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Request IR-1:

Please explain why it is appropriate to increase each class by the same percentage, including customers who pay more than R/C ratio of 1.0

Response IR-1:

In determination of the proposed revenue responsibilities by class, NS Power has applied an established and transparent process, which ensures that revenue to cost ratios for all 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 process is rooted in established ratemaking practice in the utility industry. It is cost based in that it ensures that cost responsibilities of all customer classes fall within the acceptable cost metrics. It provides for a more stable rate environment in that it minimizes fluctuations in rates attributable to imperfections in cost of service studies from one rate case to another. It yields less diversified percentage increases in rates among classes than a method of zero tolerance for the R/C ratio band would produce.[1]

[1] The 2009 GRA Settlement Agreement resulted in an equal percent increase in rates of all rate classes (NSUARB-NSPI-P-888).

NON-CONFIDENTIAL

Request IR-2:

Does the filed revenue requirement include the PeopleSoft investment that was not approved in the order on the ACE Plan? If so, please provide a 2013-14 revenue requirement with no further PeopleSoft investment included.

Response IR-2:

Of the two projects for which the Board withheld approval, CI 41424 – PeopleSoft Self Service Module was included in rate base in the Application. The Board's decision had not been received when this aspect of the revenue requirement was being developed. Further, NS Power intends to provide the additional information required for this project, as was provided for in the Board's decision. Therefore, NS Power has not performed the requested revenue requirement analysis.

NON-CONFIDENTIAL

Request IR-3:

On p. 12-13 the Company references responding to reduced sales by running plants at reduced capacity. Please describe the characteristics of the plants that will be running at reduced capacity. Would 2013-2014 revenue requirements be lower if any of the plants that will be running at reduced capacity were instead mothballed or permanently closed?

Response IR-3:

Please refer to Avon IR-6.

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Request IR-4:

On p. 13 the Company seems to state that it cannot mothball the effected plants and also meet reliability standards. Is this correct? Does this mean that NSPI could not meet reliability standards if it mothballed any generating unit even after the Port Hawkesbury biomass plant is operational? Please provide any analysis that underlies this response.

Response IR-4:

Please refer to Avon IR-6 and Multeese IR-7. The generating capacity of the biomass plant is less than half that of a coal-fired thermal unit and therefore it is insufficient, on its own, to enable the retirement of a unit.

NON-CONFIDENTIAL

Request IR-5:

On p. 13 Company describes running 2 Lingan units on a seasonal basis. Please explain the operational and cost changes that result from the seasonal running. Is this the sole or major cause of the $4.1 million in savings referenced on p. 16? Please provide workpapers detailing the specific savings that underlie this amount.

Response IR-5:

Please refer to Multeese IR-10.

NON-CONFIDENTIAL

Request IR-6:

Please provide all analyses of the impact on revenue requirements of mothballing or shutting down any generating units in 2013-2015. If the Company has not performed any such analyses, please explain why not.

Response IR-6:

Please refer to Avon IR-6.

NON-CONFIDENTIAL

Request IR-7:

Please provide any analyses in the Company's possession that compare benefits to customers versus the cost of spending more on reliability spending

Response IR-7:

Please refer to Liberty IR-59.

Request IR-8:

Please provide the numbers underlying the graph on p.90 showing hours of interruption from tree contact. How many of the hours of interruption each year were caused by falling trees from trees located outside NSPI's right of ways?

Response IR-8:

Please refer to the figure below:

Customer Hours of Interruption			
Year	**Falling Tree***	**Broken Branch**	**Untrimmed Tree**
2009	881,187	80,905	29,945
2010	5,594,622	316,374	148,418
2011	1,106,315	81,425	52,480

*Falling trees refers to trees that have fallen from outside the right-of-way.

NON-CONFIDENTIAL

Request IR-9:

Is amount of the dollars requested for vegetation management same as request prior year? What was the basis for the 2012 GRA requested amount?

Response IR-9:

The dollar figure for vegetation management is the same as last year as the required program to improve reliability for our customers remains the same. Please refer to Attachment 1 for Liberty IR-59 from the 2012 GRA which elaborates on NS Power's evidence for increased vegetation management in that Application.

The rationale behind increased vegetation management programs and the resulting improvements in customer reliability are included in in DE-03 – DE-04, Section 6.4.3 at page 89 of 159 of the Application.

NON-CONFIDENTIAL

Request IR-59:

With respect to the statement on page 81 of NSPI's application that,

> **NS Power's Vegetation Management Program is the most effective investment to improve customer reliability,**

Please provide:

(a) a description of the basis for the statement, and

(b) all analytical support for it.

Response IR-59:

(a) NSPI uses a methodology to measure the effect of projects on customer reliability. This approach divides the net present value of performing the work by the estimated annual number of customer hours of interruption that will be avoided (ACHI) through the completion of the work. The ratio $/ACHI is used to prioritize perspective projects as well as measure the effectiveness of completed work. In 2011, the vegetation management program is calculated to return the lowest $/ACHI (most cost effective investment) when compared against the other strategies in the reliability investment plan. Further details regarding NSPI's reliability program are found in Attachment 1.

(b) Please refer to Attachment 2 and the summary table below.

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2011 Reliability Investment Strategy	Forecast (NPV $)	ACHI	$/ACHI
Equipment Replacements	9,478,451	58,750	161
Storm Hardening	2,610,769	23,155	113
System Improvements	6,221,332	67,481	92
Technology Improvements	1,953,140	31,670	62
Vegetation Management	13,213,406	275,352	48
Totals:	**33,477,100**	**456,408**	**73**

Reliability Investment Strategy 2009–2014

MARCH 17, 2009

Energy Everywhere

NOVA SCOTIA POWER
An Emera Company

Executive Summary

Over the last six years, Nova Scotia Power has faced increasing challenges regarding system performance. These challenges have had a direct effect on customer satisfaction rates, and our customers' confidence in the system.

System improvements, public awareness of improvements, and customer belief that actions by Nova Scotia Power have improved reliability are key elements of the company's Reputation Plan.

More severe weather conditions and aging equipment have placed greater stress on our electrical system. As well, customer expectations related to reliability have heightened.

Research and analysis has shown three main causes of recent outages:

- defective equipment
- vegetation contact
- loss of transmission supply

Strategies targeting these issues will have the greatest effect on system reliability. This plan addresses these three main causes.

The Reliability Investment Strategy defines clear goals and presents sound tactical approaches to improve service to customers. It is an aggressive five-year plan that will improve our customers' experience and enhance the reputation of our company. The plan is focused, with specific targeted outcomes. This commitment to reliability will result in improvements that both shareholders and customers want to see. In short, this five-year plan is intended to make Nova Scotia Power the most reliable utility in Atlantic Canada.

"We intend to improve our customer's experience in terms of system reliability."

Rob Bennett, CEO, Nova Scotia Economic Development Committee, February 10, 2009.

"When we combined all of the weather events, without taking intensity of the events into account, we found a very strong correlation with the SAIFI data. A correlation that became nearly perfect in the past six years. This result strongly suggests that the largest influence on the reliability of NSPI's system, especially over the past six years, has been the weather."

Severe Weather in the Canadian Maritimes: A Study of the Recent Trends of High Winds and Ice Accretion Events (Scotia Weather Services, March 2009)

Section One: Situation Analysis

What is the problem to be solved?

Nova Scotia Power's proposed five-year plan to improve system performance will improve the customer experience. The company has given careful consideration to determine the best strategies to address the causes of outages on the Nova Scotia Power system.

This section outlines how reliability performance is actually measured. Further detail is found in the sidebar.

Measuring Reliability

Nova Scotia Power measures and reports the service performance of its electrical power distribution system using the same measures that are employed throughout the utility industry in Canada and worldwide. The common measures that are used to report service continuity are System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index (CAIDI). Briefly defined:

- SAIFI is about the average number of power interruptions that customers experience in a year
- SAIDI is about the average time customers are without power in a year
- CAIDI is about how long, on average, that each interruption a customer experiences lasts.

Currently, Nova Scotia Power spends approximately $50 million a year on the existing distribution and transmission system for inspections, capital maintenance replacements, and vegetation management activities. In addition, approximately $28 million is spent on growth and expansion of new assets to serve growing demands on the system, including new customers. An incremental investment of $20 million a year in reliability initiatives will increase proactive replacement and maintenance activities to avoid and reduce the number of customer interruptions.

FREQUENCY, DURATION, & INTERRUPTION

SAIFI is a measure of the average "frequency" of interruptions. Interruption events ranging in size from one customer interruption (CI) to several thousand CI must be averaged. SAIFI provides a weighted average for interruption frequency as all customer interruptions are counted and then averaged over the customer base.

$$SAIFI = \frac{\text{Sum of all Customer Interruptions}}{\text{Customer Base}}$$

SAIDI is the average "duration" of interruptions. The duration of each interruption is recorded and added together. The total customer hours (CH) of interruption, averaged over the customer base, produces a weighted average.

$$SAIDI = \frac{\text{Sum of all Customer Hours}}{\text{Customer Base}}$$

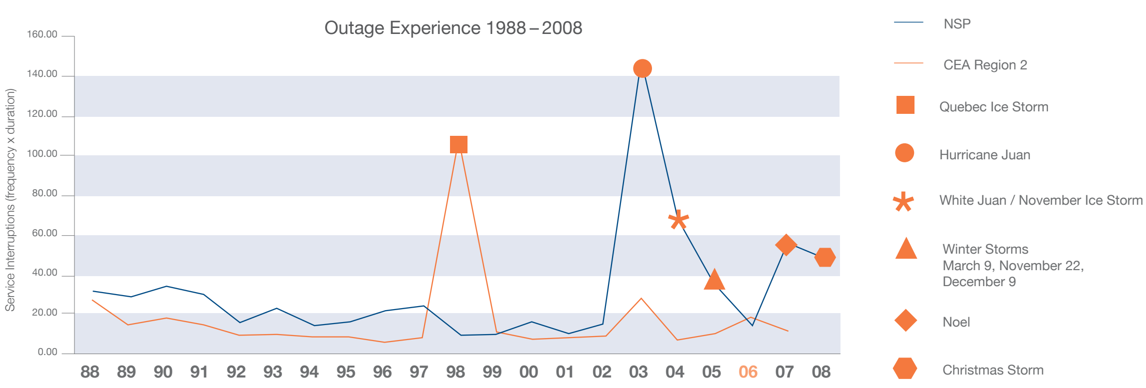
CAIDI is the average interruption duration experienced by customers who experienced an interruption.

$$CAIDI = \frac{SAIDI}{SAIFI}$$

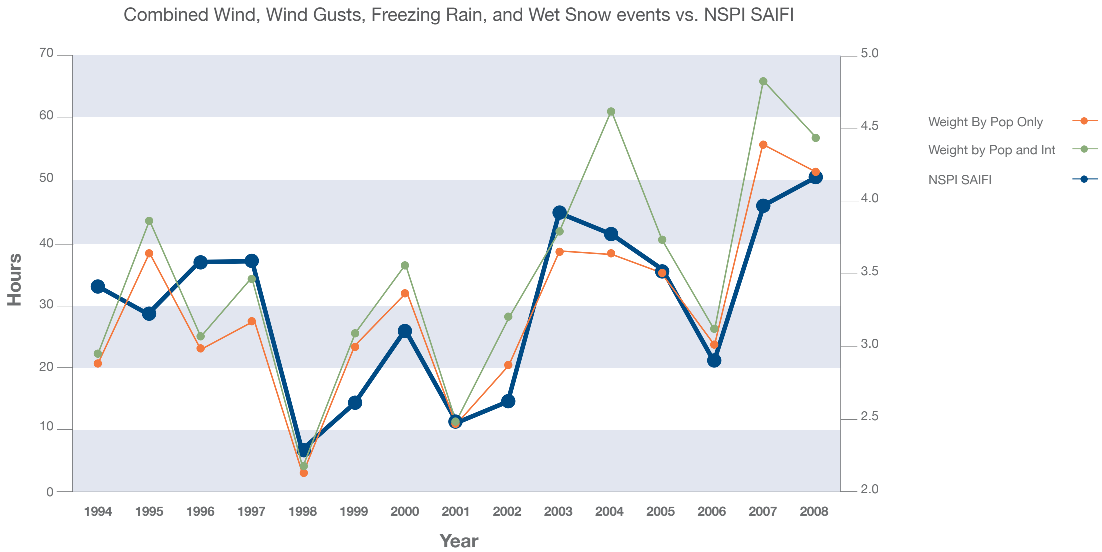
From 1997-2002, many replacement programs and initiatives were introduced to enhance the distribution and transmission system. Those programs, combined with relatively stable weather, allowed Nova Scotia Power to achieve its best-ever reliability performance during this period. This strong reliability performance correlated with high customer satisfaction during the same period.

While the system had seen many infrastructure improvements, it was not designed to withstand weather changes we have seen this decade, starting in 2003 with Hurricane Juan, continuing with the Ice Storm of November 2004 (which prompted a UARB review), White Juan in January 2005 and a large low pressure system in March of the same year. After a brief respite in 2006, the fall of 2007 brought Post-Tropical Storm Noel and 2008 concluded with three major storms as well as large related outages from salt contamination.

Since 2003, Nova Scotia Power customers have experienced more frequent and lengthier outages, primarily due to the more severe weather conditions facing our region and an increase in storms with wind gusts in excess of 90 kilometres per hour. The incidence of severe weather has been more prevalent in the Halifax area (home to the largest number of customers) than any other part of Nova Scotia. In 2006, when Nova Scotians saw a break in severe storms, Nova Scotia Power had the best reliability performance in Atlantic Canada.



BEST IN ATLANTIC CANADA



NSPI SAIFI compared to hours of all weather events (1994–2008)

Nova Scotia Power has determined strategic next steps to improve reliability performance. This document provides a high level summary of the three main causes of outages.

1. Vegetation Management

There is a strong correlation between vegetation management programs and system performance. Tree caused outages are the dominating factor for outages in wind/storm events, accounting for 45 per cent of outages during storm events.

To reduce outages caused by vegetation contacts, Nova Scotia Power will significantly increase spending on its vegetation management program.

2. Transmission

Loss of transmission supply outages account for approximately 29% of all the customer interruptions experienced annually. Transmission-related outages generally fall into two categories: forced and planned outages.

Forced transmission outages account for 64% of the loss of supply transmission interruptions. The primary causes of forced outages are failed insulators, conductor damage, damage to structures, hardware problems and vegetation (tree) contacts.

Planned transmission outages account for 36% of the loss of supply outages as measured over the last five years. Planned outages occur when crews isolate equipment to make required repairs or for maintenance and capital replacement activities. Most planned outages are short in duration but have a large effect on reliability experience because of the large number of customers interrupted.

To improve loss of transmission supply outages, this plan recommends installing improved switching and sectionalizing capabilities on transmission lines that serve customer loads. As well, Nova Scotia Power will replace known problematic cement growth ceramic insulators with toughened glass suspension insulators to improve transmission line performance.

3. Defective/Deteriorating Equipment

On average, defective equipment accounts for approximately 18% of the customer interruptions experienced annually. Current feeder inspection programs work to identify defective and deteriorated equipment prior to equipment failure that can result in outages to customers.

In 2002, Nova Scotia Power's inspection program was revamped to identify the highest priority work. While the inspection program was effective at prioritizing the problem areas, the investment for repairs has continued to be challenging.

As equipment ages, its ability to handle stress, particularly in harsh conditions, is diminished. As the average age of transmission and distribution equipment increases, more devices deteriorate. Approximately 50 per cent of Nova Scotia Power's distribution system is more than 35 years old, with a typical life expectancy of 40 years. More than 50 per cent of the transmission infrastructure is older than 35 years, with a typical life expectancy of 50-55 years.

To address defective and deteriorating equipment, Nova Scotia Power will increase its investment in equipment replacement, make improvements to the transmission and distribution system, and implement technology improvements.

Section Two: Investing Wisely

How will Nova Scotia Power respond?

Four strategies will address the main causes of customer service disruptions. The chart below provides an overview of these strategies and the causes they address.

Primary Outage Cause	Aging Assets and Deteriorated Equipment Replacements	System Performance Improvements	Technology Improvements	Storm Hardening
LOSS OF SUPPLY	●	●		●
DEFECTIVE EQUIPMENT	●	●	●	
VEGETATION CONTACT				●

STRATEGY ONE:

Aging Assets and Deteriorated Equipment Replacements

- **Transmission Line Insulator Replacements/Conductor Upgrades**

Specific types of porcelain line insulators experience a failure phenomenon known as cement growth. When this growth occurs, the mechanical strength of the insulator is compromised and random failures can occur. A replacement program for these insulators is recommended. Many transmission line conductors are more than 50 years old. In some locations, failures have occurred because conductors have become brittle or stretched and require replacement.

- **Distribution Porcelain Cutout Replacements**
  Cutouts are the fusing devices used on the distribution system to protect equipment against electrical faults. They were commonly provided with a porcelain insulator body which has had high failure rates due to cracks in the porcelain. There are approximately 200,000 porcelain cutouts on the system. Nova Scotia Power typically experiences approximately 1,200 random failures per year although this number continues to escalate. A replacement program using synthetic insulators is recommended.

- **Target Worst Performing Feeders and Highest Customer Density**
  System performance statistics are measured by distribution feeders. This allows Nova Scotia Power to monitor the effectiveness of each feeder section, and how many customers are being affected by faults on the feeders. Nova Scotia Power currently targets investments on feeders with the worst performance in terms of customer interruptions. Where the company has invested, customers have seen a significant improvement. Expansion of this approach is recommended to include additional feeders or feeder segments.

Results of 2007 Targeted Feeder Device Replacements

Feeder	Location	% CI Improvement
104H-411	KEMPT ROAD	99.5%
104H-413	KEMPT ROAD	42.5%
104H-423	KEMPT ROAD	97.5%
104H-433	KEMPT ROAD	38.6%
129H-411	KEARNEY LAKE ROAD	98.1%
15N-401	WILLOW LANE	52.1%

- **Other Distribution Device Replacements**
  Pin type insulators, porcelain lightening arrestors, in-line switches and automatic sleeves can fail without warning. The Reliability Investment Strategy includes a specific plan to replace these devices. In coastal environments, consideration will be given to replace pin insulators with high insulation clamp-tops, thereby improving performance in salt spray and high winds. As well, Nova Scotia Power has a number of distribution class underground cables nearing the end of their life expectancy. The plan takes this into account, finding the best program to refurbish or replace targeted cable sections.

STRATEGY TWO:

System Performance Improvements

- **Transmission Switch and Breaker Upgrades**
  Many existing transmission line switches are rated for operation only when the system is de-energized. This requires switching outages affecting large numbers of customers while faults on the transmission system are isolated. Upgrading switches to live-line operation, or replacing them with breakers, is recommended in locations where significant customer interruptions could be avoided.

- **Recloser Additions**
  Reliability performance can be significantly improved by installing additional sectionalizing devices to minimize the number of customers affected during outages. Additional sectionalizing points reduce the length of line that needs to be patrolled and inspected after an outage event, and can reduce restoration challenges related to cold-load pick-up. Implementing sectionalizing reclosers enables future distribution automation projects.

- **Distribution Automation/Auto-transfers**
  Distribution automation involves the automatic transfer of a load to an adjacent supply feeder when a fault is identified. Sensing devices detect and isolate faults so the load transfer can occur. This approach is limited to locations where capacity is available in an adjacent feeder, and can help avoid significant sustained service disruptions in these locations.

- **Fuse Coordination**
  Distribution protection is a system of coordinated, fast-acting switches and fuses. Over time, fuse links deteriorate, or are replaced with incorrect sizes. Miscoordination of sizes can lead to customers being exposed to broader fault conditions. Replacement of fuses is recommended as part of the cut-out replacement program.

STRATEGY THREE:

Technology Improvements

- **GIS Customer Connectivity Data Collection**
  Nova Scotia Power's Outage Management System (OMS) does not allow us to trace outages to individual customers or groups of customers because of the electrical "connectivity" model that is used. This causes challenges with precise outage prediction algorithms and limits the ability to optimize response to outages. Updating connectivity data will also improve accuracy of outage statistics. It will result in more accurate outage predictions, more focused outage response, and better planning data for reponse teams. All of this will result in shorter outage duration for customers. It will also facilitate more single-phase reclosing which can reduce the number of customers who experience interruptions.

- **Remote Communications on New Reclosers**
  New reclosers will be installed with remote communications capability. A staged approach will enable remote control and indication for sectionalized devices, improving response time and remote switching capability.

STRATEGY FOUR:

Storm Hardening

- **Conductor Upgrades, Re-Insulation and Re-Tensioning**
  Over time, conductors can deteriorate or stretch and become slack due to previous weather events. With heavy wind, conductors can easily come into contact with each other, causing customer interruptions. In many instances, insulators and ties have also become deteriorated.Nova Scotia Power recommends that targeted locations recieve new conductors and insulators.

- **Distribution Off-Road Relocations to Roadside**
  Sections of distribution lines not located along road sides are more difficult to access and inspect. As a result, faults on these sections typically result in longer outages. Nova Scotia Power proposes to expand initiatives to rebuild the worst performing off-road systems, moving them to the roadside for easier access.

- **Standard Changes**
  In some locations, Nova Scotia Power should revisit construction and design standards to ensure a more reliable system. Examples include use of insulated overhead cable in remote areas, clamp-top insulators in high-wind coastal areas and installing additional storm guys. A reliability-based design standard is recommended to complement existing standards for remote or harsh environment locations.

- **Vegetation Management**
  Approximately 45 per cent of all customer interruptions are related to tree interference. Funding has been approved by the Utility and Review Board to implement annual Vegetation Management spending of $10.4 million. Over time, this investment will improve system performance and customer experience during adverse weather.

Crescent Beach
Tropical Storm Noel, November 2007

Goshen
December 2006

Tropical Storm Noel
November 2007

Section Three: Our Results Focused Investment Approach

How will we know when we have seen improvement?

The Reliability Investment Strategy endorses the approach detailed in the attached table. This recommended approach best addresses the reliability and performance concerns expressed by customers and stakeholders, as well as balancing the interests of shareholders.

	Millions	Expected Customer Inturruptions Avoided
2010	$31.4	164765
2011	$29.65	148949
2012	$29	109470
2013	$28.8	108588
2014	$28.4	106823
TOTAL	$148.25	638595

*includes $10.4 million per year in approved vegetation management spending

This chart outlines proposed investments over the next five years, and corresponding customer interruptions that will be avoided as a direct result of that investment.

Preventing customer interruptions creates a better customer experience. Better customer experience will result in higher customer satisfaction. Customer trust regarding the company's ability to deliver core service is a key element in our Reputation Plan – and our success.

Summary

Nova Scotia Power has seen increasing challenges regarding system performance. Analysis shows a correlation between this reality and more severe weather. The challenges related to reliability have a direct effect on customer satisfaction and customer confidence.

The company's Reliability Investment Strategy identifies the problems to be resolved, how resolution will occur and sets targets for improvements in customer experience.

Successful implementation of the strategy will enable achievement of Nova Scotia Power's goal to have the best reliability in Atlantic Canada, and improve the company's reputation with customers and key stakeholders.

Five Year (2010–2014) Incremental Reliability Investment Strategy

Strategy	Tactic
Aging Assets and Deteriorated Equipment Replacements	Transmission Line Insulator Replacements / Conductor Upgrades
	Distribution Cutout Replacements
	Target Worst Perfoming Feeders and Highest Customer Density
	Distribution Device Replacements (arrestors, insulators, sleeves, cable refurbishments, etc.)
System Performance Improvements	Recloser Additions (sectionalizing / 1 phase reclosing)
	Distribution Automation / Auto-Transfers
	Fuse Coordination (linked with cutout replacements)
	Transmission Switch and Breaker Upgrades
Technology Improvements	GIS Customer Connectivity Data Collection
	Remote Communication on New Reclosers
Storm Hardening	Conductor Upgrades, Re-Insulation and Re-Tensioning
	Distribution Off-Road Relocations to Road Side
	Standard Changes (Hendrix Cable in Remote Locations, Clamp Top Insulators, etc.)
	Vegetation Management

Incremental Reliability Based Capital Investment

Vegetation Management OM&G

Total Annual Investment

Projected Customer Interruptions Avoided

Cummulative Percentage Reduction in Customer Interruptions

Investment

	2010	2011	2012	2013	2014	Total
	$3,000,000	$3,000,000	$2,000,000	$2,000,000	$2,000,000	**$12,000,000**
	$3,000,000	$3,000,000	$2,000,000	$2,000,000	$2,000,000	**$12,000,000**
	$4,000,000	$4,000,000	$4,000,000	$4,000,000	$4,000,000	**$20,000,000**
	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	**$10,000,000**
	$2,000,000	$1,500,000	$250,000	$250,000	$250,000	**$4,250,000**
			$1,400,000	$1,200,000	$800,000	**$3,400,000**
	$250,000	$250,000	$250,000	$250,000	$250,000	**$1,250,000**
	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000	**$15,000,000**
	$1,500,000					**$1,500,000**
			$700,000	$700,000	$700,000	**$2,100,000**
	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	**$7,500,000**
	$500,000	$500,000	$500,000	$500,000	$500,000	**$2,500,000**
	$250,000	$500,000	$1,000,000	$1,000,000	$1,000,000	**$3,750,000**
	$10,400,000	$10,400,000	$10,400,000	$10,400,000	$10,400,000	**$52,000,000**
	$21,000,000	$19,250,000	$18,600,000	$18,400,000	$18,000,000	**$95,250,000**
	$10,400,000	$10,400,000	$10,400,000	$10,400,000	$10,400,000	**$52,000,000**
	$31,400,000	**$29,650,000**	**$29,000,000**	**$28,800,000**	**$28,400,000**	$147,250,000
	164765	148949	109470	108588	106823	**638595**
	26%	23%	17%	17%	17%	**100%**

Investment Strategy	Item	Forecast NPV of Spend	Calculated ACHI	Average $/ACHI
Equipment Replacements	Feeder Exit Cable Replacements	$ 317,587	16,380	$ 19
Equipment Replacements	Targeted Feeder Replacements	$ 1,270,621	20,945	$ 61
Equipment Replacements	Distribution Cutout Replacements	$ 2,953,283	11,149	$ 265
Equipment Replacements	Transmission Line Insulator Replacement	$ 3,018,100	6,814	$ 443
Equipment Replacements	Substation Insulator & Cutout	$ 1,500,000	2,862	$ 524
Equipment Replacements	Halifax U/G Cable Replacement	$ 418,861	600	$ 698
		$ 9,478,451	**58,750**	**$ 161**
Storm Hardening	New Reliability Technologies	$ 110,769	16,814	$ 7
Storm Hardening	Distribution Off Road to Roadside	$ 2,500,000	6,341	$ 394
		$ 2,610,769	**23,155**	**$ 113**
System Improvements	3H/6H Recloser Replacement Program	$ 579,463	16,678	$ 35
System Improvements	Downline Recloser Additions	$ 444,765	9,950	$ 45
System Improvements	Recloser Control Replacements	$ 249,918	3,637	$ 69
System Improvements	Substation Switch & Breaker Upgrade	$ 2,866,718	29,693	$ 97
System Improvements	Distribution Feeder Ties	$ 500,000	3,257	$ 154
System Improvements	Reliability Keltic Drive New Feeder	$ 1,580,468	4,266	$ 370
		$ 6,221,332	**67,481**	**$ 92**
Technology Improvements	New RTU Deployment	$ 509,706	9,141	$ 56
Technology Improvements	GIS Connectivity Project	$ 1,443,434	**22,529**	$ 64
		$ 1,953,140	**31,670**	**$ 62**
Vegetation Management	Vegetation - Asset Protection/Customer Focus	$ 2,156,459	63,519	$ 34
Vegetation Management	Vegetation - Asset Renewal	$ 5,438,737	113,962	$ 48
Vegetation Management	Vegetation - Sustainability	$ 1,495,653	29,836	$ 50
Vegetation Management	Vegetation - Reactive	$ 4,122,557	68,035	$ 61
		$ 13,213,406	**275,352**	**$ 48**

NON-CONFIDENTIAL

Request IR-10:

Is the request for additional vegetation management still based on the analysis presented in the NSPI 2009 Rate Case? Has the Company performed any more recent analysis of the cost of trimming outside right of way trees, or has it issued a new RFP for such services.

Response IR-10:

Yes. NS Power does not have any more recent analysis on these costs.

NON-CONFIDENTIAL

Request IR-11:

Has there been any analysis of the number of trees located outside NSPI's rights of way that are a danger to reliability since 2006. When was this analysis performed?

Response IR-11:

Please refer to Liberty IR-60(b).

NON-CONFIDENTIAL

Request IR-12:

Please respond to the proposition that the number of 2010 high wind incidents illustrated in Figure 6.7 suggests that enough trees may have fallen in 2010 that there may be fewer potential problem trees remaining.

Response IR-12:

The vast majority of NS Power's distribution infrastructure resides on rights-of-way that are bordered by trees or natural forest.

High winds cause trees to fail, and place a higher number of trees in a state of susceptibility. Each severe weather experience, such as those in 2010, place the distribution system in a position of greater vulnerability from tree failure. Each successive severe weather occurrence increases the risk of tree failure during subsequent wind events. An extreme wind event, such as a hurricane, intensifies this risk. Also, the trees that remain tend to grow back and can become potential problem trees.

Please refer to Liberty IR-60(e).

NON-CONFIDENTIAL

Request IR-13:

Has there been any analysis of the distribution spans or number of kms of transmission trees that were impacted by outside right of way trees during 2010? If so, please provide.

Response IR-13:

No. Please refer to Liberty IR-60(c) for 2009 estimates.

NON-CONFIDENTIAL

Request IR-14:

What was the actual full year 2011 storm expense (refer to p. 93)? What is the resulting actual average five year storm expense?

Response IR-14:

The full year 2011 storm expense was $6.6 million. If this amount were included in the storm adjustment calculation, the resulting amount would be $10.3 million.

NON-CONFIDENTIAL

Request IR-15:

On p. 29 it is stated that the base cost of fuel BCF will be reset each year "as part of this Application". Does the 2014 revenue requirement therefore reflect the projection of fuel costs contained in this filing? If actual 2014 fuel costs are less than projected, will the FAM result in a negative factor that will make customers whole for the reduction from the forecast 2014 costs? When will any fuel cost reduction be reflected in bills?

Response IR-15:

The 2014 revenue requirement in this filing reflects the projection of fuel costs for 2014. The details are found in Section 4, OE-01A through OE-01Q of the Application. This forecast was conducted in accordance with the FAM Plan of Administration - with the exception of deviations noted in the Application. The Rate Stabilization Plan has proposed that any over or under recovery of fuel costs that would have applied to rates during the Rate Stabilization period be deferred until the end of the period for future recovery or refund.

Request IR-16:

P. 31 of Evidence states that NSPI will update its Cost of Service Study during the Rate Stabilization Period, but also states that rates will not be "aligned" to a current COS until 2015. What effect on rates will the Cost of Service studies during the Rate Stabilization Period have on rates? Will rate changes in 2015 require a GRA filing to reflect current costs and deferrals?

Response IR-16:

One of the questions that will arise during the Cost of Service Study proceeding is when and how to transition any changes to the Cost of Service Study that may be adopted. NS Power does not anticipate that the Cost of Service Study will result in changes that will need to be implemented before the end of the Rate Stabilization Period. Any such changes can be implemented in the next general rate application that follows the Rate Stabilization Period. However, if stakeholders agree that the Cost of Service Study changes must be implemented prior to 2015 or the Board so directs, NS Power will do so. Any such changes would not change the total amount of the Rate Stabilization Plan deferral because the Rate Stabilization Plan proposes a forecast based deferral like the 2012 Fixed Cost Recover Deferral. Please also refer to Multeese IR-19.

NON-CONFIDENTIAL

Request IR-17:

On p. 31, does the statement "rates will be aligned so that *each* customer class contributes the amount determined by the Cost of Service Study then in place" mean that the Company will propose rates for 2015 for each class with an R/C of 1.0? If it does not, how will Small Business classes rate contribute the amount of costs allocated to them at that time?

Response IR-17:

No. The Small Business classes will contribute to the recovery of deferral responsibilities allocated to them through rates based upon approved revenue to cost ratios established in this proceeding.

NON-CONFIDENTIAL

Request IR-18:

Please provide a worksheet showing how projected interest costs (in Appendix P) n 2013 and 2014 deferrals are calculated.

Response IR-18:

Please refer to Liberty IR-39 Attachment 1, filed electronically and Liberty IR-40.

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Request IR-19:

What is the basis for the interest rate that will be charged on the Fixed Cost Recovery deferral during 2013, 2014, and over the eight year recovery period? Is this value set or will it depend on financial markets and/or indices? Will interest be calculated on a monthly basis or other basis? If other, please specify

Response IR-19:

Please refer to Liberty IR-40.

NON-CONFIDENTIAL

Request IR-20:

Is it a correct interpretation that the Company requests that it be allowed to defer all of the approved 2013-14 revenue requirement that is not collected during these two years from the approved rates? If this is a correct interpretation, does that mean that even if actual costs in 2013-14 are less than projected in this filing, it would be allowed to collect the projected costs in the eight years after 2014?

Response IR-20:

NS Power proposes to defer any portion of the Board-approved revenue requirement for 2013 and 2014 not recovered by the 3 percent annual increases. If, over the cumulative two year period, NS Power earns in excess of 9.5 percent return on equity (ROE) then the Fixed Cost Recovery (FCR) Deferral will be reduced by that amount. This will ensure that any operating cost efficiencies, or rate-making assumptions that prove wide of the mark and cause a higher-than-expected earnings, will benefit customers rather than increase shareholder earnings. This provision will serve as a cap on NS Power's cumulative earnings during the Rate Stabilization Period. Please refer to SBA IR-21.

NON-CONFIDENTIAL

Request IR-21:

If some combination of revenue growth, interest rate reduction and other cost reduction resulted in the Company earning more than 9.5% in either 2013 or 2014, under the Company's proposal would it still be allowed to defer and then collect difference between its actual revenue collections and the revenue requirements approved in this case? If not, explain what in the proposed tariffs or filings produces this result.

Response IR-21:

Any earnings above 9.5 percent for the cumulative two year period would be returned to customers through a reduction in the amount of the Fixed Cost Recovery (FCR) Deferral. This provision will serve as a cap on NS Power's cumulative earnings over the two-year period. Please refer to DE-03 – DE-04, page 31 of 159 of the Application.

NON-CONFIDENTIAL

Request IR-22:

If some combination of revenue growth, interest rate reduction and other cost reduction resulted in the Company earning more than the return on equity approved by the Board in this case in either 2013 or 2014, under the Company's proposal would it still be allowed to defer and then collect difference between its actual revenue collections and the revenue requirements approved in this case?

Response IR-22:

NS Power's Rate Stabilization Plan is based upon its proposal to maintain the range for regulated rate of return on equity (ROE) at its present range of 9.1 to 9.5 percent, as set through the 2012 GRA.[1] Any earnings above 9.5 percent for the cumulative, two year period would be returned to customers through a reduction in the amount of the Fixed Cost Recovery Deferral. Please refer to SBA IR-21.

[1] NSPI 2012 General Rate Application, NSUARB-NSPI-P-892.

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Request IR-23:

On p. 120 the Company states that "non-fuel related fixed cost contributions… have been prorated across-the board to all non-fuel related generation." Please explain what this means in terms of how these costs are allocated to customer classes?

Response IR-23:

The above quote refers to the COSS process employed by NS Power to determine the revenue requirement from the above-the-line (ATL) classes. The COSS process requires that NS Power functionalize costs incurred in serving other classes, such as below-the-line (BTL) classes, as direct and then subtracts them from the total revenue requirement of the company, to arrive at the revenue requirement from the ATL.

For more information please refer to Section 11.3 Rate-setting Process Overview of DE-03 – DE-04, and Section 1.2.2 Operating Expenses, Exhibit 4 and Exhibit 4 – Detail B of SR-01, Attachment 1 of the Application.

Request IR-24:

Has the Company considered reducing or modifying pension benefits to new hires? If so, please provide any analyses, reports, or memos on potential modification.

Response IR-24:

NS Power has made changes to pension benefits for new hires over the last number of years.

In 2001, NS Power introduced a Defined Contribution (DC) Pension Plan. All existing employees had the choice of moving to the DC Plan and non-union new hires are provided the option between the Defined Benefit and Defined Contribution Pension Plans.

In 2004 significant changes were made to the Defined Benefit (DB) provision of the employee pension plan, including unreduced retirement age, bridge benefit and indexation of benefits. These changes resulted from union negotiations with the goal of reducing benefit costs.

NS Power has traditionally provided the identical pension plan and health benefit plan to union and non-union employees. To the extent possible, any amendment to the plan terms are made at the same time for all plan members. Any substantive changes to the pension for union members would have to be negotiated with NS Power's unionized employees represented by IBEW Local 1928.

Please refer to Eckler IR-14.

NON-CONFIDENTIAL

Request IR-25:

What would be required to increase the retirement age for existing employees? What would be required to increase the retirement age for new employees? Has the Company considered either of these actions?

Response IR-25:

Changing the eligibility criteria for an unreduced pension for future service for existing employees and new hires would need to be made through an amendment to the pension plan text.

NS Power has traditionally provided the identical pension plan and health benefit plan to union and non-union employees. To the extent possible, any amendment to the plan terms are made at the same time for all plan members. Any substantive changes to the pension for union members would have to be negotiated with NS Power's unionized employees represented by IBEW Local 1928.

Please refer to Eckler IR-14.

NON-CONFIDENTIAL

Request IR-26:

Do the responses to IRs 24 and 25 apply only to unionized employees or to all employees?

Response IR-26:

Please refer to SBA IR-24 and SBA IR-25.

NON-CONFIDENTIAL

Request IR-27:

Do any of the other divisions of Emera have different pension and retirement policies? If so, please describe.

Response IR-27:

Some, but not all, Emera affiliates share similar pension and retirement policies. Each company may have pension and retirement policies based on their unique company culture and geographic location. Pension and retirement policies must follow pension and benefit legislation for the prescribed jurisdiction.