allocator Weighting Assumptions											
	Residenti al	Residenti al (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmeter ed	Total
Service Lines	333	394	333	368	441	441	947	3,400	232	232	6,657
Meter Assets	131	131	131	367	157	421	850	4,259	0	0	6,449
Meter Reading	12	7	12	7	4	12	12	60	0	0	126
Billing	12	7	12	12	6	12	12	300	1	300	373
Remittance & Collection	12	7	12	12	6	12	12	12	1	12	85
Lighting & Unmetered Equivalence									0.40	0.40	
Base Allocators											
	Residenti al	Residenti al (S)	Farm	General Service 1	General Service 1 (S)	General Service 2	Small Industrial	Large Industrial	Lights	Unmeter ed	Total
1CP - Input (kW)	119,190	738	10,948	62,272	0	1,319	15,778	17,241	1,579	359	229,423
1CP - Input Firm (kW)	119,190	738	10,948	61,266	0	1,319	15,778	908	1,579	359	212,085
1CP - Transmission (kW)	115,674	716	10,625	60,434	0	1,280	15,313	16,732	1,532	349	222,654
1CP - Distribution Primary (kW)	115,674	716	10,625	58,638	0	1,280	15,313	2,364	1,532	349	206,490
NCP - Distribution Primary (kW)	142,428	7,449	13,082	83,244	3,958	2,349	32,095	2,770	1,552	349	289,275
NCP - Distribution Secondary (kW)	135,146	7,068	12,413	78,987	3,755	2,229	30,454	2,628	1,473	331	274,485
Energy - Input (MWh)	515,510	18,359	47,351	399,673	8,620	10,023	96,049	147,055	6,772	2,612	1,252,023
Sites	55,530	7,328	1,987	7,049	1,711	87	268	4	4,447	269	78,679
Sites - Distribution Primary	55,530	7,328	1,987	7,048	1,711	87	268	2	4,447	269	78,676
Sites - Distribution Secondary	55,530	7,328	1,987	7,048	1,711	87	268	0	4,447	269	78,674
Sites - Mass Market	55,530	7,328	1,987	7,049	1,711	87	0	0	0	0	73,691
Service Lines ($,000)	18,491	2,887	662	2,591	755	38	254	14	1,033	62	26,787
Meter Assets ($,000)	7,274	960	260	2,590	269	37	228	17	0	0	11,635
Meter Reading (Weighted Sites x	666	49	24	52	6	1	3	0	0	0	802
Billing (Weighted Sites x 1000)	666	49	24	85	10	1	3	1	3	44	886
Remittance & Collection (Weighted	666	49	24	85	10	1	3	0	4	3	846
Service Connection Revenue ($,00	427	32	0	22	3	0	1	0	0	0	485
Penalty Revenue ($,000)	490	13	0	101	5	1	20	0	1	1	632
Lighting Direct Assign	0	0	0	0	0	0	0	0	1	0	1
Sales Data											
Billing Demand (kW * 12 Months)	N/A	N/A	N/A	923,095	11,272	21,656	295,831	252,201	N/A	1,381	1,505,435
Peak metered demand	N/A	N/A	N/A	79,642	2,296	1,941	28,893	22,379	N/A	N/A	135,149
Sales (MWh)	480,053	17,210	44,094	369,228	7,962	9,421	88,930	142,152	6,236	2,405	1,167,691
Average Bills per Month	55,530	7,328	1,987	7,049	1,711	87	268	4	3,064	146	77,173
Revenue ($,000)	83,555	4,090	6,052	59,134	1,598	1,433	12,097	13,813	2,470	419	184,662
Lighting & Unmetered Fixtures									11,117	672	

Schedule 2.3							
Assumptions to Split Residential Rate Classes							
Used in Cost Allocation Model:	STATUS QUO RATE CLASSES				SPLIT RESIDENTIAL RATE CLAS		
Site Allocator Weighting Assumptions							
	Residential	Residential (S)	Farm		Residential	Residential (S)	Farm
Service Lines	333	394	0		333	394	333
Meter Assets	131	131	0		131	131	131
Meter Reading	12	7	0		12	7	12
Billing	12	7	0		12	7	12
Remittance & Collection	12	7	0		12	7	12
Base Allocators							
	Residential	Residential (S)	Farm		Residential	Residential (S)	Farm
1CP - Input (kW)	130,138	738	0		119,190	738	10,948
1CP - Input Firm (kW)	130,138	738	0		119,190	738	10,948
1CP - Transmission (kW)	126,299	716	0		115,674	716	10,625
1CP - Distribution Primary (kW)	126,299	716	0		115,674	716	10,625
NCP - Distribution Primary (kW)	155,510	7,449	0		142,428	7,449	13,082
NCP - Distribution Secondary (kW)	147,559	7,068	0		135,146	7,068	12,413
Energy - Input (MWh)	562,860	18,359	0		515,510	18,359	47,351
Sites							
Sites - Distribution Primary							
Sites - Distribution Secondary							
Sites - Mass Market							
Service Lines ($,000)							
Meter Assets ($,000)							
Meter Reading (Weighted Sites)							
Billing (Weighted Sites)							
Remittance & Collection (Weighted Sites)							
Service Connection Revenue ($,00	427	32	0		412	32	15
Penalty Revenue ($,000)	490	13	0		473	13	17
Lighting Direct Assign	0	0	0		0	0	0
Sales Data							
Billing Demand (kW * 12 Months)	N/A	N/A	N/A		N/A	N/A	N/A
Peak metered demand	N/A	N/A	N/A		N/A	N/A	N/A
Sales (MWh)	524,147	17,210	0		480,053	17,210	44,094
Sites	57,517	7,328	0		55,530	7,328	1,987
Revenue ($,000)	89,607	4,090	0		83,555	4,090	6,052

Schedule 2.4					
Classification Assumptions					
Allocator	Demand Related	Energy Related	Site Related	Total	
1CP - Input	100 %	0 %	0 %	100 %	
1CP - Input Firm	100 %	0 %	0 %	100 %	
1CP - Transmission	100 %	0 %	0 %	100 %	
1CP - Distribution Primary	100 %	0 %	0 %	100 %	
NCP - Distribution Primary	100 %	0 %	0 %	100 %	
NCP - Distribution Secondary	100 %	0 %	0 %	100 %	
Energy - Input	0 %	100 %	0 %	100 %	
Sites	0 %	0 %	100 %	100 %	
Sites - Distribution Primary	0 %	0 %	100 %	100 %	
Sites - Distribution Secondary	0 %	0 %	100 %	100 %	
Sites - Mass Market	0 %	0 %	100 %	100 %	
Service Lines	0 %	0 %	100 %	100 %	
Meter Assets	0 %	0 %	100 %	100 %	
Meter Reading	0 %	0 %	100 %	100 %	
Billing	0 %	0 %	100 %	100 %	
Remittance & Collection	0 %	0 %	100 %	100 %	
Service Connection Revenue	0 %	0 %	100 %	100 %	
Penalty Revenue	0 %	0 %	100 %	100 %	
Lighting Direct Assign	0 %	0 %	100 %	100 %	
MECL Generation	91 %	9 %	0 %	100 %	
MECL Purchases	22 %	78 %	0 %	100 %	
Primary System	50 %	0 %	50 %	100 %	
Distribution Transformers	60 %	0 %	40 %	100 %	
Secondary System	50 %	0 %	50 %	100 %	
Blended Allocator Assumptions					
	MECL Generation	MECL Purchases	Primary System	Distribution Transformers	Secondary System
1CP - Input	91 %	12 %			
1CP - Input Firm		10 %			
1CP - Transmission					
1CP - Distribution Primary					
NCP - Distribution Primary			50 %		
NCP - Distribution Secondary				60 %	50 %
Energy - Input	9 %	78 %			
Sites					
Sites - Distribution Primary			50 %		
Sites - Distribution Secondary				40 %	50 %
Total	100 %	100 %	100 %	100 %	100 %
Energy Cost Classification					
Energy Costs ($,000)	Generation	Purchased Power			
Demand Related	5,725	21,728			
Total	6,275	98,913			

Schedule 2.5	
Allocator by Function Assumptions	
Function	Allocator
Generation	MECL Generation
Purchased Power	MECL Purchases
Transmission	1CP - Transmission
Substations	1CP - Distribution Primary
Primary Lines	Primary System
Transformers	Distribution Transformers
Secondary Lines	Secondary System
Service Lines	Service Lines
Meter Assets	Meter Assets
Meter Reading	Meter Reading
Billing	Billing
Remittance & Collection	Remittance & Collection
Uncollectibles & Damage Claims	Sites - Mass Market
Service Connections	Service Connection Revenue
Late Payments	Penalty Revenue
Lighting	Lighting Direct Assign

Schedule 3.0																	
Functionalized Revenue Requirement, Summary																	
Revenue Requirement ($,000)																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	6,275	98,913	1,209	207	72	71	70	2	0	0	0	0	0	0	0	0	106,818
ECAM Adjustment	0	12,358	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12,358
Net Energy Costs	6,275	111,270	1,209	207	72	71	70	2	0	0	0	0	0	0	0	0	119,176
Distribution	65	0	65	258	1,449	1,053	497	357	0	155	0	0	0	0	0	26	3,925
Transmission	0	0	922	0	0	0	0	0	0	0	0	0	0	0	0	0	922
Transmission and Distribution -	0	0	0	212	886	601	295	0	0	0	0	0	0	0	0	0	1,994
Transmission - OATT	0	0	172	0	0	0	0	0	0	0	0	0	0	0	0	0	172
General	2,557	144	1,324	506	1,281	1,285	525	295	72	696	929	700	562	129	0	20	11,025
Total Operating Expenses	8,897	111,414	3,693	1,182	3,687	3,009	1,387	654	73	850	929	700	562	129	0	46	137,214
Amortization																	
Amortization Other	93	336	143	18	37	40	15	2	0	4	0	0	0	0	0	0	688
Amortization Plant And Equipm	3,212	29	1,777	590	3,203	2,319	1,113	1,918	367	34	19	30	6	6	0	138	14,761
Total Amortization	3,304	365	1,920	608	3,240	2,359	1,129	1,919	367	38	19	30	6	6	0	138	15,450
Total Operating Income	12,201	111,780	5,612	1,791	6,927	5,369	2,516	2,574	439	889	948	730	568	135	0	184	152,663
Financing Expenses		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Long-Term Debt	2,718	(88)	1,429	395	2,585	2,053	878	1,380	484	17	16	23	5	5	0	84	11,983
Short-Term Debt	113	(4)	60	16	108	86	37	58	20	1	1	1	0	0	0	4	500
Interest Charged To Constructi	(84)	3	(44)	(12)	(79)	(63)	(27)	(42)	(15)	(1)	(0)	(1)	(0)	(0)	0	(3)	(368)
Amortization of Financing Costs	1	(0)	1	0	1	1	0	1	0	0	0	0	0	0	0	0	5
Total Financing Expenses	2,749	(89)	1,445	399	2,614	2,076	888	1,396	489	17	16	24	5	5	0	85	12,119
Earnings before Income Taxes	14,950	111,691	7,057	2,190	9,541	7,445	3,404	3,970	928	906	964	754	573	140	0	269	164,782
Income Taxes	1,283	(42)	675	186	1,220	969	415	652	228	8	7	11	3	2	0	40	5,658
Net Earnings	2,778	(90)	1,460	403	2,641	2,098	897	1,411	494	17	16	24	5	5	0	86	12,246
Gross Revenue Requirement	19,011	111,559	9,192	2,779	13,403	10,513	4,716	6,032	1,651	931	988	789	581	147	0	394	182,686
OATT Revenue	0	0	(1,830)	0	0	0	0	0	0	0	0	0	0	0	0	0	(1,830)
Other Revenue	(36)	1	(19)	(5)	(464)	(27)	(155)	(18)	(6)	(0)	(1)	(1)	(0)	(485)	(632)	(1)	(1,852)
Net Revenue Requirement	18,975	111,560	7,343	2,774	12,939	10,485	4,561	6,014	1,645	931	987	787	581	(338)	(632)	393	179,004

Schedule 3.0 Functionalized Revenue Requirement, Summary Revenue Requirement, Demand Related ($,000)	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	5,725	21,728	1,209	207	36	42	35	0	0	0	0	0	0	0	0	0	28,982
ECAM Adjustment	0	2,715	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,715
Net Energy Costs	5,725	24,443	1,209	207	36	42	35	0	0	0	0	0	0	0	0	0	31,697
Distribution	60	0	65	258	724	632	249	0	0	0	0	0	0	0	0	0	1,987
Transmission	0	0	922	0	0	0	0	0	0	0	0	0	0	0	0	0	922
Transmission and Distribution -	0	0	0	212	443	360	148	0	0	0	0	0	0	0	0	0	1,163
Transmission - OATT	0	0	172	0	0	0	0	0	0	0	0	0	0	0	0	0	172
General	2,333	32	1,324	506	640	771	262	0	0	0	0	0	0	0	0	0	5,869
Total Operating Expenses	8,118	24,474	3,693	1,182	1,844	1,806	694	0	0	0	0	0	0	0	0	0	41,810
Amortization																	
Amortization Other	85	74	143	18	19	24	8	0	0	0	0	0	0	0	0	0	370
Amortization Plant And Equipme	2,930	6	1,777	590	1,601	1,391	557	0	0	0	0	0	0	0	0	0	8,853
Total Amortization	3,015	80	1,920	608	1,620	1,416	564	0	0	0	0	0	0	0	0	0	9,223
Total Operating Income	11,132	24,555	5,612	1,791	3,464	3,221	1,258	0	0	0	0	0	0	0	0	0	51,033
Financing Expenses		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Long-Term Debt	2,480	(19)	1,429	395	1,292	1,232	439	0	0	0	0	0	0	0	0	0	7,247
Short-Term Debt	103	(1)	60	16	54	51	18	0	0	0	0	0	0	0	0	0	302
Interest Charged To Constructi	(76)	1	(44)	(12)	(40)	(38)	(14)	0	0	0	0	0	0	0	0	0	(223)
Amortization of Financing Costs	1	(0)	1	0	1	1	0	0	0	0	0	0	0	0	0	0	3
Total Financing Expenses	2,508	(20)	1,445	399	1,307	1,246	444	0	0	0	0	0	0	0	0	0	7,329
Earnings before Income Taxes	13,640	24,535	7,057	2,190	4,771	4,467	1,702	0	0	0	0	0	0	0	0	0	58,362
Income Taxes	1,171	(9)	675	186	610	582	207	0	0	0	0	0	0	0	0	0	3,422
Net Earnings	2,534	(20)	1,460	403	1,321	1,259	449	0	0	0	0	0	0	0	0	0	7,406
Gross Revenue Requirement	17,345	24,506	9,192	2,779	6,702	6,308	2,358	0	0	0	0	0	0	0	0	0	69,189
OATT Revenue	0	0	(1,830)	0	0	0	0	0	0	0	0	0	0	0	0	0	(1,830)
Other Revenue	(33)	0	(19)	(5)	(232)	(16)	(78)	0	0	0	0	0	0	0	0	0	(384)
Net Revenue Requirement	17,312	24,506	7,343	2,774	6,469	6,291	2,280	0	0	0	0	0	0	0	0	0	66,976

Schedule 3.0																	
Functionalized Revenue Requirement, Summary																	
Revenue Requirement, Energy Related ($,000)																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	550	77,185	0	0	0	0	0	0	0	0	0	0	0	0	0	0	77,734
ECAM Adjustment	0	9,643	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9,643
Net Energy Costs	550	86,828	0	0	0	0	0	0	0	0	0	0	0	0	0	0	87,377
Distribution	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	224	112	0	0	0	0	0	0	0	0	0	0	0	0	0	0	337
Total Operating Expenses	780	86,940	0	0	0	0	0	0	0	0	0	0	0	0	0	0	87,720
Amortization																	
Amortization Other	8	262	0	0	0	0	0	0	0	0	0	0	0	0	0	0	270
Amortization Plant And Equipme	281	23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	304
Total Amortization	290	285	0	0	0	0	0	0	0	0	0	0	0	0	0	0	575
Total Operating Income	1,069	87,225	0	0	0	0	0	0	0	0	0	0	0	0	0	0	88,294
Financing Expenses		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Long-Term Debt	238	(69)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	169
Short-Term Debt	10	(3)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7
Interest Charged To Constructi	(7)	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(5)
Amortization of Financing Costs	0	(0)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	241	(70)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	171
Earnings before Income Taxes	1,310	87,156	0	0	0	0	0	0	0	0	0	0	0	0	0	0	88,466
Income Taxes	112	(32)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	80
Net Earnings	243	(70)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	173
Gross Revenue Requirement	1,666	87,053	0	0	0	0	0	0	0	0	0	0	0	0	0	0	88,719
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	(3)	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(2)
Net Revenue Requirement	1,663	87,054	0	0	0	0	0	0	0	0	0	0	0	0	0	0	88,716

Schedule 3.0																	
Functionalized Revenue Requirement, Summary																	
Revenue Requirement, Site Related ($,000)																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	0	0	0	0	36	28	35	2	0	0	0	0	0	0	0	0	101
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	0	0	0	0	36	28	35	2	0	0	0	0	0	0	0	0	101
Distribution	0	0	0	0	724	421	249	357	0	155	0	0	0	0	0	26	1,932
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	443	240	148	0	0	0	0	0	0	0	0	0	831
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	0	0	0	0	640	514	262	295	72	696	929	700	562	129	0	20	4,820
Total Operating Expenses	0	0	0	0	1,844	1,204	694	654	73	850	929	700	562	129	0	46	7,684
Amortization																	
Amortization Other	0	0	0	0	19	16	8	2	0	4	0	0	0	0	0	0	48
Amortization Plant And Equipme	0	0	0	0	1,601	928	557	1,918	367	34	19	30	6	6	0	138	5,604
Total Amortization	0	0	0	0	1,620	944	564	1,919	367	38	19	30	6	6	0	138	5,652
Total Operating Income	0	0	0	0	3,464	2,147	1,258	2,574	439	889	948	730	568	135	0	184	13,336
Financing Expenses		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Long-Term Debt	0	0	0	0	1,292	821	439	1,380	484	17	16	23	5	5	0	84	4,567
Short-Term Debt	0	0	0	0	54	34	18	58	20	1	1	1	0	0	0	4	190
Interest Charged To Constructio	0	0	0	0	(40)	(25)	(14)	(42)	(15)	(1)	(0)	(1)	(0)	(0)	0	(3)	(140)
Amortization of Financing Costs	0	0	0	0	1	0	0	1	0	0	0	0	0	0	0	0	2
Total Financing Expenses	0	0	0	0	1,307	831	444	1,396	489	17	16	24	5	5	0	85	4,619
Earnings before Income Taxes	0	0	0	0	4,771	2,978	1,702	3,970	928	906	964	754	573	140	0	269	17,955
Income Taxes	0	0	0	0	610	388	207	652	228	8	7	11	3	2	0	40	2,156
Net Earnings	0	0	0	0	1,321	839	449	1,411	494	17	16	24	5	5	0	86	4,667
Gross Revenue Requirement	0	0	0	0	6,702	4,205	2,358	6,032	1,651	931	988	789	581	147	0	394	24,778
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	(232)	(11)	(78)	(18)	(6)	(0)	(1)	(1)	(0)	(485)	(632)	(1)	(1,467)
Net Revenue Requirement	0	0	0	0	6,469	4,194	2,280	6,014	1,645	931	987	787	581	(338)	(632)	393	23,311

Schedule 3.1 Functionalized Revenue Requirement Direct Assigned ($,000)	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	5,725	98,775	748	0	0	0	0	0	0	0	0	0	0	0	0	0	105,248
ECAM Adjustment	0	12,358	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12,358
Net Energy Costs	5,725	111,133	748	0	0	0	0	0	0	0	0	0	0	0	0	0	117,606
Distribution	0	0	0	74	0	419	0	0	0	155	0	0	0	0	0	0	648
Transmission	0	0	922	0	0	0	0	0	0	0	0	0	0	0	0	0	922
Transmission and Distribution -	0	0	0	96	0	0	0	0	0	0	0	0	0	0	0	0	96
Transmission - OATT	0	0	172	0	0	0	0	0	0	0	0	0	0	0	0	0	172
General	0	0	0	0	0	0	0	0	0	376	0	0	308	0	0	0	684
Total Operating Expenses	5,725	111,133	1,842	171	0	419	0	0	0	531	0	0	308	0	0	0	120,128
Amortization																	
Amortization Other	0	329	0	0	0	0	0	0	0	0	0	0	0	0	0	0	329
Amortization Plant And Equipm	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	329	0	0	0	0	0	0	0	0	0	0	0	0	0	0	329
Total Operating Income	5,725	111,462	1,842	171	0	419	0	0	0	531	0	0	308	0	0	0	120,457
Financing Expenses																	
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructi	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	5,725	111,462	1,842	171	0	419	0	0	0	531	0	0	308	0	0	0	120,457
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	5,725	111,462	1,842	171	0	419	0	0	0	531	0	0	308	0	0	0	120,457
OATT Revenue	0	0	(1,830)	0	0	0	0	0	0	0	0	0	0	0	0	0	(1,830)
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	(485)	(632)	0	(1,117)
Net Revenue Requirement	5,725	111,462	12	171	0	419	0	0	0	531	0	0	308	(485)	(632)	0	117,510

Schedule 3.1

Functionalized Revenue Requirement

For Allocation (First)

	ECC	SCADA	Environmental	Primary & Secondary	Call Center	Labour	Customer Service	Finance Labour	Finance Admin	Head Office	T&D Plant	Right of Way Amortization	Distribution Lines	Distribution Network	Total Plant		Total
Operating Expenses																	
Energy Costs	825	0	0	0	0	0	0	0	0	0	10	0	0	0	0	0	836
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	825	0	0	0	0	0	0	0	0	0	10	0	0	0	0	0	836
Distribution	0	261	0	0	0	0	0	0	0	0	0	0	1,082	1,934	0	0	3,277
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	1,898	0	0	1,898
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	0	0	7	0	882	5,764	626	408	851	149	383	0	0	0	46	0	9,115
Total Operating Expenses	825	261	7	0	882	5,764	626	408	851	149	393	0	1,082	3,832	46	0	15,125
Amortization																	
Amortization Other	0	0	0	0	0	248	0	0	0	0	0	112	0	0	0	0	359
Amortization Plant And Equipm	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	248	0	0	0	0	0	112	0	0	0	0	359
Total Operating Income	825	261	7	0	882	6,012	626	408	851	149	393	112	1,082	3,832	46	0	15,485
Financing Expenses																	
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructi	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	825	261	7	0	882	6,012	626	408	851	149	393	112	1,082	3,832	46	0	15,485
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	825	261	7	0	882	6,012	626	408	851	149	393	112	1,082	3,832	46	0	15,485
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	(573)	0	0	0	0	0	(6)	0	0	0	0	0	0	(579)
Net Revenue Requirement	825	261	7	(573)	882	6,012	626	408	851	143	393	112	1,082	3,832	46	0	14,906

Schedule 3.1 Functionalized Revenue Requirement For Allocation (Second)	Amortization	G&T Rate Base	Rate Base Excluding WC	Rate Base													Total
Operating Expenses																	
Energy Costs	0	734	0	0	0	0	0	0	0	0	0	0	0	0	0	0	734
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	0	734	0	0	0	0	0	0	0	0	0	0	0	0	0	0	734
Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	0	0	1,227	0	0	0	0	0	0	0	0	0	0	0	0	0	1,227
Total Operating Expenses	0	734	1,227	0	0	0	0	0	0	0	0	0	0	0	0	0	1,961
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	14,761	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	14,761
Total Amortization	14,761	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	14,761
Total Operating Income	14,761	734	1,227	0	0	0	0	0	0	0	0	0	0	0	0	0	16,722
Financing Expenses																	
Long-Term Debt	0	0	0	11,983	0	0	0	0	0	0	0	0	0	0	0	0	11,983
Short-Term Debt	0	0	0	500	0	0	0	0	0	0	0	0	0	0	0	0	500
Interest Charged To Constructi	0	0	0	(368)	0	0	0	0	0	0	0	0	0	0	0	0	(368)
Amortization of Financing Costs	0	0	0	5	0	0	0	0	0	0	0	0	0	0	0	0	5
Total Financing Expenses	0	0	0	12,119	0	0	0	0	0	0	0	0	0	0	0	0	12,119
Earnings before Income Taxes	14,761	734	1,227	12,119	0	0	0	0	0	0	0	0	0	0	0	0	28,841
Income Taxes	0	0	0	5,658	0	0	0	0	0	0	0	0	0	0	0	0	5,658
Net Earnings	0	0	0	12,246	0	0	0	0	0	0	0	0	0	0	0	0	12,246
Gross Revenue Requirement	14,761	734	1,227	30,023	0	0	0	0	0	0	0	0	0	0	0	0	46,745
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	(157)	0	0	0	0	0	0	0	0	0	0	0	0	(157)
Net Revenue Requirement	14,761	734	1,227	29,866	0	0	0	0	0	0	0	0	0	0	0	0	46,588

Schedule 3.1

Functionalized Revenue Requirement

Required Allocation Factors

	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
ECC	8.3 %	16.7 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
SCADA	25.0 %	0.0 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Environmental	50.0 %	0.0 %	0.0 %	2.0 %	0.0 %	48.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Primary & Secondary	0.0 %	0.0 %	0.0 %	0.0 %	75.0 %	0.0 %	25.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Call Center	0.0 %	0.0 %	5.0 %	0.0 %	3.3 %	3.3 %	3.3 %	0.0 %	0.0 %	5.0 %	20.0 %	40.0 %	10.0 %	10.0 %	0.0 %	0.0 %	100.0 %
Labour	37.4 %	2.8 %	16.2 %	7.3 %	13.3 %	15.1 %	5.5 %	0.7 %	0.0 %	1.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Customer Service	0.0 %	0.0 %	2.8 %	0.0 %	1.8 %	1.8 %	1.8 %	0.0 %	0.0 %	27.8 %	11.0 %	22.0 %	25.5 %	5.5 %	0.0 %	0.0 %	100.0 %
Finance Labour	10.7 %	0.8 %	9.1 %	2.8 %	9.4 %	8.1 %	3.5 %	4.0 %	0.7 %	0.5 %	28.6 %	21.4 %	0.0 %	0.0 %	0.0 %	0.3 %	100.0 %
Finance Admin	5.3 %	0.4 %	4.6 %	1.4 %	4.7 %	4.1 %	1.7 %	2.0 %	0.4 %	0.2 %	64.3 %	10.7 %	0.0 %	0.0 %	0.0 %	0.1 %	100.0 %
Head Office	11.2 %	0.8 %	11.5 %	3.0 %	11.1 %	9.8 %	4.9 %	4.2 %	0.8 %	2.5 %	12.6 %	19.4 %	4.0 %	4.0 %	0.0 %	0.3 %	100.0 %
T&D Plant	0.0 %	0.0 %	21.2 %	4.0 %	26.0 %	17.7 %	8.8 %	17.6 %	3.4 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.3 %	100.0 %
Right of Way Amortization	0.0 %	0.0 %	91.9 %	0.0 %	4.0 %	2.7 %	1.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Distribution Lines	0.0 %	0.0 %	0.0 %	0.0 %	48.4 %	0.0 %	16.1 %	33.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	2.4 %	100.0 %
Distribution Network	0.0 %	0.0 %	0.0 %	6.1 %	46.7 %	31.7 %	15.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Total Plant	21.6 %	0.1 %	16.2 %	3.3 %	20.6 %	14.3 %	7.0 %	13.0 %	2.5 %	0.1 %	0.1 %	0.2 %	0.0 %	0.0 %	0.0 %	0.9 %	100.0 %
Amortization	21.8 %	0.2 %	12.0 %	4.0 %	21.7 %	15.7 %	7.5 %	13.0 %	2.5 %	0.2 %	0.1 %	0.2 %	0.0 %	0.0 %	0.0 %	0.9 %	100.0 %
G&T Rate Base	65.5 %	0.0 %	34.5 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Rate Base Excluding WC	22.9 %	(2.0)%	12.1 %	3.3 %	21.9 %	17.4 %	7.4 %	11.7 %	4.1 %	0.1 %	0.1 %	0.2 %	0.0 %	0.0 %	0.0 %	0.7 %	100.0 %
Rate Base	22.7 %	(0.7)%	11.9 %	3.3 %	21.6 %	17.1 %	7.3 %	11.5 %	4.0 %	0.1 %	0.1 %	0.2 %	0.0 %	0.0 %	0.0 %	0.7 %	100.0 %

Schedule 3.1																	
Functionalized Revenue Requirement																	
First Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	69	138	209	207	72	71	70	2	0	0	0	0	0	0	0	0	836
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	69	138	209	207	72	71	70	2	0	0	0	0	0	0	0	0	836
Distribution	65	0	65	183	1,449	634	497	357	0	0	0	0	0	0	0	26	3,277
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	116	886	601	295	0	0	0	0	0	0	0	0	0	1,898
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	2,276	169	1,176	465	1,013	1,072	434	152	22	318	928	698	254	129	0	11	9,115
Total Operating Expenses	2,410	306	1,450	971	3,419	2,377	1,296	511	22	318	928	698	254	129	0	37	15,125
Amortization																	
Amortization Other	93	7	143	18	37	40	15	2	0	4	0	0	0	0	0	0	359
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	93	7	143	18	37	40	15	2	0	4	0	0	0	0	0	0	359
Total Operating Income	2,502	313	1,593	989	3,457	2,418	1,312	513	22	322	928	698	254	129	0	37	15,485
Financing Expenses																	0
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructi	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	2,502	313	1,593	989	3,457	2,418	1,312	513	22	322	928	698	254	129	0	37	15,485
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	2,502	313	1,593	989	3,457	2,418	1,312	513	22	322	928	698	254	129	0	37	15,485
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	(1)	(0)	(1)	(0)	(430)	(1)	(144)	(0)	(0)	(0)	(1)	(1)	(0)	(0)	0	(0)	(579)
Net Revenue Requirement	2,502	313	1,592	989	3,026	2,417	1,168	513	22	322	927	697	253	128	0	37	14,906

Schedule 3.1																	
Functionalized Revenue Requirement																	
Second Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	481	0	253	0	0	0	0	0	0	0	0	0	0	0	0	0	734
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	481	0	253	0	0	0	0	0	0	0	0	0	0	0	0	0	734
Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	281	(24)	148	41	268	213	91	143	50	2	2	2	0	0	0	9	1,227
Total Operating Expenses	762	(24)	401	41	268	213	91	143	50	2	2	2	0	0	0	9	1,961
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	3,212	29	1,777	590	3,203	2,319	1,113	1,918	367	34	19	30	6	6	0	138	14,761
Total Amortization	3,212	29	1,777	590	3,203	2,319	1,113	1,918	367	34	19	30	6	6	0	138	14,761
Total Operating Income	3,974	5	2,178	631	3,471	2,532	1,204	2,061	417	36	21	32	7	7	0	147	16,722
Financing Expenses																	
Long-Term Debt	2,718	(88)	1,429	395	2,585	2,053	878	1,380	484	17	16	23	5	5	0	84	11,983
Short-Term Debt	113	(4)	60	16	108	86	37	58	20	1	1	1	0	0	0	4	500
Interest Charged To Constructio	(84)	3	(44)	(12)	(79)	(63)	(27)	(42)	(15)	(1)	(0)	(1)	(0)	(0)	0	(3)	(368)
Amortization of Financing Costs	1	(0)	1	0	1	1	0	1	0	0	0	0	0	0	0	0	5
Total Financing Expenses	2,749	(89)	1,445	399	2,614	2,076	888	1,396	489	17	16	24	5	5	0	85	12,119
Earnings before Income Taxes	6,723	(84)	3,623	1,030	6,085	4,608	2,092	3,457	906	53	37	56	12	11	0	232	28,841
Income Taxes	1,283	(42)	675	186	1,220	969	415	652	228	8	7	11	3	2	0	40	5,658
Net Earnings	2,778	(90)	1,460	403	2,641	2,098	897	1,411	494	17	16	24	5	5	0	86	12,246
Gross Revenue Requirement	10,783	(216)	5,757	1,620	9,946	7,676	3,404	5,519	1,629	78	60	91	20	19	0	357	46,745
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	(36)	1	(19)	(5)	(34)	(27)	(11)	(18)	(6)	(0)	(0)	(0)	(0)	(0)	0	(1)	(157)
Net Revenue Requirement	10,748	(215)	5,739	1,615	9,913	7,649	3,393	5,501	1,622	78	60	91	20	19	0	356	46,588

Schedule 3.1																	
Functionalized Revenue Requirement																	
Total																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	6,275	98,913	1,209	207	72	71	70	2	0	0	0	0	0	0	0	0	106,818
ECAM Adjustment	0	12,358	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12,358
Net Energy Costs	6,275	111,270	1,209	207	72	71	70	2	0	0	0	0	0	0	0	0	119,176
Distribution	65	0	65	258	1,449	1,053	497	357	0	155	0	0	0	0	0	26	3,925
Transmission	0	0	922	0	0	0	0	0	0	0	0	0	0	0	0	0	922
Transmission and Distribution -	0	0	0	212	886	601	295	0	0	0	0	0	0	0	0	0	1,994
Transmission - OATT	0	0	172	0	0	0	0	0	0	0	0	0	0	0	0	0	172
General	2,557	144	1,324	506	1,281	1,285	525	295	72	696	929	700	562	129	0	20	11,025
Total Operating Expenses	8,897	111,414	3,693	1,182	3,687	3,009	1,387	654	73	850	929	700	562	129	0	46	137,214
Amortization																	
Amortization Other	93	336	143	18	37	40	15	2	0	4	0	0	0	0	0	0	688
Amortization Plant And Equipme	3,212	29	1,777	590	3,203	2,319	1,113	1,918	367	34	19	30	6	6	0	138	14,761
Total Amortization	3,304	365	1,920	608	3,240	2,359	1,129	1,919	367	38	19	30	6	6	0	138	15,450
Total Operating Income	12,201	111,780	5,612	1,791	6,927	5,369	2,516	2,574	439	889	948	730	568	135	0	184	152,663
Financing Expenses																	
Long-Term Debt	2,718	(88)	1,429	395	2,585	2,053	878	1,380	484	17	16	23	5	5	0	84	11,983
Short-Term Debt	113	(4)	60	16	108	86	37	58	20	1	1	1	0	0	0	4	500
Interest Charged To Constructi	(84)	3	(44)	(12)	(79)	(63)	(27)	(42)	(15)	(1)	(0)	(1)	(0)	(0)	0	(3)	(368)
Amortization of Financing Costs	1	(0)	1	0	1	1	0	1	0	0	0	0	0	0	0	0	5
Total Financing Expenses	2,749	(89)	1,445	399	2,614	2,076	888	1,396	489	17	16	24	5	5	0	85	12,119
Earnings before Income Taxes	14,950	111,691	7,057	2,190	9,541	7,445	3,404	3,970	928	906	964	754	573	140	0	269	164,782
Income Taxes	1,283	(42)	675	186	1,220	969	415	652	228	8	7	11	3	2	0	40	5,658
Net Earnings	2,778	(90)	1,460	403	2,641	2,098	897	1,411	494	17	16	24	5	5	0	86	12,246
Gross Revenue Requirement	19,011	111,559	9,192	2,779	13,403	10,513	4,716	6,032	1,651	931	988	789	581	147	0	394	182,686
OATT Revenue	0	0	(1,830)	0	0	0	0	0	0	0	0	0	0	0	0	0	(1,830)
Other Revenue	(36)	1	(19)	(5)	(464)	(27)	(155)	(18)	(6)	(0)	(1)	(1)	(0)	(485)	(632)	(1)	(1,852)
Net Revenue Requirement	18,975	111,560	7,343	2,774	12,939	10,485	4,561	6,014	1,645	931	987	787	581	(338)	(632)	393	179,004

Schedule 3.2																	
Functionalized Labour																	
Direct Assigned ($,000)																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	1,677	0	18	0	0	0	0	0	0	0	0	0	0	0	0	0	1,695
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	1,677	0	18	0	0	0	0	0	0	0	0	0	0	0	0	0	1,695
Distribution	0	0	0	43	0	294	0	0	0	76	0	0	0	0	0	0	414
Transmission	0	0	377	0	0	0	0	0	0	0	0	0	0	0	0	0	377
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	136	0	0	0	0	0	0	0	0	0	0	0	0	0	136
General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Expenses	1,677	0	531	43	0	294	0	0	0	76	0	0	0	0	0	0	2,622
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Income	1,677	0	531	43	0	294	0	0	0	76	0	0	0	0	0	0	2,622
Financing Expenses		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructi	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	1,677	0	531	43	0	294	0	0	0	76	0	0	0	0	0	0	2,622
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	1,677	0	531	43	0	294	0	0	0	76	0	0	0	0	0	0	2,622
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Revenue Requirement	1,677	0	531	43	0	294	0	0	0	76	0	0	0	0	0	0	2,622

Schedule 3.2																	
Functionalized Labour																	
For Allocation																	
	ECC	SCADA	T&D Plant	Distribution Lines	Distribution												Total
Operating Expenses																	
Energy Costs	796	0	10	0	0	0	0	0	0	0	0	0	0	0	0	0	806
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	796	0	10	0	0	0	0	0	0	0	0	0	0	0	0	0	806
Distribution	0	153	0	92	1,088	0	0	0	0	0	0	0	0	0	0	0	1,333
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Expenses	796	153	10	92	1,088	0	0	0	0	0	0	0	0	0	0	0	2,139
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Income	796	153	10	92	1,088	0	0	0	0	0	0	0	0	0	0	0	2,139
Financing Expenses		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructi	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	796	153	10	92	1,088	0	0	0	0	0	0	0	0	0	0	0	2,139
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	796	153	10	92	1,088	0	0	0	0	0	0	0	0	0	0	0	2,139
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Revenue Requirement	796	153	10	92	1,088	0	0	0	0	0	0	0	0	0	0	0	2,139
Required Allocation Factors																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
ECC	8.3 %	16.7 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
SCADA	25.0 %	0.0 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
T&D Plant	0.0 %	0.0 %	21.2 %	4.0 %	26.0 %	17.7 %	8.8 %	17.6 %	3.4 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.3 %	100.0 %
Distribution Lines	0.0 %	0.0 %	0.0 %	0.0 %	48.4 %	0.0 %	16.1 %	33.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	2.4 %	100.0 %
Distribution Network	0.0 %	0.0 %	0.0 %	6.1 %	46.7 %	31.7 %	15.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %

Schedule 3.2																	
Functionalized Labour																	
Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	66	133	201	199	69	68	67	2	0	0	0	0	0	0	0	0	806
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	66	133	201	199	69	68	67	2	0	0	0	0	0	0	0	0	806
Distribution	38	0	38	104	565	357	197	30	0	0	0	0	0	0	0	2	1,333
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Expenses	105	133	239	304	634	425	264	32	0	0	0	0	0	0	0	2	2,139
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Income	105	133	239	304	634	425	264	32	0	0	0	0	0	0	0	2	2,139
Financing Expenses																	0
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructi	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	105	133	239	304	634	425	264	32	0	0	0	0	0	0	0	2	2,139
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	105	133	239	304	634	425	264	32	0	0	0	0	0	0	0	2	2,139
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Revenue Requirement	105	133	239	304	634	425	264	32	0	0	0	0	0	0	0	2	2,139

Schedule 3.2																	
Functionalized Labour																	
Total																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	1,743	133	220	199	69	68	67	2	0	0	0	0	0	0	0	0	2,501
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	1,743	133	220	199	69	68	67	2	0	0	0	0	0	0	0	0	2,501
Distribution	38	0	38	148	565	651	197	30	0	76	0	0	0	0	0	2	1,747
Transmission	0	0	377	0	0	0	0	0	0	0	0	0	0	0	0	0	377
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	136	0	0	0	0	0	0	0	0	0	0	0	0	0	136
General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Expenses	1,781	133	771	347	634	720	264	32	0	76	0	0	0	0	0	2	4,761
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Income	1,781	133	771	347	634	720	264	32	0	76	0	0	0	0	0	2	4,761
Financing Expenses																	0
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructio	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	1,781	133	771	347	634	720	264	32	0	76	0	0	0	0	0	2	4,761
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	1,781	133	771	347	634	720	264	32	0	76	0	0	0	0	0	2	4,761
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Revenue Requirement	1,781	133	771	347	634	720	264	32	0	76	0	0	0	0	0	2	4,761

Schedule 3.3 Functionalized Vehicle Direct Assigned ($,000)	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	41	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	42
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	41	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	42
Distribution	0	0	0	3	0	49	0	0	0	10	0	0	0	0	0	0	61
Transmission	0	0	46	0	0	0	0	0	0	0	0	0	0	0	0	0	46
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Expenses	41	0	47	3	0	49	0	0	0	10	0	0	0	0	0	0	149
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Income	41	0	47	3	0	49	0	0	0	10	0	0	0	0	0	0	149
Financing Expenses		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructi	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	41	0	47	3	0	49	0	0	0	10	0	0	0	0	0	0	149
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	41	0	47	3	0	49	0	0	0	10	0	0	0	0	0	0	149
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Revenue Requirement	41	0	47	3	0	49	0	0	0	10	0	0	0	0	0	0	149

Schedule 3.3																	
Functionalized Vehicle																	
For Allocation																	
	ECC	SCADA	T&D Plant	Distribution Lines	Distribution												Total
Operating Expenses																	
Energy Costs	18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	19
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	19
Distribution	0	12	0	21	139	0	0	0	0	0	0	0	0	0	0	0	172
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Expenses	18	12	0	21	139	0	0	0	0	0	0	0	0	0	0	0	190
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Income	18	12	0	21	139	0	0	0	0	0	0	0	0	0	0	0	190
Financing Expenses		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructi	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	18	12	0	21	139	0	0	0	0	0	0	0	0	0	0	0	190
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	18	12	0	21	139	0	0	0	0	0	0	0	0	0	0	0	190
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Revenue Requirement	18	12	0	21	139	0	0	0	0	0	0	0	0	0	0	0	190
Required Allocation Factors																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
ECC	8.3 %	16.7 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
SCADA	25.0 %	0.0 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
T&D Plant	0.0 %	0.0 %	21.2 %	4.0 %	26.0 %	17.7 %	8.8 %	17.6 %	3.4 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.3 %	100.0 %
Distribution Lines	0.0 %	0.0 %	0.0 %	0.0 %	48.4 %	0.0 %	16.1 %	33.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	2.4 %	100.0 %
Distribution Network	0.0 %	0.0 %	0.0 %	6.1 %	46.7 %	31.7 %	15.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %

Schedule 3.3 Functionalized Vehicle Allocation	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	2	3	5	5	2	2	2	0	0	0	0	0	0	0	0	0	19
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	2	3	5	5	2	2	2	0	0	0	0	0	0	0	0	0	19
Distribution	3	0	3	11	76	45	26	7	0	0	0	0	0	0	0	1	172
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Expenses	5	3	8	16	78	46	28	7	0	0	0	0	0	0	0	1	190
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Income	5	3	8	16	78	46	28	7	0	0	0	0	0	0	0	1	190
Financing Expenses																	0
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructi	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	5	3	8	16	78	46	28	7	0	0	0	0	0	0	0	1	190
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	5	3	8	16	78	46	28	7	0	0	0	0	0	0	0	1	190
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Revenue Requirement	5	3	8	16	78	46	28	7	0	0	0	0	0	0	0	1	190

Schedule 3.3 Functionalized Vehicle Total	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	42	3	6	5	2	2	2	0	0	0	0	0	0	0	0	0	60
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	42	3	6	5	2	2	2	0	0	0	0	0	0	0	0	0	60
Distribution	3	0	3	14	76	94	26	7	0	10	0	0	0	0	0	1	233
Transmission	0	0	46	0	0	0	0	0	0	0	0	0	0	0	0	0	46
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Expenses	45	3	55	19	78	95	28	7	0	10	0	0	0	0	0	1	339
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Income	45	3	55	19	78	95	28	7	0	10	0	0	0	0	0	1	339
Financing Expenses																	0
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructio	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	45	3	55	19	78	95	28	7	0	10	0	0	0	0	0	1	339
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	45	3	55	19	78	95	28	7	0	10	0	0	0	0	0	1	339
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Revenue Requirement	45	3	55	19	78	95	28	7	0	10	0	0	0	0	0	1	339

Schedule 3.4 Functionalized Rate Base Direct Assigned ($,000)	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	69,720	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	69,720
Transmission & Distribution																	
Substations	0	0	792	2,090	0	0	0	0	0	0	0	0	0	0	0	0	2,882
Lines and Line Transformers	0	0	32,347	0	0	55,260	0	40,051	0	0	0	0	0	0	0	0	127,658
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	14,460	0	0	0	0	0	0	0	14,460
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,439	2,439
Total Transmission & Distrib	0	0	33,139	2,090	0	55,260	0	40,051	14,460	0	0	0	0	0	0	2,439	147,440
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	69,720	0	33,139	2,090	0	55,260	0	40,051	14,460	0	0	0	0	0	0	2,439	217,160
Contributions - Net	0	0	(16,215)	0	0	0	0	0	0	0	0	0	0	0	0	0	(16,215)
Future Income Taxes																	
Fixed Assets Recovery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ECAM	0	2,669	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,669
Deferred Charges	(622)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(622)
Employee Future Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DSM	0	(639)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(639)
Future Income Tax Liability	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Tax Asset	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tax Adjustments for CAR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Future Income Taxes	(622)	2,029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,407
Deferred Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unrecoverd pre-2004 costs recove	0	992	0	0	0	0	0	0	0	0	0	0	0	0	0	0	992
Unrecoverd post-2003 costs recove	0	(9,600)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(9,600)
Regulatory Liabilities - Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Asset - Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Intangible Assets																	
Right of Ways	0	0	3,305	0	0	0	0	0	0	0	0	0	0	0	0	0	3,305
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	0	3,305	0	0	0	0	0	0	0	0	0	0	0	0	0	3,305
Deferred Charge	2,239	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,239
Working Capital																	0
Inventory	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross operating expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income taxes paid	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Working Capital	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	71,337	(6,579)	20,228	2,090	0	55,260	0	40,051	14,460	0	0	0	0	0	0	2,439	199,288

Schedule 3.4																	
Functionalized Rate Base																	
For Allocation	First Allocation											Second Al	Third Allocation				
	Substations 1841 Account	ECC	SCADA	Primary & Secondary	Distribution Facilities	Distribution Lines	Distribution Network	Transportation	Labour	Head Office	Contributions Related Distribution Plant	Net Plant	Rate Base Excluding WC	O&M			Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	22,823	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	22,823
Lines and Line Transformers	0	0	0	91,007	0	0	2,125	0	0	0	0	0	0	0	0	0	93,132
SCADA and Communications	0	0	4,328	0	0	0	0	0	0	0	0	0	0	0	0	0	4,328
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	22,823	0	4,328	91,007	0	0	2,125	0	0	0	0	0	0	0	0	0	120,284
Administrative & General	0	452	0	0	0	0	4,662	6,198	4,490	3,361	0	0	0	0	0	0	19,162
Gross Fixed Assets	22,823	452	4,328	91,007	0	0	6,787	6,198	4,490	3,361	0	0	0	0	0	0	139,446
Contributions - Net	0	0	0	0	0	0	0	0	0	0	(10,423)	0	0	0	0	0	(10,423)
Future Income Taxes																	
Fixed Assets Recovery	0	0	0	0	0	0	0	0	0	0	0	(47,722)	0	0	0	0	(47,722)
ECAM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Charges	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Employee Future Benefits	0	0	0	0	0	0	0	0	4,475	0	0	0	0	0	0	0	4,475
DSM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Tax Liability	0	0	0	0	0	0	0	0	0	0	0	3,681	0	0	0	0	3,681
Future Income Tax Asset	0	0	0	0	0	0	0	0	0	0	0	9,273	0	0	0	0	9,273
Other	0	0	0	0	0	0	0	0	0	0	0	(92)	0	0	0	0	(92)
Tax Adjustments for CAR	0	0	0	0	0	0	0	0	0	0	0	12,520	0	0	0	0	12,520
Total Future Income Taxes	0	0	0	0	0	0	0	0	4,475	0	0	(22,341)	0	0	0	0	(17,866)
Deferred Financing Costs	0	0	0	0	0	0	0	0	0	0	0	431	0	0	0	0	431
Unrecoverd pre-2004 costs recove	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unrecoverd post-2003 costs recov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Liabilities - Other	0	0	0	0	0	0	0	0	0	0	0	(11,875)	0	0	0	0	(11,875)
Regulatory Asset - Other	0	0	0	0	0	0	0	0	1,830	0	0	0	0	0	0	0	1,830
Intangible Assets																	
Right of Ways	0	0	0	0	277	0	0	0	0	0	0	0	0	0	0	0	277
Software	0	0	0	0	0	0	0	0	752	0	0	0	0	0	0	0	752
Total Intangible Assets	0	0	0	0	277	0	0	0	752	0	0	0	0	0	0	0	1,029
Deferred Charge	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Working Capital																	0
Inventory	0	0	0	0	0	5,536	0	0	0	0	0	0	0	0	0	0	5,536
Gross operating expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	4,656	0	0	4,656
Income taxes paid	0	0	0	0	0	0	0	0	0	0	0	0	217	0	0	0	217
Total Working Capital	0	0	0	0	0	5,536	0	0	0	0	0	0	217	4,656	0	0	10,409
Total	22,823	452	4,328	91,007	277	5,536	6,787	6,198	11,547	3,361	(10,423)	(33,785)	217	4,656	0	0	112,981

Schedule 3.4																	
Functionalized Rate Base																	
Required Allocation Factors																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Substations 1841 Account	0.0 %	0.0 %	72.2 %	27.8 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
ECC	8.3 %	16.7 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
SCADA	25.0 %	0.0 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Primary & Secondary	0.0 %	0.0 %	0.0 %	0.0 %	75.0 %	0.0 %	25.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Distribution Facilities	0.0 %	0.0 %	0.0 %	0.0 %	49.7 %	33.7 %	16.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Distribution Lines	0.0 %	0.0 %	0.0 %	0.0 %	48.4 %	0.0 %	16.1 %	33.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	2.4 %	100.0 %
Distribution Network	0.0 %	0.0 %	0.0 %	6.1 %	46.7 %	31.7 %	15.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Transportation	13.3 %	0.9 %	16.1 %	5.5 %	22.9 %	28.2 %	8.1 %	2.1 %	0.0 %	2.8 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.1 %	100.0 %
Labour	37.4 %	2.8 %	16.2 %	7.3 %	13.3 %	15.1 %	5.5 %	0.7 %	0.0 %	1.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Head Office	11.2 %	0.8 %	11.5 %	3.0 %	11.1 %	9.8 %	4.9 %	4.2 %	0.8 %	2.5 %	12.6 %	19.4 %	4.0 %	4.0 %	0.0 %	0.3 %	100.0 %
Contributions Related Distribution	0.0 %	0.0 %	0.0 %	0.0 %	34.8 %	23.6 %	11.6 %	23.7 %	4.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.7 %	100.0 %
Net Plant	22.1 %	0.1 %	12.0 %	3.3 %	21.2 %	17.4 %	7.2 %	11.3 %	4.2 %	0.1 %	0.1 %	0.2 %	0.0 %	0.0 %	0.0 %	0.7 %	100.0 %
Rate Base Excluding WC	22.9 %	(2.0)%	12.1 %	3.3 %	21.9 %	17.4 %	7.4 %	11.7 %	4.1 %	0.1 %	0.1 %	0.2 %	0.0 %	0.0 %	0.0 %	0.7 %	100.0 %
O&M	6.0 %	82.4 %	2.4 %	0.8 %	2.5 %	2.1 %	1.0 %	0.4 %	0.0 %	0.6 %	0.7 %	0.5 %	0.4 %	0.1 %	0.0 %	0.0 %	100.0 %

Schedule 3.4																	
Functionalized Rate Base																	
First Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	16,470	6,353	0	0	0	0	0	0	0	0	0	0	0	0	22,823
Lines and Line Transformers	0	0	0	129	69,248	673	23,083	0	0	0	0	0	0	0	0	0	93,132
SCADA and Communications	1,082	0	1,082	1,082	361	361	361	0	0	0	0	0	0	0	0	0	4,328
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	1,082	0	17,552	7,565	69,608	1,034	23,443	0	0	0	0	0	0	0	0	0	120,284
Administrative & General	2,915	284	2,226	1,165	4,604	4,265	1,682	298	26	332	422	653	134	134	0	21	19,162
Gross Fixed Assets	3,997	284	19,777	8,729	74,212	5,299	25,125	298	26	332	422	653	134	134	0	21	139,446
Contributions - Net	0	0	0	0	(3,627)	(2,459)	(1,209)	(2,473)	(478)	0	0	0	0	0	0	(178)	(10,423)
Future Income Taxes																	
Fixed Assets Recovery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ECAM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Charges	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Employee Future Benefits	1,674	125	724	326	596	676	248	30	0	72	0	0	0	0	0	2	4,475
DSM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Tax Liability	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Tax Asset	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tax Adjustments for CAR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Future Income Taxes	1,674	125	724	326	596	676	248	30	0	72	0	0	0	0	0	2	4,475
Deferred Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unrecoverd pre-2004 costs recove	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unrecoverd post-2003 costs recov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Liabilities - Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Asset - Other	685	51	296	134	244	277	102	12	0	29	0	0	0	0	0	1	1,830
Intangible Assets																	
Right of Ways	0	0	0	0	138	94	46	0	0	0	0	0	0	0	0	0	277
Software	281	21	122	55	100	114	42	5	0	12	0	0	0	0	0	0	752
Total Intangible Assets	281	21	122	55	238	207	88	5	0	12	0	0	0	0	0	0	1,029
Deferred Charge	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Working Capital																	
Inventory	0	0	0	0	2,682	0	894	1,829	0	0	0	0	0	0	0	132	5,536
Gross operating expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income taxes paid	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Working Capital	0	0	0	0	2,682	0	894	1,829	0	0	0	0	0	0	0	132	5,536
Total	6,638	481	20,920	9,244	74,345	4,000	25,248	(298)	(451)	445	422	653	134	134	0	(21)	141,893

Schedule 3.4 Functionalized Rate Base Second Allocation	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lines and Line Transformers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Contributions - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Taxes																	
Fixed Assets Recovery	(10,564)	(44)	(5,728)	(1,552)	(10,110)	(8,323)	(3,427)	(5,408)	(2,000)	(49)	(60)	(93)	(19)	(19)	0	(326)	(47,722)
ECAM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Charges	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Employee Future Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DSM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Tax Liability	815	3	442	120	780	642	264	417	154	4	5	7	1	1	0	25	3,681
Future Income Tax Asset	2,053	8	1,113	302	1,965	1,617	666	1,051	389	10	12	18	4	4	0	63	9,273
Other	(20)	(0)	(11)	(3)	(20)	(16)	(7)	(10)	(4)	(0)	(0)	(0)	(0)	(0)	0	(1)	(92)
Tax Adjustments for CAR	2,771	11	1,503	407	2,652	2,184	899	1,419	525	13	16	24	5	5	0	86	12,520
Total Future Income Taxes	(4,945)	(20)	(2,682)	(727)	(4,733)	(3,897)	(1,604)	(2,532)	(936)	(23)	(28)	(44)	(9)	(9)	0	(153)	(22,341)
Deferred Financing Costs	95	0	52	14	91	75	31	49	18	0	1	1	0	0	0	3	431
Unrecoverd pre-2004 costs recove	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unrecoverd post-2003 costs recov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Liabilities - Other	(2,629)	(11)	(1,425)	(386)	(2,516)	(2,071)	(853)	(1,346)	(498)	(12)	(15)	(23)	(5)	(5)	0	(81)	(11,875)
Regulatory Asset - Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Intangible Assets																	
Right of Ways	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Charge	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Working Capital																	
Inventory	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross operating expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income taxes paid	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Working Capital	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	(7,479)	(31)	(4,055)	(1,099)	(7,158)	(5,893)	(2,426)	(3,828)	(1,416)	(35)	(43)	(66)	(14)	(14)	0	(231)	(33,785)

Schedule 3.4																	
Functionalized Rate Base																	
Third Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lines and Line Transformers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Contributions - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Taxes																	
Fixed Assets Recovery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ECAM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Charges	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Employee Future Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DSM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Tax Liability	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Tax Asset	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tax Adjustments for CAR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Future Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unrecoverd pre-2004 costs recove	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unrecoverd post-2003 costs recov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Liabilities - Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Asset - Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Intangible Assets																	
Right of Ways	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Charge	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Working Capital																	
Inventory	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross operating expenses	280	3,836	113	39	118	96	45	18	1	29	32	24	19	4	0	1	4,656
Income taxes paid	50	(4)	26	7	47	38	16	25	9	0	0	0	0	0	0	2	217
Total Working Capital	330	3,832	139	47	165	134	61	43	10	30	32	24	19	5	0	3	4,873
Total	330	3,832	139	47	165	134	61	43	10	30	32	24	19	5	0	3	4,873

Schedule 3.4																	
Functionalized Rate Base																	
Total																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	69,720	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	69,720
Transmission & Distribution																	
Substations	0	0	17,261	8,444	0	0	0	0	0	0	0	0	0	0	0	0	25,705
Lines and Line Transformers	0	0	32,347	129	69,248	55,933	23,083	40,051	0	0	0	0	0	0	0	0	220,790
SCADA and Communications	1,082	0	1,082	1,082	361	361	361	0	0	0	0	0	0	0	0	0	4,328
Meters	0	0	0	0	0	0	0	0	14,460	0	0	0	0	0	0	0	14,460
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,439	2,439
Total Transmission & Distrib	1,082	0	50,690	9,655	69,608	56,293	23,443	40,051	14,460	0	0	0	0	0	0	2,439	267,723
Administrative & General	2,915	284	2,226	1,165	4,604	4,265	1,682	298	26	332	422	653	134	134	0	21	19,162
Gross Fixed Assets	73,718	284	52,916	10,820	74,212	60,559	25,125	40,349	14,486	332	422	653	134	134	0	2,461	356,606
Contributions - Net	0	0	(16,215)	0	(3,627)	(2,459)	(1,209)	(2,473)	(478)	0	0	0	0	0	0	(178)	(26,638)
Future Income Taxes																	0
Fixed Assets Recovery	(10,564)	(44)	(5,728)	(1,552)	(10,110)	(8,323)	(3,427)	(5,408)	(2,000)	(49)	(60)	(93)	(19)	(19)	0	(326)	(47,722)
ECAM	0	2,669	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,669
Deferred Charges	(622)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(622)
Employee Future Benefits	1,674	125	724	326	596	676	248	30	0	72	0	0	0	0	0	2	4,475
DSM	0	(639)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(639)
Future Income Tax Liability	815	3	442	120	780	642	264	417	154	4	5	7	1	1	0	25	3,681
Future Income Tax Asset	2,053	8	1,113	302	1,965	1,617	666	1,051	389	10	12	18	4	4	0	63	9,273
Other	(20)	(0)	(11)	(3)	(20)	(16)	(7)	(10)	(4)	(0)	(0)	(0)	(0)	(0)	0	(1)	(92)
Tax Adjustments for CAR	2,771	11	1,503	407	2,652	2,184	899	1,419	525	13	16	24	5	5	0	86	12,520
Total Future Income Taxes	(3,893)	2,134	(1,957)	(400)	(4,137)	(3,220)	(1,356)	(2,501)	(936)	49	(28)	(44)	(9)	(9)	0	(150)	(16,459)
Deferred Financing Costs	95	0	52	14	91	75	31	49	18	0	1	1	0	0	0	3	431
Unrecoverd pre-2004 costs recove	0	992	0	0	0	0	0	0	0	0	0	0	0	0	0	0	992
Unrecoverd post-2003 costs recov	0	(9,600)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(9,600)
Regulatory Liabilities - Other	(2,629)	(11)	(1,425)	(386)	(2,516)	(2,071)	(853)	(1,346)	(498)	(12)	(15)	(23)	(5)	(5)	0	(81)	(11,875)
Regulatory Asset - Other	685	51	296	134	244	277	102	12	0	29	0	0	0	0	0	1	1,830
Intangible Assets																	
Right of Ways	0	0	3,305	0	138	94	46	0	0	0	0	0	0	0	0	0	3,582
Software	281	21	122	55	100	114	42	5	0	12	0	0	0	0	0	0	752
Total Intangible Assets	281	21	3,427	55	238	207	88	5	0	12	0	0	0	0	0	0	4,334
Deferred Charge	2,239	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,239
Working Capital																	0
Inventory	0	0	0	0	2,682	0	894	1,829	0	0	0	0	0	0	0	132	5,536
Gross operating expenses	280	3,836	113	39	118	96	45	18	1	29	32	24	19	4	0	1	4,656
Income taxes paid	50	(4)	26	7	47	38	16	25	9	0	0	0	0	0	0	2	217
Total Working Capital	330	3,832	139	47	2,847	134	955	1,871	10	30	32	24	19	5	0	134	10,409
Total	70,826	(2,297)	37,232	10,282	67,353	53,501	22,882	35,967	12,603	440	412	611	140	125	0	2,190	312,269

Schedule 3.5																	
Functionalized Contributions Related Distribution Plant																	
Direct Assigned ($,000)																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lines and Line Transformers	0	0	0	0	0	69,853	0	70,327	0	0	0	0	0	0	0	0	140,179
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	13,583	0	0	0	0	0	0	0	13,583
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5,062	5,062
Total Transmission & Distrib	0	0	0	0	0	69,853	0	70,327	13,583	0	0	0	0	0	0	5,062	158,824
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	0	0	0	0	0	69,853	0	70,327	13,583	0	0	0	0	0	0	5,062	158,824
Intangible Assets																	
Right of Ways	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	69,853	0	70,327	13,583	0	0	0	0	0	0	5,062	158,824
For Allocation																	
	Primary &	Distribution															Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lines and Line Transformers	137,358	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	137,358
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	137,358	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	137,358
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	137,358	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	137,358
Intangible Assets																	
Right of Ways	0	282	0	0	0	0	0	0	0	0	0	0	0	0	0	0	282
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	282	0	0	0	0	0	0	0	0	0	0	0	0	0	0	282
Total	137,358	282	0	0	0	0	0	0	0	0	0	0	0	0	0	0	137,640
Required Allocation Factors																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Primary & Secondary	0.0 %	0.0 %	0.0 %	0.0 %	75.0 %	0.0 %	25.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Distribution Facilities	0.0 %	0.0 %	0.0 %	0.0 %	49.7 %	33.7 %	16.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %

Schedule 3.5																	
Functionalized Contributions Related Distribution Plant																	
Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lines and Line Transformers	0	0	0	0	103,019	0	34,340	0	0	0	0	0	0	0	0	0	137,358
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	0	0	0	0	103,019	0	34,340	0	0	0	0	0	0	0	0	0	137,358
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	0	0	0	0	103,019	0	34,340	0	0	0	0	0	0	0	0	0	137,358
Intangible Assets																	
Right of Ways	0	0	0	0	140	95	47	0	0	0	0	0	0	0	0	0	282
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	0	0	0	140	95	47	0	0	0	0	0	0	0	0	0	282
Total	0	0	0	0	103,159	95	34,386	0	0	0	0	0	0	0	0	0	137,640
Total																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lines and Line Transformers	0	0	0	0	103,019	69,853	34,340	70,327	0	0	0	0	0	0	0	0	277,537
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	13,583	0	0	0	0	0	0	0	13,583
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5,062	5,062
Total Transmission & Distrib	0	0	0	0	103,019	69,853	34,340	70,327	13,583	0	0	0	0	0	0	5,062	296,182
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	0	0	0	0	103,019	69,853	34,340	70,327	13,583	0	0	0	0	0	0	5,062	296,182
Intangible Assets																	
Right of Ways	0	0	0	0	140	95	47	0	0	0	0	0	0	0	0	0	282
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	0	0	0	140	95	47	0	0	0	0	0	0	0	0	0	282
Total	0	0	0	0	103,159	69,948	34,386	70,327	13,583	0	0	0	0	0	0	5,062	296,464

Schedule 3.6																	
Functionalized Amortization																	
Direct Assigned ($,000)																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	2,701	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,701
Transmission & Distribution																	
Substations	0	0	0	92	0	0	0	0	0	0	0	0	0	0	0	0	92
Lines and Line Transformers	0	0	1,136	0	0	2,096	0	2,110	0	0	0	0	0	0	0	0	5,341
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	407	0	0	0	0	0	0	0	407
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	152	152
Total Transmission & Distrib	0	0	1,136	92	0	2,096	0	2,110	407	0	0	0	0	0	0	152	5,993
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	2,701	0	1,136	92	0	2,096	0	2,110	407	0	0	0	0	0	0	152	8,693
Contributions - Net	0	0	(377)	0	0	0	0	0	0	0	0	0	0	0	0	0	(377)
Total	2,701	0	759	92	0	2,096	0	2,110	407	0	0	0	0	0	0	152	8,316
For Allocation																	
	Substations 1841 Account	ECC	SCADA	Primary & Secondary	Distribution Facilities	Distribution Lines	Distribution Network	Transportation	Labour	Head Office	Contributions Related Distribution Plant						Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	874	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	874
Lines and Line Transformers	0	0	0	4,121	0	0	17	0	0	0	0	0	0	0	0	0	4,138
SCADA and Communications	0	0	574	0	0	0	0	0	0	0	0	0	0	0	0	0	574
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	874	0	574	4,121	0	0	17	0	0	0	0	0	0	0	0	0	5,586
Administrative & General	0	17	0	0	0	0	232	681	690	153	0	0	0	0	0	0	1,774
Gross Fixed Assets	874	17	574	4,121	0	0	249	681	690	153	0	0	0	0	0	0	7,361
Contributions - Net	0	0	0	0	0	0	0	0	0	0	(915)	0	0	0	0	0	(915)
Total	874	17	574	4,121	0	0	249	681	690	153	(915)	0	0	0	0	0	6,445

Schedule 3.6
Functionalized Amortization

Required Allocation Factors

	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Substations 1841 Account	0.0 %	0.0 %	72.2 %	27.8 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
ECC	8.3 %	16.7 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
SCADA	25.0 %	0.0 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Primary & Secondary	0.0 %	0.0 %	0.0 %	0.0 %	75.0 %	0.0 %	25.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Distribution Facilities	0.0 %	0.0 %	0.0 %	0.0 %	49.7 %	33.7 %	16.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Distribution Lines	0.0 %	0.0 %	0.0 %	0.0 %	48.4 %	0.0 %	16.1 %	33.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	2.4 %	100.0 %
Distribution Network	0.0 %	0.0 %	0.0 %	6.1 %	46.7 %	31.7 %	15.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Transportation	13.3 %	0.9 %	16.1 %	5.5 %	22.9 %	28.2 %	8.1 %	2.1 %	0.0 %	2.8 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.1 %	100.0 %
Labour	37.4 %	2.8 %	16.2 %	7.3 %	13.3 %	15.1 %	5.5 %	0.7 %	0.0 %	1.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Head Office	11.2 %	0.8 %	11.5 %	3.0 %	11.1 %	9.8 %	4.9 %	4.2 %	0.8 %	2.5 %	12.6 %	19.4 %	4.0 %	4.0 %	0.0 %	0.3 %	100.0 %
Contributions Related Distribution	0.0 %	0.0 %	0.0 %	0.0 %	34.8 %	23.6 %	11.6 %	23.7 %	4.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.7 %	100.0 %

First Allocation

	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	631	243	0	0	0	0	0	0	0	0	0	0	0	0	874
Lines and Line Transformers	0	0	0	1	3,099	5	1,033	0	0	0	0	0	0	0	0	0	4,138
SCADA and Communications	144	0	144	144	48	48	48	0	0	0	0	0	0	0	0	0	574
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	144	0	774	388	3,146	53	1,081	0	0	0	0	0	0	0	0	0	5,586
Administrative & General	367	29	243	111	375	386	139	25	1	34	19	30	6	6	0	2	1,774
Gross Fixed Assets	511	29	1,018	499	3,521	439	1,219	25	1	34	19	30	6	6	0	2	7,361
Contributions - Net	0	0	0	0	(318)	(216)	(106)	(217)	(42)	0	0	0	0	0	0	(16)	(915)
Total	511	29	1,018	499	3,203	223	1,113	(192)	(41)	34	19	30	6	6	0	(14)	6,445

Schedule 3.6																	
Functionalized Amortization																	
Total																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	2,701	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,701
Transmission & Distribution																	
Substations	0	0	631	335	0	0	0	0	0	0	0	0	0	0	0	0	966
Lines and Line Transformers	0	0	1,136	1	3,099	2,101	1,033	2,110	0	0	0	0	0	0	0	0	9,479
SCADA and Communications	144	0	144	144	48	48	48	0	0	0	0	0	0	0	0	0	574
Meters	0	0	0	0	0	0	0	0	407	0	0	0	0	0	0	0	407
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	152	152
Total Transmission & Distrib	144	0	1,911	480	3,146	2,149	1,081	2,110	407	0	0	0	0	0	0	152	11,579
Administrative & General	367	29	243	111	375	386	139	25	1	34	19	30	6	6	0	2	1,774
Gross Fixed Assets	3,212	29	2,154	590	3,521	2,535	1,219	2,135	409	34	19	30	6	6	0	154	16,054
Contributions - Net	0	0	(377)	0	(318)	(216)	(106)	(217)	(42)	0	0	0	0	0	0	(16)	(1,293)
Total	3,212	29	1,777	590	3,203	2,319	1,113	1,918	367	34	19	30	6	6	0	138	14,761

Schedule 4.0																	
Functionalized Gross Plant																	
Direct Assigned ($,000)																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	110,331	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	110,331
Transmission & Distribution																	
Substations	0	0	808	2,878	0	0	0	0	0	0	0	0	0	0	0	0	3,685
Lines and Line Transformers	0	0	49,561	0	0	69,853	0	70,327	0	0	0	0	0	0	0	0	189,740
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	13,583	0	0	0	0	0	0	0	13,583
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5,062	5,062
Total Transmission & Distrib	0	0	50,369	2,878	0	69,853	0	70,327	13,583	0	0	0	0	0	0	5,062	212,070
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	110,331	0	50,369	2,878	0	69,853	0	70,327	13,583	0	0	0	0	0	0	5,062	322,401
Intangible Assets																	
Right of Ways	0	0	4,470	0	0	0	0	0	0	0	0	0	0	0	0	0	4,470
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	0	4,470	0	0	0	0	0	0	0	0	0	0	0	0	0	4,470
Total	110,331	0	54,839	2,878	0	69,853	0	70,327	13,583	0	0	0	0	0	0	5,062	326,871
For Allocation	First Allocation				Second Al	Third Allocation											
	Substations 1841 Account	ECC	SCADA	Primary & Secondar	Distribution Facilities	Distribution Network	Transportation	Labour	Head Office								Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	38,006	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	38,006
Lines and Line Transformers	0	0	0	137,358	0	2,134	0	0	0	0	0	0	0	0	0	0	139,492
SCADA and Communications	0	0	9,574	0	0	0	0	0	0	0	0	0	0	0	0	0	9,574
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	38,006	0	9,574	137,358	0	2,134	0	0	0	0	0	0	0	0	0	0	187,072
Administrative & General	0	697	0	0	0	7,255	9,086	5,664	5,114	0	0	0	0	0	0	0	27,815
Gross Fixed Assets	38,006	697	9,574	137,358	0	9,389	9,086	5,664	5,114	0	0	0	0	0	0	0	214,887
Intangible Assets																	
Right of Ways	0	0	0	0	282	0	0	0	0	0	0	0	0	0	0	0	282
Software	0	0	0	0	0	0	0	1,794	0	0	0	0	0	0	0	0	1,794
Total Intangible Assets	0	0	0	0	282	0	0	1,794	0	0	0	0	0	0	0	0	2,076
Total	38,006	697	9,574	137,358	282	9,389	9,086	7,458	5,114	0	0	0	0	0	0	0	216,964

Schedule 4.0																	
Functionalized Gross Plant																	
Required Allocation Factors																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Substations 1841 Account	0.0 %	0.0 %	72.2 %	27.8 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
ECC	8.3 %	16.7 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
SCADA	25.0 %	0.0 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Primary & Secondary	0.0 %	0.0 %	0.0 %	0.0 %	75.0 %	0.0 %	25.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Distribution Facilities	0.0 %	0.0 %	0.0 %	0.0 %	49.7 %	33.7 %	16.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Distribution Network	0.0 %	0.0 %	0.0 %	6.1 %	46.7 %	31.7 %	15.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Transportation	13.3 %	0.9 %	16.1 %	5.5 %	22.9 %	28.2 %	8.1 %	2.1 %	0.0 %	2.8 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.1 %	100.0 %
Labour	37.4 %	2.8 %	16.2 %	7.3 %	13.3 %	15.1 %	5.5 %	0.7 %	0.0 %	1.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Head Office	11.2 %	0.8 %	11.5 %	3.0 %	11.1 %	9.8 %	4.9 %	4.2 %	0.8 %	2.5 %	12.6 %	19.4 %	4.0 %	4.0 %	0.0 %	0.3 %	100.0 %
First Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	27,426	10,580	0	0	0	0	0	0	0	0	0	0	0	0	38,006
Lines and Line Transformers	0	0	0	0	103,019	0	34,340	0	0	0	0	0	0	0	0	0	137,358
SCADA and Communications	2,394	0	2,394	2,394	798	798	798	0	0	0	0	0	0	0	0	0	9,574
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	2,394	0	29,819	12,973	103,816	798	35,137	0	0	0	0	0	0	0	0	0	184,938
Administrative & General	58	116	174	174	58	58	58	0	0	0	0	0	0	0	0	0	697
Gross Fixed Assets	2,452	116	29,994	13,147	103,874	856	35,195	0	0	0	0	0	0	0	0	0	185,635
Intangible Assets																	
Right of Ways	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	2,452	116	29,994	13,147	103,874	856	35,195	0	0	0	0	0	0	0	0	0	185,635

Schedule 4.0																	
Functionalized Gross Plant																	
Second Allocation																	
	Generati on	Purchase d Power	Transmis sion	Substatio ns	Primary Lines	Transfor mers	Secondar y Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittan ce & Collection	Uncollecti bles & Damage Claims	Service Connecti ons	Late Payment s	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lines and Line Transformers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Intangible Assets																	
Right of Ways	0	0	0	0	140	95	47	0	0	0	0	0	0	0	0	0	282
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	0	0	0	140	95	47	0	0	0	0	0	0	0	0	0	282
Total	0	0	0	0	140	95	47	0	0	0	0	0	0	0	0	0	282
Third Allocation																	
	Generati on	Purchase d Power	Transmis sion	Substatio ns	Primary Lines	Transfor mers	Secondar y Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittan ce & Collection	Uncollecti bles & Damage Claims	Service Connecti ons	Late Payment s	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lines and Line Transformers	0	0	0	130	996	676	332	0	0	0	0	0	0	0	0	0	2,134
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	0	0	0	130	996	676	332	0	0	0	0	0	0	0	0	0	2,134
Administrative & General	3,896	282	2,970	1,506	6,789	6,210	2,434	438	40	476	643	994	205	205	0	32	27,119
Gross Fixed Assets	3,896	282	2,970	1,636	7,785	6,886	2,766	438	40	476	643	994	205	205	0	32	29,253
Intangible Assets																	
Right of Ways	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Software	671	50	290	131	239	271	100	12	0	29	0	0	0	0	0	1	1,794
Total Intangible Assets	671	50	290	131	239	271	100	12	0	29	0	0	0	0	0	1	1,794
Total	4,567	332	3,261	1,767	8,024	7,157	2,866	451	40	505	643	994	205	205	0	32	31,047

Schedule 4.0																	
Functionalized Gross Plant																	
Total																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	110,331	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	110,331
Transmission & Distribution																	
Substations	0	0	28,234	13,457	0	0	0	0	0	0	0	0	0	0	0	0	41,691
Lines and Line Transformers	0	0	49,561	130	104,015	70,528	34,672	70,327	0	0	0	0	0	0	0	0	329,232
SCADA and Communications	2,394	0	2,394	2,394	798	798	798	0	0	0	0	0	0	0	0	0	9,574
Meters	0	0	0	0	0	0	0	0	13,583	0	0	0	0	0	0	0	13,583
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5,062	5,062
Total Transmission & Distrib	2,394	0	80,188	15,981	104,813	71,326	35,469	70,327	13,583	0	0	0	0	0	0	5,062	399,142
Administrative & General	3,954	398	3,144	1,680	6,847	6,268	2,492	438	40	476	643	994	205	205	0	32	27,815
Gross Fixed Assets	116,678	398	83,332	17,661	111,660	77,595	37,962	70,765	13,623	476	643	994	205	205	0	5,094	537,288
Intangible Assets																	
Right of Ways	0	0	4,470	0	140	95	47	0	0	0	0	0	0	0	0	0	4,752
Software	671	50	290	131	239	271	100	12	0	29	0	0	0	0	0	1	1,794
Total Intangible Assets	671	50	4,761	131	379	366	146	12	0	29	0	0	0	0	0	1	6,547
Total	117,350	448	88,093	17,792	112,039	77,961	38,108	70,777	13,623	505	643	994	205	205	0	5,094	543,835

Schedule 4.1	
Revenue Requirement Summary ($,0000)	
Operating Expenses	
Energy Costs	106,818
ECAM Adjustment	12,358
Net Energy Costs	119,176
Distribution	3,925
Transmission	922
Transmission and Distribution -	1,994
Transmission - OATT	172
General	11,025
Total Operating Expenses	137,214
Amortization	
Amortization Other	688
Amortization Plant And Equipme	14,761
Total Amortization	15,450
Total Operating Income	152,663
Financing Expenses	
Long-Term Debt	11,983
Short-Term Debt	500
Interest Charged To Constructi	(368)
Amortization of Financing Costs	5
Total Financing Expenses	12,119
Earnings before Income Taxes	164,782
Income Taxes	5,658
Net Earnings	12,246
Gross Revenue Requirement	182,686
OATT Revenue	(1,830)
Other Revenue	(1,852)
Net Revenue Requirement	179,004

Schedule 4.2				
Rate Base ($,000)				
	Open	Close	Mid Year	Basis for Functionalization
Fixed Assets				
Production	69,831	69,610	69,720	Detailed Analysis
Transmission & Distribution				
Substations	25,028	26,382	25,705	Detailed Analysis
Lines and Line Transformers	216,131	225,450	220,790	Detailed Analysis
SCADA and Communications	4,471	4,185	4,328	Detailed Analysis
Meters	14,107	14,813	14,460	Detailed Analysis
Street & Private Area Lights	2,332	2,547	2,439	Detailed Analysis
Total Transmission & Distrib	262,069	273,377	267,723	
Administrative & General	18,851	19,473	19,162	Detailed Analysis
Net Fixed Assets	350,751	362,461	356,606	
Contributions - Net	(27,022)	(26,255)	(26,638)	Detailed Analysis
Future Income Taxes				
Fixed Assets Recovery	(45,858)	(49,586)	(47,722)	Net Plant
ECAM	3,768	1,569	2,669	Purchased Power
Deferred Charges	(637)	(608)	(622)	Generation
Employee Future Benefits	3,784	5,166	4,475	Labour
DSM	(108)	(1,170)	(639)	Purchased Power
Future Income Tax Liability	3,188	4,174	3,681	Net Plant
Future Income Tax Asset	8,210	10,336	9,273	Net Plant
Other	(487)	302	(92)	Net Plant
Tax Adjustments for CAR	12,520	12,520	12,520	Net Plant
Total Future Income Taxes	(15,620)	(17,298)	(16,459)	Net Plant
Deferred Financing Costs	433	428	431	Net Plant
Unrecoverd pre-2004 costs recove	1,984	0	992	Purchased Power
Unrecoverd post-2003 costs recov	(14,138)	(5,062)	(9,600)	Purchased Power
Regulatory Liabilities - Other	(10,285)	(13,465)	(11,875)	Net Plant
Regulatory Asset - Other	0	3,660	1,830	Labour
Intangible Assets				
Right of Ways	3,670	3,495	3,582	Detailed Analysis
Software	727	776	752	Detailed Analysis
Total Intangible Assets	4,397	4,271	4,334	
Deferred Charge	2,404	2,075	2,239	Generation
Working Capital				
Inventory	5,363	5,710	5,536	Distribution Lines
Gross operating expenses	4,604	4,709	4,656	O&M
Income taxes paid	306	128	217	Rate Base Excluding WC
Total Working Capital	10,273	10,546	10,409	
Rate Base	303,176	321,361	312,269	

Schedule 5.0																	
Functional Allocator Summary																	
Percent (%)																	
Functional Allocator	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Exogenous Allocators																	
Substations 1841 Account	0.0 %	0.0 %	72.2 %	27.8 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Primary & Secondary	0.0 %	0.0 %	0.0 %	0.0 %	75.0 %	0.0 %	25.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Call Center	0.0 %	0.0 %	5.0 %	0.0 %	3.3 %	3.3 %	3.3 %	0.0 %	0.0 %	5.0 %	20.0 %	40.0 %	10.0 %	10.0 %	0.0 %	0.0 %	100.0 %
ECC	8.3 %	16.7 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
SCADA	25.0 %	0.0 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Allocators Based on Fixed Assets																	
Environmental	50.0 %	0.0 %	0.0 %	2.0 %	0.0 %	48.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
T&D Transformers	0.0 %	0.0 %	1.1 %	3.9 %	0.0 %	95.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Distribution Facilities	0.0 %	0.0 %	0.0 %	0.0 %	49.7 %	33.7 %	16.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Right of Way Amortization	0.0 %	0.0 %	91.9 %	0.0 %	4.0 %	2.7 %	1.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Engineering	0.6 %	0.0 %	21.1 %	4.0 %	25.8 %	17.6 %	8.8 %	17.5 %	3.4 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.3 %	100.0 %
Procurement	0.0 %	0.0 %	21.0 %	3.4 %	26.3 %	17.8 %	8.8 %	17.9 %	3.5 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.3 %	100.0 %
Distribution Lines	0.0 %	0.0 %	0.0 %	0.0 %	48.4 %	0.0 %	16.1 %	33.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	2.4 %	100.0 %
Distribution Network	0.0 %	0.0 %	0.0 %	6.1 %	46.7 %	31.7 %	15.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
T&D Plant	0.0 %	0.0 %	21.2 %	4.0 %	26.0 %	17.7 %	8.8 %	17.6 %	3.4 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.3 %	100.0 %
Total Plant	21.6 %	0.1 %	16.2 %	3.3 %	20.6 %	14.3 %	7.0 %	13.0 %	2.5 %	0.1 %	0.1 %	0.2 %	0.0 %	0.0 %	0.0 %	0.9 %	100.0 %
Contributions Related Distributi	0.0 %	0.0 %	0.0 %	0.0 %	34.8 %	23.6 %	11.6 %	23.7 %	4.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.7 %	100.0 %
Amortization	21.8 %	0.2 %	12.0 %	4.0 %	21.7 %	15.7 %	7.5 %	13.0 %	2.5 %	0.2 %	0.1 %	0.2 %	0.0 %	0.0 %	0.0 %	0.9 %	100.0 %
Net Plant	22.1 %	0.1 %	12.0 %	3.3 %	21.2 %	17.4 %	7.2 %	11.3 %	4.2 %	0.1 %	0.1 %	0.2 %	0.0 %	0.0 %	0.0 %	0.7 %	100.0 %
Rate Base Excluding WC	22.9 %	(2.0)%	12.1 %	3.3 %	21.9 %	17.4 %	7.4 %	11.7 %	4.1 %	0.1 %	0.1 %	0.2 %	0.0 %	0.0 %	0.0 %	0.7 %	100.0 %
G&T Rate Base	65.5 %	0.0 %	34.5 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Rate Base	22.7 %	(0.7)%	11.9 %	3.3 %	21.6 %	17.1 %	7.3 %	11.5 %	4.0 %	0.1 %	0.1 %	0.2 %	0.0 %	0.0 %	0.0 %	0.7 %	100.0 %
Allocators Based on O&M																	
Transportation	13.3 %	0.9 %	16.1 %	5.5 %	22.9 %	28.2 %	8.1 %	2.1 %	0.0 %	2.8 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.1 %	100.0 %
Labour	37.4 %	2.8 %	16.2 %	7.3 %	13.3 %	15.1 %	5.5 %	0.7 %	0.0 %	1.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
O&M	6.0 %	82.4 %	2.4 %	0.8 %	2.5 %	2.1 %	1.0 %	0.4 %	0.0 %	0.6 %	0.7 %	0.5 %	0.4 %	0.1 %	0.0 %	0.0 %	100.0 %
Blended Allocators																	
Finance Labour	10.7 %	0.8 %	9.1 %	2.8 %	9.4 %	8.1 %	3.5 %	4.0 %	0.7 %	0.5 %	28.6 %	21.4 %	0.0 %	0.0 %	0.0 %	0.3 %	100.0 %
Finance Admin	5.3 %	0.4 %	4.6 %	1.4 %	4.7 %	4.1 %	1.7 %	2.0 %	0.4 %	0.2 %	64.3 %	10.7 %	0.0 %	0.0 %	0.0 %	0.1 %	100.0 %
Customer Service	0.0 %	0.0 %	2.8 %	0.0 %	1.8 %	1.8 %	1.8 %	0.0 %	0.0 %	27.8 %	11.0 %	22.0 %	25.5 %	5.5 %	0.0 %	0.0 %	100.0 %
Head Office	11.2 %	0.8 %	11.5 %	3.0 %	11.1 %	9.8 %	4.9 %	4.2 %	0.8 %	2.5 %	12.6 %	19.4 %	4.0 %	4.0 %	0.0 %	0.3 %	100.0 %

Schedule 5.1																	
Functional Allocator Worksheet																	
Exogenous Allocators																	
Functional Allocator	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Substations 1841 Account	0	0	72	28	0	0	0	0	0	0	0	0	0	0	0	0	100
Primary & Secondary	0	0	0	0	75	0	25	0	0	0	0	0	0	0	0	0	100
Call Center	0	0	5	0	3	3	3	0	0	5	20	40	10	10	0	0	100
ECC	8	17	25	25	8	8	8	0	0	0	0	0	0	0	0	0	100
SCADA	25	0	25	25	8	8	8	0	0	0	0	0	0	0	0	0	100
Allocators Based on Fixed Assets ($,000)																	
Functional Allocator	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Environmental																	0
Wires	0	0	0	2,868	0	69,853	0	0	0	0	0	0	0	0	0	0	72,720
Generation	72,720																72,720
Total	72,720	0	0	2,868	0	69,853	0	0	0	0	0	0	0	0	0	0	145,441
T&D Transformers																	
Substations			808	2,878													3,685
Lines and Line Transformers						69,853											69,853
Total	0	0	808	2,878	0	69,853	0	0	0	0	0	0	0	0	0	0	73,538
Distribution Facilities																	
Substations					0	0	0										0
Lines and Line Transformers					103,019	69,853	34,340										207,211
Total	0	0	0	0	103,019	69,853	34,340	0	0	0	0	0	0	0	0	0	207,211
Right of Way Amortization																	
Transmission Component			100.0 %														103
Distribution Component					49.7 %	33.7 %	16.6 %										9
Total	0	0	103	0	4	3	1	0	0	0	0	0	0	0	0	0	112
Engineering																	
Total Transmission & Distribut	2,394	0	80,188	15,851	103,816	70,651	35,137	70,327	13,583	0	0	0	0	0	0	5,062	397,008
Administrative & General	58	116	174	174	58	58	58	0	0	0	0	0	0	0	0	0	697
Right of Ways	0	0	4,470	0	140	95	47	0	0	0	0	0	0	0	0	0	4,752
Total	2,452	116	84,833	16,025	104,015	70,804	35,242	70,327	13,583	0	0	0	0	0	0	5,062	402,457
Procurement																	
Substations	0	0	28,234	13,457	0	0	0	0	0	0	0	0	0	0	0	0	41,691
Lines and Line Transformers	0	0	49,561	0	103,019	69,853	34,340	70,327	0	0	0	0	0	0	0	0	327,098
Meters	0	0	0	0	0	0	0	0	13,583	0	0	0	0	0	0	0	13,583
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5,062	5,062
Right of Ways	0	0	4,470	0	140	95	47	0	0	0	0	0	0	0	0	0	4,752
Total	0	0	82,265	13,457	103,159	69,948	34,386	70,327	13,583	0	0	0	0	0	0	5,062	392,186
Distribution Lines					103,159		34,386	70,327								5,062	212,934
Distribution Network				13,457	103,159	69,948	34,386										220,950
T&D Plant			84,833	16,025	104,015	70,804	35,242	70,327	13,583	0	0	0	0	0	0	5,062	399,890
Total Plant	117,350	448	88,093	17,792	112,039	77,961	38,108	70,777	13,623	505	643	994	205	205	0	5,094	543,835
Contributions Related Distribution	0	0	0	0	103,159	69,948	34,386	70,327	13,583	0	0	0	0	0	0	5,062	296,464
Amortization	3,212	29	1,777	590	3,203	2,319	1,113	1,918	367	34	19	30	6	6	0	138	14,761
Net Plant																	
Gross Fixed Assets	73,718	284	52,916	10,820	74,212	60,559	25,125	40,349	14,486	332	422	653	134	134	0	2,461	356,606
Contributions - Net	0	0	(16,215)	0	(3,627)	(2,459)	(1,209)	(2,473)	(478)	0	0	0	0	0	0	(178)	(26,638)
Total Intangible Assets	281	21	3,427	55	238	207	88	5	0	12	0	0	0	0	0	0	4,334
Total	73,999	305	40,127	10,875	70,823	58,307	24,004	37,882	14,009	344	422	653	134	134	0	2,283	334,302
Rate Base Excluding WC	70,496	(6,129)	37,093	10,236	67,188	53,367	22,822	35,924	12,593	410	380	587	121	121	0	2,187	307,396
G&T Rate Base	70,826		37,232														108,058
Rate Base	70,826	(2,297)	37,232	10,282	67,353	53,501	22,882	35,967	12,603	440	412	611	140	125	0	2,190	312,269
Allocators Based on O&M ($,000)																	
Functional Allocator	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Transportation	45	3	55	19	78	95	28	7	0	10	0	0	0	0	0	1	339
Labour	1,781	133	771	347	634	720	264	32	0	76	0	0	0	0	0	2	4,761
O&M	8,135	111,439	3,292	1,142	3,419	2,796	1,296	511	22	849	928	698	561	129	0	37	135,253

Schedule 5.2																
Functional Allocator Worksheet, Blended Allocators																
Finance Labour																
FTEs by Function																
Billing	2.0	Billing														
Customer Payments	1.0	Remittance & Collection														
Collection	0.5	Remittance & Collection														
Purchasing	0.5	Procurement														
Payroll	1.0	Labour														
Accounts Receivable (Non-Elect	1.0	Labour														
Accounts Payable	1.0	Procurement														
Total	7.0															
Weighting																
Allocator	Weight															
Billing	29 %															
Remittance & Collection	21 %															
Procurement	21 %															
Labour	29 %															
Total	100 %															
Allocator Components																
Functional Allocator	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Billing											100.0 %						100.0 %
Remittance & Collection												100.0 %					100.0 %
Procurement	0.0 %	0.0 %	21.0 %	3.4 %	26.3 %	17.8 %	8.8 %	17.9 %	3.5 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.3 %	100.0 %
Labour	37.4 %	2.8 %	16.2 %	7.3 %	13.3 %	15.1 %	5.5 %	0.7 %	0.0 %	1.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Average	10.7 %	0.8 %	9.1 %	2.8 %	9.4 %	8.1 %	3.5 %	4.0 %	0.7 %	0.5 %	28.6 %	21.4 %	0.0 %	0.0 %	0.0 %	0.3 %	100.0 %
Finance Admin																
Weighting																
Finance Labour	50 %															
Billing	50 %															
Total	100 %															
Allocator Components																
Functional Allocator	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Finance Labour	10.7 %	0.8 %	9.1 %	2.8 %	9.4 %	8.1 %	3.5 %	4.0 %	0.7 %	0.5 %	28.6 %	21.4 %	0.0 %	0.0 %	0.0 %	0.3 %	100.0 %
Billing											100.0 %						100.0 %
Average	5.3 %	0.4 %	4.6 %	1.4 %	4.7 %	4.1 %	1.7 %	2.0 %	0.4 %	0.2 %	64.3 %	10.7 %	0.0 %	0.0 %	0.0 %	0.1 %	100.0 %
Customer Service																
Weighting																
Call Centre	55 %															
Uncollectibles & Damage Claims	20 %															
Meter Reading	25 %															
Total	100 %															

Schedule 5.2

Functional Allocator Worksheet, Blended Allocators

Allocator Components

Functional Allocator	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Call Center	0.0 %	0.0 %	5.0 %	0.0 %	3.3 %	3.3 %	3.3 %	0.0 %	0.0 %	5.0 %	20.0 %	40.0 %	10.0 %	10.0 %	0.0 %	0.0 %	100.0 %
Uncollectibles & Damage Claims													100.0 %				100.0 %
Meter Reading										100.0 %							100.0 %
Average	0.0 %	0.0 %	2.8 %	0.0 %	1.8 %	1.8 %	1.8 %	0.0 %	0.0 %	27.8 %	11.0 %	22.0 %	25.5 %	5.5 %	0.0 %	0.0 %	100.0 %

Head Office

Allocation of Head Office Floor Space

Function	Floor	Occupancy	Allocator
Customer Service	1	100 %	Call Center
Customer Service	2	100 %	Call Center
Engineering	3	75 %	Engineering
Information Technology	3	25 %	Labour
Finance	4	80 %	Finance Labour
Procurement	4	20 %	Procurement
Executive	5	100 %	Labour

Weighting

Allocator	Weight
Call Center	40 %
Finance Labour	16 %
Engineering	15 %
Procurement	4 %
Labour	25 %
Total	100 %

Allocator Components

Functional Allocator	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Call Center	0.0 %	0.0 %	5.0 %	0.0 %	3.3 %	3.3 %	3.3 %	0.0 %	0.0 %	5.0 %	20.0 %	40.0 %	10.0 %	10.0 %	0.0 %	0.0 %	100.0 %
Finance Labour	10.7 %	0.8 %	9.1 %	2.8 %	9.4 %	8.1 %	3.5 %	4.0 %	0.7 %	0.5 %	28.6 %	21.4 %	0.0 %	0.0 %	0.0 %	0.3 %	100.0 %
Engineering	0.6 %	0.0 %	21.1 %	4.0 %	25.8 %	17.6 %	8.8 %	17.5 %	3.4 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.3 %	100.0 %
Procurement	0.0 %	0.0 %	21.0 %	3.4 %	26.3 %	17.8 %	8.8 %	17.9 %	3.5 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.3 %	100.0 %
Labour	37.4 %	2.8 %	16.2 %	7.3 %	13.3 %	15.1 %	5.5 %	0.7 %	0.0 %	1.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Average	11.2 %	0.8 %	11.5 %	3.0 %	11.1 %	9.8 %	4.9 %	4.2 %	0.8 %	2.5 %	12.6 %	19.4 %	4.0 %	4.0 %	0.0 %	0.3 %	100.0 %

Schedule 6.0								
Revenue Requirement 2014								
Account	Description	2014 Trial Balance	Power Supply Demand Related	Labour Related	Vehicle Related	O&M Reporting	Functionalization Method	Power Supply Demand Related (%)

[redacted]

Schedule 6.0								
Revenue Requirement 2014								

[redacted]

Schedule 6.0								
Revenue Requirement 2014								

[redacted]

Schedule 6.1														
Plant In Service 2014														
		Fixed Assets			Accumulated Amortization			WIP			Net	Annual		
Account	Name	)pen	lose	Year	)pen	lose	Year	)pen	lose	Year	Fixed Assets	Amortization	Presentation Header	Basis for Functionalization
1101	Prod Power Plant Land	2,261,810	2,261,810	2,261,810	0	0	0	0	0	0	2,261,810	0	Production	Generation
1102	Prod Power Plant Build & Structure	7,673,269	7,918,834	7,796,051	3,509,033	3,619,017	3,564,025	(0)	0	(0)	4,232,026	194,901	Production	Generation
1103	Prod Pumphouse Elect Equip	1,630,613	1,630,613	1,630,613	998,295	1,039,060	1,018,677	0	0	0	611,935	40,765	Production	Generation
1104	Prod Pumphouse Mech Equip	32,949	32,949	32,949	20,172	20,996	20,584	0	0	0	12,365	824	Production	Generation
1105	Prod Boiler Plant Equip	24,532,276	24,674,199	24,603,237	13,698,121	14,235,324	13,966,723	0	0	0	10,636,515	615,081	Production	Generation
1107	Prod Turbine & Aux Equip	22,001,131	22,091,772	22,046,451	11,301,421	11,783,906	11,542,664	(0)	0	(0)	10,503,788	551,161	Production	Generation
1109	Gas Turbine & Aux Equip	34,676,317	34,716,216	34,696,267	4,409,364	5,237,119	4,823,241	0	0	0	29,873,025	867,407	Production	Generation
1113	Prod Elect Equip Plant & Yard	2,283,113	2,283,113	2,283,113	1,647,824	1,704,902	1,676,363	0	0	0	606,750	57,078	Production	Generation
1115	Prod Misc Power Plant Equip	1,506,403	1,506,403	1,506,403	905,300	942,960	924,130	0	0	0	582,273	37,660	Production	Generation
1135	Prod Shop Equip	6,483	6,483	6,483	3,964	4,126	4,045	0	0	0	2,438	162	Production	Generation
1139	Prod River Pumphouse Build	1,026,497	1,026,497	1,026,497	364,822	390,484	377,653	0	0	0	648,844	25,662	Production	Generation
1201	Prod Borden Power Plant Land	43,567	43,567	43,567	0	0	0	0	0	0	43,567	0	Production	Generation
1202	Prod Borden Build & Structures	481,306	481,306	481,306	155,789	167,822	161,806	0	0	0	319,500	12,033	Production	Generation
1209	Prod Borden Gas Turbine & Aux Eq	10,821,169	11,966,968	11,394,068	2,474,170	2,214,800	2,344,485	(0)	0	(0)	9,049,583	284,852	Production	Generation
1215	Prod Borden Misc Equip	320,116	320,116	320,116	82,393	90,396	86,394	0	0	0	233,722	8,003	Production	Generation
1301	ECC Land	20,470	20,470	20,470	0	0	0	0	0	0	20,470	0	Administrative & General	ECC
1315	Prod ECC Misc Power Plant Equip	201,817	201,817	201,817	97,021	102,067	99,544	0	0	0	102,274	5,045	Production	Generation
1355	ECC UG Cables	0	0	0	0	0	0	0	0	0	0	0	Production	Generation
1379	ECC Build	676,209	676,209	676,209	236,136	253,041	244,589	0	0	0	431,620	16,905	Administrative & General	ECC
1740	Dist Substation Land	4,506	4,506	4,506	0	0	0	0	0	0	4,506	0	Substations	Substations
1741	Dist Substation Equip Build & Stru	2,815,526	2,919,644	2,867,585	741,196	832,959	787,078	(0)	0	(0)	2,080,507	91,763	Substations	Substations
1744	Dist Land	5,467	5,467	5,467	0	0	0	0	0	0	5,467	0	Substations	Substations
1748	Dist OH Conductors	65,119,477	69,263,558	67,191,518	19,115,890	20,830,963	19,973,427	(0)	3,478	1,739	47,216,352	2,015,746	Lines and Line Transformers	Primary & Secondary
1749	Dist Poles & Fixtures	57,501,574	59,641,439	58,571,506	22,533,443	23,928,532	23,230,987	(0)	0	(0)	35,340,519	1,757,145	Lines and Line Transformers	Primary & Secondary
1750	Dist Line Control Devices	8,540,526	8,839,199	8,689,862	2,144,193	2,015,879	2,080,036	3,156	1,952	2,554	6,607,272	260,696	Lines and Line Transformers	Primary & Secondary
1751	Dist Tranformers	58,638,965	61,376,167	60,007,566	12,758,027	13,197,361	12,977,694	(15)	0	(7)	47,029,880	1,800,227	Lines and Line Transformers	Transformers
1752	Dist Transformer Installations	9,452,237	10,237,963	9,845,100	1,538,824	1,691,625	1,615,225	(0)	0	(0)	8,229,875	295,353	Lines and Line Transformers	Transformers
1753	Dist Service Lines	66,898,375	69,751,188	68,324,782	28,451,345	30,406,155	29,428,750	0	876	438	38,895,594	2,049,743	Lines and Line Transformers	Service Lines
1754	Dist Street & Yard Lights	4,273,604	4,542,820	4,408,212	2,109,846	2,143,939	2,126,893	0	0	0	2,281,320	132,246	Street & Private Area Lights	Lighting
1755	Dist UG Conductors	2,874,264	2,936,144	2,905,204	1,020,590	1,104,321	1,062,456	0	0	0	1,842,748	87,156	Lines and Line Transformers	Primary & Secondary
1756	Dist UG Service Lines	1,994,639	2,009,154	2,001,897	817,026	873,897	845,462	0	1,261	631	1,155,804	60,057	Lines and Line Transformers	Service Lines
1757	Dist UG System Street Lights	653,789	653,789	653,789	485,835	505,449	495,642	0	0	0	158,147	19,614	Street & Private Area Lights	Lighting
1758	Dist Meters	12,956,979	13,399,311	13,178,145	324,982	183,350	254,166	(0)	0	(0)	12,923,979	395,344	Meters	Meter Assets
1759	Dist Meter Installations	384,244	424,951	404,598	(1,090,401)	(1,172,447)	(1,131,424)	0	0	0	1,536,022	12,138	Meters	Meter Assets
1760	Dist Communications System	7,846,450	8,203,900	8,025,175	4,106,516	4,588,027	4,347,272	(0)	69,460	34,730	3,643,174	481,511	SCADA and Communications	SCADA
1761	Dist Eng Test & Survey Equip	659,734	671,319	665,527	237,437	258,734	248,085	0	0	0	417,441	21,297	Administrative & General	Distribution Network
1762	Dist Tools & Stores Equip	853,852	909,867	881,860	312,902	341,121	327,012	533	0	267	554,581	28,220	Administrative & General	Distribution Network
1763	Supervisory Scada System	1,549,237	1,549,237	1,549,237	817,685	910,640	864,163	0	0	0	685,075	92,954	SCADA and Communications	SCADA
1777	Dist General Property Land	329,731	329,731	329,731	0	0	0	0	0	0	329,731	0	Administrative & General	Head Office
1778	Dist General Prop Build Office	4,668,598	4,900,561	4,784,580	1,684,906	1,822,696	1,753,801	0	0	0	3,030,779	153,107	Administrative & General	Head Office
1779	Dist General Property Build Distric	5,565,393	5,849,767	5,707,580	1,929,293	2,106,579	2,017,936	0	0	0	3,689,644	182,643	Administrative & General	Distribution Network
1780	Office Equip	857,328	862,362	859,845	562,092	589,607	575,849	0	0	0	283,995	27,515	Administrative & General	Labour
1781	Transportation Equip	8,476,117	9,695,001	9,085,559	2,518,932	3,172,675	2,845,803	84,000	0	42,000	6,197,756	681,417	Administrative & General	Transportation
1784	Computer Hardware	1,417,566	1,597,955	1,507,761	(109,717)	88,144	(10,786)	0	0	0	1,518,547	208,071	Administrative & General	Labour
1785	Computer Software	3,145,225	3,447,412	3,296,319	363,046	817,938	590,492	0	36,678	18,339	2,687,488	454,892	Administrative & General	Labour
1786	Marketing & Transition	0	0	0	0	0	0	0	0	0	0	0	Administrative & General	Labour
1840	Trans Substation Land	364,362	397,257	380,810	0	0	0	0	32,379	16,190	364,620	0	Substations	Transmission
1841	Trans Substation Equip, Build & St	36,615,548	39,395,488	38,005,518	14,002,220	14,859,765	14,430,992	460,987	1,042,162	751,575	22,822,951	874,127	Substations	Substations 1841 Account
1844	Trans Land	427,117	427,117	427,117	0	0	0	0	0	0	427,117	0	Substations	Transmission
1846	Road & Trails	73,263	73,263	73,263	7,566	9,251	8,409	0	0	0	64,854	1,685	Lines and Line Transformers	Transmission
1847	Trans Towers	878,834	878,834	878,834	652,299	672,513	662,406	0	0	0	216,428	20,213	Lines and Line Transformers	Transmission
1848	Trans OH Conductors	29,493,862	31,744,072	30,618,967	9,541,759	10,191,202	9,866,480	0	632,350	316,175	20,436,311	704,236	Lines and Line Transformers	Transmission
1849	Trans Poles & Fixtures	15,410,819	17,037,165	16,223,992	5,569,711	5,543,658	5,556,685	50,870	656,091	353,481	10,313,827	373,152	Lines and Line Transformers	Transmission
1850	Trans Line Control Devices	1,503,853	1,696,474	1,600,164	427,946	446,774	437,360	0	25,900	12,950	1,149,854	36,804	Lines and Line Transformers	Transmission
1855	Trans UG Cables	0	0	0	0	0	0	0	(0)	(0)	0	0	Lines and Line Transformers	Transmission
1877	Trans General Property Land	165,586	165,586	165,586	0	0	0	0	0	0	165,586	0	Lines and Line Transformers	Transmission
Subtotal PPE		522,612,164	547,697,014	535,154,589	173,479,218	184,767,328	179,123,273	599,532	2,502,587	1,551,060	354,480,257	16,036,610		
3200	Material & Supply Line Hardwar	2,217,587	2,042,567	2,130,077	0	0	0	0	0	0	2,130,077	0	Lines and Line Transformers	Distribution Network
3205	PST Material & Supply Line Har	0	0	0	0	0	0	0	0	0	0	0	Lines and Line Transformers	Distribution Network
3210	COGP Line Hardware	(0)	4,451	2,226	0	0	0	0	0	0	2,226	0	Lines and Line Transformers	Distribution Network
3212	COGP LH Price Variance	0	13,190	6,595	0	0	0	0	0	0	6,595	0	Lines and Line Transformers	Distribution Network
3215	COGP Other	(533)	0	(267)	0	0	0	0	0	0	(267)	0	Lines and Line Transformers	Distribution Network
3217	COGP Other Price Variance	0	(9,642)	(4,821)	0	0	0	0	0	0	(4,821)	0	Lines and Line Transformers	Distribution Network
3220	Material Quantity Variance	0	(3)	(1)	0	0	0	0	0	0	(1)	0	Lines and Line Transformers	Distribution Network
3305	HRLY Clearing	0	0	0	0	0	0	0	0	0	0	0	Lines and Line Transformers	Distribution Network
Subtotal Inventory		2,217,054	2,050,563	2,133,808	0	0	0	0	0	0	2,133,808	0		
WIP Adjustment		0	0	0	0	17,147	8,573	(518)	1	(259)	(8,315)	17,147	Lines and Line Transformers	Distribution Network
Total Fixed Assets		524,829,218	549,747,577	537,288,398	173,479,218	184,784,475	179,131,847	599,014	2,502,588	1,550,801	356,605,750	16,053,757		

Schedule 6.2							
Contributions & Intangible Assets							
Contributions		Gross					
Account	Name	Open	Close	Change	id Year		
4500	Contributions - New Services	29,354,789	29,884,859	530,070	29,619,824		
4503	Contributions - Extensions	369,349	369,349	0	369,349		
4510	Refundable Contributions	523,749	518,916	(4,834)	521,332		
4505	Contributions - Other	16,403,842	16,403,842	0	16,403,842		
Total Gross		46,651,729	47,176,965	525,236	46,914,347		
		Accumulated Amortization					
		Open	Close	Change	id Year	Basis for Functionalization	
4501	Amortization Contributions	19,629,685	20,545,000	915,315	20,087,343	Contributions Related Distribution Plant	
4501	Amortization Contributions	0	377,288	377,288	188,644	Transmission	
Total Accumulated Amortization		19,629,685	20,922,289	1,292,604	20,275,987		
		Total Net					
		Open	Close	Change	id Year	Basis for Functionalization	
	Distribution	10,618,202	10,228,123	(390,079)	10,423,162	Contributions Related Distribution Plant	
	Transmission	16,403,842	16,026,554	(377,288)	16,215,198	Transmission	
	Total Net	27,022,044	26,254,677	(767,367)	26,638,360		
Intangible		Gross					
Account	Name	Open	Close	Change	id Year	Presentation Header	Basis for Functionalization
3580	ROW Distribution	282,000	282,000	0	282,000	Right of Ways	Distribution Facilities
3580	ROW Transmission	4,502,049	4,438,646	(63,403)	4,470,348	Right of Ways	Transmission
3585	CIS and EPS	1,646,388	1,942,601	296,214	1,794,495	Software	Labour
Total Gross		6,430,437	6,663,247	232,811	6,546,842		
		Accumulated Amortization					
Account	Name	Open	Close	Change	id Year	Presentation Header	Basis for Functionalization
3580	ROW Distribution	0	9,024	9,024	4,512	Right of Ways	Distribution Facilities
3580	ROW Transmission	1,114,042	1,216,860	102,818	1,165,451	Right of Ways	Transmission
3585	CIS and EPS	918,940	1,166,580	247,640	1,042,760		
Total Accumulated Amortization		2,032,981	2,392,463	359,482	2,212,722		
		Total Net					
Account	Name	Open	Close	Change	id Year	Presentation Header	Basis for Functionalization
3580	ROW Distribution	282,000	272,976	(9,024)	277,488	Right of Ways	Distribution Facilities
3580	ROW Transmission	3,388,008	3,221,787	(166,221)	3,304,897	Right of Ways	Transmission
3585	CIS and EPS	727,448	776,022	48,573	751,735	Software	Labour
Total Net		4,397,456	4,270,784	(126,672)	4,334,120		

Appendix 11
Maritime Electric Company, Limited
Schedule of Rates

Rate Code		Effective March 1, 2015	Proposed March 1, 2016
110	**Residential Urban**		
	Service Charge	$ 24.57	$ 24.57
	Energy Charge per kWh for first 3,000 kWh *	$ 0.1316	$ 0.1359
	Energy Charge per kWh for balance kWh	$ 0.1038	$ 0.1080
130	**Residential Rural**		
	Service Charge	$ 26.92	$ 26.92
	Energy Charge per kWh for first 3,000 kWh *	$ 0.1316	$ 0.1359
	Energy Charge per kWh for balance kWh	$ 0.1038	$ 0.1080
131	**Residential Seasonal**		
	Service Charge	$ 26.92	$ 26.92
	Energy Charge per kWh for first 3,000 kWh *	$ 0.1316	$ 0.1359
	Energy Charge per kWh for balance of kWh	$ 0.1038	$ 0.1080
133	**Residential Seasonal Option**		
	Service Charge	$ 37.50	$ 37.50
	Energy Charge per kWh for first 3,000 kWh *	$ 0.1316	$ 0.1359
	Energy Charge per kWh for balance of kWh	$ 0.1038	$ 0.1080
232	**General Service**		
	Service Charge	$ 24.57	$ 24.57
	Demand Charge - per kW for first 20 kW	$ -	$ -
	Demand Charge - per kW for balance of kW	$ 13.43	$ 14.06
	Energy Charge per kWh for first 5,000 kWh	$ 0.1625	$ 0.1654
	Energy Charge per kWh for balance of kWh	$ 0.1049	$ 0.1075
233	**General Service - Seasonal Operators Option**		
	Service Charge	$ 24.57	$ 24.57
	Demand Charge - per kW for first 20 kW	$ -	$ -
	Demand Charge - per kW for balance of kW	$ 13.43	$ 14.06
	Energy Charge per kWh for first 5,000 kWh	$ 0.1625	$ 0.1654
	Energy Charge per kWh for balance of kWh	$ 0.1049	$ 0.1075
250	**General Service II**		
	Service Charge	$ 24.57	n/a
	Demand Charge - per kW for first 20 kW	$ -	n/a
	Demand Charge - per kW for balance of kW:		n/a
	(a) per kilowatt or	$ 5.68	n/a
	(b) the number of kilowatt hours consumed in the period times	$ 0.0284	n/a
	Energy Charge per kWh for first 5,000 kWh	$ 0.1626	n/a
	Energy Charge per kWh for next 5,000 kWh	$ 0.1218	n/a
	Energy Charge per kWh for balance of kWh	$ 0.1164	n/a
320	**Small Industrial**		
	Demand Charge - per kW	$ 7.46	$ 7.46
	Energy Charge per kWh for first 100 kWh per kW billing demand	$ 0.1591	$ 0.1637
	Energy Charge per kWh for balance of kWh	$ 0.0784	$ 0.0825
310	**Large Industrial**		
	Demand Charge per kW	$ 14.50	$ 14.50
	Energy Charge per kWh	$ 0.0653	$ 0.0676
340	**Long Term Contract** (Currently no customers in this rate category)		
	Demand Charge per kW	$ 15.51	$ 15.51
	Energy Charge per kWh	$ 0.0869	$ 0.0911
330	**Short Term Contract** (Currently no customers in this rate category)		
	Demand Charge - per kW	$ 16.79	$ 16.79
	Energy Charge per kWh for all kWh in the first block	$ 0.0887	$ 0.0928
	Energy Charge per kWh for balance of kWh in the month	$ 0.0730	$ 0.0771

* In 2015, Energy Charge per kWh for first 2,000 kWh

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	Rate Code	Lamp Wattage	Type		Annual kWh	Monthly kWh	Effective March 1, 2015	Proposed March 1, 2016
	619	43	LED	St Lights - Rented	176	15	$ 11.27	$ 11.55
*	620	200	HPS	St Lights - Rented	1033	86	$ 32.40	$ 33.21
	625	50	LED	St Lights - Rented	205	17	$ 11.67	$ 11.96
*	630	70	HPS	St Lights - Rented	389	32	$ 14.91	$ 15.28
*	631	100	HPS	St Lights - Rented	553	46	$ 18.96	$ 19.44
*	632	150	HPS	St Lights - Rented	799	66	$ 27.07	$ 27.75
	633	250	HPS	St Lights - Rented	1283	106	$ 36.80	$ 37.72
	634	400	HPS	St Lights - Rented	1886	157	$ 43.05	$ 44.13
*	635	125	MV	St Lights - Rented	656	54	$ 14.76	$ 15.13
*	636	175	MV	St Lights - Rented	881	73	$ 18.77	$ 19.24
*	637	250	MV	St Lights - Rented	1210	101	$ 26.10	$ 26.75
*	638	400	MV	St Lights - Rented	1906	158	$ 36.42	$ 37.33
	639	70	Lanterns	City Lanterns - Rented	389	32	$ 54.80	$ 56.17
*	640	70	HPS	St Lights - Owned	389	32	$ 5.86	$ 6.01
*	641	100	HPS	St Lights - Owned	553	46	$ 7.72	$ 7.91
*	642	150	HPS	St Lights - Owned	779	65	$ 10.38	$ 10.64
	643	250	HPS	St Lights - Owned	1283	107	$ 16.43	$ 16.84
	644	400	HPS	St Lights - Owned	1886	157	$ 25.93	$ 26.58
*	645	125	MV	St Lights - Owned	656	55	$ 8.75	$ 8.97
*	646	175	MV	St Lights - Owned	881	73	$ 11.86	$ 12.16
*	647	250	MV	St Lights - Owned	1210	101	$ 16.37	$ 16.78
	648	400	MV	St Lights - Owned	1906	159	$ 25.91	$ 26.56
*	650	200	HPS	St Lights - Owned	1033	86	$ 14.30	$ 14.66
	666	72	LED	St Lights - Rented	295	25	$ 12.97	$ 13.30
	670	100	LED	St Lights - Rented	410	34	$ 15.09	$ 15.47
	719	43	LED	St Lights - Owned	176	15	$ 2.38	$ 2.44
*	720	200	HPS	Yard Lights - Rented	1033	86	$ 29.63	$ 30.37
*	730	70	HPS	Yard Lights - Rented	389	32	$ 14.91	$ 15.28
*	731	100	HPS	Yard Lights - Rented	553	46	$ 18.92	$ 19.39
*	732	150	HPS	Yard Lights - Rented	799	66	$ 27.07	$ 27.75
	733	250	HPS	Yard Lights - Rented	1283	106	$ 36.80	$ 37.72
	734	400	HPS	Yard Lights - Rented	1886	157	$ 43.05	$ 44.13
*	735	125	MV	Yard Lights - Rented	656	54	$ 14.76	$ 15.13
*	736	175	MV	Yard Lights - Rented	881	73	$ 18.77	$ 19.24
*	737	250	MV	Yard Lights - Rented	1210	100	$ 26.11	$ 26.76
*	738	400	MV	Yard Lights - Rented	1906	158	$ 33.35	$ 34.19
*	740	70	HPS	Yard Lights - Owned	389	32	$ 5.86	$ 6.01
*	741	100	HPS	Yard Lights - Owned	553	46	$ 7.72	$ 7.91
	742	150	HPS	Yard Lights - Owned	779	65	$ 10.38	$ 10.64
	743	250	HPS	Yard Lights - Owned	1283	107	$ 16.43	$ 16.84
	744	400	HPS	Yard Lights - Owned	1886	157	$ 25.93	$ 26.58
	745	125	MV	Yard Lights - Owned	656	55	$ 8.75	$ 8.97
	746	175	MV	Yard Lights - Owned	881	73	$ 11.86	$ 12.16
	747	250	MV	Yard Lights - Owned	1210	101	$ 16.37	$ 16.78
	748	400	MV	Yard Lights - Owned	1906	159	$ 25.91	$ 26.56
	749	180	LPS	Yard Lights - Owned	869	72	$ 12.10	$ 12.40
	750	200	HPS	Yard Lights - Owned	1033	86	$ 14.30	$ 14.66
	751	135	LPS	Yard Lights - Owned	730	61	$ 9.63	$ 9.87
	752	90	LPS	Yard Lights - Owned	521	43	$ 6.75	$ 6.92
	753	250	Flood	Yard Lights - Rented	1283	107	$ 35.11	$ 35.99
	754	400	Flood	Yard Lights - Rented	1886	157	$ 43.72	$ 44.82
	755	250	Halide	Yard Lights - Rented	1148	95	$ 36.99	$ 37.92
	756	400	Halide	Yard Lights - Rented	1878	156	$ 45.52	$ 46.66
	757	1000	Halide	Yard Lights - Rented	4346	362	$ 78.13	$ 80.09
	758	70	Halide	St Lights - Owned	390	32	$ 5.28	$ 5.41
	759	100	Halide	St Lights - Owned	533	44	$ 7.22	$ 7.40
	760	175	Halide	St Lights - Owned	894	74	$ 12.12	$ 12.42
	761	250	Halide	St Lights - Owned	1148	95	$ 15.55	$ 15.94
	762	400	Halide	St Lights - Owned	1878	156	$ 25.43	$ 26.07
	763	1000	Halide	St Lights - Owned	4346	362	$ 58.85	$ 60.33
	764	100	LED	St Lights - Owned	410	34	$ 5.55	$ 5.69
	765	150	Halide	St Lights - Owned	759	63	$ 10.27	$ 10.53
	766	72	LED	St Lights - Owned	295	25	$ 3.99	$ 4.09
	775	107	LED	St Lights - Owned	438	37	$ 5.93	$ 6.08
	780	143	LED	St Lights - Owned	586	49	$ 7.94	$ 8.14
	785	175	LED	St Lights - Owned	718	60	$ 9.71	$ 9.95

* These categories are applicable to existing fixtures only.

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		Effective March 1, 2015		Proposed March 1, 2016	
610	Pole Rental -Wood	$	4.38	$	4.38
611	Pole Rental -Concrete	$	7.96	$	7.96
810	8 Hour Lighting per kWh	$	0.1624	$	0.1665
	Minimum Charge	$	11.67	$	11.67
820	12 Hour Lighting per kWh	$	0.1624	$	0.1665
	Minimum Charge	$	11.67	$	11.67
830	24 Hour Lighting per kWh	$	0.1624	$	0.1665
	Minimum Charge	$	11.67	$	11.67
840	Air Raid & Fire Sirens	Currently no customers in this rate category			
850	Outdoor Christmas Lighting - 5.77¢ per watt of connected load per week				
234	Customer Owned Outdoor Recreational Lighting				
	Service Charge	$	24.57	$	24.57
	Energy Charge per kWh for first 5,000 kWh	$	0.1624	$	0.1665
	Energy Charge per kWh for balance of kWh	$	0.0997	$	0.1022
	Short Term Unmetered Rates	Currently no customers in this rate category			
	Energy Charge:				
	per kWh of estimated consumption	$	0.1624	$	0.1665

Connection Charge:	Single-Phase	Three-Phase
A. Connecting to existing secondary voltage	$99.08	$99.08

B. Where transformer installations are required, the following connection charges will apply:

	Single-Phase	Three-Phase
(1) Up to and including 10 kVA	$148.87	$209.17
(2) 11 kVA to 15 kVA	$240.79	$301.01
(3) 16 kVA to 25 kVA	$269.20	$336.64
(4) 26 kVA to 37 kVA	$301.01	$336.64
(5) 38 kVA to 50 kVA	$336.64	$336.64
(6) 51 kVA to 75 kVA	$369.58	$523.96
(7) 76 kVA to 125 kVA	$431.07	$555.59
(8) Above 125 kVA	0	$594.94