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Request IR-17:

With respect to DE-03-DE-04, page 51, Lines 7-31:

(a) Please explain how NSPI's proposed approach is different from the method approved by the Board in its December 21, 2010 letter, and demonstrate that difference using the numbers in the Board's letter.

(b) Please explain how NSPI's proposed approach is different from the approach it proposed in the May 2010 Point Tupper Wind Farm Hearing (NSUARB-NSPI-P-128.10)

Response IR-17:

(a) NSPIs proposed approach includes the OM&G, financing and depreciation costs being recovered through non-fuel rate components. As a result of this change, the project cost components that would remain in the FAM Structure include the Fuel Expense PPA (100 percent PPA) and the Sales and EcoEnergy Revenue (49 percent). The figures presented in the Board's letter of December 21, 2010, reflect the current impact to the FAM mechanism in 2010 and 2011 (columns 1 and 2). The proposed approach beginning in 2012 is presented in columns 3 and 4. Using the figures presented in the Board's letter, the Net FAM Impact under the proposed structure is as follows:

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	Board Approved Accounting Methodology		Proposed Approach	
	2010 ($M)	**2011 ($M)**	**2010 ($M)**	**2011 ($M)**
Fuel Expense (100% PPA)	**2.6**	**6.3**	**2.6**	**6.3**
Non-Fuel Expenses				
Net Operating Income:				
Sales Revenue (49%)	(1.3)	(3.1)	(1.3)	(3.1)
EcoEnergy Revenue (49%)	(0.1)	(0.3)	(0.1)	(0.3)
Project O&MG (49%)	0.2	0.5	0.0	0.0
NSPI Internal O&MG (49%)	0.0	0.0	0.0	0.0
Capital Costs:				
Depreciation	0.6	1.4	0.0	0.0
Interest	0.7	1.1	0.0	0.0
Non-Fuel Recovery Component	**0.1**	**(0.5)**	**(1.4)**	**(3.4)**
Net FAM Impact	**2.7**	**5.8**	**1.2**	**2.9**

(b) The primary difference between this proposal and the reply submission filed for the Point Tupper Wind Project on May 13, 2010 is that NSPI is not seeking to remove the revenue streams of the project from the current FAM Mechanism. The 49 percent Sales and Eco Energy Revenue generated from the project will continue to offset the PPA expenses paid for the renewable generation. This approach is consistent with how NSPI recovers the operating costs of other NSPI owned wind projects.

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Request IR-18:

With respect to DE-03-DE-04, Section 10.1.2 (Large Industrial Rate):

(a) **Please provide a version of this tariff which highlights the specific changes being proposed.**

(b) **Please provide a list of customers currently on this rate, showing their total billing demand and their interruptible demand. (For the purposes of this response, customers can be identified as A, B, C, etc. rather than by name).**

(c) **Does NSPI intend that in future, the interruptible portion of the load of customers on this rate should be at least 2000KVA?**

(d) **If the answer to (c) is affirmative, why does NSPI propose limiting the interruptible portion to that minimum level, given that NSPI can accommodate interruptible loads of less than 2000KVA with its automated dialling system (Page 137, Lines 3-4) and NSPI relies on these loads (Page 137, Line 6)?**

(e) **Is the intent of the "grandfathering" (Page 137, Line 9) to allow existing customers whose interruptible load is less than 2000KVA to remain on the rate?**

(f) **What are the criteria that NSPI proposes to use to determine the regular billing demand which will "add value to the interruptible program" (Page 137, Line 15)?**

(g) **For each occasion in the last three years where NSPI has requested any customers on this rate to interrupt load, please specify the date of such interruption, the reason for the request, the customers who were requested to curtail load, the load reductions requested by customer, and the load actually curtailed by customer.**

(h) As NSPI adds capacity to facilitate its transition to renewable energy, does it anticipate that the need for interruptible load will diminish? Why or why not?

Response IR-18:

(a) Please refer to Attachment 1.

(b) Please refer to Attachment 2 which shows non-coincident billing demands of Large Industrial Interruptible customers broken down by firm and non-firm service from the month of February, 2011.

(c) No.

(d) N/A.

(e) Yes. Some customers who previously qualified under the current criteria have reduced load through energy efficiency initiatives and should not be disqualified as a result of taking such measures. Secondly, many of the current customers have invested considerable time and funds to be able to respond when called to interrupt and many are experienced and reliable in executing load reductions when called.

(f) NSPI has not determined yet what these criteria will be. The current number of subscribed customers and subscribed load is manageable and well balanced to suit the demand response requirements, given the NSPI resources associated with this class of customers. A drop in individual customer billing demand does not pose a problem under the automated dialing system. For the interruption call purposes, customers are grouped into several teams representing comparable loads. To the extent a team's load gets out of line with the designed average the customer team mix can easily be rearranged.

Most of the challenges revolve around the labor-intensive post interruption event analysis, customer on-site training, and process administration. Thus the challenges in the delivery of the interruptible service are concerned with the number of subscribed interruptible customers. This aspect of the service, however, is addressed under the two MVA threshold required for the Large Industrial Class membership.

NSPI would continue to monitor the effectiveness of proposed changes and would develop appropriate measures, as required and appropriate, to resolve new challenges.

(g) Please refer to Attachment 3.

(h) NSPI has not determined how increased non-dispatchable resources on the system will affect the requirement for interruptible load.

(2 000 kVA or 1 800 kW, and Over)
Rate Code 23

DEMAND CHARGE

$10.573 per month per kilovolt ampere of maximum demand of the current month or the maximum actual demand of the previous December, January or February occurring in the previous eleven (11) months.

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32 cents per kilovolt ampere reduction in demand charge where the transformer is owned by the customer.

ENERGY CHARGE

6.432 cents per kilowatt hour for firm sales

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Deleted: 5.996 cents per kilowatt hour for interruptible sales ¶
¶
These energy charges reflect the "energy charge equalization" adjustments included in the 2009 Settlement Agreement and Approved by the UARB in its November 5, 2008 Decision.¶

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the greater of $12.65 or the demand charge.

AVAILABILITY:

This tariff is applicable to three phase electric power and energy supplied at the low voltage side of the bulk power transformer to any industrial customer having a regular billing demand of 2 000 kVA or 1 800 kW, and over.

SPECIAL CONDITIONS:

(1) At the option of the Company, supply may be at distribution voltage. Meter readings shall be increased by 1.75% for each transformation between the meter and the low

voltage side of the bulk power supply transformer to adjust for transformer losses. Also, meter readings shall be reduced when metering is at transmission voltage.

(2) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering.

(3) The Company will withdraw the availability of this tariff to any specific customer, if, on a consistent basis, the customer is not maintaining a regular demand of 2 000 kVA or 1,800 kW or, as a result of transferring to this tariff from the Medium Industrial category the customer would not see a reduction in his electric cost for the energy supplied. NSPI reserves the right to grandfather any customer enrolled in the interruptible service, who no longer meets the regular demand criteria, if in the opinion of the Company, the amount of load subscribed in the service is sufficient to continue to add value to the supply interruptible program.

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

(5) The customer will make all necessary arrangements to ensure that its load does 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.

(6) 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.

INTERRUPTIBLE RIDER TO THE LARGE INDUSTRIAL TARIFF (Rate Code 25)

Customers who qualify for interruptible service will receive a $3.43 per month per kilovolt ampere reduction in demand charge for billed interruptible demand. The billed interruptible demand is defined as the difference between any contracted firm demand requirements and the total billing demand. Where the billing demand is less than the contracted firm demand, no interruptible credit shall apply. The billed interruptible demand will be the maximum interruptible demand of the current month or the maximum actual interruptible demand of the previous December, January or February occurring in the previous eleven (11) months.

AVAILABILITY:

This rider will be applicable to a minimum regular billing demand, as determined by NSPI to add value to the interruptible program, at 90% Power Factor, under the following terms and conditions:

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Deleted: of 2 000 kVA

(1) The customer has provided written notice of his desire to take service under this option, identifying that portion of the load that is to be firm and that portion that is to be interruptible.

(2) The customers will reduce their available interruptible system load by the amount requested by NSPI within ten (10) minutes of such request by the Company.

(3) Following interruption, service may only be restored by the customer with approval of the Company.

(4) Failure to comply in whole or in part with a request to interrupt load will result in penalty charges. The penalty will be comprised of two parts, a Threshold Penalty and a Performance Penalty.

The Threshold Penalty charge shall be the cost of the appropriate firm billing effective at that time for the consumption used in that billing period.

The Performance Penalty which is based on the customer's performance during the interruption event is calculated as per the formula below:

Performance Penalty = ($15/kVA x A) + ($30/kVA x B)

Where:

"A" is any residual customer demand (above that required by the interruption request) remaining in the third interval directly following two complete 5-minute intervals after the interruption call was delivered by telephone call.

"B" is the customer's average demand based on 5-minute interval data during the entire interruption event excluding the interval used to determine "A."

The total penalty will not exceed two times the cost of the appropriate firm billing effective at that time for the consumption used in that billing period.

(5) Should any customer under this rider desire to be served under any appropriate firm service rate, a five (5) year advance written notice must be given to the Company so as to ensure adequate capacity availability. Requests for conversion to firm service will be treated in the same manner as all other requests for firm service received by the Company. The Company may, however, permit an earlier conversion. In the event that the Customer desires to return to interruptible service in the future, the Customer may convert to interruptible service following two (2) years of service under the firm rate schedule. The Company may permit an earlier conversion from firm to interruptible service.

(6) Interruption is limited to 16 hours per day and 5 days per week to a maximum of 30% of the hours per month and 15% of the hours in a year.

SPECIAL CONDITIONS:

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

(2) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. 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) At the option of the Company, supply may be at distribution voltage. Meter readings shall be increased by 1.75% for each transformation between the meter and the low voltage side of the bulk power supply transformer to adjust for transformer losses. Also, meter readings shall be reduced when metering is at transmission voltage.

Current Large Industrial Interruptible Rider customer subscribed load showing firm subscription demand levels.

	Company	Feb-11 Demand kVA
Interruptible	Company A	2,247
Firm	Company A	250
Total	Company A	2,497
Interruptible	Company B	4,502
Interruptible	Company C	875
Interruptible	Company D	1,994
Interruptible	Company E	2,106
Interruptible	Company F	922
Interruptible	Company G	1,912
Interruptible	Company H	2,220
Interruptible	Company I	598
Interruptible	Company J	5,990
Interruptible	Company K	8,550
Interruptible	Company L	6,096
Interruptible	Company M	3,845
Interruptible	Company N	17,040
Firm	Company N	2,000
Total	Company N	19,040
Interruptible	Company O	23,664
Interruptible	Company P	10,536
Interruptible	Company R	10,893
Interruptible	Company S	2,032
Interruptible	Company T	1,692
Interruptible	Company U	2,110
Interruptible	Company V	384
Interruptible	Company W	4,234
Interruptible	Company X	2,435
Interruptible	Company Y	1,786
Interruptible	Company Z	2,797

Event	Reason	Customers	Load Requested	Load Reduced
January 26, 2009	Point Aconi off, Purchase cut by 90 MW, Capacity Shortage	A	0.8 MW	0.8 MW
		B	14 MW	14 MW
		C	1.8 MW	1.8 MW
		D	1.4 MW	1.4 MW
		E	0.9 MW	0.9 MW
		F	0.4 MW	0.4 MW
		G	0.4 MW	0.4 MW
		H	7.8 MW	7.8 MW
		I	3.3 MW	3.3 MW
		J	0.3 MW	0.3 MW
		K	0.2 MW	0.2 MW
		L	0.7 MW	0.7 MW
		M	15 MW	15 MW
		N	8.5 MW	8.5 MW
		O	18 MW	18 MW
		P	19.5 MW	0 MW
		Q	4.4 MW	4.4 MW
		R	3.5 MW	3.5 MW
		S	1.2 MW	1.2 MW
		T	0.6 MW	0.6 MW
		U	4.2 MW	4.2 MW
		V	1.6 MW	0 MW
		W	0.6 MW	0.6 MW
		X	0.5 MW	0.5 MW
		Y	1.9 MW	1.9 MW
		Z	5.2 MW	5.2 MW
		AA		
April 9, 2009	Tufts Cove 1 and 2 off, Lingan 1, 2 and 3 off, Wreck Cove 1 off, Capacity Shortage	A	0.6 MW	0.6 MW
		B	14 MW	14 MW
		C	1.6 MW	1.6 MW
		D	1.4 MW	1.4 MW
		E	0.8 MW	0.8 MW
		F	0.6 MW	0.6 MW
		G	0.7 MW	0 MW
		H	8.0 MW	8.0 MW
		I	3.0 MW	3.0 MW
		J	0.3 MW	0.3 MW
		K	0.2 MW	0.2 MW
		L	0.35 MW	0.35 MW
		M	11.0 MW	11.0 MW
		N	7.2 MW	7.2 MW
		O	5.0 MW	5.0 MW
		Q	1.2 MW	1.2 MW
		R	3.7 MW	3.7 MW
		S	1.0 MW	1.0 MW
		T	2.8 MW	2.8 MW
		U	2.5 MW	2.5 MW

		W X Y Z	0.6 MW 1.8 MW 1.6 MW 7.5 MW	0.6 MW 1.8 MW 1.6 MW 7.5 MW
December 1, 2009	Transmission lines L6010 and L6005 de-energized for highway shift, Metro Import Flow limit exceeded, Burnside 1 and 2 tripped off during peak load, interrupted 30MW of interruptible to maintain limits on transmission corridor (Flow into Metro) Tuft's Cove 1 off.	AB AC E G D N H	1.5 MW 6.0 MW 1.7 MW 1.4 MW 2.2 MW 8.5 MW 9.2 MW	1.5 MW 6.0 MW 1.7 MW 1.4 MW 2.2 MW 8.5 MW 9.2 MW
December 17, 2009	Tufts Cove 3 off, Capacity Deficiency	A B C D E F G H I J K L M N O Q R S T U W Y Z	0.7 MW 14 MW 1.7 MW 1.4 MW 0.7 MW 0.4 MW 0.8 MW 3.3 MW 2.7 MW 0.3 MW 0.2 MW 0.5 MW 13.2 MW 8.1 MW 18.7 MW 4.3 MW 3.8 MW 0.7 MW 3.0 MW 2.8 MW 0.6 MW 1.7 MW 2.7 MW	0.7 MW 14 MW 1.7 MW 1.4 MW 0.7 MW 0.4 MW 0.8 MW 3.3 MW 2.7 MW 0.3 MW 0.2 MW 0.5 MW 13.2 MW 8.1 MW 18.7 MW 4.3 MW 3.8 MW 0.7 MW 3.0 MW 2.8 MW 0.6 MW 1.7 MW 2.7 MW
February 1, 2010	Lingan 2 and 3 off, Capacity Deficiency	L Y R M K I C F	0.5 MW 1.8 MW 3.6 MW 15.0 MW 0.24 MW 2.5 MW 1.7 MW 0.3 MW	0.5 MW 1.8 MW 3.6 MW 15.0 MW 0.24 MW 2.5 MW 1.7 MW 0.3 MW
January 23, 2011	Tufts Cove 3 off, Lingan 2 off, Trenton 5 off, Purchase cut by	A C	0.4 MW 1.0 MW	0.4 MW 0 MW

	80MW; Capacity Shortage	D E F AB G H I J K L M N O Q R S U Y Z AA AC	0.6 MW 0.7 MW 0.3 MW 0.2 MW 0.4 MW 9.0 MW 2.5 MW 0.3 MW 0.2 MW 0.3 MW 14.5 MW 7.5 MW 17.0 MW 3.8 MW 4.3 MW 0.2 MW 1.8 MW 0.8 MW 4.6 MW 0.5 MW 2.0 MW	0.6 MW 0.7 MW 0 MW 0.2 MW 0.4 MW 9.0 MW 2.5 MW 0.3 MW 0.2 MW 0.3 MW 14.5 MW 7.5 MW 17.0 MW 3.8 MW 4.3 MW 0.2 MW 1.8 MW 0.8 MW 4.6 MW 0 MW 2.0 MW

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Request IR-19:

With respect to DE-03-DE-04, Appendix H. Provision is made on page 7 (Lines 2 - 5) for the development of a new nominal CBL between GRA's.

(a) **Can a new CBL be set at any time?**

(b) **If a new CBL is set, will the SEC also be recalculated and submitted to the UARB for approval, or will this be done only through a GRA?**

(c) **If the SEC is to be reset between GRA's when a new nominal CBL is established, how will it be calculated and how will it receive UARB approval?**

Response IR-19:

(a) Yes, subject to meeting the requirement, as specified in the Customer Baseline Load (CBL) section of the tariff, that "significant and permanent changes in customer consumption take place between GRA proceedings".

(b-c) NSPI does not propose any changes in this regard. Under the current arrangements, the Standard Energy Charge (SEC) is set only through a GRA.

NON-CONFIDENTIAL

Request IR-20:

With respect to DE-03-DE-04, Appendix H, it is proposed on page 8, Line 22 that the credit floor should be lowered to "a credit equivalent to the fuel contribution portion of the SEC".

(a) Has the "fuel contribution portion of the SEC" been identified in NSPI's filing?

(b) Should the fuel and non-fuel portions of the SEC be specified in the tariff?

Response IR-20:

(a) Yes. Please refer to NPB IR-50.

(b) Yes, subject to UARB's approval of the proposed change to the floor in the credit mechanism.

NON-CONFIDENTIAL

Request IR-21:

With respect to DE-03-DE-04, Appendix H, Appendix A, various colors are used to strikeout and add text. What is the significance of the various colors? Are all sections of Appendix A that are not struck out included in the proposed tariff?

Response IR-21:

There is no significance to various colors reflecting strikeout and add text. All sections of Appendix A that are not struck out are included in the proposed tariff.

Please refer to the Application, PR-01 for a clean version of the proposed tariff.

NON-CONFIDENTIAL

Request IR-22:

With respect to DE-03-DE-04, Appendix H, it is noted on page 15 (1st paragraph) that "The provisional CBL_{op} level will be adjusted after the event based on the average energy taken during this period."

(a) Is there any maximum time during which a provisional CBL_{op} can remain in place?

(b) Is there any limit on the number of provisional CBL_{op}'s a customer may seek to put in place in a given year?

(c) If the provisional CBL_{op} is in effect for several billing periods, will all bills affected be adjusted after the fact? If so, please describe the adjustments that will need to be made.

Response IR-22:

(a) The provisional CBL_{op} can remain in place for as long as the underlying conditions, giving rise to the CBL reduction, are in effect and are deemed temporary. There is no maximum time limit proposed in this regard. However, should the underlying conditions be deemed permanent at some point during CBL_{op} implementation, the provisional CBL_{op}, subject to UARB's approval, would be considered a nominal CBL.

(b) There is no limit proposed on the number of provisional CBL_{op}'s a customer may seek to put in place in a given year.

(c) Yes, all affected bills are proposed to be adjusted after the fact.

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At the end of the duration of CBL_{op} event the average actual energy usage level of the customer for the period will be applied, as a CBL benchmark, to actual hourly consumption records to determine actual incremental and decremental energies which will then be priced using the hourly marginal cost Debit/Credit Mechanism.

The difference between the nominal CBL and the average actual consumption level will be priced at the avoided unit costs forecasted at the time of setting CBL_{op}. The difference between the re-estimated credits and debits, as described above, and the credits and debits actually billed will be addressed through a billing adjustment.

NON-CONFIDENTIAL

Request IR-23:

With respect to DE-03-DE-04, Appendix H, it is noted on page 15 (1st paragraph) the customer will be compensated for fuel savings associated with the difference between the CBL and the CBL_{op} at the forecast average unit avoided cost associated with "this load reduction". Is "this load reduction" determined on the basis of the forecasted CBL_{op} or the CBL_{op} as determined after the fact? If the latter, will the avoided costs also be updated to be after the fact?

Response IR-23:

The customer will be compensated at the forecast average unit avoided cost, determined on the basis of the forecasted CBL_{op}, applied to the actual reduced CBL energy.

The difference between the forecast and actual (after the fact) average reduction is expected to be small. The tariff allows either party to request a review of the appropriateness of interim CBL arrangements if energy consumption differs significantly.

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Request IR-24:

With respect to SR-01 Attachment 1, Exhibit 2, why does the deferred credit ARO Wind on Line 37 not carry forward to Exhibits 2A, 2B and 3?

Response IR-24:

It is appropriate to carry the ARO Wind credit forward to Exhibits 2A, 2B and 3. NSPI is prepared to make the appropriate amendments to the cost of service study to address this item. The adjustment will not have a significant impact on the allocated costs to rate classes.

NON-CONFIDENTIAL

Request IR-25:

With respect to SR-01 Attachment 1, Exhibit 2, please provide the derivation of the Street Lighting rate base on Line 20, and its assignment to Distribution and Direct Capital.

Response IR-25:

The Street Lighting rate base of $30.8 million, on Line 20, represents a total of non-LED rate base of $22.0 million and LED rate base of $8.8 million. For the derivation of these numbers please refer to Multeese IR-13 (a).

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Request IR-26:

With respect to SR-01 Attachment 1, Exhibit 3, page 2, why is the Total Company Distribution sub-total on Line 17 different from the Total Distribution classified as Demand in Exhibit 2B, page 3, Line 12?

Response IR-26:

Please refer to Multeese IR-24 and Multeese IR-27. Adjusting for these two items, results in the Total Company Distribution sub-total (Exhibit 3) equaling Total Distribution (Exhibit 2B).

Request IR-27:

With respect to SR-01 Attachment 1, Exhibit 3B, why is the total plant ($26,205) different from the Substation plant shown on Line 13 of Exhibit 2?

Response IR-27:

The figures in Exhibit 3B do not reflect a CWIP value of $0.5 million associated with substation rate base which is appropriately accounted for in Exhibit 2. By incorporating the CWIP amounts into Exhibit 3B, the total plant allocations to each rate class would be:

Customer Class	**Total Plant – Submission**	**Total Plant - Revised**
(in thousands of $)		
Domestic	15,467	15,801
Small General	656	670
General	6,624	6,766
General Large	827	845
Small Industrial	681	696
Medium Industrial	1,155	1,177
Large Industrial	375	375
ELI 2P-RTP	42	42
Municipal	28	28
Unmetered	350	357
Total	**26,205**	**26,756**

NSPI is prepared to make the appropriate amendments to the cost of service study to address this item.

Request IR-28:

With respect to SR-01 Attachment 1, page 53 of 69 (Exhibit 9A for the year 2012), please provide load research or other data to support the following changes relative to the 2009 Compliance Filing:

(a) A change of 9.9% in the Small General load factor, as calculated from sales data and non-co-incident demand before losses. (2009 LF = 40.3%; 2012 LF = 50.2%).

(b) An increase in the Small General co-incidence factor from 68.5% to 95.3%.

(c) An increase in the Unmetered co-incidence factor from 76.5% to 100%.

Response IR-28:

(a-b) The load profiles upon which these calculations are based change from year to year due to changes in customer behavior influenced by the economy and other factors. A substantial part of the change in the Small General load profile however, is due to a change in the energy threshold required for customer participation in the Small General rate which affected the properties of the class load profile.

Prior to 2004, the Small General rate class consisted of commercial customers consuming less than 12,000 kWh per year. In 2004, the customer requirement for participation in the rate class was changed from 12,000 kWh per year to the interim level of 22,000 kWh per year. The following year, the threshold was adjusted upwards again, to customers using less than 32,000 kWh per year.

The load profile used to calculate the 2009 compliance filing used an historical Small General load profile which did not yet reflect the complete effects of all the customer migration. The 2012 forecast is based on a load profile from 2008 when all the customer migration had been completed. The addition of more and larger customers to the Small General class was a major cause of the higher load factor and higher coincidence factor.

(c) The change in the Unmetered class co-incidence factor is due to updated load profiles used to create the load statistics.

In the 2009 Compliance Filing, the system peak occurred at the hour-ending 6:00PM. Based on January sunset times, this is considered an evening shoulder hour for the photocell operated equipment on the Unmetered rate such as street and area lighting. During this shoulder transition period from day to night, not all of this equipment would be turned on. In the updated load profiles, the system peak occurred at the hour-ending 7:00PM when all the photocell operated equipment is assumed to be turned on and the rate class would be at full load.

NON-CONFIDENTIAL

Request IR-29:

With respect to SR-01 Attachment 1, Exhibit 4 (page 34 of 69), Line 21:

(a) What services are provided under Construction and Technical Services?

(b) How many people are employed in this group?

(c) What percentage of these costs is estimated to be contract costs?

Response IR-29:

(a) Please refer to Section 5.4.4, lines 9 to 12, page 92 of the Application.

(b) Please refer to Liberty IR-64 (a)

(c) Please refer to 2012 GRA DE-03 – DE-04 Appendix C page 20 for 2012 forecasted costs by account, including contracts.

NON-CONFIDENTIAL

Request IR-30:

With respect to SR-01 Attachment 1, Exhibit 4 (page 34 of 69), Line 22:

(a) What services are provided under Sustainability?

(b) How many people are employed in this group?

(c) What percentage of these costs is estimated to be contract costs?

Response IR-30:

(a) Please refer to Liberty IR-50 (d).

(b) Please refer to Liberty IR-50 (b).

(c) Please refer to 2012 GRA DE-03 – DE-04 page 23 Appendix C for 2012 forecasted costs by account, including contracts.

Request IR-31:

With respect to SR-01 Attachment 1, Exhibit 4 (page 34 of 69), Line 26, please explain why the total Distribution OM&G expense ($62,799) is 32.25% higher than it was in the 2009 Compliance Filing ($47,490).

Response IR-31:

The increase is caused by the functionalization of a newly created cost category "Technical and Construction Services", as distribution-related only.

The ensuing analysis, as prompted by this question, revealed that the cost category should have been functionalized among all areas of the Company using the following breakdown.

Category	Total ($)	Prod. Expenses ($)	Trans. Expenses ($)	Dist. Expenses ($)	Retail Expenses ($)	Direct Expenses ($)
T&C Services	13,524	3,167	1,656	3,913	4,788	0

The corrected functionalization reduces Total Distribution OM&G expense by $9.6 million and results in an increase of 12 percent over the 2009 Compliance Filing. NSPI is prepared to make the appropriate amendments to the cost of service study to address this item.

NON-CONFIDENTIAL

Request IR-32:

With respect to SR-01 Attachment 1, Exhibit 4 (page 34 of 69), Lines 38, please provide the derivation of the portion that is directly assigned.

Response IR-32:

Please refer to Multeese IR-13 (b).

NON-CONFIDENTIAL

Request IR-33:

With respect to SR-01 Attachment 1, Exhibit 4 – Detail (page 35 of 69), please confirm that the Distribution Street Lighting OM&G of $3,668 (no line number included in the exhibit) all relates to existing street lights.

Response IR-33:

Confirmed.

The $3.7 million represents Customer Operations-related costs before the final allocation of shared OM&G costs associated with the Distribution Functional Area is made in Exhibit 5 (page 3, line 14).

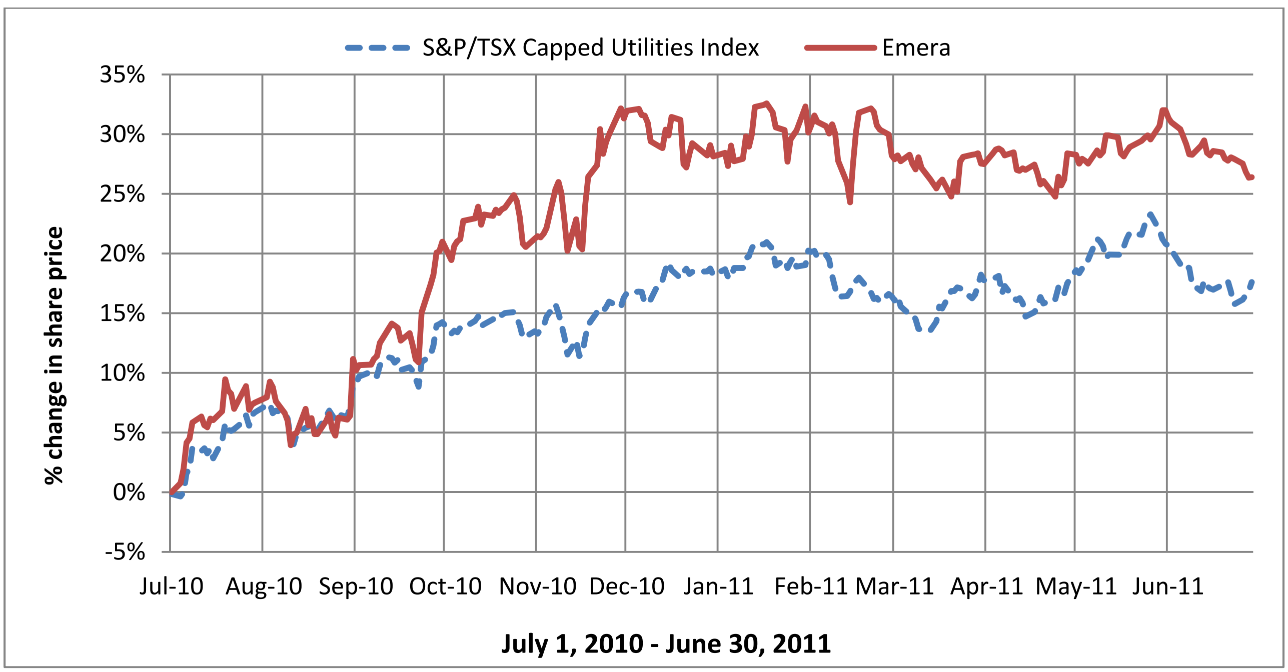
NON-CONFIDENTIAL

Request IR-34:

With respect to DE-03 - DE-04, 6.0 Capital Structure and Financing, please provide a chart outlining the performance of Emera Inc. ("EMA") versus the S&P/TSX Capped Utilities Index ("TTUT") over the past 12 months.

Response IR-34:

Please refer to the chart below.

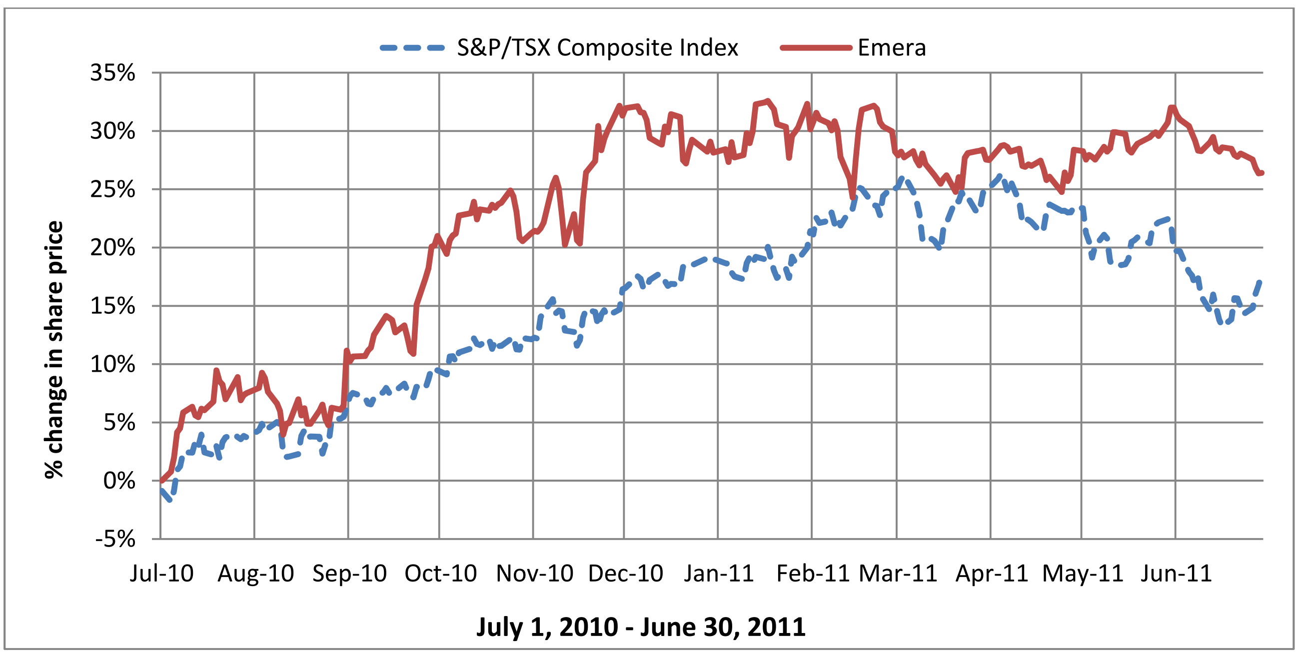


Request IR-35:

With respect to DE-03 - DE-04, 6.0 Capital Structure and Financing, please provide a chart outlining the performance of Emera Inc. ("EMA") versus the S&P/TSX Composite Index ("TSX") over the past 12 months.

Response IR-35:

Please refer to the chart below.



NON-CONFIDENTIAL

Request IR-36:

With respect to DE-03 - DE-04, 5.0 OM&G, page 65 of 161, please provide any industry benchmarks for the OM&G/MWh and OM&G/customer results of NS Power.

Response IR-36:

Please refer to 2012 GRA DE-03 – DE-04 Appendix B.