Nova Scotia Utility and Review Board

IN THE MATTER OF *The Public Utilities Act*, R.S.N.S. 1989, c.380, as amended

- and -

IN THE MATTER OF an Application by **Nova Scotia Power** Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations

2013 GRA

NS Power
Reply Evidence

September 7, 2012

REDACTED

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1 OVERVIEW

NS Power's 2013 General Rate Application (GRA), filed May 8, 2012, seeks approval of projected revenue requirements for two years: 2013 and 2014. We've made this unusual, two-year application as part of a broader Rate Stabilization Plan that would limit rate increases for all customer classes to 3 percent in 2013 and a further 3 percent in 2014. The plan would defer recovery of the remaining, Board-approved revenue requirements to future years. NS Power believes a Rate Stabilization Plan is needed to help homeowners and businesses plan their future energy expenditures in the face of the extraordinary pressures currently bearing on electricity rates.

Subsequent to our initial filing, in June Bowater Mersey Paper Company Limited (Bowater) announced that it would close. The loss of NS Power's largest remaining customer, and our forecast that loss of load will continue due to economic and industrial uncertainty and demand side management programs, underscores the need for a Rate Stabilization Plan. Major load losses force remaining customers to shoulder the fixed costs of an electricity system that has been built to accommodate a larger load and that cannot be quickly reduced. Customers need time to adjust to the reality of increased responsibility for the costs of the system.

On August 20, the Board issued its decision in the Pacific West Commercial Corporation Load Retention proceeding granting conditional approval for Load Retention Tariff pricing and dividend calculation mechanism. The Port Hawkesbury mill will hopefully reopen under the approved Tariff, assuming receipt of the Canada Revenue Agency Advance Tax Ruling in respect of the tax structure for the mill.

As part of the PWCC proceeding, NS Power sought approval for the continuation of the 2012 General Rate Application (GRA) fixed cost recovery (FCR) deferral. The Board approved this request, subject to any amendments which may be ordered through the GRA. This allows NS Power to ensure that every dollar of fixed cost contribution that is received from the mill is used to benefit our customers by using those funds to reduce the Fixed Cost Deferral. Converting the approved Fixed Cost Deferral by incorporating it into the Rate Stabilization Plan is a key component of the requested approval for 2013 and 2014.

On August 31, NS Power filed its updated load and fuel forecast, as required by the Fuel Adjustment Mechanism (FAM). Section 2 of this Reply Evidence discusses the details of this update. Based upon this updated load and fuel forecast, NS Power has also updated the 2013 and 2014 revenue requirement calculations and the calculation of the Rate Stabilization Plan deferral.

NS Power's 2013 and 2014 revenue requirement is lower than forecast in our May 8 filing, as a result of the August 31 load and fuel forecast update. Due mainly to the recently announced shutdown of the Bowater paper mill, NS Power's total forecast energy requirement for 2013 has fallen from 10,750.9 GWh (May 8 forecast) to 9,879.3 GWh (August 31 forecast). Similarly, the total forecast energy requirement for 2014 has fallen from 10,739.9 GWh (May 8) to 9,847.2 GWh (August 31). This change has reduced the revenue requirement for fuel expenses by $53.3 million in 2013 and $62.8 million in 2014. Figure 1-1 summarizes these changes.

Figure 1-1

Revenue Requirement Update ($ millions)						
			2013			**2014**
Revenue Requirement (May Submission)			$1,323.0			$1,387.9
Adjustments						
Fuel Cost before exports and FX Interest						
May Submission	$475.0			$513.7		
August Submission	<u>$421.5</u>			<u>$450.7</u>		
Total	($53.5)	($53.5)		($63.0)	($63.0)	

Revenue Requirement Update ($ millions)						
			2013			**2014**
Net Margin on Exports						
May	($0.3)			($0.3)		
August	<u>($0.2)</u>			<u>($0.2)</u>		
Total	$0.1	$0.1		$0.2	$0.2	
			<u>($53.3)</u>			<u>($62.8)</u>
Revised Revenue Requirement			$1,269.7			$1,325.1

In accordance with these changes, the Company has also updated its cost of service studies and revenue allocation analyses for 2013 and 2014. NS Power continues to seek approval for a Rate Stabilization Plan, which would result in a 3 percent increase in each of 2013 and 2014, plus deferred recovery of any Board-approved forecast revenue requirement not recovered in 2013 and 2014 by the 3 percent increases. Recovery of the deferral will commence in 2015.

For illustrative purposes, we have updated the traditional cost allocations for all classes in order to show the rate increase that would be required if not for the Rate Stabilization Plan. Please refer to Appendix A for details.

NS Power seeks a Rate Stabilization Plan that will hold rate increases for all classes to three percent in each of 2013 and 2014, with the remainder deferred for recovery in later years. We have recalculated the deferral, and the allocation of the deferral to the various customer classes, to reflect the updated fuel and load projections.

Lost industrial load causes lower overall fuel costs, but it also is accompanied by lost revenue contributions, specifically lost fixed cost contributions. With lower revenue and lower fixed cost contributions, the amount of the deferral has increased from $124.4 million to $130.7 million. This result is in line with the overall system load economics of a power system typified by the presence of significant fixed costs. As system load goes down only variable fuel-related costs can be avoided in the short term. The non-fuel related costs remain unchanged. With the marginal costs falling from approximately $55 to $50 per MWh the net avoided fuel related costs[1] are not sufficient to compensate for the forgone recovery of fixed costs associated with the system load reduction.

Figure 1-2 provides a comparison of changes in the main drivers behind the deferral cost calculations from the May and August submissions.

Figure 1-2

Revenues with FAM Riders

	May Submission		August Update		Variance		
	2013	2014	2013	2014	2013	2014	Two Test Years Combined
GWh Requirement	10,750.9	10,739.9	9,879.3	9,847.2	(871.6)	(892.7)	(1,764.3)
Revenue Increase before Rate Stabilization Plan							
Revenue at Current Rates	$1,260.8	$1,349.6	$1,202.5	$1,295.9	($58.3)	($53.7)	($112.0)
Revenue Requirement	$1,352.2	$1,387.9	$1,298.8	$1,325.1	($53.3)	($62.8)	($116.1)
Increase	$91.3	$38.3	$96.3	$29.2	$5.0	($9.1)	($4.1)
Revenue Increase under Rate Stabilization Plan							
Revene at Current Rates	$1,260.8	$1,293.2	$1,202.5	$1,228.1	($58.3)	($65.1)	($123.4)
Revenue Proposed	$1,296.1	$1,328.6	$1,238.5	$1,264.4	($57.5)	($64.3)	($121.8)
Deferral							
Before Interest	$56.1	$59.3	$60.3	$60.7	$4.2	$1.5	$5.7
With Interest	$62.9	$61.6	$67.6	$63.1	$4.7	$1.5	$6.2
Cumulative with interest		$124.4		$130.7			$6.2

Appendix B provides details of the calculation of $130.7 and allocation of this amount among rate classes, which is provided for illustrative purposes only.

[1] The net avoided fuel costs represent a difference between avoided fuel costs and forgone recovery of average fuel costs.

Our May 8 filing began the discovery and pre-hearing evidence process for our application. Board Consultants, Board Staff and intervenors posed two rounds of Information Requests (IRs) to NS Power. We responded to a total of 807 IRs (452 on June 25, and 355 on July 23).

On August 7, Board Counsel Consultants, the Consumer Advocate, the Small Business Advocate, Alton Natural Gas Storage LP, Halifax Regional Municipality, the Union of Nova Scotia Municipalities and the Affordable Energy Coalition filed intervenor Evidence. On August 28, these consultants and intervenors filed their responses to IRs put to them by NS Power and other intervenors.

This Reply evidence responds to the items identified in the evidence of these consultants and parties.

2 FUEL AND PURCHASED POWER

Three parties submitted evidence in relation to NS Power's fuel and purchased power forecast: Board Counsel, through The Liberty Consulting Group (Liberty), the Small Business Advocate, through Lee Smith, and Alton Natural Gas Storage LP (Alton), through David Birkett, Richmond Graham, Greg Hopper, and Jan van Egerton. This section of our Reply Evidence provides NS Power's response to their fuel-related evidence. We also comment on the 2013 load and fuel update filed August 31.

Of the three parties that submitted evidence on fuel and purchased power, Liberty was the only party to make specific recommendations for adjustments to our fuel and purchased power forecasts for 2013 and 2014.

2.1 Fuel and Purchased Power Update

In June, Resolute Forest Products announced the indefinite shutdown of its Bowater Mersey paper mill in Liverpool, Nova Scotia. The Board had already placed Bowater on a Load Retention Rate, effective January 1, 2012, under which it paid its incremental costs, plus a $4/MWh contribution to fixed costs. This tariff rate covered only a portion of Bowater's total load. The Mersey Contract, an agreement between Bowater and NS Power, provides for additional electricity at a rate stipulated in the contract.

The updated Fuel forecast reflects the loss of Bowater as well as other forecast sales losses in other customer classes. Please refer to Exhibit N-103, the August 31, 2012 Fuel and Purchased Forecast for details.

2.2 2014 and 2013 Fuel Forecasts

Liberty's evidence acknowledges the challenges NS Power and other utilities face in forecasting 2013 and 2014 natural gas prices. Gas prices ultimately influence the amount of coal we burn (and our coal inventory levels), and the amount of power we purchase. Under the FAM, NS Power will recover all of its prudently incurred fuel costs. The FAM also includes an incentive to encourage efficient fuel management. If actual costs come in below the FAM forecast, NS Power is entitled to keep 10 percent of the variance, to a maximum incentive of $5 million. By the same token, if fuel prices exceed our forecast, NS Power is only able to collect 90 percent of the difference, to a maximum penalty of $5 million. The existence of this incentive band has resulted in the unintended consequence of making the forecast a topic of intense interest during the rate setting process.

Under NS Power's two-year rate proposal, FAM rates will not change in 2013 and 2014, and the FAM incentive will not operate. The FAM adjustments that would occur during 2013 and 2014 will be recovered after 2014. Consequently, the objective of this forecast is to be as accurate as possible in the face of market uncertainties.

As stated in our evidence the uncertainties are significant.

Uncertainty around the status of our largest industrial customers, together with our increased use of natural gas, has made it harder to predict how much solid fuel and natural gas we will consume. Uncertainty about the amount of coal we will use also causes uncertainty around the optimal mix of solid fuels. Lower gas prices allow us to meet emissions limits using less expensive coal and petcoke. For these reasons, we continually monitor our purchase commitments and expected requirements to give ourselves maximum flexibility in deciding when and what to buy. NS Power has been able to make large shifts in the amount of solid fuel and natural gas we use from year to year, so as to take advantage of price changes in these commodities relative to one another.

NS Power's forecast follows the Board's approved forecast methodology, subject to adjustments in order to establish a multi-year forecast which is not anticipated by the methodology. The forecast methodology was developed collaboratively with Liberty and intervenors, and embedded in the FAM Plan of Administration. In NS Power's view, changes to the forecast methodology should be an outcome of a similar collaborative exercise involving stakeholders, rather than adopted on an ad hoc basis during rate setting processes. A more thoughtful and collaborative approach to changes to the FAM would align with how the FAM and fuel forecasting methodology were initially established.

With three exceptions, Liberty's review concluded that NS Power's 2013 and 2014 fuel and purchased power forecasts are acceptable. This section provides NS Power' response to these exceptions, which involve low sulphur coal purchases, natural gas pricing, and imported power. Although Liberty did not question NS Power's forecast biomass costs, it did provide comments and recommendations about them, and this section also responds to those biomass recommendations.

Aside from the below response, NS Power notes that at page 8 of its evidence Liberty notes that "Liberty's review found coal prices for 2013 Powder River Basin coal delivered to Lingan and Point Aconi too high by approximately $60.000. NS Power has stated that it will correct the price forecasts in the fuel forecast update at the end of August."[2] Liberty's review did not uncover this issue. NS Power discovered this error and advised of it its intention to make the adjustment in response to Liberty IR-11. NS Power confirms that this adjustment has been reflected in the August 31, 2012 Update.

2.2.1 Subsequent Low Sulphur Coal Purchases

NS Power confirms that subsequent to the preparation of the GRA forecast, NS Power entered into an additional contract for low sulphur coal. The contract is for [redacted] of coal for [redacted]. As required by the FAM Plan of Administration (POA), information about this contract is available for Liberty and other parties to review. It has been included in the August 31 fuel forecast update.

[2] Liberty Evidence, August 7, 2012, page 8, lines 1-3.

2.2.2 Natural Gas Pricing

NS Power disagrees with Liberty's FAM Audit findings about the way natural gas purchased by NS Power is priced in the current market. Liberty bases its conclusions on a fundamental misunderstanding of the Maritimes natural gas market, which it compounds with speculative assumptions. As a result, Liberty's proposed adjustments to the price of natural gas in the 2013 and 2014 test years should be rejected. NS Power's response to the FAM Audit Report provides extensive expert evidence to support this conclusion. The Board has established hearing dates for the FAM Audit Report, and proposes to deal with these issues at that time. NS Power welcomes the opportunity to further explain its position on this matter as part of the FAM Audit hearing. In the interim, the Liberty conclusions and recommendations should not be adopted as the basis for changes to NS Power's 2013 and 2014 fuel forecast.

On behalf of the Small Business Advocate, consultant Lee Smith has also referred to the Liberty audit findings, stating,

> These findings suggest that the two year forecast presented in this proceeding may not reflect appropriate minimization of fuel costs. While this will be explored more fully in testimony submitted on the audit, I will discuss the potential impact of any refunds or cost reductions resulting from the audit in Section IV.[3]

Section IV of Ms. Smith's evidence does not actually speak to the potential impact on refunds or cost reductions resulting from the audit. Ms. Smith provides no specific recommendation for reductions to the 2013 or 2014 fuel forecast. The only evidence before the Board that recommends specific adjustments in this regard is the Liberty testimony.

[3] Direct Testimony of Lee Smith, August 4, 2012, page 7, lines 95-99.

Liberty argues NS Power should use a [redacted] price as opposed to [redacted] ([redacted]). The effect of this recommendation, if accepted, would be to artificially lower the Base Cost of Fuel forecast. Since it is essentially an incorrect and artificial reduction in the Base Cost of Fuel, this would simply cause a larger 2014 Actual Adjustment (AA) that will need to be recovered from customers in 2015. Such an approach is not the best option for customers, and does not comport with good utility practice.

Liberty's recommended adjustments to forecast natural gas prices assume the Board's acceptance of the position Liberty took in the 2012 Audit, which NS Power has urged the Board to reject in its entirety. NS Power respectfully submits that before accepting or rejecting Liberty's recommendations on gas price forecasts for the 2013 and 2014 test years, the Board should first determine the outcome of the FAM Audit. NS Power relies upon its evidence and the evidence of its external experts in respect of these matters. We respectfully suggest there is no useful purpose to be served by debating these matters in the General Rate Application portion of this process.

2.2.3 Imported Power

Liberty correctly explains NS Power's forecast methodology for purchased power, but seeks two adjustments that would be ad hoc changes to the established fuel forecast methodology. The first relates to term purchases; the second to peak and off-peak pricing. To quantify the term purchase adjustment, Liberty relies on 2011 results; to quantify the peak/off-peak adjustment, Liberty relies on 2010/2011 results. Liberty's proposed adjustments are inconsistent with NS Power's integrated price forecasts for 2013 and 2014, which reflect [redacted] than experienced in 2011. Given the [redacted] and the related impact on import power pricing, the adjustments should not be tied to 2010 and 2011 results.

2.2.4 Biomass Costs

Liberty says it has no basis to contest the accuracy of NS Power's biomass fuel costs estimates. It does however flag several items for future review. Liberty seeks information about the accounting for performance deposit installments from New Page Port Hawkesbury (NPPH). It seeks to review and verify the allocation of costs between rate base and operations & maintenance expenditures after plant completion. It proposes an ongoing review of the allocation of non-fuel and operations & maintenance costs. It seeks confirmation that fuel costs are subject to the same reviews that apply to other fuel and energy costs.

On the last item, NS Power submits that the FAM will review and report upon biomass fuel costs just as it does other fuel and energy costs. On Liberty's other recommendations, consistent with the Board's process, NS Power will submit its final costing once the biomass work order project is complete. NS Power will account for performance deposits in accordance with US Generally Accepted Accounting Principles (USGAAP).

NS Power submits that the FAM and normal capital processes provide appropriate review for the accounting of this project's costs. Accounting will be carried out in a manner consistent with US GAAP and the FAM. There is no need for additional ongoing review beyond the well-established regulatory processes already in place.

2.3 Inventory Levels

Liberty says it is disappointed with NS Power's inventory performance in 2013 and 2014. No adjustments to revenue requirement or the fuel forecast are proposed by Liberty. In respect of our solid fuel inventory, NS Power respectfully states:

- The projected end-of-year inventory quantities for 2013 and 2014 at the time of the GRA filing [redacted], which is consistent with minimum target inventory levels

- NS Power has [redacted], which provides us flexibility to manage stockpile levels for that year, and

- Basing inventory targets on forecast coal burns may result in insufficient inventory volumes when lower coal burns are forecast.

With respect, there is no reason for the Board to adopt Liberty's "disappointment" with NS Power's inventory forecasts.

2.4 FAM Incentive

Ms. Smith testifies about the FAM incentive mechanism, which NS Power has proposed to suspend during the two-year Rate Stabilization period. Ms. Smith writes:

> The elimination of the incentive may be something of an incentive for the Company to over forecast fuel costs, even though fuel costs and FAM projections will be trued up at the end of the Plan period.[4]

Aside from this comment, Ms. Smith does not recommend that the Board reject NS Power's request, nor does she provide any further evidence on the topic. Her statement indicates a misunderstanding of how the FAM incentive works, and NS Power's reasons for asking that it be suspended during the two-year period of the Rate Stabilization Plan. As NS Power explained in its response to Avon IR-23(a), we propose to suspend the incentive for the benefit of customers, not the Company.

[4] Direct Testimony of Lee Smith, August 4, 2012, page 13, lines 245-247.

NS Power maintains that it is appropriate, and in the interests of customers, that the Board approve its request to suspend the incentive during the two-year Rate Stabilization period.

2.5 Gas Storage

Alton has submitted evidence, which according to the testimony of its company witness is intended to,

> […] demonstrate that its storage facility will provide increased gas supply security both for the Maritimes region as a whole, as Mr. Hopper will demonstrate. For the Halifax region, Mr. Graham will demonstrate how Alton increases operational flexibility and supply security on the Halifax lateral. In addition, Mr. Graham addresses how Alton can help stabilize NSP's system generation while NSP adds an increasing amount of intermittent renewable energy to its generation portfolio. Finally Mr. van Egteren demonstrates that Alton can be a valuable tool to help NSP achieve both natural gas price reductions and natural gas price volatility reductions.[5]

In its letter of June 25, 2012 confirming its approval of Alton's request for intervenor status, the Board wrote:

> Alton's participation in this proceeding is subject to the following two conditions:
>
> 1. Alton comply with the timeline in the Board's Order of May 9, 2012, on a go-forward basis; and
>
> 2. Alton will only be permitted to address issues contained in the Board's Final Issues List.
>
> Accordingly, Alton will be required to respect these conditions and not raise issues outside the scope of the Final Issues List.[6]

The GRA proceeding is not the appropriate place to discuss a proposed project that could be subject to future negotiations between NS Power and Alton. NS Power is particularly

[5] Direct Testimony of David Birkett, August 7, 2012, page 8, lines 5-14.
[6] Letter from Doreen Friis (UARB) to René Gallant (NSPI), June 25, 2012.

troubled that a knowledgeable industry participant with whom NS Power has had commercial discussions is speculating on the nature of our gas procurement practices.

Alton's last proposal to NS Power indicated an in-service date of April 1, 2015. Information provided by Alton during a meeting in March 2012 further supports this in-service date. Indeed, Alton's answers to IRs confirm Alton's view that it is extremely unlikely that its project would be operational before the end of 2014.[7] Since the status of this project is uncertain, and since it is not expected to be in service until 2015 if it proceeds at all, there is no impact on natural gas prices for 2013 and 2014 test years. Even if Alton's evidence were otherwise valid, which it is not, the evidence is irrelevant to the revenue requirement for the two year period being considered in this application.

Alton's evidence provides information on the potential benefits that may arise from the use of natural gas storage, but it omits items that are fundamental to determining whether natural gas storage would provide a net benefit to NS Power's customer in 2013 and 2014.

Storage costs typically include fees for:

- the capacity reserved for storage;
- the injection charge;
- the withdrawal charge;
- the fuel charge;
- cushion gas (if any);
- the carrying costs of buying gas in summer to withdraw in winter.

[7] Alton-Birkett (NSPI) IR-2.

Other elements of storage that can impact costs are:

- injection and withdrawal limits (or ratchets) that limit injections and withdrawals to a percent of stored gas;
- the number of cycles that the storage offers;
- any pipeline redelivery costs.

Typically natural gas storage requires long-term contractual commitments. These commitments entail a level of risk as they presume that the conditions making storage attractive initially will continue to exist throughout the term of the contract. Alton's testimony assumes that the price spreads underlying their calculations will continue into the future. As an example, the testimony of Jan van Egerton says:

> Q: Would the $0.49/MMbtu savings that you demonstrated in your example be greater than the cost of storage with Alton and associated carrying costs?
>
> Probably not, but remember, our example is for gas bought and sold at Henry Hub. The difference in seasonal prices at Henry Hub is much less than the seasonal price differences in the New England/Maritimes market as was illustrated by Mr. Hopper in his testimony. […][8]

Alton's business case therefore relies upon a continued seasonal variance in New England pricing over and above the seasonal pricing at Henry Hub. Should the seasonal variation in New England be reduced – perhaps by a build out of additional pipeline capacity and the introduction of inexpensive Marcellus shale gas - then the business case for storage will be undermined.

NS Power will continue to assess the potential benefits to customers of natural gas storage against the associated costs and risks. NS Power remains open to continuing its discussions with Alton as their project proceeds through its regulatory and internal

[8] Direct Testimony of Jan van Egerton, August 7, 2012, page 11, lines 16-25.

approvals. We respectfully suggest, however, that Board involvement in or direction about potential contractual negotiations for supply services relating to fuel procurement is neither warranted nor within the jurisdiction of the Board.

3 OPERATING COSTS

3.1 Labour

3.1.1 Actual vs. Forecast

Liberty has testified that there are significant gaps between forecast and actual costs for labour in the two most recent years, 2011 and 2012. NS Power disagrees with Liberty's analysis.

NS Power's current budget and best forecast for labour costs is [redacted]. This forecast represents the 2012 amount included in NS Power's 2013 GRA filing. We have not produced a new 2012 budget and the budget remains as filed in the GRA.

Liberty referred to NS Power's response to Liberty IR-54 which shows the actual costs incurred to the end of May 2012 plus the remaining budget figures for June-December. The figure included was [redacted]. The figure was incorrect in the response to Liberty IR-54 and it should have been [redacted]. The figure in NS Power's original IR erroneously omitted a portion of labour costs related to compensation at risk in the amount of $2.5 million. NS Power has filed a revised response to IR-54 which indicates the correct figure. The difference between NS Power's current forecast for regulated labour costs of $137.3 million and the [redacted] included in the revised response to IR-54 represents timing of labour costs incurred during the year.

Simply taking the June-December budget figures and adding them to the January to May actuals leads to incorrect conclusions. NS Power labour costs are not consistent month to month. They fluctuate based on the timing of such events as power plant shutdowns. If a maintenance shutdown is moved from one month to another, the actuals in a given month may appear to reflect savings over the budget, but the savings are not real savings because a future month will reflect a corresponding increase in labour costs over the budget when the maintenance actually occurs. For these reasons, Liberty's conclusion that NS Power's actual labour costs in 2012 are below the amounts in the 2013 GRA filing is incorrect.

On page 36 of its evidence, Liberty indicates that the 2012 January to May actuals plus January to December budget for actual 2012 labour costs of [redacted] is [redacted] lower than 2012 Compliance (2012C) estimate of [redacted]. In fact, as noted above, the correct amount is [redacted] which is [redacted] lower [redacted] than 2012C. Changes reflect NS Power's initiatives aimed at continuous improvement in our efforts to reduce costs and improve cost effectiveness. NS Power's Direct Evidence filed on May 8, 2012 discusses these initiatives to reduce costs. It would be inappropriate to use NS Power's efforts to reduce costs compared to compliance rates in a manner that unfairly penalizes the Company in future test years.

NS Power's forecast labour costs in 2011, as filed in the 2012 GRA were $143.7 million.[9] Actual labour costs in 2011 were $141.3 million. The variance of $2.4 million is the net result of increased labour costs in certain divisions and savings in others. Labour cost increases and savings cannot be viewed in isolation. We manage labour budgets in conjunction with other operating costs. Management may determine it is more appropriate to use contractors than internal employees, which would decrease labour costs, but increase contract costs, compared to budget. Both types of costs constitute operational expenses. Part of the $2.4 million in 2011 labour savings occurred in Power Production; however, the $1.3 million in Power Production saved was offset by contract costs that were $5.2 million higher than budgeted. It is more appropriate to look at total regulated operating costs for 2011, which were $261.4 million[10] compared to forecast total regulated operating costs for 2011 of $252.6 million, adjusted for reclassifications

[9] 2012 GRA DE-03-DE-04, Partially Confidential Appendix C.
[10] 2013 GRA DE-03-DE-04, Partially Confidential Appendix E.

from revenue ($236.3 million, as filed).[11] NS Power's actual regulated operating costs in 2011 were 3.5 percent higher than forecast in the 2012 GRA.

On page 36 of its evidence, Liberty refers to forecast labour costs for 2011 of $149.5 million citing NS Power's response to Liberty IR-104 in P-892. Liberty's statement is not accurate. The cited figure does not reflect the total regulated labour costs NS Power provided in response to Liberty IR-104. Liberty included the non-regulated labour of $5,250,000 on Line 41 of the Corporate Adjustments tab. These are labour related costs incurred by NS Power, are not recovered through customer rates and therefore are excluded from the revenue requirement. As discussed above, NS Power's forecast labour costs for 2011, as indicated in its response to Liberty IR-104 and set forth in the Partially Confidential 2012 GRA DE-03-DE-04 Appendix C, were $143.7 million.

3.1.2 Forecast Methodology

At page 27 of its evidence, Liberty complains that NS Power did not provide requested information for the personnel numbers for each group for which the Company provided labour costs in Partially Confidential 2013 GRA DE-03 DE-04 Appendix E. As previously explained to Liberty during the 2012 GRA and earlier in this 2013 GRA, NS Power does not develop labour forecasts based on FTEs.

NS Power develops its division forecasts based on total labour dollars. We prepare each division forecast starting from the preceding period's base labour cost, and then adjusting for position additions, position reductions, use of term labour, overtime influences, benefit influences, and wage adjustments for union and non-union positions. The 2013 forecast began with our most current estimate of 2012 labour costs by division. We adjusted for projected staff additions and reductions, benefit changes, and salary changes. Separate estimates were applied for estimated overtime labour costs and temporary term

[11] 2012 GRA DE-03-DE-04, Partially Confidential Appendix C.

labour costs based on proposed work plans and evaluation of prior periods. We developed the 2014 forecast using the same approach based on the 2013 forecast. This is the best approach to forecasting labour costs year-over-year.

3.1.3 Full Time Equivalents (FTEs)

Liberty indicated it had "no basis for assessing the staffing numbers that drive estimates of 2013 and 2014 labour costs."[12] NS Power did provide Liberty with information on staffing levels.[13] As discussed above in section 3.1.2, however, NS Power does not base labour forecasts on FTEs. In response to the information provided, Liberty indicated that the historical information provided, while not as detailed as Liberty requested, did show a drop in numbers. Liberty speculated that the increases in labour costs forecast for 2013 and 2014, by contrast, appear to require a material increase in staffing. Liberty concluded that, to the extent the forecasts for 2013 and 2014 rely upon increases in staffing, the Company has so far not provided enough identification of or justification for such increases. In fact, NS Power's Direct Evidence, and our responses to IRs provide support for the 2013 and 2014 labour costs, which are not entirely tied to increases in staffing.

The personnel figures included in NS Power's responses to CA IR-17 and CA IR-73 demonstrate changes in staffing. Seasonality in staffing levels makes it is hard to provide a single FTE figure for each year, and at this point, we only have figures for the first half of 2012. For the sake of comparing apples to apples, we can take an average FTE for the first six months of 2010, 2011 and 2012. The figures are 1972, 1962, and 1840, respectively. The change from 2011 to 2012 reflects staff reductions that NS Power has identified in its Direct Evidence. Because FTE levels change from month to month due to timing of things such as maintenance schedules, those FTE averages do not necessarily

[12] Liberty Evidence, page 28, line 203.
[13] Liberty (NSPI) IR-69.

reflect the levels for the next six months. Such factors as power plant outage schedules may vary. Nevertheless, these averages do show the decreasing FTE trend.

Average salary figures can be used to demonstrate changes in staffing levels in 2013 and 2014. Dividing the labour costs provided in NS Power's response to Revised Liberty IR-54 by the average salary of [redacted], which is based on 2012 actual salaries at the time of this filing and adjusted for wage adjustments each year, yields an approximate FTE estimate for 2011, 2012, 2013 and 2014 of 1922, 1818, 1857 and 1861, respectively. As noted, NS Power does not forecast based upon FTEs, and so this example is provided for illustrative purposes only. This demonstrates the decline in FTEs from 2011 to 2012 discussed in the Company's Direct Evidence. The increase in 2013 mainly results from the additional FTEs to operate the Biomass plant, while 2014 is relatively flat.

As indicated above, increases in staffing are not the only driver of increased labour costs in 2013. The addition of 34 employees in 2013 at the Biomass plant increases FTEs. However, reductions in FTEs have occurred across the organization. Increased storm costs in 2013 are primarily due to overtime but these do not result in additional staffing positions.

3.1.4 Comparison of 2012F to 2013F

Liberty indicated that the 2013 estimate of $144.2 million in costs is [redacted] or [redacted] above what the Company expects it will spend in 2012. As noted in section 3.1.1, the current estimate for 2012 is higher than Liberty indicated in its evidence. The 2013 estimate of labour costs excluding any adjustments for administrative overheads and corporate allocations is $144.2 million. That is [redacted] or [redacted] higher than the 2012 estimate of labour costs of [redacted]. Figure 3-1 below breaks out the components of the increased labour costs for 2013 compared to the 2012 forecast:

Figure 3-1

2012F (in millions of dollars)	[redacted]
Increased storm costs	3.1
Addition of Biomass labour	3.3
Reduction in labour due to Lingan	(3.0)
[redacted]	
Increased Corporate Groups labour	0.3
Decreased Technical & Construction Services labour	(0.1)
Decreased Power Production labour	(1.6)
Decreased Customer Service labour	(0.2)
Increased Corporate Adjustments labour	0.1
2013	**144.2**

Note: Figures presented reflect whole numbers which may cause $0.1M in rounding differences on some line items.

The increased labour costs in 2013 compared to 2012 forecast reflect significant changes, including storm costs, labour for the Biomass plant, staff reductions for the Lingan plant and salary adjustments. NS Power discussed all of these factors in our Direct Evidence. Liberty states that there is no justification but Figure 3-1 makes the reasons for the increase clear. Adding positions, outside of the biomass plant, is not among the reasons. Aside from salary and benefit adjustments, which we discuss in section 3.1.5, the two largest increases are due to storm costs and biomass labour, both of which are supported in the application. Other changes between 2012 forecast and 2013 include additions and reductions of positions within the divisions, savings in overtime and reductions in term labour.

Liberty indicated NS Power has a significant one-year increase in 2013 labour costs. However, excluding labour costs associated with storm costs and biomass operations, NS Power's labour costs have increased by [redacted], which includes the salary adjustment. This demonstrates that NS Power has reduced staffing levels and implemented savings in labour costs.

It is worth noting that the costs included in Figure 3-1 are gross labour costs. NS Power recovers certain costs from affiliates through Corporate Support recoveries. Increased Corporate Group costs associated with affiliate growth are fully recovered from those affiliates in accordance with the Affiliate Code of Conduct. As a result, NS Power does not seek recovery from customers through rates for any of those costs.

3.1.5 Forecast Wage Increase

On page 29 of its evidence, Liberty refers to the increases provided to unionized employees in the Collective Agreement from April 1, 2007, to March 31, 2012, and comments on the size of increases provided over the term of the agreement. As always in preparation for negotiations, management examined internal and external dynamics back in 2007 to determine and understand current labour issues and challenges. In 2007, the following dynamics were occurring:

- NB Power had substantially increased its wages for IBEW unionized workforce as reflected in its IBEW Generation agreement dated January 2007 to December 31, 2011. This collective agreement allowed for 3 percent in 2007, 5 percent in 2008, 3 percent in 2009, 3 percent in 2010 and 3.5 percent in 2011. At that time, NS Power was paying below the NB Power wage rates. This agreement further widened the gap for identical roles within the IBEW union and utility industry.

- The Alberta economy was strong and NS tradespersons were leaving to go out West for higher paying jobs.

- Newfoundland Power raised its wage rates by 3 percent in 2007, 4 percent in 2008, 3 percent in 2009, 3 percent in 2010 and 3.5 percent in 2011. Maritime Electric raised its wages by 2 percent in each of January 2007, July 2007, January 2008 and July 2008. In 2009, 2010 and 2011 the increases were 3 percent, 2.5 percent and 3 percent, respectively.

In 2007, in order to gain labour stability and security, NS Power and the IBEW 1928 negotiated a collective agreement that included wage increases shown in Figure 3-2:

Figure 3-2

NS Power Collective Agreement Wage Increases					
2007	2008	2009	2010	2011	2012
2.5% plus $1.50/hr rate (for some trades)	3.5%	0%	4% plus $1/hr rate (for some trades)	4%	TBD

*Note: refer to April 1 2007 to March 31, 2012 Collective Agreement for specifics. There has been no increase in 2012 and the parties are currently in negotiations.

NS Power has prepared an analysis that compares NS Power's wage increases to those noted above for NB Power, Maritime Electric and Newfoundland Power:

Figure 3-3

	2007	**2008**	**2009**	**2010**	**2011**	**2012**
NS Power	2.5% plus $1.50/hr rate (for some trades)	3.5%	0%	4% plus $1.00/hr rate (for some trade)	4%	TBD
NB Power	3%	5%	3%	3%	3.5%	4%
Maritime Electric	4%	4%	3%	2.5%	3%	3.25 %
Newfoundland Power	3%	4%	3%	3%	3.5%	3.25 %

When we negotiated this 2007 to 2012 collective agreement, there was no way to know what would occur in the North American economy in 2008 and 2009. We cannot open up collective agreements during their term to make ad hoc changes. This would violate the negotiated contract. The 5 year agreement gave us low turnover rates that benefited customers by allowing us to retain highly skilled committed employees. It enabled us to attract qualified, trained applicants into apprenticeship and journeyperson roles. It brought labour peace that enabled key customer deliverables on reliability and renewables development.

Unionized Labour Costs for 2012

In September 2011, a survey by CKF/Minas Basin collected wage data from organizations operating in the Atlantic Region and from organizations that had filed negotiated collective agreements with HRSDC. NS Power made the September 30, 2011 Milliken Compensation Survey available in response to Liberty IR-133.

Data collected from organizations operating in the Atlantic Region through the CKF/Minas Basin survey indicated that the average negotiated wage increase for 2012 was 4.1 percent and that for 2013, it was 5.0 percent. The same analysis reported median wage increases of 4.0 percent for 2012 and 5.4 percent for 2013. Table 5 of the September 2011 Milliken report reflects this information. This report validates the 4 percent increase NS Power negotiated in the 2007-2012 Collective Agreement for NS Power unionized employees for 2011as consistent with those provided by other similar organizations in 2012, and specifically with the negotiated settlements of NB Power in 2012 (4 percent), Newfoundland & Labrador Hydro in 2012 (4 percent) and, Maritime Electric in 2012 (3.25 percent) and in 2013 (4 percent).

Labour Cost Forecasts for 2013 and 2014

On page 31 its evidence, Liberty complains "the absence of meaningful response [to Liberty IR-133] means that the Company has not justified any increase, pending the provision of proper support". Our response to Liberty IR-133 indicated that NS Power would provide this information to the Board upon request. Liberty did not ask the Board to have NS Power supply this information. The list of the reports available upon Board request included:

- Human Resources and Skills Development Canada (2009 – 2010). *Wage Increases in Major Agreements; 500+ Employee.*

- Human Resources and Skills Development Canada (2007 – 2011). *Wage Increases in Major Agreements; Maritimes*.

- Human Resources and Skills Development Canada (2011). *Wage Increases in Major Agreements; Utility Sector*.

- Quebec Employers Council (2011). *Special Report on 2011 Salary Forecasts.*

- Mercer (2011/2012). *Compensation Planning Survey for Non-Union Employees (Canada) – Proprietary & Confidential.*

- World at Work (July 2011). *WorldatWork 2011-2012 Salary Budget Survey: Top-Level Data*. *– Proprietary & Confidential.*

- Caines, G. (September 2011). *Compensation Trends & Projections for 2012*. Morneau Shepell. *– Proprietary & Confidential.*

- Milliken, S (November 2010). Labour Market Analysis for Nova Scotia Power Inc. *Milliken HR.- Confidential*

- Milliken, S (June 2011). Nova Scotia Power Inc. 2010 & 2011 Market Analysis SUMMARY REPORT. *Milliken HR. – Confidential*

- Milliken, S (September 2011). NSPI Compensation Market Analysis. *Milliken HR* - - *Confidential*

- Milliken, S (November 2011). Nova Scotia Power Inc. 2012 Market Analysis – Detailed Report. *Milliken HR* - - *Confidential*

- Milliken, S (2011 – 2012) Data in support of rate case request. *Milliken HR - - Confidential*

- MacLellan, R. (2012). *Future Wage Considerations (2013 – 2014).* NS Power Internal Document.

Unionized workers account for 51 percent of NS Power employees. While they achieved increases of 4 percent in 2011 under the 2007 to 2012 collective agreement, salaries for non-union employees increased by an average of 2.25 percent in 2011. Non-union salaries are projected to increase [redacted] in 2012. Liberty's assumption on page 31 that NS Power would incur a [redacted] combined increase over two years is not correct. The recommended salary increase in the November 2010 [redacted]. In the 2012 GRA settlement agreement, the salary increase budget was reduced to [redacted], not 3 percent as stated by Liberty on page 31. [redacted] was updated in September 2011 and the updated data continues to support a market trend of [redacted].

The salary increase projected in 2013 and 2014 for NS Power is [redacted]. The justification for this increase is outlined below.

(a) Milliken HR Report – September 2011 – Highlights

The following data represents actual and forecasted wage increases, both nationally and for the Atlantic Region, as reported by 675 organizations in the 2011/2012 Mercer Planning Survey Results. When analyzing market data, it is best to focus on the 50th percentile of the marketplace, as extremes can skew the mean either up or down.

Figure 3-4 confirms that in 2011 organizations awarded increases averaging 3 percent across the board, to employees in all job categories from tradespeople to executives. These same organizations are expected to average [redacted] increases in 2012 (See Table 1 of Milliken HR Report – September 2011)

Figure 3-4

2011 & 2012 Actual and Forecasted Percentage Salary Increases (see Table 1 in September 2011 Milliken Report)						
	2011 Actual			2012 Forecast		
	50P	Mean (incl. 0)	Mean (excl. 0)	50P	Mean (incl. 0)	Mean (excl. 0)
All Employees - All Industries – Atlantic	3.0%	2.9%	2.9%	[redacted]		
All Employees - Utilities – National	3.0%	2.6%	2.9%			

This economic environment has led to some healthy wage settlements for union employees in the Atlantic region over the past 3 years (see Table 2 of Millken HR Report – September 2011) and in the utility sector generally across Canada (see Table 3 of Milliken HR Report – September 2011). Similarly, according to Mercer, non-union employees have and will continue to receive annual adjustments in the range of 3 percent according to a survey of 675 organizations as per Figure 3-4.

Figure 3-5 below provides average and median wage settlements for the Atlantic Region – All Industries and for National Utilities based on the September 2011 Milliken Report.

Figure 3-5

Wage Settlements - Atlantic Region - All Industries (see Table 2 in September 2011 Milliken Report)					
Based on the 66 collective agreements registered with the HRSDC between 2008 and 2011 each representing over 500 workers	**2009**	**2010**	**2011**	**2012**	**2013**
Average	4.2%	3.0%	2.6%	2.2%	1.8%
Median	3.2%	3.2%	2.8%	2.2%	2.5%
Average excluding 0s	4.3%	3.2%	2.9%	2.5%	2.3%
Median excluding 0s	3.3%	3.4%	2.8%	2.4%	2.8%
Wage Settlements - National - Utilities (see Table 3 in September 2011 Milliken Report)					
Based on the 24 collective agreements registered with the HRSDC between 2008 and 2011 each representing over 500 workers	**2009**	**2010**	**2011**	**2012**	**2013**
Average	2.6%	2.6%	2.7%	2.4%	2.8%
Wage Settlements - National - Utilities (see Table 3 in September 2011 Milliken Report)					
Based on the 24 collective agreements registered with the HRSDC between 2008 and 2011 each representing over 500 workers	**2009**	**2010**	**2011**	**2012**	**2013**
Average excluding 0s	2.6%	2.7%	2.8%	2.6%	2.8%
Median excluding 0s	3.0%	3.0%	3.0%	2.8%	2.9%

(b) Morneau – Compensation Trends Summary 2011 Report – Highlights

Morneau reported the following increases;

- For Atlantic Canada – 3 percent actual in 2011 and 2.8 percent forecast for 2012
- For the Utility sector – 3.3 percent forecast for 2012

(c) Mercer (2011/2012). Compensation Planning Survey for Non-Union Employees (Canada) – Highlights

Mercer reported the following average increases:

- For Non-Union Employees Canada-wide – 3 percent actual in 2011 and [redacted] forecast for 2012
- For Trades – 3 percent actual in 2011 and [redacted] forecast for 2012
- For Non-Trades – 3 percent actual in 2011 and [redacted] forecast for 2012

(d) World at Work (July 2011). 2011-2012 Salary Budget Survey: Top-Level Data. – Highlights

World at Work reported the following information in Figure 3-6:

Figure 3-6

2011 Forecast Average Salary Increase	2011 Actual Average Salary Increase	2012 Forecast Average Salary Increase	2013 Forecast Average Salary Increase
Median = 3.0%	Mean Range 2.9% to 3.1% Median 3.0%	[redacted]	To be communicated to survey participants in October 2012

Additional information:

(e) Hay Group

On August 21, 2012, the Hay Group publically released the results of their annual survey of 500 Canadian companies regarding forecasted salary increases for 2013 (full details will be released later in September 2012). The highlights of the report are as follows in Figure 3-7 :

Figure 3-7

Projected 2013 Average Increase					
Projected 2013 Average Increase	**Alberta**	**NFLD**	**Atlantic Canada**	**Oil & Gas**	**Utilities**
[redacted]					

[1] versus 2012 projection of 3.4% and 2.9% in 2011
[2] versus 2012 projection of 3.4% and 2011 of 3.5%
[3] versus 2.4% in 2012 and 2.7% in 2011

(f) CEA Comparator Group

In August 2012, NS Power's Human Resources department undertook a confidential poll to determine average salary increases for other Canadian utilities for 2012 actuals and 2013 forecasts. The results of this informal survey are as follows in Figure 3-8:

Figure 3-8

Company	**2012 Actuals Average Increase**	**2013 Forecast Average Increase**
A	[redacted]	
B		
C		
D		
E		
F		
G		

(g) HRSDC Wage Settlements filed in 2012

Additional wage settlements have also recently been filed with the Human Resources and Skills Development Canada (HRSDC) indicating the following in Figure 3-9:

Figure 3-9

Collective Agreements filed with HRSDC in 2012	Average Negotiated Wage Increases	
	2012	2013
[redacted]		

[redacted]

(h) 2012/2013 Mercer Compensation Planning survey for non-union employees.

As per Figure 3-10 salary budgets have seen further improvement from 2011 to 2012. For those organizations providing salary increases, salary budgets increased from 3 perecnt in 2011 to [redacted] in 2012. Organizations are projecting salary increases of [redacted] in 2013. Figure 3-11 provides this information by for Atlantic Canada and specific for Oil & Gas and Utilitie.

Figure 3-10

Role	2011 Actual Avg Salary Increase	2012 Actual Avg Salary Increase	2013
All Employees	[redacted]		
Professionals			
Management			
Office/Clerical			
Trades			

Figure 3-11

Region/Area	2012 Actual Avg Increase	2013 Projected Avg Increase
Atlantic Canada	[redacted]	
Oil & Gas		
Utilities		

Competitive Compensation

It is no longer just Alberta and British Columbia that are driving the competition for skilled labour and qualified professionals to work in the resource and construction sectors. Saskatchewan's and Newfoundland's resource industries now also compete actively for all types of talent - trades, engineers, project managers, financial analysts, HR professionals, middle managers, to staff large, long term infrastructure projects. A recent Statistics Canada bulletin (The Daily, July 26, 2012) indicates that average weekly earnings increased in every province in the 12 months up to May, with growth highest in Saskatchewan (up 5.4 percent) and Newfoundland and Labrador (up 5.4 percent, and exceeding the national average since December 2010). Nova Scotia had the 4th highest year over year growth in average weekly earnings by province at 4 percent.

Page 32 of Liberty's evidence suggests a "no increase approach" to OM&G labour costs. The 2011/2012 Mercer Study reports a sharp decline in the number of companies that are freezing salaries. The number reduced from 31 percent in 2009, to 5 percent in 2010, 3 percent in 2011, and just 2 percent in 2012. A "no increase approach" would be inconsistent with market trends, and would impair our ability to get and keep skilled labour to meet customer needs. Employment in Oil & Gas extraction is up 6.8 percent; in construction, up 6.3 percent. As employment rates rise, competition for skilled labour increases across the oil and gas, mining, utilities, and other sectors (Statistics Canada The Daily, July 26, 2012).

The 2 percent increase proposed by Liberty at page 37 would not align with market information on average salaries in the region, nationally, or in our sector. In reducing our average salary increase in 2012 (from [redacted] to [redacted]), and proposing [redacted] in 2013 and 2014 (versus the recommended market average increase of [redacted]), we will continue to lag the 50th percentile benchmarks, but not as widely as we would with a zero or [redacted] salary increase. Although it is below average market values, we believe a [redacted] increase will allow us to continue to attract and retain a qualified and motivated workforce.

3.1.6 Administrative Overhead

At page 32 of its evidence, Liberty contends that NS Power's Application did not provide substantial support for the forecast increase of [redacted], and that absent a meaningful response, the Company has not justified *any* increase, pending provision of proper supporting information. Liberty indicates a no-increase approach would produce adjustments in 2013 of $3,921,000 to OM&G labour and $762,000 to Administrative labour overhead credits, producing a net reduction of $3,159,000 to labour expense. Liberty also provided figures for 2014.

NS Power disagrees with Liberty's basis for assuming no forecasted increase. As discussed above, actual labour forecasts reflect a variety of changes in addition to a forecast salary adjustment. In its evidence, NS Power has fully supported our requested salary adjustment. Moreover, Administrative Overhead is not purely a labour charge.

It is not possible to reduce overhead by the forecast labour adjustment rate and expect to get a realistic estimate of administrative overhead. Administrative Overhead is charged not only on labour dollars but also on contract dollars. Contract expenses are not always determined by an escalation rate but instead vary widely depending on the projects anticipated for the year.

For the same reasons, NS Power disagrees with Liberty's approach to the projected adjustments it provides on page 34.

3.1.7 Fringe

Labour costs include fringe benefits. The fringe benefits allocation for 2013 and 2014 is set at 16.1 percent of salary, up from our historically budgeted 15 percent. Fringe benefits are **employer** costs and are calculated as a percentage of salaries. They include:

- Canadian Pension Plan (CPP)
- Employment Insurance (EI)
- Workers Compensation Benefit (WCB)
- Health Insurance
- Dental Insurance
- Life Insurance
- Accidental Death & Dismemberment Insurance
- Long Term Disability Insurance
- Employer Contributions to Pensions
- Vacation pay for term employees
- Corporate education fund for union employees
- Employer paid RRSP's for Labour Pool employees

Several fringe benefit expenses are projected to increase in 2013 and 2014, according to the suppliers of these programs (e.g. Federal Government, Group Benefits Provider):

(a) Canada Pension Plan (CPP) & Employment Insurance (EI)

- CPP and EI employer rates are set by the Federal Government. In 2011, CPP was approximately 3.6 percent of salaries which was an increase of 2 percent over 2010 rates. In 2012, the CPP maximum annual contribution rate increase was 4 percent and as a result the estimated fringe cost for CPP has been estimated at 3.8 percent of salaries over the next 3 years (an increase of 0.2 percent).

- EI was approx. 1.3 percent of salaries in 2011 which was a decrease of 0.2 percent over 2010 rates. The increase in rates in 2012 to the annual maximum contribution of 6.7 percent results in the estimated fringe cost for EI of 1.5 percent of salaries over the next 3 years (an increase of .2%).

(b) Group Benefits (includes Health, Dental, Life, Accidental Death & Dismemberment (ADD), Long Term Disability (LTD))

- Projected benefit rates for 2013 to 2014 were provided by Morneau based on industry rate increases and NS Power experience for increases in previous years. These are forecasted increase numbers.

Figure 3-12

Benefit	2012 % of Salaries	2013/14 Estimated Projected Increase	2013/14 % of Salaries
Health	[redacted]	6.00%	[redacted]
Dental		12.50%	
Life		15.00%	
ADD		2.00%	
LTD		14.00%	

The change in fringe from 15 percent to 16.1 percent in 2013 and 2014 assumes the increases above (totalling 1.1 percent) and no increases to the other fringe items listed.

3.2 Pension

Two consultants submitted evidence on NS Power's pension costs, Jeffrey Gray, on behalf of the Consumer Advocate (CA), and Peter Hayes on behalf of Board Counsel. In this section, NS Power will respond to the specific comments and recommendations made by Messrs. Hayes and Gray.

In light of the intervenor evidence, some context about NS Power's pension history may prove helpful:

(i) NS Power's pension plan is a mature plan that was transferred to NS Power at the time of privatization through the Nova Scotia Power Privatization Act.[14]

(ii) NS Power's Collective Agreement with the IBEW requires pension changes to be ratified by the union. This provision has existed in NS Power's and its predecessors' collective agreements for over 40 years.

(iii) While Peter Hayes identified opportunities to achieve savings through the changes to pension, the most significant costs associated with pension benefits are not within NS Power's control.

It may also be helpful to understand several historical facts about NS Power's pension benefits.

Before 1972, two main electrical utilities served most of Nova Scotia: the Nova Scotia Power Commission (the Commission), and Nova Scotia Light and Power Company, Limited (NSL&P).

The Province of Nova Scotia owned the Commission, which was created in 1919. By 1972, the Commission had acquired all the electric utilities in Nova Scotia except NSL&P and a few small municipal utilities.

The Commission's pension plan was the Province of Nova Scotia's Superannuation Plan. A Commission employee's pensionable service was recognized as service under the Superannuation Plan. Pension benefits were paid from the Province's Superannuation fund, and Commission employee contributions were made to that fund.

[14] *Nova Scotia Power Privatization Act*, R.S.N.S. 1992 c. 8.

The Commission also honored pension and retirement obligations to employees and pension recipients of several of the acquired utilities. As a result, the Commission had obligations for past service, indexing and other benefits and for pension service from the acquired utilities.

NSL&P employees participated in the Nova Scotia Light and Power Company, Limited Employees Improved Pension Plan (the NSL&P Plan).

In 1972 the Province "nationalized" NSL&P through the Commission's acquisition of NSL&P. The resulting Crown Agency, Nova Scotia Power Corporation (NSPC), assumed the obligation of the NSL&P Plan.

On April 1, 1973, eligible employees of Nova Scotia Light and Power Company, Limited became members of the Province of Nova Scotia Public Service Superannuation Plan, with all current service employee and employer contributions subsequent to that date being paid into the Superannuation Fund.

Between 1972 and 1992, as a result of this complicated sequence of events, NSPC found itself managing several pension plans:

- Province of Nova Scotia Superannuation. This Plan provided pension benefits for credited service with the Commission and NSPC.
- NSL&P Plan. This Plan provided benefits for credited service with NSL&P.
- Acquired Companies Plan. This plan provided benefits for credited service with utilities previously acquired by the Commission.

In 1992, NSPC was reorganized as Nova Scotia Power Inc. (NS Power), a new company created through an offering of common shares to the public. One element of this privatization was the elimination of the Province's responsibility for the pensions of

NSPC employees who became NS Power employees. The privatization legislation provides that:

- The Province was to transfer the portion of the Superannuation Plan's assets that were attributable to active NSPC employees to the newly-created NS Power Plan, which also assumed the obligation to pay pensions to transferred Plan members.

- NS Power was required to provide its employees and pensioners with the same level of benefits provided by the Superannuation Plan. In effect, the NS Power Plan was a carve-out of the Superannuation Plan for NSPC employees who became NS Power employees.

- Retired NSPC employees receiving Superannuation pension benefits, and former NSPC employees who had deferred their pension, were to remain in the Superannuation Plan as obligations of the Province.

- Both plans became subject to the Nova Scotia Pension Benefits Act and the federal Income Tax Act.

The Company's collective agreement with its union requires that changes to the pension plan be ratified by the Executive of the Union**.** This provision, or provisions to this effect, have been contained in the collective agreements that have been in place between the Company or its predecessors and the union for over 40 years.

3.2.1 Peter Hayes' Evidence

Board Counsel's witness, Peter Hayes, provides a number of pension-related criticisms of the Company. He makes the following specific recommendations:

(i) the test year revenue requirement be set at a level which reflects increased employee contribution rates, and

(ii) the company explore changes to its plan design that result in meaningful and sustained reductions in the plan's overall cost. The changes explored should relate to removal of or reductions to:

- guaranteed indexing;
- subsidized early retirement;
- the " best average 4 years" guarantee; and
- the benefit accrual rate and bridge benefit.

Mr. Hayes also suggested securing executive pensions, freezing or holding the line on salary increases for a limited time, and altering the governance structure.

NS Power's response to the specific items raised by Mr. Hayes is below.

Governance:

Mr. Hayes has stated that NS Power's Board cannot change the pension plans over which it has "ultimate responsibility" without the consent of Emera's Audit Committee. NS Power disagrees. NS Power's Board of Directors has ultimate responsibility for the oversight, management and administration of the pension plans sponsored by NS Power.

Specifically, the Emera Pension Oversight Framework states:

> Ultimate responsibility for the oversight, management and administration of the two pension plans sponsored by NSPI lies with the Board of Directors of NSPI. That Board has delegated its responsibility as Administrator of the plans to the Management Pension Committee, which is comprised of managers and officers selected by the President and Chief

> Executive Officer of NSPI. NSPI has agreed at all times at least one officer or manager of each of Emera Inc. and Bangor Hydro Electric will be a member of the Management Pension Committee of NSPI.
>
> The Board of Emera Inc. has delegated its pension oversight responsibilities to the Emera Audit Committee, which is comprised of Directors approved by the Board of Directors of Emera Inc.[15]

The Emera Pension Oversight Framework includes the following provision with respect to its oversight of the pension plans sponsored by NS Power:

> Whenever NSPI proposes an amendment to either of the pension plans that may have a material effect on the liabilities of either pension plan, NSPI will provide relevant supporting reports or documentation to the Audit Committee of Emera Inc., so as to enable both the Audit Committee and the Board of Directors of Emera Inc. to provide recommendations to the Board of Directors of NSPI before any decision is made on any such amendments.[16]

Emera's Pension Oversight Framework provides that Emera will oversee financial aspects of both pension plans, similar to any other major financial obligation, as well as considering in advance any amendments to the pension plans which may have a material financial effect. However it does not provide Emera with decision making ability with respect to the NS Power registered pension plans.

NS Power's Pension Governance Framework states that one of the responsibilities of the Board of Directors is to provide annual reports to the Board of Directors or other designated Board or Committee of Emera and to consult with Emera on any material amendments or changes to the pension plans. NS Power's Pension Governance Framework does not require Emera's consent.

[15] Eckler (NSPI) IR-13 Attachment, pages 115-116.
[16] Eckler (NSPI) IR-13 Attachment, page 116.

Composition of Management Pension Committee

Mr. Hayes stated that operational responsibility for the pension plans is delegated by NS Power's Board to a committee dominated by Emera and Bangor Hydro Electric employees. NS Power disagrees.

As at May 30, 2010, as noted in the Pension Governance Framework, the Management Pension Committee consisted of eight voting members. The President and Chief Executive Officer of NS Power appoints all members of the committee. As of May 30, 2010, 5 of 8 voting committee members were NS Power employees. The committee currently includes four members who represent NS Power, one member who represents Bangor Hydro, and two members who represent Emera.

During 2011, several committee members took on new roles within the Emera group of companies, but remained on the committee due to their experience with the registered plans. Retaining them on the committee also provides consistency since they had been involved in the Asset Liability Study carried out during their terms.

Appendix C sets forth the composition of, and changes to, the Committee from 2010 to the present.

The Committee continues to review its composition. It should be noted that other NS Power participants regularly attend committee meetings on a non-voting basis.
Regular invitees include:

- Vice President & Treasurer Emera Inc. (NS Power & Emera representation)
- Director Pension Investments NS Power (NS Power & Emera representation)
- Senior Analyst Pension Investments NS Power (NS Power & Emera representation)
- Human Resources Program Integration Emera Inc.(Emera representation)

- General Manager Human Resources NS Power (NS Power representation)
- Human Resources Administrator Bangor Hydro (Bangor Hydro representation)
- Director Human Resources & Safety Bangor Hydro (Bangor Hydro representation)

NS Power has agreed that at least one officer or manager from each of Emera Inc. and Bangor Hydro Electric will serve as members of the committee. The committee has responsibility for more than the NS Power Defined Benefit Pension Plans. Bangor Hydro Electric sponsors a separate employee pension plan, for which the committee retains responsibility. The Committee also oversees the Defined Contribution Pension Plans. There are some members of the NS Power Pension Plans who are employed by Emera and subsidiaries of Emera other than NS Power.

Focus on Assets

Mr. Hayes said the Company has acted prudently in managing its pension assets, but that there is an almost obsessive focus on the asset side of the pension equation. He believes the committee devotes an inordinate amount of reporting and management time to the performance of plan assets. Mr. Hayes says that in doing so, the Company appears to completely miss, or at least largely ignore, the growth in obligations resulting from declining interest rates, plan generosity, and the consequences of plan maturity.[17] NS Power disagrees with this assertion.

Mr. Hayes cites a line from the Statement of Investment Beliefs, to the effect that "Improving the funded status will need to come primarily from asset returns," as evidence that pension asset managers ignore the risk of declining interest rates. This is neither fair nor accurate. Asserting that improvements in the plan's funded status will need to come ***primarily*** from asset returns implies that asset returns will need to be the

[17] Direct Testimony of Peter Hayes, August 7, 2012, pages 9, line 21 to page 10, line 2.

main, but by no means the ***only***, driver of improvement. Nothing in the Statement of Investment Belief implies that the risk of declining interest rates was or is ignored. NS Power is aware that declining interest rates can degrade funded status. We gave careful consideration to this reality during the Asset Liability Study. The current asset mix, which includes 35 pension liability hedging assets, was developed in light of several variables, including interest rate decreases, and their potential impact on of the health and sustainability of the plan, including its funded status.

The Asset Liability Study gave careful consideration to an asset mix that would best achieve an improvement in the health of the plan, while considering the financial and risk tolerances.

Given the current funded status of the plans, investing a larger proportion of plan assets in investments that move in a manner similar to interest rates can be expected to cause a reduction in equity holdings, and provide lower overall plan returns. The Asset Liability Study considered the impact that a larger allocation to fixed income would have on both future contributions and pension expense given the current funded status. The study concluded moving to a larger allocation in fixed income was unsustainable at present for this very reason.

NS Power believes a 65 percent allocation to equities over the long term can be expected to provide returns that will help improve the plans' funded status. The Statement of Investment Beliefs provides that, over the long-term, as the plans become better funded, the asset mix will gradually shift to an increased amount fixed income investments.

For illustration purposes, the Acquired II plan's post Asset Liability Management asset mix holds 80 percent in fixed income, because fund managers concluded it should have a greater proportion of liability hedging investments in light of its current funded status.

In addition, an important result of the Asset Liability study has been the decision to enhance reporting to both the Management Pension Committee and the Audit Committee of the NS Power Board of Directors. NS Power and Towers Watson are currently developing a proposed framework for reporting that increases emphasis on, among other metrics, the relationship between assets and liabilities.

NS Power's pension consultant, Morneau Shepell, provides monthly updates on accounting discount rates and the impact on pension expense. The consultant also monitors changes in solvency interest rates and financial markets. In the event of significant changes in the financial markets, our consultant provides us with an updated forecast of company contributions to the pension plan for the upcoming year. Throughout the year, this information flows to senior financial and human resources leaders in NS Power and Emera, as part of their functional business roles. They, in turn, raise this information for discussion at Management Pension Committee meetings. In addition, as requested by the IBEW, we share this information with the union's Executive Board on an annual basis.

In IR-1 to Mr. Hayes, NS Power asked Mr. Hayes to clarify his recommendation for a more "holistic" approach to plan management. Mr. Hayes did not use the terms "funding policy" and "benefits policy" in his direct evidence, so we thank him for clarifying his interpretation of holistic plan management as including not only investment policy but also funding and benefit policy.

As Mr. Hayes has correctly stated in his response to IR-1,

> […] both the public service and teachers' pension plans in Nova Scotia have modified their benefit structure to substantially mitigate the risk of inflation on pensions in the post-retirement by either eliminating indexing, or by making it contingent on the plan's funded position.[18]

[18] Hayes (NSPI) IR-1.

The two pension plans he cites are exempt from the Nova Scotia Pension Benefits Act ("PBA"). This enables them to change not only future accruals, but also previously accrued benefits including pensions currently being paid. In effect, the change affected all active members, former members, and pensioners for all service.

Defined benefit pension plans sponsored by a single employer and registered under the PBA, such as NS Power's pension plan, are prohibited from changing previously accrued benefits like indexing, as described by Mr. Hayes. In fact, the PBA would permit no change to pension benefits earned prior to the date of any change in the plan's terms, and for greater certainty, no changes would be permitted to existing pensioners. In effect, for NS Power, such changes could only affect benefits accruing from the future service of active members. What the PBA allows NS Power's pension plan to do would have significantly less impact than what government allowed the public service pension plans to do.

While changing the benefit for future service would reduce current service costs (the cost of benefits being earned in respect of the current year of employment), it would not change the magnitude of the existing pension shortfall. It would not have a material impact on the total pension expense, or the cash funding requirement. This does not mean that NS Power is not considering changes to plan benefits, but rather is setting realistic expectations on the potential monetary impact of such changes.

As such, given the limited ability to impact accrued benefits, and the requirement to negotiate benefit changes in respect of union members during collective bargaining, NS Power has no formal "benefits policy." Instead, we continually monitor and review the competitiveness and costs associated with providing such pension benefits, and we consider whether changes to pension benefit should form part of our negotiations with the IBEW.

Working within the constraints set by the PBA, the collective agreement, the desire to hire and retain highly qualified employees and accounting standards, we believe that the Company does effectively manage its pension cost.

Employee Engagement

Mr. Hayes has indicated that NS Power's governance structure fails to seek input from, or engage its employees in any way. This is inaccurate. NS Power has an Employee Advisory Group for benefits that includes both union and non-union members. We established this group at the request of employees. NS Power also provides regular pension information to the members of the Pension Plan including:

- An annual letter to active members (sent as part of the annual pension statement) with information on plan performance, company and employee contributions in the most recent year, general commentary on the state of defined benefit pension plans, and updates on government provided pensions and savings plans

- Information on the member's entitlement under various scenarios, the Plan's going concern funded status, a summary of Plan terms, and contact details for additional pension information

- An annual meeting with the IBEW Executive Board to review Pension Plan financial status and to address any questions or concerns about the Pension Plan

- Retirement planning sessions, including a discussion of Pension Plan terms and benefits

- Annual total compensation statements that include pension information

- Information about the Pension Plan is available internally to employees

This information, which we provide on a voluntary basis, exceeds the typical information contained in the annual pension statements required under pension legislation.

In addition, in 2012, as part of management's annual meeting with all employees of the Company ("Employee Road Shows"), President Rob Bennett discussed the issues facing the Pension Plan and the need to balance the plan benefits and funding in a regulated utility environment.

NS Power has demonstrated that we will establish employee advisory committees upon request from employees. We established the Employee Group Benefits Committee consisting of an equal number of union and non-union employees. The committee meets two or three times a year to review the Group Benefits provided by the Company. In 2009, this committee reviewed our benefits providers and oversaw the RFP process and resulting recommendations to change the provider from Manulife to Medavie Blue Cross.

NS Power engages all members through a number of communications throughout the year. In addition, we provide a toll free number to all employees to respond to pension plan issues, and we remind employees of this contact number each year in the annual pension statement. The toll free number is operated by our pension consultants to ensure confidentiality and expertise.

We also note that union leaders are the elected representatives of the union members and are plan members themselves. NS Power provides the union leaders with unobstructed access to the Plan's actuary to discuss plan issues and finances. The union leaders are jointly responsible with NS Power to share pension plan information they receive from the actuary with their members.

NS Power makes significant effort to engage its employees on issues related to pension. The facts do not support Mr. Hayes' criticism, and NS Power respectfully requests that it be rejected.

Cost Mitigation

Mr. Hayes has recommended that the test year revenue requirement be set at a level which excludes the cash cost of approximately $800,000 for letters of credit, whose “sole purpose is to secure executive pensions in the event that the company is insolvent, which is arguably unnecessary in the context of a regulated utility.” For clarification, the cost of $800,000 covers a letter of credit to secure pensions that exceed the Income Tax Act maximums, and does include part of the pension amounts provided to some executives. It is important to note that of the $800,000, $400,000 is for the actual letter of credit, and $400,000 is deposited with the Canada Revenue Agency (CRA) as a refundable tax. Mr. Hayes confirms this cost on page 21 of his evidence by confirming that half of the cost relates to a refundable tax remitted to CRA. This could be viewed as partially pre-funding of the Supplemental Executive Retirement Plan (SERP). The remittance of the refundable tax is an Income Tax Act requirement for SERPs that purchase a letter of credit or are pre-funded.

NS Power decided to use a letter of credit to secure these benefits in order to provide security to members because NS Power is not formally pre-funding the SERP. At the time the SERP was established in 2002, NS Power concluded that pre-funding the SERP would not be tax effective since 50 percent of the pre-funding would have to be remitted to the Canada Revenue Agency as a refundable tax (and would not earn interest); the cash which would otherwise be used to pre-fund the SERP would be more efficiently used on activities that better serve customers. This was confirmed by another review undertaken about 5 years ago.

Mr. Hayes has suggested that it is not appropriate for a regulated entity to secure its SERP through a letter of credit. NS Power disagrees. As security is provided to members in the registered pension plan through pre-funding, it is also reasonable to provide some level of security to members in the SERP, in our case, through a letter of credit. While we do not expect our business to fail, we have all seen failures of businesses that were once considered too large to fail. Recent well known examples include Lehman Brothers, Arthur Anderson, Enron, Nortel, Washington Mutual Bank, and Worldcom. Regulated utilities are not immune from failure. In 2001, California's Pacific Gas and Electricity entered US Chapter 11 bankruptcy, re-emerging in 2004 after a settlement with creditors.

It is not uncommon for SERPs to be secured or pre-funded. Based on a 2008 Towers Perrin study, 52 percent of Canadian SERPs are pre-funded or secured through a letter of credit. The trend in the 7 year period up to 2008 saw an increase in the percentage of SERPs that are pre-funded or secured through a letter of credit (33 percent in 2001, and 40 percent in 2005 according to Morneau Sobeco surveys).

Salary Increases

Mr. Hayes has recommended considering the compounding effect that wage increases have on pension funding costs as a result of the solvency test.

In determining the solvency position and required solvency funding, all salary history up to the valuation date is taken into account but future salary increases are not considered. At the time of the next valuation, the solvency position takes into account the increases in salary since the prior solvency valuation. As the Pension Plan provides a benefit based on the best 4-year average earnings, any salary increase impacts the full amount of the active member solvency obligation. Note that future salary increases are taken into account for going concern valuations and accounting valuations.

NS Power is aware of the impact of salary increases on pension expense, and on both going concern and solvency funding requirements. As part of the preparation for collective bargaining, NS Power reviewed both the impact on pension expense and cash funding requirements (going concern and solvency) of various potential wage settlement rates and factored these impacts into the bargaining mandate options.

To put the impact on solvency funding into perspective, if we assume that on average employees have been receiving 3 percent annual salary increases. The impact of freezing all salaries for one year is equal to about 0.75 percent of the active solvency obligation or about $2.4 million (0.75 percent of $322 million of active member solvency obligations at December 31, 2011). Generally speaking, solvency shortfalls can be funded over 5 years, so the reduction in cash contribution relative to the status quo for the next 5 years would be about $0.5 million.

If salaries are frozen for more than one year, there is a compounding effect on the solvency contribution requirement. For example, using the same average 3 percent salary increase assumption, and salaries are frozen for two years, the overall impact is a total 2.25 percent reduction in active solvency obligations relative to the status quo. The reduction in cash contribution relative to the status quo for the next five years would be about $1.5 million.

While the potential savings is not immaterial, freezing salaries or reducing salary increases needs to be considered relative to the overall goal of being a median employer for total compensation. This is important so that NS Power remains competitive to be able to hire and retain qualified individuals with the right skill sets to serve our customers.

The impact on annual pension expense would be smaller than the amounts shown since any actuarial gains are amortized over nine years. The approximate reduction in pension expense for a two year salary freeze is about $1.1 million.

Plan Changes

On page 2, Mr. Hayes has alleged a lack of willingness to engage unionized employees in meaningful discussion around reform of the plan. However, he notes on page 33 [redacted]

[redacted] The Company has indeed engaged unionized employees – both in past negotiations and in current negotiations, and therefore Mr. Hayes' comments are unfounded.

The Company believes that all bargaining discussions should remain confidential and stay at the bargaining table until an agreement is reached. To negotiate in public would not be in the best interest of the customers, employees or the company. The current Collective Agreement expired on March 31, 2012. Negotiations began in March and reached an impasse in July. Following Department of Labour and Advanced Education regulations, the Company has filed for conciliation which is to occur in September.

The Union has shared the Company's opening proposal on pension benefits to its membership when impasse was reached in negotations in search for a strike vote to bring to conciliation to demonstrate their opposition to the Company's opening offer. The Company's proposal included:

- [redacted]

- [redacted]

- [redacted]
  - [redacted]

- [redacted]

- [redacted]
  - [redacted]
- [redacted]

Mr. Hayes indicates that NS Power has seen its costs increase and has been warned that the cost increases have become a significant issue in the context of its operations, yet appears to have done little to mitigate these rising costs. NS Power disagrees with Mr. Hayes' statements.

We are taking steps to control the costs of the pension plan that are within our control, as demonstrated by our bargaining position presented to the union. As NS Power has no control over interest rates and discount rates, we are making changes to the asset mix of the pension plan to mitigate some of the challenges of the economy and fund performances.

3.2.2 Jeffrey Gray's Evidence

As noted above, the other witness to submit evidence on NS Power's pension was Jeffrey Gray on behalf of the Consumer Advocate. Mr. Gray has recommended that NS Power "build a long term vision of plan design that is cost competitive, and competitive from a benefit level perspective, that is acceptable to ratepayers".[19]

A number of issues raised by Mr. Gray suggest he does not understand the details of NS Power's pension plan. As a result, he has made a number of incorrect conclusions which require correction. NS Power has outlined these items below.

[19] Direct Testimony of Jeffrey E. Gray, August 7, 2012, page 14, lines 15-17.

Pension Accrual Rate

On page 2, Mr. Gray has indicated that the lifetime defined benefit formula in the NS Power pension plan for employees with 15 years or more of service is a *full 2.0 percent* of the best average earnings for each year of service. Mr. Gray confirmed that this was his understanding in his response to NS Power's IR-2. The lifetime pension formula for all members is actually 1.3 percent of best average earnings up to the average Year's Maximum Pensionable Earnings ("YMPE") plus 2.0 percent of the excess of best average earnings over the average YMPE, multiplied by years of Credited Service (up to a maximum of 35 years). The misunderstanding of the benefit formula overstates the value of the plan benefits and likely impacts Mr. Gray's analysis presented on pages 5, 6 and 7 of his evidence.

The relevant excerpts from the December 31, 2010 actuarial valuation report, as referenced by Mr. Gray in his response to NS Power IR-2, are reproduced below for reference:

- **Definitions**

  Credited Service is the years credited for pension purposes and is limited to 35 years. For benefit purposes, Credited Service is split into two different types:

  - *Original Plan Credited Service:*
    - For a Member who joined the Plan prior to July 1, 2004: Credited Service accrued prior to July 1, 2004 for Union members, and Credited Service accrued prior to October 1, 2004 for Non-Union members
    - For members who joined the Plan on or after July 1, 2004, Original Plan Credited Service is zero.

- *Revised Plan Credited Service:*
  - Equal to Credited Service less Original Plan Credited Service.

- **Pension Payable**

  For a member who retires from active service after his or her unreduced retirement age, the annual pension is as follows, subject to the Income Tax Act maximum pension rules with regard to service after January 1, 1992:

  - *Amount of Pension Payable Prior to Age 65:*

    (a) If the Member (1) has Original Plan Credited Service, or (2) has no Original Plan Credited Service but has completed 15 years of Continuous Service:

    2 percent of the member's Final Average Earnings, multiplied by the member's years of Credited Service.

    (b) If the Member has no Original Plan Credited Service and has not completed 15 years of Continuous Service:

    1.3 percent of the member's Final Average Earnings up to the Average YMPE, plus 2 percent of the member's Final Average Earnings in excess of the Average YMPE, the total multiplied by Credited Service.

  - *Amount of Pension Payable After Age 65:*

    The sum of the following:

    (a) 2 percent of the member's Final Average Earnings, multiplied by the member's years of Credited Service prior to January 1, 1966; plus

(b) 1.3 percent of the member’s Final Average Earnings up to the Average YMPE, plus 2 percent of the member’s Final Average Earnings in excess of the Average YMPE, the total multiplied by Credited Service after December 31, 1965.

The lifetime pension formula for all members is 1.3 percent of best average earnings up to the average Year’s Maximum Pensionable Earnings (“YMPE”) plus 2.0 percent of the excess of best average earnings over the average YMPE, multiplied by years of Credited Service (up to a maximum of 35 years).

For a member who retires from active service, in addition to the lifetime pension benefit, the member is entitled to a bridge benefit payable to age 65 equal to 0.7 percent of best average earnings up to the average YMPE for each year of Credited Service if either a) the member joined the Plan prior to July 1, 2004 or b) the member joined the Plan after July 1, 2004 and has completed 15 years of Continuous Service.

Early Retirement Reduction

Mr. Gray indicates on page 3 that the adjustment for early retirement is 0.5 percent if the pension starts prior to age 65. We would like to clarify that the reduction is 0.5 percent for each month that the member’s age at retirement precedes their *unreduced* retirement age. The unreduced retirement age may vary by member based on their service, age at termination, and date of hire and may be prior to age 65.

35 Years of Service Cap

One page 3, Mr. Gray indicates that employees do not contribute to the pension plan once they have completed 35 years of service. It is important to also note that employees do not accrue additional credited service under the pension plan after they have accrued 35 years of service. As they are not accruing additional service, no additional contributions are required.

Relative Ranking of NS Power Defined Benefit pension plan in the Private Sector

On page 5, Mr. Gray indicates that NS Power's pension plan is "very generous**"** and "atypical" from a private sector perspective. However, for new hires, based on benchmarking studies with other Defined Benefit plans in the same sector (utilities, and oil and gas), the DB provision of the NS Power pension plan is [redacted] in terms of the net overall Company provided value. Please refer to Eckler IR-26.

Long Service Award

On page 7, Mr. Gray states that the Long Service Award ("LSA") contributes to the overall value of the benefit payable from the defined benefit pension plan. The LSA is not a benefit payable from the defined benefit pension plan. In Mr. Gray's response to NS Power IR-3, he confirmed that he included the value of the LSA in his analysis on the registered pension plan. The incorrect attribution of the LSA as a benefit payable from the plan, along with the misunderstanding of the plan's lifetime pension formula (the Pension Accrual Rate) results in an overstatement of the value of the plan and impacts his analysis regarding the generosity of the plan presented on pages 5 and 7.

The LSA is a separate benefit plan that pays out a lump sum to members who retire with an unreduced pension. The LSA mirrored a benefit provided by the provincial government at the time of privatization. Effective July 2007, NS Power closed the LSA plan to new hires.

Asset Smoothing - Solvency Financial Position

On page 9, Mr. Gray stated that the asset smoothing reserve *increased* the stated asset level for the December 31, 2010 solvency financial position. We would like to clarify that the asset smoothing reserve *decreased* the actuarial value of the assets at December 31, 2010.

Difference between Going Concern and Solvency

On page 9 of his Direct Testimony, Mr. Gray has indicated that the "difference in results is primarily the inclusion of an asset smoothing reserve in the solvency number which increases the stated asset value by $27 million." The difference between the going concern and solvency financial position is not simply due to the inclusion of the asset smoothing reserve. In fact, the same asset smoothing reserve is used to determine the going concern and solvency financial positions. The main difference is that the going concern and solvency valuations use different actuarial assumptions and methods to determine the respective obligations.

On page 9, lines 24 to 29 of his evidence, Mr. Gray suggests that the difference in solvency and going concern liabilities as at December 31, 2009 is due to the asset smoothing reserve. We would like to clarify that the asset smoothing reserve only impacts the reported assets, the asset smoothing reserve does not impact the reported liabilities.

Required Payments on Plan Wind-up – Grow In Benefits

On page 10, Mr. Gray indicates that grow-in benefits are only required to be funded if the plan had sufficient assets. We would like to clarify that this was true up to April 30, 2007. In 2007, the NS government passed Bill 4 which changed the wind-up funding requirements. Effective May 1, 2007, Nova Scotia Pension Benefits Act Section 80(1A) requires that on plan wind-up the plan sponsor is responsible for funding the full amount of any wind-up shortfall including grow-in benefits. While certain types of plans are exempted from this requirement, the NS Power plan is not exempted.

Asset Mix

Mr. Gray indicates on page 11 of his testimony that the asset mix for the Plan is transitioning to an 80 percent fixed income (and 20 percent equity). The target asset mix for the Plan is 65 percent equity and 35 percent fixed income. We believe that the reference to the 80 percent fixed income mix relates to the target mix for Part II of the Acquired Companies Pension Plan.

December 31, 2010 Financial Position References

We have reproduced Mr. Gray's comments from lines 12 to 26 on page 8 of his evidence below and have added our comments in **<bold within chevrons>** for clarification.

> The December 31, 2010 valuation reflects a going concern unfunded liability of $144 million. **< This figure includes asset smoothing>** This shortfall has grown to $185 million **<This figure excludes asset smoothing>** as at the end of 2011 per various press releases – this amount is amortized over a period of years and our understanding is this prescribed annual amount required to fund this shortfall is the concern of ratepayers. **<While the going concern unfunded liability and cash contributions are relevant, we believe that it is the pension expense on an accounting basis that is the primary concern since this is what primarily impacts the rates>** Where a private sector organization has a defined benefit plan and benefit costs escalate rapidly with probability of ongoing high or volatile costs, the need to be price competitive forces organizations to review all input costs and make changes if necessary. The

> annual solvency payment for 2010 **<This reference should be to 2011>** was approximately $26 million which would be in addition to the approximate $9 million for current service costs for a total of $35 million. By press release (which are not always very exact in their definition of pension funding numbers given accounting, ongoing, solvency, and wind-up valuation numbers) the total pension funding expense appears to have increased to $58.6 million. **<We believe the $58.6 million is a reference to projected pension expense for 2013 which is not directly comparable to the cash funding figure of $35 million shown above. As previously noted by NS Power in their submissions, the term "pension expense" refers not only to the accounting expense related to the main pension plan – it refers to the accounting expense related to all pension and post-employment benefit plans.>**

While NS Power does not take issue with Mr. Grays's suggestion to look for long term opportunities to achieve savings in pension costs (which NS Power is doing as described in further detail in its response to Mr. Hayes' evidence above), Mr. Gray's conclusions about the overall comparative value of the NS Power plan is based upon his own incorrect assumptions and conclusions about the plan and therefore we respectfully request that these findings be rejected.

3.3 Executive Compensation

Board Counsel's consultant, Liberty reviewed NS Power's executive compensation costs. No other intervenor submitted evidence on this issue.

NS Power provided full access to Liberty respecting the details of its executive compensation in order for it to perform its review. Liberty's evidence concludes that:

1. NS Power's approach to benchmarking is consistent with common elements of benchmarking performed by outside firms and is commensurate with public utility needs;
2. That NS Power's executive compensation is appropriate;
3. That NS Power should consider comparative group design for benchmarking.

NS Power's executive compensation costs are appropriate. NS Power's Management Resources Compensation and Corporate Responsibility (MRCC) committee and its Board of Directors continually review benchmarking information to ensure that NS Power's executives are compensated appropriately. It has and will continue to look for opportunities to refine and improve upon its comparator information. NS Power will continue to provide annual reports to the Board on this issue.

3.4 Vegetation Management and Storm Costs

NS Power has requested approval of $3.4 million for an enhanced Vegetation Management program to improve reliability for our customers. The $3.4 million will specifically address off right-of-way hazard trees, which in high winds can fall (from outside the right-of-way) into our lines, causing outages. These trees are not addressed through our current right-of-way based management programs. NS Power has requested this same amount in both the 2009 and 2012 GRAs for the off-right-off way part of the reliability plan. Through the negotiated settlements for 2009 and 2012, it was agreed that NS Power would not then undertake such an additional program. The need to proceed with this program however has not diminished. Indeed, as time progresses, the risk of hazard resulting from these trees falling into our power lines increases.

Additionally, NS Power requested approval for storm costs in rates to be updated to reflect the most recent five-year average, representing an increase of $5.5 million.

Two intervenors have filed evidence on these issues. Liberty, on behalf of Board Counsel has, as it did last year, confirmed their support for the increased spending requested for vegetation management. However, Liberty's evidence is that NS Power should not be permitted the increase in storm restoration costs because it believes that NS Power should see savings in the test years associated with the increased vegetation management amount. Lee Smith on behalf of the Small Business Advocate, on the other hand, raises no issue with respect to storm restoration costs, but says the increase in vegetation management spending should not be approved. Ms. Smith wrongly believes the increased spending request for vegetation management is for $4.5 million. As noted above, the requested increase is $3.4 million.

Both Board Counsel, through Liberty, and the SBA took similar positions in the 2012 GRA.

Response to Liberty Evidence on Storm Response

While Liberty recognizes the importance of the Board's approval of the increased spending of $3.4 million to commence the off-right-of-way tree program, it continues to misunderstand the relationship between this program and NS Power's actual experience with storm costs. NS Power makes the following comments:

- Liberty's primary justification for recommending the denial of the additional $5.5 million in storm response costs is that it believes that increased vegetation management should reduce storm response costs. While we do expect reliability to improve from the off right of way vegetation management program, the average amount of tree contact outages we experience during severe weather is insignificant in comparison to the volume of tree exposure across our distribution system. Tree contacts continue to be out biggest cause of outages, due to the tremendous exposure of our distribution system to trees across the province. Our current vegetation management program is helping, and our proposed off-right-of-way program would help even more. But this won't equate to a direct trade-off with storm expenses, because, as mentioned, the exposure is so widespread. Liberty's concept would only work if storms hit precisely where we conducted tree trimming each year. That simply doesn't happen.

- The off right of way vegetation management program is a 7 year program[20] and projects long-term, incremental reliability improvements and associated storm response savings. The program does not claim to eliminate storm tree contact outages, but targets 2009 reliability levels as an acceptable average for storm tree contact outages. NS Power notes that 2009 storm costs were $7.7 million ($2.7 million over the current amount in rates).

- Liberty refers to "increases…occurring over time," and "one should expect gradual, but material improvements in outage numbers and duration."[21] The prior approved increases were for our standard, ROW-based vegetation management. While we do expect and have demonstrated reliability improvements as a result, these funds are not directed at severe weather outages as is the requested $3.4 million for off-right-of-way vegetation management. As a result, the gradual reductions in storm response costs Liberty references would have negligible contribution associated with the approved prior increases associated with our existing vegetation management program.

- Liberty testifies that NS Power should be using median weather data to forecast storm expenses as opposed to mean data. Using the median is not appropriate considering the type of distribution that storm costs represent. Storm costs evaluated over time show a skewed distribution (as opposed to normally distributed, flat, or some other type) with no real maximum amount for storm

[20] NSPI (Liberty) IR-60.
[21] Liberty Evidence, August 7, 2012, page 41, lines 14-20.

costs. Additionally, there is significant variability from one year to the next. Using a median would exclude the very real impact of outlier years that are significantly costlier than a median year; using a mean is more representative of average costs. Given the variability of severe weather, which Liberty acknowledges[22], the lack of any extreme values in the data set used, and the inherent purpose of the storm response budget, the use of the median is statistically inappropriate in this scenario.

- "Re-invest savings in reliability" – this statement from Liberty IR-60 (f) both last year and this year prompted an argument from Liberty. NS Power provided full response to this issue in its 2012 GRA Reply Evidence and repeats many of these points below. The reduction in Customer Hours of Interruption (CHI) has changed from the 2012 GRA, but the estimate of "at most $400,000" in savings still stands. This is based on comparing the 2009 storm costs ($7.7 million) to the requested $10.5 million, and dividing by the 7 year time frame that it will take to implement the program.

- Storm costs for 2011 were lower, largely due to reduced significant weather events. There are other years in the storm increase calculation presented in Liberty IR-64 Attachment 1 that are similar to 2011 costs, with costs being largely a function of storm severity.

- The statement that NS Power uses resources in ascending order of cost depending on the degree of need is true – we use internal crews for lesser storms, local contractor crews for larger storms, and out-of-province crews for even larger events. However, this statement is relevant only in the context where increased vegetation management investments reduce storm response effort. This will not be the case over the term of the test years presented.

[22] Liberty Evidence, August 7, 2012, page 41, line 20.

- Liberty has proposed a very simplistic method for evaluating storm cost reductions. There are two basic factors that Liberty has overlooked, the first of which is that we do not currently have an off right-of-way tree program. Because this has not been done yet, any new program would take several years before reductions would be realized; we are only presenting information over two test years, not over the life span of the vegetation management program. In addition, this fails to consider the chaotic nature of storms.

- NS Power currently spends significantly more than is in rates for storm response; even assuming that we will save money as a result of the investment, it would need to be at least a one-for-one return on that investment in the first year, a highly unrealistic assumption. The program will take years to implement, and for benefit to be observed. There will be an increase in reliability, but this is a long-term initiative that will take time to implement. It has been demonstrated that Nova Scotia is increasingly at risk for hurricanes and other severe weather, so the best information we have is that these costs will continue.

- NS Power's storm response is based upon the guidelines of the Emergency Services Storm Restoration Plan (ESRP), which informs the degree of response that we make to significant weather events. NS Power's ESRP is filed and reviewed by the Board annually arising from its decision in in the Storm Outage Review proceeding from 2005[23]. A significant portion of the costs associated with a severe storm response is related to mobilization and demobilization costs that are incurred as a result of activating crews proactively. We do not wait for a storm to hit before deploying crews, but rather stage them where we estimate the storm damage will occur. We would only make changes to that response after having seen demonstrated reductions in storm damage over several events. We

[23] Public Review of the Power Outages resulting from the Storm of November 13 and 14, 2004; NSUARB-NSPI-P-401.32.

have no evidence that storm costs would be reduced during the test years as a result of the increase vegetation management spend.

NS Power's evidence shows that its actual experience with storm costs has well-exceeded the amount approved in rates for the last several years. NS Power requests that the Board reject Liberty's recommendation to not approve NS Power's request for increased spending to recover costs for storm restoration.

Response to Lee Smith on Vegetation Management

The essence of Ms. Smith's evidence in support of her recommendation against improving reliability through increased spending for off right of way vegetation management is that there are likely less trees that pose problems as a result of recent years' experience with severe weather:

> The Company posits that severe weather events increase risk of tree failure. This may be true for trees that remain standing. However, it seems possible if not likely that a high number of trees that fell from outside of right-of-ways just two years ago, leaving fewer trees standing that may be problems.[24]

Ms. Smith's opinion on this issue is unsupported by any factual evidence or analysis but merely reflects Ms. Smith's own musing about what 'seems possible'.

At page 7 of Ms. Smith's evidence, she comments upon NS Power's response to Liberty IR-59. Ms. Smith has misunderstood this evidence. Liberty IR-59 shows the regular, right of way based vegetation management programs return a $/ACHI of 34, overall. The calculations that are detailed in Liberty IR-60 for the off-ROW program are based on data that is independent of the data used to calculate the routine vegetation management savings.

[24] Direct Testimony of Lee Smith, August 4, 2012, page 7, lines 110-112.

Ms. Smith states “there is no basis to assume that if spending about $9 million on vegetation management costs $34 per ACHI, spending 45 percent more will produce the same benefit per dollar if additional spending.”[25] This is not what NS Power is proposing or suggesting. Ms. Smith is comparing apples to oranges.

The current vegetation management program spend that is referred to in NS Power’s response to Liberty IR-59 is the Net Present Value (NPV) of distribution, reliability-based vegetation management. The requested $3.4 million increase (as noted above, not $4.5 million as characterized in Ms. Smith’s testimony) is for a completely separate, alternative program to target off-ROW danger trees. We calculate that the requested $3.4 million for off-ROW vegetation management will return a NPV $/ACHI of 17.4.

With respect to reliability measures, Ms. Smith points to the SAIFI / SAIDI / CAIDI measures as indicating that the investment in vegetation management has not improved reliability. What she does not consider is that our response to storms significantly changed after the weather started to get worse, thus maintaining those reliability measures is increasingly challenging. NS Power has shown that the occurrence of hours of high wind gusts has been increasing. Our evidence is that there is a strong correlation between occurrences of high hours of wind gusts >90 km/h and poor reliability (see Liberty IR-62 Attachment 1, Figure 15 and Conclusion).

In essence, Ms. Smith’s conclusions contradict themselves. She agrees that successive weather events increase the risk of tree failure (line 143) for trees that remain standing. However she then goes on to state that “ is seems likely that the high number of trees that fell from outside of right-of-ways just two years ago will have resulted in natural tree trimming, leaving fewer standing trees that may be problems.”[26] The number of trees that caused the Customer Hours of Interruption (CHIs) during storms from 2003 to 2011

[25] Direct Testimony of Lee Smith, August 4, 2012, pages 8-9, lines 142-146.
[26] Direct Testimony of Lee Smith, August 4, 2012, pages 8-9, lines 143-146.

is minimal. The average storm tree contact CHIs that we are targeting with the off ROW vegetation management program were caused by an average of less than 1,500 events. Even assuming multiple trees per event, this still represents less than 0.5 percent of the estimated amount of total tree exposure on our distribution system, and that does not consider new growth for increased exposure.

Furthermore, Ms. Smith suggests that that NS Power has “done no analysis of the number of kilometers that were impact (sic) by these outside of right-of-way trees in 2010.”[27] This is untrue. In NS Power’s response to Liberty IR-60(b), we state that analysis of danger tree work to date indicates that, on average, 17.5 percent of distribution spans require danger tree management. This continues to be the case as long as the forested edge exists along our distribution system. Anything to the contrary would require complete forests to fall and cease growing. Clearly, the minimal quantity of fallen trees during severe weather events is not eliminating our forests, and therefore the exposure to off ROW tree contacts remains.

NS Power submits that there is no merit to Ms. Smith’s speculative evidence on this topic. NS Power requests that the Board resist Ms. Smith’s recommendation and reiterates its request for approval of this important component of vegetation management spending to improve reliability for customers.

3.5 Bad Debt Expense

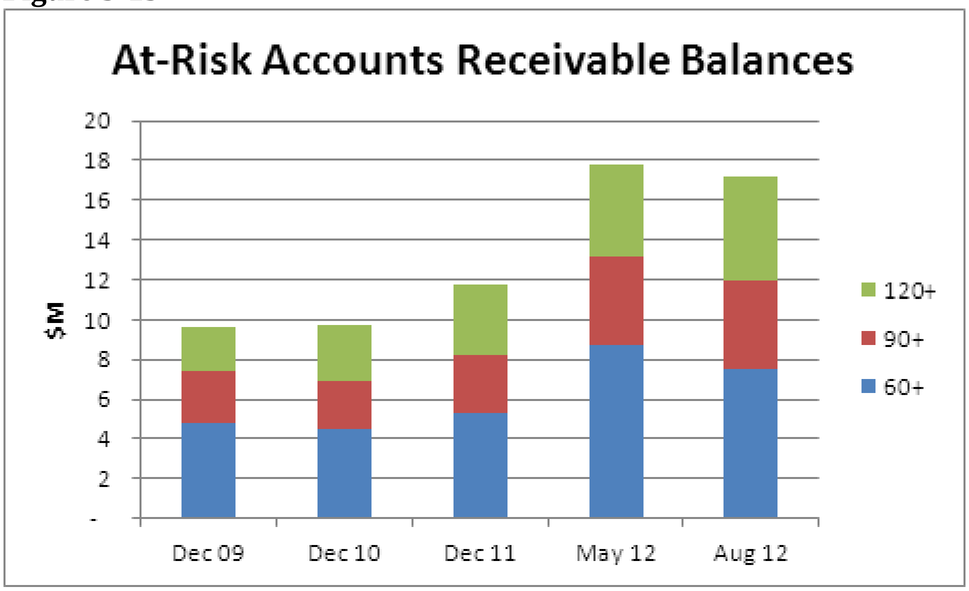
David Effron, on behalf of the Consumer Advocate, has calculated bad debt expense using a simple average for the years 2009 to 2011 and suggests NS Power’s estimate is overstated. He proposes a revenue requirement adjustment of $1.2 million.

NS Power has calculated bad debt expense using a forecast that incorporates prior results as well as current trends, rate increase sensitivities and other information. Mr. Effron’s

[27] Direct Testimony of Lee Smith, August 4, 2012, page 9, lines 146-149.

analysis only examined the historical average of net bad debt expense. This ignores the current economic trends that our customers are facing. A very strong indicator of the write-off amount is the age of the receivable; the older the receivable, the greater the likelihood that it will not be paid and will ultimately be written off. The graph below isolates the key "at-risk" receivables balances. Figure 3-13 demonstrates that our receivables balances that are at-risk have increased significantly since 2011, and indicate the need for a greater increase in the allowance associated with net bad debt expense than a simple mathematical exercise to look at historical averages.

Figure 3-13



NS Power has undertaken a number of initiatives to attempt to address the increase with at risk receivables, including:

- Initiation of a three-tier, third-party collection strategy late in 2011

- Increased focus of internal efforts on working at-risk accounts

- Modification of current processes around individual bills to intervene before balances become unmanageable, thus increasing the likelihood of payment

The 2013 and 2014 net bad debt amounts were calculated assuming that the total number of defaults in those years remains comparable to the 2011 experience, and the average amount of each default increases by the same amount as the rate increase. Concurrently, the amounts recovered from accounts that had been written off and the associated commissions paid were increased to reflect the increased third-party collection process that was initiated late in 2011.

NS Power maintains that the forecast for net bad debt reflected in the test year forecast is the best estimate and developed based on reasonable assumptions.

3.6 Workforce Reduction

As noted in NS Power's Application and IR responses, NS Power undertook a workforce reduction in 2012 as a cost saving measure. David Effron argues that savings achieved in 2012 should be transferred to 2013 for the determination of new rates, thus ignoring the test year forecast approach.

The test year is the creation of a forecast for a specific period. Mr. Effron has transferred savings from the prior period to the test year, suggesting savings should be derived. His claim is that the savings derived in 2012 are not in "rates". NS Power maintains that it anticipates earning within its allowed rate of return in 2012 and therefore recovery of costs from customers is accomplished. The 2013 labour costs reflect the continuing benefits of changes in 2012, as well as other impacts forecast for 2013. To impute the actual 2012 savings into 2013 on top of those matters would be an exercise in double counting, and as well would amount to retroactive ratemaking.

Mr. Effron further suggests that income taxes be derived differently related to the workforce reduction. The Company has followed its Board approved accounting policy with respect to the tax treatment of the workforce reduction costs. No adjustment is required.

NS Power requests that the Board reject these recommendations.

4 FINANCE

4.1 Rate Base

4.1.1 Allowance for Materials and Supplies

Board Counsel Consultant, Donna Ramas, states that the methodology used to calculate the average regulated rate base for the allowance for materials and supplies is not correct. Ms. Ramas states:

> The allowance for materials and supplies included in the 2013 and 2014 average rate base balances in the revenue requirement calculations are not reflective of the projected 2013 and 2014 average balances. The average regulated rate base should be reduced by $5.8 million in 2013 to reflect the projected average 2012 materials and supplies balance. The average regulated rate base should be increased by $2.1 million in 2014 to reflect the projected average 2014 materials and supplies balance.[28]

Ms. Ramas stated the same issue in the 2012 GRA and has indicated that although NS Power has used this method for calculating the Materials and Supplies balance incorporated in rate base for several past rate cases does not mean that the methodology is reasonable or the correct approach to use in setting rates.

Consistent with last year, NS Power's rates are set using a return on rate base methodology, which has been consistently used in the past and approved by the Board. The Board has approved NS Power's methodology to calculate the average rate base for material and supplies as well as Cash Working Capital (CWC). NS Power has followed this methodology since the Board approved the Company's rate base in 2006. Both allowance for materials and supplies and allowance for working capital use an average within the appropriate periods to calculate the averages. This has been consistently used in the past and approved by the Board. It is inappropriate to change methodologies to

[28] Direct Evidence of Donna Ramas, CPA, August 7, 2012, page 3, lines 60-66.

calculating average rate base on a specific line item. As noted by Ms. Ramas, changing the methodology results in an increase to average regulated rate base in 2014 and a decrease to average regulated rate base in 2013. NS Power requests that the Board deny this request.

Ms. Ramas' recommendations are not consistent with Board-approved methodology, and do not have the impact of improving the net revenue requirement over the two test years. NS Power requests that the Board reject Ms. Ramas' recommendations.

4.1.2 Working Capital

Ms. Ramas has suggested that the methodology used by NS Power to calculate the average regulated rate base for allowance for working capital is not correct. Ms. Ramas states that the amount of allowance for working capital included in the 2013 and 2014 average rate base balances in the revenue requirement calculations are not reflective of the projected 2013 and 2014 working capital needs. In future cases, if the allowance for working capital request is not voluntarily reduced by NS Power as it has proposed in this case, then the amount of allowance for working capital included in the average test period rate base should be based on the amount calculated specific to the test period and not on a two-year average basis. Ms. Ramas has noted that the impact if NS Power had not applied the settlement adjustment would be a decrease to average regulated rate base in 2013 of $6.9 million and an increase in 2014 of $11.1 million.

The average regulated rate base for 2013 includes the average of the 2012F and 2013 test year allowance for working capital in calculating the average. 2012F is not based on a lead-lag approach, which is the methodology used for test years, and the approach Ms. Ramas refers to in her evidence. It is not appropriate to deduct the adjustment from actuals. The adjustment was a settlement on the lead lag approach and not actual working capital. As noted above, NS Power's rates are set using a return on rate base methodology, which has been consistently used in the past and approved by the Board. It is inappropriate to change methodologies to calculating average rate base on a specific line item. As noted by Ms. Ramas, changing the methodology results in an increase to average regulated rate base in 2014 and a decrease to average regulated rate base in 2013. As NS Power adjusted the allowance for working capital in 2013 and 2014, this recommendation has no impact on the 2013 and 2014 test years. NS Power requests that the Board deny this request.

Ms. Ramas states that methodology used by NS Power in the 2013 test year does not limit the cash working capital allowance included in rate base to $27.9 million as indicated by NS Power in DE-03 -DE-04 and if NS Power's intention was, in fact, to limit the working capital allowance to the 2012 GRA Settlement Agreement level of $27.9 million, the average regulated rate base for 2013 needs to be reduced by $15.4 million. NS Power requests the Board deny this request.

NS Power indicated it applied an adjustment factor to the 2013 and 2014 forecasts to retain the cash working capital allowance at the 2012 GRA settlement level of $27.9 million. NS Power agrees the $27.9 million adjustment was not applied to 2012F, however this was the intention as 2012F is calculated on a different basis than 2013 and 2014. The allowance for working capital in 2012 was based on actual working capital and not a lead lag approach, which is how the allowance for working capital is determined for the 2013 and 2014 test years. 2012F represents NS Power's 2012 budget and is not a test year. NS Power limited the allowance for working capital to $27.9 million in the 2013 and 2014 test years, which is consistent with the 2012C test year.

NS Power submits that it has calculated working capital appropriately and has reduced revenue requirement to the benefit of customers through the adjustment made. NS Power requests that the Board reject Ms. Ramas' recommendations.

4.1.3 Plant In Service

David Effron, consultant to the Consumer Advocate suggests that NS Power over-forecasts capital expenditure in setting rates, which overstates rate base and therefore overstates revenue requirement. He proposes a revenue requirement adjustment of $4.9 million. NS Power disagrees with Mr. Effron's recommendation.

Mr. Effron's assertion is based on incorrect conclusions. NS Power's response to UARB IR-35 provided a historical summary of actual versus amounts set in rates for property plant and equipment (PP&E). For each of the last five years, the actual invested PP&E has been higher than the amount set in rates, reinforcing that NS Power does not overstate its rate base.

Figure 4-1 has been re-produced below for reference.

Figure 4-1

Year	Actual ($M)	Amounts in Rates ($M)	Variance ($M)
2007	2,384.9	2,368.3	16.6
2008	2,422.9	2,368.3	54.6
2009	2,573.7	2,478.6	95.1
2010	3,006.4	2,478.6	527.8
2011	3,107.1	2,478.6	628.5

For 2012 the forecasted average rate base provided in RB2-16 is higher than what is provided in the 2012C filing, further demonstrating that NS Power's rate base in 2012 is expected to be higher than the amount used to set 2012 rates. Adjustments to one line item are not appropriate without updating other line items that may have opposite effect adjustments to revenue requirement and as demonstrated by the table above, customer rates have consistently reflected less investment than the Company has had to make to provide service.

Mr. Effron states that NS Power has underspent in the first half of 2012 and therefore this should reduce the forecast of plant additions in 2012 for purposes of determining the 2013 test year average rate base. However, this year-to-date variance is largely a timing difference. During both the 2009 and 2012 GRAs, Mr. Effron made these same assertions. The Board should not arbitrarily reduce NS Power's annual capital spending based on partial year results as the timing of the capital expense can change throughout the year.

In addition, the forecast for setting rates is a test year that ultimately will have pluses and minuses. It is improper to adjust one item without a review and update of other items in the test year forecast.

Furthermore, capital expenditures reflect a dynamic program. Projects get deferred or cancelled while new projects are identified and substituted. The test year forecast is a snapshot of one point in time.

4.1.4 Capital Expenditure Management

Ms. Smith, on behalf of the Small Business Advocate testifies that it appears that NS Power has not managed capital expenditure costs effectively. She makes no specific recommendations.

NS Power is a cost-effective, well-run company. Independent audits have repeatedly confirmed this assessment. This is especially true during the current period of transformation as we adapt to the loss of pulp and paper load and change from a system based on imported high-carbon intensity fuels to one based more on clean, local, renewable energy sources. In response to evolving environmental regulations that focus on coal, we have made changes in the way we operate our legacy thermal plants, and reduced staffing levels – all with a view to reducing costs and further improving our cost effectiveness.

Capital expenditures reflect a dynamic program. Projects get deferred or cancelled while new projects are identified and substituted. The test year forecast is a snapshot of one point in time. Planned investments are rigorously reviewed and assessed by NS Power as well as stakeholders and ultimately approved by the Board.

4.1.5 Deferred income taxes – FCR and FAM

Mr. Effron also provides testimony with respect to Deferred Taxes on Fixed Cost Recovery (FCR) and Fuel Adjustment Mechanism (FAM) be adjusted. He recommends a net effect reduction of $0.1 million to the revenue requirement.

NS Power has prepared each forecast test year consistent with the approach used in prior years. This involves a true-up of balance sheet items for the forecast preceding the test year. This will result in more timely and accurate beginning balance sheet values for the test year. No separate adjustment is required to the test year.

Mr. Effron further suggests that the deferred tax amounts should be netted with the FAM and FCR balances before calculating interest, though does not propose any adjustment with respect to this issue. NS Power's evidence remains as referenced in its response to CA IR-65. Deferred taxes represent a non-cash asset or liability. The interest is intended to compensate for the financing of cash items. The deferred charge reflects a cash asset. Furthermore, the deferred tax position reverses and reflects only timing differences. The outcome of Mr. Effron's proposed treatment would be a lower FAM and FCR interest recovery and resulting increase to the revenue requirement.

4.1.6 Allowance for Funds Used During Construction (AFUDC)

Mr. Effron applies information from NS Power's response to Larkin IR-25 related to Construction Work in Progress (CWIP) to calculate Allowance for Funds Used During

Construction (AFUDC). This ignores how the AFUDC calculation for the test year is computed. The proposed net reduction in revenue requirement is $4.2 million.

NS Power computes AFUDC within its capital management system, PowerPlant. It calculates AFUDC on an individual project level rather than an aggregate CWIP balance. This is consistent with the approach used to develop depreciation expense. This is further consistent with how NS Power has computed AFUDC in the 2012 GRA and in earlier GRAs. This is the most accurate way to compute AFUDC on a project by project basis.

Mr. Effron's calculations are further flawed as the monthly CWIP balances contain AFUDC and the proposed calculations are further compounding interest monthly and separately semi-annually. NS Power compounds interest for AFUDC on a semi-annual basis only in accordance with its Board approved accounting policy.

NS Power maintains that computing AFUDC within PowerPlant at the project level is appropriate and there is no adjustment required to the revenue requirement.

4.1.7 Deferred Tax Charges

Similar to the adjustments proposed for work force reductions, Mr. Effron is proposing a number of adjustments that transfer savings from prior periods to the test year. The proposed adjustments for Section 21 total $28.1 million. Mr. Effron has completely overlooked the value created by the Section 21 flexible amortizations in managing rates for customers. Mr. Effron has made similar arguments related to the Section 21 regulatory asset in the 2012 and 2009 GRA processes. Mr. Effron also confuses the fact that customers have already received the benefit of these tax amendments in prior years as NS Power did not earn outside of its approved earnings band in recording these benefits. NS Power was also able to avoid seeking a rate increase in certain years by utilizing the carryover mechanism through Section 21 that allowed NS Power the ability to avoid rate increases by utilizing the mechanism and therefore passing the benefits of these amendments back to customers.

Mr. Effron has ignored the general principles of the test year. The test year is the creation of a forecast for a specific period. Mr. Effron has transferred savings from the prior periods to the test year, suggesting savings should be derived. His claim is that the savings derived in 2011 and other years are not in "rates". NS Power maintains that this is retroactive rate making and violates basic regulatory concepts. There is no condition to arbitrarily shift savings from one year to the next. In addition, as noted above, Mr. Effron has failed to acknowledge that NS Power was able to avoid rate increases in those years due to these benefits and the availability of the Section 21 carryover mechanism.

NS Power has included in the test year forecast the amortization expense as previously approved by the Board. The Board directed that recovery would commence in 2007 over an eight year amortization period. NS Power reached settlement with stakeholders on its calculation methodology used for regulated ROE. The agreement gives NS Power flexibility in amortizing the Section 21 regulated asset, allowing the Company to recognize additional amortization amounts in the current period, reducing amounts in future periods. This has provided rate stability for customers. The Board approved the agreement. As part of the 2012 GRA Settlement Agreement, the Board approved a continuation of the agreement to allow NS Power flexibility in using the regulatory asset.

Mr. Effron has confused two separate tax items. The 2011 tax deduction for routine capital projects has nothing to do with the Section 21 tax regulatory asset. To include this as a reduction to the Section 21 asset is incorrect. Similarly, the incremental 2007 income tax refund and M&P tax credit should not be deducted from the Section 21 tax regulatory asset. The Section 21 tax regulatory asset reflects amounts pre-2003 and relate to a specific tax ruling regarding the treatment of capitalized interest. The proposed adjustments reflect retroactive rate making and violate the regulatory principles of a test year.

Mr. Effron argues “inequitable” treatment with the 2011 tax deduction for routine capital projects. NS Power earned within its allowed rate of return in 2011, suggesting appropriate recovery of costs by customers and full equity balance between customers and the Company.

The claim that Section 21 is completely recovered by the end of 2012 is therefore false and ignores basic regulatory principles as well as previously approved Board Orders.

5 CAPITAL STRUCTURE /RETURN ON EQUITY

Two consultants have submitted evidence respecting NS Power's Capital Structure and/or Return on Equity, Laurence Booth, on behalf of Board Counsel, and Lee Smith, on behalf of the SBA. Ms. Smith admits she is not an expert on cost of capital matters. NS Power refers to and relies upon the evidence of its experts, Kathleen McShane and Jim Coyne provided in Appendices D and E.

In the 2012 GRA decision, the UARB set rates based upon a 9.2 percent return on equity and 37.5 percent common equity. NS Power has asked the Board to maintain the 9.2 percent return for rate setting purposes and its common equity ratio of 37.5 percent, even though the evidence of Kathleen McShane filed on May 8 confirmed that these percentages were below industry benchmarks for a utility of comparable risk to NS Power.

At page 1 of his evidence, Dr. Booth states, "I regard NSPI's current common equity ratio of 37.5% for rate setting purposes to be reasonable."[29]

Further, he states:

> NSPI is asking for the continuation of a 9.2% return on equity (ROE) on a 37.5% common equity. I regard this as marginally excessive, but would note that it is not hugely out of line with similar awards elsewhere and that NSPI has refrained from asking for clearly excessive financial metrics.[30]

Despite finding that NS Power has "refrained from asking for clearly excessive financial metrics" and that what NS Power has sought is "not hugely out of line with similar awards elsewhere", he goes on to recommend reducing NS Power's return for rate setting purposes to 7.5 percent in 2013 and 8.5 percent in 2014.

[29] Evidence of Laurence D. Booth, August 2012, page 1, lines 5-6.
[30] Evidence of Laurence D. Booth, August 2012, page 3, lines 17-20.

Lee Smith recommends reducing NS Power's reasonable range for earnings to a band of 9.1 percent to 9.3 percent.

The reply evidence of Ms. McShane and Mr. Coyne provide clear support for NS Power's requested capital structure and refute the conclusions of Dr. Booth and Ms. Smith. NS Power adopts the evidence of Ms. McShane and Mr. Coyne and requests that the Board reject the recommendations of Dr. Booth and Ms. Smith.

6 REVENUE, COSS AND RATES

Intervenor evidence on cost of service related matters was submitted by Mel Whalen on behalf of Board Counsel, and Lee Smith on behalf of the Small Business Advocate. In addition, Halifax Regional Municipality (HRM) and the Union of Nova Scotia Municipalities (UNSM) have submitted evidence specific to issues related to Streetlight ratemaking. In this section, NS Power provides its response to specific items raised by these parties.

Aside from the response provided below, NS Power notes that with respect to Mr. Whalen's suggested wording addition to the Interruptible Rider, we are in agreement with the proposed change.

6.1 Revenue to Cost Ratios of Small Business Customer Classes

Ms. Smith, on behalf of the Small Business Advocate, states that under the NS Power proposed revenue to cost (R/C) ratios, the Small Business classes will pay more relative to cost of service than other rate classes over a long period of time. Ms. Smith states:

> Under this scenario, Small Business Classes will be paying more than the cost of serving them in ten or twenty years.[31]

Ms. Smith recommends that the deferrals be computed for each class based on the cost of service as opposed to the proposed revenues.

NS Power's proposed Rate Stabilization Plan is concerned with setting rates for 2013 and 2014[32] and does not attempt to set base cost rates for the years falling outside of this two test year horizon. The deferred cost estimates by rate classes, provided in Appendix B,

[31] Direct Testimony of Lee Smith, August 4, 2012, page 16, lines 301-303.
[32] Please refer to SBA(NSPI) IR-7.

are for illustrative purposes only. They are not intended to be used for tracking accumulated deferrals by individual rate classes.[33]

Ms. Smith asserts that the COSS over allocates distribution costs to all secondary level customers, including Small Business classes, due to the use of allocation coefficients which have not been updated since the last generic cost of service hearing in 1995.

By the Board's decision on the 2012 GRA, the COSS-related matters, including the updates of the coefficients concerned with sub-functionalization of distribution infrastructure, such as poles and dedicated substations, are to be determined in a generic cost of service hearing scheduled for 2013. These updates will require significant data collection and analysis that are not suitable for a review in a GRA proceeding concerned with cost pressures of revenue requirement. Absent a comprehensive review of all COS coefficients and allocators, not just those advocated by the consultant, the COSS outcome would be incomplete and possibly biased.

If the Board approves the rate stabilization plan, the consultant's concerns about the "over charging" of her clients due to the use of the current COS model will go away. Under the proposed approach, the deferred costs will not be allocated among rate classes and reflected in base cost rates until they are set again at the next GRA. By that time, however, we anticipate that the COSS will reflect the Board's decision on the generic COS hearing.

6.2 COSS Methodology: Classification of Biomass Generation

Mr. Whalen recommends that the biomass rate base be classified on the basis of system load factor and in the same manner as other steam generation assets, such as coal-fired and oil-fired power plants, until the matter is more completely assessed in the upcoming

[33] This is to address the concerns of the Board's consultant, Mel Whalen, expressed on page 17, lines 4 – 7, of his evidence.

review of NS Power's COSS. He bases his recommendation on the fact that the biomass plant is a dispatchable steam plant, which provides capacity service and its operating costs are already classified in a similar manner as those of other steam and hydro plants. Mr. Whalen draws a parallel between the COS treatment of wind and biomass, which he assumes are classified between energy and demand.

Mr. Whalen also observes that NS Power's treatment of wind classification has not been consistent over time. In GRA proceedings, preceding the 2012 GRA, this split stayed at a constant 30 percent / 70 percent split. Starting with the 2012 GRA it has changed to a 16 percent / 84 percent split and in the 2013 GRA it was proposed by NS Power to change to a 2 percent / 98 percent split.

The guidelines for classification of generation investments established in the 1995 generic COS hearing which have evolved through decisions in subsequent GRAs leave some room for interpretation. The Board's decision on the generic COS hearing provided as follows.

> The Board directs that
>
> (i) all generation costs associated with environmental compliance and fuel conversion are to be classified as energy related;
>
> (ii) annual fixed costs associated with steam and hydro generation plant rate base asset are to be classified to energy on the basis of annual system load factor;
>
> (iii) the annual system load factor is to be calculated on the basis of gross energy generation and annual coincident peak including interruptible load
>
> (iv) the remaining costs are to be classified as demand related.
>
> (v) […][34]

[34] COS & Rate Design Generic Hearing Board Order, September 22, 1995.

Since no wind or biomass power plants were present on NS Power's system in 1995 they were not specifically mentioned in the decision. There were no renewable electricity standards (RES) in effect at that time, either.

Wind generation assets added prior to 2005 were classified between demand and energy using 30 percent / 70 percent split. This was documented in NS Power's response to UARB IR-73 in the 2007 GRA.[35] At that time no environmental consideration was given to these projects as these investments were not driven by the RES targets.

The investments in wind generation that came online after 2009 were classified in the COSS of the 2012 GRA up-front as energy-related only, because they were driven by RES targets and were justified as such in the ACE Plans. This approach was documented in NS Power's responses to CA IR-32 and NPB IR-35 from the 2012 GRA proceeding (please refer to Appendix G).

This treatment of RES compliant wind investments explains why the weighted average split of the total wind generation rate base of NS Power between demand and energy started has changed the 2012 GRA. The changing nature of the environmental considerations appear to have been recognized by Mr. Whalen who in his evidence submitted in the 2012 GRA reiterated the Board's 1995 decision as follows.

> The underlying principle is to classify as energy those assets whose acquisition allows NS Power to produce energy more economically (such as the costs of converting units from one fuel to another) and/or enable NS Power to produce energy **in conformance with all environmental targets** (such as the addition of low NOx burners).[36] [Emphasis added]

In its classification decision of the biomass rate base, similar to Mr. Whalen's reasoning, NS Power also drew a parallel with the classification of wind generation investments

[35] Please see Appendix F for details.
[36] GRA 2012 Direct Evidence of Mel Whalen, P.Eng, page 4, lines 14 – 17.

made for RES purposes. Even though the biomass generation, in contrast to wind generation, is dispatchable and as such provides firm capacity to the system, the economic capacity-related aspect of this plant appeared to be of secondary importance to that of RES compliance. The project proceeded mostly on its merits in meeting the RES targets. To classify this asset on the basis of system load factor would mean that there would be no distinction between this primarily RES driven project and ordinary fossil-fuel fired base load generation.

The classification of the operating expenses of all wind and biomass plants is consistent with the classification of their underlying rate bases. The operating costs of steam, hydro, wind, biomass and LM6000 are classified using the same one composite coefficient in COSS, which is already reflective of the weighted averaging effect of their underlying rate bases. Its effect on total classified operating costs is exactly the same as that that would be produced by distinct classifications of operating expenses of individual generation types based on application of simple, as opposed to composite, classifications of their distinct rate bases.

NS Power respectfully submits that its approach to the classification of the biomass rate base and costs as submitted are appropriate.

NS Power estimated the revenue effect of classifying the biomass rate base using system load factor as recommended by Mr. Whalen. The revenue effect of this change is muted by the application of a 95/105 R/C ratio band in the revenue allocation process. Only one class, the unmetered class, whose revenues are set exactly at cost of service, sees a direct $15,000 increase effect of this reclassification. Under the applicable revenue allocation process this $15,000 increase is redistributed as a decrease to all other rate classes producing negligible class revenue impacts.

Figure 6-1

Changes in 2013 test year class revenues due to Biomass reclassification by system load factor

	May 2012 Filing		May 2012 Filing adjusted for re-classifided biomass rate base		Revenue Variance	
Rate Classes	Revenue (in thousands of $'s)	R/C Ratio	Revenue (in thousands of $'s)	R/C Ratio	(in thousands of $'s)	%
Residential	656,557	99.0	656,549	98.8	(8.0)	0.00%
Small General	35,079	104.6	35,078	104.8	(1.0)	0.00%
General	307,787	103.5	307,783	103.6	(4.0)	0.00%
Large General	42,151	98.2	42,150	98.7	(1.0)	0.00%
Small Industrial	31,739	102.6	31,739	102.9	-	0.00%
Medium Industrial	53,486	98.4	53,485	98.8	(1.0)	0.00%
Large Industrial	82,327	95.6	82,326	96.1	(1.0)	0.00%
Municipal	20,394	97.4	20,394	97.4	-	0.00%
Unmetered	24,633	100.0	24,648	100.0	15.0	0.06%

6.3 Embedded Cost Recovery Mechanism (ECRM) under OATT

Mr. Whalen recommends that, given the complexity of the stranded cost issue, the determination of the ECRM matter be excluded from the 2013 GRA and deferred to a stand-alone proceeding. On September 6, 2012, the Board issued its decision in the expedited process to deny NS Power's ability to seek an ECRM from the Municipal Electric Utilities. There is therefore no need for any discussion of the manner in which NS Power proposed to calculate the ECRM.

NS Power understands that Board has not yet made a determination as to whether the MEUs are responsible for their deferred costs if they leave the system. NS Power submits that the MEU's responsibility for any portion of their deferred costs not recovered at the time they may exit the system should continue to be borne by the MEU.

With respect to NS Power's application to update the prices for services offered under NS Power's Open Access Transmission Tariff (OATT), no party has filed any evidence challenging NS Power's proposal. NS Power requests that the OATT pricing be updated, as proposed in its Application.

6.4 Streetlights

NS Power has been clear that the final rates for streetlights including conversion fees should be determined at the time of the capital work order process. This would avoid unnecessary confusion around estimates and allow for better use of resources in both the GRA and the capital work order proceedings.

Despite the fact that there is no application before the Board for conversion fees for streetlights, nor a request for approval of a final determination of the value of the non-LED streetlights which will not be fully depreciated at the time that they are replaced by LED streetlights in accordance with pending regulation, HRM and the UNSM have submitted evidence seemingly requesting the Board to impose a manner of calculating both on NS Power through this General Rate Application.

HRM's and the UNSM's Evidence contain several misconceptions respecting NS Power's accounting for streetlights which require correction as set out below.

The book value of NS Power-owned streetlights has been established and approved through transparent regulatory processes: past rate applications, capital filings and depreciation studies. NS Power has prudently incurred these costs and is entitled to recover its investment from customers who have enjoyed the use of these assets.

Streetlights have been pooled for accounting purposes as in the case with other assets that individually have small dollar values but are collectively material. Again, this method has been practiced and accepted over the course of many years and many rate applications.

While Mr. Dominie's suggestion of using the Handy Whitman index may make sense for estimating original value, it does not correspond with current practice and would not ultimately change the stranded asset fee. The stranded asset fee is the net book value of the asset group divided by the number of streetlights in service to produce an unrecovered amount per streetlight. To assist with understanding why this proposed methodology change does not affect the stranded asset fee the following accounting example is provided.

Current streetlight retirement:

NS Power removes a streetlight and estimates it was installed in 2001. Using the Bank of Canada index, the original value is determined to be $200.

Dr:	Accumulated Depreciation – Street lighting	200	
Cr:	Asset – Street lighting		200

Streetlight retirement during LED conversion:

NS Power removes a streetlight, to install a LED equivalent, and estimates it was installed in 2001. Using the Bank of Canada index, the original value is determined to be $200.

Dr:	Accumulated Depreciation – Street lighting	25	
Dr:	Regulatory Deferral – LED Conversion	175	
Cr:	Asset – Street lighting		200

NS Power removes a streetlight, to install a LED equivalent, and estimates it was installed in 2001. Using the Handy-Whitman index, the original value is determined to be $220.

Dr:	Accumulated Depreciation – Street lighting	45	
Dr:	Regulatory Deferral – LED Conversion	175	
Cr:	Asset – Street lighting		220

Mr. Dominie also suggests that the age of each light be determined based on a date stamp located inside the fixture. Irrespective of the actual age of the light, it is the net book value of the assets that has not been recovered through rates. While his methodology may assist individual municipalities with understanding the age of their respective lights, it does not change the overall value owed to NS Power and would certainly increase costs to track this information.

Previous streetlight rates have been set based on the approved cost of service methodology. NS Power uses depreciation, maintenance, allowed earnings and energy costs to prepare these rates. These items are then allocated using the approved inputs and methodology. This results in NS Power properly recovering expenses (depreciation, maintenance and energy) and earning on the investment as approved.

Based on the regulatory processes and structure of the accounting and rates for streetlights, the assertion that streetlights have somehow already been paid for is unfounded. Until the 2012 GRA, HRM had never raised this concern through cost of service or rate design proceedings, depreciation proceedings, or general rate applications.

The number of streetlights recorded in our Customer Information System, and used for billing purposes, is the best information currently available to NS Power. It is logical to believe that if the numbers were materially different, customers would have contacted NS Power for corrections to their bills. As part of the LED conversion, NS Power will be collecting more detailed street lighting information in the future.

Mr. Dominie suggests in his evidence that there was a 'negotiated settlement' to set the stranded asset value permanently at $12 million. With respect to streetlights, the 2012 Settlement Agreement approved by the Board states:

> 21. Streetlights – rates will be as proposed by NSPI subject to the following adjustments:

a. Parties agree that LEDs will be used for all replacements effective immediately and until UARB approval of the new capital program. The cost of these interim change-outs will be capitalized and parties will support any U&U application that may be necessary to obtain UARB approval of this interim program.

b. Interim rate will be the rate as proposed in NSPI's May 13 filing subject to two changes:

   i. Fixture capital cost will be reduced by 15% from NSPI's original proposal. This reduction in the fixture capital cost will also apply to the January 1, 2012 rates.

   ii. No conversion fees will be charged until the 2012 LED Streetlight rates are in effect.

c. The proposed realignment of rates with costs of the unmetered services of electricity and fixture capital will be introduced in two phases beginning in January 2012. NSPI will submit at the time of 2012 Compliance Filing a set of streetlight rates that will be effective January 1, 2012 that incorporate 50% (in terms of cost impact) of the methodological adjustments. The complete change will be made in the next General Rate Application.

d. **Without prejudice to a later determination of the value of stranded assets**, the parties agree that for the purposes of calculating the 2012 conversion fee, the format in NSPI's Appendix G, Schedule 10 will be used with a year-ending 2011 Net Plant Value of $12 million for rate-making purposes to be recovered over 10 years, rather than $23 million predicated on a 5 year recovery period as is the case under NSPI's Application. As well, the schedule will be amended to include forecast retirements and depreciation over the 10 year period. If the program timeline remains 5 years at the time of final UARB approval of the capital work order for LED Streetlights, parties acknowledge this value for stranded assets is not anticipated to be accurate.

e. NSPI is entitled to full recovery of its prudently incurred non-LED street light asset costs. **At future General Rate Applications, pricing of the energy and capital components of streetlight rates (LED, non-LED and conversion fees) will reflect NSPI's actual experience. NSPI will monitor the recovery of its stranded costs and is entitled to seek regulatory approval of changes to streetlight rates and conversion fees to ensure that all of its costs are recovered.**

Clearly, the intent of the inclusion of the bolded wording above in subsections d and e was to agree that $12 million was **not** the final value of the streetlights.

Mr. Boyle in his testimony on behalf of HRM alleges that NS Power 'abandoned' the settlement agreement. We have not. NS Power has proceeded cautiously with LED streetlights installation for two reasons. First, the regulations requiring conversion have not yet been enacted. Second, as is apparent from the UNSM and HRM evidence, there has been concern about proceeding with the conversion. NS Power has been proceeding cautiously with the program in attempting to find an approach supported by stakeholders.

Mr. Boyle also states, "Since the signing of the Settlement Agreement the original Schedule 10 has disappeared. HRM made submissions to the Board during the Compliance Filing stage on this issue."[37] Some content may be helpful in considering his evidence. Following the Board's Compliance Order, wherein it declined to reflect HRM's request that NS Power be urged to file a revised Schedule 10, which is the schedule calculating conversion fees, in NS Power's 2012 GRA application, HRM appealed the Board's Order to the Nova Scotia Court of Appeal. Specifically, HRM complained that the Board erred in failing to provide a calculation of revised conversion fees.[38] On June 21, 2012, HRM filed a Notice of Discontinuance with the Court of Appeal, wholly discontinuing all aspects of its appeal. It is completely improper to now come back before this Board to complain that Schedule 10 'disappeared' when the Board considered HRM's submission, rejected HRM's submission, and HRM subsequently withdrew its appeal of that Board Decision.

NS Power's approach with regards to calculating a stranded asset pool is simple and has not changed. That is, the net book value of the assets is the unrecovered investment. To determine per unit value, NS Power has proposed dividing the asset pool by the number of lights billed in the Customer Information System. NS Power has repeatedly stated through the 2013 & 2014 GRA application that the rates should be set with the capital work order process consistent with the 2012 Settlement Agreement. In an effort to be

[37] Direct Testimony of Julian Boyle, August 7, 2012, page 11, lines 23-25.
[38] HRM Amended Notice of Appeal, February 9, 2012.

helpful, NS Power has provided information over the last couple of years. In fact, draft regulations were only issued April 25th, 2012.

Despite our efforts to be helpful and request that the final stranded asset be dealt with when all information is available, Mr. Dominie has concluded that NS Power is hedging and making retroactive correction efforts. Ms. MacDonald also asserts that NS Power of being inconsistent. The letters attached to her testimony do not demonstrate that. They show a consistent approach evolving over a period of time. The August 27, 2010 letter was issued as part of an early pilot project. A letter issued to all municipalities on April, 2012 was omitted from Ms. MacDonald’s evidence and is attached for the Board’s information as Appendix H.

NS Power has worked with customers to understand their concerns and needs. We agree with Mr. Boyle’s suggestion to continue to work together through a technical working group.

In conclusion, NS Power maintains that the rates, including the conversion fees, should be determined during the capital work order process, and that the rates and fees should be expected to adjust over time as costs and knowledge are updated. As per testimony at the 2012 ACE Plan Hearing, NS Power will file the application associated with conversion once final regulations are approved.

7 LOW INCOME CONSIDERATIONS

Four organizations submitted evidence in support of the Affordable Energy Coalition: Dalhousie Legal Aid, North End Community Health Centre, Society of Saint Vincent de Paul and Parker Street Food Bank.

Each of the groups provided helpful feedback on the experiences of low income customers. For families on social assistance or limited incomes who are already paying more for things like gasoline and groceries, power rate increases are a genuine burden. The key concerns raised by the groups related to fees, connection and disconnection of power, repayment plans and points of contact for addressing concerns of this type. We share the concerns articulated and acknowledge the challenges that low income customers face in working with the utility and numerous social service agencies to secure and maintain their electricity accounts in good standing.

The issues raised were also tabled at a July 10 meeting held at NS Power to initiate action on the concerns of low-income advocacy groups. This meeting was attended by the four parties that have submitted evidence as well as a number of other representatives of Government and social agencies. NS Power is optimistic that this forum will serve to allow us to work collaboratively with interested parties to make amendments in process and structure with a vision to enhance customer service rules for low-income electricity customers that are transparent, fair and effective for all customers. A follow-up meeting is scheduled for October 26th. Subsequent meetings will be held as necessary to work through the issues and concerns. We believe working together as a group will be fruitful in identifying new approaches that can be adapted under existing regulations.

Based on the comments and suggestions tabled at the July 10 meeting, NS Power is proceeding to make the following changes in its processes:

1. Creation of the Role of a Low-income Advocate within NS Power Customer Care

The creation of a permanent role dedicated to Low-income advocacy account management with newly established guidelines and clear ability to work with both the Agencies and the actual customers in new and improved ways has occurred and is now available to our customers.

2. Development of a new Low-income Customer Charter

Education and communication are essential to a successful relationship between the customer and the utility and the various support agencies that assist low-income residents on a daily basis. New customers would receive information to better understand their energy consumption, their bill and programs available to them, including programs to conserve energy. A "customer charter" would also include general policy highlights, links, our responsibilities, and expectations and their responsibility around payments including contact information for resources and case management at the utility. A project team has been assigned to implement this and a mock up design will be shared for input with the Low Income Advocacy Committee at the October 26th meeting.

3. Reform of Security deposits and Settlement Agreement terms of repayment

We have identified the ability to extend repayment options beyond today's current practise of 3 - 12 months for customers who require longer terms. We are also implementing greater flexibility in terms for collecting security deposits. We are moving forward with internal process review and redesign in 2012 and will also incorporate feedback on design from the low income advocacy workgroups.

This will also include a change to customers who return as new customers with a past closed balance by allowing them to connect with repayment terms versus "balance in full" as a prerequisite. These process changes will be in place by September 10, 2012 as part of standard customer service processes.

4. Identification of potential regulatory or statutory reforms

Work has begun to identify and benchmark programs and approaches offered across other Canadian Utilities and the United States. Alternative proposals for regulatory reform in Nova Scotia will be documented and brought to the October 29th meeting.

References were made in the evidence of certain low income advocates of winter-time disconnections. Figure 7-1 provides the 2011-2012 monthly summary of Residential Disconnections for reference. This data is also provided from NS Power's response to AEC IR-10.

Figure 7-1

Month	Number of Residential Disconnections
Jan-11	0
Feb-11	0
Mar-11	0
Apr-11	66
May-11	341
Jun-11	216
Jul-11	277
Aug-11	270
Sep-11	337
Oct-11	221
Nov-11	175
Dec-11	71
Jan-12	0
Feb-12	0
Mar-12	0
Apr-12	84
May-12	168

8 CONCLUSION

At the time of filing its Application, NS Power proposed a Rate Stabilization Plan to provide customers with time to adjust to the changing landscape of electricity customers in Nova Scotia, while needing to make important investments in the system to achieve a better electricity future - lower emissions, green energy, better reliability and freedom from volatile world coal markets.

With continued loss of load, with the loss of Bowater just one month after NS Power's filing, NS Power believes now more than ever that a Rate Stabilization Plan is the best option for customers.

NS Power seeks an order, effective January 1, 2013, approving:

- The 2013 and 2014 revenue requirements set out in this Evidence to enable NS Power to recover the reasonable costs of providing service to customers and to meet its financial obligations.

- The Rate Stabilization Plan, which provides for the recovery of the 2013 and 2014 revenue requirements as follows:

  - For each customer class, an average 3 percent increase on January 1, 2013 and an average 3 percent increase on January 1, 2014, after factoring in the 2010 FAM deferral reductions in 2013 and 2014,

  - Deferral of any portion of the Board approved revenue requirement not recovered by the average 3 percent annual increases. Effectively, this will continue the 2012 Fixed Cost Recovery deferral, which will continue to grow until the end of 2014, with recovery of the deferral over an 8 year period beginning in 2015,

- FAM adjustments, other than for the 2010 FAM deferral reductions and the 2011 FAM imbalance both of which are reflected in the 2013 FAM Balance Adjustment, will be deferred, to be incorporated into customer rates beginning in 2015

- The FAM incentive will remain suspended until the end of 2014.

The rates, charges and regulations requested in this Application.

- Changes to the Large Industrial Interruptible Rider and Load Retention Tariff Pricing Mechanism, as described in this Application.

- A change to Accounting Policy 5900 – Tax, to allow for the accounting of fixed cost recovery deferrals on a deferred tax basis, in order to align tax expense with the deferral recovery period.

- A change in the Open Access Transmission Tariff (OATT) rates to reflect updated pricing as described in the Application.

- Adjustments to the rates, charges, or regulations as needed to reflect decisions and directives in NS Power related proceedings or as the Board may determine in response to this Application.

- A return on common equity range held at the current 9.1 percent to 9.5 percent.

- In the alternative to the Rate Stabilization Plan, recovery of the 2013 and 2014 revenue requirement using traditional rate-setting methodology as provided in the rates, charges and regulations contained in this Application.

Changes in the total Revenue Requirements

Absent the rate stabilization plan, our May application forecasted total revenue at present rates of $1,192.6[1] million in 2013 and $1,320.4 million in 2014 (priced at rates proposed for 2013). Based largely on the Bowater shutdown, we have reduced our forecast revenue at present rates to $1,136.9 million (2013) and $1,266.7 million (2014). Comparing these new forecasts to the updated 2013 and 2014 revenue requirements ($1,269.7 million and $1,325.1 million), leaves a shortfall of $132.8 million in 2013 and $58.4 million in 2014.

These amounts include some revenue related to the LED streetlight replacement program. We account for this revenue — $2.0 million in 2013 and $4.3 million in 2014 — as a *below the line* item, which means it will not affect general rates, but will be allocated to specific users according to a Board-approved formula. After adjusting for these amounts, the shortfall applicable to above-the-line and Miscellaneous Service Rates is $132.4 million in 2013 and $58.3 million in 2014 (Above-the-line rates are those intended to recover NS Power's revenue requirement according to cost-of-service principles, in which the rates paid by each class of customer is intended to recover the cost of servicing that customer class).

Revenue Responsibilities Allocated to Above the Line Classes and Miscellaneous Revenues

The following tables show the process NS Power used to allocate revenue responsibilities among various customer classes and business services for 2013 and 2014. NS Power provides these calculations for illustrative purposes only, to show what the revenue responsibility for each class would be if the rate stabilization plan was not proposed.

[1] The figure of $1,192.6 million is arrived at by subtracting the forecasted FAM BA revenue of $29.2 million for 2013 from the total revenues of $1,221.8 (present rates) displayed in the financial table FOR-01.

2013 Results (before rate stabilization plan)

Figure 1 presents 2013 revenue-to-cost ratios for customer classes resulting from the proposed revenue increases. Revenue-to-cost ratios for all rate classes fall within the prescribed 95 – 105 percent band. All classes except unmetered and small general see a uniform increase of 11.9 percent.

Figure 1

	R/C Ratio	% Revenue Increase	Proposed Revenue
ABOVE-THE-LINE CLASSES			
Residential	**98.7%**	**11.9%**	**$650.9**
Commercial			
Small General	105.0%	11.8%	$36.2
General Demand	103.5%	11.9%	$310.1
Large General	98.3%	11.9%	$42.0
Total Commercial	**103.1%**	**11.9%**	**$388.2**
Industrial			
Small Industrial	102.7%	11.9%	$31.4
Medium Industrial	98.9%	11.9%	$53.0
Large Industrial	96.6%	11.9%	$74.4
ELI 2P-RTP	N/A	N/A	N/A
Total Industrial	**98.6%**	**11.9%**	**$158.8**
Other			
Municipal	97.3%	11.9%	$20.4
Unmetered	100.0%	10.7%	$24.7
Total Other	**98.8%**	**11.2%**	**$45.1**
Total Above-the-line classes	**100.0%**	**11.9%**	**$1,243.0**
BTL (Electric Services)		**0.0%**	**$0.9**
Exports		**0.0%**	**$1.1**
LED SL Capital-related Costs		**25.4%**	**$2.0**
Miscellaneous		**2.9%**	**$22.6**
Total Revenue		**11.7%**	**$1,269.7**
Revenue Requirement			**$1,269.7**
Revenue Shortfall/Surplus			**$0.0**

2014 Results (before rate stabilization plan)

Figure 2 presents revenue-to-cost ratios for customer classes resulting from the proposed revenue increases. Revenue-to-cost ratios for all rate classes fall within the prescribed 95 – 105 percent band. All classes except unmetered see a uniform increase of 4.7 percent.

Figure 2

	R/C Ratio	% Revenue Increase	Proposed Revenue
ABOVE-THE-LINE CLASSES			
Residential	**99.0%**	**4.7%**	**$681.6**
Commercial			
Small General	104.6%	4.7%	$37.6
General Demand	102.8%	4.7%	$322.4
Large General	99.0%	4.7%	$42.9
Total Commercial	**102.5%**	**4.7%**	**$402.9**
Industrial			
Small Industrial	102.2%	4.7%	$33.0
Medium Industrial	98.1%	4.7%	$55.7
Large Industrial	97.0%	4.7%	$75.9
ELI 2P-RTP	N/A	N/A	N/A
Total Industrial	**98.4%**	**4.7%**	**$164.6**
Other			
Municipal	97.7%	4.7%	$21.5
Unmetered	100.0%	3.6%	$24.0
Total Other	**98.9%**	**4.1%**	**$45.5**
Total Above-the-line classes	**100.0%**	**4.7%**	**$1,294.5**
BTL (Electric Services)		**0.0%**	**$0.9**
Exports		**0.0%**	**$1.8**
LED SL Capital-related Costs		**N/A**	**$4.3**
Miscellaneous		**1.3%**	**$23.5**
Total Revenue		**4.6%**	**$1,325.1**
Revenue Requirement			**$1,325.1**
Revenue Shortfall/Surplus			**$0.0**

2013 REVENUE INCREASE ANALYSIS

#	Rate Classes	2013 Sales (GWh's)	2013 Revenue at current rates before cost adjustment clauses	2012 FAM AA	2012 FAM BA	Revenue at current rates including 2012 AA/BA	Proposed Revenues 2013 Before Riders			AA Component				BA Component				2013 Revenue reflective of all FAM components		
2	Columns	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
3							Amount	Increase	Increase (%) over Total Cost of Power	2012 Amount	2013 Amount	Variance	Increase (%) over Total Cost of Power	2012 Amount	2013 Amount	Variance	Increase (%) over Total Cost of Power	Amount	Variance	Increase (%) over Total Cost of Power
4	ATL																			
5	Residential	4,217.7	$581,789,060	$15,729,855	$13,940,592	$611,459,507	$650,914,302	$69,125,243	11.3%	$15,729,855	$0	($15,729,855)	-2.6%	$13,940,592	$12,361,491	($1,579,101)	-0.3%	$663,275,793	$51,816,286	8.5%
6																				
7	Small General	238.5	$32,321,560	$836,570	$784,960	$33,943,090	$36,151,031	$3,829,471	11.3%	$836,570	$0	($836,570)	-2.5%	$784,960	$694,608	($90,352)	-0.3%	$36,845,639	$2,902,549	8.6%
8	General Demand	2,449.1	$277,150,958	$9,236,101	$9,197,989	$295,585,048	$310,080,637	$32,929,679	11.1%	$9,236,101	$0	($9,236,101)	-3.1%	$9,197,989	$8,005,363	($1,192,626)	-0.4%	$318,086,000	$22,500,953	7.6%
9	Large General	392.1	$37,502,895	$1,348,850	$1,443,410	$40,295,154	$41,958,800	$4,455,905	11.1%	$1,348,850	$0	($1,348,850)	-3.3%	$1,443,410	$1,408,440	($34,970)	-0.1%	$43,367,240	$3,072,086	7.6%
10	Total Commercial	3,079.7	$346,975,412	$11,421,520	$11,426,359	$369,823,292	$388,190,468	$41,215,055	11.1%	$11,421,520	$0	($11,421,520)	-3.1%	$11,426,359	$10,108,411	($1,317,948)	-0.4%	$398,298,879	$28,475,587	7.7%
11																		$0		
12	Small Industrial	253.8	$28,101,854	$834,757	$876,178	$29,812,789	$31,440,775	$3,338,921	11.2%	$834,757	$0	($834,757)	-2.8%	$876,178	$878,181	$2,003	0.0%	$32,318,956	$2,506,167	8.4%
13	Medium Industrial	489.8	$47,379,153	$1,569,891	$1,659,488	$50,608,533	$53,008,506	$5,629,352	11.1%	$1,569,891	$0	($1,569,891)	-3.1%	$1,659,488	$1,645,795	($13,693)	0.0%	$54,654,301	$4,045,768	8.0%
14	*Large Industrial - Firm*	*163.8*	*$13,819,275*	*$721,583*	*$796,880*	*$15,337,738*	*$15,334,422*	*$1,515,147*	*9.9%*	*$721,583*	*$0*	*($721,583)*	*-4.7%*	*$796,880*	*$784,030*	*($12,850)*	*-0.1%*	*$16,118,453*	*$780,714*	*5.1%*
15	*Large Industrial - Interruptible*	*656.0*	*$52,640,800*	*$2,153,715*	*$2,378,457*	*$57,172,972*	*$59,022,104*	*$6,381,304*	*11.2%*	*$2,153,715*	*$0*	*($2,153,715)*	*-3.8%*	*$2,378,457*	*$2,429,209*	*$50,752*	*0.1%*	*$61,451,313*	*$4,278,341*	*7.5%*
16	Total Large Industrial	819.8	$66,460,075	$2,875,298	$3,175,337	$72,510,710	$74,356,526	$7,896,451	10.9%	$2,875,298	$0	($2,875,298)	-4.0%	$3,175,337	$3,213,239	$37,903	0.1%	$77,569,766	$5,059,056	7.0%
17	ELI_2PT - RTP*	0.0	$0	$0	$0	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	N/A
18	Total Industrial	1,563.4	$141,941,083	$5,279,946	$5,711,003	$152,932,031	$158,805,806	$16,864,724	11.0%	$5,279,946	$0	($5,279,946)	-3.5%	$5,711,003	$5,737,216	$26,213	0.0%	$164,543,022	$11,610,991	7.6%
19																				
20	Municipal	191.9	$18,237,345	$665,963	$716,472	$19,619,779	$20,404,214	$2,166,869	11.0%	$665,963	$0	($665,963)	-3.4%	$716,472	$542,571	($173,901)	-0.9%	$20,946,785	$1,327,006	6.8%
21	Unmetered	104.4	$22,338,108	$365,351	$422,941	$23,126,401	$24,721,463	$2,383,355	10.3%	$365,351	$0	($365,351)	-1.6%	$422,941	$427,344	$4,403	0.0%	$25,148,807	$2,022,407	8.7%
22	Total Other	296.3	$40,575,453	$1,031,314	$1,139,413	$42,746,179	$45,125,677	$4,550,225	10.6%	$1,031,314	$0	($1,031,314)	-2.4%	$1,139,413	$969,915	($169,498)	-0.4%	$46,095,592	$3,349,413	7.8%
23																				
24	Total ATL Classes	9,157.1	$1,111,281,008	$33,462,635	$32,217,367	$1,176,961,010	$1,243,036,254	$131,755,246	11.2%	$33,462,635	$0	($33,462,635)	-2.8%	$32,217,367	$29,177,033	($3,040,334)	-0.3%	$1,272,213,287	$95,252,277	8.1%
25																				
26	BTL (Electric)																			
27	GRLF	18.8	$918,137	$0	$0	$918,137	$918,137	$0	0.0%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$918,137	$0	0.0%
28	Mersey Additional Energy[1]		$0	$0	$0	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	N/A
	LRT[1]		$0	$0	$0	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	N/A
29	Bowater Mersey[1]		$0	$0	$0	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	N/A
30	Total BTL (Electric) Classes	18.8	$918,137	$0	$0	$918,137	$918,137	$0	0.0%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$918,137	$0	0.0%
31																				
32	LED SL Capital Costs		$1,565,170	$0	$0	$1,565,170	$1,962,839	$397,669	25.4%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$1,962,839	$397,669	25.4%
33																				
34																				
35	In Province Total	9,175.9	$1,113,764,315	$33,462,635	$32,217,367	$1,179,444,317	$1,245,917,230	$132,152,915	11.2%	$33,462,635	$0	($33,462,635)	-2.8%	$32,217,367	$29,177,033	($3,040,334)	-0.3%	$1,275,094,263	$95,649,946	8.1%
36																				
37	Export	16.9	$1,144,317	$0	$0	$1,144,317	$1,144,317	$0	0.0%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$1,144,317	$0	0.0%
38																				
39	Total Electric Sales	9,192.8	$1,114,908,632	$33,462,635	$32,217,367	$1,180,588,634	$1,247,061,547	$132,152,915	11.2%	$33,462,635	$0	($33,462,635)	-2.8%	$32,217,367	$29,177,033	($3,040,334)	-0.3%	$1,276,238,580	$95,649,946	8.1%
40																				
41	Misc Revenue	686.6	$21,959,249	$0	$0	$21,959,249	$22,601,883	$642,635	2.9%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$22,601,883	$642,635	2.9%
42																				
43	Grand Total	9,879.3	$1,136,867,880	$33,462,635	$32,217,367	$1,202,547,883	$1,269,663,430	$132,795,550	11.0%	$33,462,635	$0	($33,462,635)	-2.8%	$32,217,367	$29,177,033	($3,040,334)	-0.3%	$1,298,840,463	$96,292,580	8.0%
44																				
45																				

46 (1) 2012 FAM AA/BA have been excluded due to closure of mills

2013 REVENUE INCREASE ANALYSIS - RATE STABILIZATION

Line	Rate Classes	2013 Sales (GWh's)	2013 Revenue at current rates before cost adjustment clauses	2012 FAM AA	2012 FAM BA	Revenue at current rates including 2012 AA/BA	Proposed Revenues 2013 Before Riders and with Rate Stabilization			AA Component				BA Component				2013 Revenue reflective of all FAM components		
2	Columns	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
3							Amount	Increase	Increase (%) over Total Cost of Power	2012 Amount	2013 Amount	Variance	Increase (%) over Total Cost of Power	2012 Amount	2013 Amount	Variance	Increase (%) over Total Cost of Power	Amount	Variance	Increase (%) over Total Cost of Power
4	**ATL**																			
5	**Residential**	**4,217.7**	**$581,789,060**	**$15,729,855**	**$13,940,592**	**$611,459,507**	**$617,709,035**	**$35,919,975**	**5.9%**	**$15,729,855**	**$0**	**($15,729,855)**	**-2.6%**	**$13,940,592**	**$12,361,491**	**($1,579,101)**	**-0.3%**	**$630,070,526**	**$18,611,018**	**3.0%**
7	Small General	238.5	$32,321,560	$836,570	$784,960	$33,943,090	$34,266,775	$1,945,215	5.7%	$836,570	$0	($836,570)	-2.5%	$784,960	$694,608	($90,352)	-0.3%	$34,961,382	$1,018,293	3.0%
8	General Demand	2,449.1	$277,150,958	$9,236,101	$9,197,989	$295,585,048	$296,463,021	$19,312,063	6.5%	$9,236,101	$0	($9,236,101)	-3.1%	$9,197,989	$8,005,363	($1,192,626)	-0.4%	$304,468,383	$8,883,336	3.0%
9	Large General	392.1	$37,502,895	$1,348,850	$1,443,410	$40,295,154	$40,099,674	$2,596,780	6.4%	$1,348,850	$0	($1,348,850)	-3.3%	$1,443,410	$1,408,440	($34,970)	-0.1%	$41,508,115	$1,212,960	3.0%
10	**Total Commercial**	**3,079.7**	**$346,975,412**	**$11,421,520**	**$11,426,359**	**$369,823,292**	**$370,829,470**	**$23,854,057**	**6.5%**	**$11,421,520**	**$0**	**($11,421,520)**	**-3.1%**	**$11,426,359**	**$10,108,411**	**($1,317,948)**	**-0.4%**	**$380,937,881**	**$11,114,589**	**3.0%**
12	Small Industrial	253.8	$28,101,854	$834,757	$876,178	$29,812,789	$29,833,963	$1,732,109	5.8%	$834,757	$0	($834,757)	-2.8%	$876,178	$878,181	$2,003	0.0%	$30,712,144	$899,355	3.0%
13	Medium Industrial	489.8	$47,379,153	$1,569,891	$1,659,488	$50,608,533	$50,480,302	$3,101,148	6.1%	$1,569,891	$0	($1,569,891)	-3.1%	$1,659,488	$1,645,795	($13,693)	0.0%	$52,126,097	$1,517,565	3.0%
14	*Large Industrial - Firm*	163.8	*$13,819,275*	*$721,583*	*$796,880*	*$15,337,738*	$14,871,946	*$1,052,671*	*6.9%*	*$721,583*	*$0*	*($721,583)*	*-4.7%*	*$796,880*	*$784,030*	*($12,850)*	*-0.1%*	*$15,655,976*	*$318,238*	*2.1%*
15	*Large Industrial - Interruptible*	656.0	*$52,640,800*	*$2,153,715*	*$2,378,457*	*$57,172,972*	$56,600,846	*$3,960,046*	*6.9%*	*$2,153,715*	*$0*	*($2,153,715)*	*-3.8%*	*$2,378,457*	*$2,429,209*	*$50,752*	*0.1%*	*$59,030,055*	*$1,857,083*	*3.2%*
16	Total Large Industrial	819.8	$66,460,075	$2,875,298	$3,175,337	$72,510,710	$71,472,792	$5,012,717	6.9%	$2,875,298	$0	($2,875,298)	-4.0%	$3,175,337	$3,213,239	$37,903	0.1%	$74,686,031	$2,175,321	3.0%
17	ELI 2PT - RTP*	0.0	$0	$0	$0	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	N/A
18	**Total Industrial**	**1,563.4**	**$141,941,083**	**$5,279,946**	**$5,711,003**	**$152,932,031**	**$151,787,057**	**$9,845,974**	**6.4%**	**$5,279,946**	**$0**	**($5,279,946)**	**-3.5%**	**$5,711,003**	**$5,737,216**	**$26,213**	**0.0%**	**$157,524,273**	**$4,592,241**	**3.0%**
20	Municipal	191.9	$18,237,345	$665,963	$716,472	$19,619,779	$19,660,270	$1,422,925	7.3%	$665,963	$0	($665,963)	-3.4%	$716,472	$542,571	($173,901)	-0.9%	$20,202,841	$583,062	3.0%
21	Unmetered	104.4	$22,338,108	$365,351	$422,941	$23,126,401	$23,381,286	$1,043,178	4.5%	$365,351	$0	($365,351)	-1.6%	$422,941	$427,344	$4,403	0.0%	$23,808,629	$682,229	3.0%
22	**Total Other**	**296.3**	**$40,575,453**	**$1,031,314**	**$1,139,413**	**$42,746,179**	**$43,041,555**	**$2,466,103**	**5.8%**	**$1,031,314**	**$0**	**($1,031,314)**	**-2.4%**	**$1,139,413**	**$969,915**	**($169,498)**	**-0.4%**	**$44,011,470**	**$1,265,291**	**3.0%**
24	**Total ATL Classes**	**9,157.1**	**$1,111,281,008**	**$33,462,635**	**$32,217,367**	**$1,176,961,010**	**$1,183,367,116**	**$72,086,109**	**6.1%**	**$33,462,635**	**$0**	**($33,462,635)**	**-2.8%**	**$32,217,367**	**$29,177,033**	**($3,040,334)**	**-0.3%**	**$1,212,544,149**	**$35,583,139**	**3.0%**
26	**BTL (Electric)**																			
27	GRLF	18.8	$918,137	$0	$0	$918,137	$918,137	$0	0.0%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$918,137	$0	0.0%
28	Mersey Additional Energy		$0	$0	$0	$0	$0	$0	0.0%	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	N/A
	LRT		$0	$0	$0	$0	$0	$0	0.0%	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	N/A
29	Bowater Mersey		$0	$0	$0	$0	$0	$0	0.0%	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	N/A
30	**Total BTL (Electric) Classes**	**18.8**	**$918,137**	**$0**	**$0**	**$918,137**	**$918,137**	**$0**	**0.0%**	**$0**	**$0**	**$0**	**0.0%**	**$0**	**$0**	**$0**	**0.0%**	**$918,137**	**$0**	**0.0%**
32	LED SL Capital Costs**		$1,565,170	$0	$0	$1,565,170	$1,612,125	$46,955	3.0%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$1,612,125	$46,955	3.0%
35	**In Province Total**	**9,175.9**	**$1,113,764,315**	**$33,462,635**	**$32,217,367**	**$1,179,444,317**	**$1,185,897,378**	**$72,133,064**	**6.1%**	**$33,462,635**	**$0**	**($33,462,635)**	**-2.8%**	**$32,217,367**	**$29,177,033**	**($3,040,334)**	**-0.3%**	**$1,215,074,411**	**$35,630,094**	**3.0%**
37	Export	16.9	$1,144,317	$0	$0	$1,144,317	$1,144,317	$0	0.0%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$1,144,317	$0	0.0%
39	**Total Electric Sales**	**9,192.8**	**$1,114,908,632**	**$33,462,635**	**$32,217,367**	**$1,180,588,634**	**$1,187,041,695**	**$72,133,064**	**6.1%**	**$33,462,635**	**$0**	**($33,462,635)**	**-2.8%**	**$32,217,367**	**$29,177,033**	**($3,040,334)**	**-0.3%**	**$1,216,218,728**	**$35,630,094**	**3.0%**
41	Misc Revenue	686.6	$21,959,249	$0	$0	$21,959,249	$22,315,097	$355,849	1.6%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$22,315,097	$355,849	1.6%
43	**Grand Total**	**9,879.3**	**$1,136,867,880**	**$33,462,635**	**$32,217,367**	**$1,202,547,883**	**$1,209,356,793**	**$72,488,912**	**6.0%**	**$33,462,635**	**$0**	**($33,462,635)**	**-2.8%**	**$32,217,367**	**$29,177,033**	**($3,040,334)**	**-0.3%**	**$1,238,533,825**	**$35,985,943**	**3.0%**

46 * The 2012 FAM AA/BA Figures have been adjusted to reflect the 2013 LRT Load

47 **LED Capital Costs will be updated at the time of the capital work order

2014 REVENUE INCREASE ANALYSIS

#	Rate Classes	2014 Sales (GWh's)	2014 Revenue at current rates before cost adjustment clauses	2013 FAM AA	2013 FAM BA	Revenue at current rates including 2013 BA	Proposed Revenues 2014 Before Riders			AA Component				BA Component				2014 Revenue reflective of all FAM components		
2	Columns	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
3							Amount	Increase	Increase (%) over Total Cost of Power	2013 Amount	2014 Amount	Variance	Increase (%) over Total Cost of Power	2013 Amount	2014 Amount	Variance	Increase (%) over Total Cost of Power	Amount	Variance	Increase (%) over Total Cost of Power
4	**ATL**																			
5	**Residential**	**4,216.5**	**$650,872,515**	**$0**	**$12,361,491**	**$663,234,006**	**$681,556,251**	**$30,683,736**	**4.6%**	**$0**	**$0**	**$0**	**0.0%**	**$12,361,491**	**$0**	**($12,361,491)**	**-1.9%**	**$681,556,251**	**$18,322,245**	**2.8%**
7	Small General	236.7	$35,886,158	$0	$694,608	$36,580,766	$37,577,920	$1,691,762	4.6%	$0	$0	$0	0.0%	$694,608	$0	($694,608)	-1.9%	$37,577,920	$997,154	2.7%
8	General Demand	2,448.7	$307,920,637	$0	$8,005,363	$315,925,999	$322,436,775	$14,516,138	4.6%	$0	$0	$0	0.0%	$8,005,363	$0	($8,005,363)	-2.5%	$322,436,775	$6,510,776	2.1%
9	Large General	379.6	$40,983,881	$0	$1,408,440	$42,392,321	$42,915,962	$1,932,081	4.6%	$0	$0	$0	0.0%	$1,408,440	$0	($1,408,440)	-3.3%	$42,915,962	$523,641	1.2%
10	**Total Commercial**	**3,065.0**	**$384,790,675**	**$0**	**$10,108,411**	**$394,899,086**	**$402,930,657**	**$18,139,982**	**4.6%**	**$0**	**$0**	**$0**	**0.0%**	**$10,108,411**	**$0**	**($10,108,411)**	**-2.6%**	**$402,930,657**	**$8,031,570**	**2.0%**
12	Small Industrial	255.9	$31,474,632	$0	$878,181	$32,352,813	$32,958,424	$1,483,792	4.6%	$0	$0	$0	0.0%	$878,181	$0	($878,181)	-2.7%	$32,958,424	$605,611	1.9%
13	Medium Industrial	495.4	$53,239,162	$0	$1,645,795	$54,884,958	$55,748,988	$2,509,825	4.6%	$0	$0	$0	0.0%	$1,645,795	$0	($1,645,795)	-3.0%	$55,748,988	$864,030	1.6%
14	*Large Industrial - Firm*	*142.0*	*$13,798,380*	*$0*	*$784,030*	*$14,582,411*	*$14,402,647*	*$604,267*	*4.1%*	*$0*	*$0*	*$0*	*0.0%*	*$784,030*	*$0*	*($784,030)*	*-5.4%*	*$14,402,647*	*($179,763)*	*-1.2%*
15	*Large Industrial - Interruptible*	*650.8*	*$58,677,743*	*$0*	*$2,429,209*	*$61,106,952*	*$61,490,180*	*$2,812,437*	*4.6%*	*$0*	*$0*	*$0*	*0.0%*	*$2,429,209*	*$0*	*($2,429,209)*	*-4.0%*	*$61,490,180*	*$383,228*	*0.6%*
16	Total Large Industrial	792.8	$72,476,123	$0	$3,213,239	$75,689,363	$75,892,827	$3,416,704	4.5%	$0	$0	$0	0.0%	$3,213,239	$0	($3,213,239)	-4.2%	$75,892,827	$203,464	0.3%
17	ELI_2PT - RTP*	0.0	$0	$0	$0	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	N/A
18	**Total Industrial**	**1,544.1**	**$157,189,917**	**$0**	**$5,737,216**	**$162,927,134**	**$164,600,238**	**$7,410,321**	**4.5%**	**$0**	**$0**	**$0**	**0.0%**	**$5,737,216**	**$0**	**($5,737,216)**	**-3.5%**	**$164,600,238**	**$1,673,105**	**1.0%**
20	Municipal	192.3	$20,490,650	$0	$542,571	$21,033,220	$21,456,629	$965,980	4.6%	$0	$0	$0	0.0%	$542,571	$0	($542,571)	-2.6%	$21,456,629	$423,409	2.0%
21	Unmetered	98.2	$23,164,445	$0	$427,344	$23,591,789	$23,997,420	$832,975	3.5%	$0	$0	$0	0.0%	$427,344	$0	($427,344)	-1.8%	$23,997,420	$405,631	1.7%
22	**Total Other**	**290.6**	**$43,655,095**	**$0**	**$969,915**	**$44,625,009**	**$45,454,049**	**$1,798,955**	**4.0%**	**$0**	**$0**	**$0**	**0.0%**	**$969,915**	**$0**	**($969,915)**	**-2.2%**	**$45,454,049**	**$829,040**	**1.9%**
24	**Total ATL Classes**	**9,116.2**	**$1,236,508,202**	**$0**	**$29,177,033**	**$1,265,685,235**	**$1,294,541,195**	**$58,032,993**	**4.6%**	**$0**	**$0**	**$0**	**0.0%**	**$29,177,033**	**$0**	**($29,177,033)**	**-2.3%**	**$1,294,541,195**	**$28,855,960**	**2.3%**
26	**BTL (Electric)**																			
27	GRLF	18.8	$932,982	$0	$0	$932,982	$932,982	$0	0.0%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$932,982	$0	0.0%
28	Mersey Additional Energy		$0	$0	$0	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	N/A
	LRT		$0	$0	$0	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	N/A
29	Bowater Mersey		$0	$0	$0	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	N/A
30	**Total BTL (Electric) Classes**	**18.8**	**$932,982**	**$0**	**$0**	**$932,982**	**$932,982**	**$0**	**0.0%**	**$0**	**$0**	**$0**	**0.0%**	**$0**	**$0**	**$0**	**0.0%**	**$932,982**	**$0**	**0.0%**
32	LED SL Capital Costs		$4,259,866	$0	$0	$4,259,866	$4,340,815	$80,949	1.9%	$0	**$0**	**$0**	**N/A**	$0	**$0**	**$0**	**N/A**	$4,340,815	$80,949	1.9%
35	**In Province Total**	**9,135.1**	**$1,241,701,050**	**$0**	**$29,177,033**	**$1,270,878,083**	**$1,299,814,992**	**$58,113,942**	**4.6%**	**$0**	**$0**	**$0**	**0.0%**	**$29,177,033**	**$0**	**($29,177,033)**	**-2.3%**	**$1,299,814,992**	**$28,936,909**	**2.3%**
37	Export	15.5	$1,826,094	$0	$0	$1,826,094	$1,826,094	$0	0.0%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$1,826,094	$0	0.0%
39	**Total Electric Sales**	**9,150.6**	**$1,243,527,144**	**$0**	**$29,177,033**	**$1,272,704,177**	**$1,301,641,086**	**$58,113,942**	**4.6%**	**$0**	**$0**	**$0**	**0.0%**	**$29,177,033**	**$0**	**($29,177,033)**	**-2.3%**	**$1,301,641,086**	**$28,936,909**	**2.3%**
41	Misc Revenue	696.6	$23,168,569	$0	$0	$23,168,569	$23,460,802	$292,233	1.3%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$23,460,802	$292,233	1.3%
43	**Grand Total**	**9,847.2**	**$1,266,695,713**	**$0**	**$29,177,033**	**$1,295,872,746**	**$1,325,101,889**	**$58,406,175**	**4.5%**	**$0**	**$0**	**$0**	**0.0%**	**$29,177,033**	**$0**	**($29,177,033)**	**-2.3%**	**$1,325,101,889**	**$29,229,142**	**2.3%**

46 * The figures for LRT have been adjusted to reflect the correct load

2014 REVENUE INCREASE ANALYSIS - RATE STABILIZATION

Rate Classes	2014 Sales (GWh's)	2014 Revenue at current rates before cost adjustment clauses	2013 FAM AA	2013 FAM BA	Revenue at current rates including 2013 BA	Proposed Revenues 2014 Before Riders and with Rate Stabilization			AA Component				BA Component				2014 Revenue reflective of all FAM components		
Columns	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**L**	**M**	**N**	**O**	**P**	**Q**	**R**	**S**
						Amount	Increase	Increase (%) over Total Cost of Power	2013 Amount	2014 Amount	Variance	Increase (%) over Total Cost of Power	2013 Amount	2014 Amount	Variance	Increase (%) over Total Cost of Power	Amount	Variance	Increase (%) over Total Cost of Power
ATL																			
Residential	**4,216.5**	**$611,227,366**	**$0**	**$12,361,491**	**$623,588,857**	**$642,229,717**	**$31,002,351**	**5.0%**	**$0**	**$0**	**$0**	**0.0%**	**$12,361,491**	**$0**	**($12,361,491)**	**-2.0%**	**$642,229,717**	**$18,640,860**	**3.0%**
Small General	236.7	$33,999,526	$0	$694,608	$34,694,134	$35,720,705	$1,721,179	5.0%	$0	$0	$0	0.0%	$694,608	$0	($694,608)	-2.0%	$35,720,705	$1,026,571	3.0%
General Demand	2,448.7	$294,140,280	$0	$8,005,363	$302,145,643	$311,212,221	$17,071,941	5.7%	$0	$0	$0	0.0%	$8,005,363	$0	($8,005,363)	-2.6%	$311,212,221	$9,066,578	3.0%
Large General	379.6	$39,147,681	$0	$1,408,440	$40,556,122	$41,772,106	$2,624,424	6.5%	$0	$0	$0	0.0%	$1,408,440	$0	($1,408,440)	-3.5%	$41,772,106	$1,215,984	3.0%
Total Commercial	**3,065.0**	**$367,287,488**	**$0**	**$10,108,411**	**$377,395,899**	**$388,705,032**	**$21,417,545**	**5.7%**	**$0**	**$0**	**$0**	**0.0%**	**$10,108,411**	**$0**	**($10,108,411)**	**-2.7%**	**$388,705,032**	**$11,309,134**	**3.0%**
Small Industrial	255.9	$29,839,952	$0	$878,181	$30,718,133	$31,639,238	$1,799,286	5.9%	$0	$0	$0	0.0%	$878,181	$0	($878,181)	-2.9%	$31,639,238	$921,105	3.0%
Medium Industrial	495.4	$50,638,672	$0	$1,645,795	$52,284,468	$53,852,182	$3,213,509	6.1%	$0	$0	$0	0.0%	$1,645,795	$0	($1,645,795)	-3.1%	$53,852,182	$1,567,714	3.0%
Large Industrial - Firm	142.0	*$13,293,682*	*$0*	*$784,030*	*$14,077,713*	*$14,319,068*	*$1,025,386*	*7.3%*	*$0*	*$0*	*$0*	*0.0%*	*$784,030*	*$0*	*($784,030)*	*-5.6%*	*$14,319,068*	*$241,356*	*1.7%*
Large Industrial - Interruptible	650.8	*$56,330,000*	*$0*	*$2,429,209*	*$58,759,209*	*$60,701,380*	*$4,371,380*	*7.4%*	*$0*	*$0*	*$0*	*0.0%*	*$2,429,209*	*$0*	*($2,429,209)*	*-4.1%*	*$60,701,380*	*$1,942,171*	*3.3%*
Total Large Industrial	792.8	$69,623,683	$0	$3,213,239	$72,836,922	*$75,020,449*	*$5,396,766*	7.4%	$0	$0	$0	0.0%	$3,213,239	$0	($3,213,239)	-4.4%	*$75,020,449*	$2,183,527	3.0%
ELI 2PT - RTP*	0.0	$0	$0	$0	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	N/A
Total Industrial	**1,544.1**	**$150,102,307**	**$0**	**$5,737,216**	**$155,839,523**	**$160,511,869**	**$10,409,562**	**6.7%**	**$0**	**$0**	**$0**	**0.0%**	**$5,737,216**	**$0**	**($5,737,216)**	**-3.7%**	**$160,511,869**	**$4,672,346**	**3.0%**
Municipal	192.3	$19,733,699	$0	$542,571	$20,276,270	$20,879,435	$1,145,737	5.7%	$0	$0	$0	0.0%	$542,571	$0	($542,571)	-2.7%	$20,879,435	$603,166	3.0%
Unmetered	98.2	$21,895,829	$0	$427,344	$22,323,173	$22,990,285	$1,094,456	4.9%	$0	$0	$0	0.0%	$427,344	$0	($427,344)	-1.9%	$22,990,285	$667,112	3.0%
Total Other	**290.6**	**$41,629,528**	**$0**	**$969,915**	**$42,599,443**	**$43,869,720**	**$2,240,192**	**5.3%**	**$0**	**$0**	**$0**	**0.0%**	**$969,915**	**$0**	**($969,915)**	**-2.3%**	**$43,869,720**	**$1,270,278**	**3.0%**
Total ATL Classes	**9,116.2**	**$1,170,246,688**	**$0**	**$29,177,033**	**$1,199,423,721**	**$1,235,316,338**	**$65,069,650**	**5.4%**	**$0**	**$0**	**$0**	**0.0%**	**$29,177,033**	**$0**	**($29,177,033)**	**-2.4%**	**$1,235,316,338**	**$35,892,617**	**3.0%**
BTL (Electric)																			
GRLF	18.8	$932,982	$0	$0	$932,982	$932,982	$0	0.0%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$932,982	$0	0.0%
Mersey Additional Energy		$0	$0	$0	$0	$0	$0	0.0%	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	N/A
LRT		$0	$0	$0	$0	$0	$0	0.0%	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	N/A
Bowater Mersey		$0	$0	$0	$0	$0	$0	0.0%	$0	$0	$0	N/A	$0	$0	$0	N/A	$0	$0	N/A
Total BTL (Electric) Classes	**18.8**	**$932,982**	**$0**	**$0**	**$932,982**	**$932,982**	**$0**	**0.0%**	**$0**	**$0**	**$0**	**0.0%**	**$0**	**$0**	**$0**	**0.0%**	**$932,982**	**$0**	**0.0%**
LED SL Capital Costs**		$3,063,356	$0	$0	$3,063,356	$3,155,257	$91,901	3.0%	$0	**$0**	**$0**	**N/A**	$0	**$0**	**$0**	**N/A**	$3,155,257	$91,901	3.0%
In Province Total	**9,135.1**	**$1,174,243,026**	**$0**	**$29,177,033**	**$1,203,420,059**	**$1,239,404,577**	**$65,161,551**	**5.4%**	**$0**	**$0**	**$0**	**0.0%**	**$29,177,033**	**$0**	**($29,177,033)**	**-2.4%**	**$1,239,404,577**	**$35,984,518**	**3.0%**
Export	15.5	$1,826,094	$0	$0	$1,826,094	$1,826,094	$0	0.0%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$1,826,094	$0	0.0%
Total Electric Sales	**9,150.6**	**$1,176,069,120**	**$0**	**$29,177,033**	**$1,205,246,153**	**$1,241,230,671**	**$65,161,551**	**5.4%**	**$0**	**$0**	**$0**	**0.0%**	**$29,177,033**	**$0**	**($29,177,033)**	**-2.4%**	**$1,241,230,671**	**$35,984,518**	**3.0%**
Misc Revenue	696.6	$22,845,305	$0	$0	$22,845,305	$23,125,617	$280,312	1.2%	$0	$0	$0	0.0%	$0	$0	$0	0.0%	$23,125,617	$280,312	1.2%
Grand Total	**9,847.2**	**$1,198,914,425**	**$0**	**$29,177,033**	**$1,228,091,458**	**$1,264,356,288**	**$65,441,863**	**5.3%**	**$0**	**$0**	**$0**	**0.0%**	**$29,177,033**	**$0**	**($29,177,033)**	**-2.4%**	**$1,264,356,288**	**$36,264,830**	**3.0%**

* The figures for LRT have been adjusted to reflect the correct load

**LED Capital Costs will be updated at the time of the capital work order

RELIEF FROM 2013 REVENUE INCREASE UNDER RATE STABILIZATION PLAN

1	Rate Classes	2013 Proposed Revenues With Riders Before Rate Stabilization	2013 Proposed Revenues With Riders After Rate Stabilization	Revenue Increase relief by rate class by the end of 2014			
2	Columns	A	B	C	D	E	F
	Formula			A - C			C + D + E
3		Amount	Amount	2013 Deferred Amount	Fixed Cost Contribution from the NPPH Mill	Total Interest Associated with 2013 Deferral by the end of 2014	Total 2013 Deferred Amount
4	**ATL**						
5	**Residential**	**$663,275,793**	**$630,070,526**	**$33,205,268**	**$0**	**$3,989,216**	**$37,194,483**
6							
7	Small General	$36,845,639	$34,961,382	$1,884,256	$0	$226,371	$2,110,627
8	General Demand	$318,086,000	$304,468,383	$13,617,617	$0	$1,635,994	$15,253,611
9	Large General	$43,367,240	$41,508,115	$1,859,125	$0	$223,352	$2,082,477
10	**Total Commercial**	**$398,298,879**	**$380,937,881**	**$17,360,998**	**$0**	**$2,085,716**	**$19,446,715**
11							
12	Small Industrial	$32,318,956	$30,712,144	$1,606,812	$0	$193,039	$1,799,851
13	Medium Industrial	$54,654,301	$52,126,097	$2,528,204	$0	$303,733	$2,831,937
14	*Large Industrial - Firm*	$16,118,453	$15,655,976	$462,476	$0	$55,561	$518,037
15	*Large Industrial - Interruptible*	$61,451,313	$59,030,055	$2,421,258	$0	$290,885	$2,712,143
16	Total Large Industrial	$77,569,766	$74,686,031	$2,883,734	$0	$346,446	$3,230,181
17	ELI 2PT - RTP*	$0	$0	$0	$0	$0	$0
18	**Total Industrial**	**$164,543,022**	**$157,524,273**	**$7,018,750**	**$0**	**$843,219**	**$7,861,969**
19							
20	Municipal	$20,946,785	$20,202,841	$743,944	$0	$89,376	$833,320
21	Unmetered	$25,148,807	$23,808,629	$1,340,178	$0	$161,006	$1,501,184
22	**Total Other**	**$46,095,592**	**$44,011,470**	**$2,084,122**	**$0**	**$250,382**	**$2,334,504**
23							
24	**Total ATL Classes**	**$1,272,213,287**	**$1,212,544,149**	**$59,669,138**	**$0**	**$7,168,533**	**$66,837,671**
25							
26	**BTL (Electric)**						
27	GRLF	$918,137	$918,137	$0	$0	$0	$0
28	Mersey Additional Energy	$0	$0	$0	$0	$0	$0
	LRT	$0	$0	$0	$0	$0	$0
29	Bowater Mersey	$0	$0	$0	$0	$0	$0
30	**Total BTL (Electric) Classes**	**$918,137**	**$918,137**	**$0**	**$0**	**$0**	**$0**
31							
32	LED SL Capital Costs**	$1,962,839	$1,612,125	$350,714	$0	$42,134	$392,848
33							
34							
35	**In Province Total**	**$1,275,094,263**	**$1,215,074,411**	**$60,019,852**	**$0**	**$7,210,667**	**$67,230,519**
36							
37	Export	$1,144,317	$1,144,317	$0	$0	$0	$0
38							
39	**Total Electric Sales**	**$1,276,238,580**	**$1,216,218,728**	**$60,019,852**	**$0**	**$7,210,667**	**$67,230,519**
40							
41	Misc Revenue	$22,601,883	$22,315,097	$286,786	$0	$33,583	$320,369
42							
43	**Grand Total**	**$1,298,840,463**	**$1,238,533,825**	**$60,306,638**	**$0**	**$7,244,250**	**$67,550,888**
44							
45							

46 * The 2012 FAM AA/BA Figures have been adjusted to reflect the 2013 LRT Load

47 **LED Capital Costs will be updated at the time of the capital work order

RELIEF FROM 2014 REVENUE INCREASE UNDER RATE STABILIZATION PLAN

				Revenue Increase relief by rate class by the end of 2014					
1	Rate Classes	2014 Proposed Revenues With Riders Before Rate Stabilization	2014 Proposed Revenues With Riders After Rate Stabilization						
2	Columns	G	H	I	J	K	L	M	O
	Formulas			G - H			I + J + K	F	T + U + V
3		Amount	Amount	2014 Deferred Amount	Fixed Cost Contribution from the NPPH Mill	Interest	2014 Total	2013 Deferred Amount	Total Deferred Amount
4	**ATL**								
5	**Residential**	**$681,556,251**	**$642,229,717**	**$39,326,534**	**$0**	**$1,539,634**	**$40,866,168**	**$37,194,483**	**$78,060,651**
6									
7	Small General	$37,577,920	$35,720,705	$1,857,215	$0	$72,710	$1,929,925	$2,110,627	$4,040,552
8	General Demand	$322,436,775	$311,212,221	$11,224,553	$0	$439,441	$11,663,995	$15,253,611	$26,917,605
9	Large General	$42,915,962	$41,772,106	$1,143,856	$0	$44,782	$1,188,638	$2,082,477	$3,271,115
10	**Total Commercial**	**$402,930,657**	**$388,705,032**	**$14,225,624**	**$0**	**$556,933**	**$14,782,558**	**$19,446,715**	**$34,229,272**
11									
12	Small Industrial	$32,958,424	$31,639,238	$1,319,186	$0	$51,646	$1,370,832	$1,799,851	$3,170,682
13	Medium Industrial	$55,748,988	$53,852,182	$1,896,806	$0	$74,260	$1,971,066	$2,831,937	$4,803,003
14	*Large Industrial - Firm*	*$14,402,647*	*$14,319,068*	*$83,579*	*$0*	*$3,272*	*$86,851*	*$518,037*	*$604,888*
15	*Large Industrial - Interruptible*	*$61,490,180*	*$60,701,380*	*$788,799*	*$0*	*$30,881*	*$819,681*	*$2,712,143*	*$3,531,824*
16	Total Large Industrial	$75,892,827	$75,020,449	*$872,378*	*$0*	*$34,154*	*$906,532*	*$3,230,181*	*$4,136,713*
17	ELI 2PT - RTP*	$0	$0	$0	$0	$0	$0	$0	$0
18	**Total Industrial**	**$164,600,238**	**$160,511,868**	**$4,088,370**	**$0**	**$160,060**	**$4,248,430**	**$7,861,969**	**$12,110,398**
19									
20	Municipal	$21,456,629	$20,879,435	$577,194	$0	$22,597	$599,791	$833,320	$1,433,111
21	Unmetered	$23,997,420	$22,990,285	$1,007,135	$0	$39,429	$1,046,565	$1,501,184	$2,547,749
22	**Total Other**	**$45,454,049**	**$43,869,720**	**$1,584,329**	**$0**	**$62,026**	**$1,646,355**	**$2,334,504**	**$3,980,860**
23									
24	**Total ATL Classes**	**$1,294,541,195**	**$1,235,316,338**	**$59,224,857**	**$0**	**$2,318,653**	**$61,543,511**	**$66,837,671**	**$128,381,181**
25									
26	**BTL (Electric)**								
27	GRLF	$932,982	$932,982	$0	$0	$0	$0	$0	$0
28	Mersey Additional Energy	$0	$0	$0	$0	$0	$0	$0	$0
	LRT	$0	$0	$0	$0	$0	$0	$0	$0
29	Bowater Mersey	$0	$0	$0	$0	$0	$0	$0	$0
30	**Total BTL (Electric) Classes**	**$932,982**	**$932,982**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
31									
32	LED SL Capital Costs**	$4,340,815	$3,155,257	$1,185,558	$0	$46,415	$1,231,973	$392,848	$1,624,821
33									
34									
35	**In Province Total**	**$1,299,814,992**	**$1,239,404,577**	**$60,410,416**	**$0**	**$2,365,068**	**$62,775,483**	**$67,230,519**	**$130,006,002**
36									
37	Export	$1,826,094	$1,826,094	$0	$0	$0	$0	$0	$0
38									
39	**Total Electric Sales**	**$1,301,641,086**	**$1,241,230,671**	**$60,410,416**	**$0**	**$2,365,068**	**$62,775,483**	**$67,230,519**	**$130,006,002**
40									
41	Misc Revenue	$23,460,802	$23,125,617	$335,185	$0	$13,123	$348,308	$320,369	$668,677
42									
43	**Grand Total**	**$1,325,101,889**	**$1,264,356,287**	**$60,745,601**	**$0**	**$2,378,190**	**$63,123,791**	**$67,550,888**	**$130,674,679**
44									

45

46 * The figures for LRT have been adjusted to reflect the correct load

47 **LED Capital Costs will be updated at the time of the capital work order

Year	Appointments	Resignations	Members
2010-01-01			Rob Bennett, President & CEO NSPI Greg Blunden, VP Business Development Bangor Hydro Peter Dawes, VP Finance & Treasurer Bangor Hydro Nancy Tower, VP & CFO NSPI & Emera Rick Smith, VP Corporate Insurance & Asset Protection Emera (CHAIR) Bob Lysaght, VP Human Resources Bangor Hydro Sarah MacDonald, VP Human Resources Emera & NSPI
2010	Brian Rendell, GM Finance NSPI	Bob Lysaght, VP Human Resources Bangor Hydro	Rob Bennett, President & CEO NSPI Greg Blunden, VP Business Development Bangor Hydro Peter Dawes, VP Finance & Treasurer Bangor Hydro Nancy Tower, VP & CFO NSPI & Emera Rick Smith, VP Corporate Insurance & Asset Protection Emera (CHAIR) Sarah MacDonald, VP Human Resources Emera & NSPI Brian Rendell, GM Finance NSPI
2011	Judy Steele, Interim CFO NSPI & Emera	Rick Smith, VP Corporate Insurance & Asset Protection Emera Sarah MacDonald, President & CEO GBPC	Rob Bennett, President & CEO NSPI Greg Blunden, VP Business Development Bangor Hydro Peter Dawes, VP Finance & Treasurer Bangor Hydro Nancy Tower, EVP Business Development Emera & CEO ENL (CHAIR) Brian Rendell, GM Finance NSPI Judy Steele, Interim CFO NSPI & Emera
2012	Claudette Porter, VP Finance NSPI Barb Meens-Thistle, CHRO NSPI & Emera	Brian Rendell, VP Corporate Affairs ENL	Rob Bennett, President & CEO NSPI Greg Blunden, VP Business Development Emera Peter Dawes, VP Finance & Treasurer Bangor Hydro Nancy Tower, EVP Business Development Emera & CEO ENL (CHAIR) Judy Steele, Interim CFO NSPI & Emera Claudette Porter, VP Finance NSPI Barb Meens-Thistle, CHRO NSPI & Emera

REBUTTAL EVIDENCE

ON

CAPITAL STRUCTURE

AND

RETURN ON EQUITY

FOR

NOVA SCOTIA POWER INC.

Prepared by

KATHLEEN C. MCSHANE

FOSTER ASSOCIATES, INC.

September 2012

TABLE OF CONTENTS

I. INTRODUCTION AND SUMMARY OF CONCLUSIONS

Q. What is the purpose of your rebuttal evidence in this proceeding?

A. The purpose of my rebuttal evidence is to respond to certain issues related to capital structure and return on equity raised in the Evidence of Laurence D. Booth filed on behalf of the Counsel for the Nova Scotia Utility and Review Board and the Direct Testimony of Lee Smith filed on behalf of the Small Business Advocate. The fact that I do not address specific areas of their evidence should not be construed to mean that I agree with either the analysis or conclusions. My qualifications were previously filed as Appendix E to my Opinion on Capital Structure and Return on Equity for Nova Scotia Power Inc. ("NSPI").

Q. Please summarize the recommendations of Dr. Booth for NSPI's 2013 and 2014 test years.

A. Dr. Booth recommends ROEs of 7.50% and 8.50% for 2013 and 2014 respectively. Dr. Booth regards NSPI's 37.5% common equity ratio used for rate setting purposes as reasonable. In spite of his own calculations, Dr. Booth concludes that NSPI's request to be allowed 9.2% on 37.5% common equity to be within reasonable financial metrics (page 4).

Q. Please summarize the Ms. Smith's recommendations as they relate to cost of capital.

A. Ms. Smith's testimony supports a reduction in ROE due to alleged lower risk in NSPI's proposed two-year rate stabilization plan and due to lower interest rates. She also suggests that the Company's forecast deferrals could be financed with a greater proportion of debt than has been proposed.

Q. Could you please summarize the conclusions you have drawn in your rebuttal evidence?

A. My conclusions with respect to Dr. Booth's evidence are:

(1) Dr. Booth agrees that, despite his recommended ROEs, NSPI's request for an allowed return of 9.2% on 37.5% common equity to be within reasonable financial metrics.

(2) Dr. Booth's assertion that NSPI is of comparable risk to a "benchmark" or average risk Canadian utility is incorrect. NSPI's higher risk relative to the typical regulated Canadian utility means its cost of equity is higher and its allowed return on equity should be higher than that applicable to the typical Canadian utility. NSPI's higher than average financial risk alone warrants a higher ROE than applicable to a "benchmark" Canadian utility.

(3) Dr. Booth underestimates NSPI's business risk. His position that NSPI is comparable in risk to gas distribution utilities ignores the fundamentally higher business risks of NSPI. As Dr. Booth also fails to account for NSPI's lower than average common equity ratio, his recommendation that an average risk (or "benchmark") utility ROE would be applicable to NSPI is doubly flawed.

(4) Dr. Booth's utility benchmarks for assessing the reasonableness of NSPI's capital structure are either inconsistent with what the regulator determined to be appropriate, outdated, or incomplete. Dr. Booth's selection of benchmarks is selective and is limited to companies with allowed equity ratios at the lower end of the range of equity ratios allowed for Canadian utilities. The average allowed equity ratio for all investor-owned Canadian utilities with rated debt (excluding NSPI), virtually all of which are of lower business risk than NSPI, is 40%, higher than NSPI's deemed common equity ratio of 37.5%.

(5) Dr. Booth's contention that NSPI would be A- rated by S&P on a stand-alone basis (i.e., if it were not for Emera) is speculative at best, particularly given that NSPI's credit metrics have generally weakened over the past five years.

(6) Dr. Booth's virtual exclusive reliance on the Capital Asset Pricing Model (CAPM) is not reasonable. Only by applying a range of tests along with informed judgment can adherence to the fair return standard be ensured, where the fair return standard includes the comparable returns requirement, as well as the maintenance of financial integrity and the ability to attract capital.

(7) Dr. Booth's review of the major 2009 cost of capital reviews in Canada fails to either fully report (BCUC) or ignores (OEB) regulators' views where the CAPM was not the principal test considered.

(8) The application of the CAPM is particularly problematic in current financial market conditions. The historically low level of long-term Government of Canada bond yields has little, if any, correlation with trends in the market cost of equity.

(9) With reasonable estimates of the market risk premium and relative risk adjustment, the application of the CAPM at Dr. Booth's forecast long-term Canada bond yield of 3.5% during NSPI's test period indicates a cost of equity of 9.6%, higher than the 9.2% ROE that NSPI is requesting.

(10) Reliance on direct estimates of the utility equity risk premium derived from historical averages supports a utility cost of equity in the range of approximately 9.75% to 10.75%, higher than the 9.2% ROE requested by NSPI, even before any adjustment for financing flexibility.

(11) Dr. Booth, by effectively dismissing the application of the Discounted Cash Flow (DCF) test to utilities, is at odds with the majority of utility cost of equity experts in North America, including those that have appeared before the UARB in NSPI rate proceedings.

(12) Dr. Booth's concerns regarding reliance on analysts' earnings growth forecasts in DCF tests applied to utilities are unfounded.

(13) My estimated DCF costs of equity for a sample of U.S. electric utilities of comparable risk to NSPI, which are based on three different models, support a "bare bones" cost of equity of 9.25%, approximately equal to NSPI's requested ROE of 9.2%. The addition of an adjustment for financing flexibility equal to the 0.50% used by Dr. Booth supports an ROE for NSPI, even without an adjustment for NSPI's lower regulated common equity ratio of 37.5%, of 9.75%.

(14) Dr. Booth's concern with the use of U.S. data and utilities is inconsistent with his considerable reliance on U.S. data in the development of his evidence.

(15) Dr. Booth's attempt to discredit the use of U.S. electric utilities as comparables for NSPI is based on a sample whose selection criteria were not well defined and which is of relatively higher risk than my sample of electric utilities.

(16) A comparison of the historical widely available *Value Line* betas for Dr. Booth's and my vertically integrated electric utility samples and Dr. Booth's low risk U.S. utility sample indicates similar betas over time. The comparison highlights that (a) beta is only one means by which relative risk can be assessed and (b) in isolation, the history of *Value Line* betas does not indicate significant differences in risk among the samples.

(17) The average debt ratings for my sample of electric utilities are equal to or higher than those applicable to NSPI. From a debt rating perspective, NSPI is of comparable to higher total risk than my U.S. electric utility sample, and its ROE should be comparable to, or somewhat higher than, the returns on equity available to its peers.

(18) In the past year, the ROEs adopted for all U.S. utilities (electric and gas combined) have averaged approximately 10.0%. The corresponding average ROE adopted for utilities in my electric utility sample was 10.1%. Both averages are higher than NSPI's requested 9.2% ROE and underscore the conservative nature of NSPI's request.

With respect to Ms. Smith's evidence:

(1) Ms. Smith incorrectly characterizes the Company's requested return on equity as an Earnings Sharing Mechanism. NSPI's ROE is expressed within a range. During the two year test period, the upper end of the range serves as a cap on the NSPI's ROE above which customers receive 100% of the benefits. If NSPI earns below the allowed ROE, the short-fall is to the account of the shareholder.

(2) Contrary to Ms. Smith's claim, NSPI's ROE range comprises a very limited ability to earn returns above the 9.2% at which rates will be set, considerably less than is typical.

(3) Ms. Smith's claim that the proposed two-year rate stabilization plan lowers NSPI's risk is erroneous. In principle, extending a test period does not lower risk. Moreover, NSPI's proposal to limit rate increases and defer recovery of forecast test period costs well beyond the test period increases the uncertainty that those costs will be recoverable.

(4) Ms. Smith's recommendation that deferred amounts be financed with short term debt is unreasonable. Short-term debt financing is not only incompatible with the extended period over which the deferred costs are to be recovered, but would create higher leverage and weaker credit metrics.

(5) Ms. Smith's suggestion that a lower ROE is justified due to lower interest rates is unsupported. NSPI's requested ROE of 9.2% is conservative in light of both the Company's risk profile and returns available to its peers.

II. REBUTTAL TO DR. BOOTH

A. CAPITAL STRUCTURE AND ROE

Q. At page 36 of his Evidence, Dr. Booth concludes that NSPI's 37.5% common equity ratio is fair and reasonable. At page 83 of his Evidence, he judges that NSPI is similar to the "benchmark utility", and recommends the same ROE for NSPI that would be applicable to a "benchmark utility." Please comment.

A. I understand Dr. Booth's use of the term "benchmark utility" to mean an average risk utility.[1] In this context, risk comprises both business and financial risk. In other words, at the current capital structure, containing 37.5% common equity, he considers NSPI to be an average risk Canadian utility, to which he concludes his "benchmark utility" ROE should apply.

Q. Does Dr. Booth conclude that NSPI faces lower than average business risk?

A. No. Nowhere in Dr. Booth's testimony does he suggest that NSPI faces lower than average business risk compared to other Canadian utilities. In fact, he considers NSPI to be comparable to Gaz Métro (page 36), a utility that Dr. Booth considers to face above average business risk.[2]

Q. Do you agree with Dr. Booth's conclusion that NSPI is of comparable risk to a "benchmark" or average risk Canadian utility?

A. No. I discuss in detail below why NSPI faces higher business risks than the typical Canadian utility. However, even if NSPI did face "average" business risk relative to its

[1] In response to Enbridge Gas New Brunswick's Information Request No. 12 (August 2010), Dr. Booth stated that his "use of the phrase benchmark is similar to that in Alberta: a typical or average risk utility where other ROEs can be keyed off this base."

[2] In "Fair Return and Capital Structure for Gaz Metro, Evidence of Laurence D. Booth", filed with the Régie de l'énergie du Québec in July 2011, Dr. Booth stated that Gaz Métro's overall risk is higher than that of the benchmark utility, due to the composition of its customer base and competition with Hydro Québec, partly offset by the more extensive use of deferral accounts and the impact of performance based regulation (page 4).

Canadian peers, its financial risk, as captured in its deemed common equity ratio, is higher than average. NSPI's higher than average financial risk (lower than average common equity ratio) alone warrants a higher ROE than applicable to a "benchmark" Canadian utility.

Q. At pages 22-23 of his Evidence, in judging whether NSPI's existing capital structure is fair and reasonable, Dr. Booth refers to the U.S. Supreme Court decision, *Federal Power Commission v. Hope Natural Gas Co. (320 US 591, (1944))*. Does Dr. Booth take into account all relevant aspects of that decision?

A. No. Dr. Booth focuses solely on the financial integrity criterion of *Hope*. Dr. Booth cites the portion of the decision that states that the fair return "should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital." He fails to mention that the *Hope* decision also includes the comparable returns requirement. The full citation is: "**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." (emphasis added) The full citation encompasses all three requirements of the fair return standard.

Q. What is the implication of the comparable returns criterion of the *Hope* decision as regards a fair return for NSPI?

A. The implication is that the overall return for NSPI, which considers both the capital structure and ROE, should meet the comparable return requirement of the fair return standard articulated in *Hope*. Dr. Booth's application of a "benchmark utility" ROE to NSPI at its current capital structure fails to meet the comparable returns standard as it neither takes account of NSPI's lower than average common equity ratio nor of NSPI's higher than average business risk.

Q. In judging whether NSPI's capital structure is reasonable, Dr. Booth uses several benchmarks, including the 31% common equity ratio he recommended for two Alberta integrated electric utilities in 1996. Please comment on the relevance of that benchmark.

A. The 31% common equity ratio recommended by Dr. Booth for Alberta Power and TransAlta Utilities in 1996 is not relevant to the assessment of the reasonableness of NSPI's common equity ratio. First, the Alberta regulator did not accept a 31% common equity ratio for the integrated electric utilities at the time. In Decision U97097 (October 1997), the Alberta Energy and Utilities Board ("AEUB", predecessor to the Alberta Utilities Commission) found:

> Having regard to the current ratio of preferred equity, the Board is not persuaded that a common equity component in the range of 31-33%, as recommended by CGCL for an integrated utility would preserve the utility's ability to access financial markets at reasonable terms and conditions. (page 230)

The AEUB approved a common equity ratio for TransAlta of 40% and a common equity ratio of 35.7% for Alberta Power, considering that the higher common equity ratio for TransAlta was warranted due to its lower preferred share component (10% compared to 16% for Alberta Power).[3]

Moreover, what the AEUB found to be reasonable in 1997 is not relevant currently. Common equity ratios have generally risen since 1997. Although it is not possible to make an "apples to apples" comparison, as there are no longer any integrated electric utilities in Alberta, due to restructuring, the trend in the common equity ratios of the two functions that are still regulated (transmission and distribution) provides some perspective. In ATCO Electric's first litigated general rate application post-restructuring, the deemed common equity ratios for the transmission and distribution operations were

[3] In Decision U99099 (November 1999), the EUB concluded that an integrated common equity ratio of 40% to 42%, with a preferred share component of 9.5%, was appropriate for TransAlta.

set at 32% and 35% respectively,[4] raised to 33% and 37% respectively in the Generic Cost of Capital decision in 2004,[5] and raised again in the 2009 Generic Cost of Capital Decision to 36% and 39% respectively.[6] The increases in the 2009 Generic Cost of Capital Decision represented a two percentage point across the board increase plus a one percentage point additional increase for the transmission operations to recognize the impacts of the forecast large capital additions on the credit metrics. The common equity ratio of the transmission operations was further increased to 37% in the 2011 Generic Cost of Capital decision, again to mitigate the effects of the large capital build on the utility's credit metrics.[7] The common equity ratio of ATCO Electric's distribution operations, which are of lower business risk than NSPI, remains at 39%, higher than NSPI's 37.5%.

Q. Dr. Booth also uses Gaz Métro's common equity ratio of 38.5% as a benchmark to assess the reasonableness of NSPI's common equity ratio. Please comment on the relevance of that ratio.

A. Dr. Booth's comparison of Gaz Métro's deemed common equity ratio to NSPI's deemed common equity ratio of 37.5% does not tell the full story. Gaz Métro also has a 7.5% deemed preferred share component. It does not have **actual** preferred equity. Dr. Booth did not mention this deemed preferred component in his NSPI evidence, but acknowledged in response to NSPI (Booth) Request IR-10 that:

> Deeming does not increase risk the way that an actual issue of preferred shares does, so implicitly Gaz Metro has significantly more common equity that (sic) the typical Canadian gas distribution utility and I would regard this as the offset to its higher business risk.

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[4] Alberta Energy and Utilities Board, *ATCO Electric, 2003-2004 General Rate Application, Decision 2003-071*, October 2003.

[5] Alberta Energy and Utilities Board, *Generic Cost of Capital, Decision 2004-052,* July 2004.

[6] Alberta Utilities Commission, *2009 Generic Cost of Capital, Decision 2009-216*, November 2009.

[7] Alberta Utilities Commission, *2011 Generic Cost of Capital Decision, Decision 2011-474*, December 2011. In an earlier decision, ATCO Electric's transmission operations were also allowed to include CWIP in rate base and utilize the future income tax methodology for federal income taxes to mitigate credit metric effects of the utility's large capital build. (*ATCO Electric Ltd. 2011-2012 Phase 1 Distribution Tariff 2011-2012 Transmission Facility Owner Tariff, Decision 2011-134,* April 2011)

In other words, with a 7.5% deemed preferred equity component, Dr. Booth concluded that Gaz Métro was equivalent to a benchmark, or average risk, utility. NSPI's regulated common equity ratio of 37.5% is already marginally lower than Gaz Métro's 38.5% and NSPI has no deemed preferred equity component. If, as Dr. Booth contends, Gaz Métro's deemed 7.5% deemed preferred component implicitly results in significantly more common equity than the typical gas distribution utility, Dr. Booth has understated Gaz Métro's common equity ratio in assessing NSPI's capital structure. The corollary to this conclusion is that, even if NSPI were of no higher business risk than Gaz Métro, NSPI would require a higher ROE than is applicable to an average risk or "benchmark" utility.

Q. Do you have any comments on Union Gas as a benchmark?

A. Yes. As I discuss below, as a vertically integrated electric utility, NSPI is of higher business risk than gas and electric distribution utilities. In that regard, in my opinion, a comparison to Union demonstrates only that NSPI's common equity ratio is marginally higher than that of a single utility with lower business risk. Dr. Booth fails to acknowledge that all of the electricity distribution utilities in the same regulatory jurisdiction, including large utilities (Hydro One and Toronto Hydro), are allowed common equity ratios of 40%, as is Hydro One's electric transmission operations. He also failed to acknowledge that Union Gas is applying for an increase in its common equity ratio to 40%, equivalent to that of the Ontario electricity distribution utilities. He does not consider the 39% and 40% allowed common equity ratios of ATCO Gas and FortisBC Energy Inc., two other large gas distribution utilities, which have been considered benchmark utilities by Dr. Booth.[8] Nor does he mention the 39% generic allowed common equity ratio of electricity distribution utilities in Alberta (referenced above for ATCO Electric). He does mention the 40% common equity ratio of FortisBC Inc., but appears to dismiss this data point because FortisBC Inc. has low risk hydro assets and is, according to Dr. Booth, "a very small utility" (page 4), despite the fact that FortisBC Inc.'s rate base is in excess of $1 billion. He also appears not to consider the

[8] Laurence Booth Response to Heritage Gas Information Request 13, October 2011.

45% common equity ratio of Newfoundland Power, which he considers to be an average business risk utility.[9] Essentially, Dr. Booth has selected "comparables" with allowed equity ratios at the lower end of the range of equity ratios allowed for Canadian utilities. The allowed equity ratio for all investor-owned Canadian utilities with rated debt (excluding NSPI) is 40%, higher than NSPI's deemed 37.5%.[10]

Q. At page 13, Dr. Booth claims that NSPI would probably be A- rated by S&P if it were not for Emera. He also concludes that, on a stand-alone basis, NSPI would still have a very good investment grade bond rating with a significantly lower common equity ratio. Please address these assertions.

A. Dr. Booth's contention that NSPI would be rated A- by S&P if it were not for Emera is speculative at best. Virtually all S&P's rating actions have been directly related to NSPI. NSPI was downgraded by S&P from A- to BBB+ in December 2001, as was Emera. The downgrade reflected S&P's views at the time of the impact on NSPI of the introduction of competition into the provincial electric utility industry and of competition from natural gas.[11] NSPI and Emera were downgraded from BBB+ to BBB in June 2006. Again, the rating actions for both NSPI and Emera were related to NSPI specific factors, i.e., an expectation that NSPI's historically weak cash flow metrics would not materially improve in the next several years given no assurance of full recovery of fuel-related expense under the prevailing regulatory framework; an evolving fuel procurement strategy; and upcoming challenges related to the approval, financing, and execution of several proposed capital projects.[12] The upgrade from BBB to BBB+ in September 2009 was related to the adoption of the FAM at NSPI.[13] The negative trend that was assigned to NSPI and Emera in April 2012 was attributable to factors at

[9] "Fair Return for Newfoundland Power, Evidence of Laurence D. Booth", May 2012, page 2.
[10] The allowed common equity ratios for individual Canadian utilities are found on Schedule 2, page 1 of 2 of my direct testimony.
[11] S&P, *Various Ratings Actions on Nova Scotia Power Inc: Outlook Stable,* December 21, 2001 and *Summary: Emera Inc.* December 28, 2011.
[12] S&P, *Research Update: Emera Inc., Subsidiary Nova Scotia Power Inc. Ratings Lowered to 'BBB', Off Watch,* June 21, 2006.
[13] S&P, *Research Update: Emera Inc., Subsidiary Nova Scotia Power Inc. Ratings to 'BBB+' from 'BBB' As Fuel-Adjustment Mechanism Implemented; Outlook Stable*, September 14, 2009.

NSPI, i.e., S&P's expectation of heightened regulatory risk due to the potential upward pressure on rates due to expected development projects that the company is pursuing and the impact on cash flow.[14] The history of rating actions by S&P does not support the contention that NSPI would be A- rated if it were not for Emera.

Q. What about Dr. Booth's contention (page 4) that there are signs of double leverage of NSPI's assets at Emera?

A. Dr. Booth's conclusion appears to be based on a faulty comparison of equity ratios. At page 13, Dr. Booth calculated Emera Inc.'s 2011 common equity ratio inclusive of accumulated other comprehensive income (AOCI). AOCI is comprised of unrealized gains and losses, principally on pension plans, foreign currency translation and investments available for sale. In both Emera's and NSPI's 2011 GAAP financial statements, AOCI reduces total reported common equity. For Emera the reduction is largely due to unrealized pension plan losses; for NSPI, the reported reduction to equity is 100% related to pensions. The same calculation using NSPI's 2011 GAAP financial statements performed by Dr. Booth for Emera would have produced a lower common equity ratio for NSPI than for Emera. However, NSPI's regulated common equity ratio excludes AOCI, consistent with the calculation of rate base and regulated income.[15]

Q. Are there any other considerations that support the conclusion that NSPI would be a BBB+ rated utility on a stand-alone basis?

A. Yes. Before the ratings were withdrawn in March 2010, Moody's rated NSPI Baa1, which is equivalent to BBB+ on S&P's rating scale. The most recent Moody's credit opinion prior to the withdrawal of the ratings, which made no mention of Emera, reflected the adoption of the FAM. Moody's credit opinion noted that NSPI's financial metrics were weaker than those of other smaller integrated electric utilities with similar

[14] S&P, *Emera Inc.* April 18, 2012 and *Nova Scotia Power Inc.*, April 18, 2012.

[15] DBRS adjusts NSPI's debt to capital ratios by adding back to equity the reduction resulting from the pension liability adjustment required under U.S. GAAP (DBRS, *Rating Report: Nova Scotia Power Inc.*, July 27, 2012.

ratings, as well as weaker than those of Baa1 rated transmission and distribution utilities.[16]

Q. Have there been any developments that would suggest NSPI would be rated higher than Baa1 today by Moody's?

A. No. Moody's did indicate that there could be an upgrade if some combination of the following occurred: a significant sustainable improvement in credit metrics, further improvements in relationships with the UARB and other stakeholders leading to an increase in equity thickness, more rapid recovery of regulatory assets or similar measures, and a reduction of the Company's exposure to existing and potential environmental legislation/regulation related to its predominantly coal-fired fleet. There has not been an improvement in NSPI's credit metrics. NSPI's credit metrics have been weaker since the issuance of Moody's credit opinion. Rebuttal Schedule 1 attached to this testimony demonstrates that NSPI's credit metrics have generally weakened over the past five years and, in the past two years, have been weaker than those of other investor-owned Canadian electric and gas utilities. There has not been an increase in equity thickness, more rapid recovery of regulatory assets or similar measures, or a reduction in the Company's exposure to existing and potential environmental legislation/regulation related to its coal-fired fleet.

Q. Do the above considerations support Dr. Booth's contention that NSPI would "still have a very good investment grade bond rating" with "a significantly lower common equity ratio"?

A. No. The above considerations indicate that NSPI would be BBB+ and Baa1 rated on a stand-alone basis by S&P and Moody's respectively. Therefore, if on a stand-alone basis, at its current deemed common equity ratio of 37.5%, NSPI is able to achieve only BBB+/Baa1 ratings, Dr. Booth's contention is incorrect.

[16] Moody's, *Credit Opinion: Nova Scotia Power Inc.*, November 17, 2009.

B. BUSINESS RISK OF NSPI

Q. Dr. Booth claims that NSPI's business risk is comparable to that of gas distributors, including Union Gas, Gaz Métro and Enbridge Gas (page 33). Do you agree with this conclusion?

A. No. Dr. Booth's conclusion that NSPI is of comparable business risk to that of gas distribution utilities is premised on his view that regulation in Canada neutralizes fundamental business risk differences among utilities. The implication of this view is that, no matter what the type of utility or what the underlying economics of its business, regulation in Canada protects the utility and its shareholders to the extent that virtually all Canadian utilities are of reasonably comparable business risk. I disagree with that premise.

I do not disagree with Dr. Booth that regulatory mechanisms can mitigate year-to-year earnings volatility and short-term forecasting risk. However, the fact that utilities are regulated does not entail assurance that the regulator will provide compensation to investors as the risks materialize, through higher ROEs and/or assurance of return of capital. If the utility is losing customers and throughput, 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. No regulatory panel can bind its successors and thus guarantee that investors will be compensated in the future for risks as they materialize.

Further, despite Dr. Booth's view that regulation is not a risk but a protective factor (page 27), the March 30, 2012 rating action by S&P that changed the Outlook on NSPI from "Stable" to "Negative", cited a meaningful capital expenditure program to address provincial and federal energy policies, driving the need for rate increases, which heightens regulatory risk.[17]

Q. Dr. Booth points to PNG as an example of a utility where regulation helped the utility cope with fundamental business risk. Did the regulatory support of the BCUC eliminate the long-term fundamental business risks of the utility?

A. No. As of its last DBRS rating report (June 2011), PNG was rated BBB(low), barely investment grade. As challenges to PNG, DBRS cited weak economic conditions in PNG's western system (where it had lost not only Methanex,[18] the major industrial customer to which Dr. Booth referred, but also major pulp and paper customers), competitive conditions of natural gas versus electricity and a low ROE for its business risk profile. In regard to the last, PNG's allowed ROEs for its three divisions were in the range of 9.9% to 10.15% on equity ratios of 40% to 45%.

Q. Dr. Booth considers that it is the adoption of the FAM that makes NSPI comparable to Gaz Métro and Union Gas. He essentially bases this on his conclusions that the FAM operates in much the same way as purchased gas variance accounts (PGVAs) for gas distributors (page 5). Please respond.

A. With respect to the FAM versus the PGVAs, the latter have operated to recover commodity costs not only in a timelier manner, but in a less contentious manner. In addition, with particular regard to Gaz Métro, as characterized by Dr. Booth, it has an "abundance of deferral accounts"[19] in addition to the PGVA, which itself includes not only gas commodity costs, but also pipeline transportation and gas storage cost. Among Gaz Metro's abundance of deferral accounts are accounts for gas usage, referenced by

[17] Standard & Poor's, *Research Update: Nova Scotia Power Inc. Outlook to Negative From Stable On Growth Plan Stresses; 'BBB+' Ratings Affirmed,* March 30, 2012.

[18] In the 1994 BCUC decision to which Dr. Booth refers to in response to NSPI (Booth)-7, the BCUC references Dr. Booth and Berkowitz's testimony with respect to PNG, specifically that the witnesses suggested that the risks associated with the concentrated industrial base and in particular the reliance on four industrial customers were offset by the bright outlook for Methanex (page 34).

[19] "Fair Return and Capital Structure for Gaz Metro, Evidence of Laurence D. Booth", July 2011, Appendix C, page 16.

Dr. Booth at page 32, as well as accounts for variations in short-term interest rates, bad debt expense, income taxes, contributions to Québec's Green Fund, self-insurance, and severance pay.[20] NSPI does not operate with the extensive suite of deferral accounts that Gaz Métro does. Moreover, Dr. Booth considers that Gaz Metro's performance based regulation acts as an offset to its business risk.[21] NSPI is not operating under a performance based regulation plan.

Q. In selecting Canadian gas utilities that he views as of comparable risk to NSPI, Dr. Booth references Gaz Metro's and Union Gas' industrial load. Does Dr. Booth appear to attribute any material significance to the customer base in either his risk assessment or his recommendations?

A. No. Although Dr. Booth relies on Union Gas and Gaz Métro as comparables to NSPI due to their industrial load, it is not at all clear why, as Dr. Booth appears to attribute little or no significance to either load composition or the economic base of the service area. He also considers Enbridge Gas to be comparable to both Union Gas and NSPI (page 33), despite the fact that he describes Enbridge Gas as a "premier low risk Canadian utility", which operates in "traditionally the richest, most diversified area in Canada with predominantly residential load…"[22]

Q. Do the debt rating agencies consider load composition and the economic base of the service area in their business risk assessments?

A. Yes. DBRS, for example, considers the nature of the service area to be a critical business risk factor. According to DBRS, a franchise area which has minimal load growth, is economically stagnant, and has a balanced residential, commercial and industrial mix equates to an "Adequate" or BBB rating on that factor. A franchise area with consistent load declines, an economically weak service territory and customer mix weighted toward

[20] Cause tarifaire 2012, R-3752-2011, Réponse De Gaz Métro À Une Demande De Renseignements Association des consommateurs industriels de gaz (Bernard Otis), Question 1.4.
[21] Booth, *Ibid.*, page 4.
[22] "Business Risk and Capital Stucture [sic] for Enbridge Gas Distribution INC. (EGDI), EB-2011-0354, Evidence of Laurence D. Booth", August 2012, pages 2 and 44.

cyclical industrials is considered "Weak", or equivalent to a BB rating on that factor.[23] Moody's takes into account the extent of reliance on industrial customers and whether they are in defensive or cyclical industries in its assessment of a utility's diversification, which is one of its designated debt rating factors.[24] S&P takes account of the health and growth in the economy, growth in the population and the residential/commercial base and the attractiveness of the service area's business environment.[25]

Q. Dr. Booth suggests that NSPI's lost industrial load reflects a decline in business risk (page 30). Do you agree?

A. No, as I stated in response to NSPI (Booth)-9, "Not only does there remain considerable uncertainty surrounding NS Power's pulp and paper related load and the impact on the utility, Ms. McShane considers that lost load and revenue from pulp and paper customers would be a crystallization of a risk, rather than a reduction in risk that would translate into a lower investor return requirement."

Q. Does Dr. Booth's assessment that NSPI is comparable to Canadian gas distributors overlook any significant differences between the two?

A. Yes. Dr. Booth ignores fundamental business risk differences between gas (as well as electricity) distributors and vertically integrated electric utilities, including NSPI.

1. Vertically integrated utilities have the obligation to build, lease or contract for power to serve their customers. The construction of base load generation frequently has long lead times, the potential deferral of the recovery of significant financing costs until the plant goes into service, the risk that the market may not have materialized when the plant is complete, and the risk that construction costs may be disallowed. Distribution utilities do not face these risks.

[23] DBRS, *Methodology, Rating Companies in the North American Energy Utilities (Electric and Natural Gas) Industry*, May 2011.
[24] Moody's, *Global Infrastructure Finance: Regulated Electric and Gas Utilities*, August 2009.
[25] S&P, *Criteria/Corporates/Utilities: Key Credit Factors: Business and Financial Risks in the Investor-Owned Utilities Industry*, November 2008.

2. If generating plants are not operating, costs of obtaining replacement power may be borne by shareholders. Distribution utilities do not face the same risk.

3. Generating plants, particularly fossil fuel plants, are more likely to be substituted with, or bypassed by, a lower cost alternative power source or subjected to a competitive market than a distribution system.

4. Vertically integrated electric utilities that generate the preponderance of the power sold to its native load) typically have close to 50% of their rate base invested in generation plant, which is inherently more risky from an operational standpoint than distribution or transmission assets. The extent to which that is the case depends on the technologies (hydroelectric, fossil fuel, nuclear) used.

5. Fossil fuel generating capacity is subject to higher environmental risks than distribution systems.

Q. Is there any evidence that the debt rating agencies consider a vertically integrated electric utility with generation operations to face more business risk than wires or pipes utilities?

A. Yes. In its November 2008 *Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry*, S&P stated that "We view a company that owns regulated generation, transmission, and distribution operations as positioned between companies with relatively low-risk transmission and distribution operations and companies with higher-risk diversified activities on the business profile spectrum." DBRS considers utilities that are entirely regulated and largely wires utilities, i.e., primarily electric transmission and distribution with modest, if any power generation, to have lower business risk than integrated electric utilities with very timely and certain fuel recovery.[26] According to Moody's "Vertically integrated electric utilities are generally

[26] DBRS, *Ibid.*

considered to have higher business risk than T&D utilities due to the risks associated with generation including fuel price and volume, operational and environmental risks. Among utilities with generation, those with significant exposure to fossil fuels, particularly coal, are typically viewed as having higher risk due to uncertainty as to the timing and amount of capital expenditures required to comply with further anticipated restrictions on environmental emissions including carbon dioxide, mercury, sulfur dioxide and nitrogen oxides."[27]

NSPI is a prime example of a utility with significant exposure to fossil fuels, with the added risks and complexities of addressing its renewable energy resource requirements resulting from provincial energy policy while operating in an uncertain economic environment.

Q. On the basis of the discussion above, what conclusions can be drawn?

A. Dr. Booth underestimates NSPI's business risk; his position that NSPI is comparable in risk to gas distribution utilities ignores the fundamentally higher business risks of NSPI, which are not offset by a higher common equity ratio. In fact, NSPI's common equity ratio is lower than average. As a result, his conclusion that an ROE applicable to an average risk (or "benchmark") utility would be applicable to NSPI is doubly flawed.

C. CAPITAL ASSET PRICING MODEL

Q. Dr. Booth's recommendations of ROEs for NSPI of 7.50% and 8.50% for 2013 and 2014 respectively are based virtually exclusively on his application of the Capital Asset Pricing Model (CAPM). Is this a reasonable approach, in your view?

A. No. The challenges associated with the CAPM are of a sufficient magnitude to warrant the conclusion that it is not inherently superior to other approaches to the estimation of a

[27] Moody's, *Regulatory Frameworks - Ratings and Credit Quality for Investor-Owned Utilities, Evaluating a Utility's Regulatory Framework*, June 2010.

fair return, particularly in light of the adjustments to the theoretical CAPM necessary to apply it to the utility industry. Any individual cost of equity model implicitly ascribes simplicity to a cost whose determination is inherently complex. No single model is powerful enough on its own to produce "the number" that will meet the fair return standard. Only by applying a range of tests along with informed judgment can adherence to the fair return standard be ensured, where the fair return standard includes the comparable returns requirement, as well as the maintenance of financial integrity and the ability to attract capital.

Q. Dr. Booth refers to several 2009 Canadian cost of capital decisions which relied on the CAPM in arriving at the allowed ROE. What inferences can you draw from them?

A. First, with the exception of the Newfoundland Power decision[28] (cited at page 69 of Dr. Booth's testimony), none of them relied solely on the CAPM. The two that started with the CAPM as the base (the Régie for Gaz Métro[29] cited at page 68 and the AUC for the Alberta Utilities[30] cited at page 69) made significant adjustments to the CAPM results to arrive at the final allowed ROE. In setting the allowed ROE for Gaz Métro at 9.2%, the Régie adjusted its estimate of the CAPM ROE for a benchmark distributor by 1.14% to 1.92% for a combination of Gaz Métro's higher risk relative to a benchmark distributor, the financial crisis and other tests. The AUC's allowed ROE of 9.0% was 1.2% higher than the mid-point of its CAPM range.[31]

[28] Newfoundland and Labrador Board of Commissioners of Public Utilities, *Reasons for Decision: Order No. P.U. 43(2009),* December 24, 2009.

[29] Régie de l'Énergie, *Décision Demande de modifier les tarifs de Société en commandite Gaz Métro à compter du 1er octobre 2009, D-2009-156, R-3690*, 7 Decembre 2009.

[30] Alberta Utilities Commission, *2009 Generic Cost of Capital Decision 2009-216,* November 12, 2009.

[31] It bears noting that Dr. Booth's own recommendations in this proceeding entail significant judgmental adjustments to his CAPM estimates. Moreover, his recommended benchmark utility ROEs of 7.50% and 8.50% at long-term Government of Canada bond yields of 3.0% and 4.0% respectively are both **higher** than the recommendation he made for a benchmark utility in the 2009 Alberta Generic Cost of Capital proceeding (during the financial crisis) of 7.25% at a forecast long-term Government of Canada bond yield of 4.25%.

Q. What about the BCUC decision[32] which Dr. Booth cites at pages 69-70?

A. Dr. Booth references the BCUC CAPM result of 7.30% to 8.30%, but he does not provide a complete picture of the BCUC conclusions regarding the fair return for the benchmark BC utility. Dr. Booth fails to note that the BCUC set the allowed ROE for the benchmark BC utility at 9.50% and had the following to say with respect to CAPM:

> CAPM is based on a theory that can neither be proved nor disproved, relies on a market risk premium which looks back over nine decades and depends on a relative risk factor or beta. The fact that the calculated beta for PNG (considered by Dr. Booth to be the most risky utility in Canada) was 0.26 in 2008 causes the Commission Panel to consider that betas conventionally calculated with reference to the S&P/TSX are distorted and require adjustment.
>
> The Commission Panel will give weight to the CAPM approach, but considers that the relative risk factor should be adjusted in a manner consistent with the practice generally followed by analysts so that it yields a result that accords with common sense and is not patently absurd.

Q. Has Dr. Booth omitted any major 2009 Canadian cost of capital reviews in his discussion of regulators' application of CAPM?

A. Yes, Dr. Booth did not mention the OEB's cost of capital review,[33] which stated as follows.

> The Board's current formulaic approach for determining ROE is a modified Capital Asset Pricing Model methodology, and in his written comments, Dr. Booth recommended that this practice be continued. Dr. Booth recommended that "the Board base its fair ROE on a risk based opportunity cost model, with overwhelming weight placed on a CAPM estimate.
>
> This view was not shared by other participants in the consultation, who asserted that the Board should use a wide variety of empirical tests to determine the initial cost of equity, deriving the initial ERP [equity risk premium] directly by examining the relationship between bond yields and equity returns, and indirectly

[32] British Columbia Utilities Commission, *In the Matter of Terasen Gas Inc. Terasen Gas (Vancouver Island) Inc. Terasen Gas (Whistler) Inc. and Return on Equity and Capital Structure Decision,* December 16, 2009 ("BCUC 2009 Cost of Capital Decision").

[33] Ontario Energy Board, *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, *EB-2009-0084*, December 11, 2009 ("OEB 2009 Cost of Capital Report").

> by backing out the implied ERP by deducting forward-looking bond yields from ROE estimates…
>
> The Board agrees that **the use of multiple tests to directly and indirectly estimate the ERP is a superior approach to informing its judgment than reliance on a single methodology**. [emphasis in original] In particular, the Board is concerned that CAPM, as applied by Dr. Booth, does not adequately capture the inverse relationship between the ERP and the long Canada bond yield. As such, the Board does not accept the recommendation that it place overwhelming weight on a CAPM estimate in the determination of the initial ERP. (pages 34-36)

In its 2009 Cost of Capital report, the OEB set the benchmark allowed ROE at 9.75%, based on a long-term Canada bond yield of 4.25% and a spread between long-term A rated utility and Government of Canada bond yields of 1.415%.[34] At Dr. Booth's 3.5% 30-year Government of Canada bond yield forecast during NSPI's test period, the OEB automatic adjustment formula indicates an allowed ROE of approximately 9.4%, higher than NSPI's requested 9.2%, and for lower risk distribution utilities.

Q. Is it your view that the CAPM is not inherently superior to other tests and should not be used as the sole, or even the primary, test to set the allowed ROE?

A. Yes. The CAPM is intended to estimate what investors should require if the assumptions of the model hold. It does not measure the returns that are actually available to investors. Consequently, in principle, it does not measure comparable investment returns, which is a requirement of the fair return standard.

Even the "father" of Modern Portfolio Theory, Dr. Harry Markowitz has taken issue with the CAPM. Dr. Markowitz has stated that "The CAPM is a thing of beauty. Thanks to one or another counterfactual assumption, it achieves clean and simple conclusions."[35] A key counter-factual assumption is the investor's ability to borrow unlimited amounts at the risk-free rate. He concludes that because key assumptions of the model do not hold,

[34] *Ibid.*, Appendix B.
[35] Markowitz, Harry M., "Market Efficiency: A Theoretical Distinction and So What?", *Financial Analysts Journal*, September/October 2005, page 29.

then it no longer holds that expected returns are linearly related to beta. He does state that CAPM should be taught, despite its drawbacks.

> It is like studying the motion of objects on Earth under the assumption that the Earth has no air. The calculations and results are much simpler if this assumption is made. But at some point, the obvious fact that, on Earth, cannonballs and feathers do not fall at the same rate should be noted and explained to some extent.[36]

The well-known Fama French study [37] of the CAPM concluded:

> The attraction of the CAPM is that it offers powerful and intuitively pleasing predictions about how to measure risk and the relation between expected return and risk. Unfortunately, the empirical record of the model is poor – poor enough to invalidate the way it is used in applications. The CAPM's empirical problems may reflect theoretical failings, the result of many simplifying assumptions. But they may also be caused by difficulties in implementing valid tests of the model... In the end, we argue that whether the model's problems reflect weaknesses in the theory or in its empirical implementation, the failure of the CAPM in empirical tests implies that most applications of the model are invalid.

In a May 2009 survey, "Betas Used by Professors: A Survey with 2,500 Answers," Dr. Pablo Fernandez (the same professor whose market risk premium survey Dr. Booth references at page 66 of his testimony) cites nine different problems with one of the three inputs to the CAPM, beta. These problems include: (1) they have little correlation with stock returns; (2) a beta of 1.0 has a higher correlation with stock returns for many companies; (3) frequently we don't know if the beta of one company is higher than another; (4) the correlation coefficients of the regressions used to calculate the betas are very small; (5) and the relative magnitude of betas often makes very little sense. Based on the issues cited, Dr. Fernandez reaches two findings: the beta calculated with historical data is not a good approximation to the company's beta and the beta of a

[36] *Ibid.*, pages 28-29.
[37] Fama, Eugene and Kenneth French, "The CAPM: Theory and Evidence", *Journal of Economic Perspectives*, Volume 18, Number 3 (Summer 2004).

company (a common figure for all investors) does not exist. The two conclusions, Dr. Fernandez states, imply the CAPM does not work. Ultimately, Dr. Fernandez concludes:

> We argue, as many professors mention, that historical betas (calculated from historical data) are useless to calculate the required return to equity (footnote omitted), to rank portfolios with respect to systematic risk, and to estimate the expected return of companies.

Q. At page 64, Dr. Booth points to the high percentage of corporate CFOs who use CAPM to estimate their cost of capital. Does this finding provide any assurance that calculations of the CAPM cost of equity produce reasonable estimates of a fair ROE?

A. No. Unregulated firms other than utilities use their estimated cost of equity largely for capital budgeting purposes. Corporations will not undertake projects unless the expected rate of return on the project exceeds the estimated cost of capital. Unregulated firms have significant flexibility to make adjustments to simplistic CAPM estimates if and when the calculations do not appear to be reasonable. What Dr. Booth does not mention is that, while a high proportion of companies use CAPM to estimate their cost of capital, the hurdle rates that they use for capital budgeting tend to exceed their corporate weighted average costs of capital by a large margin.

The results of a survey published in 2011 found that what the authors referred to as corporations' "actual" weighted average cost of capital (WACC), i.e., what the authors thought the WACC should be based on their estimates of CAPM based cost of capital, only accounted for approximately one-half of the hurdle rate used by corporations. (In other words, the actual hurdle rates used by corporations were close to twice the authors' CAPM based WACC estimates). The survey found that the mean and median nominal hurdle rates that had been used by the surveyed corporations over the prior two years for a typical project were, respectively, 14.1% and 14.0% for firms that used a WACC equivalent hurdle rate.[38] The corresponding risk-free rate at the time the survey was conducted was estimated as the yield on 10-year Treasury bonds, which was 4.3%.[39] Of the corporations surveyed, over 70% of the respondents stated that the hurdle rate is their WACC. The analysis also showed that the firms' CAPM cost of equity explained only about 10% of the variation among the hurdle rates used by the corporations.[40] One reasonable interpretation of the observed difference between the hurdle rates that corporations use in their capital budgeting versus what they estimate as their CAPM cost of equity is that corporations are not investing in a portfolio of securities, they are investing in irreversible projects that comprise long-term assets.[41] Those projects can be extremely large and their performance can significantly impact the performance of the firm.

Q. Is the application of the CAPM particularly problematic in current financial market conditions?

A. Yes. Long-term government bond yields are abnormally low at present, largely due to a confluence of factors including weak economic conditions, the Bank of Canada's decisions to maintain its overnight rate at historically low levels, investor flight to quality, i.e., away from riskier assets including equities, and a decreasing global pool of safe haven assets. The low level of long-term Government of Canada bond yields has little, if any, correlation with trends in the market cost of equity.[42]

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[38] For all respondents, including those who did not use a WACC equivalent discount rate, the mean and medians were 14.8% and 15.0% respectively. The corresponding mean real hurdle rate was 12.3%.
[39] The survey was conducted in 2003.
[40] Jagganathan, Ravi, Iwan Meier, and Vefa Tarhan, "The Cross-Section of Hurdle Rates for Capital Budgeting: An Empirical Analysis of Survey Data", *National Bureau of Economic Research Working Paper* No. 16770, February 2011. Equity risk premium surveys of CFOs that are conducted by annually by Drs. Graham and Harvey, an article of whom Dr. Booth cites at page 63, document that, while the majority of corporations use CAPM, their market risk premium is "supplemented" so that their hurdle rate exceeds the expected excess return on the S&P 500.
[41] The authors posit that the difference in the hurdle rates and the WACC reflects the availability of valuable alternative investment opportunities, i.e., the hurdle premium reflects the option to wait for better investment opportunities.
[42] In its March 2012 *Equity Gilt Study*, Barclays Capital stated:

> Our analysis suggests that current equity prices are consistent with future returns that are not far from historic norms. By contrast, rates of returns on risk-free assets stand out as abnormally low, as they are currently negative on an inflation adjusted basis in nearly all cases. An important reason for these low

Q. Can you provide some perspective on how much higher the market equity risk premium could be at Dr. Booth's forecast 2013-2014 3.5% average long-term Government of Canada bond yield than the long-term experienced risk premium in Canada?

A. Yes. Over the long-term (1924-2011), the average achieved market risk premium was 5.4%, reflecting an average equity market return of 11.4% and a bond income return[43] of 6.0%. The latter is 2.5 percentage points higher than Dr. Booth's forecast long-term Canada bond yield of 3.5% over the two-year test period. Table 1 below shows that except at the lowest levels of long-term Government of Canada bond income returns, average equity returns have been broadly in the range of approximately 11.0% to 12.5% during the two periods. At bond income returns below 8% (average of approximately 4.5%), the corresponding equity risk premium averaged approximately 7.25%. Only when the highest levels of bond income returns are included do the average achieved equity risk premiums drop to approximately 6.0% and then to approximately 5.5%. In other words, the historical data indicate that the equity risk premium has varied with bond yields, i.e., higher risk premiums at lower levels of bond yields and vice versa. At the level of long-term Government of Canada bond yields forecast by Dr. Booth for the test period, the average achieved equity risk premium was close to 9.0%, compared to the range of 5.0% to 6.0% that Dr. Booth uses in his CAPM calculations.

> yields is the structural decrease in the supply of risk-free assets that is not likely to be corrected in the next few years. The implication is that equity risk premia - the difference between the expected yields on equities and risk free assets - are likely to remain historically high even if cyclical factors could lead them to reverse somewhat over the next few years. (page 4)

Barclays concluded that equity risk premia "are meaningfully higher than historical experience." (page 6)

[43] The bond income return reflects only the coupon payment portion of the total bond return. As such, the income return represents the riskless component of the total government bond return. The bond income return is similar to the bond yield. The bond total return includes annual capital gains or losses and reinvestment of the bond coupons. In principle, using the bond income return in the calculation of historical risk premiums more accurately measures the historical equity risk premium above a true risk-free rate.

Table 1

Bond Income Returns:	Averages for the Period: 1924-2011		
	Equity Returns	Bond Income Returns	Risk Premium
Below 4%	13.9%	3.2%	10.7%
Below 5%	12.6%	3.7%	8.9%
Below 6%	11.1%	4.2%	7.0%
Below 7%	11.3%	4.3%	7.0%
Below 8%	11.8%	4.6%	7.3%
Below 9%	10.9%	4.9%	5.9%
All Observations	11.4%	6.0%	5.4%

Source: www.bankofcanada.ca, Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924- 2011.*

Alternatively, the expected market equity rate of return and equity risk premium can be estimated from historical returns and their relationship to inflation. The expected return on equity should be equal to the sum of the real risk-free cost of capital, the expected rate of inflation and an equity risk premium. Historically, on average, the actual rate of consumer price (CPI) inflation in Canada was higher than the rate of inflation currently forecast to prevail over the longer term. The arithmetic average CPI rate of inflation from 1926-2011 in Canada was 3.0%; the most recent consensus long-term (2013-2022) forecast of CPI inflation is 2.0%.[44] The lower forecast rate of inflation compared to the historical rate of inflation might suggest that expected nominal equity returns would be lower than they have been historically. However, an analysis of nominal equity returns, rates of inflation and real returns on equity shows that real equity returns have generally been higher when inflation was lower. Table 2 below summarizes the nominal and real rates of equity market returns historically at different levels of CPI inflation.

[44] Consensus Economics, *Consensus Forecasts*, April 2012.

Table 2

Inflation Range	Nominal Equity Return	Average Rate of Inflation	Real Equity Return
Less than 1%	15.7%	-1.4%	17.0%
1-3%	12.4%	1.9%	10.4%
3-5%	4.8%	4.1%	0.7%
Over 5%	12.5%	9.2%	3.3%
Avg. 1924-2011	11.4%	3.0%	8.4%

Source: Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2011;* www.statscan.ca.

The observed negative relationship between the real equity return and the rate of inflation does not support a reduction to the historic nominal equity rates of return for expected lower inflation for the purpose of estimating the future equity risk premium. It also bears noting that, while the average real equity return in Canada over the longer period was 8.4%, the average is materially affected by the inclusion of high inflation years. When years in which inflation exceeded 10% are excluded (seven of 88 observations), the average real equity return is a full percentage point higher, i.e., 9.4%. The corresponding average rate of CPI inflation was 2.3%, similar to the forecast rate of inflation. The average real equity return is similar, at approximately 9.5%, when the years in which inflation exceeded 10% and the same number of abnormally low inflation years (average of -4.1%) are removed. At a real equity return of 9.5% and an inflation rate of 2.0%, the indicated nominal equity return is approximately 11.5%. At a nominal equity return of 11.5%, the market equity risk premium at Dr. Booth's forecast 3.0%-4.0% long-term Canada bond yield is 7.5% to 8.5%.

The two analyses above support a market risk premium of no less than 8.0% at Dr. Booth's forecast long-term Canada bond yield.

Q. How do you reconcile these results with the results of the most recent (2012) Fernandez survey that Dr. Booth cites (page 12), which shows that the median market risk premium estimate of analysts, professors and companies for Canada was 5.5%?

A. Surveys of market risk premiums are problematic for several reasons. First, there appears to be a significant amount of circularity in the results. Of the 1650+ responses to the 2102 Fernandez survey that provided the source of their estimates, close to 85% of the respondents appear to use other published sources, rather than their own estimates.[45] Second, it is not clear with what risk-free rate the survey market risk premium estimates are intended to be applicable. In the 2009 generic cost of capital proceeding before the Alberta Utilities Commission, Dr. Booth was asked to define the market equity risk premium, and responded that "As used by most expert witnesses before the AUC the equity market risk premium is the difference between the long run equity and long run government bond return."[46] The 2013-2014 forecasts of long-term Government of Canada bond yields are materially lower than either their long-term historical average or the forecast long-run average.[47] The survey does not specify whether, when they use their reported estimates of the equity market risk premium, respondents use them in conjunction with a long-run average risk-free rate or whether they make adjustments they to the estimated market risk premium to account for differences between the long-run average and prevailing risk-free rates. Third, the survey does not specify what other adjustments respondents might make if they are using their estimate of the market risk premium to derive a cost of equity for a particular company.[48]

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[45] Fernandez, Pablo, Javier Aguirreamalloa and Luis Corres, *Market Risk Premium used in 82 countries in 2012: a survey with 7,192 answers"*, page 10.

[46] Dr. Laurence Booth, Response to ATCO-CAPP-11(b), 2009 Generic Cost of Capital Proceeding, Application No. 1578571, ID 85, March 24, 2009.

[47] As shown in Table 1, the historical average long-term Government of Canada bond income return was 6.0%. The most recent long-term Consensus Economics, *Consensus Forecasts*, April 2012, indicates that, over the longer-term, the 30-year Government of Canada bond yield is expected to be approximately 5.0%.

[48] For example, analysts frequently make adjustments to the market equity risk premium for the size of the company, as the "market" is dominated by large capitalization stocks and empirical studies that have documented higher returns for smaller companies than predicted by the CAPM. To provide some perspective, using the U.S. equity market as an illustration, such adjustments for size could range from approximately one percentage point for a mid-cap equity to over six percentage points for micro-capitalization equities (Ibbotson, *SBBI 2012 Valuation Yearbook Market Results for Stocks, Bonds, Bills, and Inflation 1926-2011,* pages 89-95).

Q. Dr. Booth uses a beta of approximately 0.50 to adjust his equity market risk premium to derive his estimate of the benchmark utility risk premium. Please comment on the reasonableness of his downward adjustment.

A. The 0.50 downward adjustment made by Dr. Booth is based largely on the long-term correlation between utility share price movements and share price movements in the TSX and his judgment. However the correlation in share price movements bears no relationship to the actual relationship between actual market returns for utilities and returns for the market as a whole. Over the long-term, the market returns over long-term Canada bonds that investors have achieved in utility shares in both Canada and the U.S. have been higher than 50% of the achieved equity market risk premiums. That experience is consistent with the empirical evidence that lower (higher) beta stocks generally have achieved higher (lower) returns than the CAPM and beta would have predicted. The objective of the CAPM is an estimate of the returns that investors expect or require. Using a beta or relative risk adjustment of 0.50 for a benchmark utility will understate that return.

Q. Dr. Booth claims (page 65) that using a long-term risk-free rate rather than the short-term interest rates in the CAPM adjusts for the bias in the tests of the CAPM that showed lower beta stocks earned higher returns than the CAPM predicted. Please comment.

A. Applying the model using a long-term rather than the short-term risk-free rate that has typically been used in empirical studies of the CAPM does adjust somewhat for the flatter relationship observed between beta and average return. However, Dr. Booth presents no evidence that suggests using a long-term rate rather than a short-term risk-free rate fully adjusts for the bias.

The Fama French study of the CAPM (referenced above) found, based on analysis covering 1928 to 2003 for the U.S. market, the predicted return on the lowest beta stock portfolio was 2.8 percentage points lower than the actual return. As illustrated below, the results of this study suggest that using a long-term risk-free rate rather than a short-term rate does not come close to close to capturing the observed difference between the predicted and actual returns for low beta portfolios generally or for utility stocks in Canada and the U.S. specifically.

At page 65, Dr. Booth references a spread (or maturity premium) in Canada between Treasury bill and long-term Canada bond yields. Assume, illustratively, that over the long-run, the long-term Canada bond yield is 5.0%, the Treasury bill rate is 3.75% (i.e., 1.25% lower), and the market return is 10.5% (equal to a long-run market risk premium of 5.5% plus the 5.0% long-term Canada bond yield) and the "raw" beta of a utility portfolio is 0.50. Using the short-term rate as the risk-free rate produces a CAPM return of 7.125% (3.75% + 0.50 (10.5%-3.75%)). When a long-term Government of Canada bond yield of 5.0% is used as the risk-free rate, the CAPM return is equal to 7.75% (5.0% + 0.50 (10.5%-5.0%)). Replacing the short-term Treasury bill rate with the long-term government bond yield adjusts the cost of equity of a stock with a 0.50 "raw" beta upward by 0.625 percentage points, significantly less than the 2.8 percentage points referenced in the Fama and French study.

Q. Is it possible to demonstrate this using data specifically for Canadian utilities?

A. Yes. A regression of the monthly returns on the TSX Utilities Index against the market risk premium measured as the return on the TSX Composite less the risk-free rate as proxied by 90-day Treasury bill returns over the period 1970-2011[49] shows the following:

[49] The Monthly TSX Utilities Index Returns are comprised of the monthly returns on the TSE Gas & Electric Index for the period January 1970 to April 2003 and the monthly returns on the S&P/TSX Utilities Index for the period May 2003 to December 2011.

Table 3

$$\text{Monthly TSX Utilities Index Return} = 0.009 + 0.465 \left\{ \text{Monthly TSX Composite Excess Return} \right\}$$

t-statistics	=	5.4	13.8
R^2	=	28%	

The relationship quantified in the above equation suggests a long-term utility beta of 0.465. However, the R^2, which measures how much of the variability in utility returns is explained by variability in the returns of the equity market as a whole, is only 28%. That means 72% of the monthly volatility in utility returns remains unexplained. The intercept in the equation should, in principle, represent the risk-free rate. Over the entire 1970-2011 period, the average annual return on Treasury bills was 7.0%; the corresponding intercept in the equation above is 10.85%, when expressed on an annualized basis.[50] The difference between the calculated intercept and the average 90-day Treasury bill return of approximately 3.9% represents the component of the utility return incremental to what the CAPM would predict, considerably greater than the adjustment implied by using a long-term rather than a short-term risk-free rate.

Q. Dr. Booth states in Appendix C (page 11) that his calculation of betas is consistent with conventional practice. He compares utility betas published by three other sources to his own calculated betas, and notes that none of the three sources of betas does any adjustments to their calculations nor discusses any adjustments. Do these observations constitute evidence that unadjusted betas are appropriate for use in the application of the CAPM?

A. No. The sources cited by Dr. Booth are simply providing calculations of historical regressions of percentage share price changes for specific companies on percentage changes in an equity market index. They are not prescribing the use of the resulting calculated betas to estimate the cost of equity. They make no claims that the historical

[50] The regression was performed using monthly data, so the intercept of 0.009 is equal to the monthly return on 90-day Treasury bills. The annualized return is equal to $(1+.009)^{\wedge 12}-1.0 = 0.1085 = 10.85\%$.

regression results they publish will produce a reasonable estimate of the cost of equity if utilized in the application of the CAPM.

Q. Are you aware of any studies that indicate that adjusted betas do a better job of predicting returns than the calculated regression or "raw" betas, such as the ones cited by Dr. Booth in Appendix C?

A. Yes. In an article released in May 2009 ("β = 1 Does a Better Job than Calculated Betas"), the same Dr. Fernandez cited above and co-author, Vicente Bermejo find that adjusted betas (i.e., the Blume adjustment cited by Dr. Booth at page 8 of Appendix C, equal to 0.67 X calculated "raw" beta + 0.33 X Market Beta of 1.0) do a better job of predicting returns than the calculated beta. They also find that assuming a beta of 1.0 (i.e., the market beta) does a better job than the adjusted beta.

Q. Given the latter finding, would you recommend using a beta of 1.0 for utility stocks?

A. No. I recommend using adjusted betas with the "Blume" formulation, used by a number of major publishers of betas, including *Value Line*, Bloomberg and Merrill Lynch, which balances the importance of reliance on a risk adjustment that reasonably predicts expected and required returns with the recognition that utility stocks are of lower than average (compared to the market) risk.

Q. What have been the adjusted betas of the sample of electric utilities that you used as comparables for NSPI?

A. As shown in Rebuttal Schedule 2, since the mid-1990s, the adjusted betas for the comparable electric utilities as reported by *Value Line*, have averaged approximately 0.70.

Q. Given Dr. Booth's forecast of long-term Canada bond yields, an estimate of the market risk premium of 8.0% at that level of yields, and an adjusted beta of 0.70, what is a reasonable estimate of the CAPM cost of equity for NSPI?

A. The estimated CAPM cost of equity, including, as Dr. Booth does, an adjustment of 0.50% for financing flexibility, is 9.6%, higher than the 9.2% ROE that NSPI is requesting.

Q. How does the CAPM cost of equity compare to a more direct estimate of the expected utility return on equity developed from historical utility market data?

A. It is a conservative estimate. As shown in Table 4 below, over the longest term available (1956-2011),[51] the average achieved utility (electric and gas combined) equity risk premium in Canada was 4.8% in relation to bond income returns for long-term Government of Canada bonds.[52] For U.S. electric utilities, the average historic utility equity risk premium in relation to bond income returns over the entire post-World War II period (1947-2011) was 5.1%. For U.S. gas utilities, the corresponding average historic utility equity risk premium was and 6.0%.

Table 4

	Utility Equity Returns	Bond Income Returns	Utility Risk Premium Relative To Bond Income Returns
Canadian Utilities	12.1%	7.3%	4.8%
U.S. Electric Utilities	11.0%	5.9%	5.1%
U.S. Gas Utilities	11.9%	5.9%	6.0%

Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2011*; www.federalreserve.gov; Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2012 Yearbook*; www.standardandpoors.com; and *TSX Review*.

[51] The longest period for which Canadian utility index data are available from the Toronto Stock Exchange.

[52] Based on the Gas/Electric Index of the TSE 300 from 1956 to 1987 and on the S&P/TSX Utilities Index from 1988-2011.

As with the risk premiums for the market composite, the magnitude of achieved utility equity risk premiums is a function of both the equity returns and the bond returns. An analysis of the underlying data indicates there has been no secular upward or downward trend in the utility equity returns. Trend lines fitted to the historic utility equity returns for each of the three utility indices are flat. The historical average utility returns in both Canada and the U.S. have clustered in the range of 11.0-12.0%. However, the achieved government bond income returns in Canada over the period of analysis, at 7.3%, were materially higher than Dr. Booth's 3.5% test period average forecast yield on 30-year Government of Canada bonds.

A reasonable approach to interpreting the historical utility equity market return data is the recognition of the inverse relationship between utility equity risk premiums and government bond yields. Table 5 derives estimates of the utility equity risk premium for the longer term from the historical average risk premiums by applying a 50% sensitivity factor to the difference between the historical average bond income returns and the forecast Government of Canada bond yield forecast.[53]

Table 5

		Canadian Utilities	U.S. Electric Utilities	U.S Gas Utilities
Equity Returns	(1)	12.1%	11.0%	11.9%
Bond Income Returns	(2)	7.3%	5.9%	5.9%
Utility Risk Premium (RP)	(3) = (1) – (2)	4.8%	5.1%	6.0%
Forecast 30-Year Canada Bond Yield (LCBY)	(4)	3.5%	3.5%	3.5%
Change in Bond Yield/Return	(5) = (4) – (2)	-3.8%	-2.4%	-2.4%
Change in Utility Equity RP	(6) = – (5) X 50%	+1.9%	+1.2%	+1.2%
Utility Equity Risk Premium at 3.5% LCBY	(7) = (3) + (6)	6.7%	6.3%	7.2%

Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2011*; www.federalreserve.gov; Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2012 Yearbook*; www.standardandpoors.com; and *TSX Review*.

[53] The 50% sensitivity factor with the sensitivity factor on long-term Government bonds utilized in the automatic adjustment formula adopted by the OEB in 2009, which, in turn, was based on the empirical evidence filed with the OEB in its 2009 cost of capital consultation, as discussed at pages 20-21 of my direct evidence.

At Dr. Booth's forecast 3.5% 30-year Government of Canada bond yield and a 50% sensitivity factor between utility equity risk premiums and long-term government bond yields, the indicated utility equity risk premium derived from historical averages is in the approximate range of 6.25% to 7.25% (mid-point of estimates of approximately 6.75%). The corresponding utility cost of equity, is in the range of approximately 9.75% to 10.75%, higher than the 9.2% ROE requested by NSPI, even before any adjustment for financing flexibility.

D. DISCOUNTED CASH FLOW TEST

Q. Dr. Booth effectively dismisses the discounted cash flow (DCF) test applied to utilities (Appendix D, page 13-16), and claims that DCF estimates are unreliable when estimated from analysts' growth rates that are known to be biased (page 78 and Appendix D, pages 14-16). Please address.

A. At the outset, I would point out that Dr. Booth's position on the importance of the DCF test applied to utilities is at odds with the perspectives of the experts who gave evidence on the cost of equity in NSPI's 2012 GRA. Although the four experts, including myself, who filed evidence with the Board gave different weights to the DCF test applied to utilities, ranging from preponderant weight to approximately one-third weight, all four experts agreed that the DCF test is an important methodology for the estimation of a fair return on equity for a utility.

I would also note that in the BCUC 2009 Cost of Capital Decision,[54] the BCUC found that "As for the two most commonly used approaches [CAPM and DCF], the Commission Panel finds that the DCF approach has the more appeal in that it is based on a sound theoretical base, it is forward looking and can be utility specific." In its 2009

[54] BCUC, *2009 Cost of Capital Decision*, page 45.

Cost of Capital Report, the OEB implicitly gave significant weight to the DCF test in arriving at its benchmark utility cost of equity.[55]

In addition, the DCF test applied to utilities is one of the principal tests employed by U.S. regulators, both federal and state, to estimate the fair ROE. While utility cost of capital experts in the U.S. routinely take the position that the DCF test, like other tests, has its own set of "warts" and is not inherently superior to other tests (and thus should be used exclusively), I am not aware of any expert who has taken the position that it should be disregarded.

With respect to Dr. Booth's reference to analysts' forecasts that "are known to be biased", I acknowledge that there have been studies that have concluded that analysts' earnings forecasts have tended to be optimistic. Analyst optimism became a high profile issue during the irrational exuberance phase of the technology boom during the 1990s, when analysts were accused of fueling the market by exaggerating the prospects of dot.com firms. It was this behaviour that ultimately led to Regulation FD (Fair Disclosure) in 2000 and the Global Analyst Research Settlements of 2002 in the U.S. which removed incentives for sell-side analysts to curry favor with company management by issuing inflated earnings forecasts.

A study conducted after the Global Settlement found that following the settlement, the mean forecast bias declined significantly, whereas the median forecast bias essentially disappeared.[56] There are also studies which have shown that analyst optimism is at least in part related to the difference between forecasting earnings for firms who report losses versus firms who report profits. For example, Jeffery Abarbanell and Reuven Lehavy, "Biased Forecasts or Biased Earnings? The Role of Reported Earnings in Explaining Apparent Bias and Over/Underreaction in Analysts' Earnings Forecasts", *Journal of Accounting and Economics 36* (2003), pages 105-146, found that while, on an average

[55] The OEB's benchmark utility equity risk premium and cost of equity was based on the composite of estimates provided by expert witnesses, which included a significant number of DCF-based cost of equity estimates.

[56] Armen Hovakimian and Ekkachai Saenyasiri, "Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation", Arizona State University, April 20, 2009.

basis, there appeared to be a forecast bias, the median forecast error was zero. The same article cited an earlier study, Michael P. Keane and David E. Runkle, "Are Financial Analysts' Forecasts of Corporate Profits Rational?", *Journal of Political Economy 100* (1998), pages 768-805, which, when the authors eliminated observations from their data sample based on the size of negative special items "nearly eliminate evidence of mean optimism in their sample."

Given the greater transparency of the utility business model (e.g., regulatory filing requirements) relative to some other industries, the more stable operations of utilities, and the value rather than "glamour" nature of utility shares, analyst optimism should be less of an issue with utility earnings forecasts. Moreover, to the extent that any analyst optimism is shared by investors and impounded in the stock prices, it would be incorrect to reduce the analysts' growth forecasts without a simultaneous adjustment to dividend yields.

The potential bias of the analysts' growth rates for U.S. utilities was assessed in three separate ways. First, because utilities are quintessentially mature companies, it is reasonable to expect that investors would anticipate that, over the long-term, growth would parallel the long-term nominal rate of growth in the economy. In this context, the Thomson Reuters earnings growth forecasts, for which Foster Associates maintains a data base which contains monthly consensus forecasts for utilities back to 1976, were compared to the consensus forecasts of long-term growth. Over the past 15 years (since 1997, the median consensus analysts' forecast long-term earnings growth rate for the sample of U.S. utilities electric utilities was 5.3%. That growth rate is very similar to the average consensus forecast of long-term nominal growth in the economy over the same period. The average expected long-term nominal rate of growth in the U.S. economy, based on consensus forecasts (Blue Chip *Economic Indicators*, March and October editions, 1997-2012), was 5.1% from 1997-2012Q2. The similar expected nominal growth in the economy compared to the consensus analysts' forecasts suggests that the consensus long-term earnings growth forecasts are not an upwardly biased measure of investor expectations.

Second, the consensus analysts' forecasts were compared to the long-term earnings forecasts for the same companies made by *Value Line*. As an independent research firm, *Value Line* has no incentive to "inflate" its estimates of earnings growth in an attempt to make stocks more attractive to investors, which is the criticism frequently aimed at equity analysts. Since 1997, the average *Value Line* long-term earnings growth rate forecast for the sample of companies was 6.2%, compared to the average consensus analysts' long-term earnings growth rate forecast for the same companies of 5.3%. Again, the higher *Value Line* than the consensus analysts' forecasts suggest that the consensus long-term earnings forecasts are not upwardly biased.[57]

Third, allowed returns for U.S. utilities are derived in large part by reference to the results of the DCF model. Regulators in all jurisdictions, however, do not use the same form of the DCF model. For example, some regulators may rely on the constant growth model, while others prefer to use a multi-stage growth model. In addition, even if different jurisdictions use the same form (e.g., constant growth) of the model, the inputs to the model are not necessarily derived in equivalent ways. For example, two jurisdictions may use the constant growth model but one may favour the use of forecast growth, while another may favour the use of historic growth rates. In the aggregate, however, across all jurisdictions, the differences in approach likely balance out, resulting in the allowed returns reflecting neither an upwardly or downwardly biased measure of the utility cost of equity as a result of the underlying growth assumptions. When the allowed returns for all U.S. utilities published by Regulatory Research Associates (RRA) are compared to monthly constant growth DCF costs of equity for the sample of U.S. electric utilities estimated using the consensus long-term earnings forecasts for the past 15 years, the comparison shows that the allowed returns for all U.S. utilities as reported by RRA exceeded the returns estimated using the constant growth DCF models as follows:

[57] In BCUC, *2009 Cost of Capital Decision*, page 45, the BCUC stated:

> The Commission Panel has considered the submission of the JIESC concerning "upward bias" of analysts' estimates and considers that no allegations of upward bias have been levelled against utility analysts and that *Value Line* estimates will be free from any suggestion of upward bias. Accordingly the Commission Panel will not give any weight to suggestions of analyst bias.

Table 6

Average Allowed ROEs 1997Q3-2012Q2[1/]	10.5%	**Average Difference From Allowed ROEs**
Constant Growth DCF Cost of Equity 1997Q3-2012Q2	10.2%	-0.3%

[1/] Weighted average.
Sources: Regulatory Research Associates and Rebuttal Schedule 3.

The comparison of the DCF costs of equity to the ROEs allowed by regulators provides a further indication that the earnings forecasts are not an upwardly biased measure of investor expectations.

In addition, I have estimated DCF costs of equity for the sample of U.S. electric utilities using three different models, one based on analysts' earnings growth forecasts, one based on sustainable growth, and a three-stage growth model, which incorporates both analysts' forecasts and long-term growth in the economy. The results of the three models establish a range of DCF costs of equity, bounded at the lower end by the sustainable growth model results and at the upper end by the analysts' earnings forecasts model results, with an average for all three models approximately equal to NSPI's requested ROE of 9.2%.[58] The addition of an adjustment for financing flexibility equal to the 0.50% used by Dr. Booth supports an ROE for NSPI, even without an adjustment for NSPI's low regulated common equity ratio of 37.5% compared to the sample average 48%, of 9.75%.

E. USE OF U.S. COMPARABLES

Q. Dr. Booth takes issue with the use of U.S. utilities in deriving estimates of the cost of equity for Canadian utilities for several reasons, including (1) higher market volatility in the U.S.; (2) higher estimates of the market risk premium in the U.S. than Canada; (3) higher 30-year Treasury than Government of Canada bond yields

[58] As stated at page 33 of my direct testimony, "The results of the constant growth and three-stage DCF models indicate an estimated "bare bones" cost of equity of approximately 9.25%. A cost of equity of 9.25% is similar to the 9.2% ROE proposed by NSPI."

and (4) higher risk of U.S. utilities than Canadian utilities. Please address each of these factors.

A. As a general comment, I find Dr. Booth's concerns with the use of U.S. utilities somewhat perplexing, given that (1) Dr. Booth concludes at page 77 that his estimates of the equity market returns in Canada and the U.S. are similar; (2) he states at page 78 that his estimate of the utility equity risk premium using the U.S. S&P gas and electric index is broadly similar to his CAPM risk premium estimate for Canadian utilities; (3) he gives weight to U.S. evidence in deriving his equity market risk premium for Canada (page 66); (4) he shows that the most recent Fernandez market risk premium surveys indicate virtually identical equity risk premiums in the two countries (Appendix B, page 11); and (5) he agrees that one can select a sample of utilities from the U.S. universe that is comparable to the overall population of utilities in Canada (Appendix C, page 7).

With respect to his comment that there has been higher market volatility in the U.S. market than in Canada, the historic annual volatility in the two markets over the longer-term has been quite similar. The table below compares the average arithmetic equity market returns and the corresponding standard deviations, as well as the compound (geometric) average returns from 1926-2011 and post-World War II (1947-2011) for the two countries.

Table 7

	Canada		
	Arithmetic Average	**Standard Deviation**	**Compound Average**
1926-2011	11.2%	18.9%	9.6%
1947-2011	11.8%	17.1%	10.4%
	United States		
	Arithmetic Average	**Standard Deviation**	**Compound Average**
1926-2011	11.8%	20.3%	9.8%
1947-2011	12.3%	17.4%	10.9%

Source: Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2011*, Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2012 Yearbook*.

To put the differences in the relative volatility and risk of the two markets in perspective over these two time periods, it is useful to compare the differences between the arithmetic and compound average returns in the two markets. The difference between the arithmetic and compound average returns is approximately equal to one-half of the variance in the annual returns. The variance in the arithmetic average returns in turn is equal to the standard deviation squared. The larger the difference between the arithmetic and compound averages, the more volatility there has been in the annual returns.

For the longer period, 1926-2011, the difference in the arithmetic and compound average returns in Canada was 1.7%; the corresponding difference in the U.S. was 2.0%, a difference between the two of approximately 0.3%. During the post-World War II period, the difference in both Canada and the U.S. was approximately 1.4%. The two differentials between the Canadian and U.S. arithmetic and compound average returns can be interpreted as the difference in equity return required for the difference in volatility between the two markets. In other words, based on the longer period, the equity market return required would be 0.30% higher in the U.S. than in Canada and based on the post-World War II period, the equity market return required would be the same in the U.S. and in Canada. In sum, the differences are *de minimus*.

Further, a comparison of the volatility of the two equity markets from approximately the time of the Lehman Brothers failure that Dr. Booth references at page 41 (i.e., over the past four years from August 2008 to July 2012) shows that, based on the standard deviations of weekly price changes in the S&P/TSX Composite (Canada) and the S&P 500 (United States), the two markets have exhibited virtually identical volatility.

With respect to the higher estimates of market risk premiums in the United States than Canada, that difference may be simply due to the derivation of estimates from historical data. Historically, achieved risk premiums in Canada were lower than in the U.S., due largely to the fact that interest rates in Canada were historically significantly higher than in the U.S. That is no longer the case. As noted above, the most recent Fernandez survey of equity market risk premiums would no longer appear to support Dr. Booth's contention that estimates of market risk premiums are higher in the U.S. than in Canada.

With respect to higher 30-year Treasury than Government of Canada bond yields, while it is true that they are higher, other interest rate comparisons show very similar levels in the two countries. As shown in the Table below, the 10-year government bond yield (which is the benchmark yield in the U.S.) has been higher in Canada, and the yields on corporate bonds of various investment grade categories have been very similar. On balance, the comparison across multiple categories of interest rates indicates a similar cost of capital environment in the two countries.

Table 8

	Interest Rate Differences (%): Canada Minus U.S.				
	10-Year Government	30-Year Government	Long-term Corporate AAA/AA	Long-term Corporate A	Long-term Corporate BBB
1/2011-7/2012	0.03	-0.55	-0.05	-0.06	0.01
8/2011-7/2012	0.10	-0.41	0.04	0.02	0.03
2/2012-7/2012	0.06	-0.46	-0.15	-0.03	-0.08
7/2012	0.17	-0.29	-0.04	0.18	0.07

Source: Rebuttal Schedule 4

Finally, with regard to the risk of U.S. versus Canadian utilities, the population of Canadian investor-owned utilities is dominated by "pipes" and "wires" companies and the population of U.S. investor-owned utilities is dominated by vertically integrated electric utilities. It is therefore not surprising that the universe of U.S. utilities is somewhat riskier than the universe of Canadian utilities.

Q. Dr. Booth claims that U.S. vertically integrated utilities are riskier than NSPI. He purports to demonstrate this conclusion by comparing the betas of a sample of low risk U.S. utilities that he considers to be of similar risk to his benchmark Canadian

utility, a sample of vertically integrated electric utilities and Emera. Do you agree with his analysis?

A. No, in several respects. First, not all utilities in the U.S. would be considered of comparable risk to NSPI, just as not all utilities in the U.S. are of comparable risk to each other. Although it is possible to select a sample of U.S. electric utilities that may be of higher risk than NSPI, it does not logically follow that all U.S. vertically integrated utilities are of higher risk than NSPI or that it is not possible to select a sample of U.S. electric utilities that is of comparable risk to NSPI.

Dr. Booth's selection of U.S. electric utilities appears to have been fairly random, in contrast to my own selection criteria, which are set out on page 27 and 28 of my direct testimony.[59] Rebuttal Schedule 5[60] provides comparative data for Dr. Booth's electric utility sample and mine. Rebuttal Schedule 5 demonstrates that Dr. Booth's sample of electric utilities is a higher risk sample than mine. To illustrate, the median S&P and Moody's debt ratings for my sample are A- and Baa1 respectively. The corresponding ratings for his sample are BBB and Baa2.

Q. Dr. Booth attempts to demonstrate that his sample of vertically integrated utilities are of materially higher risk than the sample of low risk U.S. utilities that he considers of comparable risk to a benchmark Canadian utility by comparing the betas of the two samples over time. Would you please comment on his findings?

A. Rebuttal Schedule 2 presents the published *Value Line* betas for his vertically integrated electric utility sample and low risk utility sample as well as my vertically integrated electric utility sample from 1996 to 2012. The table below summarizes the differences in

[59] Dr. Booth judges whether the utilities in his sample are relatively "pure" utilities by the percentage of revenues reported by his data source as "electric utility". These percentages can be misleading, as in the case of Hawaiian Electric Industries, for which Dr. Booth's data source reports 92% regulated revenues. Hawaiian Electric Industries is a combined electric utility and banking firm, whose 2011 earnings were comprised of $100 million electric utility, $60 million banking and -$22 million "Other". Hawaiian Electric Industries is categorized by the Edison Electric Institute as a diversified utility, as contrasted with "Regulated" or "Mostly Regulated".

[60] Rebuttal Schedule 5, pages 1 and 2 of 2 is an update of Schedule 6 from my direct testimony and corresponding data for Dr. Booth's sample.

the *Value Line* betas among the three samples. The *Value Line* betas for Dr. Booth's electric utility samples have been somewhat higher than those of his low risk utility sample. For my electric utility sample, however, the average and median *Value Line* betas have actually been slightly lower than those of Dr. Booth's **low risk** utility sample. The comparison highlights the facts that (1) beta is only one measure by which relative risk can be assessed; and (2) in isolation, the reported *Value Line* betas do not indicate significant differences in risk among the various samples.

Table 9

	Average Differences	
	1996-2012	**2008-2012**
	McShane-Booth Electric Utility Sample	
Average	-0.03	-0.02
Median	-0.03	-0.05
	McShane Electric Utility - Booth Low Risk Sample	
Average	-0.03	-0.06
Median	-0.03	-0.09
	Booth Electric Utility - Booth Low Risk Sample	
Average	0.03	0.06
Median	0.03	0.09

Q. What about Dr. Booth's comments that Emera's beta is even lower than the low risk utility sample and the universe of Canadian utilities, from which he infers that the "market views Emera differently from the U.S. electrics" and "Since NSPI has been the major holding of Emera since inception this conclusion also applies to NSPI" (page 84)?

A. As Dr. Booth quite correctly points out (page 84), one cannot put much stock in individual company betas. This is particularly true in cases where a company has been transforming its business or, as Emera has been over the past 10+ years, growing and diversifying its operations. Given the company's evolution since 2001 (the year Bangor Hydro was acquired), no reliable inferences as to how the market views Emera can be drawn from its betas.

Q. At page 87, Dr. Booth says that it is commonly accepted that U.S. utilities are riskier than U.S. utilities, and cites both Moody's and S&P in support of his conclusion. Please respond.

A. With the caveat that its risk assessment is from the perspective of a bond holder, not an equity holder, Dr. Booth is correct that Moody's considers the Canadian regulatory environment generally to be more supportive than the U.S. regulatory environment generally. However, that does not mean that that Moody's views all U.S. regulatory jurisdictions as the same, that it views all U.S. utilities to be higher business risk than all Canadian utilities, or that Moody's views all Canadian utilities as of lower overall (business plus financial) risk than U.S. utilities. Schedule 6 of my direct evidence (and as noted above) shows that the average and median Moody's rating for my sample of electric utilities is Baa1, which is the same rating that it had assigned to NSPI prior to withdrawal. From Moody's perspective, then, my electric utility sample is of comparable total risk to NSPI.

.**Q. At page 89, Dr. Booth highlights the Moody's reference to the four utility bankruptcies that have occurred in the U.S. in the past 50 years due to insufficient rate relief as evidence of the regulatory higher risk attributed to the U.S. by Moody's. Was the point of Moody's reference to the bankruptcies to underscore higher regulatory risk in the U.S.?**

A. No, it was, as I interpreted Moody's comment, to underscore the importance of regulatory relief to the financial health of utilities. With regard to the specific four bankruptcies, that were related to insufficient rate relief; two of those were nuclear related and the other two were California utilities who were unable to obtain sufficient rate relief when power costs spiked during the transition to a deregulated market. It is of note, with regard to the latter, that Moody's rates the two California utilities' regulatory framework factors as "A", the rating on that factor that it has accorded Canadian utilities operating in Alberta, British Columbia, Ontario, Newfoundland and Labrador as well as Nova Scotia.

Q. What about S&P?

A. Dr. Booth claims at page 89 that the typical bond rating in the U.S. is BBB and the typical bond rating in Canada is A. Neither of these conclusions is correct. As S&P stated in a recent report "Our present ratings on U.S. regulated utility companies remain firmly entrenched at an average 'BBB+'…"[61], which is the same as NSPI's S&P rating.[62] By comparison, the average S&P rating for Canadian utilities is A-, one notch lower (see Schedule 1 of my direct evidence). The average and median rating for my electric utility sample is A-, as shown in Schedule 6 of my direct evidence, the same as for the universe of investor-owned Canadian utilities, and higher than NSPI's S&P rating. From S&P's perspective, NSPI is of similar total risk to the universe of U.S. utilities, and of somewhat higher risk than both the universe of Canadian utilities and my U.S. electric utility sample.

Q. As part of his support for the higher risk of U.S. utilities, Dr. Booth refers to S&P's concern with FERC regulation in respect to Enron and ring fencing. Does this statement by S&P lead to the conclusion that S&P finds FERC regulated utilities to face higher regulatory risk than Canadian utilities?

A. No. In a report comparing transmission utilities, AltaLink (regulated by the Alberta Utilities Commission), American Transmission Company (ATC) and Independent Transmission Company (ITC), the latter two FERC-regulated, S&P concluded that AltaLink faced higher business risk than ATC. This conclusion was largely due to S&P's conclusion that ATC faced the lowest regulatory risk of the three transmission companies.[63]

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[61] S&P, *Industry Economic and Ratings Outlook: U.S. Regulated Utilities Will Likely Stay On A Stable Trajectory For The Rest Of 2012 And Into 2013*, July 17, 2012.

[62] Dr. Booth also states in response to Booth (NSPI)-21, "Note Dr. Booth is aware that many US utilities are rated non-investment grade, but this reflects the different degree of regulatory protection in Canada versus the U.S." Contrary to Dr. Booth's assertion, there are not many utilities in the US that are rated non-investment grade. In its August 2012 report entitled *Issuer Ranking: U.S. Regulated Utility Companies, Strongest To Weakest*, of S&P's 234 regulated utility ratings, there were six that were non-investment grade, three of which were for affiliated companies.

[63] S&P, *Peer Comparison: North American Stand-Alone Transmission Companies Deliver Electricity… and Profits,* April 2006. In addition, Moody's considers the FERC-regulated electric transmission utilities to have the lowest

Q. What is the implication of the conclusion that NSPI's debt ratings are similar to or lower than those of your U.S. electric utility sample?

A. The implication is that NSPI is of comparable to somewhat higher total risk than my sample of U.S. electric utilities and its return on equity should be comparable to somewhat higher than the returns available to its peers.

Q. What have been the returns on equity allowed for U.S. utilities, which, according to S&P are, on average, rated BBB+, the same as NSPI?

A. Over the past 12 months, U.S. utilities (electric and gas) have been allowed returns on equity averaging approximately 10.0%. The ROEs that were adopted for companies in my comparable electric utility sample over the same 12-month period, averaged 10.1%.[64] Both are higher than the 9.2% ROE that NSPI is requesting in this GRA, underscoring the conservative nature of NSPI's request.

III. REBUTTAL TO MS. SMITH

Q. Ms. Smith takes issue with several aspects of NSPI's requested return on equity. Please address Ms. Smith's concerns.

A. First, at page 12 of her Direct Testimony, Ms. Smith incorrectly characterizes the Company's requested return on equity as an Earnings Sharing Mechanism. NSPI is not proposing an earnings sharing mechanism. As NSPI confirmed in Exhibit OR-06, "Sharing mechanisms are typical of Performance-Based regulatory frameworks. There is no such framework in effect for NS Power. Thus this information is not applicable." Nova Scotia Power is requesting to have its return on equity set in the same manner, i.e., expressed within a range, and the same return on equity range of 9.1% to 9.5%, with rates

regulatory risk among U.S. utilities. Moody's gives American Transmission Co. an AA rating on regulatory framework.

[64] Regulatory Research Associates Inc. and Rebuttal Schedule 6.

set with the ROE at the same level (9.2%), as was approved by Board for 2012. The Board has expressed NSPI's allowed return on equity within a range since NSPI's first rate application subsequent to privatization. In each test year since 1993, NSPI's rates have been set at the mid-point of the allowable ROE range, with the exception of the 2012 test year. For the 2012 test year, rates were set using an ROE slightly below the mid-point of the range (9.2% rather than 9.3%), as agreed to as part of the negotiated settlement.

For the 2013 and 2014 test years, as part of the proposed Rate Stabilization Plan, NSPI is explicitly proposing to ensure that 100% of any earnings above the upper end of the allowable ROE range are to the benefit of ratepayers. To the extent that NSPI earns an ROE in excess of 9.5%, 100% of the earnings will be used to reduce costs that were forecast to be incurred in the test years, but deferred for future recovery. However, if NSPI earns an ROE less than 9.2%, 100% of the short-fall in earnings from the target ROE will be to the account of the shareholder. Contrary to Ms. Smith's assertion, there is no provision in the Company's proposed Rate Stabilization Plan that would permit NSPI to raise rates if its actual regulated ROE falls below 9.1%. In other words, during the test period, there is a cap on the actual regulated ROE with no corresponding floor. While Ms. Smith is correct that the ROE proposed for rate setting purposes is below the mid-point of the ROE range, the asymmetry in the range of potential actual ROEs favours customers, not the shareholder.

Second, Ms. Smith claims that what she refers to as the earnings sharing mechanism would allow NSPI to earn an ROE that is considerably higher than the target ROE, i.e., up to 300 basis points above the target ROE before any cost reductions would be flowed through to customers. This is not correct. If the upper end of the ROE range were 300 basis points above the 9.2% target ROE, NSPI would be allowed to earn an allowed ROE of 12.2% before any reduction of the Fixed Cost Recovery Deferral. The Company is proposing to flow through to customers 100% of earnings when the ROE exceeds 9.5%, 30 basis points (0.30%) above the 9.2% ROE at which 2013 and 2014 rates would be set. NSPI's ability to earn returns in excess of the ROE at which rates are set will be considerably less than is typical of other utilities, both those that are operating with and without performance-based rate plans. Most Canadian utilities not operating with performance-based rate plans are allowed to retain 100% of earnings above the allowed ROE. For those operating with performance-based rate plans that include an earnings sharing mechanism are permitted to earn ROEs that exceed the specified allowed ROE by materially more than 0.30%.[65]

Q. Ms. Smith states, at page 13, "While I am not a cost of capital expert, I believe that the reduction in risk alone from the Rate Stabilization Plan should result in some reduction to the ROE." Do you agree with Ms. Smith?

A. No. First, Ms. Smith seems to ignore entirely the context of NSPI's proposal. This is not a typical two-year test period. NSPI is proposing to limit rate increases and defer recovery of forecast costs well beyond the two-year test period during which those costs are expected to be incurred. Allowing approved costs to be deferred is not a guarantee that those costs will be recovered, contrary to Ms. Smith's claim at page 12. The longer the recovery of incurred costs is deferred, the greater the uncertainty that those costs will be recoverable. All other things equal, the deferral of cost recovery increases, not decreases, NSPI's risk. Second, Ms. Smith appears to believe that by proposing a two-year, rather than a one-year, test period reduces NSPI's risk (page 10, lines 170-171). This contention is erroneous. Extending a test period from one to two years does not decrease risk, as the Company's forecasting risk is higher than it would be if it were only forecasting costs and load for a single test year. Ms. Smith appears to acknowledge that to be true, as she states at page 13, "It is usually more difficult to develop accurate forecasts of loads and of fuel costs the further into the future the forecast is being made."

Both one and two-year test periods are fairly common in Canada.[66] While Ms. Smith expects that the approval of revenue amounts for two years will be viewed very

[65] For example, under its incentive regulation plan, Union Gas, with whom Dr. Booth has compared NSPI, is allowed to earn an ROE of up to 200 basis points above the benchmark return on equity before any sharing with customers.

[66] For example, two-year test periods are typical in Alberta and have been frequently used in British Columbia.

favourably by the financial markets, in my more than 30 years of experience as a cost of capital expert, I have found that neither financial markets nor financial market participants have attributed lower risk to utilities with two-year rather than one-year test periods.

Q. Ms. Smith comments at page 12 that amounts approved as part of the 2013 and 2014 revenue requirements that are deferred will not be subject to any further review of prudency. Would you view that as unusual?

A. No. This GRA is the forum for testing the prudency of the costs forecast to be incurred during the 2013 and 2014 test period. Once the UARB has approved the 2013 and 2014 revenue requirements, whether NSPI sets rates to recover 100% of the forecast costs during 2013 and 2014 or defers a portion of those approved costs for future recovery, any after-the-fact prudence review of the approved costs would constitute retroactive ratemaking, a practice well understood to be precluded by law.

Q. Ms. Smith recommends at page 13 that the deferred amounts be financed with short-term debt, rather than at NSPI's weighted average cost of capital. Is this a reasonable proposal?

A. No. The deferred amounts will not be short-term assets; they are to be recovered over an extended period of time. Ms. Smith recognizes that, stating at pages 9 to 10 that the deferred amounts are to be recovered over an eight-year period, commencing in 2015. There is no basis for attributing a short-term cost of financing to these long-term deferred amounts. Further, as discussed earlier, NSPI's regulated common equity ratio is already low for a utility of its business risk. If the deferred costs were required to be financed with short-term debt only, NSPI's regulated common equity ratio would be lower and its credit metrics would be weaker. Higher leverage and weaker credit metrics would put pressure on the existing debt ratings and potentially raise, not lower, the costs of both debt and equity, and thus the overall cost of capital.

Q. At page 6, Ms. Smith speculates that a lower ROE would be justified because of lower interest rates. Please comment.

A. While Ms. Smith is correct that prevailing government and investment grade bond yields are lower currently than at the time NSPI negotiated its current and requested allowed ROE, the reductions in interest rates that have transpired are, as indicated in my response to Dr. Booth above, largely due to a confluence of factors that have little, if any, correlation with trends in the market cost of equity. NSPI's requested 9.2% is, as demonstrated in both my direct testimony and response to Dr. Booth, a conservative ROE in light of the Company's risk profile and returns available to its peers.

Q. Does this conclude your rebuttal evidence?

A. Yes.

DBRS CREDIT METRICS OF INVESTOR-OWNED CANADIAN UTILITIES

	EBIT Coverage (X)						EBITDA Coverage (X)					
	2007	2008	2009	2010	2011	2007-11 Average	2007	2008	2009	2010	2011	2007-11 Average
Nova Scotia Power	**2.83**	**2.67**	**2.69**	**2.04**	**1.67**	**2.38**	**4.30**	**4.22**	**4.42**	**3.72**	**3.23**	**3.98**
AltaLink L.P.	1.78	1.84	1.94	2.31	2.51	2.08	3.44	3.60	3.79	3.99	4.02	3.77
CU Inc.	2.30	2.20	2.00	2.40	3.00	2.38	3.90	3.80	3.00	3.70	4.30	3.74
Enbridge Gas Distribution	2.62	2.55	2.87	2.62	2.69	2.67	4.06	3.92	4.51	4.41	4.65	4.31
FortisAlberta Inc.	2.05	2.02	2.17	2.09	2.06	2.08	4.17	4.02	4.12	4.28	4.11	4.14
FortisBC Inc.	2.04	2.05	2.04	2.10	2.40	2.13	3.04	3.09	3.06	3.21	3.52	3.18
FortisBC Energy Inc	1.99	1.92	1.96	2.17	2.17	2.04	2.72	2.62	2.72	3.04	3.00	2.82
Gaz Metro	2.52	2.52	2.43	2.37	2.41	2.45	4.16	4.18	4.21	3.97	4.08	4.12
Newfoundland Power	2.20	2.73	2.59	2.76	2.88	2.63	3.34	3.93	3.78	3.95	4.07	3.81
Union Gas Limited	2.18	2.36	2.35	2.55	2.66	2.42	3.29	3.56	3.54	3.81	3.99	3.64
Median (Excluding NSPI)	**2.18**	**2.20**	**2.17**	**2.37**	**2.51**	**2.38**	**3.44**	**3.80**	**3.78**	**3.95**	**4.07**	**3.77**

	Cash Flow/Total Debt (%)					
	2007	2008	2009	2010	2011	2007-11 Average
Nova Scotia Power	**21.7**	**19.6**	**17.1**	**12.6**	**15.1**	**17.2**
AltaLink L.P.	12.6	13.3	14.8	14.8	13.2	13.7
CU Inc.	17.9	18.5	13.2	18.3	17.7	17.1
Enbridge Gas Distribution	16.8	17.1	21.7	19.5	19.4	18.9
FortisAlberta Inc.	18.2	15.7	15.9	17.4	16.5	16.7
FortisBC Inc.	11.4	11.4	12.2	12.4	13.3	12.1
FortisBC Energy Inc	8.9	10.1	10.3	10.9	11.8	10.4
Gaz Metro	29.9	21.5	22.3	18.4	24.0	23.2
Newfoundland Power	12.9	16.2	15.0	18.6	18.1	16.2
Union Gas Limited	15.1	14.9	14.1	16.7	16.2	15.4
Median (Excluding NSPI)	**15.1**	**15.7**	**14.8**	**17.4**	**16.5**	**16.2**

Source: DBRS Reports

Historic Value Line Betas

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012Q2
McShane U.S. Electric Utility Sample																	
ALLETE Inc.	0.65	0.70	0.60	0.45	0.50	0.45	0.60	0.70	nmf	nmf	0.90	0.95	0.75	0.70	0.70	0.70	0.70
Alliant Energy Corp.	0.60	0.55	nmf	nmf	0.55	0.55	0.65	0.70	0.80	0.85	0.95	0.80	0.70	0.70	0.70	0.75	0.75
Avista Corp.	0.70	0.70	0.70	0.50	0.55	0.60	0.65	0.75	0.85	0.90	0.95	1.00	0.85	0.70	0.70	0.70	0.70
Dominion Resources	0.70	0.70	0.55	0.50	0.55	0.50	0.75	0.80	0.85	0.90	1.00	0.75	0.70	0.70	0.70	0.70	0.70
IDACORP Inc.	0.70	0.70	0.65	0.50	0.50	0.50	0.60	0.75	0.85	0.95	1.00	1.00	0.85	0.70	0.70	0.70	0.70
Integrys Energy Group Inc.	0.65	0.65	0.65	0.50	0.55	0.55	0.60	0.70	0.75	0.75	0.85	0.80	0.70	0.95	0.90	0.90	0.90
MGE Energy Inc.	na	na	na	na	na	na	na	0.55	0.60	0.70	0.75	0.95	0.70	0.65	0.65	0.60	0.60
NextEra Energy Inc.	0.80	0.75	0.55	0.50	0.45	0.45	0.55	0.65	0.70	0.75	0.85	0.75	0.80	0.75	0.75	0.75	0.75
OGE Energy Corp.	0.75	0.70	0.60	0.45	0.45	0.45	0.55	0.60	0.70	0.75	0.75	0.85	0.75	0.75	0.75	0.80	0.80
Sempra Energy	0.70	0.75	0.75	0.55	0.55	0.55	0.70	0.80	0.90	1.00	1.10	1.00	0.90	0.85	0.85	0.80	0.80
Southern Company	0.70	0.70	0.50	0.45	0.50	nmf	nmf	0.60	0.65	0.65	0.70	0.70	0.55	0.55	0.55	0.55	0.55
Vectren Corp.	0.70	0.75	0.75	0.55	nmf	nmf	0.70	0.75	0.75	0.80	0.90	0.90	0.85	0.75	0.70	0.70	0.75
Westar Energy	0.65	0.65	0.55	0.35	0.30	0.35	0.50	0.60	0.75	0.85	0.90	0.85	0.80	0.75	0.75	0.75	0.75
Wisconsin Energy Corp.	0.70	0.70	0.65	0.45	0.50	0.50	0.55	0.60	0.70	0.70	0.80	0.85	0.65	0.65	0.65	0.65	0.65
Xcel Energy Inc.	na	na	na	na	nmf	nmf	0.60	0.70	0.80	0.80	0.90	1.05	0.75	0.65	0.65	0.65	0.65
Average	**0.69**	**0.69**	**0.63**	**0.48**	**0.50**	**0.50**	**0.62**	**0.68**	**0.76**	**0.81**	**0.89**	**0.88**	**0.75**	**0.72**	**0.71**	**0.71**	**0.72**
Median	**0.70**	**0.70**	**0.63**	**0.50**	**0.50**	**0.50**	**0.60**	**0.70**	**0.75**	**0.80**	**0.90**	**0.85**	**0.75**	**0.70**	**0.70**	**0.70**	**0.70**
Booth Low Risk Utility Sample																	
AGL Resources	0.75	0.75	0.65	0.65	0.60	0.60	0.75	0.75	0.80	0.90	0.95	0.85	0.75	0.75	0.75	0.75	0.75
New Jersey Resources	0.65	0.60	0.55	0.55	0.55	0.55	0.65	0.70	0.75	0.75	0.80	0.85	0.70	0.65	0.65	0.65	0.65
Northwest Natural Gas	0.45	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.65	0.70	0.75	0.90	0.60	0.60	0.60	0.60	0.60
Piedmont Natural Gas	0.65	0.60	0.55	0.55	0.60	0.60	0.70	0.70	0.75	0.75	0.80	0.85	0.70	0.65	0.65	0.70	0.70
Vectren Corp.	0.70	0.75	0.75	0.55	nmf	nmf	0.70	0.75	0.75	0.80	0.90	0.90	0.85	0.75	0.70	0.70	0.75
WGL Holdings	0.70	0.75	0.60	0.60	0.60	0.60	0.65	0.70	0.75	0.80	0.85	0.85	0.75	0.65	0.65	0.65	0.65
Average	**0.65**	**0.68**	**0.62**	**0.58**	**0.59**	**0.59**	**0.68**	**0.70**	**0.74**	**0.78**	**0.84**	**0.87**	**0.73**	**0.68**	**0.67**	**0.68**	**0.68**
Median	**0.68**	**0.68**	**0.60**	**0.58**	**0.60**	**0.60**	**0.68**	**0.70**	**0.75**	**0.78**	**0.83**	**0.85**	**0.73**	**0.65**	**0.65**	**0.68**	**0.68**
Booth Electric Utility Sample																	
ALLETE Inc.	0.65	0.70	0.60	0.45	0.50	0.45	0.60	0.70	nmf	nmf	0.90	0.95	0.75	0.70	0.70	0.70	0.70
American Electric Power Co.	0.70	0.70	0.65	0.45	0.55	0.55	0.75	0.95	1.15	1.20	1.35	0.95	0.75	0.70	0.70	0.70	0.70
Cleco Corp.	0.60	0.70	0.70	0.55	0.55	0.55	0.65	0.90	1.10	1.15	1.30	1.15	0.80	0.65	0.65	0.70	0.65
Edison International	0.65	0.75	0.75	0.60	0.65	0.65	0.80	0.90	1.05	1.05	1.15	1.05	0.85	0.80	0.80	0.80	0.80
El Paso Electric Co.	na	na	na	na	0.65	0.65	0.55	0.55	0.65	0.70	0.70	0.80	0.95	0.75	0.75	0.75	0.75
FirstEnergy Corp.	0.80	0.80	0.70	0.50	0.55	0.55	0.55	0.75	0.75	0.75	0.80	0.85	0.85	0.80	0.80	0.80	0.80
Great Plains Energy Inc.	0.80	0.75	0.60	0.60	0.60	0.55	0.65	0.70	0.80	0.85	0.95	0.80	0.65	0.75	0.75	0.75	0.75
Hawaiian Electric Industries Inc.	0.75	0.70	0.70	0.50	0.50	0.50	0.55	0.55	0.65	0.70	0.70	0.70	0.75	0.70	0.70	0.70	0.70
IDACORP Inc.	0.70	0.70	0.65	0.50	0.50	0.50	0.60	0.75	0.85	0.95	1.00	1.00	0.85	0.70	0.70	0.70	0.70
NextEra Energy Inc.	0.80	0.75	0.55	0.50	0.45	0.45	0.55	0.65	0.70	0.75	0.85	0.75	0.80	0.75	0.75	0.75	0.75
Pinnacle West Capital Corp.	0.80	0.75	0.70	0.45	0.45	0.45	0.55	0.70	0.85	0.90	1.00	1.00	0.75	0.75	0.70	0.70	0.70
PNM Resources Inc.	0.65	0.80	0.65	0.45	0.45	0.50	0.60	0.70	0.85	0.90	1.00	0.95	0.90	0.95	0.95	0.95	0.95
Portland General Electric	na	na	na	na	na	na	na	na	na	na	nmf	nmf	0.70	0.70	0.75	0.75	0.75
Southern Company	0.70	0.70	0.50	0.45	0.50	nmf	nmf	0.60	0.65	0.65	0.70	0.70	0.55	0.55	0.55	0.55	0.55
Westar Energy	0.65	0.65	0.55	0.35	0.30	0.35	0.50	0.60	0.75	0.85	0.90	0.85	0.80	0.75	0.75	0.75	0.75
Average	**0.71**	**0.73**	**0.64**	**0.49**	**0.51**	**0.52**	**0.61**	**0.71**	**0.83**	**0.88**	**0.95**	**0.89**	**0.78**	**0.73**	**0.73**	**0.74**	**0.73**
Median	**0.70**	**0.70**	**0.65**	**0.50**	**0.50**	**0.50**	**0.60**	**0.70**	**0.80**	**0.85**	**0.93**	**0.90**	**0.80**	**0.75**	**0.75**	**0.75**	**0.75**
Differences:																	
McShane-Booth Electric Utility Sample																	
Average	**-0.02**	**-0.03**	**-0.01**	**-0.01**	**-0.02**	**-0.02**	**0.01**	**-0.03**	**-0.07**	**-0.07**	**-0.06**	**-0.01**	**-0.03**	**-0.01**	**-0.02**	**-0.02**	**-0.02**
Median	**0.00**	**0.00**	**-0.03**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**-0.05**	**-0.05**	**-0.03**	**-0.05**	**-0.05**	**-0.05**	**-0.05**	**-0.05**	**-0.05**
McShane Electric Utility - Booth Low Risk Sample																	
Average	**-0.06**	**-0.05**	**-0.02**	**0.09**	**0.08**	**0.07**	**0.07**	**-0.01**	**-0.09**	**-0.09**	**-0.11**	**-0.03**	**-0.06**	**-0.06**	**-0.07**	**-0.06**	**-0.05**
Median	**-0.02**	**-0.02**	**-0.05**	**0.08**	**0.10**	**0.10**	**0.08**	**0.00**	**-0.05**	**-0.08**	**-0.10**	**-0.05**	**-0.08**	**-0.10**	**-0.10**	**-0.08**	**-0.08**
Booth Electric Utility - Booth Low Risk Sample																	
Average	**0.06**	**0.05**	**0.02**	**-0.09**	**-0.08**	**-0.07**	**-0.07**	**0.01**	**0.09**	**0.09**	**0.11**	**0.03**	**0.06**	**0.06**	**0.07**	**0.06**	**0.05**
Median	**0.02**	**0.02**	**0.05**	**-0.08**	**-0.10**	**-0.10**	**-0.08**	**0.00**	**0.05**	**0.08**	**0.10**	**0.05**	**0.08**	**0.10**	**0.10**	**0.08**	**0.08**

Source: Value Line 4th quarter issues, and 2nd quarter 2012 issues.

DCF COST OF EQUITY ESTIMATE FOR MCSHANE U.S. ELECTRIC UTILITY SAMPLE
(Annual Averages of Monthly Data)

Year	Expected Dividend Yield[1/]	Analysts' Forecast EPS Growth Forecast	DCF Cost of Equity
	(1)	(2)	(3)
1997 (3Q-4Q)	5.9	3.2	9.1
1998	5.4	3.4	8.8
1999	6.2	4.3	10.3
2000	5.9	5.2	11.4
2001	5.1	6.4	11.5
2002	5.0	6.8	12.3
2003	4.7	5.8	10.4
2004	4.1	4.7	9.0
2005	3.8	4.5	8.5
2006	3.6	5.4	9.2
2007	3.6	5.6	9.5
2008	4.3	6.1	10.6
2009	5.1	6.1	11.7
2010	4.6	5.4	10.5
2011	4.4	5.7	10.2
2012 (Through Q2)	4.2	5.3	9.7
Means:			
1997Q3 - 2012Q2	**4.7**	**5.3**	**10.2**

[1/] Dividend Yield adjusted for analysts' forecast growth (DY (1+g)).

Source: I/B/E/S; Standard & Poor's *Research Insight*; and www.reuters.com.

MONTHLY BOND YIELDS FOR CANADA AND THE U.S.

	10 Year Canada	10 Year U.S. Treasury	Difference	30 Year Canada	30 Year U.S. Treasury	Difference	DEX AAA/AA	Moody's Corp. AAA/AA Avg	Difference	DEX A	Moody's Corp. A	Difference	DEX BBB	Moody's Corp. BBB	Difference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Jan-11	3.27	3.42	-0.15	3.73	4.58	-0.85	5.10	5.22	-0.12	5.36	5.57	-0.21	5.90	6.10	-0.20
Feb-11	3.30	3.42	-0.12	3.70	4.49	-0.79	4.98	5.16	-0.18	5.28	5.48	-0.20	5.89	5.99	-0.10
Mar-11	3.35	3.47	-0.12	3.75	4.51	-0.76	5.06	5.23	-0.17	5.36	5.54	-0.18	6.02	6.05	-0.03
Apr-11	3.20	3.32	-0.12	3.69	4.40	-0.71	4.95	5.14	-0.19	5.28	5.42	-0.14	5.96	5.90	0.06
May-11	3.07	3.05	0.02	3.49	4.22	-0.73	4.76	4.98	-0.22	5.08	5.22	-0.14	5.76	5.70	0.06
Jun-11	3.11	3.18	-0.07	3.55	4.38	-0.83	4.88	5.16	-0.28	5.15	5.41	-0.26	5.91	5.90	0.01
Jul-11	2.79	2.82	-0.03	3.29	4.12	-0.83	4.51	4.77	-0.26	4.85	5.09	-0.24	5.61	5.59	0.02
Aug-11	2.49	2.23	0.26	3.10	3.60	-0.50	4.55	4.46	0.09	4.80	4.80	0.00	5.60	5.48	0.12
Sep-11	2.15	1.92	0.23	2.77	2.90	-0.13	4.28	4.02	0.27	4.56	4.43	0.13	5.41	5.22	0.19
Oct-11	2.29	2.17	0.12	2.92	3.16	-0.24	4.36	3.95	0.41	4.70	4.43	0.27	5.56	5.19	0.37
Nov-11	2.15	2.08	0.07	2.69	3.06	-0.37	4.30	4.12	0.18	4.58	4.51	0.07	5.37	5.32	0.05
Dec-11	1.94	1.89	0.05	2.49	2.89	-0.40	4.10	3.84	0.26	4.33	4.29	0.04	5.23	5.16	0.07
Jan-12	1.89	1.83	0.06	2.50	2.94	-0.44	3.99	3.81	0.18	4.24	4.27	-0.03	5.13	5.07	0.06
Feb-12	1.98	1.98	0.00	2.60	3.08	-0.48	3.97	3.88	0.10	4.27	4.33	-0.06	5.06	5.08	-0.02
Mar-12	2.11	2.23	-0.12	2.66	3.35	-0.69	4.05	4.13	-0.08	4.31	4.58	-0.27	5.05	5.30	-0.25
Apr-12	2.04	1.95	0.09	2.61	3.12	-0.51	3.70	3.98	-0.28	4.36	4.39	-0.03	5.10	5.15	-0.05
May-12	1.74	1.59	0.15	2.29	2.67	-0.38	3.43	3.70	-0.27	4.10	4.11	-0.01	4.87	4.99	-0.12
Jun-12	1.74	1.67	0.07	2.33	2.76	-0.43	3.42	3.72	-0.30	4.16	4.16	0.00	4.95	5.06	-0.11
Jul-12	1.68	1.51	0.17	2.27	2.56	-0.29	3.33	3.37	-0.04	4.04	3.86	0.18	4.85	4.78	0.07
Average:															
Jan11-Jul12	**2.44**	**2.41**	**0.03**	**2.97**	**3.52**	**-0.55**	**4.30**	**4.35**	**-0.05**	**4.67**	**4.73**	**-0.06**	**5.43**	**5.42**	**0.01**
Aug11-Jul12	**2.02**	**1.92**	**0.10**	**2.60**	**3.01**	**-0.41**	**3.96**	**3.91**	**0.04**	**4.37**	**4.35**	**0.02**	**5.18**	**5.15**	**0.03**
Feb 12-Jul12	**1.88**	**1.82**	**0.06**	**2.46**	**2.92**	**-0.46**	**3.65**	**3.80**	**-0.15**	**4.21**	**4.24**	**-0.03**	**4.98**	**5.06**	**-0.08**

Source: www.bankofcanada.ca; www.federalreserve.gov; www.moodys.com; and PC Bond Analytics *Debt Market Indices* .

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INDIVIDUAL COMPANY DATA FOR MCSHANE U.S. ELECTRIC UTILITY SAMPLE

	Value Line							S & P			Moody's
	Safety	Forecast Common Equity Ratio 2015-2017 [1/]	Forecast Return On Average Common Equity 2015-2017	Dividend Payout Forecast 2015-2017	2012 Q2 Beta	Common Equity Ratio 2Q2012 (Trailing Four Quarters)	2007-2011 Average Earned Returns	Business Risk Profile	Financial Risk Profile	Debt Rating [2/]	Debt Rating [3/]
ALLETE Inc.	2	60.0%	10.4%	57.1%	0.70	55.7%	9.4%	Strong	Significant	BBB+	Baa1
Alliant Energy Corp.	2	50.5%	11.0%	62.9%	0.75	50.0%	10.2%	Excellent	Significant	BBB+	Baa1
Avista Corp.	2	48.0%	9.5%	62.2%	0.70	48.2%	7.5%	Excellent	Aggressive	BBB	Baa2
Dominion Resources	2	43.5%	15.1%	65.0%	0.70	36.5%	18.3%	Excellent	Significant	A-	Baa2
IDACORP Inc.	3	53.5%	8.5%	55.9%	0.70	51.8%	8.9%	Excellent	Aggressive	BBB	Baa2
Integrys Energy Group Inc.	2	55.5%	9.9%	65.9%	0.90	54.9%	5.5%	Excellent	Significant	A-	Baa1
MGE Energy Inc.	1	66.0%	10.5%	58.4%	0.60	60.5%	11.4%	Excellent	Intermediate	AA-	A1
NextEra Energy Inc.	2	47.5%	12.5%	53.3%	0.75	39.2%	13.6%	Strong	Intermediate	A-	Baa1
OGE Energy Corp.	2	50.0%	11.9%	44.7%	0.80	47.4%	13.7%	Strong	Significant	BBB+	Baa1
Sempra Energy	2	48.0%	11.5%	48.7%	0.80	47.7%	12.7%	Strong	Intermediate	BBB+	Baa1
Southern Company	1	46.0%	12.6%	69.2%	0.55	44.5%	13.1%	Excellent	Intermediate	A	Baa1
Vectren Corp.	2	48.0%	12.2%	64.0%	0.75	44.5%	10.1%	Excellent	Significant	A-	A3
Westar Energy	2	50.0%	8.7%	61.7%	0.75	45.9%	8.9%	Excellent	Aggressive	BBB	Baa2
Wisconsin Energy Corp.	1	46.5%	13.9%	65.5%	0.65	44.3%	11.9%	Excellent	Significant	A-	A3
Xcel Energy Inc.	2	50.0%	10.6%	60.0%	0.65	45.4%	9.7%	Excellent	Significant	A-	Baa1
Mean	**2**	**50.9%**	**11.2%**	**59.6%**	**0.72**	**47.8%**	**11.0%**	**Excellent**	**Significant**	**A-**	**Baa1**
Median	**2**	**50.0%**	**11.0%**	**61.7%**	**0.70**	**47.4%**	**10.2%**	**Excellent**	**Significant**	**A-**	**Baa1**

[1/] Based on permanent capital.
[2/] Rating for MGE Energy Inc. is for Madison Gas & Electric Co.
[3/] Rating for MGE Energy Inc. is for Madison Gas & Electric Co. Rating for Vectren Corp. is for Vectren Utility Holdings.

Source: www.Moodys.com; Standard and Poor's, *Issuer Ranking: U.S. Regulated Utility Companies, Strongest To Weakest* (August 6, 2012); Standard and Poor's *Research Insight*; *Value Line* (May, June, and August 2012); *Value Line Index*, August 17, 2012; and www.yahoo.com.

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INDIVIDUAL COMPANY DATA FOR BOOTH U.S. ELECTRIC UTILITY SAMPLE

	Value Line							S & P			Moody's
	Safety	Forecast Common Equity Ratio 2015-2017 [1/]	Forecast Return On Average Common Equity 2015-2017	Dividend Payout Forecast 2015-2017	2012 Q2 Beta	Common Equity Ratio 2Q2012 (Trailing Four Quarters)	2007-2011 Average Earned Returns	Business Risk Profile	Financial Risk Profile	Debt Rating	Debt Rating
ALLETE Inc.	2	60.0%	10.4%	57.1%	0.70	55.7%	9.4%	Strong	Significant	BBB+	Baa1
American Electric Power Co.	3	51.5%	10.2%	57.3%	0.70	44.9%	11.4%	Excellent	Aggressive	BBB	Baa2
Cleco Corp.	1	58.0%	11.1%	58.5%	0.65	51.4%	14.2%	Excellent	Aggressive	BBB	Baa3
Edison International	3	40.0%	9.3%	44.3%	0.80	40.1%	9.6%	Strong	Aggressive	BBB-	Baa2
El Paso Electric Co.	2	43.5%	10.8%	52.0%	0.75	46.0%	11.6%	Excellent	Aggressive	BBB	Baa2
FirstEnergy Corp.	2	45.5%	10.0%	64.0%	0.80	42.5%	11.9%	Strong	Aggressive	BBB-	Baa3
Great Plains Energy Inc.	3	52.0%	7.5%	62.9%	0.75	43.5%	7.4%	Excellent	Aggressive	BBB	Baa3
Hawaiian Electric Industries Inc.	3	54.0%	10.0%	70.0%	0.70	47.6%	7.3%	Strong	Aggressive	BBB-	Baa1
IDACORP Inc.	3	53.5%	8.5%	55.9%	0.70	51.8%	8.9%	Excellent	Aggressive	BBB	Baa2
NextEra Energy	2	47.5%	12.5%	53.3%	0.75	39.2%	13.6%	Strong	Intermediate	A-	Baa1
Pinnacle West Capital Corp.	2	57.5%	9.3%	65.3%	0.70	51.8%	7.4%	Excellent	Aggressive	BBB	Baa2
PNM Resources Inc.	3	49.0%	9.5%	48.8%	0.95	47.6%	0.8%	Excellent	Aggressive	BBB-	Ba1
Portland General Electric	2	54.5%	8.7%	55.6%	0.75	48.9%	8.3%	Excellent	Aggressive	BBB	Baa2
Southern Co.	1	46.0%	12.6%	69.2%	0.55	44.5%	13.1%	Excellent	Intermediate	A	Baa1
Westar Energy Inc.	2	50.0%	8.7%	61.7%	0.75	45.9%	8.9%	Excellent	Aggressive	BBB	Baa2
Mean	**2**	**50.8%**	**9.9%**	**58.4%**	**0.73**	**46.7%**	**9.6%**	**Excellent**	**Aggressive**	**BBB**	**Baa2**
Median	**2**	**51.5%**	**10.0%**	**57.3%**	**0.75**	**46.0%**	**9.4%**	**Excellent**	**Aggressive**	**BBB**	**Baa2**

[1/] Based on permanent capital.

Source: www.Moodys.com; Standard and Poor's, *Issuer Ranking: U.S. Regulated Utility Companies, Strongest To Weakest* (August 6, 2012); Standard and Poor's *Research Insight*; *Value Line* (May, June, and August 2012); *Value Line Index*, August 17, 2012; and www.yahoo.com.

Rebuttal Schedule 6

EQUITY RETURN AWARDS AND COMMON EQUITY RATIOS
ADOPTED FOR THE MCSHANE U.S. ELECTRIC UTILITY SAMPLE
2011Q3-2012

Parent	Subsidiary	State	Decision Date	Allowed ROE	Allowed Common Equity Ratio	
Alliant Energy Corp.	Interstate P&L	MN	8/12/2011	10.35	47.74	
Alliant Energy Corp.	Wisconsin P&L	WI	6/15/2012	10.40	49.31	
Dominion Resources	Virginia Electric & Power	VA	3/23/2012	10.40	53.25	a/
IDACORP Inc.	Idaho Power Company	ID	12/30/2011	10.50	49.27	b/
IDACORP Inc.	Idaho Power Company	OR	2/23/2012	9.90	49.90	
Integrys Energy Group Inc.	Upper Peninsula Power	MI	12/20/2011	10.20	54.90	
Integrys Energy Group Inc.	Wisconsin Public Service	WI	5/24/2012	9.70	50.48	
OGE Energy Corp.	Oklahoma G&E	OK	7/9/2012	10.20	NA	
Southern Co.	Gulf Power Co.	FL	2/27/2012	10.25	46.26	
Westar Energy	Westar Energy Inc.	KS	4/18/2012	NA	NA	c/
Wisconsin Energy Corp.	Wisconsin Electric Power	MI	6/26/2012	10.10	43.51	
Xcel Energy Inc.	Public Service of CO	CO	4/26/2012	10.00	56.00	
Xcel Energy Inc.	Northern States Power-MN	MN	3/29/2012	10.37	52.56	
Xcel Energy Inc.	Northern States Power-MN	ND	2/29/2012	10.40	51.77	
Xcel Energy Inc.	Northern States Power-SD	SD	6/19/2012	9.25	53.04	
Xcel Energy Inc.	Northern States Power-WI	WI	12/22/2011	10.40	52.59	
Mean				**10.16**	**50.76**	
Median				**10.25**	**51.13**	

a/ Allowed ROE is base return excluding 100 basis point plant-specific premium.
b/ Decision of 6/29/12 gives no detail on ROE,
c/ Westar is authorized to calculate its rate of return for regulatory accounting purposes with an assumed ROE of 10.0% and 52.629% equity ratio until Westar's next general rate proceeding.

Source: Regulatory Research Associates and various regulatory decisions.

NOVA SCOTIA UTILITY AND REVIEW BOARD

REPLY EVIDENCE OF
JAMES M. COYNE

September 7, 2012

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REPLY EVIDENCE OF JAMES M. COYNE

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, AFFILIATION, AND BUSINESS ADDRESS.

A1. 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.

Q2. ARE YOU THE SAME JAMES M. COYNE WHO SUBMITTED DIRECT TESTIMONY EARLIER IN THIS PROCEEDING?

A2. Yes, I am.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING?

A3. I am submitting this Testimony on behalf of Nova Scotia Power, Inc. ("NSPI", or the "Company") in this proceeding.

Q4. WHAT IS THE PURPOSE OF YOUR REPLY TESTIMONY?

A4. The purpose of my Reply Testimony is to respond to portions of the evidence submitted by Dr. Laurence D. Booth and Ms. Lee Smith relating to business and economic risk. My Reply Testimony supplements my Direct Testimony, and that of Kathleen C. McShane with regard to the appropriateness of Ms. McShane's proxy group selection and her description of risk factors specific to NSPI. These issues have a direct bearing on the allowed cost of equity ("ROE") for NSPI in this proceeding.

Dr. Booth acknowledges NSPI's requested ROE and capital structure to be reasonable: "I would therefore regard NSPI's request to be allowed a 9.2% on 37.5% common equity to be within, but near the top end of reasonable financial metrics."[1] But, there are several elements of Dr. Booth's testimony that ultimately lead to his unduly low recommended ROE of 7.5 - 8.5 percent[2] in contrast to the above conclusion. I address each of these issues in turn, principally relating to the Company's business risk:

- The facts related to NSPI's business and economic risks; and
- The relative risks of the Canadian and U.S. investment environment.

[1] Evidence of Laurence D. Booth, at 4, lines 12-14.
[2] For the years 2013 and 2014, respectively. Booth, at 2, line 30.

I ultimately conclude that Ms. McShane appropriately characterizes NSPI's business and economic risk in her statement of evidence, and has appropriately relied on a proxy group consisting of U.S. electric utilities to estimate NSPI's cost of equity.

My analyses and recommendations are supported by the data presented in Exhibits JMC-1 and JMC-2, which have been prepared by me or under my direct supervision.

Q5. **WHAT ARE YOUR CONCLUSIONS REGARDING THE EFFECT OF BUSINESS RISK ON NSPI'S COST OF EQUITY?**

A5. Based on my review of the facts in this proceeding, along with my experience evaluating business risk in other jurisdictions, it is my opinion that NSPI faces significant business risks, particularly in the areas of potential load loss, fuel pricing, capital expenditures, environmental compliance, and the recovery of costs related to those items. I find that NSPI's business risks are higher than those of the various Canadian companies referred to by Dr. Booth, that Dr. Booth has misconstrued the facts related to NSPI's business and economic risks, and that many of his statements are unsupported. I also find that NSPI faces comparable business and economic risks to that of integrated electric utilities in the U.S. Following a review of the business risks of comparable Canadian and U.S. utilities, I find that Ms. McShane has appropriately relied on a proxy group consisting of U.S. utilities in her analysis of the appropriate return on equity for NSPI.

Q6. **HOW IS THE REMAINDER OF YOUR REPLY TESTIMONY ORGANIZED?**

A6. The remainder of my Reply Testimony is organized as follows. In Section II, I define business risk and discuss its effect on a utility's return on equity. Section III describes the primary business risks of NSPI, and addresses issues presented by Dr. Booth and Ms. Smith on this topic. In Section IV, I comment on the appropriateness of using a proxy group of U.S. utilities in order to calculate return on equity. Finally, Section V provides my conclusions.

II. THE EFFECTS OF BUSINESS RISK ON A UTILITY'S RETURN ON EQUITY

Q7. **AS A PRELIMINARY MATTER, DOES YOUR TESTIMONY ADDRESS DR. BOOTH'S TESTIMONY ON CAPITAL STRUCTURE?**

A7. No. The allowed common equity ratio for the Company does not appear to be a matter of contention. Dr. Booth concludes "I regard NSPI's current common equity ratio of 37.5% for rate setting purposes to be reasonable."[3] I would note, however, that Dr. Booth's rationale for accepting the Company's common equity ratio as "reasonable" is based on Union Gas' current equity ratio of 36%, but Union has a pending application before the Ontario Energy Board ("OEB") for a 40% equity ratio, and Gaz Metro's 38.5% common equity ratio cited by Dr. Booth is supplemented by a deemed 7.5% preferred share component of the capital structure, for a combined 46%. By virtue of Dr. Booth's logic, and comparison to industry peers, NSPI's common equity ratio is on the low end of the spectrum.

Given that the Company is not requesting any change to its common equity ratio, it is not evident why Dr. Booth dedicates so much of his testimony to business risk as it relates to capital structure, (beginning on page 5 and running through page 24), other than perhaps for his stated personal preference to adjust for business risk in the capital structure.[4] Dr. Booth even ascribes motives for NSPI's management to favor the interests of shareholders over customers by "asking for too much equity", but NSPI is not asking for more equity in this proceeding.[5]

Q8. **PLEASE DESCRIBE THE GUIDING PRINCIPLES TO BE CONSIDERED WHEN EVALUATING THE BUSINESS RISKS FACED BY A REGULATED UTILITY.**

A8. In both Canada and the U.S., one of the key principles for establishing a fair return on equity for a regulated utility is that a reasonable return should be "comparable with the

[3] *Ibid*., at 2, lines 5-6.
[4] *Ibid*., at 11, lines 20-21.
[5] *Ibid*., at 14, lines 19-23.

return available from the application of capital to other enterprises of like risk."[6] This principle implies that any evaluation of the reasonableness of a particular return should consider investment risk, or the level of risk faced by investors in the enterprise, and how the balance of risk and return compares with other companies. Investment risk is composed of business risk and financial risk. Business risk includes such things as supply risk, demand risk, competitive risk, operating risk, and regulatory risk. Also, many business risks are driven by the macro-economy. For example, a weakening local or national economy translates to lower electric demand. Financial risk considers the amount of financial leverage that is applied to operations, but is apparently not at issue in this proceeding.

Q9. **HOW DO BUSINESS RISKS AFFECT A COMPANY'S RETURN ON EQUITY?**

A9. Business risks are relevant because of their potential to lead to variation in earnings and cash flow, and the level of variation in a company's earnings and cash flow is directly proportional to its return on equity. This relationship between risk and return can be observed in the Capital Asset Pricing Model ("CAPM"), which uses the beta coefficient to reflect the market (non-diversifiable) business, economic and financial risks of a proxy group of companies with similar risk profiles. By incorporating betas from a group of similar risk companies, the CAPM provides an estimated ROE for companies with similar market risk to the subject company. Company specific risks must then be considered in order to determine whether the subject company's ROE should be adjusted relative to that estimate.

Similarly, under the Discounted Cash Flow ("DCF") model, the required cost of equity is estimated based on the sum of the dividend yield and the forecasted earnings growth rate for a set of proxy group companies. Business risks for each company are reflected in dividend yields and growth rates, and through the initial selection of proxy companies. Since the DCF analysis incorporates an average of the dividend yields and the growth

[6] National Energy Board, Reasons for Decision, RH-1-70, p. 7-5. See also National Energy Board, Reasons for Decision, RH-2-2004, p. 17, where the NEB stated that a fair or reasonable return on capital should meet three requirements. It should: (1) be comparable to the return available from the application of invested capital to other enterprises of like risk (the comparable investment standard), (2) enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and (3) permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).

rates for the proxy group, the DCF result reflects the risk of that group as a whole. As in the CAPM analysis, company-specific risks must then be considered to determine whether the subject company ROE should be adjusted to reflect those risks.

Q10. **WHAT ARE THE PRIMARY SOURCES OF BUSINESS RISK THAT MAY AFFECT A COMPANY'S COST OF CAPITAL?**

A10. The business risks that may affect a company's cost of capital range from narrow local risks that affect only the subject company to broad market risks of the international and sovereign economies in which the subject company resides and which are reflected across the entire proxy group. Narrow company-specific risks include such risks as regional or provincial-level economic growth risk, provincial or state-level regulatory risk, or risks involved in local fuel procurement and cost recovery. Broad market risks may include risks such as GDP growth risk, inflation risk, or federal-level regulatory risks. Given that the purpose of the proxy group is to provide an estimate of the subject company's market risk by proxy, it is important that the subject company and the proxy group are affected similarly by this set of broad market risks. Later in my testimony I will discuss the relevance of the proxy group companies to which Dr. Booth refers in his evidence, and the appropriateness of the U.S. proxy group referred to by Ms. McShane.

Q11. **WHAT ARE THE PRIMARY SOURCES OF BUSINESS AND ECONOMIC RISK THAT MAY AFFECT AN ELECTRIC UTILITY'S COST OF CAPITAL IN PARTICULAR?**

A11. As in other industries, the business risks that affect an integrated electric utility's cost of capital may materialize in any of the company's revenue, expenses or cash flow line items that are subject to variability. Integrated electric utilities are subject to variability in their revenues due to factors such as unexpected changes in load or changes in customer rates. Integrated electric utilities are subject to variability in expenses due to factors such as unexpected fuel price variations, or unexpected variations in other operating costs, including non-cash costs such as accruals to satisfy pension obligations. Utilities are subject to variability in their cash flow due to factors such as timing differences between when capital expenditures are made and when the return of, and return on, that capital is recovered through rates.

These are some examples of business risk for utilities. Unlike non-regulated companies that must absorb the impact of these events in real time, the utility regulator has the ability to defer their effect through cost deferral accounts, thereby smoothing the effects on customer bills over some future time period.

III. ANALYSIS OF NSPI BUSINESS RISKS

Q12. **ON PAGES 26-27 DR. BOOTH CHARACTERIZES NSPI'S BUSINESS RISKS, DO YOU AGREE WITH HIS ASSESSMENT?**

A12. No, I do not.

Q13. **PLEASE EXPLAIN YOUR AREAS OF DISAGREEMENT.**

A13. On page 27 of his direct evidence, Dr. Booth states that "most companies have to deal with labour costs, getting their customers to pay their bills, the vagaries of weather impacting demand and the impact of interest rate volatility on short-term financing costs." This statement is made in the context of refuting NSPI's itemized description of its risks as provided by the Company in its 2011 Annual Information Form.[7] From this itemization, Dr. Booth dismisses regulatory risk as being solely a protective factor as a result of deferrals, and lumps commodity price and foreign exchange risk into the same category. I disagree with Dr. Booth's dismissal of regulatory and commodity price risk. Dr. Booth's broad-sweeping and unsupported statement is made in attempt to dismiss a significant portion of NSPI's remaining list of risks, and to imply that these risks are no different from risks borne by other utilities. While I agree that most companies do indeed have to deal with the issues noted in Dr. Booth's statement, the extent to which any given company is affected by any one of those issues can and does vary significantly.

For example, given its coastal Atlantic location, NSPI has experienced significant weather events in recent years, which have increased its outages and associated costs. By way of comparison, from the 2006-2010 period (the most recent comparable data for U.S. utilities) NSPI has had average System Average Interruption Duration Index (SAIDI) and

[7] See NSPI 2013 Annual Information Form, at 17-23.

System Average Interruption Frequency Index (SAIFI) of 10.77 and 3.65, respectively,[8] while, from 2000 to 2009, U.S. integrated electric utilities reported SAIDI of approximately 2.3 to 11.0, and SAIFI of approximately 1.4 to 1.9.[9] In both cases, NSPI is at or beyond the range for U.S. utilities. System outages create both load loss and increase O&M expenditures, and these are not equally distributed among utilities.

Q14. **ON PAGE 10 OF HIS DIRECT EVIDENCE, DR. BOOTH STATES THAT, WITH DEFERRAL ACCOUNTS, "'RATEPAYERS' ALWAYS PAY THE FULL COST OF SERVICE AND STOCKHOLDER RISK IS LOWERED. DO YOU AGREE?**

A14. Not at all. A deferral account will typically spread the cost of a particular cost or investment over time, and may deprive the utility of cash flow between the time of spending those funds today and the time that those funds are recovered at some future date. Further, there is no guarantee that this future obligation will be fulfilled, as the utility is always subject to regulatory review of funds to be received through the deferral account. In NSPI's case, the fuel adjustment mechanism ("FAM") audit and recommendation of imprudent actions by Liberty Consulting Group ("Liberty') is a case in point.

Q15. **DO YOU KNOW OF ANY EXAMPLES OUTSIDE OF NOVA SCOTIA WHERE A UTILITY WAS NOT ALLOWED TO RECOVER ITS DEFERRAL ACCOUNT?**

A15. Yes, I do. Enbridge Gas New Brunswick ("EGNB"), a small natural gas local distribution company located in New Brunswick and a subsidiary of Enbridge, Inc., will likely forgo a deferral account exceeding $180 million. This past winter the Government of New Brunswick legislated changes to amend its Gas Distribution Act ("GDA") that was originally passed in 1999. As part of the amendments to the GDA, the New Brunswick Energy and Utilities Board will not:

- Recognize or consider the deferral account as part of the regulated assets of EGNB;

[8] Direct Testimony of Lee Smith, at 8, lines 129-140, based on data provided by NSPI.

[9] Including major events; SAIDI expressed in hours for comparability. Source: "An Examination of Temporal Trends in Electric Reliability Based on Reports from U.S. Electric Utilities, Berkeley National Laboratory, January 2012, Figures 4-5.

- Permit EGNB to depreciate, amortize or earn a return on the deferral account; or
- Permit EGNB to establish additional similar revenue shortfall deferral accounts in the future.

The change is intended to be temporary, with recovery of the deferral account reinstated once the distribution system is self-sustainable. Unfortunately for EGNB, there is no set time line for a reinstatement, and it is not clear if it will be able to recover the loss. This present-day example, taken from the same region as NSPI, illustrates the ongoing regulatory risk inherent in deferral accounts, despite the other risk mitigating benefits that they provide.

Q16. **ON PAGE 16 OF HIS DIRECT EVIDENCE, DR. BOOTH STATES THAT "UTILITIES HAVE THE LOWEST BUSINESS RISK OF JUST ABOUT ANY SECTOR IN THE CANADIAN ECONOMY." DO YOU AGREE?**

A16. Not necessarily. While I agree that the business risk for regulated utilities is generally lower than that of other sectors, Dr. Booth provides no support for his claim that "utilities have the lowest business risk of just about any sector in the Canadian economy." Generally speaking, regulated utilities do have relatively low risk given their exclusive service area and the fact that they are provided a competitive return of and on capital employed as long as that capital is invested prudently. However, given the greater business risks of providing for reliable generation, integrated electric utilities generally have higher business risks than pure distribution utilities. Further, NSPI in particular has higher business risk than many integrated electric utilities as I will describe later in my testimony and as confirmed by the Company's Standard & Poor's business risk rating of "Strong" as opposed to the "Excellent" business risk rating provided to most integrated electric utilities.[10] Therefore, the implication that NSPI's business risk is among the lowest of just about any industrial sector in Canada is unsupported and misleading.

[10] *"Nova Scotia Power Inc. outlook revised to negative on growth plan stresses; BBB+ Ratings Affirmed,"* Standard and Poor's, at 1.

Q17. **ON PAGE 16 OF HIS DIRECT TESTIMONY, DR. BOOTH STATES THAT "MOST OF THE RISKS OF NSPI STEM FROM ITS GENERATION FACILITIES." DO YOU AGREE?**

A17. While a significant portion of NSPI's business risks do stem from its generation facilities, Dr. Booth's statement is unsupported, and it is misleading to conclude that the generation facilities are the primary source of NSPI's business risks. NSPI's primary business risks are derived not only from its generation facilities, but also from its exposure to continuing load losses, its significant capital expenditures program in support of transmission upgrades and the LED streetlight changeover, and from the risks surrounding the recovery of historical and future costs related not only to these items, but also to fuel, demand side management and vegetation management costs.[11]

Q18. **WHAT ARE THE RISKS THAT NSPI FACES AND THAT DR. BOOTH DISPUTES?**

A18. The primary risks that Dr. Booth disputes are also the primary risks that NSPI faces. These are:

- The risk of continuing load loss, primarily as the result of a weak economy, and as exemplified by the NewPage and Bowater plant closures;
- The risks posed by an increasing capital expenditures program required to comply with federal and/or provincial environmental regulations and other purposes; and
- The residual risk presented by the implementation of deferral accounts which, while mitigating some of the financial impact from load loss and other financial losses to the NSPI in the near term will continue to subject the Company to delayed recovery or non-recovery of those losses.

Q19. **HOW HAS THE NOVA SCOTIA ECONOMY AFFECTED THE COMPANY'S LOAD?**

A19. As I described in my Direct Evidence, and as further detailed in Exhibit JMC-1, the Nova Scotia economy continues to struggle economically. The Nova Scotia pulp and paper sector has been especially hard-hit, with sales volume falling nearly 18 percent in the first

[11] 2013 GRA, at 128-131.

quarter of 2012 from the same period in 2011. Meanwhile, continuing high unemployment and a general slowdown in commercial and industrial activity have combined to reduce the Company's load. Further, continuing loss of load in other sectors is expected to reduce demand by 3.2 percent from the 2012 General Rate Application ("GRA") load forecast[12], and there is no specific regulatory deferral or other form of compensation for stranded fixed costs that were associated with supporting this load.

Dr. Booth indicates that "demand is typically insensitive to rate increases,"[13] but he provides no supporting evidence to this opinion. When asked in an interrogatory, Dr. Booth responds, "Insensitive means inelastic. If demand were elastic there would be no justification for regulation as by definition the market is competitive."[14] However, the price sensitivity of load to increasing electricity prices is evidenced by the significant involvement of commercial and industrial customer advocates in this case. Also, for the purpose of its load forecast, NSPI estimates a price elasticity of approximately -0.1 for residential customers, indicating some price sensitivity. In general, econometric evidence shows that electric price elasticities are typically in the -0.1 through -0.9 range for all customer classes, suggesting electric consumers do indeed respond to price signals.[15]

Q20. **WHAT ARE THE EFFECTS ON NSPI'S RISK PROFILE IN LIGHT OF THE NEWPAGE PORT HAWKESBURY AND BOWATER PLANT CLOSURES AND SUBSEQUENT REVENUE DEFERRALS?**

A20. Recent plant closures in Nova Scotia's pulp and paper sectors are manifestations of the continuing risk that NSPI will not fully recover its fixed costs associated with supporting this load. Dr. Booth concedes that "if both [plants] operate and the load retention rates are approved then at best the rates will recover incremental electricity costs plus a much reduced contribution to NSPI's fixed costs."[16] Indeed, the Company's 2013 General Rate

12 NS Power 2013 GRA, at 34-35
13 Booth, at 16, line 31.
14 NSPI Information Requests to Nova Scotia Utility and Review Board, Dr. Laurence Booth, Response to IR-20.
15 See, for example "Regional Difference in Price-Elasticity of Demand for Energy," RAND Corporation, 2005. It is important to note that while elasticity metrics with absolute values between 0.0 and 1.0 are typically described as "inelastic," this is a relative term. Given that the statistic describes the expected percentage change in demand for any given percentage change in price, it follows that for statistics of -0.1 to -1.0, one would expect a reduction in demand for any given increase in price, although that percentage reduction in demand would not be expected to be as great as the given percentage increase in price.
16 Booth at 28, lines 15-17.

Application assumes that the NewPage mill will not contribute to system fixed costs in 2013 and 2014, and that any contribution to fixed costs will benefit customers – but not equity holders – by reducing the fixed cost deferral.[17] The Bowater plant is now permanently closed, so it will make no further contribution to fixed costs.

A reduced customer contribution to NSPI's fixed costs has financial implications at two levels. First, these reduced contributions mean that NSPI's remaining customers will have to bear the remaining fixed costs associated with those plants, which are expected to reach $44 million by the end of 2012.[18] Second, the deferral account as proposed would recover these fixed costs over an eight-year period, meaning that NSPI will only recover its fixed costs over the eight years following the approval of those costs through the General Rate Application. This delay in receiving whatever fixed costs are recovered through the deferral account harms the Company's liquidity and puts it at risk for cash shortfalls.

Q21. **DR. BOOTH STATES ON PAGE 29 OF HIS EVIDENCE THAT "BY PLACING THE PORT HAWKESBURY COSTS IN A DEFERRAL ACCOUNT FOR FUTURE DISPOSITION [THIS] EFFECTIVELY REMOVES THE STRANDED ASSET RISK FACED BY NSPI'S SHAREHOLDER." DO YOU AGREE?**

A21. No I do not, for three primary reasons. First, as described above, by stretching the fixed cost payments over time, deferral accounts adversely impact liquidity, given that the Company's cash receipts are being deferred from the time incurred to some later date. Reinforcing this point, Pacific Northern Gas, which Dr. Booth cited on pages 28-29 of his evidence as having been helped by its regulator to avert "a huge company threatening event", states in its 2005 annual report:

> The recovery of the Company's accumulated deferral accounts has an impact on liquidity requirements. Recovery of the deferral accounts through rates charged to customers is dependent upon regulatory approval and the ability to set rates high enough to recover such balances while maintaining the competitiveness of retail gas prices, and is therefore at risk.[19]

17 2013 GRA, at 35.
18 *Ibid.*, at 129.
19 Pacific Northern Gas, Annual Report, 2005, at 12.

Second, and as the Pacific Northern Gas citation above demonstrates, since the deferral account recovers a pre-determined set of stranded fixed costs from a smaller customer base, customer rates will need to increase. As noted in the 2013 General Rate Application, while fuel and other variable costs will fall as a result of the loss of load, "the fixed costs of the plants and equipment used to generate and distribute electricity will not decrease enough to compensate for the lost revenue caused by the drop in load – and those fixed costs will be spread among fewer customers."[20] Higher electricity rates would then put additional pressure on NSPI's already-stressed customer base, and may lead to additional plant closings or defections, especially at the commercial and industrial customer level. Equity analysts have specifically identified this risk:

> In our view, one of the critical issues facing [NSPI] is the potential bias upwards in electricity rates. In general, the woes of the forest products sector look to likely drive power rates higher in Nova Scotia.[21]

Dr. Booth seems to recognize the potential for such a "death spiral" presenting TransCanada Mainline as a prime example of rising customer rates. At Page 34 of his evidence, Dr. Booth cites the National Energy Board ("NEB") in RH-4-2001 as follows:

> Specifically, the Mainline's ability to recover its full cost of service would be put in jeopardy if its throughput declines to a point where the resulting tolls exceeded what the market could bear.

While the NEB made this observation in 2001, TransCanada continues to be plagued by the potential for a cycle of falling throughput volumes and increasing rates for remaining customers. In July 2012, TransCanada announced it was reducing its original 2012 forecast for the Mainline of 2.4 billion cubic feet per day ("BCFD") by 1.0 BCFD, and explained that this reduced forecast is "enough to boost expected tolls on the Mainline by 30 percent, given that tolls rise when volumes fall."[22] In its current mainline tolls proceeding before the NEB, industrial and consumer advocates have recommended write-offs to the existing TransCanada ratebase of $400 million - $1.2 billion. Dr. Booth believes that "we may yet see a Canadian utility suffer a material loss with the TransCanada Mainline being the main candidate.[23] This scenario is obviously one with

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[20] 2013 GRA, at 35-36.
[21] "Emera Inc.", Credit Suisse, July 20, 2012.
[22] "TransCanada Cuts Output Forecasts as Industry Malaise Deepens," The Globe and Mail, June 19, 2012.
[23] Booth response to NSPI Information Request IR-36.

significant risks for TransCanada's shareholders, and describes the risks that even regulated utilities must bear.

Third, the deferral account remains an asset that is subject to Nova Scotia Utility and Review Board ("NSUARB") review before any amortization of that asset is incorporated in rates. As noted earlier, the ongoing Liberty audit of the Fuel Adjustment Mechanism is a primary example of just such a review, standing in stark contrast to Dr. Booth's belief that "whenever a risk arises that seriously threatens a utility it is brought before the regulator and invariably the utility is protected."[24]

Q22. **IS THE COMPANY'S BUSINESS RISK REDUCED BY THE FACT THAT THE BOWATER PLANT AND A PORTION OF THE NEWPAGE PLANT ARE NO LONGER A PART OF NSPI'S CUSTOMER BASE?**

A22. No, it is not. The Company has proposed to take a 30% equity stake in the NewPage plant in order to be sure that the plant is capitalized sufficiently, and NSPI took over the engineering procurement and construction ("EPC") responsibility for the NewPage biomass plant as part of this transaction, further subjecting the Company to EPC risk until the plant is completed. These actions increase, rather than decrease the Company's exposure to the troubled pulp and paper sector and to NewPage specifically. While the closure of the Bowater plant and only partial re-opening of the NewPage plant will reduce NSPI's exposure to the industrial customer class by approximately 1,500 GWh per year, these two examples highlight the risk of NSPI's ongoing exposure to more than 2,400 GWh per year of remaining industrial load. Finally, the Company's Demand-Side Management ("DSM") program also subjects the company to load loss in the event that actual DSM results exceed the Company's DSM forecast.

[24] Booth, at 27.

Q23. **DR. BOOTH STATES ON PAGE 27 OF HIS EVIDENCE THAT, GIVEN NSPI'S FUEL ADJUSTMENT MECHANISM, RISKS RELATED TO FUEL PURCHASES ARE "BORNE BY UTILITY RATEPAYERS AND NOT NSPI'S SHAREHOLDER." DO YOU AGREE?**

A23. Not entirely. In general, the FAM does provide substantial protection against fuel price variability for NSPI's equity holders, but it provides far from complete protection. The NSUARB retains the authority to review the FAM in order to determine that NSPI's fuel procurement operations were conducted in a prudent manner. For example, at issue in the 2013 GRA is a prudence investigation into NSPI's natural gas procurement actions in 2008 with regard to gas purchases during the 2010 and 2011 FAM period. Liberty Consulting, which was hired by the NSUARB to conduct an audit of these procurement activities, has identified several procurement decisions made by NSPI as being imprudent, and has recommended to the NSUARB that more than $22 million in fuel procurement and associated plant costs should be disallowed.[25] NSPI and its consultants, including Concentric consultant John J. Reed, find no basis for this assessment and disagree with its conclusions. Nonetheless, the NSUARB's ability to review the prudence of NSPI's fuel purchases under the FAM leaves the Company vulnerable to the risk of disallowance through the current proceeding or through similar proceedings in the future.

Q24. **DOES DR. BOOTH FAIRLY ACCOUNT FOR THE BUSINESS RISK IMPACTS OF GOVERNMENTAL ENERGY POLICY ON NSPI?**

A24. No. Dr. Booth takes the "tremendous opportunities" statement from Emera's Annual Report without a fair characterization of the overall context presented. The Emera Annual Report statement cited by Dr. Booth refers to the overall corporate strategy of transformation to a lower carbon energy mix, and not to the specific requirements of governmental policies and risks to NSPI. Those impacts are referenced on the same page, which Dr. Booth seems to have ignored.

> In Nova Scotia, we continue to focus on meeting the province's legislated renewable energy standards, which require 25 per cent of our generation to

[25] "Confidential Report to the NSUARB," July 9, 2012, Liberty Consulting Group, at IV-28, V-20 and V-25. Includes $12.8 million in recommended deferrals related to hedging activities.

> come from renewable sources by 2015, and 40 per cent by 2020. We are on track to meet these targets, with Nova Scotia Power's (NSPI's) renewables comprising 17 per cent of the generation mix in 2011. NSPI's CO2 emissions last year were the lowest since 1999, and the percentage of coal and heavy fuel oil in NSPI's generation mix was the lowest in the company's history, 57 per cent of total generation compared with 80 per cent only five years ago.[26]

Notwithstanding Dr. Booth's mischaracterization, every "opportunity" at NSPI or in Emera's unregulated businesses also represent risks. Requiring a company to transform its generation mix is not business as usual for an integrated utility such as NSPI, and it undoubtedly increases business risk.

Q25. **HOW DOES INCREASED INVESTMENT INCREASE BUSINESS RISK?**

A25. Increased investment for a regulated utility creates risk in two ways: increased cash outlays without matching cash inflows during the construction period, and the potential for rate disallowances or deferrals. On this point, S&P expresses concerns for the impacts of these requirements for NSPI's credit rating:

> The Nova Scotia government recently introduced amendments to its legislation that will increase the percentage of renewable energy in the generation mix to 25% in 2015 and 40% in 2020. Consequently, consistent with the initiatives and its own focused-growth strategy, we expect NSPI to make significant capital expenditures in the near-to-medium term. However, we view these expenditures in a regulatory context, which provides limited cash flow relief during construction for multiyear projects; and a balanced-but-measured perspective on yearly rate applications, leading to large rate increases.
>
> As a result, we believe NSPI's near-term credit metrics could weaken because of the timing difference between the regulatory asset's development (with the resulting debt) and the commencement of cash flow in the context of heightened regulatory risk. The extent to which this occurs is a function of the heightened regulatory risk of limited rate increases, the timing of such investments in conjunction with the capital structure employed with respect to the projects' development.[27]

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[26] Emera 2011 Annual report, Page 2.
[27] Standard & Poors, Global Credit Portal, Ratings Direct, Nova Scotia Power Inc., April 18, 2012, at 2.

Q26. **DOES THE COMPANY BEAR OTHER RISKS REGARDING THE RECOVERY OF ITS FIXED COSTS?**

A26. Yes, it faces the risk of non-recovery of fixed costs related to the potential exit of municipal utilities wholesale customers. There are six municipal utilities in Nova Scotia that are current wholesale customers of NSPI and that have indicated that they would like to move to a supplier other than NSPI. As a result NSPI has requested in its 2013 General Rate Application that the approximately $7 million in fixed costs associated with those customers would be recovered through exit fees.[28] However, the municipal utilities involved contend that NSPI's proposed mechanism for recovering these fees, the Embedded Cost Recovery Mechanism ("ECRM"), is in violation of a 2005 Consensus Proposal that, according to the municipal utilities, explicitly exempts the municipal utilities from paying an exit fee.[29] On September 6, 2012, the NSUARB issued its decision denying NSPI's request for an ECRM and, without making a finding on the point, stated, "Having foregone the opportunity to recover stranded costs from the MEUs, it is not at all clear that NSPI should be entitled to claim those stranded costs from other customers."[30] This is a clear example of business risk that remains with NSPI.

Q27. **DOES THE COMPANY'S PROPOSED TWO-YEAR RATE APPROVAL REDUCE BUSINESS RISK AS MS. SMITH SUGGESTS?[31]**

A27. No, it does not. A longer approval period presents the Company with the greater likelihood of actual outcomes differing from the Company's forecast. This creates higher risk than having to forecast for just a single year. While there is just as much chance that the Company will over-forecast as there is that it will under-forecast, this uncertainty presents risk to equity holders. Under the proposed rate stabilization plan, any realized upside risk is passed on to ratepayers while any downside risk is held for shareholders.

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28 GRA, at 136-138; Appendix L.

29 Hearing Transcript, "In the Matter of an Application by Nova Scotia Power Incorporated, and a Hearing Approval of Certain Revisions to its Rates, Charges and Regulations, Including a Request for an Embedded Cost Recovery Mechanism ("ECRM") Applicable to the Municipal Utilities," NSUARB-NSPI 2013 GRA-P-893/M04972, at 7.

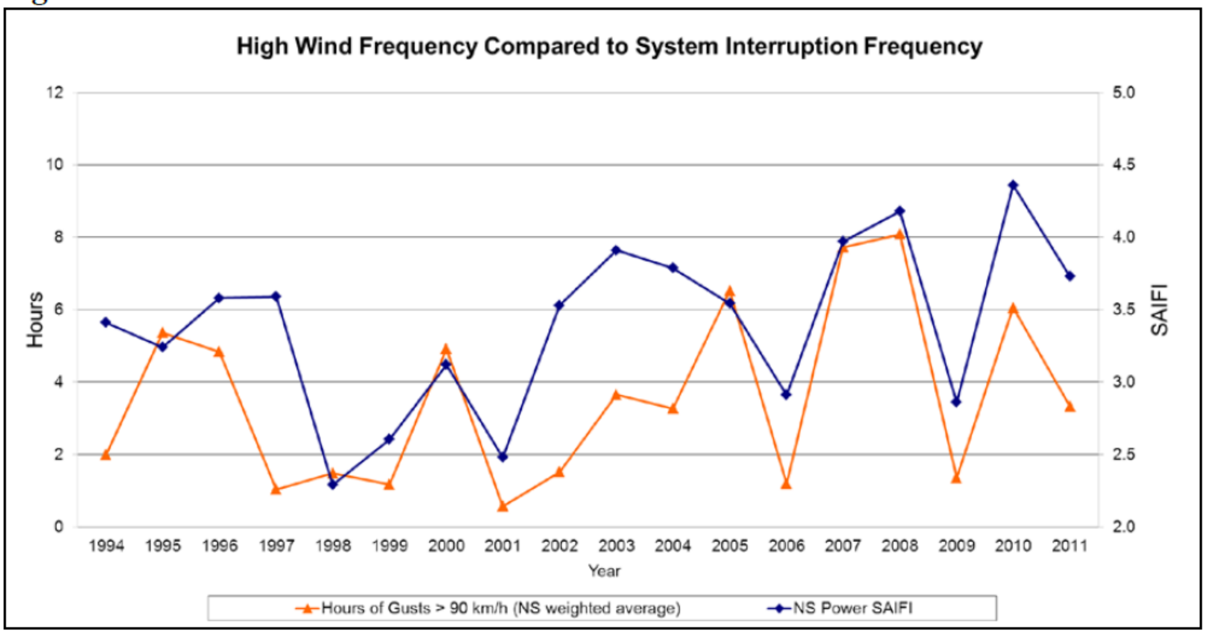
30 2012 NSUARB 133, at paragraph 52.

31 Smith, at 10.

Q28. **IS IT TRUE THAT THE COMPANY'S RELIABILITY INDICES DO NOT INDICATE AN INCREASING RELIABILITY PROBLEM, AS MS. SMITH SUGGESTS?**[32]

A28. No, it is not. Figure 6-7 in the Company's 2013 General Rate Application, which is reproduced below, clearly shows an increasing trend in SAIFI since 2001.

Figure 6-7



Source: NSPI 2013 General Rate Application, Figure 6-7.

Ms. Smith also provides NSPI's SAIDI and CAIDI statistics. I observe that since 2003 the SAIDI statistic has been noticeably higher than it was in 2000-2002. The CAIDI statistic, which measures the average amount of time a customer is without power per interruption, can be misleading because a low CAIDI can simply mean that the utility is experiencing more outages of shorter duration.[33]

Q29. **WHAT DO YOU CONCLUDE WITH REGARD TO THE BUSINESS RISKS DISCUSSED BY MS. MCSHANE IN HER DIRECT EVIDENCE?**

A29. I agree with Ms. McShane regarding the primary business risks that NSPI faces. In her direct evidence, Ms. McShane describes business risks related to 1) the weak economy in NSPI's service area; 2) the risks of maintaining a reliable generation fleet that, through a

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32 Smith, at 8-9.
33 "Reliability: Beyond the Numbers," Burns & McDonnell, at 4.

substantial capital expenditures program, is also made to comply with provincial and federal regulatory requirements with respect to greenhouse gases and renewable electricity standards; 3) the uncertainty of load, and the related deferral of fixed costs with respect to lost load; and 4) the fact that NSPI has few if any peers in Canada with respect to the risks presented by its generating portfolio. Dr. Booth himself would "expect utilities without low-cost power, such as hydro, and without a protective regulator to be allowed higher ROEs reflecting the risks attached to the cost of purchased power."[34] All of these risks, which I have described in my testimony, lead me to the same conclusion drawn by Ms. McShane: NSPI's business risks are unique and substantial, and do not compare well with other utilities in Canada. The next section of my testimony describes the appropriateness of looking to U.S. integrated utilities as a better proxy for the risks borne by NSPI.

IV. *THE USE OF U.S. VS. CANADIAN PROXY GROUPS*

Q30. DO YOU AGREE WITH DR. BOOTH'S ASSESSMENT THAT THE U.S. AND CANADA ARE SO DIFFERENT THAT AN ADJUSTMENT IS REQUIRED IN ORDER TO ESTIMATE ROE BASED ON A U.S. PROXY GROUP?

A30. No, I do not. Dr. Booth presents the following objections to the use of U.S. data in establishing comparability between Canadian and U.S. utilities: a) U.S. financial markets exhibit more risk than Canadian markets; and b) although the principles of regulation are the same between the U.S. and Canada, the implementation is different.

Below, I refute Booth's premise that macroeconomic financial conditions and markets in the U.S. are more risky than in Canada. In this, I review his overly general comparisons that do not portray an accurate picture of financial conditions and markets between Canada and the U.S. Secondly, I show how the NEB, the OEB, and the British Columbia Utilities Commission ("BCUC") believe that the use of U.S. utilities in ROE proxy groups is necessary and reasonable. Finally, I discuss the similarities between Nova Scotia and the U.S.'s economic and financial environments.

[34] Booth response to NSPI Information Request, IR-25.

Q31. **DO YOU BELIEVE THE U.S. DECISION TO LET LEHMAN BROTHERS GO INTO BANKRUPTCY HAS ANY RELEVANCE OR BEARING ON THE ALLOWED ROE'S OF NORTH AMERICAN PUBLICALLY TRADED UTILITY COMPANIES IN 2012?**[35]

A31. No, I do not. The Lehman Brothers bankruptcy was only one of several complex factors that led to the global economic crisis. Since that time, government regulators have strengthened their controls over banking and financial systems on a global basis. There is no evidence whatsoever that utility investors in Canada or the U.S. factor this single event into their cost of capital requirements.

Q32. **IS DR. BOOTH'S COMPARISON OF MACROECONOMIC FINANCIAL CONDITIONS BETWEEN CANADIAN AND U.S. ECONOMIES ACCURATE?**[36]

A32. No. Although Dr. Booth may insist that the Canadian economy is thriving, Standard & Poor's ("S&P") would suggest quite the contrary. In its recent Global Credit Report, S&P notes that:

> Canada's economic recovery lost momentum in the second half of 2011. Although trade with other countries improved and export growth rebounded, Canada's consumers and businesses restrained their spending, meaning that GDP growth suffered. We don't expect the recovery's momentum to start building again anytime soon because Canadian companies appear to be positioning themselves for a global slowdown. Planned investment spending could be postponed as Canadian companies weigh the risks to their operations and consider the potential fallout from the Eurozone sovereign debt crisis. The slowdown in employment growth and increases in Canada's national unemployment rate since October 2011 might be a sign that these influences are already rippling through the economy.[37]

S&P also states that it does not believe the Canadian economy will hit its stride until 2014.[38] As demonstrated later in this evidence, the macroeconomic financial conditions of Canada and U.S. are more similar than Dr. Booth would like to admit.

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35 Booth, at 86, lines 13-15.

36 *Ibid.*, at 86, line 9, through 87, line 20.

37 Industry Report Card: Growth Poses Biggest Challenge to an Otherwise Stable Canadian Midstrean and Utility Sector, Global Credit Portal, Standard & Poor's, February 15, 2012, at 2.

38 *Ibid.*, at 3.

Q33. **HAVE INSTITUTIONAL BODIES ANALYZED HOW MARKET SHOCKS, LIKE THE LEHMAN BROTHERS FAILURE IN THE U.S. ECONOMY ARE TRANSMITTED TO THE CANADIAN ECONOMY?**

A33. Yes. A Discussion Paper presented by the Bank of Canada discusses how U.S. financial shocks are transmitted to Canada. The Discussion Paper notes that:

> For Canada in particular, developments in U.S. economic activity and financial conditions are likely to exert a significant effect on the Canadian business cycle. Historically, the effect of the U.S. business cycle on the Canadian business cycle has generally been studied through trade linkages, since the United States represents about three-quarters of Canadian trade. However, there are also strong financial linkages between Canada and the United States. For example, Canadian non-financial corporations rely on U.S. financing, since about 20 per cent of shares of Canadian firms are held by U.S. residents. Moreover, foreign loans typically account for about 40 per cent of total bank loans to the Canadian non-bank sector, highlighting the importance of foreign credit for Canada. [excluding mortgages] Therefore, developments in U.S. financial conditions may exert a significant effect on the Canadian business cycle.[39]

Clearly, Canada was not a "bystander" during the 2008 financial crisis as Dr. Booth asserts,[40] but rather a full-fledged trading and investment partner with shared national and economic interests as its closest trading partner.

Q34. **DO YOU AGREE WITH DR. BOOTH THAT THE IMPLEMENTATION OF UTILITY REGULATION IN CANADA IS DIFFERENT THAN IT IS IN THE U.S.?**

A34. No, I do not. My experience is that the two countries are more alike than they are different. This view was shared by the NEB in its TransQuébec and Maritimes Pipeline ("TQM") Decision, when the Board found that the regulatory regimes in Canada and the U.S. are sufficiently similar as to justify comparison. This issue is addressed by the NEB, where the Board dismisses such singular events as evidence of non-comparability:

> The Board is not persuaded that the U.S. regulatory system exposes utilities to notable risks of major losses due either to unusual events or cost disallowances. The Board views the losses and disallowances

[39] Financial Spillovers Across Countries: The Case of Canada and the United States, Bank of Canada Discussion Paper, 2011-1, Kimberly Beaton and Brigitte Desroches, January, 2011, at 1.

[40] Booth, at 86, line 18.

> experienced by U.S. regulated entities as a result of the restructuring that took place to terminate the merchant gas function of pipelines, as well as some other circumstances such as the Duquesne nuclear build, to be, to a large extent, unique events. The Board also finds that such instances are not likely to weigh significantly in investors' perceptions today, and would thus have little or no impact on cost of capital.[41]

Likewise, the OEB concluded that the U.S. is a relevant source of comparable data and that it often looks to the U.S. to inform its decisions.

> The Board is of the view that the U.S. is a relevant source for comparable data. The Board often looks to the regulatory policies of State and Federal agencies in the United States for guidance on regulatory issues in the province of Ontario. For example, in recent consultations, the Board has been informed by U.S. regulatory policies relating to low income customer concerns, transmission cost connection responsibility for renewable generation, and productivity factors for 3rd generation incentive ratemaking.
>
> Finally, the Board agrees with Enbridge that, while it is possible to conduct DCF and CAPM analyses on publicly-traded Canadian utility holding companies of comparable risk, there are relatively few of these companies. As a result, the Board concludes that North American gas and electric utilities provide a relevant and objective source of data for comparison.[42]

Finally, the BCUC stated the following in 2009:

> In addition, the Commission Panel continues to be prepared to accept the use of historical and forecast data of U.S. utilities when applied: as a check to Canadian data, as a substitute for Canadian data when Canadian data do not exist in significant quantity or quality, or as a supplement to Canadian data when Canadian data gives unreliable results.[43]

Q35. **PLEASE DISCUSS THE NEB'S TQM DECISION FURTHER.**

A35. In its TQM Decision, the NEB found that U.S. market returns are relevant to the cost of capital for Canadian firms, and that the regulatory regimes in Canada and the U.S. are sufficiently similar as to justify comparison. Unlike Dr. Booth, the NEB appears to view U.S. market returns as valuable information in terms of establishing the cost of capital for

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[41] NEB Reasons for Decision, TQM RH-1-2008 (March 2009) at 67.
[42] *Ibid*., at 23.
[43] British Columbia Utilities Commission, In the Matter of Terasen Gas, Inc., Terasen Gas (Vancouver Island), Inc. Terasen Gas (Whistler) Inc. and Return on Equity Capital Structure, Decision, December 16, 2009.

Canadian utilities. Similarly, the NEB found that Canadian utilities are competing for capital in global financial markets that are increasingly integrated. The NEB recognized that it is no longer possible to view Canada as insulated from the remainder of the investing world, and that doing so would be detrimental to the ability of Canadian utilities to compete for capital.[44]

This finding suggests that it is reasonable and appropriate for Ms. McShane to consider the investment returns provided by U.S. utilities when assessing whether the allowed ROE in Nova Scotia satisfies the Fair Return Standard. Further, it suggests that it is reasonable and appropriate to consider a proxy group of U.S. gas and electric companies as sufficiently comparable to Canadian regulated utilities in terms of their risk profile. Importantly, the NEB also found that the regulatory regimes in the U.S. and Canada were sufficiently similar as to justify comparison between utilities in the two countries.

Q36. **HAVE YOU DONE ANY FURTHER RESEARCH OR ANALYSIS THAT COMPARES THE U.S. AND CANADIAN REGULATORY CONDITIONS?**

A36. Yes, I have analyzed the use of deferral accounts and other risk mitigating regulatory practices for both Canadian utilities and U.S. utilities and found no material differences in the use of these mechanisms.[45] Specifically, many U.S. utilities have been allowed to implement further risk protection features such as revenue stabilization mechanisms to address declining average use per customer and cost tracking mechanisms to facilitate replacement of aging gas and electric infrastructure. Many utilities with significant capital expansion programs are allowed a cash return on Construction Work in Progress ("CWIP"). These types of risk protection measures appear to be less common among Canadian regulated utilities based on my review of shareholder annual reports and regulatory filings.

44 NEB Reasons for Decision, TQM RH-1-2008 (March 2009).

45 A Comparative Analysis of Return on Equity of Natural Gas Utilities, Prepared for The Ontario Energy Board, June 14, 2007; 2009 Consultative Process of Cost of Capital Review, On Behalf of Enbridge Gas Distribution, Inc., September 8, 2009, EB-2009-0084; Direct Testimony of James Coyne on Behalf of ATCO Utilities, November 20, 2008, Proceeding ID. 85; Equity Thickness Evaluation and Recommendation, Prepared for Enbridge Gas Distribution, January 27, 2012; 2009 Consultative Process of Cost of Capital Review , On Behalf of The Coalition of Large Distributors and Hydro One Networks, Inc., September 8, 2009.

Q37. **PLEASE DISCUSS WHY YOU BELIEVE IS IT IMPORTANT TO INCLUDE U.S. UTILITIES IN THE ANALYSIS OF CANADIAN ROE ESTIMATES?**

A37. In order for utilities to fund their operations, they must be able to attract capital on reasonable terms and conditions from investors with a broad array of alternative investment options (the capital attraction standard). In order to do so, utilities must offer returns that are comparable to enterprises of similar risk (the comparable investment standard). These elements of capital attraction and comparability of investment risk cannot be separated from the business and economic environment that frames capital market and investor expectations. In a world of increasingly linked economies and capital markets, investors seek returns from a global basket of investment options. Investors discriminate between risks on a country-to-country basis, factoring in the comparability of the economies and the business environments.

Q38. **HAS INVESTMENT RISK BEEN COMPARED ON A COUNTRY BY COUNTY BASIS?**

A38. Yes. Country-specific economic and business conditions that affect investment risk may be measured through a variety of qualitative and quantitative metrics. One such measure, produced by the Economist Intelligence Unit (affiliated with the Economist magazine), provides a ranking of the world's largest economies based on a range of factors impacting the business environment. This report is produced in conjunction with the Columbia University Program on International Development. According to the report, "The business rankings model measures the quality or attractiveness of the business environment in the 82 countries covered by Country Forecasts using a standard analytical framework. It is designed to reflect the main criteria used by companies to formulate their global business strategies, and is based not only on historical conditions but also on expectations about conditions prevailing over the next five years." … "The business rankings model examines [91 indicators] in ten separate criteria or categories, covering the political environment, the macroeconomic environment, market opportunities, policy towards free enterprise and competition, policy towards foreign investment, foreign trade and exchange controls, taxes, financing, the labor market and infrastructure."[46] The business environment ranks are updated annually in individual country forecasts. Based on the April 2012 update, which provides both the historical 2007-2011 rank and the projected 2012-2016 rank out of 82 countries, Canada and the U.S. are ranked 4th and 9th respectively over the historic period, and 5th and 9th over the projected five years. This report suggests that from a business investment perspective, Canada and the U.S. are highly comparable in a global context.

The World Economic Forum also publishes its annual *Global Competitiveness Report*, which ranks 142 countries on twelve economic factors, including institutions, infrastructure, the macroeconomic environment, health and primary education, higher education and training, goods market efficiency, labor market efficiency, financial market development, technological readiness, market size, business sophistication, and innovation.[47] According to the 2011-2012 report, Canada is ranked 12th and the U.S. is ranked 5th in competitiveness and productivity.[48] The report describes the Global Competitiveness Index as "a comprehensive tool that measures the microeconomic and macroeconomic foundations of national competitiveness."[49] The report further explains: "We define competitiveness as the set of institutions, policies, and factors that determine the level of productivity of a country. The level of productivity, in turn, sets the level of prosperity that can be earned by an economy. The productivity level also determines the rates of return obtained by investments in an economy, which in turn are the fundamental drivers of its growth rates."[50] In a recent update to the Global Competitiveness Index, Canada has slipped from 12th to 14th, and the U.S. from 5th to 7th.[51]

46 "World Investment Prospects to 2011", Economist Intelligence Unit, written with the Columbia Program on International Development, 2007 Edition, at 38, 39, 235.

47 "The Global Competitiveness Report: 2011-2012", World Economic Forum, Centre for Global Competitiveness and Performance, at 5-8.

48 *Ibid.*, Table 3, at 15.

49 *Ibid.*, at 4.

50 *Ibid*.

51 Globe and Mail, September 6, 2012, at B3.

Q39. **HAVE YOU COMPARED THE OVERALL ECONOMIC AND INVESTMENT ENVIRONMENT BETWEEN CANADA AND THE U.S.?**

A39. Yes, Exhibit JMC-2 presents several measures that reflect the overall economic and investment environment in Canada and the U.S. The first measure compares the returns to investors from the TSE 300 and S&P 500 stock indices. The total return on the TSE 300 has been 4.0% higher than the S&P 500 over the past ten years and 1.7% higher over the past five years. Turning to the Utility Stock Index, U.S. utilities outperformed their Canadian counterparts in five of the last nine years.[52] While the broader market returns were higher for Canadian companies over the most recent ten and five year periods, average total returns for Canadian and U.S. utility investors have been very similar between 2003 and 2011 (i.e., 12.77% vs. 12.90%).[53]

As also shown on Exhibit JMC-2, the correlation between real GDP growth rates in the two countries is strong, as is the correlation between the consumer price indices for each country, indicating that these metrics tend to move together over time between the two countries. Over the 25-year period, real GDP growth has been 2.50% in Canada and 2.58% in the U.S., while consumer inflation has been 2.44% in Canada and 2.92% in the U.S. Unemployment rates over the 25 year and ten year periods have been substantially higher in Canada (e.g., 7.51% in Canada vs. 5.94% in the U.S. since 1987), but that trend reversed since 2009 as the U.S. has been slower to recover from the recent recession.

Q40. **HAVE YOU ALSO ANALYZED AND COMPARED BOND YIELDS BETWEEN CANADA AND THE U.S.?**

A40. Yes. The average yields on 10-year government bonds have also been very similar in Canada and the U.S. over the past decade. Specifically, the average yield on 10-year Canadian government bonds has been 4.01%, while the average yield on U.S. Treasury bonds has been 3.95%. During 2011, the average yield on 10-year government bonds was 2.78 in Canada and 2.79 in the U.S. Today, the relative 10-year bond yields stand at 1.74% in Canada and 1.59% in the U.S.[54] The correlation between average annual

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52 Dividend data for the S&P/TSX Utilities Index is not available prior to 2003.

53 Source: Bloomberg Professional Service. Return includes both price appreciation and dividend yield. Dividend data for the S&P/TSX Utilities Index were not available prior to 2003.

54 Canadian bond data from Bank of Canada. US bond data from U.S. Federal Reserve for September 4, 2012.

interest rates on 10-year government bonds in Canada and the U.S. since 1987 has been 0.98; similarly, the correlation between daily average interest rates on 10-year government bonds in Canada and U.S. from 2008 through 2011 has been 0.99, as central banks in both countries responded to the credit crisis and financial market dislocation by providing supportive monetary policy. Correlations of this degree are certainly reflective of closely integrated financial markets. Those low interest rates on government bonds reflect the risk aversion in global financial markets, as investors sought the relative safety of government bonds rather than assuming the risks associated with equity ownership.

Q41. **WHAT DO YOU CONCLUDE FROM AN INVESTERS STANDPOINT?**

A41. Based on those 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) which would warrant significant differences in investors' return expectations. Furthermore, the magnitude and significance of trade between the two countries indicates the high degree of integration between the two markets. In 2011, in terms of trade in goods, 73.7% of Canada's total exports went to the U.S., and imports from the U.S. accounted for 49.5% of Canada's total imports.[55]

The value of the Canadian dollar has fluctuated versus the U.S. dollar (as with all currencies) over the past 25 years. The Canadian dollar fell to $1.57 per U.S. dollar in 2002 before rebounding to $0.99 in 2011; it currently stands at $0.99 as of August 31, 2012.[56] Consensus Forecasts projects that exchange rates between the Canadian and U.S. dollar are expected to remain relatively stable through 2014.[57] For a Canadian investor, while the fluctuation in exchange rates over the past decade does not affect an investment in a Canadian utility, it does affect the value of U.S. utility investments. The same is true reciprocally for a U.S. investor.

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. It is no accident that Canadian utilities, such as Emera, Fortis BC, AltaGas, TransCanada Pipelines, Hydro One

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55 Trade Data Online – Canadian Trade by Industry, Industry Canada.
56 U.S. Federal Reserve.
57 Consensus Forecasts, Inc., Survey Date August 13, 2012.

and Ontario Power Generation, and Enbridge have recently moved to adopt US GAAP for accounting and regulatory reporting standards.[58] From a business risk perspective, including overall business environment and competitiveness, Canada and the U.S. are ranked closely when compared against other developed and developing countries. The capital markets are highly integrated. Based on these metrics and qualitative assessments, it is reasonable to conclude that over the long term a reasonable investor would prudently expect comparable returns from the two countries. Therefore, I conclude that there is no justification for an adjustment to investor returns to reflect differences in economic or institutional risk between Canada and the U.S. Unlike Dr. Booth, who concludes that the U.S., Europe and Canada are on different trajectories[59], I believe a more accurate description is that offered in response to the Bank of Canada's strategy, "The Canadian economy is like a boat in the ocean, our economic fortunes are dictated by what's going on in the rest of the world."[60]

Q42. **WHAT IS THE STATE OF THE NOVA SCOTIA ECONOMY, RELATIVE TO THE CANADIAN ECONOMY AS A WHOLE?**

A42. As shown by the statistics provided in Exhibit JMC-1, Nova Scotia's economic recovery has been among the slowest of all the Canadian provinces, but it compares favorably with the economic recovery in the U.S. Nova Scotia's real GDP growth of only 1.6 percent in 2010 and 0.3 percent in 2011 compares to average real GDP growth of 2.8 percent in that two-year period for Canada as a whole and 2.1 percent for the U.S. in that period. Similarly, Nova Scotia's unemployment rate, while having fallen to 7.7 percent in 2011, was higher in that year than all other provinces except Prince Edward Island, Newfoundland and New Brunswick, and has not yet recovered from its 2007 pre-recession rate of 6.9 percent. The 2011 unemployment rate for Canada as a whole was 6.5 percent. The 2011 unemployment rate in the U.S. was 8.9 percent. From these figures I conclude that the U.S. and Canada are both recovering slowly from the

58 The Fortis BC Utilities (comprised of FortisBC Inc., Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., and Terasen Gas (Whistler) Inc.) Application to Adopt US Generally Accepted Accounting Principles ("US GAAP") effective January 1, 2012; and Enbridge Gas Distribution Inc., 2013 Rates Application, Board File No. EB-2011-0354.

59 Booth, at 54, lines 16-17.

60 Darcy Briggs at Franklin Templeton, Calgary, quoted in *The Globe and Mail* "With global economy on edge, Carney holds rates flat", September 6, 2012, p. B3.

recession, but that Nova Scotia's rate of recovery compares more favorably to that of the U.S. than it does to that of other provinces.

V. CONCLUSIONS

Q43. WHAT DO YOU CONCLUDE REGARDING NSPI'S BUSINESS RISKS?

A43. If anything, the Company's business risk has increased since the fall of 2011 when the rate decision of the 2012 GRA was being drafted. In November 2011, Standard and Poor's downgraded the Company's outlook to "Negative", based primarily on the Company's significant capital expenditures program related to energy policies at both the federal and provincial levels."[61] In May 2012 and as part of 2013 GRA, the Company produced a load forecast for 2013 that was more than 15 percent lower than the previous forecast it made for 2012.[62] And in June 2012 the Bowater plant announced that it would remain permanently closed. Together, these events point to the Company's increasing business risk.

Further, there is ample evidence that NSPI's business risk is greater than that of the other regulated Canadian gas and electric distributors cited by Dr. Booth, and at least comparable, if not greater risk than the U.S. proxy group sample utilized by Ms. McShane. The evidence ultimately suggests that NSPI's requested continuation of its existing ROE and common equity ratio are conservative and to the benefit of the Company's ratepayers.

Q44. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A44. Yes, it does.

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[61] "Nova Scotia Power Inc. Outlook Revised to Negative on Growth Plan Stresses", Standard & Poor's, March 30, 2012.

[62] NS Power 2013 General Rate Application, at 34.

2007 **NSUARB-P-886**

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act,* R.S.N.S. 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations

RESPONSE TO INFORMATION REQUEST

TO: **NSPI**

FROM: **UARB**

Question IR-73: **Appendix G**

a. **Page 5, (last line but one): Provide an explanation of why wind assets are assigned 30% to 3CP demand and the remaining plant to energy.**

b. **Exhibit 7: Why isn't line 17 the same as Appendix A, Table 2, line 5, column 5?**

c. **Exhibit 9A, line 8: Column 2 shows energy sales of 2,076.1 GW.h, the same value as used by NSPI in the ELIIR-2 hearing (P-883) for the cost of service study in SEB IR-1a. Column 6 shows a coincident demand of 264,400 KW versus the SEB IR-1a value of 247,000 KW. This results in a drop in customer load factor from 95.85% in SEB IR-1a to 89.64% in the present filing. Please provide an explanation for the higher peak demand forecast for this customer in the present filing while leaving energy sales constant between the two cost of service studies.**

Response IR-73: a. Wind energy is a variable resource. In Nova Scotia, the current installed wind generation has generally achieved approximately a 30 percent capacity factor, compared to nameplate rating. NSPI has used these results in the Cost of Service Study to assign 30 percent of wind assets to demand, with the remainder being assigned to energy.

2007 **NSUARB-P-886**

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act,* R.S.N.S. 1989, c.380 as amended

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RESPONSE TO INFORMATION REQUEST

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Response IR-73: (cont'd)

b. The difference between Non-Rate Revenue of $9.3 million in Exhibit 7, line 17 and Misc. Revenue of $10.8 million in Table 2, line 5 of Appendix A is associated with $1.5 million in Retail Sales. This Retail Sales figure when netted against Cost of Goods Sold of $1.1 million in Table 2, line 10 of Appendix A results in a credit of $0.4 million that is identified in Exhibit 4, Line 24 of Appendix G.

c. The demand of 264,400 kW for 2007 is based on 2005 actual load shape information that was not available in the P-883 hearing.

2012 General Rate Application (NSUARB P-892)
NSPI Responses to CA Information Requests

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Request IR-32:

Please list all the "Environmental and fuel conversion assets in the rate base [that are] are extracted up front and classified 100% as energy-related."

(a) Do these costs include the conversion of Point Tupper from oil to coal in 1987?

(b) Do these costs include the conversion of Tufts Cove to gas?

(c) Do these costs include the conversion of the Point Tupper, Lingan, Point Aconi, and Trenton to burn different grades of coal?

Response IR-32:

(a-c) Yes. Please refer to Attachment 1 for the list of the Environmental and fuel conversion assets in the rate base that are extracted up front and classified 100 percent as energy related.

Environmental and Fuel Conversion Assets

Title/Description	Generating Unit	Original Cost of the Item ($)	In service date	Average Remaining Life
2008 Pcb Equipment Inventory	Total Distribution Plant	$12,066.56	2009	N/A
Ash Lagoon Capping	Trenton - Common	$125,438.68	2007	29.7
Ash Lagoon Covering	Trenton - Common	$100,162.92	2008	29.7
Ash Site North "A" Cell Development	Lingan - Common	$396,802.30	2009	21.5
Ash Site Sealing and Capping	Lingan - Common	$990,203.25	2003	21.5
Bear River Oil Protection	Bear River	$60,364.23	2009	43.3
Cell 3 Stage 3 Residue Management Site	Point Aconi 1	$2,598,775.18	2009	30.6
Connect Plant to Municipal Sewer System at HRM Request	Tufts Cove - Common	$154,138.30	2007	21.5
Continuous Emission Monitoring System Replacement	Trenton 5	$143,962.63	2005	29.7
CT'S -Replace Halon Fire Protection	Victoria Junction	N/A	2012	N/A
Digby Wind Project	Wind General	N/A	2012	N/A
Disposal of PCB Transformers	Line Transformers	$75,693.27	2009	16.4
Eastern Valley Oil Protection	Black River	$75,665.55	2008	45
EP&M Mercury Measurement Instrumentation	Total General Plant	$252,962.17	2010	N/A
FAC Enviro Property Remed Routine	General Plant	N/A	2017	N/A
FAC Environment Site Assess Routine	General Plant	N/A	2016	N/A
FAC Environmental Property Remediation Routine	Total General Plant	$81,957.20	2010	N/A
FAC Environmental Site Assessment	Total General Plant	$422,919.57	2010	N/A
Fire Suppression - Replace Halon Gas System	Total General Plant	$346,847.56	2009	N/A
Fuel Oil Storage Handling	Tufts Cove - Common	$94,010.15	2006	21.5
GS Upgrade of Ambient Air Shelters	Total General Plant	$126,967.12	2010	N/A
Harmony Intake	Harmony	$84,958.08	2006	21.2
HYD Oil Relaease Risk Assessment	Hydro General	N/A	2012	N/A
Installation of a Wastewater Treatment Facility	Lingan - Common	$5,420,997.33	2003	21.5
In-Stream Tidal Generation	Annapolis Tidal	$4,573,089.13	2009	34.5
Lingan Precipitator Refit Program	Lingan - Common	$127,486.35	2007	21.5
Lingan Unit # 3 Low Nox Combustion Firing System	Lingan 3-4	$3,813,164.19	2006	21.2
Lingan Unit #1 Low Nox Combustion Firing System	Lingan 1-2	$3,875,372.97	2009	8.4
Lingan Unit #1 Mercury Abatement	Lingan 1-2	$1,800,618.17	2010	8.4
Lingan Unit #2 Low Nox Combustion Firing System	Lingan 1-2	$3,751,101.84	2007	8.4
Lingan Unit #2 Mercury Abatement	Lingan 1-2	$1,847,112.87	2010	8.4
Lingan Unit #3 Low Nox Combustion Firing System	Lingan 3-4	$4,181,454.76	2007	21.2
Lingan Unit #3 Mercury Abatement	Lingan 3-4	$4,459,213.27	2010	21.2
Lingan Unit #4 Mercury Abatement	Lingan 3-4	$1,754,566.56	2010	21.2
Little River Lake Dam Refurbishment	Black River	$290,246.93	2006	45

Title/Description	Generating Unit	Original Cost of the Item ($)	In service date	Average Remaining Life
Nictaux Lube & Oil Governor Update	Lequille System	$39,929.16	2009	33.6
Nuttby Mountain Wind Project Development	Wind Turbines	$110,050,218.00	2010	18.5
Padmount Replacement Program	Total Distribution Plant	$398,607.31	2010	N/A
PCB Equipment Removal/Destruction	Total Distribution Plant	$36,013.19	2010	N/A
PCB Management at Sensitive Sites	Total Distribution Plant	$294,139.13	2004	N/A
Pipeline Life Extension	Lequille System	$69,074.70	2003	33.6
Pipeline Rupture Detection	Bear River	$41,501.55	2009	43.3
Pipeline Rupture Detection	Lequille System	$123,812.50	2004	33.6
POA Ash Cell Capping Cell 3 Stage 1	Point Aconi Generating Station	N/A	2011	N/A
POA Bag house Bag Replacement Pro	Point Aconi 1	$854,385.19	2009	30.6
Point Aconi	Point Aconi 1	$75,000,000.00	1993	30.6
Point Tupper Fuel Conversion	Point Tupper 2	$94,469,366.00	1987	21.3
Point Tupper Unit #1 Mercury Abatement	Point Tupper 1	$2,461,060.04	2010	20.4
Point Tupper Unit #1 Replacement of Opacity Monitors	Point Tupper 1	$68,849.55	2008	20.4
Point Tupper Unit #2 Low Nox Combustion Firing System	Point Tupper 2	$3,074,920.62	2009	21.3
Point Tupper Wind Project	Wind Turbines	$18,730,503.00	2010	18.5
Port Hawkesbury Biomass Project	Steam General	N/A	2013	N/A
POT - Develop new ash cells	Point Tupper Generating Station	N/A	2012	N/A
POT - Marine Terminal Dust Mitigati	Strait Marine Terminal	N/A	2011	N/A
POT - Utilization of Heavy Biofuel	Point Tupper Generating Station	N/A	2011	N/A
POT - Wastewater cell refurbishment	Point Tupper Generating Station	N/A	2011	N/A
POT Ash Cell Capping Cell B	Point Tupper Generating Station	N/A	2013	N/A
Pt. Tupper Relocate Port Malcolm Rd	Point Tupper 2	$1,567,961.15	2009	21.3
Reburbish Fly ash Handling	Lingan 1-2	$598,380.44	2005	8.4
Recoat Bunker C Tank	Lingan - Common	$332,966.56	2008	21.5
Refurbish Light Oil Tanks and Lines	Lingan - Common	$178,299.88	2008	21.5
Removal of External Street Light Ballasts (contain PCB's)	Total Distribution Plant	$32,152.13	2006	N/A
Replace Deteriorated Padmount Transformers	Line Transformers	$54,373.98	2007	16.4
Replace Deteriorated Padmount Transformers	Line Transformers	$257,513.00	2008	16.4
Replace Deteriorated Padmount Transformers	Line Transformers	$28,633.27	2008	16.4
Replace Deteriorated Padmount Transformers	Line Transformers	$116,557.60	2006	16.4
Replace HFO Tank Interface Liner	Tufts Cove - Common	$103,050.60	2008	21.5
Replace water Treatment Equipment	Tufts Cove - Common	$102,291.11	2010	21.5
Replacement of Deteriorated Padmount Transformers	Line Transformers	$573,925.73	2005	16.4
Roseway Dyke Repair	Roseway	$58,705.62	2010	38
Rusty Transformers	Line Transformers	$48,741.00	2007	16.4

Title/Description	Generating Unit	Original Cost of the Item ($)	In service date	Average Remaining Life
Ruth Falls Canal Fish Lovre Improvements	Sheet Harbor	$405,953.17	2006	25.5
Spherical Valve Replacement	Wreck Cove System	$263,006.64	2009	41.8
Stage 3 Residue Management Site	Point Aconi 1	$1,737,016.93	2007	30.6
Sydney Replace Deteriorated Padmount Transformers	Line Transformers	$137,000.00	2006	16.4
TRE - Ash Site Management	Trenton - Common	$124,720.10	2010	29.7
TRE - CW Outlet Oil Boom	Trenton Generating Station	N/A	2012	N/A
TRE - Storm Drainage Improvements	Trenton - Common	$120,524.75	2010	29.7
TRE - Wastewater Treatment Plant Up	Trenton Generating Station	N/A	2011	N/A
Trenton Ash Site Covering	Trenton - Common	$99,210.85	2009	29.7
Trenton Ash Site Covering Project	Total Trenton	$113,372.43	2010	N/A
Trenton Site Environ. Improvements	Trenton - Common	$121,586.35	2007	29.7
Trenton Unit #5 Bag House Addition	Trenton 5	$29,051,521.15	2009	29.7
Trenton Unit #5 Mercury Abatement	Trenton 5	$1,588,705.12	2010	29.7
Trenton Unit #6 Low Nox Combustion Firing System	Trenton 6	$4,106,621.42	2008	29.7
Trenton Unit #6 Mercury Abatement	Trenton 6	$1,877,140.40	2010	29.7
TUC - Oil Tank Protective Coating	Tufts Cove - Common	$23,365.65	2010	21.5
Tufts Cove Fuel Conversion	Total Tufts Cove	$25,601,694.00	2000	N/A
Tufts Cove No#2 Precipitator	Tufts Cove 2	$4,278,674.00	1998	10.3
Tufts Cove Oil Tank #4 Refburb/Upgrade	Tufts Cove - Common	$1,300,701.30	2002	21.5
Tufts Cove Unit #1 Electrostatic Precipitator	Tufts Cove 1	$9,225,531.00	2005	10.3
Tufts Cove Unit #3 Electrostatic Precipitator	Tufts Cove 3	$11,430,257.74	2005	21.4
Vault Oil Containment	Total Distribution Plant	$209,748.00	2007	N/A
Vault Oil Containment	Total Distribution Plant	$121,051.34	2005	N/A
West Replace Deteriorated Padmounts	Total Distribution Plant	$148,535.00	2006	N/A
Weymouth Falls Oil Containment	Bear River	$175,006.99	2005	43.3
White Rock Bar Rack Refurbishment	Black River	$44,827.44	2006	45
Wolfville Site Remediation	Total General Plant	$213,526.01	2007	N/A
Yard Oil Piping Upgrade	Tufts Cove - Common	$88,715.57	2008	21.5

2012 General Rate Application (NSUARB P-892)
NSPI Responses to NPB Information Requests

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Request IR-35:

Please provide all workpapers supporting the $115,618 of wind plant classified as energy related in GRA Section SR-01, Exhibit 2A, page 1, line 3.

Response IR-35:

Consistent with the currently used cost of service methodology, as approved by the UARB in its decision in the last Cost of Service and Rate Design Hearing[1] conducted in 1995, NSPI has repeatedly classified generation costs with environmental compliance and fuel conversion as energy related.

[1] NSPI 1995 Cost of Service and Rate Design, UARB Decision NSUARB – NSPI – 864, September 22, 1995 (page 23, paragraph 2)

Nova Scotia POWER
An Emera Company

energy everywhere.™

April xx, 2012.

To:

Via email:

RE: LED Streetlights

Dear

As you are aware, the provincial government passed legislation on May 19, 2011 that will make LED lighting mandatory on Nova Scotia's roads and highways. Detailed regulations are available for public comment.

Nova Scotia Power Inc. (NSPI) is in the process of gathering customer information to formulate an implementation plan to meet these regulations. We will be requesting your input on how you'd like to work with NSPI on streetlights in your community. A second letter will be sent with specifics for your community in order to assist with your decision.

Going forward NSPI customers have 2 options:

1. Continue to rent streetlights from NSPI; or
2. Assume responsibility of ownership of streetlights in your area.

Under both options, you will be responsible for energy costs associated with your usage.

Customers will be responsible for the costs of the existing lights that have not yet been fully paid. We estimate this cost to be approximately $175 per light based on our most recent assessment of un-depreciated costs for the total existing streetlight inventory, which equals $23 million for the entire province. This amount will be subject to continued depreciation until the time of purchase or conversion. It is important to note that this amount will require approval by the Nova Scotia Utility and Review Board (NSUARB) during a future regulatory process, and are therefore only estimates at this time.

Nova Scotia Power
PO Box 910
Halifax, Nova Scotia
Canada B3J 2W5

Customer Service
1.800.428.6230
(428.6230 in HRM)

nspower.ca

A pilot project is planned to be submitted for approval of the UARB to better understand the costs for installation of LED streetlights and other costs. The pilot project would see NSPI change a limited number of lights over a 12 month period in various areas of the province and collect data for a better assessment of the costs and reusable parts, if any.

We encourage customers to participate in the pilot by contacting us at the email or phone number below. If you choose to participate in the pilot, both the purchase and rent options will still be available to you until you make your final decision per draft regulations by June 30, 2013.

Options:

1. **<u>Continue to Rent from NSPI</u>**

Customers who choose to continue to rent streetlights from NSPI will pay the monthly UARB approved rate per light for the number of lights in their area. These lights will form a new asset pool, separate from existing streetlight asset pool.

NSPI will develop a plan to switch existing streetlights to LED streetlights in co-operation with customers who choose to continue to rent from NSPI.

2. **<u>Assume Responsibility of Ownership of Streetlights in your Area</u>**

Municipalities who wish to assume ownership of streetlights in their area should consider the following:

a. When a municipality purchases the existing lights from NSPI at cost, the municipality will be able to use existing brackets to install municipally-owned LED lights on NSPI-owned poles. NSPI will continue to own the poles.

b. Municipalities will be responsible for costs associated with the safe and environmentally responsible disposal of existing street light assets when replaced by the new lights.

c. You will need to establish a process for streetlight outage reporting in your area.

d. NSPI will require an inventory of decommissioned lights and wattage of new LED lights installed. Once the change-out is completed, you will be billed on an approved energy-only rate.

e. NSPI will no longer be responsible for the maintenance of your streetlights.

f. Roadway lighting must comply with the Canadian Electrical Code Part I. You will need to ensure that this equipment is upgraded and inspected for compliance with the CEC.

g. Only qualified technicians are allowed to install and maintain streetlights - please refer to Department of Labor Bulletin issued in March 2012.

If you would like to discuss your options or you have any further questions, please contact us at 428-6773 or LEDStreetlightProjec@nspower.ca

Sincerely,

Judy O'Leary
Customer Lead, LED Streetlight Replacement Project

Cc: Kerry Jennex, Acting Director Retail Operations