Request IR-1:

NSPI has provided CONFIDENTIAL comparisons of fuel costs for solid fuel (Figure 14), Natural Gas (Figure 17), HFO (Figure 18), LFO (Figure 19), Biomass (Figure 20), IPP (Figure 21, 22 and 23). With respect to the information, the Board notes:

(i) Some report 2015 actuals while others do not;

(ii) Some report 2016 BCF figures while others do not;

(iii) The cost per energy unit varies between MWh and MMBtu with solid fuel only reported in MT.

(iv) It does not appear that full information related to the Nova Scotia Block of the Maritime Link has been provided, providing instead the total annual assessment and summary breakdown.

(a) Please provide 2015 actual fuel cost, energy and cost/unit of energy for each fuel.

(b) Please provide the 2016 approved BCF forecast cost, energy and cost/unit of energy for each fuel.

(c) For comparable purposes, please provide the fuel cost comparable information for each year 2015-2019 in the same unit of energy, $/MWh.

	2015 Actual	2016 BCF Approved	2017 Forecast	2018 Forecast	2019 Forecast
Natural Gas	$/Mwh				
Coal					
Etc.					
M. Link Supplemental*					
M. Link Surplus*					
M. Link 20 for 20					

*Grouped as necessary to best reflect the impact to NSPI's system

Response IR-1:

(a) Please refer to CA IR-7 Confidential Attachment 2, Tab 3, for 2015 actual fuel cost, energy (MMBtu), and $/MMBtu for each fuel type.

(b) Please refer to Appendix A OE-01B Attachment 1, Tab 3 (Confidential), for 2016 BCF Compliance Forecast fuel cost, energy (MMBtu), and $/MMBtu for each fuel type.

(c) Please refer to Confidential Attachment 1.

NSUARB IR-1 Attachment 1 has been removed due to confidentiality.

Request IR-2:

With respect to NSPI's process of assessing and informing management decisions related to economic dispatch:

(a) The Board would like to understand the cost elements of each fuel that NSPI considers as it decides the fuel mix. Please provide the proposed fuel mix and proposed economic dispatch throughout the Rate Stability Plan. Understanding this could result in hourly detail, for 3 years, please provide this using some form of actual data relied upon in this application that provides an understanding of how dispatch decisions are made and identifies the balancing of these decisions.

(b) Please explain how NSPI assesses the cost and benefit of various hedging requirements and alternatives, both before commitment to a fuel, and after a hedge has settled, to account for costs and benefits of decisions.

Response IR-2:

(a) Forecast system dispatch decisions are made using the chronological hourly dispatch simulation in PLEXOS. This system dispatch optimization considers many elements including fuel prices, fuel blend restrictions, emission constraints, generating unit start/stop costs, unit commitment constraints, planned maintenance, randomized forced outages, transmission system constraints and plant efficiency.

The PLEXOS system dispatch optimization algorithm considers all of these factors in the development of an optimal system dispatch solution, which it does in two phases:

(i) The first optimization phase is a linear solution which determines a draft annual target system dispatch and fuel blends in order to achieve all four emissions limits without considering all hourly system constraints. This simulation phase is

conducted by PLEXOS using a load duration curve dispatch optimization methodology.

(ii) The second optimization phase is a full chronological dispatch, considering all hourly and non-linear system generating unit commitment constraints. The chronological dispatch optimization phase is executed by PLEXOS in steps of one day with the decomposed annual targets from the annual solution described in part (a)(i). The annual solution daily targets are continuously monitored and adjusted by the optimization algorithm, throughout the chronological dispatch period, in order to arrive at an optimal solution, while meeting all system dispatch constraints, including all four emissions caps.

While the dispatch optimization solution output is available in an hourly format, NS Power relies on monthly and annual system dispatch and fuel blends results to inform its fuel procurement strategy. Hourly system output is used for periodic model validation and simulation accuracy verification. However, the hourly data does not necessarily give an indication of why certain dispatch decisions may have been made; the optimization software considers multiple constraining factors and bases its dispatch on both the linear annual and chronological hourly simulation.

(b) Please refer to CA IR-35.

After the hedges have settled, gains or losses are added or subtracted from the cost of fuel and flow through FAM accounts in accordance with NS Power's Accounting Policy.

Request IR-3:

In a letter from the Board dated February 26, 2016, under M06966, the Board noted that a second generating unit, in addition to Lingan 2 (scheduled to shut down in 2018), could likely be shut down. The Board noted:

> **In Figure 19 of the SO Report, starting in 2017 and continuing to 2024, a surplus capacity of 176 MW above that required to meet renewables and planning reserve requirements is noted. This suggests that another generator can be removed from service in addition to Lingan 2, which is planned for 2018. In response to IR-9, NSPI stated that the new end-use load forecasting showed a lower system peak than the previous econometric load forecast, so a further understanding of this and monitoring of future trends is needed before making a decision on reducing firm capacity. NSPI is directed to provide a more fulsome explanation and analysis of this load forecasting concern in its April 30th filing of the 2016 Load Forecast Report, as well as a more definitive response in the 2016 SO Report regarding retirement of a second generating unit.**

With respect to the potential changes in the Fuel Stability Period:

(a) Please identify all units NSPI has included in the modelling and assumptions related to this Fuel Stability Period and application.

(b) Did any of these models or assumptions include Lingan units, which are scheduled to be shutdown with the Maritime Link coming into service.

(c) Provide the average annual operating and fuel costs to run each generation station included as an option within the Plexos or other runs, by year 2017-2019?

(d) What is the undepreciated capital cost of each unit and the anticipated remaining useful life?

Response IR-3:

NS Power continuously monitors its fleet for generation planning purposes, including capacity requirements necessary to meet firm peak. The Company will provide further analysis of the potential for unit retirements and their forecast timeframes in compliance with the reference UARB letter as part of the 2016 System Outlook.

(a) Please refer to part (c).

(b) Yes, it was assumed that Lingan 2 would be shutdown coincident with the Maritime Link coming into service in 2018.

(c) The following table provides the average annual fuel cost and the variable O&M for the thermal units. The values are based on the PLEXOS simulations for the Fuel Stability Period 2017 to 2019.

Unit	Average Annual Fuel Cost ($/MWh)			Variable O&M ($/MWh)
	2017	2018	2019	2017-2019
Lingan 1	35.3	34.2	36.1	1.365
Lingan 2	35.5	32.5	-	1.365
Lingan 3	35.7	33.4	35.2	1.365
Lingan 4	34.8	32.8	34.0	1.365
Point Aconi	26.3	27.0	28.0	4.702
Point Tupper	31.1	31.1	33.2	1.494
Trenton 5	37.0	39.5	41.0	1.755
Trenton 6	32.2	33.6	35.5	1.755
Tufts Cove 1	99.9	115.6	113.1	1.088
Tufts Cove 2	68.1	97.0	77.5	1.088
Tufts Cove 3	73.0	102.0	97.7	1.088
Tufts Cove 4	62.8	73.9	65.5	1.430
Tufts Cove 5	63.4	75.1	66.1	1.430
Tufts Cove 6	4.8	3.0	5.4	1.088
Tufts Cove CC (units 4, 5 & 6)	50.2	59.1	52.5	1.354
CT – Burnside 1	262.9	256.6	272.9	5.526

Unit	Average Annual Fuel Cost ($/MWh)			Variable O&M ($/MWh)
	2017	2018	2019	2017-2019
CT – Burnside 2	254.0	259.2	278.7	5.526
CT – Burnside 3	254.3	259.4	-	5.526
CT – Burnside 4	256.2	254.1	278.6	5.526
CT – Tusket	344.9	345.2	-	5.526
CT – VJ 1	272.6	-	293.6	5.526
CT – VJ 2	270.8	-	-	5.526

(d) The following table provides the remaining Net Book Value and anticipated remaining useful life based on the forecast retirement as of the end of 2015:

Unit	Net Book Value ($)	Forecast Useful Life (years)
Lingan Admin/Common Capital	97,840,883	-
Lingan 1	35,479,075	23
Lingan 2	17,366,960	2
Lingan 3	74,071,698	23+
Lingan 4	38,997,890	23+
Tufts Cove Admin/Common Capital	51,899,088	-
Tufts Cove 1	14,334,852	9
Tufts Cove 2	19,055,298	16
Tufts Cove 3	35,427,812	20
Trenton Admin/Common Capital	18,873,421	-
Trenton 5	83,694,549	19
Trenton 6	153,517,719	23+
Point Tupper	107,802,401	23+
Point Aconi	327,330,256	23+

REDACTED

Request IR-4:

To understand how hedging costs could impact the economic dispatch of fuels:

(a) Please explain how the hedging costs are accounted for during the economic dispatch. Use 2015 as an example.

(b) Layer the hedge and other fuel derivative costs onto the core cost of fuel in each of 2015 (as an example of actual) and 2017 (as an example of projected plan) to identify what the "all in" costs are.

(c) Would the economic dispatch change with all costs associated with each respective fuel layered on to the core fuel cost?

(d) If NSPI is confident the choices related to economic dispatch would not change, please explain how it has confirmed this.

(e) If NSPI is unable to answer this question on the forecast, use the 2015 example and restate the economic dispatch, had all costs of hedging been included.

(f) Please identify all hedging costs recorded in NSPI's financial results in 2015, categorize by fuel type and whether they were realized or not realized.

Response IR-4:

(a) Hedges are not considered during Day-Ahead or Real-Time economic dispatch. From a fuel forecasting perspective, the forecast mark-to-market impact of financial hedges is not incorporated into the economic optimization modeling, but is taken into account in the fuel and purchased power forecasting process once the economic optimization modeling is completed.

(b) NS Power does not perform this analysis as part of its dispatch modelling as hedges entered will settle regardless of conditions at the time of dispatch. While natural gas and power hedges are recorded as expense or credit to expenses in the periods in which they become realized, solid fuel hedges are applied to the cost of inventory when a corresponding solid fuel vessel arrives. The cost or benefit of the hedge is then reflected in FAM over time as the inventory is consumed. As a result, hedge costs are already included in Fuel and Purchase Power expense giving an "all-in" cost.

(c-d) Depending on the fuel, timing of fuel purchase / contracting, pricing mechanism and actual cost of the fuel at the time of consumption, the actual (real-time) economic dispatch could change relative to the forecast if hedged prices for each respective fuel are used for the purpose of economic dispatch (as opposed to un-hedged forward prices). By way of example, if the un-hedged forward pricing of a commodity is $10/MMBtu and the hedged pricing of that same commodity is $8/MMBtu, using the hedged pricing for the commodity in the economic dispatch process could impact the economic dispatch.

(d-e) NS Power has not completed this analysis as part of developing the forecast fuel and purchased power costs for this Application. As stated in part (a), the forecast mark-to-market impact of financial hedges is taken into account in the fuel and purchased power forecasting process once the economic optimization modeling is completed. The fuel forecast provided with the Application considers the mark-to-market impact of financial hedges.

(f) In 2015, the settled value of coal hedges was a [redacted]. Natural gas hedges settled with [redacted]. During the same period foreign currency hedges for the purposes of fuel procurement was [redacted]. Natural gas and power hedges are recorded as a FAM expense in the period in which they settle. Coal hedges are added to the weighted average cost of inventory in the period the corresponding coal vessel arrives. As the physical coal is consumed over time, the impact of the coal hedge is

included in FAM expense due to being a component of the weighted average cost of the inventory. As a result the impact of coal hedges settled in 2015 are not fully recognized as a FAM expense immediately but rather over future periods. For this reason NS Power is unable to indicate the portion of the settled coal hedges included in FAM expense during the 2015 period. The Confidential Data Cart contains FST Records of Approval to enter into the various hedges.

Request IR-5:

NSPI has modelled this three-year Rate Stability period on an increasing load, starting from the 2015 actual load. Understanding 2015 may have been an exceptional year, please clarify:

(a) Did NSPI make any adjustment for the recent average load compared to 2015? If so, please provide detail and reasoning behind the adjustment.

Response IR-5:

(a) NS Power created the load forecast in accordance with amendments to FAM POA introduced and accepted during the 2016 BCF proceeding. 2015 information was incorporated into the forecast in two areas:

(1) Historical sales from January 2003 to November 2015 were included in the regression models on which the forecast is based.

(2) Future years are forecast on a normal weather basis which is defined in the POA as a 10 year average. The weather normal definition was advanced to drop 2005 from the average and include 2015.

Request IR-6:

NSPI explains in its application that it has assumed a 0.4% increase in load annually, beyond the 2015 load. To understand the sensitivity to this assumption (Note: the Board is not requesting justification for that assumption), assume the load was as NSPI provided in the Energy Requirement values in Table A1, in Appendix A SR-02 (Appendix A SR-02 Attachment 1 Page 32 of 65) adjusted for the Board's decision under M06733 and provide:

(a) The annual resulting load and resulting base cost of fuel.

(b) Are there any fuel or hedging decisions made in the current application that would change? If so, please explain.

(c) What percent of the total fuel costs would be hedged?

(d) Please provide an explanation of the impact on costs resulting from fuels that are hedged at either an amount in excess of target or in excess of 100%.

Response IR-6:

(a) The table below compares the 2017 – 2019 BCF load forecast to the load provided in the Energy Requirement values in Table A1, in Appendix A SR-02 (Appendix A SR-02 Attachment 1 Page 32 of 65) adjusted for the Board's decision under M06733.

Year	BCF Load Forecast (GWh)	2015 Adjusted Load Forecast (GWh)	Variance (GWh)
2017	11,235	11,123	-112
2018	11,260	11,104	-156
2019	11,281	11,070	-211

NS Power is unable to determine the fuel expense for the Rate Stability Period under the revised load expectations without completing a full forecast update, including a Plexos run. This cannot be completed by the deadline for submission of these information requests. In order to approximate the Base Cost of Fuel under this revised load forecast, NS Power has assumed the decreased GWh would result in lower imports. The estimated change in fuel costs based upon the revised load forecast above is shown in the table below:

Year	BCF as Submitted ($ millions)	[redacted]
2017	527.5	
2018	672.1	
2019	681.6	

(b) NS Power has designed its Fuel Hedging Plan to be responsive to changes in its fuel forecast resulting from updated assumptions including commodity pricing and load. The framework, strategies, and mechanisms contained in the Fuel Hedging Plan would not change as a result of using this different load assumption. The forecast of expected requirements for each individual fuel type may differ slightly from the base BCF forecast. As detailed in the Fuel Hedging Plan, as forecasts are updated through the Rate Stability Period, the hedge portfolio will be rebalanced as required to reflect the most current assumptions.

(c) As detailed in the Fuel Hedging Plan, NS Power anticipates hedging up 75 - 100% of forecast fuel requirements. This change in forecast load would not have a material change on the percentage of forecast fuel costs currently hedged.

(d) Based on this alternative load forecast and the resulting change in fuel requirements, NS Power would not currently have over 100% of the forecast requirement of any fuel type hedged.

Request IR-7:

Exhibit N-1, p. 10, line 4

Despite current relative market stability:

(a) Please describe the impact on fuel costs if price volatility does indeed occur during the Rate Stability Period (2016-2019).

(b) Please provide what sensitivity analysis and results NSPI has prepared with respect to this potential volatility.

(c) As an example, the actual reliance on natural gas compared to forecast in prior Natural Gas Reports (M06911 & M06614) identify sharp variances in the forecast use of natural gas for 2016 within a 6 month period. NSPI in M07243, Figure 29, provided its long-term forecast through the Fuel Stability Period. Please explain and quantify the impact on the annual budgets if similar variances occur related to the reliance on natural gas.

Response IR-7:

(a) The impact of price volatility on fuel costs varies depending on the commodity, magnitude of the volatility, and the relative cost of other fuel options. Changes in pricing can affect the reliance on various fuels and shift the fuel mix in order to provide the most economic dispatch given actual prices. As the volatility of fuel prices increase, NS Power is able to mitigate some of this impact through fuel switching and other real optionality within its portfolio. Additionally, the increased hedging proposed in the Fuel Hedging Plan will help protect customers from the impact of higher levels of volatility in fuel markets. Increased volatility could result in either increased or decreased overall fuel

costs, depending on the circumstances of the volatility, with hedging dampening the impact in either direction.

(b) NS Power has considered the impact of price volatility by conducting a statistical analysis which estimated cost and consumption impacts using varied pricing of solid fuel, natural gas, and market energy. This analysis indicates that the costs presented in this Application represent a reasonable value with an appropriate level of statistical confidence, given the current system and market conditions.

(c) Natural gas prices are modeled in Plexos using a daily pricing shape. Accordingly, the forecasted budgets for this Application consider a natural gas variance depending on the price of other commodities in a given hour. In addition, the statistical analysis described in part (b) considered varied natural gas reliance through pricing changes. The natural gas reliance forecasted for this Application falls within reasonable statistical bounds of this analysis. As indicated in part (a), the impact of pricing volatility on the overall budget depends on many factors and cannot be explicitly quantified.

Request IR-8:

Exhibit N-1, p. 22, Figure 1 and p. 96, line 14

(a) Please provide Figure 1 in the same table format without the application of the smoothing effect of section 6(2) of the Electricity Plan Implementation (2015) Act.

(b) With respect to p. 22, Figure 1, do the annual percentage increases reflect any present value adjustments? Explain the process that was used to determine the equal annual increments over the Rate Stability Period.

Response IR-8:

(a) Please refer to the table below

Percent Change				
FAM Classes	**2017**	**2018**	**2019**	**2020**
Residential	-8.0%	18.3%	0.5%	1.7%
Small General	-5.7%	14.7%	0.0%	1.8%
General Demand	-9.8%	18.2%	1.1%	2.3%
Large General	1.1%	10.5%	-1.7%	2.6%
Total Commercial	-8.1%	16.9%	0.6%	2.2%
Small Industrial	-9.2%	18.1%	1.4%	2.3%
Medium Industrial	-6.9%	15.7%	1.1%	2.5%
Large Industrial				
Firm	-7.4%	15.6%	1.0%	2.8%
Interruptible	-7.3%	16.3%	1.1%	3.0%
Large Industrial Total	-7.3%	16.2%	1.0%	2.9%
Total Industrial	-7.6%	16.4%	1.1%	2.7%
Municipal	-9.6%	20.6%	0.7%	2.3%
Unmetered	-6.4%	12.6%	0.7%	1.4%
Total Other	-7.9%	16.4%	0.7%	1.8%
Total FAM Classes	-8.0%	17.6%	0.6%	2.0%

(b) The annual percentage increases reflect a present value adjustment for a Weighted Average Cost of Capital of 7.78%.

The equal annual increments over the Rate Stability Period were determined for each rate class separately by finding a uniform annual rate increase that would draw each rate class's imbalance in its FAM balance (including application of the non-fuel revenues and tax benefits) to zero at the beginning of 2020 as shown in cells AR30 to AR49 of Appendix H – Rate Stability Balance.

Request IR-9:

Exhibit N-1, p. 30, line 10

(a) Please confirm that the Independent Power Producer ("IPP") costs associated with the Tidal FIT are costs related to the FORCE berths only. Please provide a detailed background.

(b) Please indicate the projected costs associated with the Tidal FIT for each of the years 2017, 2018 and 2019.

(c) Please indicate the amount of GWh of the Tidal FIT for each of the years 2017, 2018 and 2019. What is the basis for these assumptions?

(d) Please confirm the Emera project at FORCE is included in the above costs and GWh totals?

Response IR-9:

(a) Confirmed. All Tidal FIT approvals issued by the Nova Scotia Department of Energy (NSDOE) are for FORCE berth holders. NS Power has no further detail as the Tidal FIT program is administered by NSDOE.

(b) Please refer to Appendix A OE-01A Confidential Attachments 1-3 (tab 10) for the projected costs for Tidal FIT.

(c) Please refer to Appendix A OE-01A Confidential Attachments 1-3 (tab 9) for the projected generation for Tidal FIT. 22 MW of tidal capacity is approved by NSDOE under the Tidal FIT program. NS Power received notification from NSDOE that, to date, four projects (6.5 MW total) have progressed to the Power Purchase Agreement phase of

the program. Please refer to IG IR-16. Due to the early stage of this program and the highly developmental nature of these projects, a total installed capacity of 10 MW was forecast for 2017 and 16 MW for 2018 and 2019. A capacity factor of 26% was assumed based on industry knowledge to forecast generation volumes.

(d) Confirmed.

Request IR-10:

NSPI and its consultant Mr. Moreno refer to the operational flexibility embedded within NSPI's generation portfolio. Please explain:

(a) How much flexibility is (or was) available, by unit, in each year 2015 through 2019?

(b) Is NSPI relying on the excess generation capacity as a hedging product?

(c) If so, is NSPI seeking the Board's approval to do so?

(d) What cost has NSPI assigned to units' excess capacity to quantify the hedge?

(e) Please outline the annual cost per unit of using such operational flexibility as a hedge.

(f) Please provide the annual cost of each alternative financial, physical or other hedge.

(g) How did NSPI compare the alternative fuel options?

Response IR-10:

(a-g) In the context of the proposed Fuel Hedging Plan, the "operational flexibility embedded within NS Power's generation portfolio" refers to the following:

- The capability to switch between natural gas and HFO at Tufts Cove as the relative cost of these fuel types vary;

- The capability to optimize dispatch on a daily and hourly basis to meet and reliably serve load at the lowest cost for customers;

- Solid fuel and HFO storage capacity which gives NS Power the ability to optimize the timing of the consumption of these fuels.

The use of this operational flexibility is part of NS Power's existing optimization activities to maximize the value of its assets for the benefit of customers. The Company does not believe that this flexibility is a hedging product.

Request IR-11:

To understand the hedging requirements that NSPI has assumed:

(a) By year and fuel type, provide a table that shows how much fuel is required at the proposed load.

(b) Provide detail of what percent, by year and fuel type, is being hedged.

(c) Break out detail of what form of hedges NSPI expects to have in place.

(d) Identify, regardless of how the hedge (or derivative) was categorized for financial statement purposes, the total additional cost resulting from hedges.

(e) The Board understands NSPI has already committed to a portion of the hedging tools. Is NSPI requesting the Board provide approval of any of these decisions?

(f) Please provide all analysis NSPI has prepared over the past 2 years that compared the benefit of increased stability and predictability achieved to the hedging costs.

(g) Do any of NSPI's hedging strategies involve an affiliated counterparty?

Response IR-11:

(a) Please refer to Fuel Stability Plan Appendix A OE-01A Confidential Attachment 1.

(b) In order to provide greater fuel cost stability for customers, NS Power will target hedging levels between 75% and 100% of forecast fuel and purchased power portfolio consumption during the Rate Stability Period.

(c) Please refer to Appendix C (Hedging Products) the Appendix D (Hedging Plan) for a list of hedging products NS Power may use in the execution its Fuel Hedging Plan. The actual timing and composition of hedges is not finalized at this point in time.

(d) One cost of hedging is represented by the amount of money or credit/collateral needed to execute or maintain the hedge. NS Power's Fuel Hedge Plan (p. 9-10) defines four distinct products and trade types: Futures, Forwards, Swaps and Options. For the purpose of the cost of a particular hedge, Futures, Forwards and Swaps can be grouped as Fixed Price Instruments, and Options can be left as its own distinct group.

The cost of a Fixed Price Instrument depends on how it is executed. If the hedge is executed through the Chicago Mercantile Exchange/New York Mercantile Exchange ("CME/NYMEX"), the cost of the collateral required at the time the hedge is placed ("Margin Account") and adjustments to this collateral are made ("Maintenance Margin") as the value of the hedge changes. This Margin Account ensures that the counterpart will have the money to pay for the settlement of the hedge at the time of expiration. The money in the Margin Account will either be returned at the expiration of the contract or used to offset the settlement of the hedge. In either instance there is a cost to tying-up that money. For more details see the Performance Bonds/Margin documentation by CME/NYMEX.[1]

The cost of Options is higher and it is directly tied to the option premium. The option contract awards the buyer the Option or right to buy (a call Option) or to sell (a put Option) at a pre-determined price during a certain period of time. To acquire such a right the buyer of the Option needs to pay a premium up-front. This premium represents the cost of the hedge. The availability of Options tends to be limited to the more liquid commodities, and therefore may not be available on the specific contracts that would provide effective hedges for NS Power.

[1] http://www.cmegroup.com/clearing/cme-clearing-overview/performance-bonds.html

Additional direct costs of hedging are exchange and clearing fees charged by exchanges and the hedger's Clearing Member. In addition, both cleared and bilateral OTC hedges may require the use of a broker who charges a fee for arranging the transaction.

(e) NS Power is not currently requesting the Board provide approval of any existing hedges. The Company is requesting approval of the proposed Fuel Hedging Plan which provides for the approach, framework, strategies, and mechanisms to be used, but is not requesting approval of specific transactions.

(f) NS Power received, through the EPIA, a clear mandate to provide stable and predictable and affordable fuel costs and electricity rates to customers. Customers have made a significant investment in renewable energy to meet renewable targets and emissions caps. The recent decrease in global commodity prices and the current flatness of the forward price curves (particularly for coal) provides an opportunity for the Company to hedge its fuel prices at a level that results in rate increases below the rate of inflation. The proposed Fuel Hedging Plan has been designed to increase hedging targets to capitalize on this opportunity and provide fuel cost stability and predictability, while ensuring that hedging costs borne by customers are reasonable. Hedging does not guarantee that the lowest possible fuel costs will be achieved, but NS Power believes that the costs of hedging are justified by the increased stability customers will experience during the Rate Stability Period.

(g) NS Power has not identified specific hedges that would involve affiliated counterparties. However should any hedging activity involve an affiliated counterparty, the Company will abide by the terms of the Affiliate Code of Conduct.

Request IR-12:

NSPI has requested Board approval of its Fuel Hedging Plan. Please provide:

(a) With respect to the approval being requested, please identify what exactly NSPI is requesting approval of?

(b) If NSPI's response to part (a) is anything beyond the theory and risk assessment approach outlined in Section 9 and Appendix D, please provide a list and supporting detail for all management decisions NSPI is requesting approval of.

Response IR-12:

(a-b) NS Power has requested UARB approval of the theory and risk assessment approach set out in its proposed Fuel Hedging Plan as described in Section 9 of the Application, including the ability to hedge between 75% to 100% of its commodity costs to achieve the fuel cost stability goal described in Section 6(b) of *the Electricity Implementation Plan (2015) Act*. Although not requesting UARB pre-approval of any specific hedging transactions, the Company anticipates the requested approval will include a determination that the decision to implement this theory and risk assessment approach is prudent at the time of approval.

Request IR-13:

Exhibit N-1, p. 16

Section 6(4) of the *Electricity Plan Implementation (2015) Act* indicates that NSPI shall apply to the Board for "…approval of revised hedging strategies or mechanisms in the event that a change in circumstances relating to fuel costs makes it no longer reasonable to adhere to the approved hedging strategy or mechanism." What types of circumstances or potential impact on fuel costs does NSPI contemplate would require such an application under s. 6(4)?

Response IR-13:

NS Power has interpreted Section 6(4) of the EPIA as a means to provide flexibility in the event unforeseen circumstances arise during the Rate Stability Period. The Company has not compiled an exhaustive list of potential circumstances that would require it to make an application to the Board under Section 6(4) of the EPIA. This would be a management decision made contemporaneously with the decision to revise the hedging strategies or mechanisms and would be dependent on the circumstances at the time the decision is made. For example, material changes to commodity costs or significant over/under collection of fuel costs may require the Company to revise its hedging mechanisms or strategies. The Company has not quantified the cost magnitude that would require a change to be made. NS Power will monitor and evaluate the effectiveness of its hedging strategies and mechanisms during the Rate Stability Period and make changes accordingly.

Request IR-14:

Exhibit N-1, p. 16, line 38

How does the lack of an incentive in the FAM impact NSPI's management of fuel costs under the proposed hedging program?

Response IR-14:

The removal of the FAM incentive for the Rate Stability Period pursuant to section 8(2) of the *Electricity Plan Implementation (2015) Act* does not impact the Company's management of fuel costs. NS Power strives to deliver stable, low cost fuel for customers and its fuel procurement will continue to be reviewed for prudency through the FAM Audit process despite the absence of the FAM incentive.

Request IR-15:

Exhibit N-1, p. 25, line 14

It is indicated that for price stability, NSPI has begun entering into financial hedges in advance of physical purchases. Are these financial hedges based on a current hedging policy? If so, please indicate the source. If not, also indicate the authority for such hedges.

Response IR-15:

NS Power is compliant with current policies in the execution of current financial hedges. The Fuel Strategy Table (FST) approved the financial hedges that have been entered into in advance of physical purchases. The FST based its decision on rate stability benefit to customers, the Fuel Manual, and other key information such as [redacted]. Upcoming revisions to the Fuel Manual include clarifying the guidelines for filling of required positions. Please refer to IG IR-4 and NSUARB IR-16. The plan to obtain fuel cost stability through financial hedging at favourable market pricing [redacted].

Request IR-16:

Exhibit N-1, p. 26, line 1

Please explain why the existing hedging plan is no longer applicable to solid fuel purchases.

Response IR-16:

The proposed revisions to the Fuel Manual will replace the existing guidelines in the Fuel Manual which specify [redacted] The revisions will be found in upcoming Revision 10 of the Fuel Manual. Note that the Fuel Hedging Plan supports the revised guidelines and if the Fuel Hedging Plan is approved, it will supersede these guidelines during the Rate Stability Period. The revisions will otherwise be implemented irrespective of the Rate Stability application and the Fuel Hedging Plan. [redacted] Please refer to NSUARB IR-15.

REDACTED

Request IR-17:

With respect to the projections provided, specifically related to the Maritime Link, NSPI explains the information provided in Figure 28 on page 73 of the application "compares to the estimated Revenue Requirement included in NSPML's original application for approval of the Maritime Link…":

(a) The Board did not approve NSPML's original application. Please provide the cost buildup of the information included to support this Fuel Stability Plan application.

(b) Please provide the formula and referenced inputs of how each of the following cost elements have been determined annually:

- **Debt financing costs (provide detail of annual debt repayment to identify remaining loan balances and interest cost and explain which costs are being recovered as part of the assessment)**
- **Equity financing costs (provide rate base and regulated capitalization, identifying any variances between the balances)**
- **Depreciation (provide the total capital cost and amortization period, as well as any reconciling items)**
- **Other operating costs**

(c) Please provide a breakdown of the costs proposed between the 20 for 20 Energy, Supplemental and Surplus as well as energy assumptions.

(d) Please tie the cost projections back to the NSPML application. Explain any variance in proposed amount to be included and why.

Response IR-17:

(a) The reference to the original Maritime Link (ML) Application contained in page 73 of the Fuel Stability Plan Application should be considered to refer to the original ML Application and subsequent approval of the condition set out in the original ML application as determined by the Board in the Supplemental Decision it issued on November 29, 2013. The costs of the Project did not change by the approval of the condition.

The NSPML projected balance sheet information summarized below, as at December 31, 2017 represents the cost buildup included in this application. Projected balance sheets for 2018 – 2020 are also provided to support the costs estimated in those years. These costs represent total rate base and capitalization of debt and equity.

Assets ($ Millions)	**2017**	**2018**	**2019**	**2020**
Cash (Including Debt Service Reserve Account) (Note 1)	$23	$75	$128	$152
Property Plant & Equipment: Capital costs, net of 20-for-20 true-up (Note2) AFUDC Total	 $1,555 $230 $1,785	 $1,734	 $1,683	 $1,632
Deferred Finance Charges	$52	$51	$49	$48
Total Assets	**$1,860**	**$1,860**	**$1,860**	**$1,832**

Liabilities and Equity				
Long Term Debt (Note 3)	$1,300	$1,300	$1,300	$1,280
Common Stock	$465	$465	$465	$458
Retained Earnings	$95	$95	$95	$94
Total Liabilities and Equity	**$1,860**	**$1,860**	**$1,860**	**$1,832**

Note 1: Debt Service Reserve Account is a requirement of the Federal Loan Guarantee.
Note 2: The breakdown of these capital costs is as outlined in NSPML's quarterly reports filed with the UARB. Figure 27 of the Application provides a breakdown of these costs prior to the 20-for-20 true up of $22 million.
Note 3: Long term debt principal repayment begins on December 1, 2020.

(b) Projected Debt Financing Costs comprise the following:

	2018	**2019**	**2020**
Bond coupon interest cost (Note 1)	$45.5m	$45.5m	$45.5m
Interest revenue on cash balances	($1.2m)	($3.1m)	($3.6m)
Deferred Financing Cost Amortization (Note 2)	$1.5m	$1.5m	$1.5m
Total	$45.8m	$43.9m	$43.4m

(1) 3.5% Interest expense on $1.3b bond issuance (3.5% x $1.3b = $45.5m per year)
(2) Amortization of Deferred Finance Charges during operating period: $52m ÷ 35 years = $1.5m per year.

Equity Financing Costs comprise:

- 9% ROE on total shareholder equity (combination of Common Stock and Retained Earnings) balance as noted in (a).

Depreciation charges comprise:

- $1,785M amortized straight-line over approximately 35 years ($51m per year).

Operating & Maintenance costs projection comprise:

Operating & Maintenance Cost Projection (Amounts in $M's)	**2018**	**2019**	**2020**
Labour and administration	[redacted]		
Converters and substations operations			
Marine surveillance			
Vegetation management			
Insurance			
Independent Engineer			
Environmental Assessment			
Contingency and escalation			
Total	**14.3**	**18.4**	**19.5**

(c) Please refer to Attachment 1. Please note that the 2018 NS Block volume of 715 GWh is overstated in error. Actual volumes will be ~673 GWh. This will be reflected in the refresh.

(d) The variance of cost projections between the Application as compared to the original ML Application is as follows:

Cost Projections per Application (including 2020):

Amounts in $M's	**2018**	**2019**	**2020**
Depreciation	51	51	51
Operating & Maintenance	14	18	20
Debt Financing Costs	46	44	43
Equity Financing Costs	51	51	50
Total Anticipated Assessment	162	164	164

Cost Projections per Appendix 4.01 of the original ML Application:

Amounts in $M's	2018	2019	2020
Depreciation	50	50	50
Operating & Maintenance	11	18	11
Debt Financing Costs	46	45	44
Equity Financing Costs	53	52	50
Total Anticipated Assessment	160	165	155

The reasons for the primary variances are as follows:

- Depreciation varies due to the change in capital cost of $41m.

- Revised estimates for Operating & Maintenance are described in (b) representing increases in 2018 and 2020. These remain projections and as construction proceeds these costs will become better known.

- Debt financing in Appendix 4.01 assumes all costs of debt financing are included in projected interest rate cost of 4.0% whereas current forecast represents actual cost of debt financing including the funding of a Debt Service Reserve Account and Deferred Finance Charges.

- Cost of equity financing in the NSPI BCF Application is lower due to an escalating rate of return modeled in Appendix 4.01 of the NSPML Application in 2013 whereas the NSPI BCF Application models the approved 9.0%.

- Maritime Link in-service date represented in Appendix 4.01 is October 1, 2017 and under the current forecast it is estimated to be in-service by December 31, 2017.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

GWh	**2017**	**2018**	**2019**	**2020**
Maritime Link NS Block		715.0	894.0	894.0
Maritime Link Supplemental Block		114.5	275.8	277.3
Maritime Link (NS & Supplemental)	-	829.5	1,169.8	1,171.3
Maritime Link Surplus	-	386.1	591.3	962.4
	-	**1,215.6**	**1,761.1**	**2,133.7**

Costs ($M)	**2017**	**2018**	**2019**	**2020**
Maritime Link (NS & Supplemental)	$ -	$ 162.0	$ 164.0	$ 164.0
Maritime Link Surplus	$ -	$ 11.7	$ 21.6	$ 45.0
	$ -	**$ 173.7**	**$ 185.6**	**$ 209.0**

REDACTED

Request IR-18:

Exhibit N-1, p. 34, line 8

It is indicated that Surplus Energy under the Maritime Link is included in Imports. Please provide the projected estimates in costs and GWh of Surplus Energy for 2018 and 2019.

Response IR-18:

Please refer to Figure 23 on page 56 of the Application for the projected estimates in costs and volume (GWh) of Surplus Energy for 2018 and 2019. The forecasted volume of Surplus Energy in 2018 and 2019 is [redacted] GWh and [redacted] GWh respectively. The estimated total cost of the Surplus Energy is [redacted] in 2018 and [redacted] in 2019.

Request IR-19:

Exhibit N-1, p. 44, line 7

Does the 49,500 MT of SO2 emissions for 2019 reflect increased Surplus Energy from the Maritime Link? If not, what further impact from the Surplus Energy may result in 2019?

Response IR-19:

Yes, the 49,500 MT of SO_2 emissions for 2019 reflect increased Surplus Energy from the Maritime Link.

Request IR-20:

Exhibit N-1, p. 63, line 20

It is indicated that the Anticipated Assessment for the Maritime Link is $162 million for 2018 and $164 million for 2019, assuming the Nova Scotia Block and Supplemental Energy commence in April 2018.

(a) How would the amount of fuel costs for 2018 be impacted if the Nova Scotia Block and Supplemental Energy were to be delayed

(i) 3 months;
(ii) 6 months; and
(iii) 9 months

(for this purpose assume that AFUDC is capitalized to December 31, 2017 and the Maritime Link goes in service on January 1, 2018)?

(b) Under each of the above (i) to (iii) scenarios, please provide the replacement fuel costs.

Response IR-20:

(a) Please refer to the table below for the estimated increase in fuel and purchased power costs if NS Block and Surplus energy delivery were to be delayed by 3, 6 and 9 months from April 1, 2018

REDACTED

	Costs ($000)
Incremental F&PP Costs 3 Months (April - June)	[redacted]
Incremental F&PP Costs 6 Months (April - September)	
Incremental F&PP Costs 9 Months (April - December)	

(b) Please refer to the tables below for the replacement fuel costs if the Nova Scotia, Supplemental and Surplus Energy Blocks were delayed by 3 months, 6 months and 9 months.

2018 Incremental F&PP Costs 3 Months (April - June)	Costs ($000)
Coal Incremental F&PP Costs	[redacted]
NG/HFO (Tuffs Cove) Incremental F&PP Costs	
Purchased Power Incremental F&PP Costs	
NSPI Wind, Hydro, PHBM and CT's Incremental F&PP Costs	
Generator Start & Shutdown Incremental F&PP Costs	
Abatement Incremental F&PP Costs	
Total Incremental F&PP Costs	

NOTE: NS Block Start date of April 1, 2018 in the Base case

2018 Incremental F&PP Costs 6 Months (April - September)	Costs ($000)
Coal Incremental F&PP Costs	[redacted]
NG/HFO (Tuffs Cove) Incremental F&PP Costs	
Purchased Power Incremental F&PP Costs	
NSPI Wind, Hydro, PHBM and CT's Incremental F&PP Costs	
Generator Start & Shutdown Incremental F&PP Costs	
Abatement Incremental F&PP Costs	
Total Incremental F&PP Costs	

NOTE: NS Block Start date of April 1, 2018 in the Base case

REDACTED

2018 Incremental F&PP Costs 9 Months (April - December)	Costs ($000)
Coal Incremental F&PP Costs	[redacted]
NG/HFO (Tuffs Cove) Incremental F&PP Costs	
Purchased Power Incremental F&PP Costs	
NSPI Wind, Hydro, PHBM and CT's Incremental F&PP Costs	
Generator Start & Shutdown Incremental F&PP Costs	
Abatement Incremental F&PP Costs	
Total Incremental F&PP Costs	

NOTE: NS Block Start date of April 1, 2018 in the Base case

Request IR-21:

NSPI has summarized its anticipated annual combined fuel and non-fuel costs, resulting in the Rate Stability Balance by year, in Appendix H. Please provide the impact of the potential adjustments below:

(a) NSPI has assumed load will increase by 0.4% annually from the 2015 load. Assuming instead, the load follows the load sensitivity analysis (requested in IR-6) annually, what are the resulting balances in Appendix H.

(b) NSPI has used the WACC, as currently directed by the Board, of 7.78%. If this is adjusted to the 7.23% that NSPI has requested approval of, what is the impact on the Interest by year and accumulated balance by the end of the Rate Stability Period?

Response IR-21:

(a) NS Power is unable to determine the fuel expense for the Rate Stability Period under the revised load expectations without completing a full forecast update, including a PLEXOS run. This process is approximately two to three weeks' duration and cannot be completed by the deadline for submission of these information requests. NS Power approximated the decrease in fuel and purchased power expense based upon the revised load forecast in NSUARB IR-6. In order to approximate the decrease in revenue related to this load decrease, NS Power took the average $/MWh that is forecast to be recovered from FAM customers for each year in the rate stability period and multiplied that by the change in load. The revenue reduction calculated in each year is:

Year	Decreased Load (GWh)	Revenue Change ($ millions)
2017	(112)	($5.8)
2018	(156)	($8.4)
2019	(211)	($11.7)

Updating the Base Cost of Fuel amounts based upon the revised load forecast in NSUARB IR-6 would result in the following end of year FAM balances:

Year	FAM Balance ($ millions)
2017	($128.5)
2018	($61.2)
2019	$1.8

The negative balances represent the FAM balance in an over-recovery position. Please refer to Attachment 1.

(b) The forecast interest on the FAM balance by year calculated at both 7.78% and 7.23% is shown in the table below. The negative values represent interest paid by NS Power to customers related to an over recovery balance on the FAM.

	Interest at 7.78%	Interest at 7.23%
2016	(3,720,337)	(3,457,332)
2017	(6,990,818)	(6,477,593)
2018	(7,194,234)	(6,629,523)
2019	(2,351,937)	(2,088,719)

The FAM balance at the end of the Rate Stability Period is forecast to be nil as filed. Updating the NS Power's approved WACC to 7.23% would result in a forecast FAM under-recovery balance of $1,604,160.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Rate Plan	2016										
	Sales (GWh)	BCF		Rate Stability Fund							
		Requirement	Recovery at 2016 Rates	Year-beginning	Contribution from BCF Recovery	Deferred FAM	DSM RSA Adjustment	Additional Cash Taxes	Year-end bfr Interest	Interest
Total FAM Classes	**9,352.4**	**$490,811,695**	**$490,811,695**	**-$41,978,422**	**$0**	**$3,511,348**	**$0**	**-$15,193,000**	**-$53,660,074**	**-$3,720,337**

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Rate Plan	2017										
	Sales (GWh)	BCF		Rate Stability Fund							
		Requirement	Recovery at 2017 Rates	Year-beginning	Contribution from BCF Recovery	Deferred FAM	DSM RSA Adjustment	Additional Cash Taxes	Year-end bfr Interest	Interest
Total FAM Classes	**9,405.9**	**$460,087,666**	**$517,575,567**	**-$57,380,411**	**-$57,487,901**	**$0**	**$0**	**-$6,654,000**	**-$121,522,312**	**-$6,959,316**

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Rate Plan	2018										
	Sales (GWh)	BCF		Rate Stability Fund							
		Requirement	Recovery at 2018 Rates	Year-beginning	Contribution from BCF Recovery	Deferred FAM	DSM RSA Adjustment	Additional Cash Taxes	Year-end bfr Interest	Interest
Total FAM Classes	**9,445.9**	**$611,583,035**	**$534,819,495**	**-$128,481,628**	**$76,763,540**	**$0**	**$0**	**-$2,371,878**	**-$54,089,966**	**-$7,102,035**

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Rate Plan	2019											
	Sales (GWh)	BCF		Rate Stability Fund								
		Requirement	Recovery at 2019 Rates	Year-beginning	Contribution from BCF Recovery	Deferred FAM	DSM RSA Adjustment	Additional Cash Taxes	Year-end bfr Interest	Interest	Rate Stability Fund - Year Beginning 2020
Total FAM Classes	9,462.5	$615,939,092	$550,478,022	-$61,192,001	$65,461,070	$0	$0	-$219,943	$4,049,125	-$2,222,858	$1,826,267

Request IR-22:

NSPI explains in Section 10.1.2, on page 93-94, that non-fuel overearnings and tax benefits totalling $57.2 million for 2015 AND 2016 were applied as a credit against fuel costs in 2017.

(a) Please provide a copy of NSPI's 2015 audited financial statements.

(b) Please provide detail of the cost elements, and support, totalling $57.2 million given as the opening credit.

(c) Please provide detail of how this figure reconciles from the 2015 overearnings as reported in the 2015 financial statements of $44.7 million.

Response IR-22:

(a) Please refer to Attachment 1.

(b) The detail related to the opening credit of $57.2 million to be applied as a credit against fuel costs in the rate stability period is shown in the table below:

Amount	Detail
$21.9M	Excess Non-Fuel Revenues in 2015 kept for Rate Stability Period
$18.3M	2015 Benefit due to Change in Tax Treatment of South Canoe and Sable Wind Farm
$15.2M	2016 Benefit due to Change in Tax Treatment of South Canoe and Sable Wind Farm
$1.8M	Interest on Excess Non-Fuel Revenues and Benefits due to change in tax treatment
$57.2M	**Total**

(c)

Amount	Detail
$57.2M	**Opening Credit to Fuel Expense in Rate Stability Period**
($15.2M)	less: 2016 Benefit due to Change in Tax Treatment of South Canoe and Sable Wind Farm
($1.8M)	less: Interest on Excess Non-Fuel Revenues and Tax Benefits
$4.6M	plus: 2015 excess non-fuel revenues applied to FAM balance in 2015 so no customer class required a rate increase in 2016
($0.1M)	Rounding
$44.7M	**2015 Excess non-fuel revenues and 2015 benefit related to change in tax treatment of South Canoe and Sable**

NOVA SCOTIA POWER INC.

Financial Statements

December 31, 2015 and 2014

MANAGEMENT REPORT

Management's Responsibility for Financial Reporting

The accompanying financial statements of Nova Scotia Power Inc. ("NSPI" or "the Company") and the information in this annual report are the responsibility of management and have been approved by the Board of Directors ("Board").

The financial statements have been prepared by management in accordance with United States Generally Accepted Accounting Principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. In preparation of these financial statements, estimates are sometimes necessary when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Management represents that such estimates, which have been properly reflected in the accompanying financial statements, are based on careful judgements and are within reasonable limits of materiality. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly in all material respects. Management has prepared the financial information presented elsewhere in the annual report and has ensured that it is consistent with that in the financial statements.

NSPI maintains effective systems of internal accounting and administrative controls, consistent with reasonable cost. Such systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate, and that NSPI's assets are appropriately accounted for and adequately safeguarded.

The Board is responsible for ensuring that management fulfils its responsibilities for financial reporting and is ultimately responsible for reviewing and approving the financial statements. The Board carries out this responsibility principally through its Audit and Corporate Responsibility Committee ("the Committee").

The Committee is appointed by the Board, and its members are directors who are not officers or employees of NSPI. The Committee meets periodically with management, as well as with the internal auditors and with the external auditors, to discuss internal controls over the financial reporting process, auditing matters and financial reporting issues, to satisfy itself that each party is properly discharging its responsibilities, and to review the annual report, the financial statements and the external auditors' report. The Committee reports its findings to the Board for consideration when approving the financial statements for issuance to the shareholders. The Committee also considers, for review by the Board and approval by the shareholders, the appointment of the external auditors.

The financial statements have been audited by Ernst & Young LLP, the external auditors, in accordance with Canadian Generally Accepted Auditing Standards. Ernst & Young LLP has full and free access to the Committee.

February 12, 2016

"Robert Hanf"
President and Chief Executive Officer

"Scott Balfour"
Chief Financial Officer

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Nova Scotia Power Inc.

We have audited the accompanying financial statements of Nova Scotia Power Inc., which comprise the balance sheets as at December 31, 2015 and 2014, and the statements of income, comprehensive income, cash flows and changes in shareholder's equity for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with United States generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Nova Scotia Power Inc. as at December 31, 2015 and 2014, and the results of its operations and its cash flows for the years then ended in accordance with United States generally accepted accounting principles.

Halifax, Canada
February 12, 2016

"Ernst & Young LLP"
Chartered accountants

Nova Scotia Power Inc.
Statements of Income

For the millions of Canadian dollars		Year ended December 31 **2015**		 2014
Operating revenues	**$**	**1,417.3**	$	1,348.2
Operating expenses				
Fuel for generation and purchased power		**542.8**		511.7
Fuel adjustment mechanism and fixed cost deferrals (note 4)		**41.6**		46.6
Operating, maintenance and general		**263.1**		273.6
Demand side management		**35.0**		-
Provincial grants and taxes		**38.5**		38.3
Depreciation and amortization		**206.5**		204.0
Total operating expenses		**1,127.5**		1,074.2
Income from operations		**289.8**		274.0
Other expenses, net (note 5)		**5.7**		5.0
Interest expense, net (note 6)		**122.1**		116.5
Income before provision for income taxes		**162.0**		152.5
Income tax expense (recovery) (note 7)		**23.4**		19.7
Net income of Nova Scotia Power Inc.		**138.6**		132.8
Preferred stock dividends		**8.7**		7.9
Net income attributable to common shareholders	**$**	**129.9**	$	124.9

The accompanying notes are an integral part of these financial statements.

Nova Scotia Power Inc.
Statements of Comprehensive Income

For the millions of Canadian dollars		Year ended December 31 **2015**		 2014
Net income of Nova Scotia Power Inc.	**$**	**138.6**	$	132.8
Other Comprehensive Income (loss)				
Amortization of unrecognized pension and post-retirement benefit costs (note 8)		**91.3**		(49.6)
Comprehensive income	**$**	**229.9**	$	83.2

The accompanying notes are an integral part of these financial statements.

Nova Scotia Power Inc.
Balance Sheets

As at millions of Canadian dollars	**December 31 2015**	December 31 2014
Assets		
Current assets		
Receivables, net (note 9)	**$ 251.5**	$ 237.8
Inventory (note 10)	**200.0**	198.9
Derivative instruments (notes 11 and 12)	**88.5**	36.2
Regulatory assets (note 13)	**52.8**	83.5
Prepaid expenses	**8.5**	8.5
Total current assets	**601.3**	564.9
Property, plant and equipment, net of accumulated depreciation of $2,555.6 and $2,454.2, respectively (note 14)	**3,366.3**	3,276.4
Other assets		
Income taxes receivable	**48.7**	28.9
Derivative instruments (notes 11 and 12)	**121.4**	61.5
Pension and post-retirement asset (note 15)	**7.9**	5.3
Regulatory assets (note 13)	**368.5**	268.9
Intangibles, net of accumulated amortization of $51.1 and $51.7, respectively	**84.7**	78.6
Other long-term assets	**42.8**	33.6
Total other assets	**674.0**	476.8
Total assets	**$ 4,641.6**	$ 4,318.1

The accompanying notes are an integral part of these financial statements.

Nova Scotia Power Inc.
Balance Sheets – Continued

As at millions of Canadian dollars	**December 31 2015**	December 31 2014
Liabilities and Equity		
Current liabilities		
Short-term debt (note 16)	$ **15.9**	$ 2.3
Current portion of long-term debt (note 17)	**0.3**	70.5
Accounts payable	**114.3**	124.6
Due to related parties (note 18)	**4.6**	5.7
Income taxes payable	**4.1**	10.0
Derivative instruments (notes 11 and 12)	**22.8**	6.1
Regulatory liabilities (note 13)	**88.5**	36.2
Pension and post-retirement liabilities (note 15)	**7.0**	7.0
Other current liabilities (note 19)	**79.2**	84.5
Total current liabilities	**336.7**	346.9
Long-term liabilities		
Long-term debt (note 17)	**2,429.6**	2,235.0
Deferred income taxes (note 7)	**294.5**	234.0
Derivative instruments (notes 11 and 12)	**4.4**	8.7
Regulatory liabilities (note 13)	**165.3**	61.5
Asset retirement obligations (note 20)	**101.6**	94.1
Pension and post-retirement liabilities (note 15)	**191.7**	247.3
Other long-term liabilities	**4.7**	5.6
Total long-term liabilities	**3,191.8**	2,886.2
Commitments and contingencies (note 21)		
Redeemable preferred stock, $25 par value; unlimited First Preferred Series D shares authorized; nil and 5.4 million shares issued and outstanding, respectively (note 22)	**-**	132.2
Equity		
Common stock, no par value, unlimited shares authorized, 121.1 million and 117.2 million shares issued and outstanding, respectively	**1,074.5**	1,035.4
Accumulated other comprehensive loss (note 8)	**(291.5)**	(382.8)
Retained earnings	**330.1**	300.2
Total equity	**1,113.1**	952.8
Total liabilities and equity	**$ 4,641.6**	$ 4,318.1

The accompanying notes are an integral part of these financial statements.

Approved on behalf of the Board of Directors

"James D. Eisenhauer" ***"Robert Hanf"***

Chair of the Board **President and Chief Executive Officer**

Nova Scotia Power Inc.
Statements of Cash Flows

For the millions of Canadian dollars	Year ended December 31 **2015**	 2014
Operating activities		
Net income of Nova Scotia Power Inc.	**$ 138.6**	$ 132.8
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**213.8**	212.4
Allowance for equity funds used during construction	**(2.2)**	(2.7)
Deferred income taxes, net	**(19.9)**	(16.5)
Net change in pension and post-retirement obligations	**33.1**	0.8
Fuel adjustment mechanism	**76.1**	42.2
Fixed cost deferrals	**(37.0)**	(1.9)
Other operating activities, net	**(7.5)**	(13.3)
Changes in non-cash working capital:		
Receivables, net	**(13.7)**	8.0
Income taxes receivable	**(19.8)**	(1.1)
Inventory	**(1.1)**	(34.8)
Prepaid expenses	**-**	(0.1)
Accounts payable	**(10.3)**	15.5
Due to (from) related parties	**(1.1)**	2.7
Income taxes payable	**(5.9)**	(18.6)
Other current liabilities	**(3.4)**	9.9
Net cash provided by operating activities	**339.7**	335.3
Investing activities		
Additions to property, plant and equipment	**(253.0)**	(261.0)
Allowance for borrowed funds used during construction	**(2.3)**	(3.2)
Removal of assets from service, net of salvage	**(7.8)**	(7.2)
Additions to intangible assets	**(11.1)**	(5.5)
Proceeds from sale of assets	**1.3**	8.0
Net cash used in investing activities	**(272.9)**	(268.9)
Financing activities		
Change in short-term debt, net	**13.6**	(4.5)
Retirement of long-term debt	**(70.0)**	-
Proceeds from long-term debt	**175.0**	-
Net borrowings (repayments) under committed credit facility	**20.2**	66.2
Issuance of common stock	**39.1**	0.7
Dividends on common stock	**(100.0)**	(120.0)
Dividends on preferred stock	**(7.9)**	(7.9)
Preferred stock redemption	**(135.0)**	-
Other financing activities	**(1.8)**	(0.9)
Net cash used in financing activities	**$ (66.8)**	$ (66.4)
Net change in cash	**-**	-
Cash, beginning of year	**-**	-
Cash, end of year	**-**	-
Supplemental disclosure of cash paid (received):		
Interest	**$ 129.0**	$ 126.9
Income taxes	**$ 64.1**	$ 53.2

The accompanying notes are an integral part of these financial statements.

Nova Scotia Power Inc.
Statements of Changes in Equity

millions of Canadian dollars		Common Stock		Accumulated Other Comprehensive Loss ("AOCL")		Retained Earnings		Total Equity
2015								
Balance, December 31, 2014	$	1,035.4	$	(382.8)	$	300.2	$	952.8
Net income of Nova Scotia Power Inc.		-		-		138.6		138.6
Other comprehensive income		-		91.3		-		91.3
Issuance of common stock		39.1		-		-		39.1
Dividends declared on common stock		-		-		(100.0)		(100.0)
Dividends declared on preferred stock ($1.1063 per share)		-		-		(8.7)		(8.7)
Balance, December 31, 2015	$	1,074.5	$	(291.5)	$	330.1	$	1,113.1

millions of Canadian dollars		Common Stock		AOCL		Retained Earnings		Total Equity
2014								
Balance, December 31, 2013	$	1,034.7	$	(333.2)	$	295.3	$	996.8
Net income of Nova Scotia Power Inc.		-		-		132.8		132.8
Other comprehensive income		-		(49.6)		-		(49.6)
Issuance of common stock		0.7		-		-		0.7
Dividends declared on common stock		-		-		(120.0)		(120.0)
Dividends declared on preferred stock ($1.475 per share)		-		-		(7.9)		(7.9)
Balance, December 31, 2014	$	1,035.4	$	(382.8)	$	300.2	$	952.8

The accompanying notes are an integral part of these financial statements.

Nova Scotia Power Inc.
Notes to the Financial Statements

As at December 31, 2015 and 2014

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The significant accounting policies of Nova Scotia Power Inc. are as follows:

A. Nature of Operations

Nova Scotia Power Inc. ("NSPI" or the "Company") is a fully-integrated regulated electric utility and the primary electricity supplier in Nova Scotia, Canada, providing electricity generation, transmission and distribution services to approximately 506,000 customers. NSPI is a public utility as defined under the Public Utilities Act of Nova Scotia (the "Act") and is subject to regulation by the Nova Scotia Utility and Review Board ("UARB"). The Company's accounting policies are subject to examination and approval by the UARB.

B. Basis of Presentation

These financial statements are prepared and presented in accordance with United States Generally Accepted Accounting Principles ("USGAAP").

In the opinion of management, these financial statements include all adjustments that are of a recurring nature and necessary to fairly state the financial position of NSPI.

All dollar amounts are presented in Canadian dollars, unless otherwise indicated.

C. Use of Management Estimates

The preparation of financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Management evaluates the Company's estimates on an ongoing basis based upon historical experience, current conditions and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in income in the year they arise. Significant estimates are included in unbilled revenues, allowance for doubtful accounts, inventory, valuation of derivative instruments, capitalized overhead, depreciation, amortization, regulatory assets and regulatory liabilities (including the determination of the current portion), income taxes (including deferred income taxes), pension and post-retirement benefits, asset retirement obligations ("AROs") and contingencies. Actual results may differ significantly from these estimates.

D. Regulatory Matters

Regulatory accounting applies where rates are established by, or subject to approval by, an independent third party regulator; are designed to recover the costs of providing the regulated products or services; and it is reasonable to assume rates are set at levels such that the costs can be charged to and collected from customers.

Regulatory assets represent incurred costs that have been deferred because it is probable that they will be recovered through future rates collected from customers. Management believes that existing regulatory assets are probable for recovery either because the Company received specific approval from the UARB, or due to regulatory precedent established for similar circumstances. If management no longer considers it probable that an asset will be recovered, the deferred costs are charged to income.

Regulatory liabilities represent obligations to make refunds to customers or to reduce future revenues for previous collections. If management no longer considers it probable that a liability will be settled, the related amount is recognized in income.

For regulatory assets and liabilities that are amortized, the amortization is approved by the UARB.

E. Foreign Currency Translation

Monetary assets and liabilities, denominated in foreign currencies, are converted to Canadian dollars at rates of exchange prevailing at the balance sheet date. The resulting differences between the translation at the original transaction date and the balance sheet date are included in “Other expense, net”.

F. Revenue Recognition

Operating revenues are recognized when electricity is delivered to customers or when products are delivered and services are rendered. Revenues are recognized on an accrual basis and include billed and unbilled revenues. Revenues related to the sale of electricity are recognized at rates approved by the UARB and recorded based on meter readings and estimates, which occur on a systematic basis throughout a month. At the end of each month, the electricity delivered to customers, but not billed, is estimated and the corresponding unbilled revenue is recognized. The accuracy of the unbilled revenue estimate is affected by energy demand, weather, line losses and changes in the composition of customer classes.

Other revenues are recognized when services are performed or goods delivered.

G. Employee Benefits

The costs of the Company’s pension and other post-retirement benefit programs for employees are expensed over the periods during which employees render service. The Company recognizes the funded status of its defined-benefit and other post-retirement plans on the balance sheet and recognizes changes in funded status in the year the change occurs. The Company recognizes the unamortized gains and losses and past service costs in AOCL.

H. Receivables and Allowance for Doubtful Accounts

Customer receivables are recorded at the invoiced amount and do not bear interest. Standard payment terms for electricity sales for bi-monthly customers are 30 days and for monthly customers, payment terms are 20 days. A late payment fee of 1.5 percent may be assessed on account balances after the due date.

The Company is exposed to credit risk with respect to amounts receivable from customers. Credit risk assessments are conducted on all new customers and deposits are requested on any high risk accounts. The Company also maintains provisions for potential credit losses, which are assessed on a regular basis.

Management estimates uncollectible accounts receivable after considering historical loss experience, current events and the characteristics of existing accounts. Provisions for losses on receivables are expensed to maintain the allowance at a level considered adequate to cover expected losses. Receivables are written off against the allowance when they are deemed uncollectible.

I. Inventory

Fuel and materials inventory are measured at the lower of cost or market. Fuel costs are determined using the weighted average method and material costs are determined using the average costing method. Fuel and materials are recorded as inventory when purchased and then expensed or capitalized,

as appropriate, using the weighted average cost method for fuel and average costing method for materials.

J. Property, Plant and Equipment

Property, plant and equipment are recorded at original cost, including allowance for funds used during construction ("AFUDC"), net of contributions received in aid of construction.

The cost of additions, including betterments and replacements of units of property, plant and equipment are included in "Property, plant and equipment". When units of regulated property, plant and equipment are replaced, renewed or retired, their cost plus removal or disposal costs, less salvage proceeds, is charged to accumulated depreciation, with no gain or loss reflected in income.

Normal maintenance projects are expensed as incurred. Planned major maintenance projects that do not increase the overall life of the related assets are expensed. When a cost increases the life of the underlying asset, the cost is capitalized.

K. Capitalization Policy

The cost of property, plant and equipment represents the original cost of materials, contracted services, direct labour, AFUDC for regulated property, AROs and overhead attributable to the capital project. Overhead includes costs related to support functions, employee benefits, insurance, procurement, and fleet operating and maintenance.

L. Allowance for Funds Used During Construction

AFUDC represents the cost of financing regulated construction projects and is capitalized to the cost of property, plant and equipment until the asset is operational. The Company includes an equity cost component in AFUDC, in addition to a charge for borrowed funds. AFUDC is a non-cash item; cash is realized under the rate-making process over the service life of the related property, plant and equipment through future revenues resulting from a higher rate base and recovery of higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to "Interest expense, net", while the equity component is included as a reduction to "Other expenses, net". AFUDC is calculated using a weighted average cost of capital, as per the method of calculation approved by the UARB, and is compounded semi-annually.

M. Intangible Assets

Intangible assets consist primarily of land rights and computer software with definite lives. Amortization is determined by the straight-line method, based on the estimated remaining service lives of the depreciable asset in each category. The service lives of assets are determined based on formal depreciation studies and are approved by the UARB. The last depreciation study was completed in 2010.

The estimated useful lives, in years, for each major category of intangibles with definite lives consist of the following:

Land rights	50 to 80
Computer software	10

The estimated average amortization expense for each of the five succeeding fiscal years is $1.3 million for land rights and $4.1 million for computer software.

N. Asset Impairment

Long-lived assets and intangibles are periodically reviewed for impairment when events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. NSPI bases its evaluation on long-lived assets and intangibles on the presence of impairment indicators such as the future economic benefit of the assets, any historical or future profitability measurements and other external market conditions or factors. If the sum of the undiscounted cash flows expected from an asset is less than the carrying value of the asset, the asset is written down to fair value.

There were no material asset impairments of these assets for the years ended December 31, 2015 and 2014.

O. Debt Financing Costs

The Company capitalizes the external costs of obtaining debt financing and includes them in “Other” as part of “Other assets” on the Balance Sheets; premiums and discounts are netted against “Long-term debt” on the Balance Sheet. The deferred charges are amortized over the life of the related debt on an effective interest basis and included in “Interest expense, net” on the Statements of Income**.**

P. Income Taxes and Investment Tax Credits

NSPI recognizes deferred income tax assets and liabilities for the future tax consequences of events that have been included in the financial statements or income tax returns. Deferred income tax assets and liabilities are determined based on the difference between the carrying value of assets and liabilities on the balance sheet and their respective tax bases using enacted tax rates in effect for the year in which the differences are expected to reverse. NSPI recognizes the effect of income tax positions only when it is more likely than not that they will be realized. If management subsequently determines that it is likely that some or all of a deferred income tax asset will not be realized, then a valuation allowance is recorded to report the balance at the amount expected to be realized.

NSPI recognizes regulatory assets or liabilities where the deferred income taxes are expected to be recovered from or returned to customers in future years, unless specifically directed otherwise by the UARB.

Investment tax credits arise as a result of incurring qualifying scientific research and development expenditures and are recorded as a reduction to income tax expense in the current or future periods to the extent that realization of such benefit is more likely than not.

NSPI classifies interest and penalties associated with unrecognized tax benefits in the statement of income as interest expense, net and operating maintenance and general expense, respectively.

Q. Asset Retirement Obligations

An ARO is recognized if a legal obligation exists in connection with the future disposal or removal costs resulting from the permanent retirement, abandonment or sale of a long-lived asset. A legal obligation may exist under an existing or enacted law or statute, written or oral contract, or by legal construction under the doctrine of promissory estoppel.

An ARO represents the fair value of the estimated cash flows necessary to discharge the future obligation using the Company’s credit adjusted risk-free rate. The amounts are reduced by actual expenditures incurred. Estimated future cash flows are based on completed depreciation studies, remediation reports, prior experience, estimated useful lives and governmental regulatory requirements. The present value of the liability is recorded and the carrying amount of the related long-lived asset is correspondingly increased. The amount capitalized at inception is depreciated in the same manner as the related long-lived asset. Over time, the liability is accreted to its estimated future value. Accretion expense is included as part of “Depreciation and amortization”. Differences between accretion expense recognized for rate

regulatory purposes and USGAAP, and accretion expense not yet approved by the UARB, are deferred to "Property, plant and equipment" and included in the next depreciation study.

Some transmission and distribution assets may have conditional AROs, which are required to be estimated and recorded as a liability. A conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Management monitors these obligations and a liability is recognized at fair value when an amount can be determined.

R. Derivatives and Hedging Activities

NSPI's risk management policies and procedures provide a framework through which management monitors various risk exposures. The risk management policies and practices are overseen by the Board of Directors. Daily and periodic reporting of positions and other relevant metrics are performed by a centralized risk management group which is independent of all operations.

The Company manages its exposure to normal operating and market risks relating to commodity prices and foreign exchange through contractual protections with counterparties where practicable, as well as by using financial instruments consisting mainly of foreign exchange forwards and swaps, and coal, oil and gas, options, forwards and swaps. In addition, the Company has contracts for the physical purchase and sale of natural gas. Collectively, these contracts are considered "derivatives".

The Company recognizes the fair value of all its derivatives on its balance sheet, except for non-financial derivatives that meet the normal purchases and normal sales ("NPNS") exception. Non-financial derivatives that meet the NPNS exception are contracts for the physical purchase of coal. A physical contract generally qualifies for the NPNS exception if the transaction is reasonable in relation to the Company's business needs, the counterparty owns or controls resources within the proximity to allow for physical delivery, the Company intends to receive physical delivery of the commodity, and the Company deems the counterparty creditworthy. The Company continually assesses contracts designated under the NPNS exception and will discontinue the treatment of these contracts under this exception where the criteria are no longer met.

Derivatives entered into by NSPI, that are documented as economic hedges or that do not qualify for NPNS exception, are subject to regulatory accounting treatment, as approved by the UARB. These derivatives are recorded at fair value on the balance sheet as derivative assets or liabilities. Any change in fair value of the derivatives at period end is deferred to a regulatory asset or liability. The gain or loss is recognized in fuel for generation and purchased power, inventory or property, plant and equipment, depending on the nature of the item being economically hedged. The UARB has approved that any gains or losses resulting from settlement of these derivatives related to fuel for generation and purchased power will be refunded to or collected from customers in future rates through the FAM.

Derivatives that do not meet any of the above criteria are designated as held-for-trading ("HFT") derivatives and are recorded on the balance sheet at fair value, with changes recorded in net income of the period. The Company has not elected to designate any derivatives to be included in the HFT category where another accounting treatment would apply.

NSPI classifies gains and losses on derivatives as a component of fuel for generation and purchased power, inventory and property, plant and equipment, depending on the nature of the item being economically hedged. Cash flows from derivative activities are presented in the same category as the item being hedged within operating or investing activities on the Statements of Cash Flows.

S. Fair Value Measurement

The Company is required to determine the fair value of all derivatives except those which qualify for the NPNS exception (refer to notes 11 and 12), and uses a market approach to do so. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly arms-length transaction

between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information, including the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. The Company uses a fair value hierarchy, based on the relative objectivity of the inputs used to measure fair value, with Level 1 representing the highest. These classifications are further discussed in Note 12.

Derivative assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

T. Variable Interest Entities

The Company performs ongoing analysis to assess whether it holds any variable interest entities ("VIEs"). To identify potential VIEs, management reviews contracts under leases, long-term purchase power agreements and jointly owned facilities.

VIEs of which the Company is deemed the primary beneficiary must be consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses or the right to receive benefits of the entity that could potentially be significant to the entity. In circumstances where NSPI is not deemed the primary beneficiary, the VIE is not consolidated in the Company's financial statements.

2. CHANGES IN ACCOUNTING POLICIES AND PRACTICES

Income Taxes – Balance Sheet Classification of Deferred Taxes, Accounting Standards Update ("ASU") 2015-17

In November 2015, the Financial Accounting Standards Board ("FASB") issued ASU 2015-17, *Income Taxes – Balance Sheet Classification of Deferred Taxes*, which simplifies the presentation of deferred income taxes. The amendment requires that deferred tax assets and liabilities be classified as noncurrent on the Balance Sheet, regardless of whether the deferred income taxes are expected to be recovered or settled within the next twelve months. ASU 2015-17 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2016. Early adoption is permitted for any interim or annual financial statements that have not yet been issued.

The Company has early adopted ASU 2015-17 effective October 1, 2015. Prior periods have been retrospectively restated. This change reclassified a $2.8 million current deferred income tax asset (2014 – $11.5 million current deferred income tax liability) to the long-term deferred income tax liability on the Balance Sheets as at December 31, 2015 and 2014.

This change also reclassified a $6.4 million current deferred income tax regulatory liability (2014 - $6.2 million) to the long-term deferred income tax regulatory asset on the Balance Sheets as at December 31, 2015 and 2014.

3. FUTURE ACCOUNTING PRONOUNCEMENTS

Revenue from Contracts with Customers, ASU No. 2014-09

In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers,* which creates a new, principle-based revenue recognition framework and a new topic in the Accounting Standards Codification ("ASC"), Topic 606. ASC 606 also changes the basis for determining when revenue is recognized over time or at a point in time, provides new and more detailed guidance on specific aspects of revenue recognition and expands revenue disclosures. On July 9, 2015, the FASB deferred the effective date by one year. This standard will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017.

The Company is currently in the process of evaluating the impact of adoption of this standard on its financial statements.

Income Statement – Extraordinary and Unusual Items, ASU No. 2015-01
In January 2015, the FASB issued ASU No. 2015-01, *Income Statement – Extraordinary and Unusual Items,* which simplifies the income statement presentation requirements by eliminating the concept of extraordinary items. ASU No. 2015-01 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. The adoption of this standard will not have an impact on its financial statements.

Interest – Imputation of Interest, ASU No. 2015-03
In April 2015, the FASB issued ASU No. 2015-03, Interest – *Imputation of Interest*, which simplifies the presentation of debt issuance costs. The amendments require debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of debt liability, consistent with debt discounts or premiums. The recognition and measurement guidance for debt issuance costs is not affected by the amendments in the update. ASU No. 2015-03 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2015. The adoption of this update will result in the reclassification of debt issuance costs from “Other long-term assets” to “Long-term debt” on the Company’s balance sheets. As at December 31, 2015, debt issuance costs included in long-term other assets were $12.4 million (2014 - $12.0 million).

In August 2015, the FASB issued ASU No. 2015-15, *Interest – Imputation of Interest – Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements*, which clarifies that the guidance in ASU No. 2015-03 does not apply to line-of-credit arrangements. ASU No. 2015-15 permits an entity to defer and present debt issuance costs as an asset and subsequently amortize these costs ratably over the time of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. ASU No. 2015-15 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2015. As at December 31, 2015, debt issuance costs associated with line-of-credit arrangements included in “Other long-term other assets” were $1.4 million (2014 - $1.5 million).

Compensation – Retirement Benefits, ASU No. 2015-04
In April 2015, the FASB issued ASU No. 2015-04, *Compensation – Retirement Benefits,* which is part of FASB’s initiative to reduce complexity in accounting standards. This standard provides certain practical expedients for defined benefit pension or other post-retirement benefit plan measurement dates. ASU No. 2015-04 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. The adoption of this standard will not have an impact on the Company’s financial statements.

Intangibles – Goodwill and Other – Internal-Use Software, ASU No. 2015-05
In April 2015, the FASB issued ASU No. 2015-05, *Intangibles – Goodwill and Other – Internal-Use Software,* which provides guidance to customers about whether a cloud computing arrangement includes a software license. If a cloud computing arrangement includes a software license, then the customer should account for the software license element of the arrangement consistent with the acquisition of other software licenses. If a cloud computing arrangement does not include a software license, the customer should account for the arrangement as a service contract. The guidance will not change GAAP for a customers’ accounting for service contracts. ASU No. 2015-05 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. The adoption of this standard will not have an impact on the Company’s financial statements.

Technical Corrections and Improvements - ASU No. 2015-10
In June 2015, the FASB issued ASU No. 2015-10, *Technical Corrections and Improvements,* covering a wide range of topics in the codification to correct unintended application of guidance, or make minor improvements to the Codification that are not expected to have a significant effect on current accounting practice or create a significant administrative cost. ASU No. 2015-10 is effective for fiscal years, and

interim periods within those fiscal years, beginning after December 15, 2015. The adoption of this standard will not have an impact on the Company's financial statements.

Inventory – Simplifying the Measurement of Inventory – ASU No. 2015-11
In July 2015, the FASB issued ASU No. 2015-11, *Inventory – Simplifying the Measurement of Inventory*. The amendments require an entity to measure inventory at the lower of cost or net realizable value, whereas previously, inventory was measured at the lower of cost or market. ASU No. 2015-11 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2016. The Company is currently in the process of evaluating the impact of adoption of this standard on its financial statements.

Financial Instruments – Recognition and Measurement of Financial Assets and Financial Liabilities, ASU No. 2016-01
In January 2016, the FASB issued ASU No. 2016-01, Financial Instruments – Recognition and Measurement of Financial Assets and Financial Liabilities. The standard provides guidance for the recognition, measurement, presentation and disclosure of financial assets and liabilities. ASU No. 2016-01 is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017. The Company is currently in the process of evaluating the impact of adoption of this standard on its financial statements.

4. FUEL ADJUSTMENT MECHANISM AND FIXED COST DEFERRALS

Fuel adjustment mechanism and fixed cost deferrals recognized in the Statements of Income consisted of the following:

For the		Year ended December 31		
millions of Canadian dollars		**2015**		2014
Fuel adjustment mechanism (see chart below)	**$**	**31.9**	$	6.4
Application of non-fuel revenues		**44.7**		40.2
Fixed cost deferral related to 2015 demand side management ("DSM")		**(35.0)**		-
	$	**41.6**	$	46.6

Fuel Adjustment Mechanism

The Fuel Adjustment Mechanism ("FAM") included in the Statements of Income includes the effect of prudently incurred fuel for generation and purchased power and certain fuel related costs ("Fuel Costs") in both the current and preceding years, specifically, and as detailed in the table below:

- The difference between actual Fuel Costs and amounts recovered from customers in the current year. This amount is deferred to a FAM regulatory asset in "Regulatory assets" or a FAM regulatory liability in "Regulatory liabilities" on the Balance Sheets; and
- The recovery from (rebate to) customers of under (over) recovered Fuel Costs from prior years.

The fuel adjustment mechanism on the Income Statement consisted of the following:

For the		Year ended December 31		
millions of Canadian dollars		**2015**		2014
Over (Under) recovery of current year Fuel costs	**$**	**(24.1)**	$	1.3
Recovery from customers of prior years' Fuel costs		**56.0**		-
FAM audit disallowance		**-**		5.1
Fuel adjustment mechanism	**$**	**31.9**	$	6.4

The Company has recognized a deferred income tax recovery related to the fuel adjustment mechanism based on NSPI's enacted statutory tax rate.

Pursuant to the FAM Plan of Administration, NSPI's Fuel Costs are subject to independent audit. On January 20, 2015, the UARB disallowed $6.0 million of 2012 and 2013 fuel-related costs, which includes interest of $0.9 million. The disallowances resulted in a reduction in the amount of the FAM deferral as at December 31, 2014 and resulted in an after-tax impact to 2014 net income of $3.3 million.

On December 21, 2015, the UARB approved NSPI's setting of the 2016 base cost of fuel and its recovery of prior period unrecovered fuel related costs as submitted in the Company's August and November 2015 filings. The recovery of these costs will begin January 1, 2016. The approved customer rates resets the base cost of fuel rate for 2016 and seeks to recover $13.7 million of prior years' unrecovered Fuel Costs in 2016. This results in a combined average rate decrease for customers of approximately 1 per cent.

On December 18, 2015, the Electricity Plan Implementation (2015) Act (the "Electricity Plan Act") was enacted by the Province of Nova Scotia. The Electricity Plan Act requires NSPI to file a three-year rate plan for Fuel Costs in Q1 2016 and to file a three-year general rate application to change non-fuel rates by April 30, 2016, if required by NSPI. A primary goal of the Electricity Plan Act is to provide rate stability over those years. Differences between actual Fuel Costs and amounts recovered from customers through electricity rates during this period will be deferred to a FAM regulatory asset or liability and recovered from or returned to customers subsequent to 2019.

The Electricity Plan Act directs NSPI to apply non-fuel revenues in excess of NSPI's approved range of return in 2015 and 2016 to the FAM, which will be reserved to be applied in the 2017 to 2019 period. In addition the financial benefit resulting from a change in the recognition of tax benefits for the South Canoe and Sable wind projects is to be reserved to be applied to the FAM in the 2017 to 2019 period. The exception to this direction is to apply a sufficient amount of non-fuel revenues to offset potential fuel related rate increases for certain customer classes in 2016 that would have been otherwise required. This amount totals $4.6 million. As a result, as at December 31, 2015, NSPI has deferred $4.6 million of excess non-fuel revenues to 2016 and $40.1 million of excess non-fuel revenues for the periods 2017 to 2019.

A settlement agreement approved by the UARB in November 2014, resulted in $56.0 million of the outstanding FAM balance at December 31, 2014, being collected in 2015. The settlement agreement also reduced the FAM regulatory asset at the end of 2014 of $86.1 million by $38.2 million via an offset from the liability balance in the Rate Stabilization deferral account, such that at December 31, 2014 the FAM regulatory asset was $47.9 million.

Through a related settlement agreement with stakeholders approved in December 2014, NSPI agreed to apply any non-fuel revenues above that required to achieve its approved range of return to reduce the FAM deferral account. This was effective as of January 1, 2015, and last until the next General Rate Application ("GRA") approval or similar process where non-fuel rates are adjusted. This settlement agreement required NSPI to contribute a minimum of $41.3 million to the FAM deferral account by the end of 2015. As at December 31, 2015, NSPI had exceeded the minimum required contribution through the $38.2 million in 2014 referred to above and an additional $26.4 million in 2015. In 2015, NSPI applied $44.7 million in excess non-fuel revenues against the FAM, $18.3 million was the result of the change to South Canoe and Sable Wind Projects tax treatment.

Fixed Cost Adjustments

NSPI has the following Regulatory Assets arising from UARB approved fixed cost deferral mechanisms.

<u>2015 DSM Deferral</u>

In April 2014, the Government of Nova Scotia announced new energy efficiency legislation to remove a previous charge for conservation and efficiency programs from power bills of Nova Scotia customers effective January 1, 2015. In addition, the legislation requires NSPI to purchase electricity efficiency and conservation activities ("Program Costs") from EfficiencyOne, the provincially appointed franchisee to deliver energy efficiency programs to Nova Scotians. The Program Costs are set for 2015 at $35 million

and are being deferred as a regulatory asset and recoverable from customers over an eight-year period beginning in 2016. In August 2015 the UARB approved a budget of $102.0 million for the three year period of 2016 through 2018. The Electricity Plan Act has placed a cap of $34.0 million on the 2019 DSM spending. The 2016 DSM cost of $24.7 million will not be deferred. A decision on the timing of the cost recovery for 2017 through 2019 will be made at a future date.

The Company has recognized a deferred income tax expense related to the 2015 DSM deferral based on NSPI's enacted statutory tax rate.

The deferred DSM amounts are recognized as a "Regulatory asset" on the Balance Sheets. The DSM regulatory asset balance of $36.4 million is disclosed in Note 13 and includes associated interest that is recorded as "Interest expense, net" on the Statements of Income.

2013/2014 Rate Stabilization Fixed Cost Recovery Deferral

In December 2012, the UARB approved deferral of recovery of certain fixed costs for fiscal 2013 and 2014 as part of a rate stabilization plan. As previously noted above in the FAM commentary, the resulting regulatory liability at the end of 2014 of $38.2 million was applied against the FAM regulatory asset balance in 2014 and is included in the application of non-fuel revenues line in the table above.

5. OTHER (INCOME) EXPENSES, NET

Other (income) expenses, net consisted of the following:

For the millions of Canadian dollars		Year ended December 31 **2015**		 2014
Allowance for equity funds used during construction	**$**	**(2.2)**	$	(2.7)
Amortization of defeasance costs		**6.7**		7.9
Foreign exchange losses (gains)		**1.4**		0.2
Other		**(0.2)**		(0.4)
	$	**5.7**	$	5.0

6. INTEREST EXPENSE, NET

Interest expense, net consisted of the following:

For the millions of Canadian dollars		Year ended December 31 **2015**		 2014
Interest on debt	**$**	**127.6**	$	125.4
Allowance for borrowed funds used during construction		**(2.3)**		(3.2)
Interest revenue, net		**(4.8)**		(7.6)
Other		**1.6**		1.9
	$	**122.1**	$	116.5

7. INCOME TAXES

The income tax provision differs from that computed using the statutory income tax rate for the following reasons:

For the millions of Canadian dollars	Year ended December 31 **2015**	2014
Income before provision for income taxes	$ **162.0**	$ 152.5
Statutory income tax rate	**31.0%**	31.0%
Income taxes, at statutory income tax rate	**50.2**	47.3
Deferred income taxes on regulated income recorded as regulatory assets and regulatory liabilities	**(24.7)**	(24.8)
Other	**(2.1)**	(2.8)
Income tax expense (recovery)	$ **23.4**	**$** 19.7
Effective income tax rate	**14.4%**	12.9%

The 2015 and 2014 statutory income tax rate of 31.0 per cent represents the combined Canadian federal and Nova Scotia provincial income tax rates, which are the relevant tax jurisdictions for NSPI.

The following reflects the composition of taxes on income from continuing operations presented in the Statements of Income:

For the millions of Canadian dollars	Year ended December 31 **2015**	2014
Income tax expense (recovery) – current	**$ 43.3**	$ 36.2
Income tax expense (recovery) – deferred	**(19.9)**	(16.5)
Income tax expense (recovery)	**$ 23.4**	$ 19.7

The deferred income tax assets and liabilities consisted of the following:

As at millions of Canadian dollars	**December 31** **2015**	December 31 2014
Deferred income tax assets:		
Regulatory liabilities (deferrals related to derivative instruments)	**$ 94.3**	$ 43.8
Pension and other post-retirement liabilities	**89.3**	114.2
Asset retirement obligations	**45.6**	42.3
Intangibles	**27.4**	25.3
Tax loss carry forwards	**12.9**	13.1
Other	**37.7**	17.2
Total deferred income tax assets before valuation allowance	**307.2**	255.9
Valuation allowance	**(12.9)**	(13.1)
Total deferred income tax assets after valuation allowance	**$ 294.3**	$ 242.8
Deferred income tax liabilities:		
Property, plant and equipment	**$ 445.2**	$ 385.1
Derivative instruments	**94.3**	43.8
Other	**49.3**	47.9
Total deferred income tax liabilities	**$ 588.8**	$ 476.8
Balance Sheets presentation:		
Long-term deferred income tax liabilities	**$ (294.5)**	$ (234.0)

The offset to substantially all of the net deferred income tax assets and liabilities has been recorded as a deferred income tax regulatory asset. These amounts include a gross up to reflect the income tax associated with future revenues required to fund these deferred income tax liabilities and the income tax benefits associated with reduced revenues resulting from the realization of deferred income tax assets.

As at December 31, 2015, NSPI had a gross capital loss carryover of $57.2 million (2014 - $58.2 million). NSPI had a deferred tax asset of $12.9 million (2014 - $13.1 million) relating to the capital loss carryover.

The capital loss carryover has an indefinite carryover period and a valuation allowance of $12.9 million (2014 - $13.1 million) has been recognized as realization is uncertain.

Considering all evidence regarding the utilization of the Company's deferred income tax assets, it has been determined that NSPI is more-likely-than-not to realize all recorded deferred income tax assets, except for the capital loss noted above. The only valuation allowance recorded as at December 31, 2015 is related to the capital loss carryover.

The following table provides details of the change in unrecognized tax benefits for the years ended December 31 as follows:

millions of Canadian dollars		**2015**		2014
Balance, January 1	**$**	**4.8**	$	5.2
Increases due to tax positions related to current year		**0.5**		0.1
Increases due to tax positions related to a prior year		**0.8**		1.7
Decreases due to tax positions related to a prior year		**-**		(1.2)
Decreases due to expiration of statute of limitations		**-**		(1.0)
Balance, December 31	**$**	**6.1**	$	4.8

The total amount of unrecognized tax benefits as at December 31, 2015 was $6.1 million (2014 - $4.8 million), which would affect the effective tax rate if recognized. The total amount of accrued interest with respect to unrecognized tax benefits was $0.6 million (2014 - $0.8 million). No penalties have been accrued. The balance of unrecognized tax benefits could change up to $4.9 million in the next twelve months as a result of settlements of Canada Revenue Agency ("CRA") audits.

NSPI files a Canadian federal income tax return, which includes its Nova Scotia provincial income tax. As at December 31, 2015, NSPI's tax years still open to examination by taxing authorities include 2006 and subsequent years.

NSPI and the CRA are currently in a dispute with respect to the timing of certain tax deductions for its 2006 through 2010 taxation years. The ultimate permissibility of the tax deductions is not in dispute; rather, it is the timing of those deductions. The cumulative net amount in dispute to date is $62.3 million, including taxes and interest. NSPI has prepaid $22.7 million of the amount in dispute, as required by CRA.

Should NSPI be successful in defending its position, all payments including applicable interest will be refunded with respect to NSPI's deductions. If NSPI is unsuccessful in defending any portion of its position, the resulting taxes and applicable interest will be deducted from amounts previously paid, with the excess, if any, owing to CRA. The related tax deductions will be available in subsequent years.

In Q2 2015, CRA commenced audit of NSPI's 2011 through 2013 taxation years. Should NSPI receive notices of reassessment for those years, and should the 2014 and 2015 taxation year be similarly reassessed, further payments will be required, however, the ultimate permissibility of the deductions is similarly not in dispute.

NSPI and its advisors believe that NSPI has reported its tax position appropriately and NSPI is disputing the reassessments through the CRA Appeal process. The outcome of this process is not determinable at this time.

8. ACCUMULATED OTHER COMPREHENSIVE LOSS

The changes in AOCL by component are as follows:

millions of Canadian dollars		**Defined benefit pension and non-pension benefits**
Balance, January 1, 2015	$	**(382.8)**
Amounts reclassified from AOCL		**91.3**
Balance, December 31, 2015	$	**(291.5)**

millions of Canadian dollars		**Defined benefit pension and non-pension benefits**
Balance, January 1, 2014	$	(333.2)
Amounts reclassified from AOCL		(49.6)
Balance, December 31, 2014	$	(382.8)

The reclassifications out of AOCL are as follows:

For the millions of Canadian dollars			**2015**		2014
	Affected line item in the Statements of Income (1)		Amounts reclassified from AOCL		
Amortization of defined pension and non-pension benefit costs					
Actuarial losses	Operating, maintenance and general ("OM&G")	**$**	**41.1**	$	33.0
Past service gains	OM&G		**(0.5)**		(0.6)
Amounts reclassified to obligations	Pension and post retirement obligations		**50.7**		(82.0)
Total reclassifications out of AOCL for the period		**$**	**91.3**	$	(49.6)

(1) These AOCL components are included in the computation of net periodic pension cost (see Employee Benefit Plan note 15 for additional details).

9. RECEIVABLES, NET

Receivables, net consisted of the following:

As at millions of Canadian dollars		**December 31 2015**		December 31 2014
Customer accounts receivable – billed	**$**	**108.0**	$	105.2
Customer accounts receivable – unbilled		**119.8**		119.4
Total customer accounts receivable		**227.8**		224.6
Allowance for doubtful accounts		**(2.8)**		(2.3)
Customer accounts receivable, net		**225.0**		222.3
Other		**26.5**		15.5
	$	**251.5**	$	237.8

10. INVENTORY

Inventory consisted of the following:

As at millions of Canadian dollars		**December 31 2015**		December 31 2014
Fuel	**$**	**156.4**	$	159.7
Materials		**43.6**		39.2
	$	**200.0**	$	198.9

11. DERIVATIVE INSTRUMENTS

The Company enters into forwards, swaps and option contracts as part of its risk management strategy to limit exposure to:

- commodity price fluctuations related to the purchase and sale of commodities in the course of normal operations; and
- foreign exchange fluctuations on foreign currency denominated purchases

The Company also enters into physical contracts for energy commodities. Collectively, these contracts are considered "derivatives". The Company accounts for derivatives under one of the following two approaches:

1. Physical contracts that meet the normal purchases normal sales ("NPNS") exception are not recognized on the balance sheet; they are recognized in income when they settle. A physical contract generally qualifies for the NPNS exception if the transaction is reasonable in relation to the Company's business needs, the counterparty owns or controls resources within the proximity to allow for physical delivery, the Company intends to receive physical delivery of the commodity, and the Company deems the counterparty credit worthy. The Company continually assesses contracts designated under the NPNS exception and will discontinue the treatment of these contracts under this exception if the criteria are no longer met.

2. Derivatives entered into by NSPI that are documented as economic hedges or that do not qualify for NPNS exception are subject to regulatory accounting treatment, as approved by the UARB. These derivatives are recorded at fair value on the balance sheet as derivative assets or liabilities. The change in fair value of the derivatives is deferred to a regulatory asset or liability. The realized gain or loss is recognized when the hedged item settles in fuel for generation and purchased power, inventory or property, plant and equipment, depending on the nature of the item being economically hedged. The UARB has approved that any gains or losses resulting from settlement of fuel related derivatives will be refunded to or collected from customers in future rates through the FAM.

Derivative assets and liabilities receiving regulatory deferral consisted of the following:

	Derivative Assets		Derivative Liabilities	
As at millions of Canadian dollars	**December 31 2015**	December 31 2014	**December 31 2015**	December 31 2014
Current				
Commodity swaps and forwards				
Coal purchases	**-**	-	**$ 11.7**	$ 5.4
Natural gas purchases and sales	**$ 1.5**	$ 0.8	**0.7**	1.4
Foreign exchange forwards	**85.3**	36.0	**10.5**	-
Physical natural gas purchases and sales	**1.8**	0.1	**-**	-
Total gross current derivatives	**88.6**	**36.9**	**22.9**	**6.8**
Impact of master netting agreements with intent to settle net or simultaneously	**(0.1)**	(0.7)	**(0.1)**	(0.7)
Total current derivatives	**88.5**	36.2	**22.8**	6.1
Long-term				
Commodity swaps and forwards				
Coal purchases	**-**	-	**4.4**	4.8
Foreign exchange forwards	**121.4**	61.5	**-**	3.9
Total long-term derivatives	**121.4**	61.5	**4.4**	8.7
Total derivatives	**$ 209.9**	$ 97.7	**$ 27.2**	$ 14.8

Derivative assets and liabilities are classified as current or long-term based upon the maturities of the underlying contracts.

Regulatory Deferral

As previously noted, NSPI received approval from the UARB for regulatory deferral of gains and losses on certain derivatives documented as economic hedges, including certain physical contracts that do not qualify for the NPNS exception.

The Company has recorded the following changes in realized and unrealized gains (losses) with respect to derivatives receiving regulatory deferral:

For the millions of Canadian dollars	**2015**			Year ended December 31 2014		
	Commodity swaps and forwards	**Physical natural gas purchases and sales**	**Foreign exchange forwards**	Commodity swaps and forwards	Physical natural gas purchases and sales	Foreign exchange forwards
Unrealized gain (loss) in regulatory assets	**$ (16.7)**	**- $**	**(7.0)**	$ (11.2)	- $	(4.6)
Unrealized gain (loss) in regulatory liabilities	**1.4**	**$ 8.8**	**172.7**	7.8	$ 2.4	75.9
Realized (gain) loss in regulatory assets	**(3.3)**	**-**	**-**	3.3	-	-
Realized (gain) loss in property, plant and equipment	**-**	**-**	**(1.0)**	-	-	(0.1)
Realized (gain) loss in inventory (1)	**11.5**	**-**	**(43.9)**	4.3	-	(16.3)
Realized (gain) loss in fuel for generation and purchased power (2)	**2.6**	**(7.1)**	**(18.2)**	(13.4)	(2.3)	(5.7)
Total change derivative instruments	**$ (4.5)**	**$ 1.7**	**$ 102.6**	$ (9.2)	$ 0.1	$ 49.2

(1) Realized (gains) losses will be recognized in fuel for generation and purchased power when the hedged item is consumed.

(2) Realized (gains) losses on derivative instruments settled and consumed in the period, hedging relationships that have been terminated or the hedged transaction is no longer probable.

Commodity Swaps and Forwards

As at December 31, 2015, the Company had the following notional volumes of commodity swaps and forward contracts designated for regulatory deferral that are expected to settle as outlined below:

	2016	2017	2018
millions	Purchases	Purchases	Purchases
Coal (metric tonnes)	0.3	0.7	0.7
Natural Gas (mmbtu's)	3.2	-	-

Foreign Exchange Forwards

As at December 31, 2015, the Company had the following notional volumes of foreign exchange forward contracts designated as a regulatory deferral that are expected to settle as outlined below:

	2016	2017	2018	2019	2020
Foreign exchange contracts (millions of US dollars)	$ 200.4	$ 222.3	$ 143.0	$ 96.5	$ -
Weighted average rate	1.0257	1.0707	1.1053	1.1265	-
% of USD requirements	79%	93%	68%	46%	0%

Credit Risk

The Company is exposed to credit risk with respect to amounts receivable from customers and derivative assets. Credit risk is the potential loss from a counterparty's non-performance under an agreement. The Company manages credit risk with policies and procedures for counterparty analysis, exposure measurement, and exposure monitoring and mitigation. Credit assessments are conducted on all new customers and counterparties, and deposits or collateral are requested on any high risk accounts.

The Company assesses the potential for credit losses on a regular basis, and where appropriate, recognizes provisions. With respect to counterparties, the Company has implemented procedures to monitor the creditworthiness and credit exposure of counterparties and to consider default probability in valuing the counterparty positions. The Company monitors counterparties' credit standing, including those that are experiencing financial problems, have significant swings in default probability rates, have credit rating changes by external rating agencies, or have changes in ownership. Net liability positions are adjusted based on the Company's current default probability. Net asset positions are adjusted based on the counterparty's current default probability. The Company assesses credit risk internally for counterparties that are not rated.

As at December 31, 2015, the maximum exposure the Company has to credit risk is $446.4 million (2014 – $323.2 million) which includes accounts receivable net of collateral/deposits and assets related to derivatives.

It is possible that volatility in commodity prices could cause the Company to have material credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the Company could suffer a material financial loss. The Company transacts with counterparties as part of its risk management strategy for managing commodity price and foreign exchange. Counterparties that exceed established credit limits can provide a cash deposit or letter of credit to the Company for the value in excess of the credit limit where contractually required. The Company also obtains cash deposits from electric customers. The total cash deposits/collateral and letters of credit on hand as at December 31, 2015 was $15.0 million (December 31, 2014 - $12.3 million). The Company uses the cash as payment for the amount receivable or returns the deposit/collateral to the customer/counterparty where it is no longer required by the Company.

The Company enters into commodity master arrangements with its counterparties to manage certain risks, including credit risk to these counterparties. The Company generally enters into International

Swaps and Derivatives Association agreements ("ISDA"), North American Energy Standards Board agreements ("NAESB") and, or Edison Electric Institute agreements. The Company believes that entering into such agreements offers protection by creating contractual rights relating to creditworthiness, collateral, non-performance and default.

As at December 31, 2015, the Company had $42.3 million (December 31, 2014 - $40.9 million) in financial assets, considered to be past due, which have been outstanding for an average 77 days. The fair value of these financial assets is $39.9 million (December 31, 2014 - $39.0 million), the difference of which is included in the allowance for doubtful accounts. These assets primarily relate to accounts receivable from electric revenue.

Concentration Risk

The Company's concentrations of risk consisted of the following:

As at		**December 31, 2015**			December 31, 2014	
		millions of Canadian dollars	**% of total exposure**		millions of Canadian dollars	% of total exposure
Receivables, net						
Residential	**$**	**135.5**	**30%**	$	136.7	42%
Commercial		**63.2**	**14%**		61.5	17%
Industrial		**25.0**	**5%**		23.1	7%
Other		**27.8**	**6%**		16.5	5%
		251.5	**55%**		237.8	71%
Derivative Instruments (current and long-term)						
Credit rating of A- or above		**208.1**	**45%**		97.6	29%
Credit rating of BBB- to BBB+		**1.8**	**0%**		0.1	0%
		209.9	**45%**		97.7	29%
	$	**461.4**	**100%**	$	**335.5**	**100%**

Cash Collateral

Derivatives, as reflected on the Balance Sheets, are not offset by the fair value amounts of cash collateral with the same counterparty. Rights to reclaim cash collateral are recognized in "Receivables, net" and obligations to return cash collateral are recognized in "Accounts payable". As at December 31, 2015 and December 31, 2014, the Company's cash collateral position was a receivable of $9.5 million (2014 – nil).

Collateral is posted in the normal course of business based on the Company's creditworthiness, including its senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Company's derivatives contain financial assurance provisions that require collateral to be posted if a material adverse credit-related event occurs. If a material adverse event resulted in the senior unsecured debt to fall below investment grade, the counterparties to such derivatives could request ongoing full collateralization.

As at December 31, 2015, the total fair value of these derivatives, in a liability position, was $27.2 million (2014 – $14.8 million). If the credit ratings of the Company were reduced below investment grade the full value of the net liability position could be required to be posted as collateral for these derivatives.

12. FAIR VALUE MEASUREMENTS

The Company is required to determine the fair value of all derivatives except those which qualify for the NPNS exception (see note 11), and uses a market approach to do so. The three levels of the fair value hierarchy are defined as follows:

Level 1 - Where possible, the Company bases the fair valuation of its financial assets and liabilities on quoted prices in active markets ("quoted prices") for identical assets and liabilities.

Level 2 - Where quoted prices for identical assets and liabilities are not available, the valuation of certain contracts must be based on quoted prices for similar assets and liabilities with an adjustment related to location differences. Also, certain derivatives are valued using quotes from over-the-counter clearing houses.

Level 3 - Where the information required for a Level 1 or Level 2 valuation is not available, derivatives must be valued using unobservable or internally-developed inputs. The primary reasons for a Level 3 classification are as follows:

- While valuations were based on quoted prices, significant assumptions were necessary to reflect seasonal or monthly shaping and locational basis differentials.
- The term of certain transactions extends beyond the period when quoted prices are available, and accordingly, assumptions were made to extrapolate prices from the last quoted period through the end of the transaction term.
- The valuations of certain transactions were based on internal models, although quoted prices were utilized in the valuations.

Derivative assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

The following tables set out the classification of the methodology used by the Company to fair value its derivatives:

As at				**December 31, 2015**
millions of Canadian dollars	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Regulatory deferral				
Commodity swaps and forwards				
Natural gas purchases and sales	**-**	**$ 1.4**	**-**	**$ 1.4**
Foreign exchange forwards	**-**	**206.7**	**-**	**206.7**
Physical natural gas purchases and sales	**-**	**-**	**$ 1.8**	**1.8**
Total assets	**-**	**208.1**	**1.8**	**209.9**
Liabilities				
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	**-**	**16.1**	**-**	**16.1**
Natural gas purchases and sales	**$ 0.6**	**-**	**-**	**0.6**
Foreign exchange forwards		**10.5**	**-**	**10.5**
Total liabilities	**0.6**	**26.6**	**-**	**27.2**
Net assets (liabilities)	**$ (0.6)**	**$ 181.5**	**$ 1.8**	**$ 182.7**

As at				December 31, 2014
millions of Canadian dollars	Level 1	Level 2	Level 3	Total
Assets				
Regulatory deferral				
Commodity swaps and forwards				
Natural gas purchases and sales	$ 0.1	-	-	$ 0.1
Foreign exchange forwards	-	$ 97.5	-	97.5
Physical natural gas purchases and sales	-	-	$ 0.1	0.1
Total assets	0.1	97.5	0.1	97.7
Liabilities				
Regulatory deferral				
Commodity swaps and forwards				
Coal purchases	-	10.2	-	10.2
Natural gas purchases and sales	0.7	-	-	0.7
Foreign exchange forwards	-	3.9	-	3.9
Total liabilities	0.7	14.1	-	14.8
Net assets (liabilities)	$ (0.6)	$ 83.4	$ 0.1	$ 82.9

The change in the fair value of the Level 3 financial assets for the year ended December 31, 2015 was as follows:

millions of Canadian dollars	Physical natural gas purchases and sales
Balance, January 1	**$ 0.1**
Reduction of benefit included in fuel for generation and purchased power	**(7.1)**
Unrealized gains included in regulatory assets or liabilities	**8.8**
Balance, December 31, 2015	**$ 1.8**

The change in the fair value of the Level 3 financial assets for the year ended December 31, 2014 was as follows:

millions of Canadian dollars	Physical natural gas purchases and sales
Balance, January 1	$ 0.3
Reduction of benefit included in fuel for generation and purchased power	(2.6)
Unrealized gains included in regulatory assets or liabilities	2.4
Balance, December 31, 2014	$ 0.1

There were no Level 3 financial liabilities for the years ended December 31, 2015 and December 31, 2014.

The Company's Enterprise Risk Management group is responsible for valuation policies, processes and the measurement of fair value. Fair value accounting rules provide a three level hierarchy that prioritizes the inputs used to measure fair value. When possible, determining fair value is based primarily on observable market inputs in active markets.

Contracts with quoted prices available in active markets and exchanges for identical assets or liabilities are classified as level 1 in the hierarchy. For those contracts whereby pricing inputs are either directly or indirectly observable through markets, exchanges or third party sources, but do not qualify as level 1, are classified as level 2 in the hierarchy. For a level 3 classification, the processes and methods of measurement for third-party pricing information and illiquid markets are developed with input and using the market knowledge of marketing operations within the Company.

Significant unobservable inputs used in the fair value measurement of the Company's commodity derivatives includes third-party-sourced pricing for instruments based on illiquid markets; internally developed correlation factors and basis differentials; own credit risk; and discount rates. Internally developed correlations and basis differentials are reviewed on a quarterly basis based on statistical analysis of the spot markets in the various illiquid term markets. Where possible, the Company also

sources multiple broker prices in an effort to evaluate and substantiate these unobservable inputs. Discount rates may include a risk premium for those long-term forward contracts with illiquid future price points to incorporate the inherent uncertainty of these points. Any risk premiums for long-term contracts are evaluated by observing similar industry practices and in discussion with industry peers. Significant increases (decreases) in any of these inputs in isolation would result in a significantly lower (higher) fair value measurement.

The following table outlines quantitative information about the significant unobservable inputs used in the fair value measurements categorized within Level 3 of the fair value hierarchy:

As at				**December 31, 2015**
millions of Canadian dollars	**Fair Value**	**Valuation Technique**	**Unobservable Input**	**Range**	**Weighted average**
Assets					
Regulatory deferral – Physical natural gas purchases and sales	**$ 1.8**	Modelled pricing	Third-party pricing	$5.15 - $6.21	$5.72
			Probability of default	0.01%	0.01%

As at				**December 31, 2014**
millions of Canadian dollars	**Fair Value**	**Valuation Technique**	**Unobservable Input**	**Range**	**Weighted average**
Assets					
Regulatory deferral – Physical natural gas purchases and sales	**$** 0.1	Modelled pricing	Third-party pricing	$9.52 - $12.94	$9.52
			Probability of default	0.05%	0.05%

The financial assets and liabilities included on the Balance Sheets that are not measured at fair value consisted of the following:

As at	**December 31, 2015**		December 31, 2014	
millions of Canadian dollars	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Long-term debt (including current portion)	**$ 2,429.9**	**$ 2,854.1**	$ 2,305.5	$ 2,865.3

The fair values of long-term debt instruments, classified as level 3 in the fair value hierarchy, are estimated based on the quoted market price for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturity, without considering the effect of third party credit enhancements.

All other financial assets and liabilities, such as cash, receivables, short-term debt and accounts payable, are carried at cost. The carrying value approximates fair value due to the short-term nature of these financial instruments.

13. REGULATORY MATTERS

The Company is a public utility as defined in the Act and is subject to regulation under the Act by the UARB. The Act gives the UARB supervisory powers over NSPI's operations and expenditures. Electricity rates for NSPI's customers are also subject to UARB approval. The Company is not subject to a general annual rate review process, but rather participates in hearings held from time to time at the Company's or the UARB's request.

NSPI is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers, and provide an appropriate return to investors. NSPI's target regulated return on equity ("ROE") range for 2015 and 2014 was 8.75 per cent to 9.25 per cent based on an actual average regulated common equity component of up to 40 per cent. NSPI has a FAM, which enables NSPI to seek recovery of Fuel Costs through regularly scheduled rate adjustments. Differences between actual Fuel Costs and amounts recovered from customers through electricity rates in a year, are

deferred to a FAM regulatory asset or liability and recovered from or returned to customers in a subsequent year.

On December 21, 2012, the UARB approved a General Rate Application ("GRA") settlement agreement between NSPI and customer representatives which resulted in an average net rate increase of 3 per cent by customer class effective January 1, 2013 and January 1, 2014. To achieve the net 3 per cent increase in rates, the UARB approved a rate stabilization plan under which a portion of non-fuel costs from 2013 and 2014 could be deferred for future recovery. NSPI committed to $27.5 million in non-fuel cost savings over a two-year period beginning in fiscal 2013.

As at December 2014, NSPI had under recovered approximately $86.1 million in Fuel Costs. Pursuant to NSPI's FAM Plan of Administration, this amount would be recovered commencing in 2015. On November 25, 2014, the UARB approved a settlement agreement that resulted in approximately $56.0 million of the 2014 outstanding FAM balance being collected in 2015. In addition, the UARB directed NSPI to transfer $38.2 million of the payable balance of the rate stabilization deferral account to reduce the FAM balance of $86.1 million, resulting in a revised balance of $47.9 million at December 31, 2014.

Through a related settlement agreement with stakeholders approved in December 2014, NSPI agreed to apply any non-fuel revenues above that required to achieve its approved range of return to reduce the FAM deferral account. This was effective as of January 1, 2015, until the next GRA approval or similar process where non-fuel rates are adjusted. This settlement agreement required NSPI to contribute a minimum of $41.3 million to the FAM deferral account by the end of 2015.

As at December 31, 2015, NSPI had exceeded the minimum required contribution of $41.3 million through the $38.2 million contributed in 2014 referred to above and an additional $44.7 million applied in 2015. Of the $44.7 million applied in 2015, $18.3 million relates to changes to the South Canoe and Sable Wind Projects tax treatment.

On December 21, 2015, the UARB approved NSPI's setting of the 2016 base cost of fuel and its recovery of prior period unrecovered fuel related costs as submitted in the Company's August and November 2015 filings. The recovery of these costs will begin January 1, 2016. The approved customer rates seek to recover $13.7 million of prior years' unrecovered Fuel Costs in 2016, the current FAM asset on the balance sheet. This results in a combined average rate decrease for customers of approximately 1 per cent.

The excess non-fuel revenues in 2015 include a benefit of $18.3 million which is the result of the changes to South Canoe and Sable Wind Projects tax treatments, as legislated by the Electricity Plan Act. The Electricity Plan Act also directs NSPI to apply sufficient 2015 excess non-fuel revenues so as to offset 2016 fuel rate increases in certain classes. This amount totals $4.6 million and included in the $13.7 million current FAM asset on the balance sheet. The remaining 2015 excess non-fuel revenues of $40.1 million, plus interest, have been deferred for future periods beyond 2016, as further directed by the Electricity Plan Act and are classified as long-term FAM liability on the balance sheet.

Regulatory Assets and Regulatory Liabilities

Regulatory assets represent incurred costs that have been deferred because it is probable that they will be recovered through future rates collected from customers. Management believes that existing regulatory assets are probable of recovery either because the Company received specific approval from the UARB, or due to regulatory precedent set for similar circumstances. If management no longer considers it probable that an asset will be recovered, the deferred costs are charged to income.

Regulatory liabilities represent obligations to make refunds to customers or to reduce future revenues for previous collections. If management no longer considers it probable that a liability will be settled, the related amount is recognized in income.

Regulatory assets and liabilities as at December 31, excluding certain regulatory assets related to property, plant and equipment and ARO's as discussed in notes 14 and 20, consisted of the following:

As at millions of Canadian dollars		**December 31 2015**		December 31 2014
Regulatory assets				
Deferred income tax regulatory asset	**$**	**294.5**	$	214.1
Unamortized defeasance costs		**45.7**		52.5
2015 DSM deferral		**36.4**		-
Deferrals related to derivative instruments		**30.7**		20.1
2012 Large industrial customers fixed cost recovery deferral		**-**		15.8
Other		**0.3**		2.0
Fuel adjustment mechanism		**13.7**		47.9
	$	**421.3**	$	352.4
Current	**$**	**52.8**	$	83.5
Long-term		**368.5**		268.9
Total regulatory assets	**$**	**421.3**	$	352.4
Regulatory liabilities				
Deferrals related to derivative instruments	**$**	**209.9**	$	97.7
Fuel adjustment mechanism		**42.0**		-
Other		**1.9**		-
	$	**253.8**	$	97.7
Current	**$**	**88.5**	$	36.2
Long-term		**165.3**		61.5
Total regulatory liabilities	**$**	**253.8**	$	97.7

Deferred Income Tax Regulatory Asset

NSPI recognizes deferred income tax assets and liabilities for the future tax consequences of events that have been included in the financial statements or income tax returns, in accordance with NSPI's rate-regulated accounting policy as approved by the UARB. To the extent deferred income taxes are expected to be recovered from or returned to customers in future rates, NSPI recognizes a net deferred income tax regulatory asset or liability as appropriate, unless specifically directed otherwise by the UARB.

Unamortized Defeasance Costs

Upon privatization in 1992, NSPI became responsible for managing a portfolio of defeasance securities held in trust that provide the principal and interest streams to match the related defeased debt, which as at December 31, 2015, totaled $0.8 billion (2014 – $0.7) billion). The excess of the cost of defeasance investments over the face value of the related debt is deferred on the balance sheet and amortized over the life of the defeased debt as permitted by the UARB.

2015 DSM Deferral

As discussed in Note 4, following the new energy efficiency legislation, the UARB approved the implementation of the 2015 DSM deferral set at $35 million for 2015 and recoverable from customers over an eight year period beginning in 2016. The change in the 2015 DSM regulatory asset balance for the year ended December 31 consisted of the following:

millions of Canadian dollars		**2015**
DSM regulatory asset – Balance as at January 1		**-**
Current period Program Costs	**$**	**35.0**
Interest on DSM balance		**1.4**
DSM regulatory asset – Balance as at December 31	**$**	**36.4**

Deferrals Related to Derivative Instruments

NSPI defers changes in fair value of derivatives that are documented as economic hedges or that do not qualify for normal purchase normal sale ("NPNS") exception, as a regulatory asset or liability as approved by the UARB. The realized gain or loss is recognized when the hedged item settles in fuel for generation and purchased power, inventory or property, plant and equipment, depending on the nature of the item being economically hedged.

Large Industrial Customers Fixed Cost Deferral

The UARB approved a FCR for 2012 to address uncertainty associated with the operations of two large industrial customers who experienced financial challenges and idled their mills. Where actual sales to these customers in 2012 was less than expected when rates were set, the resultant shortfall in contribution toward non-fuel costs was deferred as a regulatory asset for future recovery. The 2013 GRA settlement agreement, approved on December 21, 2012 by the UARB, allowed recovery of this deferral from customers over a three-year period commencing January 1, 2013.

The change in the large industrial customers regulatory asset balance for the years ended December 31 consisted of the following:

millions of Canadian dollars		**2015**		2014
Large industrial customers regulatory asset – Balance as at January 1	**$**	**15.8**	**$**	**33.0**
Recovery of regulatory asset recorded as regulatory amortization		(16.4)		(19.1)
Interest on large industrial customers FCR balance	**$**	0.6		1.9
Large industrial customers regulatory asset – Balance as at December 31		**-**	**$**	**15.8**

Fuel Adjustment Mechanism

The change in the FAM balance for the years ended December 31 consisted of the following:

millions of Canadian dollars		**2015**		2014
FAM regulatory asset – Balance as at January 1	**$**	**47.9**	**$**	**86.4**
Under (over) recovery of current year Fuel Costs		24.1		(1.3)
Recovery from customers of prior years' Fuel Costs		(56.0)		-
FAM audit disallowance, including interest adjustment		-		(6.0)
Application of non-fuel revenues		(44.7)		(38.2)
Interest on FAM balance		0.4		7.0
FAM regulatory (liability) asset – Balance as at December 31	**$**	**(28.3)**	**$**	**47.9**

Details of the change are discussed further in note 4. The FAM balance is recorded on the balance sheet as a current FAM asset of $13.7 million, to be recovered in 2016 and a long-term FAM liability of $42.0 million to be applied during 2017 through 2019 as legislated,

14. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consisted of the following:

As at millions of Canadian dollars		**December 31 2015**		December 31 2014
Generation	**$**	**3,243.2**	$	3,063.7
Transmission		**773.4**		750.1
Distribution		**1,343.4**		1,309.1
General plant and other		**466.6**		448.1
Total cost		**5,826.6**		5,571.0
Less: Accumulated depreciation		**(2,555.6)**		(2,454.2)
		3,271.0		3,116.8
Construction work in progress		**95.3**		159.6
Net book value	**$**	**3,366.3**	$	3,276.4

For the year ended December 31, 2015, AFUDC of $4.5 million (2014 – $5.9 million) was capitalized to "Property, plant and equipment".

As a result of regulator-approved accounting policies and depreciation rates, NSPI defers certain costs within "Property, plant and equipment" that would not otherwise be deferred in the absence of rate regulation. Cumulative differences between items recognized for rate regulatory purposes and applicable accounting standards including depreciation rates, AFUDC and overhead costs, cannot be separately determined. Cumulative deferred accretion expense related to AROs was $7.9 million as at December 31, 2015 (2014 – $10.3 million).

Depreciation

Depreciation is determined by the straight-line method, based on the estimated remaining service lives of the depreciable assets in each category. The service lives of assets are determined based on formal depreciation studies and are approved by the UARB. The last depreciation study was completed in 2010.

The estimated useful lives, in years, for each major category of property, plant and equipment consist of the following:

Generation	32 to 65
Generation - hydro	63 to 131
Generation - wind	25
Transmission	40 to 65
Distribution	14 to 65
General plant	5 to 40

15. EMPLOYEE BENEFIT PLANS

NSPI maintains contributory defined-benefit and defined-contribution pension plans, which cover substantially all of its employees; and plans providing non-pension benefits for its retirees.

Defined Benefit Plans

The Company maintains contributory defined benefit pension plans which cover the majority of the employees. The pension benefits are determined based on the years of service and average salary at the time the employee terminates employment. The plan provides annual post-retirement indexing equal to the change in the Consumer Price Index up to a maximum increase of 6% per year. The measurement date for the defined benefit pension plan is December 31. Effective November 1, 2014, the defined benefit plan was closed to new entrants.

Other retirement benefit plans ("Non-pension benefit plans") include the unfunded long service award (which is impacted by expected future salary increases) and contributory health care plan. The unfunded long service award was closed to new entrants effective August 1, 2007.

Benefit Obligation and Plan Assets

The changes in benefit obligation and plan assets, and the funded status for all plans were as follows:

For the millions of Canadian dollars	**2015**		Years ended December 31 2014	
Change in Projected Benefit Obligation and Accumulated Post-retirement Benefit Obligation	**Defined benefit pension plans**	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Balance, January 1	**$ 1,257.1**	**$ 38.2**	$ 1,100.8	$ 36.0
Service cost	**15.9**	**1.5**	12.5	1.5
Plan participant contributions	**7.4**	**-**	7.1	-
Interest cost	**49.7**	**1.5**	54.2	1.8
Benefits paid	**(51.8)**	**(3.2)**	(52.6)	(3.2)
Actuarial (gains) losses	**(3.4)**	**(2.7)**	135.2	2.1
Special termination	**-**	**-**	(0.1)	-
Balance, December 31	**1,274.9**	**35.3**	1,257.1	38.2
Change in Plan assets				
Balance, January 1	**1,046.4**	**-**	938.3	-
Employer contributions	**20.1**	**3.2**	44.8	3.2
Plan participant contributions	**7.4**	**-**	7.1	-
Benefits paid	**(51.8)**	**(3.2)**	(52.6)	(3.2)
Actual return on assets, net of expenses	**97.3**	**-**	108.8	-
Balance, December 31	**1,119.4**	**-**	1,046.4	-
Funded Status, end of year	**$ (155.5)**	**$ (35.3)**	$ (210.7)	$ (38.2)

As at December 31, the aggregate financial position for all pension plans where the Projected Benefit Obligation (PBO) or, for post-retirement benefit plans, the Accumulated Post-retirement Benefit Obligation (APBO), exceeds the plan assets was as follows:

Plans with PBO/APBO in excess of Plan assets

	2015		2014	
millions of Canadian dollars	**Defined benefit pension plans**	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
PBO/APBO	**$ 1,248.1**	**$ 35.3**	$ 1,228.0	$ 38.2
Fair value of Plan Assets	**1,084.7**	**-**	1,012.0	-
Funded Status	**$ (163.4)**	**$ (35.3)**	$ (216.0)	$ (38.2)

The Accumulated Benefit Obligation ("ABO") for the defined benefit pension plans was $1,227.2 million as at December 31, 2015 (2014 – $1,213.4 million). As at December 31, the aggregate financial position for those plans with an ABO in excess of the Plan assets was as follows:

Plans with ABO in excess of Plan assets

	2015	2014
millions of Canadian dollars	**Defined benefit pension plans**	Defined benefit pension plans
ABO	**$ 1,200.3**	$ 1,184.3
Fair value of Plan Assets	**1,084.7**	1,012.0
Funded Status	**$ (115.6)**	$ (172.3)

Balance Sheet

The amounts recognized in the Balance Sheets as at December 31 consisted of the following:

		2015		2014
millions of Canadian dollars	**Defined benefit pension plans**	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Current liabilities	**$ (3.9)**	**$ (3.1)**	$ (3.6)	$ (3.4)
Long-term liabilities	**(159.4)**	**(32.3)**	(212.5)	(34.8)
Other asset (noncurrent)	**7.9**	**-**	5.3	-
AOCL	**293.2**	**(1.7)**	381.4	1.4
Net amount recognized at end of year	**$ 137.8**	**$ (37.1)**	$ 170.6	$ (36.8)

Unamortized gains and losses and past service costs arising on post-retirement benefits are recorded in AOCL. The following tables provide detail on the change in AOCL during fiscal 2015 relating to these items; and the composition of the year-end balance:

Accumulated Other Comprehensive Loss millions of Canadian dollars	Actuarial losses (gains)	Past service (gains) costs
Defined Benefit Pension Plans		
Balance, January 1	**$ 386.2**	**$ (4.8)**
Amortized in current period	**(41.0)**	**0.8**
Current year addition (reduction) to AOCL	**(48.0)**	**-**
Balance, December 31	**$ 297.2**	**$ (4.0)**
Non-pension benefits plans		
Balance, January 1	**$ 0.8**	**$ 0.6**
Amortized in current period	**(0.1)**	**(0.3)**
Current year addition (reduction) to AOCL	**(2.7)**	**-**
Balance, December 31	**$ (2.0)**	**$ 0.3**

		2015		2014
Accumulated Other Comprehensive Loss millions of Canadian dollars	**Defined benefit pension plans**	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Actuarial (gains) losses	**$ 297.2**	**$ (2.0)**	$ 386.2	$ 0.8
Past service (gains) costs	**(4.0)**	**0.3**	(4.8)	0.6
Net amount in AOCL	**$ 293.2**	**$ (1.7)**	$ 381.4	$ 1.4

The amounts in the foregoing table were not recognized in NSPI's net periodic benefit cost as at December 31.

Benefit Cost Components		**2015**		2014
millions of Canadian dollars	**Defined benefit pension plans**	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Service cost	**$ 15.9**	**$ 1.5**	$ 12.5	$ 1.5
Interest cost	**49.7**	**1.5**	54.2	1.8
Expected return on plan assets	**(52.8)**	**-**	(53.7)	-
Current year amortization of:				
Actuarial losses	**41.0**	**0.1**	33.2	(0.2)
Past service (gains) costs	**(0.8)**	**0.3**	(0.8)	0.2
Special termination	**-**	**-**	(0.1)	-
Total	**$ 53.0**	**$ 3.4**	$ 45.3	$ 3.3

The expected return on plan assets is determined based on the market-related value of plan assets of $938.0 million as at January 1, 2015 (2014 – $868.8 million), adjusted for interest on certain cash flows during the year. The market-related value of assets is based on a five-year smoothed asset value. Any investment gains (or losses) in excess of (or less than) the expected return on plan assets are recognized on a straight-line basis into the market-related value of assets over a five-year period.

Pension Plan Asset Allocations

NSPI's defined benefit pension plan employs a long-term strategic approach with respect to asset allocation, real return and risk. The underlying objective is to earn an appropriate return given the Company's goal of preserving capital within an acceptable level of risk for the pension fund investments.

To achieve the overall long-term asset allocation pension assets are managed by external investment managers per the pension plan's investment policy and governance framework. The asset allocation includes investments in the assets of Canadian and global equities, bonds, and short-term investments. NSPI reviews investment manager performance on a regular basis and maintains the plans' asset allocations within the ranges permitted in the pension plans' investment policy.

NSPI's target asset allocation for 2015 and 2014 is as follows:

Asset Class	2015 Target Range at Market			2014 Target Range at Market		
Short-term securities	0%	to	5%	0%	to	5%
Fixed income	35%	to	50%	30%	to	45%
Equities:						
Canadian	12%	to	22%	17%	to	27%
Non-Canadian (World)	36%	to	50%	36%	to	50%

The investment of the pension assets, including the performance of investment managers, is overseen by the NSPI Pension Committee.

The fair values of investments as at December 31, 2015, by asset category, are as follows:

millions of Canadian dollars		**Level 1**	**Percentage**
Cash and cash equivalents	**$**	**9.8**	**0.9 %**
Equity securities:			
Canadian equity		**188.3**	**16.8 %**
International equity		**476.1**	**42.5 %**
Fixed income securities			
Government		**296.1**	**26.5 %**
Corporate debt		**149.1**	**13.3 %**
Total	**$**	**1,119.4**	**100.0 %**

The fair value of investments as at December 31, 2014, by asset category, are as follows:

millions of Canadian dollars		Level 1	Percentage
Cash and cash equivalents	$	5.4	0.5 %
Equity Securities:			
Canadian equity		208.0	19.9 %
International equity		465.8	44.5 %
Fixed income securities:			
Government		258.0	24.7 %
Corporate debt		109.2	10.4 %
Total	$	1,046.4	100.0 %

Refer to Note 1(S), "*Summary of Significant Accounting Policies – Fair Value Measurement*," for more information on the fair value hierarchy and inputs used to measure fair value. All investments were deemed Level 1 for the years ended December 31, 2015 and 2014.

Investments in Emera Incorporated or NSPI

As at December 31, 2015 and 2014, the pension funds do not hold any material investments in Emera Incorporated ("Emera") or NSPI securities. However, as a significant portion of assets for the benefit plan are held in pooled assets, there may be indirect investments in these securities.

Other post-retirement benefit plan assets

There are no assets set aside to pay for the other post-retirement benefit plans. As is common in Canada, post-retirement health benefits are paid from NSPI's general accounts on a pay as you go basis.

Cash Flows

The following table shows the expected cash flows for defined benefit pension and other post-retirement benefit plans:

millions of Canadian dollars	Defined benefit pension plans	Non-pension benefit plans
Expected employer contributions		
2016	$ 15.5	$ 3.1
Expected benefit payments		
2016	55.7	3.1
2017	60.1	3.0
2018	64.0	3.2
2019	68.2	3.3
2020	72.8	3.5
2021 – 2025	416.0	17.5

Assumptions

The following table shows the assumptions that have been used in accounting for defined benefit pension and other post-retirement benefit plans:

	2015		2014	
(weighted average assumptions)	**Defined benefit pension plans**	**Non-pension benefit plans**	Defined benefit pension plans	Non-pension benefit plans
Benefit obligation – December 31:				
Discount rate	**4.00 %**	**4.00 %**	4.00 %	4.00 %
Rate of compensation increase	**2.25 - 4.75%**	**2.25 - 4.75%**	2.25 - 4.75%	2.25 - 4.75%
Health care trend - initial (next year)	**-**	**4.00 %**	-	4.00 %
- ultimate	**-**	**4.00 %**	-	4.00 %
- year ultimate reached	**-**	**2015**	-	2014
Benefit cost for year ended December 31:				
Discount rate	**4.00 %**	**4.00 %**	5.00 %	5.00 %
Expected long-term return on plan assets	**5.75 %**	**N/A**	6.25 %	N/A
Rate of compensation increase	**2.25 - 4.75%**	**2.25 - 4.75%**	2.50 - 5.00%	2.50 - 5.00%
Health care trend - initial (current year)	**-**	**4.00 %**	-	3.75 %
- ultimate	**-**	**4.00 %**	-	3.75 %

The rate of compensation increase is based on age. For the December 31, 2015 benefit obligation disclosure, it ranges from 2.25% (age 50 and over) to 4.75% (age 30 and under).

The expected long-term rate of return on plan assets is based on historical and projected real rates of return for the plan's current asset allocation, and assumed inflation. A real rate of return is determined for each asset class. Based on the asset allocation, an overall expected real rate of return for all assets is determined. The asset return assumption is equal to the overall real rate of return assumption added to the inflation assumption, adjusted for assumed expenses to be paid from the plan.

The discount rate is based on high-quality long-term Canadian corporate bonds, with maturities matching the estimated cash flows from the pension plan.

Sensitivity Analysis for Defined Benefit Pension Plans

The impact on the 2015 benefit cost of a 25 basis point change (0.25 per cent) in the discount rate and asset return assumptions is as follows:

	Increase		Decrease	
millions of Canadian dollars	**2015**	2014	**2015**	2014
Discount rate assumption	**$ (4.5)**	$ (4.7)	**$ 4.6**	$ 4.8
Asset return assumption	**$ (2.3)**	$ (2.2)	**$ 2.3**	$ 2.2

Sensitivity Analysis for Non-Pension Benefits Plans

The health care cost trend significantly influences the amounts presented for health care plans. An increase or decrease of one percentage point of the assumed health care cost trend would have had the following impact in 2015:

	Increase		Decrease	
millions of Canadian dollars	**2015**	2014	**2015**	2014
Discount rate assumption	**$ 0.2**	$ 0.2	**$ (0.2)**	$ (0.2)
Asset return assumption	**$ 2.4**	$ 2.4	**$ (2.0)**	$ (2.0)

Amounts to be Amortized in the Next Fiscal Year

The following table shows the amounts from the AOCL, which are expected to be recognized as part of the net periodic benefit cost in fiscal 2016:

millions of Canadian dollars	Defined benefit pension plans	Non-pension benefit plans
Actuarial gains (losses)	$ (35.7)	$ 0.2
Past service gains	0.7	(0.2)
Total	$ (35.0)	$ -

Defined Contribution Plan

The Company also provides a defined contribution pension plan for certain employees. The Company's contribution for the year ended December 31, 2015 was $1.3 million (2014 – $1.0 million).

16. SHORT-TERM DEBT

NSPI's short-term debt as at December 31 consisted of the following:

millions of Canadian dollars	**2015**	2014
Bank indebtedness (1)	**$ 15.9**	$ 2.3

(1) Upon privatization of NSPI in 1992, NSPI became responsible for managing a portfolio of defeasance securities that provide the principal and interest streams to match the related defeased debt. Under the privatization agreements, NSPI administers the defeasance cash flows and obligations which are not recorded in NSPI's financial statements. All of the bank accounts are included in NSPI's pool of bank accounts under a mirror netting agreement therefore NSPI's bank indebtedness position is offset by cash held for defeasances and no interest charges are incurred.

Advances on the long-term revolving credit facility (note 17) can be made by way of overdraft on accounts for up to $50 million at prime rate borrowing.

17. LONG-TERM DEBT

NSPI's long-term debt includes the issuances detailed below. Medium-term notes and debentures are issued under trust indentures at fixed interest rates and are unsecured unless noted below. Also included is commercial paper where the Company has the intention and the unencumbered ability to refinance the obligations for a period greater than one year. Long-term debt as at December 31 consisted of the following:

millions of Canadian dollars	Stated Interest Rate	Effective Interest Rate	Maturity	**2015**	2014
Commercial paper (1)	-	0.85%	2020	**$ 369.3**	$ 349.1
Medium-term notes					
Series F	8.85%	8.21%	2025	**125.0**	125.0
Series I	8.40%	8.43%	2015	**-**	70.0
Series L	8.30%	8.88%	2036	**60.0**	60.0
Series M (2)	8.50%	7.76%	2026	**40.0**	40.0
Series N	7.60%	7.57%	2097	**50.0**	50.0
Series P	6.28%	6.28%	2029	**40.0**	40.0
Series R	7.45%	7.51%	2031	**75.0**	75.0
Series S	6.95%	7.12%	2033	**200.0**	200.0
Series V	5.67%	5.71%	2035	**150.0**	150.0
Series W	5.95%	6.01%	2039	**200.0**	200.0
Series X	5.61%	5.65%	2040	**300.0**	300.0
Series Y	4.15%	4.19%	2042	**250.0**	250.0
Series Z	4.50%	4.57%	2043	**300.0**	300.0
Series AA	3.61%	3.65%	2045	**175.0**	-
				$ 1,965.0	$ 1,860.0
Debentures – Series 3	9.75%	9.99%	2019	**95.0**	95.0
Capital lease obligations	-	4.3% and 4.8%	2016 and 2019	**0.5**	1.0
				$ 2,429.8	$ 2,305.1
Unamortized debt premium - net				**0.1**	0.4
Amount due within one year				**(0.3)**	(70.5)
Long-Term Debt				**$ 2,429.6**	$ 2,235.0

(1) Commercial paper is backed by a revolving credit facility which matures in 2020.
(2) Notes are extendable until 2056 at the option of the holders.

The Company's total long-term revolving credit facility, outstanding borrowings and available capacity as at December 31 were as follows

millions of Canadian dollars	Maturity	**2015**	2014
Revolving credit facility (1)	October 2020	**$ 500.0**	$ 500.0
Less:			
Borrowings under credit facility		**369.6**	349.5
Letters of credit issued inside the line of credit		**0.8**	0.2
Use of available facility		**370.4**	349.7
Available capacity under existing agreement		**$ 129.6**	$ 150.3

(1) Advances on the revolving credit facility can be made by way of overdraft on accounts up to $50 million at prime rate borrowing. Such advances are classified as short-term debt (Note 16).

As at December 31, 2015, the credit facility has standby fees of 0.20% associated with the unused portion. The weighted average interest rate on the outstanding borrowings on the credit facility were 0.85% as at December 31, 2015 (2014 - 1.24%).

Credit Facilities

NSPI has an active commercial paper program for up to $400 million, of which the full amount outstanding is backed by the Company's bank line referred to above, which results in an equal amount of credit being considered drawn and unavailable.

Debt Covenants

NSPI's debt obligations contain covenants related to the amount of debt to capitalization as defined in certain agreements. In addition, other covenants and financial reporting obligations exist. Failure to comply with these covenants could result in an event of default, which if not cured or waived, could result in the acceleration of outstanding debt obligations.

NSPI has debt covenants associated with its credit facility. As at December 31, 2015 and 2014, NSPI was in compliance with all respective financial covenants related to outstanding debt. NSPI's significant covenant is listed below:

Instrument	Financial Covenant	Requirement/Restriction	As at December 31, 2015
Syndicated credit facility	Debt to capital ratio	Less than or equal to 0.65 to 1	0.64:1

Long-Term Debt Maturities

As at December 31, 2015 long-term debt maturities for each of the next five years and in aggregate thereafter are as follows:

Year of maturity	millions of Canadian dollars
2016	$ 0.3
2017	0.1
2018	0.1
2019	95.0
2020	369.3
Greater than 5 years	1,965.0
Total	$ 2,429.8

18. RELATED PARTY TRANSACTIONS

The Company enters into transactions with related parties in the normal course of operations. All related party transactions entered by NSPI are governed by an affiliate Code of Conduct that is approved by the UARB.

Emera Energy Services Inc., Emera Energy Inc., Emera Maine, Emera Utility Services, Emera Brunswick Pipeline and Emera Newfoundland and Labrador are wholly-owned subsidiaries of Emera Inc. and affiliates of NSPI.

Related party transactions between NSPI and Emera and its affiliates are summarized in the following table:

For the millions of Canadian dollars			Year ended December 31	
			2015	2014
	Nature of Service	**Presentation**		
Sales:				
Emera and affiliates	Net sale of natural gas	Fuel for generation and purchased power	**-**	$ 1.8
Emera and affiliates	Corporate support and other services	OM&G	**$ 14.9**	11.3
Emera and affiliates	Rent and other services	Operating revenues	**2.8**	3.3
Purchases:				
Emera and affiliates	Net purchase of natural gas	Fuel for generation and purchased power	**5.0**	-
Emera and affiliates	Purchase of electricity	Fuel for generation and purchased power	**11.6**	16.5
Emera and affiliates	Construction services	Property, plant and equipment	**21.1**	15.5
Emera and affiliates	Maintenance services	OM&G	**2.1**	2.4

NSPI recorded the impact of two agreements with an Emera affiliate on a net basis in the Statements of Income. Under the agreements, NSPI purchased power from an Emera affiliate and received contract revenues from an Emera affiliate of $10.6 million (2014 - $10.6 million) for the year ended December 31, 2015.

For the year ended December 31, 2015, the Company issued 3.9 million (2014 - 0.1 million) common shares to Emera and an affiliate under common control of Emera for total consideration of $39.1 million (2014 - $0.7 million). NSPI paid $100.0 million (2014 - $120.0 million) in dividends to common shareholders during the year ended December 31, 2015.

Amounts due (to) from related parties are summarized in the following table:

As at millions of Canadian dollars	**December 31 2015**	December 31 2014
Due from related parties:		
Emera and affiliates	**$ 1.9**	$ 2.0
Due to related parties:		
Emera and affiliates	**$ (6.5)**	$ (7.7)
Net due from (to) related parties	**$ (4.6)**	$ **(5.7)**

19. OTHER CURRENT LIABILITIES

Other current liabilities consisted of the following:

As at millions of Canadian dollars	**December 31 2015**	December 31 2014
Accrued charges	**$ 40.5**	$ 42.1
Accrued interest on long-term debt	**34.8**	34.8
Sales taxes payable	**3.9**	5.6
Dividends payable on preferred shares	**-**	2.0
	$ 79.2	$ 84.5

20. ASSET RETIREMENT OBLIGATIONS

AROs mostly relate to the reclamation of land at the Company's thermal, hydro and combustion turbine sites; and the disposal of polychlorinated biphenyls in transmission and distribution equipment. Certain hydro, transmission and distribution assets may have additional ARO that cannot be measured as these assets are expected to be used for an indefinite period and, as a result, a reasonable estimate of the fair value of any related ARO cannot be made.

The change in ARO for the years ended December 31 is as follows:

millions of Canadian dollars		**2015**	2014
Balance, January 1	**$**	**94.1**	$ 89.2
Liabilities settled		**(1.5)**	(1.4)
Accretion included in depreciation expense		**7.3**	7.2
Accretion deferred to regulatory asset (included in property, plant and equipment) (1)		**(2.4)**	(2.4)
Revisions in estimated cash flows		**4.1**	1.5
Balance, December 31	**$**	**101.6**	$ **94.1**

(1) Differences between accretion expense recognized for rate regulatory purposes and USGAAP, and accretion expense not yet approved by the UARB, are deferred to "Property, plant and equipment" and included in the next depreciation study.

As at December 31, 2015 and 2014, some of the Company's transmission and distribution assets may have additional conditional ARO which are not recognized in the financial statements as the fair value of these obligations could not be reasonably estimated, given there is insufficient information to do so. Management will continue to monitor these obligations and a liability will be recognized in the period in which an amount becomes determinable.

21. COMMITMENTS AND CONTINGENCIES

A. Commitments

As at December 31, 2015, contractual commitments (excluding pensions and other post-retirement obligations, long-term debt and ARO) for each of the next five years and in aggregate thereafter consisted of the following:

millions of Canadian dollars	**2016**	**2017**	**2018**	**2019**	**2020**	**Thereafter**	**Total**
Purchased power - IPP (1)	$ 104.5	$ 112.7	$ 112.7	$ 112.7	$ 109.2	$ 1,239.6	$ 1,791.4
Purchased power - COMFIT (1)	74.6	79.3	79.3	79.3	79.3	1,137.0	1,528.8
Coal and biomass supply	82.7	38.9	12.2	-	-	-	133.8
DSM	24.7	34.0	34.9	-	-	-	93.6
Transportation (2)	17.5	10.0	5.7	1.3	-	-	34.5
Long-term service agreements (3)	14.9	14.3	8.7	8.3	8.0	13.5	67.7
Capital projects	32.4	1.2	-	-	-	-	33.6
Leases (4)	1.6	1.4	1.3	1.3	1.3	18.5	25.4
Other	0.2	0.2	0.2	0.2	-	-	0.8
	$ 353.1	$ 292.0	$ 255.0	$ 203.1	$ 197.8	$ 2,408.6	$ 3,709.6

(1) Purchased power: annual requirement to purchase 100 percent of electricity production from independent power producers ("IPP") including community feed in tariff ("COMFIT") over varying contract lengths up to 25 years.

(2) Transportation: purchasing commitments for transportation of solid fuel and transportation capacity on the Maritimes & Northeast Pipeline ("MN&P").

(3) Long-term service agreements: outsourced management of the Company's computer and communication infrastructure, vegetation management, software maintenance and support, transmission and distribution line construction and maintenance services related to a generation facility and wind operating agreements.

(4) Leases: operating lease agreements for office space, land leases and rail cars.

B. Legal Proceedings

The Company may, from time to time, be involved in legal proceedings, claims and litigation that arise in the ordinary course of business which the Company believes would not reasonably be expected to have a material adverse effect on the financial condition of the Company.

C. Environment

NSPI's activities are subject to a broad range of federal, provincial, regional and local laws and environmental regulations, designed to protect, restore and enhance the quality of the environment including air, water and solid waste. NSPI's environmental capital expenditures, excluding AFUDC, based upon present environmental laws and regulations were $43.2 million during fiscal 2015 and are estimated to be $63.9 million from 2016 through 2019. Amounts that have been committed to are included in "Capital projects" in the commitments table in note 21A. The estimated expenditures do not include costs related to possible changes in the environmental laws or regulations and enforcement policies that may be enacted in response to issues such as climate change and other pollutant emissions.

NSPI is subject to regulation by federal, provincial and municipal authorities with regard to environmental matters, primarily through its utility operations. In addition to imposing continuing compliance obligations, there are laws, regulations and permits authorizing the imposition of penalties for non-compliance, including fines, injunctive relief and other sanctions. The cost of complying with current and future environmental requirements is material to the Company. Failure to comply with environmental requirements or to recover environmental costs in a timely manner through rates could have a material adverse effect on the Company.

Conformance with legislative and Company requirements is verified through a comprehensive environmental audit program. There were no significant environmental or regulatory compliance issues identified during the audits completed to December 31, 2015.

Poly Chlorinated Bi-Phenol Transformers

In response to the Canadian Environmental Protection Act 1999, 2008 Poly Chlorinated Bi-Phenol ("PCB") Regulations to phase out electrical equipment and liquids containing PCBs, NSPI has implemented a program to eliminate transformers and other oil-filled electrical equipment on its system that do not meet the 2008 PCB Regulations Standard by the end of 2025. This also includes PCB contaminated pole mounted transformers. The combined total cost of these projects is estimated to be $40.1 million and, as at December 31, 2015, approximately $19.7 million (December 31, 2014 – $14.8 million) has been spent to date. NSPI has recognized an ARO of $15.0 million as at December 31, 2015 (December 31, 2014 – $11.8 million) associated with the PCB phase-out program.

D. Principal Risks and Uncertainties

In this section, NSPI describes some of the principal risks management believes could materially affect NSPI's business, revenues, operating income, net income, net asset or liquidity or capital resources. The nature of risk is such that no list can be comprehensive, and other risks may arise, or risks not currently considered material may become material in the future.

Sound risk management is an essential discipline for running the business efficiently and pursuing the Company's strategy successfully. NSPI has a business-wide risk management process, monitored by the Board of Directors, to ensure a consistent and coherent approach.

Regulatory and Political Risk

NSPI faces risk with respect to the recovery of costs and investments in a timely manner. As a regulated cost-of-service utility with an obligation to serve, NSPI must obtain regulatory approval to change general electricity rates. The recovery of costs and investments are subject to the approval of the UARB, through

the adjustment of rates, which normally requires a public hearing process. Capital investments are approved in advance of spending, primarily through an annual capital expenditure public hearing. In addition, the regulatory framework under which NSPI operates can be impacted by significant shifts in government policy and changes in governments.

During public hearing processes, consultants and customer representatives scrutinize the Company's costs, actions and plans, and the UARB determines whether to allow recovery and to adjust rates based upon NSPI's evidence and any contrary evidence from other hearing participants. The Company manages this regulatory risk through transparent regulatory disclosure, ongoing stakeholder and government consultation and multi-party engagement on aspects such as utility operations, fuel-related audits, rate filings and capital plans. The Company employs a collaborative regulatory approach through technical conferences and, where appropriate, negotiated settlements.

Changes in Environmental Legislation

The Company is subject to regulation by federal, provincial and municipal authorities with regard to environmental matters primarily related to its utility operations. Changes in climate change and air emissions standards could adversely affect utility operations.

NSPI is committed to operating in a matter that is respectful and protective of the environment, and in full compliance with legal requirements and Company policy. NSPI has implemented this policy through development and application of environmental management systems.

In November 2014 a greenhouse gas equivalency agreement between the Government of Canada and the Province of Nova Scotia was officially authorized by the Governor General, which will allow NSPI to achieve compliance with federal greenhouse gas emissions regulations by instead meeting existing provincial requirements. With that agreement in place, NSPI continues to take appropriate steps to meet the provincial greenhouse gas emissions caps for the years 2015-2030.

The Nova Scotia government introduced changes to the Air Quality Regulations in the fall of 2014. The changes added sulphur dioxide, nitrogen dioxide and mercury emission caps for the period 2015-2030. NSPI aligns its plans and operations to address these requirements.

Commodity Price and Foreign Exchange Rate Fluctuations in Fuel Prices

Commodity price fluctuations related to the purchase of fuel for generation and purchased power and foreign exchange fluctuations on foreign currency denominated purchases of fuel affect NSPI's Fuel Costs. Fuel contracts may be exposed to broader global conditions which may include impacts on delivery reliability and price, despite contracted terms. The Company seeks to manage this risk through the use of financial hedging instruments and physical contracts and utilizes a portfolio strategy for fuel procurement with a combination of long, medium, and short-term supply agreements. It also provides for supply and supplier diversification. The strategy is designed to reduce the effects from market volatility through agreements with staggered expiration dates, volume options and varied pricing mechanisms. The adoption and implementation of the FAM, effective January 1, 2009 which allows for recovery of prudently incurred Fuel Costs from customers, has further helped NSPI manage this risk.

Commercial Relationships

NSPI's five largest customers contributed approximately 8.6 percent (2014 – 9.4 percent) of electric revenues for the year ended December 31, 2015. The loss of a large customer could have a material effect on NSPI's operating revenues. NSPI works to mitigate this risk through operational adjustments, cost management as well as the regulatory process.

Labour Risk

Certain NSPI employees are subject to a collective labour agreement. On June 30, 2015, NSPI employees subject to the collective labour agreement voted to accept a new collective agreement which expires on March 31, 2019. NSPI's prior collective agreement expired on March 31, 2015. Approximately 47 percent of NSPI's regular and term employees are represented by a local union affiliated with the International Brotherhood of Electrical Workers

Interest Rate Risk

The Company utilizes a combination of fixed and variable rate debt financing for operations and capital expenditures resulting in an exposure to interest rate risk. The Company seeks to manage interest rate risk through a portfolio approach that includes the use of fixed and floating rate debt with staggered maturities. The Company will, from time to time, issue fixed long term debt to limit its exposure to fluctuations in floating interest rate debt. As at December 31, 2015, 84.8 percent of NSPI's debt position is fixed rate in nature, with an average term to maturity of approximately 23 years.

E. Letters of Credit

NSPI had no liability recognized in the Balance Sheets related to any potential obligations under letters of credit. NSPI had the following letter of credit as at December 31, 2015:

- A standby letter of credit to secure obligations under an unfunded pension plan in NSPI. The letter of credit expires in June 2016 and is renewed annually. The amount committed as at December 31, 2015 was $42.6 million.

Collaborative Arrangements

Collaborative arrangements are contractual arrangements that involve a joint operating activity involving two (or more) parties who are both active participants in the activity and exposed to significant risks and rewards depending on the success of the activity. Payments made to or collected from collaborative partners or third parties related to the project are presented in the Statement of Income and Balance Sheet based on the nature of the transaction and contractual terms of the arrangement.

NSPI is a participant in a 23.3 megawatt ("MW") wind energy project with Renewable Energy Services Ltd. in Point Tupper, Nova Scotia. Percentage ownership of the wind project assets is based on the relative value of each party's project assets by the total project assets with NSPI owning 47.4 percent. NSPI's has a power purchase arrangement to purchase the entire net output of the project and therefore NSPI's portion of the revenues are recorded net, within fuel for generation and purchased power. NSPI's portion of operating expenses, are recorded in operating, maintenance and general ("OM&G") expenses. In 2015, NSPI recognized $2.8 million net expense (2014 - $3.0 million) in fuel for generation and purchase power and $0.5 million (2014 - $0.5 million) in OM&G. As part of this arrangement, NSPI received a portion of an Eco Energy revenue claim totaling $0.3 million in 2015.

NSPI is a participant in a 102 MW wind energy project with the South Canoe Development Partnership for South Canoe Wind Farm, in New Ross, Nova Scotia. Percentage ownership of the wind project assets is based on the relative value of each party's project assets by the total project assets with NSPI owning not more than 49 percent. NSPI's has a power purchase arrangement to purchase the entire net output of the project and therefore NSPI's portion of the revenues are recorded net, within fuel for generation and purchased power. NSPI's portion of operating expenses, are recorded in OM&G expenses. The project reached commercial operation in Q2 2015. In 2015, NSPI recognized a $6.4 million net expense in fuel for generation and purchase power and $1.1 million in OM&G.

NSPI is a participant in a 13.8 MW wind energy project with the Municipality of the District of Guysborough for Sable Wind Farm, near Canso, Nova Scotia. Percentage ownership of the wind farm is

based on the relative value of each party's project assets by the total project assets with NSPI owning not more than 49 percent. NSPI's has a power purchase arrangement to purchase the entire net output of the project and therefore NSPI's portion of the revenues are recorded net, within fuel for generation and purchased power. NSPI's portion of operating expenses, are recorded in OM&G expenses. The project went reached commercial operation in Q2 2015. In 2015, NSPI recognized a $1.0 million net expense in fuel for generation and purchase power and $0.1 million in OM&G.

22. REDEEMABLE PREFERRED STOCK

Redeemable preferred stock is considered mezzanine equity and is presented outside of equity because the preferred stock is exchangeable at the option of the holder into Emera common stock.

Authorized:
Unlimited number of First Preferred shares, issuable in series.
Unlimited number of Second Preferred shares, issuable in series.

Issued and Outstanding:	**2015 millions of shares**	**2015 millions of Canadian dollars**	2014 millions of shares	2014 millions of Canadian dollars
Redeemable Preferred Stock	-	-	5.4	$ 135.0
Issue costs	-	-	-	(2.8)
	-	-		$ 132.2

Series D First Preferred Stock:

On October 15, 2015, NSPI redeemed all of its outstanding Cumulative Redeemable First Preferred Shares, Series D for a redemption price of $25.00 per share for a total of $135 million. The issuance costs are treated as a deemed dividend of $2.8 million, recognized when the redemption occurred on October 15, 2015.

23. STOCK-BASED COMPENSATION

EMPLOYEE COMMON STOCK PURCHASE PLAN

All employees may participate in Emera's Employee Common Share Purchase Plan to which employees make cash contributions of a minimum of $25 to a maximum of $8,000 per year for the purpose of purchasing common shares of NSPI's parent company, Emera. The Company also contributes to the plan a percentage of the employees' contributions. If an employee contributes any amount up to $3,000 to employees plan account, the Company will contribute 20 percent of that amount. When an employee contributes any amount over $3,000, up to the $8,000 maximum, the Company will contribute ten percent of that amount.

The plan allows the reinvestment of dividends. The maximum aggregate number of Emera common shares reserved for issuance under this plan is 4.0 million common shares.

The Company uses the fair value based method to measure the compensation expense related to the employee purchase plan and recognizes the expense over the vesting period on a straight-line basis.

Compensation cost for shares issued by Emera for the year ended December 31, 2015 to employees of NSPI under the Employee Common Share Purchase Plan was $0.6 million (2014 – $0.6 million) and is included in "Operating, maintenance and general" on the Statements of Income.

STOCK-BASED COMPENSATION PLANS

The Company has deferred share unit ("DSU") and performance share unit ("PSU") plans. The DSU and PSU liabilities are marked-to-market at the end of each period based on the common share price at the end of the period.

Deferred Share Unit Plan

Under the Directors' DSU plan, Independent Directors of the Company may elect to receive all or any portion of their compensation in DSUs in lieu of cash compensation, subject to requirements to receive a minimum portion of their annual retainer in DSUs. Directors' fees are paid on a quarterly basis and, at the time of each payment of fees, the applicable amount is converted to DSUs.

A DSU has a value equal to one Emera common share. When a dividend is paid on Emera's common shares, referred to as the Dividend Reinvestment Plan ("DRIP"), the Director's DSU account is credited with additional DSUs.

DSUs cannot be redeemed for cash until the Director retires, resigns or otherwise leaves the Board. The cash redemption value of a DSU equals the market value of a common share at the time of redemption, pursuant to the plan. Following retirement or resignation from the board, the value of the DSUs credited to the participant's account is calculated by multiplying the number of DSUs in the participant's account by the average of Emera's stock closing price during the ten trading days ending on the tenth trading day prior to the payment date.

Under the executive and senior management DSU plan, each participant may elect to defer all or a percentage of their annual incentive award in the form of DSUs with the understanding, for participants who are subject to executive share ownership guidelines, a minimum of 50% of the value of their actual annual incentive award (25% in the first year of the program) will be payable in DSUs until the applicable guidelines are met.

When incentive awards are determined, the amount elected is converted to DSUs, which have a value equal to the market price of an Emera common share. When a dividend is paid on Emera's common shares, each participant's DSU account is allocated additional DSUs equal in value to the dividends paid on an equivalent number of Emera common shares. Following termination of employment or retirement, and by December 15 of the calendar year after termination or retirement, the value of the DSUs credited to the participant's account is calculated by multiplying the number of DSUs in the participant's account by the average of Emera's stock closing price for the fifty trading days prior to a given calculation date. Payments are usually made in cash. At the sole discretion of the Human Resources and Governance Committee ("HRGC"), payments may be made in the form of actual shares.

In addition, special DSU awards may be made from time to time by the HRGC to selected executives and senior management to recognize singular achievements or to achieve certain corporate objectives.

A summary of the activity related to employee and director DSUs for the year ended December 31, 2015 is presented in the following table:

	Employee DSU	Weighted Average Grant Date Fair Value	Director DSU	Weighted Average Grant Date Fair Value
Outstanding as at December 31, 2014	68,165	$ 28.72	92,820	$ 30.01
Granted including DRIP	24,759	31.45	16,868	36.41
Transferred	6,503	28.81	-	-
Outstanding as at December 31, 2015	**99,427**	**$ 31.45**	**109,688**	**$ 31.48**

Compensation cost recognized for employee and director DSU for the year ended December 31, 2015 was $2.2 million (2014 – $2.3 million). Tax benefits related to this compensation cost for share units

realized for the year ended December 31, 2015 were $0.8 million (2014 – $0.9 million); $0.5 million was offset with a regulatory liability (2014 – $0.6 million). The aggregate intrinsic value of the outstanding shares for the year ended December 31, 2015 was $8.5 million.

Performance Share Unit Plan

Under the PSU plan, executive and senior employees are eligible for long-term incentives payable through the PSU plan. PSUs are granted annually for three-year overlapping performance cycles. PSUs are granted based on the average of Emera's stock closing price for the fifty trading days prior to a given calculation date. Dividend equivalents are awarded and are used to purchase additional PSUs, also referred to as DRIP. The PSU value varies according to the Emera common share market price and corporate performance.

PSUs vest at the end of the three-year cycle and will be calculated and approved by the HRGC early in the following year. The value of the payout considers actual service over the performance cycle and will be pro-rated in the case of retirement, disability or death.

A summary of the activity related to employee PSUs for the year ended December 31, 2015 is presented in the following table:

	Employee PSU	Weighted Average Grant Date Fair Value	Aggregate Intrinsic Value
Outstanding as at December 31, 2014	109,184	$ 32.43	$ 3.6
Granted including DRIP	52,792	36.44	1.9
Exercised	(52,595)	32.54	(1.7)
Forfeited	(3,431)	33.63	(0.1)
Transferred	(16,339)	39.42	(0.6)
Outstanding as at December 31, 2015	**89,611**	**$ 34.34**	**$ 3.9**

Compensation cost recognized for the PSU plan for the year ended December 31, 2015 was $2.2 million (2014 – $2.1 million). Tax benefits related to this compensation cost for share units realized for the year ended December 31, 2015 were $0.7 million (2014 – $0.6 million).

24. VARIABLE INTEREST ENTITIES

The Company performs ongoing analysis to assess whether it holds any variable interest entities ("VIEs"). To identify potential VIEs, management reviews contracts under leases, long-term purchase power agreements and jointly owned facilities.

VIEs of which the Company is deemed the primary beneficiary must be consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses or the right to receive benefits from the entity that could potentially be significant to the entity. In circumstances where NSPI is not deemed the primary beneficiary, the VIE is not recorded in the Company's financial statements.

The Company held a variable interest in RESL, a VIE for which it was determined that NSPI was not the primary beneficiary since it does not have the controlling financial interest of RESL. The Company had provided a guarantee for the indebtedness of RESL under a loan agreement between RESL and a third-party lender for $23.5 million, in support of which NSPI held a security interest in the present and future assets owned by RESL in connection with a wind energy project at Point Tupper, Nova Scotia. As at December 31, 2015, RESL's indebtedness is no longer guaranteed by NSPI. As a result NSPI no longer holds a variable interest in RESL.

The Company has identified certain long-term purchase power agreements that could be defined as variable interests as the Company has to purchase all or a majority of the electricity generation at a fixed price. However, it was determined that the Company was not the primary beneficiary since it lacked the

power to direct the activities of the entity, including the ability to operate the generating facilities and make management decisions.

For the years ended December 31, 2015 and 2014, the Company has not identified any new VIEs.

25. COMPARATIVE INFORMATION

These financial statements contain certain reclassifications of prior period amounts to be consistent with the current period presentation with no effect on net income.

26. SUBSEQUENT EVENTS

The financial statements and notes reflect the Company's evaluation of events occurring subsequent to the balance sheet date through February 12, 2016, the date the financial statements were available for issuance.

Request IR-23:

NSPI explains in Section 10.1.2, on page 93-94, that non-fuel overearnings and cash taxes associated with South Canoe and Sable wind projects are outlined in Appendix H.

With respect to the estimates provided for 2016-2019, please clarify:

(a) Please provide a summary of the totals, year over year, starting with 2015 overearnings. Keep separate the non-fuel overearnings by year, cash taxes associated with the wind projects, variance from BCF, Deferred FAM, DSM RSA and interest.

(b) Has NSPI included non-fuel over-earnings for the 2016, 2017, 2018 or 2019 years? If so, please provide figures and how NSPI arrived at the estimates.

(c) Where the cash taxes are being deemed a recovery of fuel costs, please clarify the tax treatment for FAM and how that differs generally from tax timing variances.

(d) Please provide the actual CCA compared to depreciation for these projects, year over year, and explain what NSPI will be recording annually and how these costs will be accounted for and tracked.

(e) If NSPI is still recording deferred taxes, outside of the FAM, please clarify how such future costs/benefits will be accounted for, i.e. whether that will follow the FAM tax policy or otherwise.

Response IR-23:

(a) Please refer to Attachment 1.

(b) NS Power has not forecast any excess non-fuel revenues in the filing for the 2016-2019 time periods.

(c) In general, NS Power recognizes regulatory assets or liabilities where deferred income taxes are expected to be recovered from or returned to customers in future years. However, with respect to FAM, deferred income taxes are recorded in the Statement of Earnings per NS Power's Income tax accounting policy.

(d) Please refer to Attachment 2.

Depreciation will be calculated monthly on a straight line basis in accordance with NS Power Accounting Policy 5300- Depreciation and Amortization Expense. The gross book value of the asset is multiplied by the depreciation rate to determine the depreciation expense to be incurred in the month. The annual depreciation rate for these assets is four percent. The depreciation is calculated and tracked in NS Power's capital asset management software, PowerPlant.

Tax benefits related to CCA will reduce current income tax expense. Deferred income taxes will be offset to a regulatory asset or liability as appropriate.

Current and deferred income tax estimates will be updated at year end if required, as CCA and depreciation expense estimates are not expected to materially change.

(e) As required under the *Electricity Plan Implementation (2015) Act*, NS Power is following cash tax treatment with respect to the South Canoe and Sable wind projects. Deferred income taxes are offset to a regulatory asset or liability as appropriate.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Start of Year Balance	Excess Non-Fuel Revenues	Benefit due to Change in Tax Treatment of South Canoe and Sable Wind Farm	Deferred FAM Balance	Fuel Cost Variance from BCF*	DSM RSA	Interest	Total
2016	(21,849,547)	(18,291,000)	3,511,348	-	-	(1,837,875)	(38,467,074)
2017	(21,849,547)	(33,484,000)	3,511,348	-	-	(5,558,212)	(57,380,411)
2018	(21,849,547)	(40,138,000)	-	(54,786,367)	-	(12,549,030)	(129,322,944)
2019	(21,849,547)	(42,509,878)		21,289,643	-	(19,743,264)	(62,813,046)
2020	(21,849,547)	(42,729,821)		86,674,570	-	(22,095,201)	-

*2017 Fuel Cost Variance from BCF adjusted to reflect recovery of Deferred FAM Balance

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

In millions

Estimated annual CCA and depreciation expense for South Canoe and Sable wind projects (2016-2019)

Year	CCA	Depreciation
2016	38.7	4.9
2017	19.7	4.9
2018	10.1	4.9
2019	5.4	4.9

Request IR-24:

NSPI has outlined in sections 2.2.2 and 2.2.3, that through the Rate Stability Period the riders will be calculated for each of the three years and carried forward to the 2020 AA/BA. Further stating in its application:

> **The AA/BA application will be suspended during the Rate Stability Period and the next AA/BA application will be filed in 2019 for rates effective January 1, 2020. (Note: Footnote 3 referenced EPIA, s.10)**

The Board notes, EPIA, s.10 states:

> **Notwithstanding any requirement of the Fuel Adjustment Mechanism for annual adjustments, any adjustments implemented on January 1, 2017, must remain in place throughout the Rate Stability Period and must be adjusted so that any intended recovery or reimbursement of costs is made over the course of the Rate Stability Period.**

Further, the Board notes, EPIA, s.13 states:

> **For greater certainty, nothing in Sections 3 to 12 restricts or suspends any reporting or auditing requirements of the Fuel Adjustment Mechanism, except that no hearing related to an audit may occur during the Rate Stability Period other than for the purpose of setting the base cost of fuel for the calendar year 2020.**

Please clarify:

(a) Is NSPI's request that the annual AA/BA filing and reporting should cease throughout the Rate Stability Period until such time as NSPI files an application for 2020 riders/rates?

(b) If NSPI intended to eliminate any AA/BA reporting during this period, please explain why NSPI believes this would be appropriate and reconcile that with section 13 of the EPIA.

(c) If the reference to "suspended" was intended to be isolated to just the resulting adjustments, please confirm NSPI expects the AA/BA process will continue as normal up to the Board decision; with only the Board order outstanding. Otherwise, explain what exactly NSPI is proposing as a replacement process.

Response IR-24:

(a-c) NS Power will continue to comply with its FAM filing and reporting requirements as directed under the Plan of Administration through the Rate Stability Period.

The Company expects the AA/BA process to continue as normal up to the Board's decision, with only the Board's order outstanding. Consistent with s. 11(1) of EPIA, any variance in actual recovery of the base cost of fuel and other costs approved for recovery through the FAM during the Rate Stability Period will be addressed in the 2020 FAM AA/BA proceeding.

Consistent with s. 10 of EPIA, any imbalances in recovery of fuel costs prior to 2017 will be addressed in the FAM AA/BA proceeding in the fall of 2016. NS Power expects to file AA/BA Riders to remain in place throughout the Rate Stability Period and fully recover or reimburse the outstanding amounts. Please refer to CA IR-2 and IR-4.

NS Power will address any outstanding issues in its 2017-2019 FSP compliance filing.

Request IR-25:

In the Board's decision, dated December 10, 2015, the Board outlined an unresolved concern of stakeholders:

> **[22] In past AA/BA proceedings, various stakeholders have raised concerns about the process for approval of the annual AA and BA amounts.**
>
> **[23] In its December 2014 Decision approving the 2015 AA and BA amounts [2014 NSUARB 204], the Board concluded:**
>
> **[40] The Industrial Group suggested improvements could be made to the AA/BA process, recommending an effort through the FAM Small Working Group to find a more efficient way to adjust rates that does not involve a true up for November and December fuel forecasts, which can involve a rushed process before year end. The Board concurs that this issue be referred to the Small Working Group.**
> **[Board Decision, para. 40]**
>
> **[24] This concern has not been resolved. The same issue was raised again in this proceeding.**

The Board directed NSPI to complete consultations with its Small Working Group that have been ongoing without resolution since at least 2012 and to report no later than May 31, 2016 a proposal that responds to stakeholders concerns.

(a) Does NSPI believe the legislation eliminates, or intended to eliminate, the ongoing work and requirements of its fuel group? If so, please provide the sections of the Act relied upon for this position.

(b) Alternatively, does NSPI believe it would be useful to use this first reporting period in 2016 to begin to refine the AA/BA process, as requested by stakeholders and directed by the Board in the 2015 NSUARB 257 Decision.

Response IR-25:

(a) No, NS Power does not believe the EPIA eliminates or is intended to eliminate the ongoing work and requirements of its Fuels, Energy and Risk Management group.

(b) Yes, NS Power believes it would be useful to use this first reporting period in 2016, and the remainder of the Rate Stability Period, to refine the AA/BA process, as requested by stakeholders and directed by the Board in the 2015 NSUARB 257 Decision.

Request IR-26:

Exhibit N-1, p. 8, line 7

Please indicate the percentage and GWh of the Province's electricity that will be supplied by renewable energy sources for each year from 2016 to 2020, inclusive.

Response IR-26:

Please see the table below which is calculated in accordance with the methodology used for Renewable Energy Standards (RES) compliance reporting.

	2016	**2017**	**2018**	**2019**	**2020**
Renewable Energy in MWh	3,281,880	3,356,852	3,428,881	3,449,009	4,618,339
Total Electric Sales in MWh	10,437,653	10,547,372	10,588,904	10,602,482	10,639,541
Forecast RES %	**31.4%**	**31.8%**	**32.4%**	**32.5%**	**43.4%**

Renewable Energy includes COMFIT. The NS Block is not included in 2018-2019 per Section 6(4) of the Renewable Electricity Regulations. NS Block energy is included in 2020 renewable energy amounts.

Request IR-27:

Exhibit N-1, p. 8, line 11

Please indicate whether any impact is expected between now and 2019, inclusive, as a result of any new or revised environmental standards and emission restrictions resulting from the 2015 Paris Climate Change Conference and/or the proposed National Climate Change Plan agreed to between the Government of Canada and the Provinces on March 3, 2016.

Response IR-27:

No, NS Power has forecast its forecast fuel cost for the Rate Stability Period based on currently established emissions compliance requirements in effect in Nova Scotia. The Equivalency Agreement (between the federal and provincial governments) regarding greenhouse gas emissions is in effect. This allows NS Power to be compliant with The Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations by complying with the hard target reductions outlined in the Nova Scotia Greenhouse Gas Emissions Regulations.

NS Power did not consider the March 3, 2016 National Climate Change Plan as part of the Fuel Stability Plan filed on March 7, 2016.

Request IR-28:

Exhibit N-1, p. 59, line 8 and 10

Why are the three redacted amounts confidential? It does not appear that they were redacted in IR responses in the 2016 BCF matter.

Response IR-28:

The amounts identify the costs incurred by a particular customer (Port Hawkesbury Paper) as it is the only customer on that particular tariff. Treating those amounts as confidential is consistent with the quarterly PHP LRT filings.

The amounts should have been redacted in IR responses in the 2016 BCF matter.