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Request IR-6:

Section 5.3.3 of the Cary report (Appendix 16) discusses possible options for the self-supply of top-up. Regarding the second (self-supply from a non-renewable generator), it is noted that "the top-up would not contribute to fulfilling an LRS's compliance requirement". From this perspective, please identify any differences between this option and the supply of top-up from NS Power.

Response IR-6:

Neither self-supplied top-up nor NS Power-supplied top-up would contribute to fulfilling an LRS's compliance requirement.

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Request IR-7:

Appendix 19A provides avoided fuel cost calculations as derived from Plexos simulations, with further details provided in NS Power's responses to CA IR-5, SBA IR-8 and to SWEB IR-7.

(a) Please describe what each of the "Flat 50MW RTR – No Curtailment" case and the "Wind 50MW RTR –No Curtailment" cases is intended to simulate and for each case, describe the adjustments that were made to the Plexos base case inputs to simulate it.

(b) As indicted in SWEB IR-7, the 50MW wind scenario assumes a 33% annual capacity factor for the wind. Please confirm that for simulation purposes, the wind output was based on expected wind profiles for Nova Scotia. If this is not the case, please provide the assumptions on which it was based.

(c) Appendix 19A calculates the difference in costs between two Plexos simulations and states that this difference "is an incremental fuel cost arising from provision of energy balance service to departing customers". Please explain why this is so.

(d) Please explain why the inclusion of the incremental costs associated with providing energy balance service is appropriate in an RtR context but is not included in the Wholesale BUTU tariff.

(e) Appendix 19A indicates that going forward, when NS Power has actual data from the RtR market, its simulations will be different. Please confirm that the following simulations will be required (or if these cannot be confirmed, provide a description of the scenarios that will be required):

- **A base case simulation assuming no RtR**

- **The base case with load decremented by the hourly RtR load only (excluding LRS generation or purchases)**

- **The base case with hourly loads adjusted to reflect both RtR loads and LRS generation and purchases**

(f) Please update Appendix 19A to reflect the fact that the Plexos runs were based on 50 MW blocks rather than 25 MW blocks.

(g) Please explain why NS Power is proposing rates based on avoided costs levelized over the period 2018 – 2027, as opposed to avoided costs in 2016?

(h) SBA IR-8(b) indicates that simulation results for 2016 are provided in SWEB IR-7(b), but this is not the case. If such results have been provided, please identify where. If not, please provide them.

(i) Further to CA IR-5, please provide the calculations to show how the $13,052,400 and the $11,541,300 are derived from the Plexos simulations.

Response IR-7:

(a) The "Flat 50 MW RTR – No Curtailment" case was intended to simulate a constant hourly Renewable to Retail generator output. A generator with constant 50MW hourly must-take generation was added to the Plexos base case with no associated cost.

The "Wind 50MW RTR – No Curtailment" case was intended to simulate a Renewable to Retail generator similar to a typical wind farm. A generator with an hourly shape based on a 50MW wind farm (please refer to CA IR-33) was added to the Plexos base case as must-take generation with no associated cost.

(b) Confirmed.

(c) In order to provide balancing service under top-up and spill the Company will to have to ramp up and down its dispatchable generation, and therefore operate in suboptimal heat rate conditions more often than is the case absent this service. This activity has identifiable costs. The proposed top-up charge appropriately reflects additional costs associated with the balancing service.

(d) The energy balancing service provided under the top-up and spill services has an identifiable cost. Absent its inclusion in the EBS charges this cost will be transferred to bundled service customers. Under the 50 MW case, tested for the purpose of this submission, the balancing service is expected to have an annual cost of $1.5 million. This cost differential has not been reflected in the Wholesale Back-up and Top-up rates. Revision to those rates is outside the scope of this proceeding.

(e) Confirmed.

(f) The Company did not prepare 25 MW Plexos runs for the purpose of this Application.

(g) Please refer to SBA IR-10 (a).

(h) The statement in SBA IR-8 (b) is an error. Simulations were not conducted for the year 2016. For the purpose of this Application, the simulations were run for the period 2018 to 2027. NS Power apologizes for confusion caused by this misstatement.

(i) The Company did not did not prepare 25 MW Plexos runs for the purpose of this Application as noted in (f) above. However, for the illustrative purposes of the top-up and spill charge calculations in **Appendix 19A** only, the Company calculated the avoided costs by multiplying energy associated with the 25 MW decrement by unit avoided costs

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coming from multiple runs of 50 MW blocks over the 10 year period 2018-2027 as follows:

$13,052,400 = 219 GWh * 5.96 c per kWh * 10,000
$11,541,300 = 219 GWh * 5.27 c per kWh * 10,000

The calculations of avoided costs of 5.96 c/kWh and 5.27 c/kWh are provided in **Attachment 1** to SBA IR-8.

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Request IR-8:

The first sentence of the final paragraph of Section 5.7.1 at page 27 of 41 of the Cary RtR Design Basis Report (Appendix 16) refers to the Billing Demand that would result from the application of the existing Wholesale Market Back-up/Top-up Service Tariff and states that "This calculation will generally understate the requirement set out above to cover the cost of system needs".

Please elaborate on why this is so in the RtR context but not so in the wholesale market context.

Response IR-8:

The Cary Report (**Appendix 16**) refers only to the RtR context and does not seek to comment on the wholesale market context.

The contribution of the LRS to its share of the system capacity obligation is based on the firm dependable capacity available to serve the system in peak periods. Considering wind and solar generation, this firm dependable capacity (e.g. 17% of installed capacity for NRIS-connected wind generation, and 0% for ERIS-connected) is significantly less than the average production assumption currently reflected in the wholesale market tariff.[1] The use of firm dependable capacity (e.g. 17% for wind) as the metric ensures that cost allocation principles reflect the current practice of the Company in planning for system adequacy and in recognising the adequacy contribution of each generation resource. This practice has evolved in respect of variable generation from the practice at the time that the wholesale market BUTU tariff was developed. The application of the wholesale market assumption in the RtR market context

[1] For the purposes of the BUTU tariff, the accepted capacity factor of wind generation was 32% at the time of the UARB's decision (NSUARB-NSPI-P-889).

would thus overstate the extent of the LRS's firm dependable capacity, and understate its required contribution through the Standby Tariff to overall system adequacy.

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Request IR-9:

Please explain how the incremental locational loss factors provided in Attachment 1 of NS Power's response to CA IR-1 were calculated and how they should be interpreted. For example, the incremental losses shown for 110MW added at 101S Woodbine is 11.5%. How was this calculated and what does it mean?

Response IR-9:

The loss factors of **CA IR-1 Attachment 1** reflect the impact on overall system losses by placing a generation plant of the specified size at the specific location on the transmission system. A positive number means that system losses will increase if generation is added at that location, while a negative number means that system losses will decrease if generation is added at that location. These factors represent the current system configuration. There is no attempt to confirm whether a generator of the specified size can be installed at that location without system upgrades.

The calculation of loss factors reflects that the Nova Scotia load centre is in and around 91H-Tufts Cove. Loss factors are calculated by running a load flow using a winter peak base case with and without the generation while keeping 91H-Tufts Cove generation as the Nova Scotia Area Interchange bus. The loss factor is the differential MW displaced or increased at 91H-Tufts Cove calculated as a percentage of the new generator nameplate MW rating.

As an example, a 110 MW generator added at Woodbine would result in system losses increasing by 12.6 MW (11.5%) during periods of full Woodbine generation and peak system load.

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Request IR-10:

Schedule 4A (Appendix 21) proposes that hourly deviations of actual LRS generation from forecast LRS generation be charged at 10% of the appropriate peak or off-peak marginal costs. Please discuss the basis for the 10%.

Response IR-10:

The 10% figure is carried over from the existing NS Power Open Access Transmission Tariff (OATT) Schedule 4: Energy Imbalance Service, which in turn was based on Schedule 4 of the FERC pro forma OATT.

The FERC pro forma OATT established the deviation band of +/- 1.5% with a minimum of 2 MW, but simply stated that “energy imbalances outside the deviation band will be subject to charges to be specified by the Transmission Provider.”

The 10% factor (of marginal cost) was established as part of the 2005 OATT settlement process.

In Schedule 4A, the 10% factor is applicable as an incentive to encourage accurate scheduling.

Request IR-11:

Beginning with the data in Figure 5 on page 19 of 29 of the Strawman Distribution Tariff provided on May 21, 2015, please show the derivation of the proposed DT charges for each rate class.

Response IR-11:

For the overview of the ratemaking process used by the Company in determination of its distribution rates please refer to section 2.0, Distribution Tariff Rate Development Process of the May 21, 2015 Distribution Tariff Strawman report (which is provided as **NSUARB IR-8 Attachment 4**).

The class revenue requirement classified by energy, demand and customer related components in Figure 5 of the Strawman were extracted from Exhibit 6.1 of the COSS included in the Compliance Filing in the COS Proceeding in 2014 (which is provided as **NSUARB IR-8 Attachment 1**). For the Large Industrial class, the Company reported only usage and cost data for customers served at a distribution voltage level. As explained in section 4.0, Customer Classes Applicable to Distribution Tariff Services of the Strawman Report, the Municipal and Below-the-Line rate classes were excluded.

The classified class costs from Figure 5 were used as inputs in the determination of rates in "Proof of Revenue" calculations included in Appendix 17A Rates Calculations Electronics (which is provided as **NSUARB IR-8 Attachment 3**). The Total Cost column of Figure 5 matches the total revenue requirement in column "Proposed Rates Forecast 2014" in **NSUARB IR-8 Attachment 3**. The class usage statistics come from the "Proof of Revenue" submitted in the 2014 GRA Compliance Filing, except for the Large Industrial class, which shows only distribution customer data.

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Rate components, shown in "Proof of Revenue" have been calculated by dividing the appropriate portion of revenue requirement by usage. This can be verified by inspecting cell formulas in **NSUARB IR-8 Attachment 3**.

For the description of the process used by the Company in design of these rates please refer to Section 9.3 of the Strawman Report and Multeese DR-17, 18, 19 and 21 (which are provided in **NSUARB IR-8 Attachment 5**). For the discussion of how unmetered class rates were determined please refer to Multeese IR-12.

Attachment 1, also provided electronically, contains "Proof of Revenue" calculations with an explanation of how individual Distribution Tariff charges were calculated.

Proposed Distribution Tariffs	Distribution Usage in KWhs			Demand in kWs or kVa			Base Charge			PROPOSED	Explanation of charge calculations
Above-the-line Classes	Energy in GWh -	Per KWh Charge	Revenue $M	GWS or GVAS	Charge per KW or KVA	Revenue $M	Bill months (in millions)	Base Charge	Revenue $M	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	The charge of 2.549 c/kWh is calculated jointly for the two residential rate classes by dividing revenue requirement of $107.5 million, which excludes revenues collected through the $10.83/month customer charge, by kWh usage of 4,216.5 GWh.
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	The charge of 2.362 c/kWh is calculated by dividing revenue requirement of $5.6 M, which excludes revenues collected through the customer charge of $12.65/month, by kWh usage of 236.7 GWh.
General Demand	2,448.7	NA	NA	7.0	$ 5.458	$ 38.2	-	$ -	$ -	$ 38.2	The charge of 5.458 $/KW is calculated by dividing the total revenue requirement of 38.2M by GW usage (sum of customers' non-coincident demands) of 7.0.
Large General											
Without Trans. Own.	245.8	NA	NA	0.5	$ 3.361	$ 1.7				$ 1.7	The charge of 3.361 $/KVA is calculated by dividing the total revenue requirement of $1.7M by the total of customers' metered non-coincident demands of 0.5 GVA.
With Trans. Own.	133.8	NA	NA	0.3	$ 3.041	$ 1.0				$ 1.0	The charge of 3.041 $/KVA is calculated by subtracting the transformer ownership credit of 0.320 $/KVA from the Large General Non-Coincident Demand Charge of 3.361$/KVA
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	The charge of 4.494 $/KVA is calculated by dividing the total revenue requirement of $4.5 M by the total of customers' metered non-coincident demands of 1.0 GVA.
Medium Industrial	495.4	NA	NA	1.4	$ 3.496	$ 5.0				$ 5.0	The charge of 3.496 $/KVA is calculated by dividing the total revenue requirement of $5.0 M by the total of customers' metered non-coincident demands of 1.4 GVA.
Large Industrial Firm		NA	NA								
Without Trans. Own.	46.3	NA	NA	0.1	$ 2.430	$ 0.3				$ 0.3	The charge of 2.430 $/KVA is calculated by dividing the total revenue of $0.3 M by the total of customers' metered non-coincident demands of 0.1 GVA.
With Trans. Own.	-	NA	NA	-	$ 2.110	$ -				$ -	The charge of 2.110 $/KVA is calculated by subtracting the transformer ownership credit of 0.32 $/KVA from the Large Industrial Demand Charge of 2.430 $/KVA
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	The charge of 2.430 $/KVA is calculated by dividing the total revenue requirement of 1.2 M by the total of customers' metered non-coincident demands of 0.5 GVA.
With Trans. Own.	52.8	NA	NA	0.3	$ 2.110	0.6				$ 0.6	The charge of 2.110 $/KW or KVA is calculated by subtracting the transformer ownership credit of 0.32 $/KVA from the Large Industrial Demand Charge of 2.430 $/KVA
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	The charge of 3.551 c/kWh is calculated by dividing total revenue requirement of $3.5 by kWh usage of 98.2GWh.
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

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Request IR-12:

Please explain how the charges on pages 16-21 of Appendix 17 are derived.

Response IR-12:

In preparing the response to this IR, the Company determined that the streetlight charges and Miscellaneous Small Load charges in the Application were not correct. They were underestimated by about 1% and did not balance with the unmetered costs in the "Proof of Revenue" calculations included in Appendix 17A Rates Calculations Electronics. The response to this question is based on the updated calculations included in **Attachment 1,** also provided electronically.

Using the electronic model for calculation of streetlight rates submitted in the 2014 GRA Compliance Filing[1], the Company adjusted the approved Miscellaneous Small Load tariff charges by setting the energy charges to zero and increasing the demand charge of $11.777/kW to $13.039/kW to balance the simulated revenues from the electric service portion of the Unmetered Rate Class Revenues with the distribution costs of $3.489 million of the Unmetered Rate class provided in Figure 5 of the Distribution Tariff Strawman Report.

The charge of $13.039/kW was applied in calculation of individual streetlight rates using the same two-step process as in the GRA proceedings.

(1) Using Miscellaneous Small Load charges, the Company calculates blended unit revenues for continuous and non-continuous services.

[1] Appendix 10 – 2014 Unmetered Report

(2) Unit revenues from step 1 are applied to kWh usage of each streetlight to arrive at the monthly electric service rate which is then added to the monthly streetlight maintenance and fixture capital rates to arrive at the bundled rate.

Please refer to **Attachment 1** for details.

The proposed streetlight rates for full service LED lights reflect the interim fixture costs which are a subject of the LED Capital Work Order proceeding currently before the Board in Matter M06973. The Distribution Tariff full service LED rates will be updated for the UARB's Decision on the LED Capital Work Order proceeding at the time of the RtR compliance filing.

STEP 1 - DETERMINATION OF UNIT REVENUES OF POWER AND ENERGY SERVI

Based on Misc. Small Loads Tariff Rate Components & 1kW lighting load

		Charge	Annual Revenue
Photocell Operation (4000 burning hours per year)			
Demand Charge $/kW (annual)		13.039	$156.47
Energy Charge :			
1st Block : 1st 200 kW.h (annual)	2,400	0.00000	0.00
2nd Block : All additional (annual)	1,600	0.00000	0.00
			$156.47
Rate per kW.h	4,000		**$0.0391179**

		Charge	Annual Revenue
Continuous Burning (8760 burning hours per year)			
Demand Charge $/kW (annual)		13.039	$156.47
Energy Charge :			
1st Block : 1st 200 kW.h (annual)	2,400	0.00000	0.00
2nd Block : All additional (annual)	6,360	0.00000	0.00
			$156.47
Rate per kW.h	8,760		**$0.0178621**

STEP 2 - DETERMINATION OF STREETLIGHT RATES[1]

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	Proposed DT Rates
Incandescent :						
Incandescent < 300 Watts - Note 1	001	97	$3.79	5.16	$1.88	$10.83
Incandescent > 300 Watts - Note 1	002	154	6.01	5.16	2.00	$13.17
Incandescent < 300 Watts - Note 1	003	97	3.79	0.00	0.00	$3.79
Mercury Vapour :						
Mercury Vapour 100 Watts	100	43	1.69	5.16	3.20	$10.05
Mercury Vapour 125 Watts	101	52	2.02	6.87	3.00	$11.90
Mercury Vapour 175 Watts	102	69	2.68	5.16	2.97	$10.81
Mercury Vapour 250 Watts	103	97	3.79	5.16	3.69	$12.64
Mercury Vapour 400 Watts	104	154	6.01	5.16	3.77	$14.94
Mercury Vapour 700 Watts	105	260	10.17	5.16	4.96	$20.28
Mercury Vapour 1000 Watts	106	363	14.20	5.16	5.99	$25.34
Mercury Vapour 250 Watt Cont. Oper.	107	212	3.79	10.31	3.69	$17.79
Mercury Vapour 125 Watts	201	52	2.02	6.87	0.00	$8.89
Mercury Vapour 175 Watts	202	69	2.68	5.16	0.00	$7.84
Mercury Vapour 250 Watts	203	97	3.79	5.16	0.00	$8.95
Mercury Vapour 400 Watts	204	154	6.01	5.16	0.00	$11.17
Mercury Vapour 700 Watts	205	260	10.17	5.16	0.00	$15.33
Mercury Vapour 1000 Watts	206	363	14.20	5.16	0.00	$19.36
Mercury Vapour 125 Watts	301	52	2.02	0.00	0.00	$2.02
Mercury Vapour 175 Watts	302	69	2.68	0.00	0.00	$2.68
Mercury Vapour 250 Watts	303	97	3.79	0.00	0.00	$3.79
Mercury Vapour 400 Watts	304	154	6.01	0.00	0.00	$6.01
Mercury Vapour 700 Watts	305	260	10.17	0.00	0.00	$10.17
Mercury Vapour 1000 Watts	306	363	14.20	0.00	0.00	$14.20
Fluorescent :						
Fluorescent 2x24" 70 Watts	110	30	1.18	10.31	2.43	$13.92
Fluorescent 2x48" 220 Watts	111	85	3.33	10.31	2.68	$16.33
Fluorescent 2x72" 300 Watts	112	116	4.56	10.31	3.15	$18.02
Fluorescent 4x72" 600 Watts	113	222	8.66	10.31	4.30	$23.27
Fluorescent 1x96" 110 Watts	114	47	1.83	10.31	2.96	$15.11
Fluorescent 1x72" 150 Watts	115	60	2.35	10.31	2.58	$15.24
Fluorescent 4x48" 440 Watts	116	166	6.51	10.31	3.25	$20.07
Fluorescent 4x72" 600 Watts	213	222	8.66	10.31	0.00	$18.97
Fluorescent 1x96" 110 Watts	214	47	1.83	10.31	0.00	$12.14
Fluorescent 1x72" 150 Watts	215	60	2.35	10.31	0.00	$12.66
Fluorescent 4x48" 440 Watts	216	166	6.51	10.31	0.00	$16.82
Fluorescent 1x48" 120 Watts	217	49	1.90	10.31	0.00	$12.21
Fluorescent 2x48" 220 Watts	218	85	3.33	10.31	0.00	$13.64
Fluorescent 4x35"	330	47	1.83	0.00	0.00	$1.83

Fluorescent Crosswalk - Continuous Burning - Customer Owned :						
Fluorescent 4x72" 600 Watts	117	486	8.67	0.00	0.00	$8.67
Fluorescent 2x24" 70 Watts	118	66	1.17	0.00	0.00	$1.17
Fluorescent 4x48" 440 Watts	119	364	6.51	0.00	0.00	$6.51
Fluorescent 2x96"	120	254	4.55	0.00	0.00	$4.55
Fluorescent 4x96"	150	613	10.95	0.00	0.00	$10.95
Fluorescent Crosswalk - Photocell Burning - Customer Owned :						
Fluorescent 2x24" 70 Watts	310	30	1.18	0.00	0.00	$1.18
Fluorescent 4x48" 440 Watts	311	166	6.51	0.00	0.00	$6.51
Fluorescent 2x72" 300 Watts	312	116	4.56	0.00	0.00	$4.56
Fluorescent 4x72" 600 Watts	313	222	8.66	0.00	0.00	$8.66
Fluorescent 1x96" 110 Watts	314	47	1.83	0.00	0.00	$1.83
Fluorescent 1x72" 150 Watts	315	60	2.35	0.00	0.00	$2.35
Fluorescent 4x96"	350	280	10.96	0.00	0.00	$10.96
Low Pressure Sodium :						
Low Pressure Sodium 135 Watts	130	60	2.35	15.47	5.79	$23.61
Low Pressure Sodium 180 Watts	131	80	3.13	15.47	8.39	$26.98
Low Pressure Sodium 90 Watts	132	45	1.75	15.47	5.79	$23.01
Low Pressure Sodium 180 Watts E&M	231	80	3.13	15.47	0.00	$18.60
Low Pressure Sodium 180 Watts E/O	331	80	3.13	0.00	0.00	$3.13
High Pressure Sodium :						
High Pressure Sodium 250 Watts	121	100	3.91	5.16	3.22	$12.28
High Pressure Sodium 400 Watts	122	150	5.87	5.16	3.33	$14.36
High Pressure Sodium 70 Watts	123	32	1.24	5.16	3.02	$9.42
High Pressure Sodium 100 Watts	124	45	1.75	5.16	3.05	$9.95
High Pressure Sodium 150 Watts	125	65	2.54	5.16	3.23	$10.92
HP Sodium 100 Watts - Cont. Oper.	126	99	1.75	10.31	3.05	$15.11
High Pressure Sodium 250 Watts	221	100	3.91	5.16	0.00	$9.07
High Pressure Sodium 70 Watts	222	32	1.24	5.16	0.00	$6.40
High Pressure Sodium 100 Watts	223	45	1.75	5.16	0.00	$6.91
High Pressure Sodium 150 Watts	224	65	2.54	5.16	0.00	$7.70
High Pressure Sodium 250 Watts	321	100	3.91	0.00	0.00	$3.91
High Pressure Sodium 70 Watts	322	32	1.24	0.00	0.00	$1.24
High Pressure Sodium 100 Watts	323	45	1.75	0.00	0.00	$1.75
High Pressure Sodium 150 Watts	324	65	2.54	0.00	0.00	$2.54
High Pressure Sodium 400 Watts	326	150	5.87	0.00	0.00	$5.87
High Pressure Sodium 500 Watts	327	183	7.17	0.00	0.00	$7.17
High Pressure Sodium 1000 Watts	328	363	14.21	0.00	0.00	$14.21
High Pressure Sodium 1500 Watts	329	500	19.56	0.00	0.00	$19.56

Metallic Additive :						
Metallic Arc 400 Watts	140	150	5.87	8.25	3.81	$17.93
Metallic Arc 1000 Watts	141	360	14.08	12.37	5.57	$32.02
Metallic Arc 250 Watts	142	100	3.91	12.37	3.75	$20.03
Metallic Arc 150 Watts	143	67	2.61	12.37	3.75	$18.73
Metallic Arc 100 Watts	144	50	1.96	12.37	3.75	$18.08
Metallic Arc 1000 Watts	341	360	14.08	0	0	$14.08
Metallic Arc 400 Watts	342	150	5.87	0	0	$5.87
Metallic Arc 250 Watts	343	100	3.91	0	0	$3.91
Metallic Arc 175 Watts	344	75	2.93	0	0	$2.93
Metallic Arc 150 Watts	345	67	2.61	0	0	$2.61
Metallic Arc 100 Watts	346	50	1.96	0	0	$1.96
Light Emitting Diode - Traffic Lights						
Light Emitting Diode 4.6 Watts	530	3	0.06	0	0	$0.06
Light Emitting Diode 7.5 Watts	531	5	0.10	0	0	$0.10
Light Emitting Diode (Energy Only)						
Lighting Emitting Diode 44 Watts	532	15	0.59	0	0	$0.59
Lighting Emitting Diode 66 Watts	533	22	0.86	0	0	$0.86
Lighting Emitting Diode 88 Watts	534	29	1.13	0	0	$1.13
Lighting Emitting Diode 92 Watts	535	31	1.21	0	0	$1.21
Lighting Emitting Diode 105 Watts	536	35	1.37	0	0	$1.37
Lighting Emitting Diode 173 Watts	537	57	2.23	0	0	$2.23
Lighting Emitting Diode 110 Watts	539	37	1.45	0	0	$1.45
Lighting Emitting Diode 65 Watts	540	22	0.86	0	0	$0.86
Lighting Emitting Diode 55 Watts	541	18	0.70	0	0	$0.70
Lighting Emitting Diode 83 Watts	542	28	1.10	0	0	$1.10
Lighting Emitting Diode 48 Watts	543	16	0.63	0	0	$0.63
Lighting Emitting Diode 72 Watts	544	24	0.94	0	0	$0.94
Light Emitting Diode (Energy & Capital						
Lighting Emitting Diode 44W	615	15	0.59	0	7.27	$7.86
Lighting Emitting Diode 55W	616	18	0.70	0	7.27	$7.97
Lighting Emitting Diode 28W	623	9	0.35	0	7.27	$7.62
Lighting Emitting Diode 50W	624	17	0.67	0	7.27	$7.94
Lighting Emitting Diode 72W	625	24	0.94	0	7.27	$8.21
Lighting Emitting Diode 100W	626	33	1.29	0	7.27	$8.56
Lighting Emitting Diode 200W	627	67	2.62	0	7.27	$9.89

(1) Maintenance and Capital Components are the same as under the currently approved streetlight rates.

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Request IR-13:

In MCI DR-20, NSPI states that it does not have functional area specific data on which the $83.3 million deferral of fixed costs could be attributed across functions. One possibility to adjust the 2014 COSS to remove the $83.3 million might be to apportion the $83.3 million on the basis of functional revenue requirements as they appear in Exhibit 4 of the COSS, but with fuel costs excluded from the generation function. Please provide NSPI's thoughts on this option.

Response IR-13:

In the Company's view such an adjustment is not appropriate.

The fixed cost deferral was required to support rate stability applicable to bundled service customer rates. The deferral of these costs and their subsequent recovery from customers is not applicable to below-the-line (i.e. Annually Adjusted) rates, as NS Power has proposed for this application. Consistent with this, the Company notes that the OATT, which supports the wholesale market opening was not subject to the deferral. Please refer to **SBA IR-11**.

With respect to the approach to apportionment proposed in the question, the Company submits that, consistent with the foregoing, this is not necessary and anticipates that without formal Board review or an established practice in place, the approach would prove contentious.