Request IR-6:

In response to Multeese IR-3, NSPI provided an example of how the security deposit would be calculated in Attachment 1. In an effort to better understand the intended cash flows:

(a) Please clarify whether the security deposit would be 200% of each amount in the "Total Revenue" column and how NSPI proposes to adjust this month to month?

(i) Would the security deposit for February be $834,160 ($417,080 x 2)?

(ii) There is a wide range of possible monthly costs, please clarify what the maximum amount under this scenario NSPI could charge as a security deposit.

(iii) Would NSPI be requesting (refunding) the net variance from the prior month?

(iv) If not, how does NSPI propose to account for and credit LRS customers for security deposits?

(v) With the current applications under the OATT, please identify the deposit requirements. If necessary, use the Antigonish application that is before the Board under Matter M07086 to demonstrate anticipated, comparable deposits and cash flow.

Response IR-6:

Please refer to **Multeese IR-3 Attachment 1**.

(a) The amount of credit assurance required is calculated as 200% of the forecasted payment for the LRS Tariffed Services and DT Charges combined, rounded up for any fractional amount to the nearest $1000. For the examples shown in the spreadsheet and notes in **Multeese IR-3 Attachment 1**, the forecasted payment is the amount shown in the "Total Revenue" column. The table illustrates a monthly forecasting period and this is reflected in the response to this IR.

Monthly adjustments to the amount of credit assurance required will be based on NS Power's forecast of the LRS's payments for the upcoming month. The forecast will consider the LRS's service requirements over the previous month(s), seasonal load patterns and take into account projected changes in service requirements provided by the LRS for the upcoming month (e.g. RtR Customer transfers to or from the LRS). This process would be repeated on a monthly basis to determine the credit assurance requirement for the upcoming month.

(i) The credit assurance amount required for February in **Multeese IR-3 Attachment 1** example would be $835,000. ($417,080 x 2 = $834,160 rounded up to $835,000).

(ii) Under the **Multeese IR-3 Attachment 1** scenario, the maximum amount of credit assurance required by NS Power of the LRS would be $2,660,000. This is calculated as 200% of the example's forecasted payment of $1,329,674 for the month of September, rounded up to the nearest $1000.

(iii–iv) Yes.

If the credit assurance currently held by NS Power is insufficient to meet the amount required for the upcoming month, NS Power will request the LRS to provide additional credit assurance in an amount sufficient to cover the shortfall. In the **Multeese IR-3 Attachment 1** example, an amount of $432,000 was provided as credit assurance required for January. Based on the February forecast of the LRS's Tariffed Services and DT Charges, the additional credit assurance requirement for February would be $403,000 ($835,000 less $432,000 previously provided).

If the credit assurance currently held by NS Power is in excess of the amount required, the LRS could, upon payment of the current charges (inclusive of any amounts in arrears), request that NS Power reduce the credit assurance amount in an amount up to the excess.

(v) The OATT in Section 11 states that the Transmission Provider may require reasonable credit review procedures to determine the Transmission Customer's ability to meet its payment obligations related to transmission services. Additionally, the Transmission Provider may require the Transmission Customer to provide and maintain, during the term of their OATT service, an unconditional and irrevocable letter of credit (or an alternative form of security acceptable to the Transmission Provider) to meet the Transmission Customer's payment responsibilities and obligations under the OATT and protect the Transmission Provider against the risk of non-payment.

The transmission service application procedures in Sections 17.3 (Point to Point service) and Section 29.2 (Network service) of the OATT set out the requirement for the submission of an application deposit by the Transmission Customer in an amount approximating the charge for one month of service. This deposit is required to constitute a complete application for transmission service, and is necessary to enter the transmission service study queue. The application deposit is separate from the security required under Section 11 of the OATT which is required once transmission service commences.

The amount of security required for OATT service is not quantified in Section 11. It is to be determined by the Transmission Provider in an amount sufficient to meet the Transmission Customers payment obligations under the OATT. For a LRS receiving transmission service for RtR, the OATT security requirements of Section 11 would be addressed through the Credit Assurance provisions of Section 18 of the LRS Terms & Conditions.

Request IR-7:

With respect to the response to NSUARB IR-5, NSPI provided a rough estimate of costs to be deferred related to the development of this market at $1 million.

(a) Please clarify if these are tax affected estimates, if not, please provide the net deferral NSPI would assign to this.

(b) Would NSPI require Board approval to ensure there is no inappropriate assignment of tax deferrals related to the timing of these deductions?

(c) Will any portion of these be considered a rate base item impacting other customers?

Response IR-7:

(a) The estimate of costs to be deferred of $1 million is not tax affected. Under deferred tax accounting, the net deferral would be $690K reflecting the RtR deferral of $1M, net of a deferred tax liability of $310K.

(b) NS Power will apply to the Board for approval to use deferred tax accounting and to record the deferred tax effect of the RtR spending in the Statement of Earnings in accordance with US Generally Accepted Accounting Principles and in accordance with NS Power's approved accounting policy 5900.04. **Please refer to Attachment 1.**

(c) The deferral will be included in rate base and NS Power will earn a return on the deferral similar to other rate base items however as noted in **NSUARB IR-5**, the inclusion of the cost of financing the deferral in the deferral balance, through the application of the Company's weighted average cost of capital, will offset the cost of financing this asset, similar to other deferrals, thereby not imposing costs on other NS Power customers.

NOVA SCOTIA POWER
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COST OF OPERATIONS

INCOME TAXES - 5900

POLICY

01 Income tax expense should be categorized as current or deferred income tax expense as appropriate.

02 The Company uses the applicable enacted tax rate when measuring current and deferred income tax expense.

03 The Company follows the flow-through method of accounting for investment tax credits (“ITC’s”). ITC’s are recorded in the year earned as a reduction to income tax expense to the extent that realization of such benefit is more likely than not.

04 The Company recognizes deferred income tax assets (liabilities) as appropriate. To the extent deferred income taxes are expected to be recovered from or returned to customers in future rates, the Company will recognize a deferred regulatory asset (liability)[1], unless directed otherwise by the Nova Scotia Utility and Review Board.

FEDERAL INCOME TAXES

05 The Company is subject to federal income tax at prescribed rates applied to taxable income.

PROVINCIAL INCOME TAXES

06 The Company is subject to provincial income tax at prescribed rates applied to taxable income.

PART VI.1 TAX

07 The Company is subject to Part VI.1 tax at a prescribed rate applied to preferred share dividends paid. The Company receives a tax deduction equal to a prescribed multiple of the Part VI.1 tax.

1 FASB ASC 980-740-25-2

INCOME TAXES - 5900

PROCEDURES

08 A monthly income tax provision is recorded by multiplying the Company's effective combined federal and provincial income tax rate forecasted for the year by the net earnings before tax for the period.

09 The net Part VI.1 tax is calculated using enacted rates and recorded as current income tax expense (recovery). The monthly Part VI.1 tax expense is based on the amount of preferred dividends declared in the month. The monthly Part VI.1 tax deduction is based on the annual forecasted Part VI.1 deduction prorated based upon the total preferred dividends declared in a month.

10 The Company currently follows the policy of claiming sufficient capital cost allowance and cumulative eligible capital (the tax system's equivalent of depreciation and amortization), to minimize taxable income.

11 Federal and provincial income taxes, including net Part VI.1 tax, are included in general ledger account 086 - Income Tax Expense.

Request IR-8:

Pre-amble: In NSPI's application, each tariff is referenced to an electronic appendix for support of how the rates are derived. It is challenging to reconcile the various tariffs from the initial revenue requirement/cost of service through to resulting rates. As an example, the Energy Balancing Tariff is presented in Figure 4, referencing Appendix 19A as support, which then references "Appendix C 2014 COS Costs - Exhibit 5; page 1 Energy - Exhibit 9A, line 11, col 3 divided by a transmission loss factor of 1.032".

It is unclear where some of this material is on the record and what costs in the COS result in the tariff rates being requested.

To clarify the supporting information and calculations as well as simplify reconciling the rate build up for each tariff, could you consolidate and reference the backup for each tariff. Please consolidate all such material and supporting calculations, by tariff, as separate attachments to this IR.

Response IR-8:

(1) COSS Model

The COSS Model used to derive some of the rates is provided as **Attachment 1,** provided electronically only. It is unchanged from Application Appendix 11A. References to "COSS Exhibit" sources refer to the Tabs of this workbook.

(2) Distribution Tariff (DT)

Proposed Distribution Tariff	**Attachment 2**
Proof of Revenue	**Attachment 3,** also provided electronically; refers to **Attachment 1**, Tab "Input Data Two", column R. (originally Application Appendix 17A)
Strawman May 21, 2015	**Attachment 4**
Data Requests relating to the Distribution Tariff	**Attachment 5**
Please refer also to these IR responses:	
IRs from Round 1	
Distribution losses	**CA IR-4**
IRs from Round 2	
DT charges	**Multeese IR-11**
Streetlight charges	**Multeese IR-12**

(3) Energy Balancing Services Tariff (EBS)

Proposed EBS Tariff	**Attachment 6**
Top-up Energy Charge Components Fuel Cost (6.650 cents / kWh)	**Attachment 7,** also provided electronically. "Energy Balancing Rate Calc" tab, rows 20-25; Plexos simulation
Fixed Cost Adder (3.309 cents / kWh)	**Attachment** 7 **ELECTRONIC** "Energy Balancing Rate Calc" tab, Rows 27-30 and 34-48 Some numbers are sourced from tabs "Exh 5" and "Exh 9a Annual" of the COSS model in **Attachment 1**.
Spill Energy Credit (5.27 cents / kWh;	**Attachment** 7 **ELECTRONIC**

subject to discount for excess spill)	"Energy Balancing Rate Calc" tab, rows 6-14; Plexos simulation
Administration Charge	**Attachment** 7 **ELECTRONIC** "Customer Charge Calc" tab
Presentation: Proposed Energy Balancing Service and Standby Service for Renewable to Retail	**Attachment 8**
Data Requests relating to EBS	**Attachment 9**
Please refer also to these IR responses:	
IRs from Round 1	
Top-up and Spill	**CA IR-8, 9, 15, 16, 19** **ECI IR-7** **Multeese IR-4** **NSUARB IR-2** **SBA IR-8**
Avoided Costs	**CA IR-10**
Administration Charge	**SWEB IR-7**
Losses	**CA IR-22, 23**
FAM balance	**CA IR-31**
IRs from Round 2	
Top-up and spill	**Multeese IR-7, SBA IR-10**

(4) Standby Service Tariff (SS)

Proposed Standby Service Tariff	**Attachment 10**
Demand Charge $5.370 /month/kW	**Attachment 11**, also provided electronically. Refers to **Attachment 1** COSS tab "Exh 5" and **Attachment 12,** pages 7-8
2013 General Rate Application, DE-03-DE-	**Attachment 12**

04 Appendix L Attachment 3, pages 7 and 8. This is from Exhibit N-3(i) on the UARB Website, under M04972.	
Administration Charge	**Attachment 7**, Tab “Customer Charge Calc”
Data Requests relating to SS	**Attachment 13**
Please refer also to these IR responses:	
IRs from Round 1	
Demand charge	**NSUARB IR-2** **SWEB IR-6**

(5) Renewable to Retail Market Transition Tariff (RTT)

Proposed Renewable to Retail Market Transition Tariff	**Attachment 14**
Rate Derivation Energy Charge • Fixed Cost Adder from EBS, 3.309 cents / kWh	Same as Fixed Cost adder in EBS: **Attachment 7 ELECTRONIC** “Energy Balancing Rate Calc” tab, Rows 27-30 and 34-48 Some numbers are sourced from tabs “Exh 5” and “Exh 9a Annual” of the COSS model in Attachment 1.
Rate Derivation Demand Charge Demand Charge from Standby Tariff $5.370 /month/kW	Same as Demand Charge in SS: **Attachment 11 ELECTRONIC** Refers to **Attachment 1** COSS tab “Exh 5” and **Attachment 12**, pages 7-8
DRs on RTT	Multeese DR-29
Please refer also to these IR responses:	
Round 1 IRs	

NON-CONFIDENTIAL

Demand charge	**CA IR-27, 28, 29**

(6) OATT Schedule 4A

Proposed OATT Schedule 4A	**Attachment 15**
Rationale for OATT Schedule 4A	Multeese DR-33, provided as **Attachment 16**
Please refer also to these IR responses:	
Round 1 IRs	
10% threshold	**CA IR-24**
Round 2 IRs	
10% threshold	**Multeese IR-10**

(7) Sample rate calculations

(a) Unit revenues, under certain assumptions, in cents per kWh - **Application Figure 7, Application Appendix 24,** and **NSUARB IR-9.**

(b) Detailed simulation scenarios under certain assumptions, calculating total tariff charges - **SWEB IR-1 Attachments 1 and 2.**

NSUARB IR-8 Attachment 1 has been provided electronically only.

Nova Scotia POWER An Emera Company

NOVA SCOTIA POWER INCORPORATED

DISTRIBUTION TARIFF

As Approved by the UARB on ●

Nova Scotia Power Distribution Tariff

TABLE OF CONTENTS

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NS Power Distribution Tariff

1. DEFINITIONS

In this Distribution Tariff, the following terms shall have the following meanings:

Act: The *Electricity Act*, S.N.S. 2004, c. 25, as amended from time to time.

Ancillary Services: Services that are necessary to support the transport of capacity and energy from generation resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Board: The Nova Scotia Utility and Review Board.

Bundled Service: Electrical service taken from NS Power under NS Power tariffs approved by the Board. This takes the form of having generation, transmission, distribution, Ancillary Services and all other items associated with the provision of such service blended or bundled within the rate. For certainty, Bundled Service does not include services taken from NS Power under the Distribution Tariff, the Energy Balancing Service Tariff, the Standby Service Tariff or the Renewable to Retail Market Transition Tariff.

Customer Information: Information including, but not limited to, the name, telephone number, mailing address, e-mail address, service address, site contact name, site contact telephone number and information regarding electricity consumption, class of service and payment history of a Retail Customer or an RtR customer, as applicable.

Demand Side Management Recovery Charges: Costs of demand side management programs that NS Power is entitled to recover from RtR Customers.

Distribution System: NS Power's facilities and equipment (generally rated at less than 69 kV) used to distribute electricity to ultimate usage points such as homes and industries either directly from nearby generators or from interchanges from the Transmission System.

Distribution System Access: The services provided by NS Power to the RtR Customer under the Distribution Tariff provide for the connection of the RtR Customer to the Distribution System, but does not include the provision of electricity. These services are comprised of delivery of electricity on the distribution system and related services including connections, disconnections, line and service extensions, inspection services, meter services, power restoration, meter reading, and customer service, all in accordance with applicable NS Power Regulations.

Distribution Tariff: This Distribution Tariff, its terms and conditions and all appendices and attachments referenced herein, including the Distribution Tariff Rate Schedules.

Distribution Tariff Rate Schedules: The rate schedules attached hereto as Appendix A which outline the pricing and availability provisions for Distribution System Access.

DT Charges: This term shall have the meaning set out in Section 11.2.

Good Utility Practice: Those practices, methods or acts (including but not limited to the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America) that at a particular time, in the exercise of reasonable judgment, would have been expected to accomplish the desired result in a manner consistent with regulations, reliability, safety, environmental protection, economy and expedition as applied and practiced in the utility industry with respect to power generation, delivery, purchase and sale.

Licenced Retail Supplier (LRS): A Retail Supplier who:

(a) holds a valid Retail Supplier Licence; and

(b) has a valid LRS Participation Agreement executed with NS Power.

For certainty, a Wholesale Customer is not a Licenced Retail Supplier.

LRS Participation Agreement: The agreement (and any amendments or supplements thereto) between a Licenced Retail Supplier and NS Power with respect to the sale of renewable low-impact electricity by the LRS in the form approved by the Board.

NS Power: Nova Scotia Power Incorporated.

NS Power Regulations: NS Power Regulations approved by the Board pursuant to the *Public Utilities Act* (Nova Scotia) as such regulations may be amended from time to time with the approval of the Board.

Open Access Transmission Tariff (OATT): NS Power's Open Access Transmission Tariff, as approved by the Board.

Province: Province of Nova Scotia

Real Power Losses: Resistive losses occurring as the result of current flow through primary distribution feeders, distribution transformers, secondary conductors and service drops.

Reasonable Efforts: With respect to an action required to be attempted or taken by a party, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a party would use to protect its own interests.

renewable low-impact electricity: This term has the same meaning as in the Renewable Electricity Regulations (Nova Scotia).

Retail Supplier: This term has the same meaning as under the Act.

Retail Supplier Licence: A Retail Supplier licence issued by the Board in accordance with the Act and regulations made thereunder which authorizes a person to sell renewable low-impact electricity generated within the Province.

Retail Customer: This term has the same meaning as under the Act. For certainty, a customer of a municipal utility (as defined under the Act) is not a Retail Customer for the purposes of this Distribution Tariff.

RtR Customer: A Retail Customer who is acquiring renewable low-impact electricity from an LRS at an individual RtR Customer Premises and is not receiving Bundled Service from NS Power at that RtR Customer Premises.

RtR Customer Premises: A premises that is provided with electricity through a single meter and, as the context requires, either:

(a) a complete building such as an office building, factory or house; or

(b) a part of a building such as a suite of offices in an office building or an apartment in an apartment building, and in such cases the part of the building occupied must be contiguous and include no space not controlled by the customer; or

(c) a group of buildings served by one electric service and at its discretion accepted by NS Power as one RtR Customer for LRS billing purposes.

RtR Customer Transaction Request Application: A NS Power document to be used by a Licenced Retail Supplier for the purpose of applying to NS Power to accept and process RtR Customer transactions.

Transmission Provider: NS Power.

Transmission Services: The services obtained by market participants under the terms and conditions of the OATT to access the Transmission System for the purpose of transporting electric energy and Ancillary Services.

Transmission System: The facilities, generally rated at 69 kV and above, owned, controlled or operated by the Transmission Provider that are used to provide transmission service under the OATT.

Wholesale Customer: This term has the same meaning as under the Act.

2. PURPOSE OF THE DISTRIBUTION TARIFF

In accordance with the provisions of the Act and the regulations made thereunder, NS Power will, subject to the terms of this Distribution Tariff, provide Distribution System Access to RtR Customers to enable the connection of the RtR Customer to the Distribution System.

3. SCOPE OF THE DISTRIBUTION TARIFF

The Distribution Tariff is applicable to all RtR Customers connected to the Distribution System.

This Distribution Tariff is not applicable to RtR Customers directly connected to the Transmission System. Transmission-connected RtR Customers must have their Transmission System access arranged by the LRS under the provisions of the OATT.

The Distribution Tariff outlines the terms and conditions that apply to the provision of Distribution System Access to RtR Customers.

The Distribution Tariff Rate Schedules apply to the provision of Distribution System Access.

4. BOARD APPROVAL

The Distribution Tariff has been approved by the Board.

Nothing contained in the Distribution Tariff shall be construed as affecting in any way the right of NS Power to make application to the Board for a change in any rates (including the Distribution Tariff Rate Schedules), terms and conditions, charges, classification of service, rules or regulations.

5. APPENDICES

For greater certainty, Appendix A attached hereto forms part of the Distribution Tariff.

6. APPLICABILITY OF NS POWER REGULATIONS TO THE RTR CUSTOMER

The NS Power Regulations apply to an RtR Customer receiving Distribution System Access.

7. NS POWER RESPONSIBILITIES

NS Power shall be responsible for:

(a) provision of Distribution System Access;

(b) processing RtR Customer Transaction Request Applications that are received from an LRS on behalf of the RtR Customer;

(c) providing billing data for the RtR Customer's Distribution Tariff charges for inclusion on the RtR Customer's invoice; and

(d) acting as the point of contact for RtR Customers for matters related to the provision of Distribution Access Service.

NS Power shall not be responsible to the RtR Customer for the supply of electricity (whether renewable low-impact electricity or otherwise) which the RtR Customer shall be obligated to obtain from an LRS.

NS Power shall not be responsible for monitoring, reviewing or enforcing contracts or arrangements between the RtR Customer and the LRS and shall not be liable for any loss, damages, cost, injury, expense or other liability, whether direct, indirect, consequential or special in nature, howsoever caused, as a result of the LRS's failure to perform its obligations to its RtR Customer(s).

8. RtR CUSTOMER RESPONSIBILITIES

The RtR Customer shall be responsible for:

(a) payment of all fees and charges arising in connection with the Distribution Tariff;

(b) compliance with the terms and conditions of the Distribution Tariff and the NS Power Regulations;

(c) obtaining a supply of renewable low-impact electricity from an LRS; and

(d) all contractual arrangements with an LRS for the supply of renewable low-impact electricity.

9. INTERRUPTION OF DISTRIBUTION SYSTEM ACCESS

Notwithstanding any term of this Distribution Tariff, NS Power shall have the right to suspend or interrupt, in whole or in part, the provision of Distribution System Access for the purpose of safeguarding life or property, for making repairs, changes, renewals, improvements or replacements to the Distribution System provided NS Power shall make Reasonable Efforts to ensure all such suspensions or interruptions are of a minimum duration consistent with the exigencies of the case, provided, however, any such suspensions or interruptions shall not release the RtR Customer from its obligation to pay all charges pursuant to this Distribution Tariff during the period of any such suspensions or interruption and to resume the use of power and energy when the supply is restored.

9A. LIMITATION OF LIABILITY

(a) NS Power shall not be responsible for any claim, loss, cost, liability, action, judgment, suit, proceeding, expense, disbursement or damage whatsoever arising, either directly or indirectly, whether in contract or tort (including negligence) or otherwise, in respect of any interruptions, diversions, curtailments, or other procedures necessary to maintain the efficient and effective operation of the Distribution System or the Transmission System. This would include all Distribution Access Service as permitted by this Distribution Tariff.

(b) NS Power not liable for damages in respect of any delay, interruption or other partial or complete failure in supplying Distribution System Access where such damages are caused by something which is beyond the ability of the Company to control by reasonable and practicable effort.

(c) Notwithstanding any other provision herein or applicable law to the contrary, NS Power shall not be liable for:

i. any indirect or consequential loss or incidental or special damages, including, without limitation, any punitive or aggravated damages;

ii. any loss of profit, loss of contract, loss of opportunity or loss of goodwill; or

iii. damages for loss of use,

arising, directly or indirectly, with the performance or delivery of the Distribution Access Service or any other obligations of NS Power under this Distribution Tariff, including but not limited to interruptions, diversions, curtailments or suspensions of any of the Distribution Access Services or from any acts or omissions of its employees and agents, and whether arising in contract, indemnity, tort (including negligence) or any other legal theory.

10. METERING

10.1. Provision and Ownership

NS Power will provide, install and seal all revenue class meters as necessary for application of this Distribution Tariff. The meters will be used for determining charges for Distribution System Access under the Distribution Tariff applicable to the RtR Customers.

Interval meters with remote polling capability shall be installed for all RtR Customers.

All meters and associated revenue metering equipment shall remain the property of NS Power. All revenue metering equipment installations shall meet the requirements under the Electricity and Gas Inspection Act regulations in effect at the time.

RtR Customer metering requirements are set out in the NS Power Regulations Section 4 - Metering.

10.2. Meter Reading

RtR Customer meter reading requirements are set out in NS Power Regulations Section 5 – Meter Reading and Billing.

11. BILLING

11.1. Application of Distribution Tariff Rates

The Distribution Tariff amounts payable by the RtR Customer will be calculated by NS Power using the RtR Customer's meter readings and the Distribution Tariff Rate Schedule applicable to the RtR Customer's rate class.

If the operational or consumption characteristics of the RtR Customer change, such that the RtR Customer, in NS Power's determination, no longer qualifies for its current rate class, NS Power shall apply a Distribution Tariff rate appropriate to the RtR Customer's new operational or consumption characteristics.

11.2. Billing

Unless NS Power directs otherwise, the RtR Customer shall be invoiced by the LRS and will pay the LRS for any charges or fees, inclusive of all applicable taxes, owing by the RtR Customer to NS Power under this Distribution Tariff (DT Charges).

For greater certainty, the DT Charges shall include:

(a) All fees and charges for the provision of Distribution System Access under this Distribution Tariff;

(b) Demand Side Management Recovery Charges;

(c) any applicable costs incurred by NS Power resulting from performance of repairs, changes, renewals, improvements or replacements outside of normal working hours, at the RtR Customer's request; and

(d) Other items as may be approved by the Board.

NS Power may, at its discretion, include fees for any special customer services provided at the LRS's or the RtR Customer's request, pursuant to NS Power Regulation 7.1 - Schedule of Charges.

The RtR Customer consents to NS Power providing the LRS with Customer Information for the purposes of facilitating the billing arrangements between the LRS and the RtR Customer.

The RtR Customer acknowledges and agrees that unless NS Power directs otherwise, it shall be responsible to the LRS with respect to all matters relating to the payment and collection of the DT Charges and any other amounts owing by it under this Distribution Tariff.

The RtR Customer shall not make or bring any claim, action or demand against NS Power arising out of or in any way attributable to the collection of the DT Charges by the LRS, its servants, agents or employees.

11.3. Real Power Losses

Distribution System Real Power Losses associated with Distribution System Access are incorporated in the Distribution Tariff rates applicable to each RtR Customer's rate class. The RtR Customer is responsible for the costs of such Real Power Losses.

12. DISCONTINUANCE OF DISTRIBUTION SYSTEM ACCESS BY NS POWER

For certainty, NS Power may discontinue Distribution System Access to an RtR Customer in accordance with the requirements of NS Power Regulations Section 6 – Collection of Accounts, Regulations 6.1 - Disconnection of Electric Service, 6.2 - Rules Governing Disconnection and 6.3 - Medical Emergency.

APPENDIX A: DISTRIBUTION TARIFF RATE SCHEDULES

NOVA SCOTIA POWER INCORPORATED

*DISTRIBUTION TARIFF RATES**

Note: For certainty, all capitalized terms shall, unless otherwise defined herein, have the meanings ascribed thereto in Distribution Tariff.

APPLICABILITY

This schedule provides charges for Distribution System Access applicable to distribution-connected RtR Customers receiving supply of renewable low-impact electricity from a Licenced Retail Supplier as provided for under the Electricity Act (Nova Scotia).

CHARGES

Rate Class	**Customer Charge**	**Distribution Charge**	**Demand Charge**	**Minimum Monthly Charge**	**Transformer Ownership Credit**
	$/month	**¢/kWh**	**$/kVA**	**$/month**	**$/kVA**
Domestic Service	10.83	2.549	0.000	10.83	0
Domestic Service Time of Day	10.83	2.549	0.000	10.83	0
Small General	12.65	2.362	0.000	12.65	0
General (1)	0	0.000	5.458	12.65	-0.32
Large General (2)	0	0.000	3.361	12.65	-0.32
Small Industrial	0	0.000	4.494	12.65	-0.32
Medium Industrial	0	0.000	3.496	12.65	-0.32
Large Industrial Firm (2) Rate Code 23	0	0.000	2.430	12.65	-0.32
Outdoor Recreational Light Rate	0	3.551	0.000	0	0
Unmetered Service Rates	0	0.000	11.960	17.51	0
Miscellaneous Small Loads	0	0.000	11.960	17.51	0

Footnotes

(1) Demand Charges and credits are applicable to kilowatt (kW) demand.
(2) Demand Charges and credits are applicable to kilovolt-ampere of maximum (kVA) demand of the current month or the maximum actual demand of the previous December, January or February occurring in the previous eleven months regardless whether service was taken under the bundled or unbundled service.

PROPOSED: September 1, 2015 EFFECTIVE:

NOVA SCOTIA POWER INCORPORATED

DISTRIBUTION TARIFF RATES*

MAXIMUM PER KWH CHARGE/MINIMUM BILL

The same maximum per kWh charges and minimum bills will apply as stated in tariffs for NS Power Bundled Service for each Rate Class listed above.

AVAILABILITY

The same Availability conditions will apply as stated in tariffs for NS Power Bundled Service for each Rate Class listed above, saving and excepting the Interruptible Rider to the Large Industrial Tariff (Rate Code 25) which will not apply.

SPECIAL CONDITIONS

The same Special Conditions will apply as stated in tariffs for NS Power Bundled Service for each Rate Class listed above, saving and excepting the Interruptible Rider to the Large Industrial Tariff (Rate Code 25) which will not apply.
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NOVA SCOTIA POWER INCORPORATED

*DISTRIBUTION TARIFF RATES**

(A) **STREET AND AREA LIGHTING**

RATES

(1) **INCANDESCENT**

Rate Code	Watts	kWh/Mo.	$/Mo.	Other
a) Operating, Maintenance and Capital (Full Charge)				
001	300 and less	97	$10.78	
002	Greater than 300	154	13.09	
b) Operating Only				
003	300 and Less	97	3.74	

(2) **MERCURY VAPOUR**

Rate Code	Watts	kWh/Mo.	$/Mo.	Other
a) Operating, Maintenance and Capital (Full Charge)				
100	100	43	$10.03	
101	125	52	11.88	
102	175	69	10.77	
103	250	97	12.59	
104	400	154	14.86	
105	700	260	20.14	
106	1000	363	25.15	
107	250	212	17.74	Continuous Operation
b) Operating and Maintenance Only				
201	125	52	$8.87	
202	175	69	7.80	
203	250	97	8.90	
204	400	154	11.09	
205	700	260	15.19	
206	1000	363	19.17	
c) Operating Only				
301	125	52	$2.00	
302	175	69	2.64	
303	250	97	3.74	
304	400	154	5.93	

PROPOSED: September 1, 2015 EFFECTIVE:

NOVA SCOTIA POWER INCORPORATED

*DISTRIBUTION TARIFF RATES**

305	700	260	10.03
306	1000	363	14.01

(3) **FLUORESCENT**

Rate Code	Bulb Length	Number of Bulbs/Unit	kWh/Mo.	$/Mo.	Other
a)	Operating, Maintenance and Capital (Full Charge)				
110	24	2	30	13.91	
111	48	2	85	16.28	
112	72	2	116	17.96	
113	72	4	222	23.16	
114	96	1	47	15.08	
115	72	1	60	15.21	
116	48	4	166	19.99	
b)	Operating and Maintenance Only				
213	72	4	222	$18.86	
214	96	1	47	12.11	
215	72	1	60	12.63	
216	48	4	166	16.74	
217	48	1	49	12.18	
218	48	2	85	13.59	
c)	Operating Only				
330	35	4	47	1.80	

NOVA SCOTIA POWER INCORPORATED

*DISTRIBUTION TARIFF RATES**

(4) **FLUORESCENT CROSSWALK**

a) Continuous Burning - Operating Only

117	72	4	486	$8.56
118	24	2	66	1.15
119	48	4	364	6.43
120	96	2	254	4.49
150	96	4	613	10.80

PROPOSED: September 1, 2015 EFFECTIVE:

NOVA SCOTIA POWER INCORPORATED

*DISTRIBUTION TARIFF RATES**

(4) **FLUORESCENT CROSSWALK (cont.)**

b) Photocell Operation - Operating Only

310	24	2	30	$1.17
311	48	4	166	6.43
312	72	2	116	4.50
313	72	4	222	8.55
314	96	1	47	1.80
315	72	1	60	2.32
350	96	4	280	10.82

(5) **LOW PRESSURE SODIUM**

Rate Code	**Watts**	**kWh/Mo.**	**$/Mo.**	**Other**
a) Operating, Maintenance and Capital (Full Charge)				
130	135	60	$23.58	
131	180	80	26.94	
132	90	45	22.99	
b) Operating and Maintenance Only				
231	180	80	18.56	
c) Operating Only				
331	180	80	3.09	

(6) **HIGH PRESSURE SODIUM**

a) Operating, Maintenance and Capital (Full Charge)

121	250	100	$12.23	
122	400	150	14.28	
123	70	32	9.41	
124	100	45	9.93	
125	150	65	10.89	
126	100	99	15.08	Continuous Operation

PROPOSED: September 1, 2015 EFFECTIVE:

NOVA SCOTIA POWER INCORPORATED

*DISTRIBUTION TARIFF RATES**

(6) **HIGH PRESSURE SODIUM (**cont'd)

Rate Code	Watts	kWh/Mo.	$/Mo.	Other
b) Operating and Maintenance Only				
221	250	100	$9.02	
222	70	32	6.39	
223	100	45	6.89	
224	150	65	7.67	
c) Operating Only				
321	250	100	$3.86	
322	70	32	1.23	
323	100	45	1.73	
324	150	65	2.51	
326	400	150	5.79	
327	500	183	7.07	
328	1000	363	14.02	
329	1500	500	19.30	

(7) **METALLIC ADDITIVE**

Rate Code	Watts	kWh/Mo.	$/Mo.	Other
a) Operating, Maintenance and Capital (Full Charge)				
140	400	150	$17.85	
141	1000	360	31.83	
142	250	100	19.98	
143	150	67	18.70	
144	100	50	18.05	
b) Operating Only				
341	1000	360	$13.89	
342	400	150	5.79	
343	250	100	3.86	
344	175	75	2.89	
345	150	67	2.58	
346	100	50	1.93	

PROPOSED: September 1, 2015 EFFECTIVE:

NOVA SCOTIA POWER INCORPORATED

*DISTRIBUTION TARIFF RATES**

(8) **LIGHT EMITTING DIODE (LED) LESS THAN 30 WATTS FOR TRAFFIC CONTROL SIGNALS ONLY**

Rate Code	$/Mo.	Other
530	$0.06	Non – Continuous
531	$0.09	Continuous

(9) **LIGHT EMITTING DIODE (LED) – Operating Only**

Rate Code	Watts	kWh/Mo.	$/Mo.
532	44	15	$0.58
533	66	22	0.85
534	88	29	1.12
535	92	31	1.20
536	105	35	1.35
537	170	57	2.20
539	110	37	1.43
540	65	22	0.85
541	55	18	0.69
542	83	28	1.08
543	48	16	0.62
544	72	24	0.93

(10) **INTERIM LIGHT EMITTING DIODE (LED) – Operating & Capital Only***

Rate Code	Watts	kWh/Mo.	$/Mo.	Other
615	44	15	$7.85	
616	55	18	7.96	
623	28	9	7.62	
624	50	17	7.93	
625	72	24	8.20	
626	100	33	8.54	
627	200	67	9.86	

* While fixture maintenance costs associated with LED streetlights may occur, this component is currently not reflected in the rates.

PROPOSED DISTRIBUTION TARIFF AS BASED ON 2014 COSS

RESIDENTIAL TARIFFS

		units	Current Bundled Rate	Proposed Distribution Rate	% change
Domestic Service Rate					
Customer Charge		$/mo	10.830	10.830	0.0%
Energy Charge		¢/kWh	14.251	2.549	-82.1%
Domestic Service TOD Rate					
Customer Charge		$/mo	18.820	10.830	-42.5%
December, January & Feb: energy charge					
	on-peak	¢/kWh	18.609	2.549	-86.3%
	shoulder	¢/kWh	14.251	2.549	-82.1%
	off-peak	¢/kWh	7.324	2.549	-65.2%
Other months: energy charge					
	on-peak	¢/kWh	14.251	2.549	-82.1%
	off-peak	¢/kWh	7.324	2.549	-65.2%

COMMERCIAL TARIFFS

	units	Current Bundled Rate	Proposed Distribution Rate	% change
Small General Rate				
Customer Charge	$/mo	12.650	12.650	0.0%
Energy Charge, block 1 (first 200 kWhs)	¢/kWh	15.092	2.362	-84.3%
Energy Charge, block 2	¢/kWh	13.278	2.362	-82.2%
General Rate				
Demand Charge	$/kW	10.497	5.458	-48.0%
Energy Charge, block 1 (first 200kWh * demand)	¢/kWh	11.208	-	-100.0%
Energy Charge, block 2	¢/kWh	7.929	-	-100.0%
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	0.0%
Large General Rate				
Demand Charge (Ratcheted)	$/kVA	13.345	3.361	-74.8%
Energy Charge	¢/kWh	8.029	-	-100.0%
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	0.0%

INDUSTRIAL TARIFFS

	units	Current Bundled Rate	Proposed Distribution Rate	% change
Small Industrial Rate				
Demand Charge	$/kVA	7.714	4.494	-41.7%
Energy Charge, block 1 (first 200 kWhs * demand)	¢/kWh	10.090	-	-100.0%
Energy Charge, block 2	¢/kWh	7.707	-	-100.0%
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	0.0%
Medium Industrial Rate				
Demand Charge	$/kVA	12.501	3.496	-72.0%
Energy Charge	¢/kWh	7.241	-	-100.0%
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	0.0%

Large Industrial Rate				
Demand Charge (Ratcheted)	$/kVA	11.995	2.430	-79.7%
Energy Charge to firm Customers	¢/kWh	7.620	-	-100.0%
Energy Charge to interruptible customers		7.222	-	-100.0%
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	0.0%
Interruptible Credit	$/kVA	(3.430)	(3.430)	0.0%

OTHER TARIFFS

Outdoor Recreational Light Rate	**units**	**Current Bundled Rate**	**Proposed Distribution Rate**	**% change**
Energy Charge	¢/kWh	14.354	3.551	-75.3%
Miscellaneous Small Loads Rate				
Demand Charge	$/kW	11.777	11.960	1.55%
Energy Charge, block 1 (first 200kWh * demand)	¢/kWh	13.467	-	-100.00%
Energy Charge, block 2	¢/kWh	8.941	-	-100.00%

September 1, 2015 Note: this is a revision to the
Spreadsheet issued as Attachment D on May 21, 2015.
Refer to Multeese DR-21 issued July 3, 2015

Proposed Distribution Tariffs	Distribution Usage in KWhs			Demand in kWs or kVa			Base Charge			PROPOSED
Above-the-line Classes	Energy in GWh -	Per KWh Charge	Revenue	GWS or GVAS	Charge per KW or KVA	Revenue	Billmonths (in millions)	Base Charge	Revenue	RATES FORECAST 2014
Residential Sector										
Non-ETS	3,993.3	$ 0.02549	$ 101.8	NA	NA	NA	5.1	$ 10.83	$ 55.4	**$ 157.2**
ETS	223.2	$ 0.02549	$ 5.7	NA	NA	NA	0.1	$ 10.83	$ 1.6	**$ 7.3**
Total	**4,216.5**		**$ 107.5**	**NA**	**NA**	**NA**	**5.3**		**$ 56.99**	**$ 164.5**
Commercial Sector										
Small General	236.7	$ 0.02362	$ 5.6	-		$ -	0.3	$ 12.65	$ 3.6	**$ 9.2**
General Demand	2,448.7	NA	NA	7.0	$ 5.458	$ 38.2	-	$ -	$ -	**$ 38.2**
Large General										
Without Trans. Own.	245.8	NA	NA	0.5	$ 3.361	$ 1.7				**$ 1.7**
With Trans. Own.	133.8	NA	NA	0.3	$ 3.041	$ 1.0				**$ 1.0**
Sub-total	379.6	NA	NA	0.9		$ 2.8				**$ 2.8**
Total	**3,065.0**		**$ 5.6**	**7.9**		**$ 41.0**	**0.3**		**$ 3.6**	**$ 50.2**
Industrial Sector										
Small Industrial	255.9	NA	NA	1.0	$ 4.494	$ 4.5				**$ 4.5**
Medium Industrial	495.4	NA	NA	1.4	$ 3.496	$ 5.0				**$ 5.0**
Large Industrial Firm		NA	NA							
Without Trans. Own.	46.3	NA	NA	0.1	$ 2.430	$ 0.3				**$ 0.3**
With Trans. Own.	-	NA	NA	-	$ 2.110	$ -				**$ -**
Sub-total	46.3	NA	NA	0.1		$ 0.3				**$ 0.3**
Large Industrial Interr.										
Without Trans. Own.	176.4	NA	NA	0.5	$ 2.430	1.2				**$ 1.2**
With Trans. Own.	52.8	NA	NA	0.3	$ 2.110	0.6				**$ 0.6**
Sub-total	229.1	NA	NA	0.8		1.8				**$ 1.8**
Total Large Industrial	**275.4**	**NA**	**NA**	**0.89**		**$ 2.1**				**$ 2.1**
Total Industrial	**1,026.7**	**NA**	**NA**	**3.3**		**$ 11.6**	**0.0**		**0.0**	**$ 11.6**
Other										
Unmetered [1,2]										
Electric Service Only	98.2	$ 0.03551	$ 3.5							**$ 3.5**
Street light Fixtures										**$ 8.8**
Total										**$ 12.2**
Total Above-the-line	**8,406.5**		**$ 116.6**	**11.2**		**$ 52.6**	**5.5**		**$ 60.6**	**$ 238.5**

(1) Illustrates energy for unmetered customers, as well as LED and Non-LED Streetlights

(2) Per kWh charge is not applicable as the class is made up of a number of rates

Nova Scotia Power Inc.

2015 Renewable to Retail Proceeding

Distribution Tariff Rate Strawman Report

DRAFT – subject to NS Power management review and approval

May 21, 2015

Nova Scotia POWER An Emera Company

TABLE OF CONTENTS

ATTACHMENTS

1.0 INTRODUCTION

This Strawman Report discusses the process and methodology used by Nova Scotia Power (NS Power, the Company) in development of a distribution tariff (DT) applicable to Renewable to Retail (RtR) Customers[1].

The DT is being developed in consultation with stakeholders consistent with s. 3G (1) of the Electricity Act (Nova Scotia) (Act). The Company is seeking to arrive at a consensus among the Company and stakeholders in advance of the Company's filing with the UARB.

The DT is intended for use by distribution-connected RtR customers. It includes terms, conditions and rates under which Distribution System Access will be provided. The DT design is consistent with the cost allocation and tariff design included in rates for customers who continue to take bundled electric service from NS Power.

1.1 Terms and Conditions

The DT contains both rates and terms and conditions. NS Power based the terms and conditions in the DT on existing approved documents, adjusting them for the unique features and participants in the Renewable to Retail Market. RtR Customers who take Distribution System Access are also subject to NS Power Regulations[2] as applicable.

[1] A RtR Customer is a Retail Customer purchasing renewable energy from a Licensed Retail Supplier. A RtR customer is a subset of "Retail Customer" defined under s. 2(1) of the *Electricity Act* (Nova Scotia) as "…a person who uses, for the person's own consumption in the Province, electricity that the person did not generate." . Licensed Retail Suppliers (LRS) LRSs are persons who are licensed by the Nova Scotia Utility and Review Board (UARB, Board) to sell renewable low-impact electricity, as provided for under the Electricity Act (Nova Scotia) (Act).

[2] NS Power Regulations are approved by the UARB and may be found at http://www.nspower.ca/en/home/about-us/electricity-rates-and-regulations/rates/default.aspx

Attachment A contains the Draft Distribution Tariff Terms and Conditions. **Attachment B** contains the Draft Distribution Tariff Rates.

RtR Customers purchase electricity from Licensed Retail Suppliers (LRS) who supply renewable low-impact electricity generated in Nova Scotia. Each LRS will be licensed by the UARB and will be subject to other tariffs, rules and procedures governing use of the NS Power system and NS Power tariffed services. Those tariffs, rules and procedures will also be developed in consultation with stakeholders and submitted for approval to the UARB.

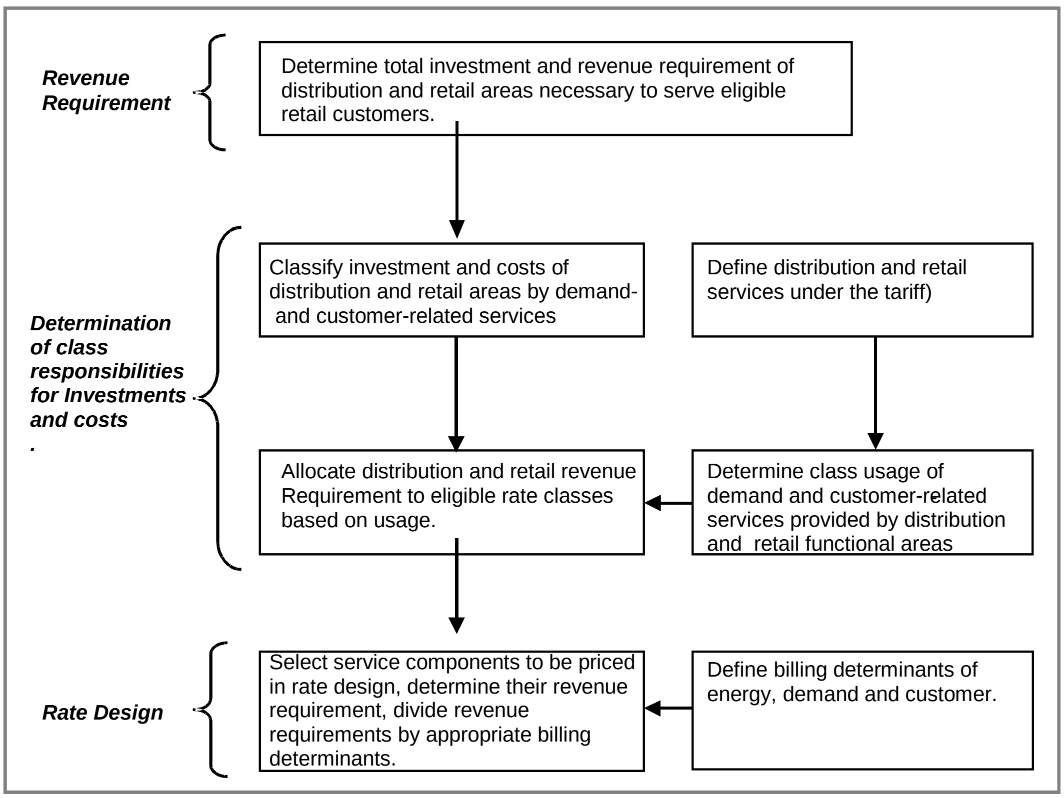
1.2 Rates

In the development of the DT Rates, the Company sought to leverage the existing ratemaking processes used in the Open Access Transmission Tariff (OATT) and General Rate Applications (GRA) while seeking an appropriate balance among competing ratemaking objectives. The Company sought to design rates which are cost based, fairly apportion cost responsibilities among customer classes and customers within each class, are simple and transparent and do not negatively affect NS Power's bundled service customers.

2.0 DISTRIBUTION TARIFF RATE DEVELOPMENT PROCESS

The proposed form of the DT Rates is provided as **Attachment B**. The DT defines the terms, conditions and prices under which eligible distribution-connected RtR Customers can gain access to NS Power's distribution system in the Renewable to Retail Market created under the Act. In the development of the DT, NS Power employed a sequential three step process, used in regulated, cost causative ratemaking, as illustrated in Figure 1.

Figure 1: Overview of the Steps taken in the Development of Distribution Rates



The Company used the most recent Cost of Service Study[3] (COSS) which employed the 2014 Test Year revenue requirement from the 2013 GRA Compliance Filing[4], for the determination of class responsibilities for investments and costs of distribution and retail areas. The COSS is provided as **Attachment C**. The COSS used the following three step process:

- Functionalization of investments and costs by the areas of Distribution and Retail
- Classification of functionalized costs between demand-related and customer-related services
- Allocation of classified costs among the eligible rate classes

The proposed approach to the recovery of distribution and retail costs aligns with those in use in other North American jurisdictions[5].

[3] The Cost of Service Study was filed as part of NS Power's Compliance filing in the Cost of Service proceeding, M05473, July 31, 2014. Please note, several elements of COS were deferred after the Cost of Service Decision for further study and consultation, which may change the total revenue requirement of the Distribution and Retail area and individual class cost responsibilities. Please refer to NS Power 2014 Cost of Service Study Progress Update M06555, Exhibits N-1 and N-2.
[4] 2013 General Rate Application, P-893/M04972, NS Power Compliance Filing, January 16, 2013.
[5] NS Power reviewed Distribution Tariffs from the following utilities: Enmax Power Corporation, EPCOR Utilities Incorporated, ATCO Electric, Milton Hydro Distribution Inc., Appalachian Power Company, Ohio Power Company, Pacific Gas and Electric Company, Southern California Edison.

3.0 DISTRIBUTION AND RETAIL SERVICES

The substantial majority of customers can accept power only at much lower voltage levels of service than that used in transmission.[6] The purpose of the distribution system is, therefore, to connect customers served at a distribution voltage level with the transmission grid.

The Primary Distribution System routes power closer to the majority of customers at moderate voltages in order to minimize electricity losses. Using moderate voltage levels for Primary, while approaching the voltage levels which most customers can accept, reduces amperage and therefore losses. NS Power's Primary Level Distribution System has nominal voltages of 4 kV, 12 kV and 25 kV. There are about 350 customers served at a primary voltage level representing about 20% of the total distribution load. The remaining 80% of the distribution system load enters the secondary voltage lines via distribution line transformers to be delivered to half a million NS Power customers. The assets supporting this last activity consist of Secondary Service conductors and poles and the customers' meters. The majority of NS Power customers take service directly from the distribution transformer low voltage bushings or from secondary lines originating at the transformer.

NS Power segments its investments (rate base) and costs into four functional areas: Generation, Transmission, Distribution, and Retail. The Distribution Tariff applies only costs from the Distribution and Retail areas, not Generation or Transmission. Costs relating to Generation and Transmission are covered in separate tariffs applicable to the Licensed Retail Supplier. The Distribution function is separated into three voltage-differentiated service levels:

- Bulk Power Substations

[6] There are currently ten bundled service transmission-connected customers at NS Power.

- Primary Service (4-25 kV)
- Secondary Service (less than 4 kV).

The Cost of Service (COS) model's functionalization approach also includes a "direct" component that contains rate base and cost elements attributed to street lighting services under the Unmetered Service rate class. General Plant and Property is apportioned among the four functional areas based on their relative shares in the total plant in service. Working Capital is apportioned among the functional areas on the basis of their relative shares in the total plant in service or operational costs already recorded by functional areas. For the purpose of the DT analysis, streetlight assets and costs are kept separate from the remaining distribution rate bases and costs.

The current COSS sub-functionalizes its distribution investment categories in the following manner:

Figure 2: Summary of Distribution Plant in Service by Voltage Service Levels (Thousands of dollars)

DISTRIBUTION PLANT FOR THE YEAR ENDING DECEMBER 31, 2014 (IN THOUSANDS OF DOLLARS)				
	(1)	(2)	(3)	(4)
PLANT	SHARED INVESTMENT BY VOLTAGE-SERVICE LEVELS			TOTAL
	BULK POWER SUBSTATION	PRIMARY	SECONDARY	
LAND	346	2,623	1,465	4,435
EASEMENTS & SURVEY	1,319	9,985	5,578	16,882
OTHER	171	1,295	724	2,190
SUBSTATIONS	26,128	3,985	0	30,113
POLES & FIXTURES		119,005	64,080	183,085
O.H. LINES		78,818	42,441	121,259
U.G. LINES		22,658	12,200	34,858
LINE TRANSFORMERS		0	163,242	163,242
SERVICES		0	60,998	60,998
METERS	21	606	24,445	25,072
STREET LIGHTING (DIRECT)		0	34,507	34,507
TOTAL DIST. PLANT	27,985	238,976	409,680	676,641
GEN. PROPERTY PLANT	2,013	17,193	29,474	48,680
TOTAL BFR WORKING CAPITAL	29,999	256,169	439,153	725,321
WORKING CAPITAL				68,081
TOTAL				793,401

The retail area, under bundled service, includes customer care services such as metering, billing, wiring inspections, responding to customer inquiries, credit services, marketing and sales. The investments associated with COS retail areas such as computer systems, office equipment and general buildings are assigned to other functional areas.

If Retail costs increase or decrease as a result of the introduction of Renewable to Retail, these changes will be reflected in the future DT rates.

4.0 CUSTOMER CLASSES APPLICABLE TO DISTRIBUTION TARIFF SERVICES

4.1 Above the Line Rates

Embedded Cost of Service Studies are conducted for nine retail rate classes and one wholesale class. The retail rate classes include:

- two Residential classes
- three General Service classes
- three Industrial classes
- Unmetered Service class

The two Residential classes, Domestic Service and Domestic Service Time of Day (DTD) are combined into one category for the COSS; however, they are billed under two separate tariffs. The Unmetered rate class includes about 100 published streetlight rates and a few hundred unpublished, customized miscellaneous small load rates designed to meet individual customer needs.

Renewable to Retail service is not applicable to the Wholesale Municipal Class. Wholesale customers[7] are excluded under the Act from being an LRS. There are six wholesale municipal customers served under this class. Four of them are supplied at a distribution voltage level. Since the total COS-based distribution rate base includes these customers, for the DT analysis the distribution rate base must be adjusted to remove rate base costs apportioned to wholesale municipal customers.

[7] Section 2(1)(aaa) of the Act defines a "municipal utility" as "the Board of Commissions of the Berwick Electric Commission, The Electric Light Commissions for Riverport, in the Count of Lunenburg or an electric utility of the Municipality of the District of Guysborough, the Town of Antigonish, the Town of Lunenburg or the Town of Mahone Bay." Section 2(1)(d) of the Act defines a "wholesale customer" as "Nova Scotia Power Incorporated or a municipal utility." Section (2) (1)(c) of the Act specifies that a "wholesale customer" is not a "retail supplier".

There are also seven transmission-connected Large Industrial Customers who are eligible for the Renewable to Retail market but to whom the DT does not apply.

The ten classes above are responsible for all the "above the line" (ATL) rate base and operating expenses of the Company. The summaries of annual usage and costs of these classes are included in COSS Exhibits 9A Annual, 9B, and 10 in Attachment E.

4.2 Below the Line Rates

The Company also provides optional pricing to large customers under formula-based rates. These rates receive accounting treatment outside the COS process, and are deemed to be "below the line" (BTL).[8] If a distribution-connected customer on a BTL rate opts to purchase electricity from a LRS, the corresponding DT rate for the applicable bundled ATL service will apply.

[8] The rates include three 1P-RTP tariffs, Generation Replacement and Load Following, Shore Power Rate and Load Retention Rate.

5.0 REVENUE REQUIREMENT OF DISTRIBUTION AND RETAIL AREAS

The first step in designing the DT rates was to determine the appropriate revenue requirement for the provision of Distribution and Retail Services. From the financial records of the Company, net plant investment is readily identifiable for the Power Production, Transmission, and Distribution functions. Most of the expenses for operations and maintenance for Power Production, Transmission, Distribution and Retail are also readily identifiable. However, there are several components of plant, depreciation and expenses that are not identified by these functional areas. Also, corporate overhead expenses and miscellaneous revenue credits are not tracked by functional areas and must be functionalized in the COSS prior to classification and allocation of costs.

The total distribution and retail revenue requirement of Retail Customers, excluding the capital component of the Light Emitting Diode (LED) fixtures[9] and the distribution-related revenue requirement of the Municipal class, is $238.4 million for 2014.

[9] For the 2012 and 2013 GRAs, the LED fixture costs were proposed to be treated as a BTL item, determined outside of the COSS, due to uncertainty in their estimates ahead of the LED Capital Work Order submission.[NTD LED work order to be filed soon]

Figure 3: Summary of Revenue Requirement of Distribution and Retail Areas (Thousands of dollars)

Revenue Requirement Component	**All Distribution Customers**	**Retail Customers Only**		
		Electric Service only	**Streetlight Fixtures (non-LED)**	**Total**
Distribution				
Depreciation	56,309	54,191	1,924	56,116
O&M including corporate overhead costs	66,773	60,607	5,825	66,433
Interest, taxes and return on equity	67,093	65,705	1,000	66,705
Miscellaneous Revenue	-2,028	-1,907	0	-1,907
Distribution Total	**188,147**	**178,596**	**8,750**	**187,346**
Retail(1)	**51,358**	**51,088**	**0**	**51,088**
Total	**239,506**	**229,684**	**8,750**	**238,434**

(1) Excludes retail costs of $271,000 of transmission connected Large Industrial and Municipal customers.

Overhead corporate costs assigned to Distribution and Retail, and credits associated with miscellaneous revenues are still being finalized as they were elements of the 2013 Cost of Service proceeding deferred for further study.[10] The overhead costs currently assigned to the Distribution and Retail areas are $43.9 million. The miscellaneous revenues assigned to the Distribution and Retail areas are $10.1 million.

A detailed breakdown of the revenue requirement is included in Exhibits 4, 4 Detail A, and 5 of COSS in **Attachment C**.

[10] Please refer to M05473, Decision 2014 NSUARB 53, pages 44-45.

In its proposed approach, NS Power used the revenue requirement of the Distribution and Retail areas, as predicated on the 2014 Test Year revenue requirement before accounting for a deferral of $83.3 million of fixed costs, which were used to set the current bundled service rates under the two-year Rate Stabilization Plan. The proposed revenue requirement treatment of the DT aligns with that of OATT in the 2013 GRA.

6.0 CLASSIFICATION OF REVENUE REQUIREMENT

NS Power's distribution investments and costs are classified into demand-related and customer-related components.

6.1 Demand-related components

The demand classification is applied to utility assets that are added based upon maximum customer load. Examples of distribution assets classified entirely to demand are substations and line transformers. About two-thirds of total distribution costs and assets are classified to demand.

6.2 Customer-related components

Utilities apply the customer-related classification to equipment necessary to enable a customer to receive service but unrelated to the amount of power consumed. This cost category includes distribution costs which do not vary with customer consumption but may vary directly with the number of customers to be served, such as service drops and meters. Other costs are a fixed requirement necessary for a distribution system regardless of quantity of usage, such as protective devices which operate in the same manner with or without load on the system.

6.3 Components with both customer- and demand-related characteristics

Certain types of distribution equipment cannot be classified as entirely customer-related or demand-related, but instead must be split between the two because the equipment both serves a maximum load requirement (demand) and enables the customer to be connected and thereby capable of receiving service (customer).

Examples of such equipment are distribution poles and distribution line conductors. The first 30% of their rate base and costs are assigned to Primary Service level and classified to demand. The remaining 70 percent is split equally between Primary and Secondary levels. At each level a further equal split occurs between demand- and customer-related costs.

Finally there are supportive assets to the Primary distribution equipment shared among various primary distribution assets and/or other functional areas such as land, general buildings and working capital. The classification of these assets will vary but in most cases is based on the weighted average classification of the most relevant distribution equipment.

Retail expenses are all classified to customer. The classification breakdown of these costs is as follows.

Figure 4: Classification Summary of Revenue Requirement of Distribution and Retail (thousands of dollars)

Functional Area	Demand	Customer	Total
Distribution			
Non-Streetlight Related			
Retail Customers bfr Streetlights	116,708	61,888	178,596
Streetlights	8,750		8,750
Wholesale Customers	798	3	801
Distribution Total	126,255	61,892	188,147
Retail			
Retail Customers		51,182	51,182
Wholesale Customers		176	176
Retail Total		51,358	51,358
Total	126,255	113,250	239,506

The details of classification results of distribution assets are included in Exhibit 2B and those of distribution and retail costs in Exhibit 5 of COSS (**Attachment C)**.

7.0 ALLOCATION OF REVENUE REQUIREMENT

To the extent possible and practical, costs should be assigned to rate classes directly. This can be done when costs are readily identified with a particular customer group or rate class. A direct assignment of costs reflects cost causation and is fair and equitable to customers. The only costs assigned directly in the current COSS are the distribution-related costs of streetlight fixtures and maintenance assigned to the Unmetered Class. Due to the shared nature of NS Power's remaining Distribution and Retail costs, they are apportioned to rate classes based on the relative usage of these resources by rate classes. Demand-related Distribution costs are allocated to rate classes based on each class' share of their total non-coincident demands. Customer-related costs are allocated based on class relative shares of customer count. The breakdown of class demand- and customer-related costs by functional area is provided below.

Figure 5: Summary of Revenue Requirement classification by rate class (Thousands of dollars)

Rate Class	Customers	MWh sales	Distribution Costs			Retail Cost	Total Cost
			Demand	Customer	Total	customer	
Domestic Service	456,991	4,216,538	$68,783	$53,644	$122,428	$42,045	$164,472
Small General	24,109	236,657	$3,878	$2,807	$6,686	$2,498	$9,184
General	11,349	2,448,685	$31,281	$3,804	$35,084	$3,158	$38,242
Large General	19	379,649	$2,394	$8	$2,402	$366	$2,768
Small Industrial	2,221	255,893	$3,122	$744	$3,866	$661	$4,527
Medium Industrial	198	495,412	$4,386	$55	$4,441	$582	$5,023
Large Industrial	25	275,419	$1,303	$14	$1,317	$756	$2,073
Unmetered Service Rates					$0		$0
Electric Service	9,604	98,246	$1,561	$812	$2,372	$1,117	$3,489
Streetlight Maintenance & Capital			$8,750		$8,750		$8,750
Unmetered Total	9,604	98,246	$10,311	$812	$11,122	$1,117	$12,239
Total	504,516	8,406,498	$125,458	$61,888	$187,346	$51,182	$238,528

A detailed classification of class costs by activity is contained in Exhibit 6 of **Attachment C.**

8.0 DETERMINATION OF DISTRIBUTION AND RETAIL USAGE

Rate classes are defined based on discernible customer characteristics (residential, commercial/general, industrial, and other) and size, as delineated by energy consumption and demand criteria (small, medium or large).[11] Implicitly, this segmentation also reflects differentiation by voltage level of service as a practical matter, since larger customers are typically served at higher voltage levels than smaller customers. The usage of these customers is assigned (levelized) in the COS and Load Research Studies at the customer's voltage level of service.

Distribution service costs are allocated to customer classes on the basis of class non-coincident demands and number of customers. For the purpose of determining the demand-based allocation the class demand usage is levelized among three voltage levels: Bulk Power Substation, Primary Voltage and Secondary Voltage. The distribution assets and costs, broken down by these three voltage levels, are then allocated to rate classes based on their relative shares in total class non-coincident demands at these three service levels. NS Power allocates bulk power substation costs based upon Non-Coincident Peak[12] (NCP) rate class demands at the low side of the bulk power transformer. Primary demand-related costs are allocated based upon the NCP rate class demand at primary voltage level. These NCP demands at primary are the combination of secondary NCP demands plus their respective losses and NCP demands for primary customers. Secondary demand-related costs are allocated to rate classes based upon NCP rate class demands at secondary. The non-coincident demand usage by rate classes is provided in Exhibit 9B of **Attachment C**.

[11] Other criteria are used for delineation in some cases. For example, the Domestic Time of Day optional rate is available only to customers with electric heating, a somewhat less immediately discernible feature than residential status itself. Other "niche" rates, such as Unmetered, have special criteria, such as no metering of consumption.

[12] The Non-Coincident Peak Demand of a rate class is measured as the highest hourly energy consumption during a calendar year. It may or may not coincide with class hourly consumption during the hour in which the system peak occurs.

The non-coincident demands of rate classes, other than the Large General, Large Industrial and Municipal classes, are estimated based on the statistical load research sample. The non-coincident demands of all rate classes are also a function of hourly line losses.

The distribution customer-related costs, with the exception of service drops, are apportioned to rate classes based on their relative shares in absolute customer counts. NS Power allocates primary customer-related distribution cost based upon average number of customers at primary and secondary. Secondary customer-related distribution costs are allocated based upon average number of customers at secondary. Service drop costs are currently allocated on the basis of weighted customer counts.

Retail services are allocated to rate classes based on weighted or absolute customer counts modified for the voltage service level, seasonal service, or class membership relevant to the retail activity in question. There are seven customer based allocators. The approach to weighting of customer counts is based on a weighted average of a number of monthly bills and billed revenues in each class per year. The rationale for a weighted customer count is based on recognition that aside from customer number there are other secondary causative factors at work which affect total cost of a retail activity.[13]

[13] As reflected in allocator C-2B in Exhibit 8a of Attachment C, for example, the customer weighting of the Large Industrial customer is 20 times higher than that of the Small Industrial customer. In turn, the weighting of a Small Industrial customer is 5 times higher than that of a Small General customer.

9.0 DISTRIBUTION TARIFF RATE DESIGN

In its design of the DT rates, the Company was guided by the following principles:

- In compliance with s. 3G(2) of the Act, NS Power's remaining customers were not to be negatively affected.
- To the extent practical, leverage existing rates and processes.
- Seek stakeholder consensus.
- Adhere to established ratemaking principles to achieve an appropriate balance among potentially competing ratemaking objectives such as intra-class equitability and simplicity; efficiency and simplicity; and stability and efficiency.

9.1 Rate Classification

In the design of the DT, the Company followed the existing base cost rate classification among the metered and unmetered categories. This approach was chosen for the following reasons:

- The existing COS methodology is well established, following the UARB Decision in the 2013 COS proceeding.[14] It is reflective of cost causation on the distribution system, therefore supportive of the principle of no harm to NS Power's customers.

- Relying on the existing COS methodology makes for easier implementation by leveraging existing ratemaking processes.

- Adherence to the existing COS methodology will be the least disruptive to electric services under the bundled service as this will help avoid artificial pricing

[14] NSPI 2013 Cost of Service Study, UARB Decision, 2014 NSUARB 53, M05473.

incentives to customer migration arising from differences in rate structures between bundled and unbundled rates.

9.2 Revenue to Cost Ratios

To determine revenue responsibilities of bundled service rate classes, NS Power applies an established process, which ensures that the revenue to cost (R/C) ratios for classes fall within the Board-approved 95 to 105 percent band. The process consists of applying first, an across-the-board increase to all classes and then making adjustments to those classes whose ratios fall outside the band. The adjustment is applied at the Board's discretion to provide a more stable rate environment to customers by minimizing fluctuations in rates attributable to imperfections in the COSS as well as uneven cost pressures on rate classes in GRA proceedings.

The Company is proposing that the DT rates be set directly at cost, without R/C adjustments, for the following reasons:

1. Setting DT rates strictly at cost of service aligns with the ratemaking treatment under the OATT, which allows for a consistent treatment of all delivery charges applicable to open access distribution customers.

2. With generation and transmission rates of open access distribution customers being already exempted from the R/C ratio adjustment there is less compelling reason, from a rate stability perspective, to apply such an adjustment solely to distribution rates which represent about a quarter of the total cost of electricity.

3. The R/C ratios used for the bundled rates are reflective of broad cost considerations accounting for all four functional cost areas. There is no conceptual basis for transferring these ratios to a small portion of bundled service revenue requirement associated with distribution and retail costs.

4. Strictly cost of service based DT rates allow for a more transparent rate setting process.

9.3 Rate Structure for Metered Services

In the design of the distribution rate structures, the Company sought to find the right balance among simplicity, efficiency and intra-class equity as affected by pricing signals embedded in rates. To deliver on the objective of designing efficient and equitable rates the Company endeavored to align, to the extent practical, the rate structures of DT with classification of class costs by demand-related and customer-related components. A comparison of the proposed DT class rate structures to their bundled service counterparts is set out in **Attachment D**.

9.3.1 Customers on Energy and Customer charges

The Company proposes to retain the current rate structure for the two Domestic and Small General rate classes with the following exceptions:

- The time-differentiated energy charge components of the Domestic Time of Day (TOD) rate are proposed to be replaced with one distribution usage charge component. The distribution usage charge component is proposed to be the same for the two Domestic rate classes.

- The declining block rate structure of the Small General class is proposed to be replaced with the one distribution usage charge component.

The customer charges under the two Domestic and Small General rate classes were retained at their current levels. The charges currently recover about two-thirds of the COSS-based customer-related costs representing about 10% of the total bundled service class costs. The current level of these charges is reflective of historical rate design practices including the UARB Decision in the 2003 Generic Rate Design Hearing[15] which effectively froze these charges. In order to not create an artificial incentive or disincentive for customers to move to alternate service providers, due to a difference in rate structures, the Company retained customer charges at their current level.

The energy charges under these rates are designed to recover both energy and demand-related costs. Given the small loads of these customers and their general inability to respond to price signals embedded in demand charges, installation of more expensive demand meters would not be warranted. The Company proposes, therefore, that the energy charges in cents per kWh continue to be used as a proxy for the recovery of demand-related distribution costs.

Domestic Time of Day rates

The purpose of the current TOD rate structure is to recognize the generation-related cost savings to NS Power from load shifting using the electric thermal storage (ETS) equipment-control under the bundled service. The higher customer charge of $18.82 per month for TOD Domestic Service, compared to $10.83 for Domestic Service, under the bundled services, is reflective of higher TOD meter costs and an additional charge to make up for lost revenue due to introduction of reduced rates for the afternoon shoulder period in the winter months of January, February and December[16].

There is no time-differentiated cost causation effect present in the bundled TOD rate for recovery of distribution and retail costs. Therefore, application of a flat distribution usage charge is appropriate to TOD customers who will retain the TOD meters. The

[15] NSUARB-NSPI-P-878, NSPI Generic Rate Design Hearing, Matter Number M05002, Decision 2003 NSUARB 91, August 1, 2003, pages 47-48

[16] NS Power 1995 Rate Hearing, UARB Decision, M06131, March 4, 1996, page 68.

customer charge is proposed to be reduced by $5.67 to $13.15 to reflect the retail and distribution costs and TOD meter costs included in the TOD customer charge.

Customers who no longer require TOD meters will have them replaced with non-TOD meters and will be billed under the Domestic Service rate.

Small General Class

The Company proposes to recover distribution costs of the Small General class through a flat distribution charge in cents per kWh instead of the two declining block charges. This approach allows for a simpler rate design which aligns customer treatment between the Small General and Residential rate classes.[17]

9.3.2 Customers on Demand charges

The Company proposes that all demand-related distribution costs of customers currently billed under the bundled rates with demand charges be recovered through demand charges. In addition, as is the case with the bundled service rates, it is also being proposed that all customer-related costs be recovered through the demand charges. Since there are no energy-related costs in the distribution and retail areas, there is no need to retain distribution usage charges in cents per kWh for these customers.

Rates with demand charges do not include customer charges. Customer-related costs represent only a very small portion of the total cost of power of these customers, who are

[17] Since the time of the design of its declining block structure, which predates the generic cost of service and rate design proceedings conducted in 1993, the availability criterion under the rate has increased from usage less than 12 MWh per year to 45 MWh per year. This change was justified, among other things, on the basis of similarity in usage profiles between the residential and small general customers consistent with the ratemaking concept of "like rates for like service".

much bigger consumers than customers billed under the energy only rates.[18] In order to keep the rate structures of these classes as simple as possible, the customer-related costs are currently recovered through the rate components of energy in cents per kWh and demand in dollars per kW or kVA. NS Power proposes that this practice continue under the rate design of the DT.

9.3.3 Proof of Revenue

The rates for each metered service are determined by dividing their revenue requirements associated with services provided under the rate component by their respective billing determinant. Please refer to **Attachment E** for the Proof of Revenue calculations behind the rate components applicable to metered services under the DT.

9.4 Unmetered Rates

The Company proposes that its ratemaking approach for the determination of Unmetered Streetlight and Small Miscellaneous Loads rates be applied in the design of DT rates for these customers. This will result in the same types and number of rates as provided under bundled service.

The DT streetlight rates are proposed to be offered under the three distinct service categories for non-LED types of fixtures:

1. Electric service only, applicable to both streetlight and miscellaneous loads;

2. Electric service combined with streetlight fixture maintenance; and

[18] The customer-related costs account from 1 percent to 2 percent of the total costs of the rate classes on demand charges.

3. Full streetlight service, which includes electric service, maintenance and capital costs associated with streetlight fixtures.

In addition the DT will accommodate two types of LED services:

1. Electric service only, applicable to both streetlight and miscellaneous loads; and

2. Full streetlight service, which includes electric service, maintenance and capital costs associated with streetlight fixtures.

10.0 CONCLUSION

The proposed approach to the design of the DT rates leverages existing rate structures and cost of service methodology. It is grounded in established ratemaking principles and, as such, provides a cost neutral rate framework that will support development of the Renewable to Retail market. The proposed distribution rate structures, by their alignment with their bundled service counterparts, make for easy implementation and fair allocation of costs among customers. They also provide unbiased pricing signals that will enable rational generation service choice decisions.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Consumer Advocate Data Requests

NON-CONFIDENTIAL

Request DR-4:

Please explain why NSPI believes that recovering all DT revenue for classes with demand charges from demand charges on the customer's single maximum monthly or annual load, rather than a broader measure of the customer's contribution to maximum loads on distribution equipment.

(a) Does NSPI agree that a customer with many high-load hours would likely contribute more to the capacity requirements and costs of the distribution system than a customer with just one hour at the same maximum load?

(b) Please identify the seasonal and daily time periods in which feeders and substations are most likely to experience peak or near-peak load.

(c) Please provide any data on the timing and magnitude of load on each distribution substation and each feeder for which NS Power has such data.

Response DR-4:

Please refer section 9.3.2 Customers on Demand Charges of the Distribution Tariff Strawman Report of May 21, 2105.

(a) The cost of the distribution system, as driven by the amount of investment in distribution infrastructure, is primarily determined by a customer's instantaneous demand on the system, as opposed to duration of its usage or energy, and also the number of customers attached to the system. Please refer to the example distribution planning study provided in **Attachment 1** (originally provided in Matter M06514, the NS Power 2015 Annual Capital Expenditure Plan), for the usage considerations in investment decisions. Consistent with this, investment and costs of the system are classified between demand-

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and customer-related categories.[1] Accordingly, it is appropriate to recover these costs through demand charges as applicable to monthly metered customer demands.

(b-c) Please refer to **Attachment 2**, which shows an illustration of the times of annual peaks on bulk power substations, using data from September, 2013. As demonstrated under column F, Peak Occurrence, substation load tends to peak during mornings and evenings during the winter. However, there are some substations that register their peak load outside of these periods, and there are several substations which peak during non-winter months.

[1] This classification is ascertained by NARUC's manual pages 87 and 88.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Consumer Advocate Data Requests

NON-CONFIDENTIAL

Request DR-5:

Please provide any information that NS Power believes is relevant to the time periods in which residential load is most likely to contribute to peak loads on

(a) shared line transformers,

(b) feeders, and

(c) distribution substations.

Response DR-5:

(a-c) NS Power has not conducted studies concerned with time periods in which residential load contributes to peak loads on its individual transformers, feeders and distribution substations. For the allocation purposes of demand-related costs of distribution in its Cost of Service Studies, the Company uses class non-coincident annual demands as presented in Exhibit 9B included in Appendix C. Please refer to **Attachment 1** which was CA DR-4 from the 2013 COS proceeding[1] for information on dates and hours of class annual peaks. Note that some rate classes peak during non-winter months and outside of on-peak daily periods.

[1] 2013 NS Power Cost of Service Study, M05473, Exhibit N-1, Appendix B, June 28, 2013.

2013 Cost of Service Study
NSPI Responses to Consumer Advocate Data Requests

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Request DR-4:

Date and time of each monthly class NCP in COSS Sheet "Input Data Two"

Response DR-4:

The class non-coincident peak is selected from the constructed forecast load shape file as the maximum hourly load in each specific rate class for each month.

Rate Class	Date	Time	Peak MW
Domestic	Tue, Feb-02	19:00	1,037
Small General	Thu, Feb-04	12:00	56
General Demand	Mon, Jan-11	10:00	488
Large General	Thu, Sep-02	11:00	73
Small Industrial	Tue, Aug-31	12:00	48
Medium Industrial	Fri, Dec-10	09:00	85
Large Industrial	Fri, Sep-03	15:00	139
ELI 2P-RTP			0
Municipal	Wed, Feb-03	09:00	41
Unmetered	Thu, Dec-02	00:00	24
Bowater Mersey	N/A (calculated)		42
Gen. Repl. & Load Follow.	Tue, Sep-21	00:00	24
RTP			0
LRT	N/A (calculated)		38

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Request DR-6:

If the probability of customer load contributing to distribution peak loads varies over time, please explain whether NS Power favours time-differentiating the DT rate for customers on the Time of Use rate.

(a) If NS Power believes that the probability of customer load contributing to distribution peak loads does not vary over time, please explain why.

(b) If NS Power believes that the probability of customer load contributing to distribution peak loads varies over time, but does not believe that the Time of Use DT rate should be time-differentiated, please explain why.

Response DR-6:

(a-b) As provided in section 9.0 of the Distribution Tariff Strawman of May 21, 2015, in its design of the Distribution Tariff, NS Power was guided, among other criteria, by the objective of leveraging existing rates and processes. The existing rate setting methodology does not provide cost information or guidelines on the basis of which a Time-Of-Day (TOD) differentiated distribution tariff could be developed for residential customers.

The current residential TOD rates have been designed for bundled service customers utilizing Electric Thermal Storage (ETS) load shifting equipment without consideration of savings arising specifically from changes in utilization of distribution infrastructure. The primary motivation for the development of the TOD Tariff was the deferral of investment in generation assets. Consistent with this, the highest TOD rates apply during morning and evening periods in January, February and December. While the system total load always peaks during these periods, the load on individual distribution substations and feeders may not. This approach is also reflected in the design of the 1P-RTP adders

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whose generation cost component is differentiated by the time of day, while the transmission and distribution costs are not.

Cost of Service Studies are conducted for the TOD and non-TOD residential rate classes combined and therefore TOD class-specific cost information is not available from the COS. Further, the COS apportions all distribution costs to rate classes on the basis of annual usage (total number of customers or annual peak) without consideration of time of day or season-differentiated periods.

Please refer also to CA DR-5. The Company has not conducted studies concerned with time periods in which residential load contributes to peak loads on its distribution assets and therefore does not know whether the probability of customer load contributing to distribution peak loads varies over time. As such, the Company does not have information as to what time of day and seasonal periods the DT rates should be differentiated and by what amounts.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

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Request DR-16:

Reference: Distribution Tariff Draft and Attachments

Re page 10, Lines 6-9, please elaborate on how retail capital and operating costs are functionalized.

Response DR-16:

Under the approved Cost of Service Studies, capital investment is functionalized among the three functional areas of generation, transmission and distribution. Please refer to **Attachment 1,** page 3. Attachment 1 is a print version of Tab 2B of Attachment C, the Excel Cost of Service Model that was issued to stakeholders with the Draft Distribution Tariff on May 21, 2015.

Direct operating expenses are functionalized into the retail area based on the Uniform System of Accounts, mandated by the National Association of Regulatory Utility Commissioners (NARUC), followed by NS Power in its accounting practice. In addition to this, some miscellaneous revenues and a portion of the overhead expenses of the Company are also functionalized to retail.[1] The retail-related overhead expenses are apportioned to the individual direct retail expense categories based on their relative shares in the total direct retail expenses. Please refer to **Attachment 2,** page 4. Attachment 2 is a print version of Tab 5 in Attachment C of May 21, 2015. It contains a list of operating costs and miscellaneous revenues functionalized to retail, as well as proration formulas used in assignment of overhead retail costs to individual direct retail cost categories.

[1] Note that a final report on the COS treatment of Miscellaneous Revenues and Overhead Cost, includes recommendations regarding changes to the current approach. M06555, Exhibit N-2, February 9, 2015.

EXHIBIT 2B
PAGE 1 of 3

NOVA SCOTIA POWER INC.
CLASSIFICATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		INITIAL R/B CLASSIFICATION			FURTHER CLASSIFICATION			FULLY CLASSIFIED RATE BASE		
		DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT
(1)	**GENERATION FUNCTION**									
(2)										
(3)	STEAM PLANT	$1,191,036	$179,496	$0	($673,293)	$673,293	$0	$517,743	$852,789	$0
(4)	HYDRO PLANT	366,637	4,824	0	-207,260	207,260	0	159,377	212,084	0
(5)	WIND PLANT	201,182	0	0	-179,039	179,039	0	22,143	179,039	0
(6)	LM6000 PLANT	71,417	0	0	-40,372	40,372	0	31,045	40,372	0
(7)	GAS TURBINE PLANT - OTHER	6,513	0	0	0	0	0	6,513	0	0
(8)	TOTAL GENERATION PLANT	1,836,785	184,320	0	-1,099,963	1,099,963	0	736,822	1,284,283	0
(9)										
(10)	GENERAL PROPERTY PLANT	137,057	13,754	0	-82,077	82,077	0	54,980	95,830	0
(11)	TOTAL PLANT IN SERVICE	1,973,842	198,074	0	-1,182,040	1,182,040	0	791,802	1,380,114	0
(12)										
	Working Capital & Deferred									
(13)	Charges/Credits:									
(14)	CASH - FUEL	0	0	0	0	0	0	0	0	0
(15)	CASH - OTHER	4,223	9,353	0	0	0	0	4,223	9,353	0
(16)	MAT. & SUPPLIES - FUEL	0	84,441	0	0	0	0	0	84,441	0
(17)	MAT. & SUPPLIES - OTHER	16,768	1,683	0	-10,041	10,041	0	6,726	11,724	0
(18)	DEF. CHG. - Financing	38,421	3,856	0	-23,009	23,009	0	15,413	26,864	0
(19)	DEF. CHG. - Tax	6,665	669	0	-3,991	3,991	0	2,674	4,660	0
(20)	DEF. CHG. - Pension	12,601	27,906	0	0	0	0	12,601	27,906	0
(21)	DEF. CHG. - Steam Assets	0	0	0	0	0	0	0	0	0
(22)	DEF. CHG. - Fuel Deferral	0	-5,043	0	0	0	0	0	-5,043	0
(23)	DEF. CHG. - Other	1,637	164	0	-980	980	0	657	1,144	0
(24)	DEF. CHG. - FCR	17,170	1,723	0	-10,282	10,282	0	6,888	12,005	0
(25)	DEF. CR. - ARO Steam	-37,934	-5,717	0	21,444	-21,444	0	-16,490	-27,161	0
(26)	DEF. CR. - ARO Hydro	-22,466	-296	0	12,700	-12,700	0	-9,766	-12,996	0
(27)	DEF. CR. - ARO Wind	-10,720	-141	0	6,060	-6,060	0	-4,660	-6,201	0
(28)	DEF. CR. - ARO CT	-4,150	0	0	0	0	0	-4,150	0	0
(29)	DEF. CR. - Other	-5,716	-861	0	3,231	-3,231	0	-2,485	-4,092	0
(30)	CONTRACT RECEIVABLE	0	0	0	0	0	0	0	0	0
(31)	SUB-TOTAL	16,498	117,737	0	-4,868	4,868	0	11,630	122,605	0
(32)								0	0	0
(33)	**TOTAL GENERATION FUNCTION**	1,990,340	315,810	0	-1,186,908	1,186,908	0	803,432	1,502,719	0
(34)										
(35)	**TRANSMISSION FUNCTION**									
(36)										
(37)	**Transmission - HV**	109,080	0	0	-61,663	61,663	0	47,417	61,663	0
(38)										
(39)	GENERAL PROPERTY PLANT	8,139	0	0	-4,601	4,601	0	3,538	4,601	0
(40)	TOTAL PLANT IN SERVICE	117,219	0	0	-66,264	66,264	0	50,955	66,264	0
(41)										
	Working Capital & Deferred									
(42)	Charges/Credits:									
(43)	CASH - FUEL	0	0	0	0	0	0	0	0	0
(44)	CASH - OTHER	266	346	0	0	0	0	266	346	0
(45)	MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(46)	MAT. & SUPPLIES - OTHER	996	0	0	-563	563	0	433	563	0
(47)	DEF. CHG. - Financing	2,282	0	0	-1,290	1,290	0	992	1,290	0
(48)	DEF. CHG. - Tax	396	0	0	-224	224	0	172	224	0
(49)	DEF. CHG. - Pension	795	1,033	0	0	0	0	795	1,033	0
(50)	DEF. CHG. - Other	69	0	0	-39	39	0	30	39	0
(51)	DEF. CHG. - ARO Trans.	-5,787	0	0	3,271	-3,271	0	-2,516	-3,271	0
(52)	SUB-TOTAL	-984	1,380	0	1,156	-1,156	0	172	224	0
(53)										
(54)	Transmission - HV	116,235	1,380	0	-65,108	65,108	0	51,127	66,488	0

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		INITIAL R/B CLASSIFICATION			FURTHER CLASSIFICATION			FULLY CLASSIFIED RATE BASE		
		DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT
(1)	**Transmission - EHV**	357,074	0	0	-201,854	201,854	0	155,220	201,854	0
(2)										
(3)	GENERAL PROPERTY PLANT	26,644	0	0	-15,062	15,062	0	11,582	15,062	0
(4)	TOTAL PLANT IN SERVICE	383,718	0	0	-216,916	216,916	0	166,802	216,916	0
(5)										
(6)	Working Capital & Deferred Charges/Credits:									
(7)	CASH - FUEL	0	0	0	0	0	0	0	0	0
(8)	CASH - OTHER	872	1,134	0	0	0	0	872	1,134	0
(9)	MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(10)	MAT. & SUPPLIES - OTHER	3,260	0	0	-1,843	1,843	0	1,417	1,843	0
(11)	DEF. CHG. - Financing	7,469	0	0	-4,222	4,222	0	3,247	4,222	0
(12)	DEF. CHG. - Tax	1,296	0	0	-732	732	0	563	732	0
(13)	DEF. CHG. - Pension	2,601	3,382	0	0	0	0	2,601	3,382	0
(14)	DEF. CHG. - Other	225	0	0	-127	127	0	98	127	0
(15)	DEF. CHG. - FCR	4,357	0	0	-2,463	2,463	0	1,894	2,463	0
(16)	DEF. CR. - ARO Trans	-18,943	0	0	10,709	-10,709	0	-8,235	-10,709	0
(17)	SUB-TOTAL	1,136	4,516	0	1,321	-1,321	0	2,457	3,195	0
(18)										
(19)	Transmission - EHV	384,854	4,516	0	-215,595	215,595	0	169,259	220,111	0
(20)										
(21)	**TOTAL TRANSMISSION FUNCTION**	$501,090	$5,896	$0	($280,703)	$280,703	$0	$220,387	$286,599	$0

EXHIBIT 2B
PAGE 3 of 3

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		INITIAL R/B CLASSIFICATION			FURTHER CLASSIFICATION			FULLY CLASSIFIED RATE BASE		
		DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT
(1)	**DISTRIBUTION FUNCTION**									
(2)										
(3)	DISTRIBUTION PLANT:									
(4)	LAND	$3,023	$0	$1,412	$0	$0	$0	$3,023	$0	$1,412
(5)	EASEMENTS & SURVEY	11,505	0	5,377	0	0	0	11,505	0	5,377
(6)	OTHER	1,493	0	697	0	0	0	1,493	0	697
(7)	SUBSTATIONS	30,113	0	0	0	0	0	30,113	0	0
(8)	POLES & FIXTURES	119,005	0	64,080	0	0	0	119,005	0	64,080
(9)	O.H. LINES	78,818	0	42,441	0	0	0	78,818	0	42,441
(10)	U.G. LINES	22,658	0	12,200	0	0	0	22,658	0	12,200
(11)	LINE TRANSFORMERS	163,242	0	0	0	0	0	163,242	0	0
(12)	SERVICES	0	0	60,998	0	0	0	0	0	60,998
(13)	METERS	0	0	25,072	0	0	0	0	0	25,072
(14)	STREET LIGHTING	10,251	0	0	0	0	0	10,251	0	0
(15)	TOTAL DISTRIBUTION PLANT	440,108	0	212,277	0	0	0	440,108	0	212,277
(16)										
(17)	GENERAL PROPERTY PLANT	32,840	0	15,840	0	0	0	32,840	0	15,840
(18)	TOTAL PLANT IN SERVICE	472,947	0	228,117	0	0	0	472,947	0	228,117
(19)										
(20)	Working Capital & Deferred Charges/Credits:									
(21)	CASH - FUEL	0	0	0	0	0	0	0	0	0
(22)	CASH - OTHER	4,130	0	7,343	0	0	0	4,130	0	7,343
(23)	MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(24)	MAT. & SUPPLIES - OTHER	4,018	0	1,938	0	0	0	4,018	0	1,938
(25)	DEF. CHG. - Financing	9,206	0	4,440	0	0	0	9,206	0	4,440
(26)	DEF. CHG. - Tax	1,597	0	770	0	0	0	1,597	0	770
(27)	DEF. CHG. - Pension	12,321	0	21,908	0	0	0	12,321	0	21,908
(28)	DEF. CHG. - Other	277	0	134	0	0	0	277	0	134
(29)	SUB-TOTAL	31,548	0	36,533	0	0	0	31,548	0	36,533
(30)										
(31)	**(24) TOTAL DISTRIBUTION FUNCTION**	$504,496	$0	$264,650	$0	$0	$0	$504,496	$0	$264,650
(32)										
(33)	**RETAIL FUNCTION**									
(34)										
(35)	DISTRIBUTION PLANT:									
(36)	SERVICES	$0	$0	$0	$0	$0	$0	$0	$0	$0
(37)	METERS	0	0	0	0	0	0	0	0	0
(38)	TOTAL RETAIL PLANT	0	0	0	0	0	0	0	0	0
(39)										
(40)	GENERAL PROPERTY PLANT	0	0	0	0	0	0	0	0	0
(41)	TOTAL PLANT IN SERVICE	0	0	0	0	0	0	0	0	0
(42)										
(43)	Working Capital & Deferred Charges/Credits:									
(44)	CASH - FUEL	0	0	0	0	0	0	0	0	0
(45)	CASH - OTHER	0	0	0	0	0	0	0	0	0
(46)	MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(47)	MAT. & SUPPLIES - OTHER	0	0	0	0	0	0	0	0	0
(48)	DEF. CHG. - Financing	0	0	0	0	0	0	0	0	0
(49)	DEF. CHG. - Tax	0	0	0	0	0	0	0	0	0
(50)	DEF. CHG. - Pension	0	0	0	0	0	0	0	0	0
(51)	DEF. CHG. - Other	0	0	0	0	0	0	0	0	0
(52)	SUB-TOTAL	0	0	0	0	0	0	0	0	0
(53)										
(54)	**TOTAL RETAIL FUNCTION**	0	0	0	0	0	0	0	0	0
(55)										
(56)	**TOTAL AVE. RATE BASE**	**$2,995,925**	**$321,706**	**$264,650**	**($1,467,611)**	**$1,467,611**	**$0**	**$1,528,314**	**$1,789,317**	**$264,650**

NOVA SCOTIA POWER INC.

CLASSIFICATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

		(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
	GENERATION FUNCTION				
(1)	FUEL	367,943	$0	$367,943	$0
(2)	PURCHASED PWR REG - IPP	896	390	507	0
(3)	PURCHASED PWR REG - BIOMASS	13,799	2,205	11,595	0
(4)	PURCHASED PWR WIND - FIXED	67,031	7,048	59,982	0
(5)	PURCHASED PWR REG - Imports	217	0	217	0
(6)	OPER. & MAINT. - STEAM	109,984	33,681	76,303	0
(7)	OPER. & MAINT. - HYDRO	12,650	3,874	8,776	0
(8)	OPER. & MAINT. - WIND	6,110	1,871	4,239	0
(9)	OPER. & MAINT. - BIOMASS	8,092	2,478	5,614	0
(10)	OPER. & MAINT. - LM6000	425	130	295	0
(11)	OPER. & MAINT. - OTHER CT's	1,257	1,056	201	0
(12)	DSM AMORTIZATION	1,056	385	671	0
(13)	FCR DEFERRAL	13,408	4,671	8,737	0
(14)	GRANTS IN LIEU OF TAXES	24,672	8,995	15,678	0
(15)	DEPRECIATION:				
(16)	STEAM	65,371	24,695	40,676	0
(17)	HYDRO	11,163	4,790	6,373	0
(18)	WIND	8,186	901	7,285	0
(19)	LM6000	2,084	906	1,178	0
(20)	GAS TURBINE - OTHER	1,202	1,202	0	0
(21)	GENERAL PROPERTY	25,696	9,368	16,328	0
(22)	INTEREST NET OF AFUDC	92,022	32,059	59,963	0
(23)	PREFERRED DIVIDENDS	5,106	1,779	3,327	0
(24)	CORPORATE TAXES	26,336	9,175	17,161	0
(25)	NON-OPERATING REVENUE:				
(26)	EXPORT SALES	-1,826	0	-1,826	0
(27)	OTHER REVENUE	-10,677	-1,873	-8,804	0
(28)	RETURN (PROFIT/LOSS)	77,701	27,070	50,631	0
(29)					
(30)	**TOTAL GENERATION**	**$929,904**	**$176,854**	**$753,049**	**$0**

NOVA SCOTIA POWER INC.

CLASSIFICATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

		(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
	TRANSMISSION FUNCTION				
	Transmission - HV:				
(1)	O&M - HV	6,250	2,717	3,533	0
(2)	GRANTS IN LIEU OF TAXES	1,320	574	746	0
(3)	DEPRECIATION:				
(4)	TRANSMISSION	5,371	2,335	3,036	0
(5)	GENERAL PROPERTY	1,387	603	784	0
(6)	INTEREST NET OF AFUDC	4,693	2,040	2,653	0
(7)	PREFERRED DIVIDENDS	260	113	147	0
(8)	CORPORATE TAXES	1,343	584	759	0
(9)	NON-OPERATING REVENUE:				
(10)	OTHER REVENUE	-264	-115	-149	0
(11)	RETURN (PROFIT/LOSS)	3,963	1,723	2,240	0
	TOTAL - HV	**24,324**	**10,573**	**13,750**	**0**
	Transmission - EHV:				
(12)	O&M - HV	20,461	8,894	11,567	0
(13)	GRANTS IN LIEU OF TAXES	4,370	1,900	2,471	0
(14)	DEPRECIATION:				
(15)	TRANSMISSION	17,580	7,642	9,938	0
(16)	GENERAL PROPERTY	4,540	1,973	2,566	0
(17)	INTEREST NET OF AFUDC	15,537	6,754	8,783	0
(18)	PREFERRED DIVIDENDS	862	375	487	0
(19)	CORPORATE TAXES	4,447	1,933	2,514	0
(20)	NON-OPERATING REVENUE:				
(21)	OTHER REVENUE	-866	-376	-489	0
(22)	FCR DEFERRAL	3,092	1,344	1,748	0
(23)	RETURN (PROFIT/LOSS)	13,119	5,703	7,416	0
(24)	**TOTAL - EHV**	**83,143**	**36,142**	**47,001**	**0**
(25)	**TOTAL TRANSMISSION**	**$107,466**	**$46,716**	**$60,751**	**$0**

NOVA SCOTIA POWER INC.

CLASSIFICATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

		(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
	DISTRIBUTION FUNCTION				
(1)	BEFORE STREETLIGHTS				
(2)	SUBSTATIONS	$306	$306	$0	$0
(3)	OVERHEAD LINES	38,749	25,187	0	13,562
(4)	UNDERGROUND LINES	693	451	0	243
(5)	LINE TRANSFORMERS	1,484	1,484	0	0
(6)	METERS	948	0	0	948
(7)	COMMUNICATIONS	8,880	8,880	0	0
(8)	GRANTS IN LIEU OF TAXES	7,858	5,117	0	2,740
(9)	DEPRECIATION:				
(10)	DISTRIBUTION - Land	0	0	0	0
(11)	DISTRIBUTION - Easements	433	295	0	138
(12)	DISTRIBUTION - Other	-3,612	-2,462	0	-1,150
(13)	DISTRIBUTION - Substations	906	906	0	0
(14)	DISTRIBUTION - Poles and Fixtures	18,878	12,271	0	6,607
(15)	DISTRIBUTION - OH Lines	7,800	5,070	0	2,730
(16)	DISTRIBUTION -UG Lines	1,669	1,085	0	584
(17)	DISTRIBUTION -Line Transformers	11,573	11,573	0	0
(18)	DISTRIBUTION -Services	6,646	0	0	6,646
(19)	DISTRIBUTION -Meters	3,721	0	0	3,721
(20)	GENERAL PROPERTY	8,294	5,595	0	2,699
(21)	INTEREST NET OF AFUDC	30,282	19,722	0	10,560
(22)	PREFERRED DIVIDENDS	1,680	1,094	0	586
(23)	CORPORATE TAXES	8,666	5,644	0	3,022
(24)	RETURN (PROFIT/LOSS)	25,569	16,653	0	8,917
	STREETLIGHTS				
	non-LED				
(25)	MAINTENACE	5,825	5,825	0	0
(26)	GRANTS IN LIEU OF TAXES	106	106	0	0
(27)	DEPRECIATION	1,924	1,924	0	0
(28)	INTEREST NET OF AFUDC	409	409	0	0
(29)	PREFERRED DIVIDENDS	23	23	0	0
(30)	CORPORATE TAXES	117	117	0	0
(31)	RETURN (PROFIT/LOSS)	345	345	0	0
(32)	Subtotal	8,750	8,750	0	0
(33)	OTHER REVENUE	-2,028	-1,366	0	-662
(35)	**TOTAL DISTRIBUTION**	**$188,147**	**$126,255**	**$0**	**$61,892**

NOVA SCOTIA POWER INC.

CLASSIFICATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

		(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
	RETAIL FUNCTION				
(1)	QTY. ASSURANCE. & COMM.	5,401	0	0	5,401
(2)	CALL CENTRE	20,974	0	0	20,974
(3)	BILLING SERVICES	6,536	0	0	6,536
(4)	ELECT. WIRING INSPECT. - H/O	471	0	0	471
(5)	METER DATA SERVICES	831	0	0	831
(6)	METER READING - FIELD	10,853	0	0	10,853
(7)	ELECT. WIRING INSPECT. - FIELD	6,098	0	0	6,098
(8)	PAYMENT SERVICES	1,250	0	0	1,250
(9)	CREDIT SERVICES	0	0	0	0
(10)	BAD DEBT EXPENSE	5,704	0	0	5,704
(11)	MARKETING & SALES	2,047	0	0	2,047
(12)	COGS (NET OF RETAIL SALES)	-499	0	0	-499
(13)	GRANTS IN LIEU OF TAXES	0	0	0	0
(14)	DEPRECIATION:				
(15)	DISTRIBUTION	0	0	0	0
(16)	GENERAL PROPERTY	0	0	0	0
(17)	INTEREST NET OF AFUDC	0	0	0	0
(18)	PREFERRED DIVIDENDS	0	0	0	0
(19)	CORPORATE TAXES	0	0	0	0
(20)	NON-OPERATING REVENUE:				
(21)	LATE PAYMENT CHARGE	-5,330	0	0	-5,330
(22)	MISC. ELECTRIC	-1,969	0	0	-1,969
(23)	OTHER REVENUE	-737	0	0	-737
(24)	RETURN (PROFIT/LOSS)	0	0	0	0
(26)	**TOTAL RETAIL**	**$51,629**	**$0**	**$0**	**$51,629**
(27)	**TOTAL NET EXPENSES**	**$1,277,146**	**$349,825**	**$813,800**	**$113,521**

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-17:

Reference: Distribution Tariff Draft and Attachments

Re page 11, Lines 23-25, please provide details of how rate base and expenses are adjusted to remove the Municipals.

Response DR-17:

Please refer to the following table.

Category	Total	Transmission-connected customers	Municipal Class	Total Net of Municipal Class
Revenue Requirement (in thousands of $'s)				
Distribution	$188,147	NA	$801	$187,346
COS reference	Exh 5, Page 3 line 35, col 1		Exh 6,(Page 1, line 43, col 10 + Page 4, line 14, col 10)	
Retail	$51,629	$271	$176	$51,182
COS reference	Exh 5, Page 4, line 26, col 1	(Exh 6, (Page 4, line 38, col 8) * 5/32 + (Page 4, line 38 col 1) * 2/8	(Exh 6, Page 4, line 38 col 1) * 6/8	
Rate Base (In thousands of $'s)				
Distribution	$769,145	NA	$2,826	$766,319
COS reference	Exh 2A, Page 2, line 53, col 1		Exh 3,(Page 1, line 42, col 10 + Page 5, line 20, col 10)	

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Please note that the value of the retail cost of retail customers set at $51,088 in the DT Strawman Report is incorrect due to an error in the original calculation. The correct value is $51,182. The Company will make an adjustment to the DT Tariff calculations to address this issue.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-18:

Reference: Distribution Tariff Draft and Attachments

Re page 12, Lines 1-3, does the COS distribution rate base and expenses already reflect that there are seven transmission connected customers? If not, what adjustments are necessary?

Response DR-18:

The COS distribution rate base and expenses already reflect that there are seven transmission-connected customers. No adjustments are necessary.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-19:

Reference: Distribution Tariff Draft and Attachments

Re page 12, Lines 14-15, please specify for each BTL what "applicable bundled ATL service" would apply.

Response DR-19:

The Large Industrial Distribution Tariff would apply to all distribution-connected large industrial customers billed under any Below-The-Line rates.

The Large General Distribution Tariff would apply to all distribution-connected large general customers billed under any Below-The-Line rates, other than the Shore Power rate. For customers billed under the Shore Power rate, the distribution component of the bundled Shore Power rate would apply.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-20:

Reference: Distribution Tariff Draft and Attachments

Re page 15, Lines 1-6, how much of the $83.3 million relates to distribution and retail and what effect (in percentage terms) does its exclusion have on the revenue requirement of the proposed DT?

Response DR-20:

The fixed cost deferral of $83.3 million was determined in the 2013 GRA proceeding outside of the Cost of Service framework. The deferral represents the remaining portion of the total revenue requirements in test years 2013 and 2014, after accounting for a 3% annual increase in composite rates. The $83.3 million of fixed costs whose recovery through rates was deferred in years 2013-2014 is included in the Cost of Service.

NS Power does not have functional area-specific fixed cost deferral information on the basis of which it could determine a portion of the deferral attributable to distribution and retail.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-21:

Reference: Distribution Tariff Draft and Attachments

Re page 26, Lines 2-4, are not all RtR customers required to have the TOD meters?

Response DR-21:

Yes, NS Power recommends that all Renewable to Retail customers be required to have interval/time-of-day meters with remote polling capability.

The proposed differentiated rate treatment between residential customers billed under the non-TOD and TOD rates is based on the assumption, originally contemplated by NS Power, that no interval metering would be required for RtR customers. The text in the "Domestic Time of Day rates" section on pages 25 and 26 has not been updated to reflect a change in this assumption. With the Company's proposal that all RtR customers are required to have interval metering, there is no longer a need to differentiate residential customer charges between the non-TOD and TOD customers. All open access residential customers will be, therefore, proposed to continue to pay the same charge of $10.83. Any incremental operational costs associated with interval metering, undetermined at this point, will be proposed to flow through to energy charges.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-22:

Reference: Distribution Tariff Draft and Attachments

Re Distribution Tariff, Section 4 – Is this section necessary? For what purpose?

Response DR-22:

Section 4 of the draft Distribution Tariff states:

> The Distribution Tariff has been approved by the Board. Nothing contained in the Distribution Tariff shall be construed as affecting in any way the right of NS Power to unilaterally make application to the Board for a change in any rates (including the Distribution Tariff rates set out in Appendix A), terms and conditions, charges, classification of service, rules or regulations.

This section was included in the Distribution Tariff for consistency with our Open Access Transmission Tariff in which it is included in Section 9.0 with the intent of providing clarity to users with respect to NS Power's right to make application to the Board for changes in the Distribution Tariff's elements.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-23:

Reference: Distribution Tariff Draft and Attachments

Re Distribution Tariff, Section 7 – Does the last paragraph fit here, under the heading "Ns Power Responsibilities"?

Response DR-23:

No, the last paragraph should not be included in the Distribution Tariff Section 7, and has been deleted. The clause is properly located in the LRS Terms and Conditions document, in Section 8.1.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-24:

Reference: Distribution Tariff Draft and Attachments

Re Appendix A, please provide derivation of minimum monthly charge of $17.51.

Response DR-24:

Starting with the 2013 GRA, NS Power has increased the minimum charge of the Miscellaneous Small Load rate commensurate with the overall increase in the unmetered base cost rates (electric service component before fixture capital and maintenance). The charge of $17.51 is the outcome of the cumulative effect of three rate increases:

1. 2012 GRA: $12.65 * 1.0981 = $13.89
2. 2013 GRA (2013 test year): $13.89 * 1.1722 = $16.28
3. 2013 GRA (2014 test year): $16.28 * 1.0757 = $17.51

ENERGY BALANCING SERVICE TARIFF
Renewable to Retail

ENERGY BALANCING SERVICE

The Energy Balancing Service is a supplemental generation service provided to Licenced Retail Suppliers (LRS) in respect of the Licenced Retail Supplier's RtR Customers utilizing the production from renewable low-impact generators. The service consists of delivery of complementary energy to RtR Customers and reception of surplus generation from qualifying generators. The service is required to be taken in conjunction with Standby Service under the Standby Service Tariff so that the reliability of service to RtR Customers is equivalent to that provided under Bundled Service. For the purposes of this Energy Balancing Service Tariff, hourly LRS load in excess of generation is defined as top-up energy and hourly generation in excess of LRS load is defined as spill energy.

All capitalized terms herein shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

AVAILABILITY

This Energy Balancing Service Tariff is applicable to the LRS in order to facilitate the purchase of renewable low-impact electricity by RtR Customers.

This Energy Balancing Service Tariff is provided under the following terms and conditions:

(1) The LRS must have a valid LRS Participation Agreement executed with NS Power; and

(2) The LRS must be providing service to RtR Customers.

APPLICABILITY

(1) An LRS taking service under this Energy Balancing Service Tariff shall also take service under the OATT, the Standby Service Tariff, and the Renewable to Retail Market Transition Tariff.

(2) The service under this Energy Balancing Service Tariff is based on metered energy quantities, and is independent of the LRS's forecasts. OATT Schedule 4 is not applicable, but the Generation Forecasting Service under Schedule 4A of the OATT is applicable.

(3) The hourly top-up and spill quantities are determined at the delivery point from the transmission system. The hourly top-up quantity equals the excess in each hour, if positive, of the LRS's aggregate customer load adjusted by the addition of distribution losses over the aggregate renewable low impact electricity supplied by the LRS or its contracted generation adjusted by the deduction of transmission losses. The hourly spill quantity equals the excess in each hour, if positive, of the aggregate renewable low impact electricity supplied by the LRS or its contracted generation adjusted by the deduction of

ENERGY BALANCING SERVICE TARIFF
Renewable to Retail

transmission losses over its aggregate customer load adjusted by the addition of distribution losses. The aggregate hourly load quantities are determined in accordance with the applicable provisions in the LRS Terms and Conditions.

(4) To qualify for this service, the LRS must ensure that the imbalance between low impact renewable generation and energy consumption over the established compliance period conforms to Section 10 of the Board Electricity Retailers Regulations (Nova Scotia) enacted under the Act.

(5) Maximum Spill Capacity must be approved by NS Power prior to commencement of service and will be limited to a level agreed as being required to provide the contracted annual amount of participating LRS energy. Spill capacity will be reviewed annually and will include the LRS' proposal to mitigate it on a going forward basis. If NS Power is not satisfied with the LRS' proposal, it may impose a limit on hourly production of the LRS's generation portfolio.

ADMINISTRATION CHARGE

The monthly administration charge is applicable to each LRS and is set annually according to the following formula:

$$\text{Monthly charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of LRS's subscribed} * 12}$$

This charge will be $1,053.03 per month.

ENERGY CHARGE

Energy charge for top-up service is made up of the following two components:

1. Annually adjusted fuel cost component based on NS Power's incremental cost of serving the LRS's forecasted incremental top-up load.

2. Fixed cost adder reflective of fixed cost energy-related generation costs.

Energy Charge Components	**Cents per kWh**
Fuel Cost	6.650
Fixed Cost Adder	3.309
Total	9.959

The charge is applicable to top-up energy consumed in each hour.

ENERGY BALANCING SERVICE TARIFF
Renewable to Retail

ENERGY CREDIT

The Energy Credit for spill service is set annually, on a calendar year basis, and is made up of two components:

1. Monthly compensation for spill energy delivered to NS Power and applicable in each hour of 5.27 cents per kilowatt hour

2. The year-end refund to NS Power on monthly compensation in respect of annual excess spill energy above annual consumption of the LRS's RtR Customers recognized without discount as set out in the following table:

Annual Excess Spill Quantity in the range	**Discount Applied**	**Cents per kWh**
from 0% to 10% of Annual LRS Load	0%	5.270
greater than 10% up to 20% of Annual LRS Load	10%	4.743
greater than 20% up to 30% of Annual LRS Load	25%	3.953
greater than 30% of Annual LRS Load	50%	2.635

MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the administration charge

SPECIAL CONDITIONS

(1) NS Power reserves the right to have a separate service agreement, if in the opinion of NS Power issues not specifically set out herein, must be addressed for the ongoing benefit of NS Power and its customers.

(2) The LRS's RtR Customers and generators will make all necessary arrangements to ensure that their generation and load do not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the

following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(4) Nothing contained in this Energy Balancing Service Tariff or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to make application to the Nova Scotia Utility and Review Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this Energy Balancing Service Tariff, the Standby Service Tariff or the Renewable to Retail Market Transition Tariff.

Energy Balancing Service: Administration Charge Calculations

Assumptions
(1) One Full Time Equivalent is sufficient to provide admin service in the initial market opening
(2) Assume 4 Licensed Service Providers. Note that this approach aligns with that used under the current Backup/Top-up Tariff.
(3) Admin costs to be shared equally between Energy Balancing and Standby Services

Full Time Equivalent (FTE) Cost

Salary		58,098
Fringe Benefits	16.0%	$9,296
Salary (including fringe benefits)		$67,394
Administrative Overhead	50%	$33,697
Forecast Cost		$101,090.88

Administration Charge Under Energy Balancing Service

Customer Charge Under BackUp Rate

Annual Cost (50% of total)	$50,545
Number of LRS	4
Monthly Administration Charge	**$1,053.03**

Standby Service: Customer Charge Calculations

Full Time Equivalent (FTE) Cost

Salary		58,098
Fringe Benefits	16.0%	$9,296
Salary (including fringe benefits)		$67,394
Administrative Overhead	50%	$33,697
Forecast Cost		$101,091

Administration Charge Under Standby Service

Annual Cost (50% of total)	$50,545
Number of LRS	4
Monthly Administration Charge	**$1,053.03**

Item #	Annual Avoided Fuel Cost Calculations					
	Source		**Annual GWh Load at Transmission Level**	**Cost**	**Avoided Unit Cost (c/kWh)**	**Comments/Assumptions**
		Avoided Costs				
1	Plexos Simulations	Avoided Costs of departing customer Load before taking energy balancing service from NS Power.	219	$13,052,400	5.960	Going forward the Company intends to use forecast load and hourly loadshape of customers served in the RtR market. For the purposes of this simulation the Company used flat 25 MW decrement.
2	Plexos Simulations	Avoided Costs of departing customer Load after taking energy balancing service from NS Power	219	$11,541,300	5.270	Going forward the Company intends to use NS Power's system hourly loadshape which will reflect the combined effect of hourly load of departing customers to the RtR market and 3rd party renewable generation under assumption that some of it may be curtailed. For the purposes of this simulation the Company used only the effect of 3rd party renewable generation under no curtailment assumption.
3		Cost Differential between items 1 and 2 above		$1,511,100		This is an incremental fuel cost arising from provision of energy balancing service to departed customers
4		**Spill Energy Credit rate**			5.270	Set at par with unit avoided costs under item #2.
5		**Top-up Energy Rate Calculation**				
5.1		**Avoided Fuel Cost Component**				
5.1.1		Average avoided cost after energy balancing service			5.270	Set at par with unit avoided costs under item #2.
5.1.2		Incremental costs associated with energy balancing service	109.5	$1,511,100	1.380	Going forward the Company intends to use forecast annual top-up energy in the RtR market in calculation of this charge. For now a simplifying assumption was made that top-up energy accounts for 50% of the total energy consumed in the RtR market (219 GWh/2 = 109.5 GWh)
		Fuel Cost charge			**6.650**	
4.2		**Energy-related fixed cost Component**				
	Appendix C 2014 COS Costs - Exhibit 5; page 1 Energy - Exhibit 9A, line 11, col 3 divided by a transmission loss factor of 1.032.	Fixed Energy-related Cost in '000's of $	9,507,746	$314,631,000	3.309	Calculated as follows: total of $753,049 (less fuel of $367,943, purchased power regular of $507, purchased biomass power $11595, purchased wind power of $59,982, purchased imports of $217; plus export sales of $1,826
		Charge in cents per kWh				

Total top-up charge in cents per kWh	**9.959**

Top-up Energy Rate Calculation	
Energy-related fixed cost Component	
COST	
Energy Expenses (Generation Function) from COSS Exh 5, cell E42	753049000
Fuel	367943000
Purchased Power regular	507000
Purchased Biomass Power	11595000
Purchased Wind Power	59982000
Purchased Imports	217000
Export Sales	1826000
	314631000
Annual GWh Load at Transmission Level	
Energy Requirement from COSS Exh 9a Annual, cell D24	9811994
Transmsission Loss Factor from XXXXX	1.032
	9507746.124

Nova Scotia POWER
An Emera Company

JUNE 8, 2015

Proposed Energy Balancing Service and Standby Service Tariffs for the Renewable to Retail Market

energy everywhere.™

Legislative Directive – Electricity Reform Act

"NS Power shall develop in consultation with stakeholders, and file with the Board for approval, any tariffs, … and any amendments to existing tariffs …, that are necessary to facilitate the purchase of renewable low-impact electricity … including

- a new or amended backup/top-up service tariff
- a new or amended non-dispatchable supplier spill tariff

Rationale

- The output of non-dispatchable low impact renewable generation cannot be controlled on-demand by the operator and matched with RtR customer load on an hourly basis.
- In hours when generation falls below customer load, the utility must provide top-up energy.
- In hours of surplus generation (spill), the utility must absorb it into its system.
- To ensure that service to RtR customers is reliable, the utility must also provide backup/standby service.

BUTUS redesign for RtR

- Energy Balancing Service (EBS) and Standby Service (SS) will be mandatory services provided by NS Power to Licensed Retail Suppliers
- Cost-based: no cost transfer to bundled service customers
- Top-up and Spill services - combined into Energy Balancing Service
- Backup service - replaced by Standby Service

Proposed design of EBS

For the RtR Market, NS Power proposes a new Energy Balancing Service

- Customer charge based on incremental admin costs
- Energy charge for top-up (10.101 ¢/kWh) to include:
  - Annually adjusted fuel cost (6.650 ¢/kWh)
  - Fixed cost for fixed energy-related gen costs (3.451 ¢/kWh)
    - Same philosophy as used in Shore Power rate
- Energy credit (5.27 ¢/kWh) for spill to include
  - Monthly credit reflective of value of incremental energy
  - Year-end compensation adjustment for surplus Spill energy
  - Max. Spill Capacity subject to NS Power approval
- Generation scheduling similar to Market Rules and OATT with addition of a charge for forecasting discrepancies – OATT Schedule 4A: Generation Forecasting Service.
- RtR Load included in NSP system load schedule

Note: Rates shown are indicative and conditional on the Board's approval.

Proposed design of Standby Service

- Instead of amending existing Backup rate, NS Power proposes new SS service for RtR market.
  - Customer charge based on incremental admin costs.
  - Non-coincident Billing demand replaced with ratcheted Monthly Coincident Demand (MCD).
    - MCD is maximum firm demand coincident with system peaks - Dec, Jan, Feb.
    - Separate coincidence values for each (firm) rate class of the LRS' RtR customers, interruptible customers excluded.
    - Recognizes contributions to capacity from 3rd party generators.
  - MCD charge is $5.370/month/kW of maximum firm coincident demand

Note: Rates shown are indicative and conditional on the Board's approval.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-25:

Reference: Energy Balancing Service (EBS), Standby Service (SS) and Generation Forecasting Service (GFS) Proposals

Please provide the derivation of all charges in the EBS tariff.

Response DR-25:

Please refer to **Attachment 1**, also provided electronically, for derivation of the administration charge, energy charge and monthly energy credit. The avoided cost results are preliminary at this stage. Some of the cost and load figures are estimates at this stage and are used for illustrative purposes.

The proposed year-end refund to the Company for excess spill has been designed to align directionally with the perceived progression in costs of displaced generation, but is not rooted in actual cost analysis at this point. The Company is in the process of conducting an analysis of displaced costs at various RtR service uptake levels using Plexos. Upon completion, the Company will review and refine the calculation.

Energy Balancing Service: Administration Charge Calculations

Assumptions
(1) One Full Time Equivalent is sufficient to provide admin service in the initial market opening
(2) Assume 4 Licensed Service Providers. Note that this approach aligns with that used under the current Backup/Top-up Tariff.
(3) Admin costs to be shared equally between Energy Balancing and Standby Services

Full Time Equivalent (FTE) Cost

Salary		58,098
Fringe Benefits	16.0%	$9,296
Salary (including fringe benefits)		$67,394
Administrative Overhead	50%	$33,697
Forecast Cost		$101,090.88

Administration Charge Under Energy Balancing Service

Customer Charge Under BackUp Rate

Annual Cost (50% of total)	$50,545
Number of LRS	4
Monthly Administration Charge	**$1,053.03**

Standby Service: Customer Charge Calculations

Full Time Equivalent (FTE) Cost

Salary		58,098
Fringe Benefits	16.0%	$9,296
Salary (including fringe benefits)		$67,394
Administrative Overhead	50%	$33,697
Forecast Cost		$101,091

Administration Charge Under Standby Service

Annual Cost (50% of total)	$50,545
Number of LRS	4
Monthly Administration Charge	**$1,053.03**

Item # **Annual Avoided Fuel Cost Calculations**

Item #	Source		Annual GWh Load	Cost	Avoided Unit Cost (c/kWh)	Comments/Assumptions
		Avoided Costs				
1	Plexus Simulations	Avoided Costs of departing customer Load before taking energy balancing service from NS Power.	219	$13,052,400	5.960	Going forward the Company intends to use forecast load and hourly loadshape of customers served in the RtR market. For the purposes of this simulation the Company used flat 25 MW decrement.
2	Plexus Simulations	Avoided Costs of departing customer Load after taking energy balancing service from NS Power	219	$11,541,300	5.270	Going forward the Company intends to use NS Power's system hourly loadshape which will reflect the combined effect of hourly load of departing customers to the RtR market and 3rd party renewable generation under assumption that some of it may be curtailed. For the purposes of this simulation the Company used only the effect of 3rd party renewable generation under no curtailment assumption.
3		Cost Differential between items 1 and 2 above		$1,511,100		This is an incremental fuel cost arising from provision of energy balancing service to departed customers
4		**Spill Energy Credit rate**			5.270	Set at par with unit avoided costs under item #2.
5		**Top-up Energy Rate Calculation**				
5.1		**Avoided Fuel Cost Component**				
5.1.1		Average avoided cost after energy balancing service			5.270	Set at par with unit avoided costs under item #2.
5.1.2		Incremental costs associated with energy balancing service	109.5	$1,511,100	1.380	Going forward the Company intends to use forecast annual top-up energy in the RtR market in calculation of this charge. For now a simplifying assumption was made that top-up energy accounts for 50% of the total energy consumed in the RtR market (219 GWh/2 = 109.5 GWh)
		Fuel Cost charge			**6.650**	
4.2		**Energy-related fixed cost Component**				
	Appendix C 2014 COS Costs - Exhibit 5, page 1 Energy - Exhibit 9A, line 11, col 1.	Fixed Energy-related Cost in '000's of $ Charge in cents per kWh	9,116,236	$314,631,000	3.451	Calculated as follows: total of $753,049 less fuel of $367,943, purchased power regular of $507, purchased biomass power $11595, purchased wind power of $59,982, purchased imports of $217; plus export sales of $1,826
		Total top-up charge in cents per kWh			**10.101**	

NON-CONFIDENTIAL

Request DR-27:

Reference: Energy Balancing Service (EBS), Standby Service (SS) and Generation Forecasting Service (GFS) Proposals

With respect to the EBS APPLICABILITY Clause 4, would it make sense to replace this clause with some reference to Board regulations that address this, to ensure consistency (particularly considering that the Board regulation on this issue is still under development)?

Response DR-27:

The EBS Availability Clause (4) states:

> To qualify for this service, the LRS must ensure that low impact renewable generation meets the kWh energy needs of its customers on an annual basis. This requires that top-up energy not exceed spill energy on an annual basis.

The Company concurs with Multeese's suggestion and proposes the following changes to the wording of Clause (4):

> To qualify for this service, the LRS must ensure that the imbalance between low impact renewable generation and energy consumption over the established compliance period conforms to Section 10 of the Board-approved Regulation.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-34:

Reference: Energy Balancing Service (EBS), Standby Service (SS) and Generation Forecasting Service (GFS) Proposals

Please discuss whether the fixed cost adder in the EBS includes the cost of the GFS.

Response DR-34:

The fixed cost adder in the EBS tariff does not include costs incurred by RtR generators in forecasting its generation.

The adder also does not include the cost to the Company associated with inaccurate generation forecasts provided by RtR generators. While such costs exist they are difficult to determine. The proposed compensation mechanism under Schedule 4A is aligned with the payment structure under *Generation Energy Imbalance for Non-Dispatchable Generators* in Schedule 4. Under both schedules generators see similar disincentives equivalent to 10% of marginal cost per each MWh falling outside of a deviation band of +/-10% (with a minimum deviation band of +/-2 MW). Please refer also to Multeese DR-33.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Port Hawkesbury Paper Data Requests

NON-CONFIDENTIAL

Request DR-1:

On the slide entitled "Proposed Design of EBS, NSPI states that the energy charge for top-up will include an annually adjusted fuel cost of 6.650 cents/kWh and fixed cost for fixed energy-related generation costs of 3.451 cents/kWh, and the Energy credit for spill will be 5.27 cents/kWh.

(a) Please confirm that the annually adjusted fuel cost is a forecast that will be changed annually and provide the supporting calculations for the 6.650 cents/kWh figure.

(b) Please provide the supporting calculation for the 5.27 cents/kWh energy credit for spill figure, and indicate whether this is also based on a forecast.

(c) Please provide an explanation as to why the fuel component of the energy charge for top-up is significantly higher than the energy credit for spill.

(d) Will the energy credit for spill also be subject to change on an annual basis, and if so, what process would be followed to change this figure?

(e) Is it NSPI's position that the fixed energy-related generation costs would not be incurred absent the energy balancing service? If not, please explain the rationale for including this cost in the energy charge for top-up, given that these costs would be incurred anyway.

Response DR-1:

(a-b) Confirmed. Please refer to Multeese DR-25 for supporting calculations.

(c) The variable cost element of top-up is higher than the variable cost credit for spill. There are a number of contributing factors:

(i) There is a non-fuel variable cost associated with the management of top-up and spill. This is added to the top-up rate but deducted from the spill credit.

(ii) Irrespective of the RtR generation profile, it can be expected that top-up will be required more often at times of above average RtR load which can reasonably be expected to coincide with above average system load (with a tendency for higher marginal generation cost), and spill will be more prevalent at times of below average RtR load which can reasonably be expected to coincide with below average system load (with a tendency for lower marginal generation cost). This effect will contribute to the variable top-up rate being higher than the spill credit.

(iii) There is a large quantity of wind generation already connected to and supplying, or committed for supply to, the Nova Scotia system. RtR wind generation will have a production profile strongly correlated with the production profile of this other existing or committed wind generation. RtR wind generation will therefore have high production, with a tendency to produce spill, at times of high system wind production and thus of low system marginal fuel cost. Top-up is likely to be required in respect of RtR wind generation at times of low system wind production, and thus of higher system marginal fuel cost.

(d) The energy credit will be changed on annual basis. Please refer to Multeese DR-25 for more details.

(e) The Company needs generation resources to deliver top-up service. In accordance with the Company's Cost of Service methodology, the total fixed costs of the generation resources required are classified into those recoverable from demand and recoverable from energy. The backup tariff addresses recovery of costs classified as recoverable from demand, and the energy balancing tariff addresses recovery of costs classified as recoverable from energy. The energy supplied under this tariff is top-up energy, and the

NON-CONFIDENTIAL

fixed cost recovery is therefore applicable to this quantity. There is no reduction in NS Power's fixed generation costs due to RtR spill, so there is no corresponding spill credit in respect of those fixed costs.

STANDBY SERVICE TARIFF
Renewable to Retail

STANDBY SERVICE

Standby Service is a supplemental generation capacity service provided to Licenced Retail Suppliers (LRS). The service is provided in combination with Energy Balancing Service under the Energy Balancing Service Tariff. The service has two components:

> **Capacity adequacy service –** fulfillment of the LRS's obligation to provide or pay for its share of firm capacity required to meet adequacy standards of the Nova Scotia electricity system arising from forced and unforced generation outages. Energy delivered during generation outages will be billed under the Energy Balancing Service Tariff.
>
> **Top-up capacity service –** provision of capacity to support energy delivery through the Energy Balancing Service in respect of imbalance between load and generation.

All capitalized terms herein shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

AVAILABILITY

This Standby Service Tariff is applicable to the LRS to facilitate the purchase of renewable low-impact electricity by RtR Customers.

This Standby Service Tariff is provided under the following terms and conditions:

(1) The LRS must have a valid LRS Participation Agreement executed with NS Power; and.

(2) The LRS must be providing service to RtR Customers.

APPLICABILITY

(1) An LRS taking service under this Standby Service Tariff shall also take service under Open Access Transmission Tariff (OATT), the Energy Balancing Service Tariff and the Renewable to Retail Market Transition Tariff.

(2) The service under this Standby Service Tariff is complementary to the generation ancillary services to the Renewable to Retail market under OATT.

(3) The aggregate hourly load quantities are determined at the delivery point from the transmission system, inclusive of distribution system losses, in accordance with the provisions of the LRS Terms and Conditions.

(4) This service is applicable to firm load only.

STANDBY SERVICE TARIFF
Renewable to Retail

ADMINISTRATION CHARGE

The monthly administration charge is applicable to each LRS and is set annually according to the following formula:

$$\text{Monthly charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of LRS's subscribed} * 12}$$

This charge will be $1,053.03 per month.

DEMAND CHARGE

$5.370 per month, per kilowatt (kW) of monthly standby contract demand.

MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the administration charge.

DETERMINATION OF MONTHLY STANDBY CONTRACT DEMAND

Monthly Standby Contract Demand (MSCD) in kW is determined using the following formula:

$$MSCD = LWPFD - \min\left(LWPFD, \left(\sum_{i=1}^{n} CCi * GCi\right)/(1+PR)\right)$$

Where :

LWPFD is LRS Winter Peak Firm Demand in respect of each billing month calculated as follows:

$$LWPFD = \sum_{i=1}^{k} (CMPFDi * CMDAFi)$$

"k" is the number of otherwise applicable bundled service rate classes to RtR customers of LRS.

"CMPFDi" is hourly kW Class Monthly Peak Firm Demand of the LRS firm load in each tariff class at the time of system coincident firm load peak in each month at transmission delivery points (i.e. inclusive of distribution system losses). The CMPFD for the unmetered customer class shall be determined by use of research based class load profile data.

STANDBY SERVICE TARIFF
Renewable to Retail

"CMDAFi" is the Class Monthly Demand Adjustment Factor applicable to each class as set out below:

Classes	Jan, Feb, Dec	Mar, Apr	May, June	Jul, Aug, Sep	Oct, Nov
Domestic	1.00	1.27	1.67	2.17	1.47
Small General	1.00	1.21	1.32	1.09	1.28
General	1.00	1.12	1.32	1.05	1.19
Large General	1.00	1.05	1.04	0.78	0.99
Small Industrial	1.00	1.06	1.01	0.94	1.00
Medium Industrial	1.00	1.14	1.08	1.01	1.02
Large Industrial Firm	1.00	1.10	1.03	0.89	1.09
Unmetered	1.00	8.24	7.90	7.68	2.28

"PR" is Planning Reserve (%) (based on Northeast Power Coordinating Council planning criteria, i.e., 20% or as updated)

"CCi" is a capacity contribution factor of LRS' generator to NS Power's system peak as determined by NS Power. The capacity contribution factor may be the subject of periodic adjustment if operating conditions of the generator, such as a prolonged deration, depart from those assumed by NS Power.

"GCi" is the generator capacity dedicated to serving LRS load.

"n" is the total number of LRS' generators including those under contract.

SPECIAL CONDITIONS

(1) NS Power reserves the right to have a separate service agreement, if in the opinion of NS Power issues not specifically set out herein, must be addressed for the ongoing benefit of NS Power and its customers.

(2) The LRS's RtR Customers and generators will make all necessary arrangements to ensure that their generation and load do not unduly deteriorate the integrity of the power supply system, either by its design or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

STANDBY SERVICE TARIFF
Renewable to Retail

(4) Nothing contained in this Standby Service Tariff or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to make application to the Nova Scotia Utility and Review Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this Standby Service Tariff, the Energy Balancing Service Tariff or the Renewable to Retail Market Transition Tariff.

Source	Category				Comments/ Assumptions
	Demand-related Costs	**Cost in thousands of $'s**			
Appendix C 2014 COS Costs - Exhibit 5, page 1, column 2.	**Demand-related fixed gen costs net of fuel costs**		$167,212		Calculated as follows: total of $176,854 k less purchased power regular of $390 k, purchased biomass power $2,205 k, purchased wind power of $7,048 k
GRA 2013 DE-03 - DE-04 Appendix L Attachment 3 pages 7 and 8, Figures 3-7 and 3-8	**Less: Ancillary generation-related costs recovered under OATT**				
	Reactive Supply & Voltage Control	$4,329			
	Regulation & Frequency	$5,092			
	Load Following	$18,225			
	Operating Reserve - Spinning (10 min)	$3,908			
	Operating Reserve - Supplemental (10 min)	$7,785			
	Operating Reserve - Supplemental (30 min)	$6,598			
		$45,937			
	Demand-related fixed Gen. Costs net of Ancillary Service Costs3		$121,275		

Source	**Capacity Usage in kW**			
	Transmission Loss at 69 kV			3.2%
		Sum of 3 Coincident Winter Peaks	**3CP Monthly Ave**	**At 69 kV**
		At Generator's Gate		**Transmission**
	(1) DOMESTIC	3,327,702	1,109,234	1,074,881
	(2) SMALL GENERAL	123,720	41,240	39,963
	(3) GENERAL	1,361,828	453,943	439,884
	(4) GENERAL LARGE	161,337	53,779	52,114
	(5) SMALL INDUSTRIAL	116,650	38,883	37,679
Appendix C 2014 COS Costs - page 65 of 80, Exhibit 9A, col 10.	(6) MEDIUM INDUSTRIAL	225,735	75,245	72,915
	(7) LARGE INDUSTRIAL	318,264	106,088	102,802
	(8) ELI 2P-RTP	0	0	0
	(9) MUNICIPAL	122,088	40,696	39,436
	(10) UNMETERED	69,089	23,030	22,316
		5,826,414	1,942,138	1,881,990

Standby Demand Charge Calculation	**Cost**	**Usage**	**Unit Cost per kW**
Annual Rate per kW demand at 69 kV Voltage	$121,275.45	1,881,990	$64.440
Monthly Rate per kW demand at 69 kV Voltage			$5.370

FIGURE 3-1

NOVA SCOTIA POWER INC.
ANCILLIARY SERVICE RATE CALCULATION
2013 SCHEDULING, SYSTEM CONTROL AND DISPATCH

Service	(1) Total Cost of Service (in $000s)	(2) Total Usage (in MW)	(3) Yearly Cost $/MW-year	(4) Monthly Cost $/MW-month
Scheduling, System Control & Dispatch	$78	16	$4,838.94	$403.24

Sched., Sys. Cntrl. & Disp. for Point-to-Point		Rate for Services Billed Monthly Services	$/MW-year	$/MW-month
Yearly		Monthly Cost	4,838.94	403.24
Monthly	($/MW-m)	Yearly/12		403.24
Weekly	($/MW-w)	Yearly/52		93.06
On-Peak Daily	($/MW-d)	Weekly/5		18.61
Off-peak Daily	($/MW-d)	Yearly/365		13.26
On-Peak Hourly	($/MW-h)	Daily/16		1.16
Off-Peak Hourly	($/MW-h)	Yearly/8760		0.55

	Cost of Service					
	Total Cost of Service (in $000s)	Total Usage (in MW)	($MW-year)	($MW-month)	Coincidence Factor	Rate Monthly ($MW-month)
Sched., Sys. Cntrl. & Disp. for Network Service	$8,052	1,664	$4,838.94	$403.24	85.0%	$342.76

NOTE:
This approach facilitates the use of non-coincident peaks for billing purposes consistent with EMGC Recommendation 28.

FIGURE 3-2

NOVA SCOTIA POWER INC.
CAPACITY BASED ANCILLARY SERVICES
NOVA SCOTIA USAGE

	(1)	(2)	(3)	(4)	(5)
		Network Service Billing Determinants			
	Usage by Point-to-Point MW	Total MW	Loads that Self Supply MW	Loads that Purchase From Third Party MW	Net Usage in Tariff MW
Regulation and Frequency Response					
Regulation	0	1,958			1,958
Load Following	0	1,958			1,958
Operating Reserves (Contingency Reserves)					
Spinning (10 Minute)	0	1,958			1,958
Supplemental (10 Minute)	0	1,958			1,958
Supplemental (30 Minute)	0	1,958			1,958

NOTES:
1. The Network Billing Determinants (based on 12 NCP) are as per Figure 2-2.
2. These services apply only to Network Service loads or to point-to-point services within Nova Scotia. They do not apply to point-to-point service used for exports, because for exports, those services would be the responsibility of the customer receiving the supply. That customer would purchase these ancillary services from the transmission provider in the operating area where the load is located.

FIGURE 3-3

NOVA SCOTIA POWER INC.
CAPACITY BASED ANCILLARY SERVICES
2013 REVENUE REQUIREMENT AND RATE DESIGN

	(1) Revenue Requirement ($/kW-yr)	(2) Services Required (MW)	(3) Revenue Requirement ($000/yr)	(4) Usage (MW)	(5) Rate for Network ($/MW-yr)	(6) Rate for Network ($/MW-mo)	(7) Rate for Pt.-to-Pt. ($/MW-mo)	(8) Rate for Pt.-to-Pt. ($/MW-wk)	(9) Rate for Pt.-to-Pt. ($/MW-dy)
Regulation and Frequency Response									
Regulation	$ 87.49	58	$5,092.18	1,958	$2,600.70	$216.73	$216.73	$50.01	$7.13
Load Following	$ 120.77	151	$18,224.83	1,958	$9,307.88	$775.66	$775.66	$179.00	$25.50
Operating Reserves (Contingency Reserves)									
Spinning (10 Minute)	$ 118.42	33	$3,908.02	1,958	$1,995.92	$166.33	$166.33	$38.38	$5.47
Supplemental (10 Minute)	$ 56.41	138	$7,784.77	1,958	$3,975.88	$331.32	$331.32	$76.46	$10.89
Supplemental (30 Minute)	$ 131.95	50	$6,597.75	1,958	$3,369.64	$280.80	$280.80	$64.80	$9.23

NOTES:
1. Revenue Requirement is from Attachment 4.

FIGURE 3-4

NOVA SCOTIA POWER INC.
2013 REACTIVE SUPPLY AND VOLTAGE CONTROL
RATE DESIGN

	(1) Revenue Requirement ($000/yr)	(2) Billing Determinants (MW)	(3) Yearly ($/MW-yr)	(4) Monthly ($/MW-mo)	(5) Weekly ($/MW-wk)	(6) On-Peak Daily ($/MW-dy)	(7) Off-Peak Daily ($/MW-dy)	(8) On-Peak Hourly ($/MW-hr)	(9) Off-Peak Hourly ($/MW-hr)
Reactive Supply and Voltage Control									
Total	$4,329.0								
Less: Credits	0.0								
Net	4,329.0								
Point-to-Point	$41.5	16	$2,576.61	$214.72	$49.55	$9.91	$7.06	$0.62	$0.29
Network Services	$4,287.5	1,958	$2,189.72	$182.48					
		1,974							

NOTES:
1. Point-to-Point and Network Services Reactive Supply and Voltage Control Revenue Requirements are segregated as per Figure 2-2, Col. 3.

FIGURE 3-5

NOVA SCOTIA POWER INC.
ANCILLIARY SERVICE RATE CALCULATION
2014 SCHEDULING, SYSTEM CONTROL AND DISPATCH

Service	(1) Total Cost of Service (in $000s)	(2) Total Usage (in MW)	(3) Yearly Cost $/MW-year	(4) Monthly Cost $/MW-month
Scheduling, System Control & Dispatch	$80	16	$4,997.38	$416.45

Sched., Sys. Cntrl. & Disp. for Point-to-Point		Rate for Services Billed Monthly Services	$/MW-year	$/MW-month
Yearly		Monthly Cost	4,997.38	416.45
Monthly	($/MW-m)	Yearly/12		416.45
Weekly	($/MW-w)	Yearly/52		96.10
On-Peak Daily	($/MW-d)	Weekly/5		19.22
Off-peak Daily	($/MW-d)	Yearly/365		13.69
On-Peak Hourly	($/MW-h)	Daily/16		1.20
Off-Peak Hourly	($/MW-h)	Yearly/8760		0.57

	Cost of Service: Total Cost of Service (in $000s)	Cost of Service: Total Usage (in MW)	Cost of Service: ($MW-year)	Cost of Service: ($MW-month)	Coincidence Factor	Rate Monthly ($MW-month)
Sched., Sys. Cntrl. & Disp. for Network Service	$8,306	1,662	$4,997.38	$416.45	85.0%	$353.98

NOTE:
This approach facilitates the use of non-coincident peaks for billing purposes consistent with EMGC Recommendation 28.

FIGURE 3-6

NOVA SCOTIA POWER INC.
2014 CAPACITY BASED ANCILLARY SERVICES
NOVA SCOTIA USAGE

	(1)	(2)	(3)	(4)	(5)
		Network Service Billing Determinants			
	Usage by Point-to-Point MW	Total MW	Loads that Self Supply MW	Loads that Purchase From Third Party MW	Net Usage in Tariff MW
Regulation and Frequency Response					
Regulation	0	1,955			1,955
Load Following	0	1,955			1,955
Operating Reserves (Contingency Reserves)					
Spinning (10 Minute)	0	1,955			1,955
Supplemental (10 Minute)	0	1,955			1,955
Supplemental (30 Minute)	0	1,955			1,955

NOTES:
1. The Network Billing Determinants (based on 12 NCP) are as per Figure 2-7.
2. These services apply only to Network Service loads or to point-to-point services within Nova Scotia. They do not apply to point-to-point service used for exports, because for exports, those services would be the responsibility of the customer receiving the supply. That customer would purchase these ancillary services from the transmission provider in the operating area where the load is located.

FIGURE 3-7

NOVA SCOTIA POWER INC.
CAPACITY BASED ANCILLARY SERVICES
2014 REVENUE REQUIREMENT AND RATE DESIGN

	(1) Revenue Requirement ($/kW-yr)	(2) Services Required (MW)	(3) Revenue Requirement ($000/yr)	(4) Usage (MW)	(5) Rate for Network ($/MW-yr)	(6) Rate for Network ($/MW-mo)	(7) Rate for Pt.-to-Pt. ($/MW-mo)	(8) Rate for Pt.-to-Pt. ($/MW-wk)	(9) Rate for Pt.-to-Pt. ($/MW-dy)
Regulation and Frequency Response									
Regulation	$ 87.49	58	$5,092.18	1,955	$2,604.69	$217.06	$217.06	$50.09	$7.14
Load Following	$ 120.77	151	$18,224.83	1,955	$9,322.16	$776.85	$776.85	$179.27	$25.54
Operating Reserves (Contingency Reserves)									
Spinning (10 Minute)	$ 118.42	33	$3,908.02	1,955	$1,998.99	$166.58	$166.58	$38.44	$5.48
Supplemental (10 Minute)	$ 56.41	138	$7,784.77	1,955	$3,981.98	$331.83	$331.83	$76.58	$10.91
Supplemental (30 Minute)	$ 131.95	50	$6,597.75	1,955	$3,374.81	$281.23	$281.23	$64.90	$9.25

NOTES:
1. Revenue Requirement is from Attachment 4.

FIGURE 3-8

NOVA SCOTIA POWER INC.
2014 REACTIVE SUPPLY AND VOLTAGE CONTROL
RATE DESIGN

	(1) Revenue Requirement ($000/yr)	(2) Billing Determinants (MW)	(3) Yearly ($/MW-yr)	(4) Monthly ($/MW-mo)	(5) Weekly ($/MW-wk)	(6) On-Peak Daily ($/MW-dy)	(7) Off-Peak Daily ($/MW-dy)	(8) On-Peak Hourly ($/MW-hr)	(9) Off-Peak Hourly ($/MW-hr)
Reactive Supply and Voltage Control									
Total	$4,329.0								
Less: Credits	0.0								
Net	4,329.0								
Point-to-Point	$41.5	16	$2,579.68	$214.97	$49.61	$9.92	$7.07	$0.62	$0.29
Network Services	$4,287.4	1,955	$2,193.06	$182.76					
		1,971							

NOTES:
1. Point-to-Point and Network Services Reactive Supply and Voltage Control Revenue Requirements are segregated as per Figure 2-7, Col. 3.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-28:

Reference: Energy Balancing Service (EBS), Standby Service (SS) and Generation Forecasting Service (GFS) Proposals

With respect to the two components of the SS identified on page 1, please identify each of these in the formula proposed for the calculation of the Monthly Standby Contract Demand.

Response DR-28:

The description of the two components of SS on page 1 is intended to provide information about the reasons for the service, but not a description of two separate rate formula elements. The proposed formula does not differentiate between the capacity adequacy service during RtR generator outages and the delivery of top-up service.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-29:

Reference: Energy Balancing Service (EBS), Standby Service (SS) and Generation Forecasting Service (GFS) Proposals

Please provide the derivation of all charges in the SS tariff.

Response DR-29:

Please refer to **Attachment 1**, also provided electronically, for the derivation of the demand charge. For the derivation of the administration charge please refer to Multeese DR-25 Attachment 1.

Source	Category				Comments/ Assumptions
	Demand-related Costs	**Cost in thousands of $'s**			
Appendix C 2014 COS Costs - Exhibit 5, page 1, column 2.	**Demand-related fixed gen costs net of fuel costs**		$167,212		Calculated as follows: total of $176,854 k less purchased power regular of $390 k, purchased biomass power $2,205 k, purchased wind power of $7,048 k
GRA 2013 DE-03 - DE-04 Appendix L Attachment 3 pages 7 and 8, Figures 3-7 and 3-8	**Less: Ancillary generation-related costs recovered under OATT**				
	Reactive Supply & Voltage Control	$4,329			
	Regulation & Frequency	$5,092			
	Load Following	$18,225			
	Operating Reserve - Spinning (10 min)	$3,908			
	Operating Reserve - Supplemental (10 min)	$7,785			
	Operating Reserve - Supplemental (30 min)	$6,598			
		$45,937			
	Demand-related fixed Gen. Costs net of Ancillary Service Costs3		$121,275		

Source	**Capacity Usage in kW**			
	Transmission Loss at 69 kV			3.2%
		Sum of 3 Coincident Winter Peaks	**3CP Monthly Ave**	
		At Generator's Gate		**At 69 kV Transmission**
	(1) DOMESTIC	3,327,702	1,109,234	1,074,881
	(2) SMALL GENERAL	123,720	41,240	39,963
	(3) GENERAL	1,361,828	453,943	439,884
	(4) GENERAL LARGE	161,337	53,779	52,114
	(5) SMALL INDUSTRIAL	116,650	38,883	37,679
Appendix C 2014 COS Costs - page 65 of 80, Exhibit 9A, col 10.	(6) MEDIUM INDUSTRIAL	225,735	75,245	72,915
	(7) LARGE INDUSTRIAL	318,264	106,088	102,802
	(8) ELI 2P-RTP	0	0	0
	(9) MUNICIPAL	122,088	40,696	39,436
	(10) UNMETERED	69,089	23,030	22,316
		5,826,414	1,942,138	1,881,990

Standby Demand Charge Calculation	**Cost**	**Usage**	**Unit Cost per kW**
Annual Rate per kW demand at 69 kV Voltage	$121,275.45	1,881,990	$64.440
Monthly Rate per kW demand at 69 kV Voltage			$5.370

NON-CONFIDENTIAL

Request DR-30:

Reference: Energy Balancing Service (EBS), Standby Service (SS) and Generation Forecasting Service (GFS) Proposals

Please provide the rationale for the formula proposed to calculate the Monthly Standby Contract Demand.

Response DR-30:

NS Power is a winter peaking utility; its investment in its generation capacity is determined on the basis of winter system peak. Accordingly, rate class responsibilities for the demand-related generation costs are determined in the Cost of Service Studies through their weighted average contribution to the three winter peaks of January, February and December. For rate classes billed under demand charges these costs are primarily recovered through monthly demand charges applicable to non-coincident monthly metered demands. For rate classes whose usage is billed only under energy charges these costs are recovered through monthly energy charges.

In both cases it is necessary for the Company to be able to reliably predict a test year class usage. This pricing model cannot be applied in the context of the RtR market because this information cannot be reliably determined.

It is expected that customers will switch between bundled and RtR services, and among LRSs, at any time of year. In addition, in the early stages of the RtR market opening, the Company expects a continued increase in customer participation in the RtR market but is not able to predict it with a level of accuracy required for rate setting purposes.

The historical peak demands of an LRS in December, January and February will likely be unrepresentative of the customer portfolio partway through the calendar year. The LRS historic winter demand may not even be available for a better part of the first year of its operation if the LRS commences service in non-winter months.

In order to reflect load changes to the LRS portfolio over the year, the Company proposes to recalculate an equivalent annual coincident demand on the basis of each month's actual peak coincident demand for the LRS portfolio. The calculation of this equivalent annual peak will reflect the differing load profiles of each customer class.

Just as the LRS's load may vary over the year, so may its generation resources, particularly as generation comes on line following the RtR market opening. It is therefore necessary to recognise firm dependable generation capacity on the basis of resources becoming available each month.

The Company proposes that the billing demand of an LRS be calculated as follows:

1. To determine the firm dependable capacity requirement associated with that LRS's load:

   (i) determine in each month the system peak firm demand hour;

   (ii) determine for that hour the total LRS load (excluding interruptible load) in each customer class, including distribution system losses;

   (iii) apply the applicable adjustment factor to derive the equivalent contribution to the weighted average of three system firm peaks of January, February and December for each class;

   (iv) aggregate the class equivalent annual contributions to determine the LRS total equivalent coincident peak firm demand;

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2. Determine the dependable capacity contribution provided by the LRS's owned and contracted generation as the sum of contributions of firm dependable capacity of those generation facilities. Recognising the requirement for 20% reserve over coincident peak firm load, divide the firm dependable capacity by (1 + 20%) to arrive at the quantity of the LRS's equivalent coincident peak firm demand that is supported by the LRS's own firm dependable capacity.

3. Determine the billing demand of the LRS as the excess of the LRS's equivalent coincident peak firm demand associated with the LRS's load under #1 above over the quantity supported by the firm dependable capacity provided by the LRS's owned and contracted generation under #2 above.

4. If the quantity supported by the firm dependable capacity provided by the LRS exceeds the LRS's equivalent coincident peak firm demand, there is no payment.

Renewable to Retail (NSUARB M06214)
NSPI Responses to Multeese Data Requests

NON-CONFIDENTIAL

Request DR-31:

Reference: Energy Balancing Service (EBS), Standby Service (SS) and Generation Forecasting Service (GFS) Proposals

Please provide the derivation of the Class Monthly Demand Adjustment Factors.

Response DR-31:

Please refer to **Attachment 1**, also provided electronically.

EXHIBIT 9C

NOVA SCOTIA POWER INC.

DETAIL OF MONTHLY CLASS SYSTEM COINCIDENT KW DEMAND

FOR THE YEAR ENDING DECEMBER 31, 2014

MONTH	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUST.	(7) MEDIUM INDUST.	(8) LARGE INDUST.	(10) MUNICIPAL	(11) UNMETERED	(12) MERSEY SYSTEM	(13) GRLF	(14) REAL TIME PRICING	(15) LRT
(1) JANUARY	**1,964,311**	**1,104,057**	**43,147**	**486,923**	**53,307**	**41,413**	**75,544**	**99,525**	**40,866**	**19,648**	**0**	**-119**	**0**	**0**
(2) FEBRUARY	**1,981,599**	**1,173,908**	**40,667**	**431,736**	**52,870**	**39,011**	**73,290**	**103,535**	**42,022**	**24,524**	**0**	**38**	**0**	**0**
(3) MARCH	1,703,830	916,421	43,848	451,054	54,668	39,330	66,321	94,790	34,721	2,689	0	-12	0	0
(4) APRIL	1,487,479	828,353	24,511	358,217	47,826	33,707	65,546	97,816	28,440	2,904	0	159	0	0
(5) MAY	1,355,817	651,803	35,218	367,903	56,740	43,146	71,137	101,700	24,276	3,168	0	726	0	0
(6) JUNE	1,309,156	679,292	27,446	320,523	47,104	33,847	68,575	104,904	24,831	2,664	0	-29	0	0
(7) JULY	1,271,920	472,812	39,874	423,318	66,270	43,029	77,215	117,200	26,605	3,141	0	2,457	0	0
(8) AUGUST	1,353,115	526,585	37,826	436,203	69,731	41,855	73,583	119,528	26,796	3,002	0	18,006	0	0
(9) SEPTEMBER	1,365,156	532,092	35,370	442,411	69,677	39,462	73,306	119,016	27,554	2,855	0	23,413	0	0
(10) OCTOBER	1,382,088	657,260	31,104	381,063	56,167	42,855	74,543	107,711	27,449	2,430	0	1,506	0	0
(11) NOVEMBER	1,588,273	855,786	33,410	379,930	52,855	35,226	72,943	87,753	32,527	17,812	0	20,031	0	0
(12) DECEMBER	**1,880,818**	**1,049,737**	**39,906**	**443,170**	**55,161**	**36,226**	**76,901**	**115,203**	**39,201**	**24,917**	**0**	**396**	**0**	**0**
(13) TOT. SUMMED DMD.	18,643,563	9,448,108	432,327	4,922,450	682,375	469,107	868,902	1,268,681	375,288	109,755	0	66,571	0	0
(14) 3 C/P DEMANDS	**5,826,729**	**3,327,702**	**123,720**	**1,361,828**	**161,337**	**116,650**	**225,735**	**318,264**	**122,088**	**69,089**	**0**	**315**	**0**	**0**
(14) 3 C/P AVE DEMANDS	1,942,243	1,109,234	41,240	453,943	53,779	38,883	75,245	106,088	40,696	23,030	-	105	-	

RATIOS OF AVERAGE OF 3 WINTER MONTH COINCIDENT PEAKS TO MONTHLY COINCIDENT PEAKS

MONTH	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUST.	(7) MEDIUM INDUST.	(8) LARGE INDUST.	(10) MUNICIPAL	(11) UNMETERED	(12) MERSEY SYSTEM	(13) GRLF	(14) REAL TIME PRICING	(15) LRT
(1) JANUARY	0.99	1.00	0.96	0.93	1.01	0.94	1.00	1.07	1.00	1.17	-	0.88		
(2) FEBRUARY	0.98	0.94	1.01	1.05	1.02	1.00	1.03	1.02	0.97	0.94		2.79		
(3) MARCH	1.14	1.21	0.94	1.01	0.98	0.99	1.13	1.12	1.17	8.56	-	8.62		
(4) APRIL	1.31	1.34	1.68	1.27	1.12	1.15	1.15	1.08	1.43	7.93		0.66		
(5) MAY	1.43	1.70	1.17	1.23	0.95	0.90	1.06	1.04	1.68	7.27		0.14		
(6) JUNE	1.48	1.63	1.50	1.42	1.14	1.15	1.10	1.01	1.64	8.64	-	3.57		
(7) JULY	1.53	2.35	1.03	1.07	0.81	0.90	0.97	0.91	1.53	7.33		0.04		
(8) AUGUST	1.44	2.11	1.09	1.04	0.77	0.93	1.02	0.89	1.52	7.67		0.01		
(9) SEPTEMBER	1.42	2.08	1.17	1.03	0.77	0.99	1.03	0.89	1.48	8.07		0.00		
(10) OCTOBER	1.41	1.69	1.33	1.19	0.96	0.91	1.01	0.98	1.48	9.48		0.07		
(11) NOVEMBER	1.22	1.30	1.23	1.19	1.02	1.10	1.03	1.21	1.25	1.29		0.01		
(12) DECEMBER	1.03	1.06	1.03	1.02	0.97	1.07	0.98	0.92	1.04	0.92		0.26		

RATIOS OF AVERAGE OF 3 WINTER MONTH COINCIDENT PEAKS TO AVERAGE SEASONAL COINCIDENT PEAKS

Jan, Feb, Dec	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Mar, Apr	1.22	1.27	1.21	1.12	1.05	1.06	1.14	1.10	1.29	8.24
May, June	1.46	1.67	1.32	1.32	1.04	1.01	1.08	1.03	1.66	7.90
Jul, Aug, Sep	1.46	2.17	1.09	1.05	0.78	0.94	1.01	0.89	1.51	7.68
Oct, Nov	1.31	1.47	1.28	1.19	0.99	1.00	1.02	1.09	1.36	2.28

Classes	Jan, Feb, Dec	Mar, Apr	May, June	Jul, Aug, Sep	Oct, Nov
Domestic	1.00	1.27	1.67	2.17	1.47
Small General	1.00	1.21	1.32	1.09	1.28
General	1.00	1.12	1.32	1.05	1.19
Large General	1.00	1.05	1.04	0.78	0.99
Small Industrial	1.00	1.06	1.01	0.94	1.00
Medium Industrial	1.00	1.14	1.08	1.01	1.02
Large Industrial Firm	1.00	1.10	1.03	0.89	1.09
Unmetered	1.00	8.24	7.90	7.68	2.28

Bundled Service Market

	Usage: Customers	Usage: MWh	Revenue: Amount	Revenue: Cents/kWh
January	429	7,265	$802,132	11.04
February	678	7,027	$805,268	11.46
March	969	8,062	$908,900	11.27
April	1199	8,058	$922,884	11.45
May	1411	8,597	$969,658	11.28
June	1629	8,472	$978,803	11.55
July	1926	9,576	$1,094,816	11.43
August	2144	10,091	$1,156,840	11.46
September	2442	15,167	$1,719,610	11.34
October	2772	15,558	$1,738,920	11.18
November	3006	15,871	$1,797,183	11.32
December	3357	15,763	$1,884,693	11.96
TOTAL		129,506	$14,779,707	11.41

RENEWABLE TO RETAIL MARKET

Distribution

	Usage: Customers	Usage: MWh	Revenue: Amount	Revenue: Cents/kWh
January	429	7,265	$67,183	0.9
February	678	7,027	$76,290	1.1
March	969	8,062	$88,295	1.1
April	1,199	8,058	$93,799	1.2
May	1,411	8,597	$97,955	1.1
June	1,629	8,472	$103,921	1.2
July	1,926	9,576	$116,035	1.2
August	2,144	10,091	$124,782	1.2
September	2,442	9,806	$135,516	1.4
October	2,772	10,331	$145,535	1.4
November	3,006	10,727	$158,882	1.5
December	3,357	11,348	$193,964	1.7
TOTAL		109,360	$1,402,157	1.3

OATT

	Usage: LRS	Usage: MWs	Usage: MWh	Revenue: Amount	Revenue: Cents/kWh
January	1	13.2	7,459	$94,143	1.26
February	1	14.2	7,238	$95,786	1.32
March	1	14.7	8,341	$100,539	1.21
April	1	15.5	8,294	$107,985	1.30
May	1	15.6	8,890	$106,079	1.19
June	1	16.8	8,661	$112,329	1.30
July	1	18.0	9,799	$118,974	1.21
August	1	19.2	10,412	$127,114	1.22
September	1	20.0	15,363	$133,002	0.87
October	1	20.1	15,869	$134,953	0.85
November	1	21.1	16,190	$140,351	0.87
December	1	24.7	16,342	$166,409	1.02
TOTAL		213.2	132,857.6	$1,437,663	1.08

ENERGY BALANCING SERVICE

	Load (MWh): RtR Direct Delivery	Load (MWh): Top-up	Load (MWh): Total	Spill (MWh): Total	Spill (MWh): Net of Top-up
January	5,627	1,832	7,459	7,176	5,344
February	4,931	2,307	7,238	4,125	1,817
March	5,295	3,046	8,341	4,201	1,154
April	4,939	3,355	8,294	4,671	1,316
May	4,048	4,842	8,890	2,910	(1,932)
June	3,768	4,893	8,661	522	(4,371)
July	5,874	3,925	9,799	4,803	879
August	6,329	4,083	10,412	5,408	1,325
September	7,531	7,832	15,363	2,218	(5,614)
October	9,601	6,268	15,869	3,992	(2,276)
November	10,841	5,349	16,190	8,163	2,814
December	10,931	5,411	16,342	4,958	(453)
TOTAL	79,714	53,143	132,858	53,148	4

	Revenue: Admin	Revenue: Top-up	Revenue: Spill Credit	Revenue: Refund for Excess Spill	Revenue: Total	Revenue: Cents/kWh
January	$1,053	$182,414	-$378,156		-$194,689	(2.61)
February	$1,053	$229,794	-$217,372		$13,476	0.19
March	$1,053	$303,378	-$221,375		$83,056	1.00
April	$1,053	$334,169	-$246,186		$89,036	1.07
May	$1,053	$482,208	-$153,372		$329,889	3.71
June	$1,053	$487,284	-$27,519		$460,818	5.32
July	$1,053	$390,848	-$253,143		$138,759	1.42
August	$1,053	$406,629	-$285,022		$122,660	1.18
September	$1,053	$779,964	-$116,878		$664,140	4.32
October	$1,053	$624,245	-$210,382		$414,916	2.61
November	$1,053	$532,745	-$430,211		$103,587	0.64
December	$1,053	$538,841	-$261,262		$278,632	1.71
TOTAL	$12,636	$5,292,520	-$2,800,878	$0	$2,504,279	1.88

STANDBY SERVICE

	Coincident Firm Demand kW: Metered	Coincident Firm Demand kW: Contributed Capacity	Coincident Firm Demand kW: Net	Revenue: Admin	Revenue: Demand	Revenue: Total	Revenue: Cents/kWh
January	11,543	6,385	5,159	$1,053	$27,703	$28,756	0.39
February	12,534	6,385	6,150	$1,053	$33,023	$34,076	0.47
March	14,608	6,385	8,224	$1,053	$44,161	$45,214	0.54
April	14,778	6,385	8,393	$1,053	$45,073	$46,126	0.56
May	16,373	6,385	9,988	$1,053	$53,638	$54,691	0.62
June	16,358	6,385	9,973	$1,053	$53,555	$54,608	0.63
July	17,280	14,695	2,585	$1,053	$13,882	$14,935	0.15
August	18,648	14,695	3,952	$1,053	$21,224	$22,277	0.21
September	27,330	13,158	14,172	$1,053	$76,103	$77,156	0.50
October	28,956	14,695	14,261	$1,053	$76,582	$77,635	0.49
November	28,251	14,695	13,556	$1,053	$72,796	$73,849	0.46
December	30,565	14,695	15,869	$1,053	$85,219	$86,272	0.53
TOTAL	237,225	124,943	112,283	$12,636	$602,958	$615,594	0.46

EMBEDDED COST RECOVERY under RTT / Total Revenue

	Energy-related: Displaced Energy (MWh)	Energy-related: Forgone Energy-related Revenue	Demand-Related: Displaced Demand (MW)	Demand-Related: Forgone Demand-related Revenue	Total Revenue	Cents/kWh	Total Revenue: $ Amount	Total Revenue: Cents/kWh
January	5,627	$186,197	6.4	$34,286	$220,483	3.0	$215,875	2.9
February	4,931	$163,167	6.4	$34,286	$197,453	2.7	$417,080	5.8
March	5,295	$175,200	6.4	$34,286	$209,486	2.5	$526,590	6.3
April	4,939	$163,432	6.4	$34,286	$197,717	2.4	$534,663	6.4
May	4,048	$133,952	6.4	$34,286	$168,238	1.9	$756,852	8.5
June	3,768	$124,673	6.4	$34,286	$158,959	1.8	$890,635	10.3
July	5,874	$194,371	14.7	$78,913	$273,284	2.8	$661,987	6.8
August	6,329	$209,427	14.7	$78,913	$288,340	2.8	$685,172	6.6
September	7,531	$249,201	13.2	$70,660	$319,861	2.1	$1,329,674	8.7
October	9,601	$317,697	14.7	$78,913	$396,610	2.5	$1,169,650	7.4
November	10,841	$358,729	14.7	$78,913	$437,642	2.7	$914,311	5.6
December	10,931	$361,707	14.7	$78,913	$440,620	2.7	$1,165,897	7.1
TOTAL	79,714	$2,637,752	124.9	$670,942	$3,308,694	2.5	$9,268,387	7.0

The remaining tabs in Appendix 24 have been provided in electronic format only.

Request DR-35:

Further to Multeese DR-30:

(a) Please identify any adjustments NSPI anticipates making its Cost of Service model or its inputs to reflect RtR?

(b) It is noted at Lines 19-21 on page 1 that NSPI's current pricing model cannot be applied to RtR because test year class usage cannot be reliably predicted. Please elaborate on how the proposed adjustment of actual monthly demands to equivalent winter peak demands in the SS tariff addresses this issue, from both a cost allocation and a revenue perspective.

(c) Apart from the cost allocation and revenue perspectives, please identify any other aspects of RtR that would preclude using the actual monthly demands as the Monthly Standby Contract Demand.

Response DR-35:

(a) NS Power does not anticipate making any adjustments to the COS model for the rate setting purposes of this RtR proceeding. For General Rate Applications (GRA) filed in future with the benefit of RtR service uptake estimates, the Company expects to treat the RtR customer usage and revenues in the test year COS model in a manner similar to the treatment of below-the-line (BTL) rate classes. In planning for such future GRAs, the Company will prepare a forecast of RtR service uptake taking account of information included in Retail Suppliers' applications for licences and ongoing compliance filings. The RtR customer usage is expected to be separated in the Exhibit 9 series from the above-the-line (ATL) classes and reported in the below-the-line category, grouped by their original ATL classes. Similarly, anticipated revenues, to be recovered from RtR customers and suppliers, are expected to be treated as an offset to the revenue requirement from the ATL classes. RtR revenue will be cost itemized in the Direct Expense category of exhibits 4 and 4A, as is the case with the BTL rate classes, today. In parallel with the above COS adjustments, the Company will adjust test year billing determinants by the bundled service ATL classes in its "Proof of Revenue" calculations. The Company will also have to adjust its estimates of fuel cost to recognise that the Company's generation requirements and thus the average unit fuel cost will need to reflect the impacts of energy provided as top-up and received as spill and the potential spread in the average marginal costs between these.

Once the CoS model is completed on this basis, it is recognised that it may indicate changes in allocated unit costs from those on which the RtR tariff charges are based. In this case, the RtR charges used for the calculation of BTL cost recovery will be adjusted on an iterative basis until there is proper reconciliation between the RtR charges and the corresponding allocated unit costs in the ATL calculation.

(b) The proposed adjustment of actual monthly demands to equivalent winter peak demands will ensure accurate recovery of utility costs as allocated on a fair basis, as long as the ATL customers supplied by LRSs have similar coincident factors[1] to those assumed in the GRA rate setting process for the bundled service customers.

With the coincident factors being equal, any differences between the actual and test year forecast of a number of departed customers and their kWh load make no difference to the recovery of utility costs, as far as the billing demand aspect is concerned[2], because the

[1] Coincident factors, for the purposes of this discussion, include two types of constructs

a) Ratios between monthly coincident demand and average winter peak demand as used in the Standby Service tariff
b) Ratios between non-coincident and coincident monthly demands of individual customers billed under demand charges implicit in test year rate setting process.

[2] Another factor that can affect the recovery of utility's costs is the distribution of migrating load by bundled service rate classes which vary in terms of their revenue to cost (R/C) ratios. The utility will under- or over-recover its costs to the extent the migrating load is skewed towards bundled service classes with R/C ratios above or below unity.

proposed RtR rates, inclusive of the revenues under the RtR Market Transition Tariff, are based on fully embedded costs.

In order to avoid inequity that could arise due to differences between the coincident factors of RtR customer groups in each class and the ATL averages for the customers in the classes from which they originate, the Company will monitor the coincident factors of RtR customers. If they differ from the ATL class averages, assumed in the test year COSS, and cause a material discrepancy in the recovery of utility's costs, the Company will propose mitigating measures. For example, a change to the class monthly adjustment factors to reflect the coincident factors of RtR customers in each class in contrast to their ATL class average statistics. If the need arises, these changes could be submitted in a rate application.

Please refer to part (c) for discussion of the more fundamental reasons for the selection of the equivalent winter peak demand methodology for this tariff, and the way in which this methodology provides proper cost allocation and revenue recovery.

(c) The level of Standby Service required by each LRS will be determined by its load and by the firm reliable capability of its generation. From a system adequacy perspective, the most critical measures of firm reliable capability and of peak demand are those applicable in the winter months in which the winter peak is likely to occur and when reserve margins are therefore expected to be at their tightest. The CoS model therefore adopts the winter peak (coincident peak) as the appropriate basis for allocating demand-related generation cost among Bundled Service customer classes. Demand-related generation costs will be allocated to the RtR customer group on the same basis.

The proposed Standby Service tariff and the proposed RtR Transition Tariff demand charge collectively provide for the allocation of cost to, and recovery of cost from, each LRS on that same basis. This differs from the approach in bundled service tariffs, where the charge determinant used as the basis for recovery from members of the class is typically different from the basis of cost allocation to the class as a whole.

Within this framework, the appropriate metric of the Standby Service determinant is therefore the excess of the winter peak demand of the LRS's portfolio over the corresponding demand supported by the self-supplied firm dependable capability of its generation. The proposed adjustment of actual monthly demands to equivalent winter peak demands for use as the Monthly Standby Contract Demand, before deducting the self-supplied firm dependable (winter) capability achieves the proper Standby Service recovery from each LRS.

Consideration was given to the alternative of a tariff based on the use of actual monthly peak customer demand of each LRS. There are three reasons why this was not adopted:

(i) Given accurate forecasts of RtR load in each customer class and RtR generation of each technology, it would theoretically be possible to determine the total standby cost properly allocated to the total RtR market load and demand portfolio (i.e. as aggregated across all LRSs). From this, it would be possible to determine an average rate per unit of LRS portfolio customer peak monthly demand for use as a rate. This would however be inequitable between LRSs. It would fail to recognise that different generation technologies have different relationships between installed capacity, energy production, and firm dependable capability. A single demand-based tariff could not reflect these differences between LRSs. An LRS whose generation has a high firm dependable capability relative to its energy generated would share in the costs arising from another LRS's low quantity of firm dependable capability.

(ii) The calculation of a monthly demand rate as described above would be highly dependent on the forecasts of generation and RtR market load and demand. The rate thus determined would thus be subject to wide variation from year to year, particularly during a period of initial market uptake. Standby Service tariff charges by this methodology would be significantly less stable than under the tariff as proposed.

(iii) NS Power would not have confidence in the accuracy of forecasts during the initial years of the RtR market.

RENEWABLE TO RETAIL MARKET TRANSITION TARIFF
Renewable to Retail

PURPOSE

Pursuant to Section 3G(2) of the Electricity Act (Nova Scotia), this Renewable to Retail Market Transition Tariff (RTT) is designed to recover from Licenced Retail Suppliers (LRS) NS Power's embedded fixed costs and deferred costs, recovered through Bundled Service, which are not otherwise recovered through other tariffs applicable to the LRS or its RtR Customers. For certainty, for the purposes of this RTT, NS Power's embedded fixed costs include, but are not limited to, generation related fixed costs (e.g. depreciation, cost of financing including return on common equity, income tax and OM&G). Deferred costs of NS Power are those costs approved by the Nova Scotia Utility and Review Board (Board) for recovery by NS Power from customers at a future date.

All capitalized terms herein shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

APPLICABILITY

1. The RTT is applicable to the LRS, and is in addition to (and not in substitution of) any charges owing by the LRS to NS Power under the Open Access Transmission Tariff (OATT), the Standby Service Tariff or the Energy Balancing Service Tariff.

2. The RTT employs certain usage determinants and rate components applicable under both the Standby Service Tariff and the Energy Balancing Service Tariff.

3. Energy Charges and Demand Charges (both as set out below) under this RTT include provision for mitigation in respect of forecasted NS Power savings enabled by the LRS's supply of electricity to its RtR Customers. The savings credits will be determined annually on the basis of experience and will be applied on a prospective basis.

4. The Energy Charge under this RTT includes provision for annual adjustment on a prospective basis to account for the forecasted difference between NS Power's average avoided cost by the LRS's supply of electricity and its average system fuel cost. If the average avoided cost exceeds the average system fuel cost, this adjustment will be a reduction in the Energy Charge; if the average avoided cost is less than the average system fuel cost, this adjustment will be an addition to the Energy Charge.

5. An LRS taking service under this RTT shall also take service under the OATT, the Standby Service Tariff, and the Energy Balancing Service Tariff.

RENEWABLE TO RETAIL MARKET TRANSITION TARIFF
Renewable to Retail

ENERGY CHARGE

Energy charge is made up of the following components:

Energy Charge Components	**Cents per kWh**
Fixed Cost Adder from Energy Balancing Service Tariff	3.309
Annually Adjusted Energy Savings Credit	-
Annual Energy Cost Adjustment	-
Total	3.309

The Energy Charge is applicable to the LRS's monthly displaced energy on NS Power's generation system, defined as the total monthly LRS load, including distribution losses, minus the total monthly LRS top-up quantity as determined under the Energy Balancing Service Tariff for that LRS.

DEMAND CHARGE

Demand Charge is made up of two components:

Demand Charge Components	**Dollars per kW**
Demand Charge from Standby Service Tariff	$5.370
Annually Adjusted Demand Savings Credit	$0.000
Total	$5.370

The Demand Charge is applicable to the LRS's monthly displaced demand on NS Power's system determined as the difference between Winter Peak Firm Demand, in respect of the monthly bill of the LRS, and Monthly Standby Contract Demand, both as determined under the Standby Service Tariff for that LRS. For greater certainty, Winter Peak Firm Demand and Monthly Standby Contract Demand are as set out in the Standby Service Tariff.

SPECIAL CONDITIONS

(1) Nothing contained in this RTT or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to make application to the Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this RTT, the Standby Service Tariff or the Energy Balancing Service Tariff.

SCHEDULE 4: ENERGY IMBALANCE SERVICE

This Schedule 4 is not applicable to Licenced Retail Suppliers.

The Generation Forecasting Service set out in Schedule 4A of the OATT will apply to Licenced Retail Suppliers only and is not applicable to any other Eligible Customer.

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within an Operating Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligation. To the extent the Operating Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

For a bilateral schedule of a single load and its single generator, this ancillary service will be applied to the net of the generation and load imbalance. Otherwise, this Ancillary Service will be applied separately to deviations from load schedules and deviations from generation schedules. This ancillary service does not apply to power exported from the Operating Area, which is covered by the Generation Balancing Service of the Standard Generator Interconnection and Operation Agreement.

Energy Imbalance Service does not apply to inadvertent energy imbalances that occur as a result of actions directed by the Operating Area operator to:

- Balance total load and generation for the Operating Area through the use of Automatic Generation Control;
- Maintain interconnected system reliability, through actions such as re-dispatch or curtailment;

- Support interconnected system frequency; or to
- Respond to transmission, generation or load contingencies.

For the purposes of Energy Imbalance Service, peak hours are between 07:00 and 23:00 Atlantic Time, Monday to Friday. All other hours are considered non-peak hours.

<u>Load Energy Imbalance Associated with Point-to-Point or Network Integration Transmission Service:</u>

For each Transmission Customer taking service under Part II or Part III of this Tariff, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

A deviation band of +/- 1.5 percent of the scheduled transaction (with a minimum deviation band of +/- 2 MW) will be applied hourly to any net load energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s).

Parties should attempt to eliminate energy imbalances within the limits of the deviation band within the billing month in accordance to the following:

- For hourly imbalances that arise during peak hours, such imbalances should be eliminated via deliveries or withdrawals during peak hours; and

- For hourly imbalances that arise during non-peak hours, such imbalances should be eliminated via deliveries or withdrawals during non-peak hours.

Net load energy imbalances within the deviation band that have not been eliminated at the end of the billing month will be subject to the charges set below:

- Energy supplied by the Transmission Provider during peak hours to compensate for a net shortfall in peak hours delivery over the billing month will be charged at the average on-peak system marginal cost for the billing month. Energy supplied by the Transmission Provider during non-peak hours to compensate for a net shortfall in non-peak hours delivery over the billing month will be charged at the average non-peak system marginal cost for the billing month.

- Energy supplied to the Transmission Provider during peak hours as a net excess of the peak hours delivery over the billing month will be purchased by the Transmission Provider at the average on-peak system marginal cost for the billing month. Energy supplied to the Transmission Provider during non-peak hours as a net excess of the non-peak hours delivery over the billing month will be purchased by the Transmission Provider at the average non-peak system marginal cost for the billing month.

Energy imbalances outside of the deviation band are not eligible for elimination and are subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net hourly shortfall in delivery will be charged at 110 percent of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90 percent of the hourly system marginal cost in the hour of the deviation.

<u>Generation Energy Imbalance - Dispatchable Generators:</u>

For Dispatchable Generators in the Transmission Provider’s Operating Area supplying load in the Transmission Provider’s Operating Area, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at 110 percent of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90 percent of the hourly system marginal cost in the hour of the deviation.

Generation Energy Imbalance - Non-Dispatchable Generators

For Non-dispatchable Generators in the Transmission Provider's Operating Area supplying load in the Transmission Provider's Operating Area, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

Energy Imbalances inside a deviation band of +/- 10 percent of the scheduled transaction (with a minimum deviation band of +/- 2 MW) will be subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at the hourly system marginal cost in the hour of the deviation.

All deviations from schedule outside of the +/- 10 percent deviation band will be subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at 110 percent of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90 percent of the hourly system marginal cost in the hour of the deviation.

SCHEDULE 4A: GENERATION FORECASTING SERVICE

This Generation Forecasting Service set out in Schedule 4A of the OATT applies to Licenced Retail Suppliers only and is not applicable to any other Eligible Customer. Generation Forecasting Service addresses the accuracy of generation scheduling by Licenced Retail Suppliers.

This Schedule does not apply to forecasting discrepancies that occur as a result of actions directed by the Operating Area operator to:

- Balance total load and generation for the Operating Area through the use of Automatic Generation Control;
- Maintain interconnected system reliability, through actions such as re-dispatch or curtailment;
- Support interconnected system frequency; or to
- Respond to transmission, generation or load contingencies.

For the purposes of Forecast Deviation Service, peak hours are between 07:00 and 23:00 Atlantic Time, Monday to Friday. All other hours are considered non-peak hours.

Each Licenced Retail Supplier shall use commercially reasonable efforts to provide accurate schedules and forecasts of production from renewable low-impact generators that are not dispatchable.

To the extent that such schedules or forecasts of hourly production of the aggregate of a Licenced Retail Supplier's RtR generation resources deviate from the actual production for reasons other than those that occur as a result of actions directed by the Operating Area operator the following charges shall apply:

An hourly deviation band of +/- 10 percent of the aggregate hourly scheduled or forecast quantity (with a minimum deviation band of +/- 2 MW) will be applied hourly to any forecast discrepancy that occurs as a result of the Transmission Customer's scheduled transaction(s).

- Hourly forecast discrepancies falling outside the hourly deviation band during peak hours will be charged at 10% of the average on-peak system marginal cost for the billing month.
- Hourly forecast discrepancies falling outside the hourly deviation band during non-peak hours will be charged at 10% of the average non-peak system marginal cost for the billing month.

NON-CONFIDENTIAL

Request DR-33:

Reference: Energy Balancing Service (EBS), Standby Service (SS) and Generation Forecasting Service (GFS) Proposals

Please provide the rationale for the creation of a new Schedule 4A in OATT to accommodate the GFS.

Response DR-33:

The current wholesale market approach to imbalance between supply and demand includes two elements:

1. scheduled hourly energy balancing service requirements, which are addressed by the existing Backup/Top-up/Spill (BUTUS) tariff; and

2. deviations of the actual hourly quantities from the scheduled hourly quantities, which are addressed by Schedule 4 of the OATT.

This two-part approach was not considered suitable for the RtR market for the following reasons:

(a) The expected diversity of RtR load over multiple delivery points from the transmission system would make hourly load forecasting too onerous. It would also have questionable value in that it would not alter total loads at each delivery point.

(b) The asymmetric nature of the top-up charge and spill credit under the proposed EBS tariff, with the top-up charges including energy-related fixed cost recovery, would yield a material incentive for an LRS to under-forecast its load at times of expected top-up. Such under-forecasting would lead to LRS avoidance of the energy-related fixed cost recovery and could adversely affect the NSPSO's system management and optimization.

NON-CONFIDENTIAL

(c) Settlement under the two-part approach would be significantly more complex than under the proposed RtR market approach.

Having determined that the Energy Balancing Service tariff should provide for settlement against actual metered imbalances only, NS Power had to give consideration to the implications with respect to the OATT Schedule 4. The application of Schedule 4 as it stands would result in overlapping settlement for the marginal energy cost of imbalances which would not be appropriate.

Accurate forecasting is important to the NSPSO in the management of the system. Whereas the load forecasting element has limited value, as noted above, due to the embedding of RtR loads at delivery points, the generation forecasting element remains important. Schedule 4A is designed to provide the forecasting incentive element of existing schedule 4, as applicable to the production from non-dispatchable RtR generation.

Request IR-9:

The "Illustrative Unit Revenues by RtR tariff" presented in Figure 7 is reflective of a specific scenario. In an effort to understand how sensitive these resulting rates are to fluctuations in energy balancing scenarios, please provide revised figures that assume sensitivity scenarios that change top up and spill assumptions by 20%.

Response IR-9:

The table below provides six scenarios of a breakdown of RtR rates by ratios of top-up and total LRS energies in increments of 20% for the Domestic, General and Large Industrial (Firm) Rate classes under the following assumptions:

(i) the LRS's customers are all from a single rate class;
(ii) the customers have the same load profile characteristics as the NS Power class average; and
(iii) there is no excess annual spill.

Any changes in class blended unit revenue, due to changes in the amount of delivered top-up energy, are caused only by the difference between the Energy Credit (5.27 cents/kWh) under spill and the fuel portion of the Energy Charge (6.65 cents/kWh) under top-up. Any changes in the recovery of fixed costs through the Fixed Cost Adder (3.309 cents/kWh) to the Energy Charge of the EBS tariff are automatically offset by parallel changes in the opposite direction under the RTT.

Unit revenues in cents per KWh at the point of delivery to customer's premise

DOMESTIC CLASS	**DT**	**OATT**	**EBS**	**SS**	**RTT**	**Total**
0% Top-up 0% Spill	4.0	1.6	0.0	1.2	4.0	**10.9**
20% Top-up 20% Spill	4.0	1.6	1.0	1.2	3.3	**11.2**
40% Top-up 40% Spill	4.0	1.6	2.0	1.2	2.6	**11.5**
60% Top-up 60% Spill	4.0	1.6	3.0	1.2	1.9	**11.8**
80% Top-up 80% Spill	4.0	1.6	4.0	1.2	1.2	**12.1**
100% Top-up 100% Spill	4.0	1.6	5.0	1.2	0.5	**12.4**
GENERAL RATE CLASS	**DT**	**OATT**	**EBS**	**SS**	**RTT**	**Total**
0% Top-up 0% Spill	1.5	1.5	0.0	0.7	3.9	**7.6**
20% Top-up 20% Spill	1.5	1.5	1.0	0.7	3.2	**7.9**
40% Top-up 40% Spill	1.5	1.5	1.9	0.7	2.6	**8.2**
60% Top-up 60% Spill	1.5	1.5	2.9	0.7	1.9	**8.5**
80% Top-up 80% Spill	1.5	1.5	3.9	0.7	1.2	**8.7**
100% Top-up 100% Spill	1.5	1.5	4.8	0.7	0.5	**9.0**
INDUSTRIAL LARGE FIRM SERVED AT DISTRIBUTION VOLTAGE	**DT**	**OATT**	**EBS**	**SS**	**RTT**	**Total**
0% Top-up 0% Spill	0.6	1.1	0.0	0.3	3.9	**5.9**
20% Top-up 20% Spill	0.6	1.1	1.0	0.3	3.2	**6.2**
40% Top-up 40% Spill	0.6	1.1	1.9	0.3	2.5	**6.5**
60% Top-up 60% Spill	0.6	1.1	2.9	0.3	1.9	**6.8**
80% Top-up 80% Spill	0.6	1.1	3.8	0.3	1.2	**7.0**
100% Top-up 100% Spill	0.6	1.1	4.8	0.3	0.5	**7.3**