Request IR-144:

With respect to the response to IR 56, please provide:

(a) a description of all available NSPI analyses showing what new, different, increased, or other altered vegetation-management work will be performed with the increased expenditures,

(b) a description of all available NSPI analyses showing the relationship between such work and the physical and electrical causes of wind-induced reliability issues, and

(c) copies of all the analyses referred to in parts (a) and (b).

Response IR-144:

(a) Please refer to Liberty IR-60 (a). Increased use of mechanized equipment will be required to manage off right-of-way tree buffers that are adjacent to the existing right-of-way. In addition, current trimming practices may be altered to topping when hazard trees are located adjacent to the right-of-way.

(b) Please refer to Liberty IR-60 (e). The figures below show the actual customer hours of interruption and the cause of tree contact outages during major storm events, respectively. Tree contacts are consistently the largest contributor to major storm event outages, with falling trees being the leading cause.

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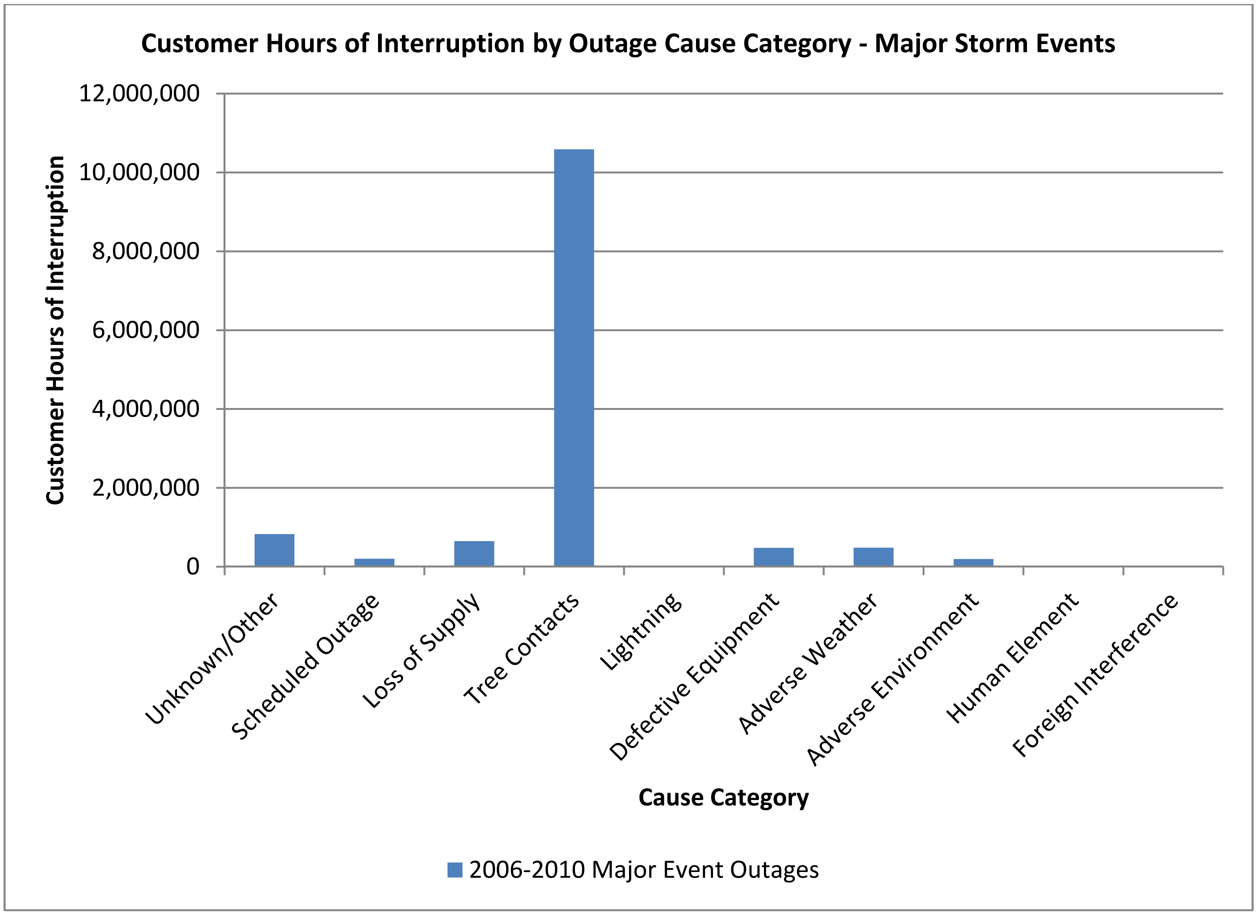

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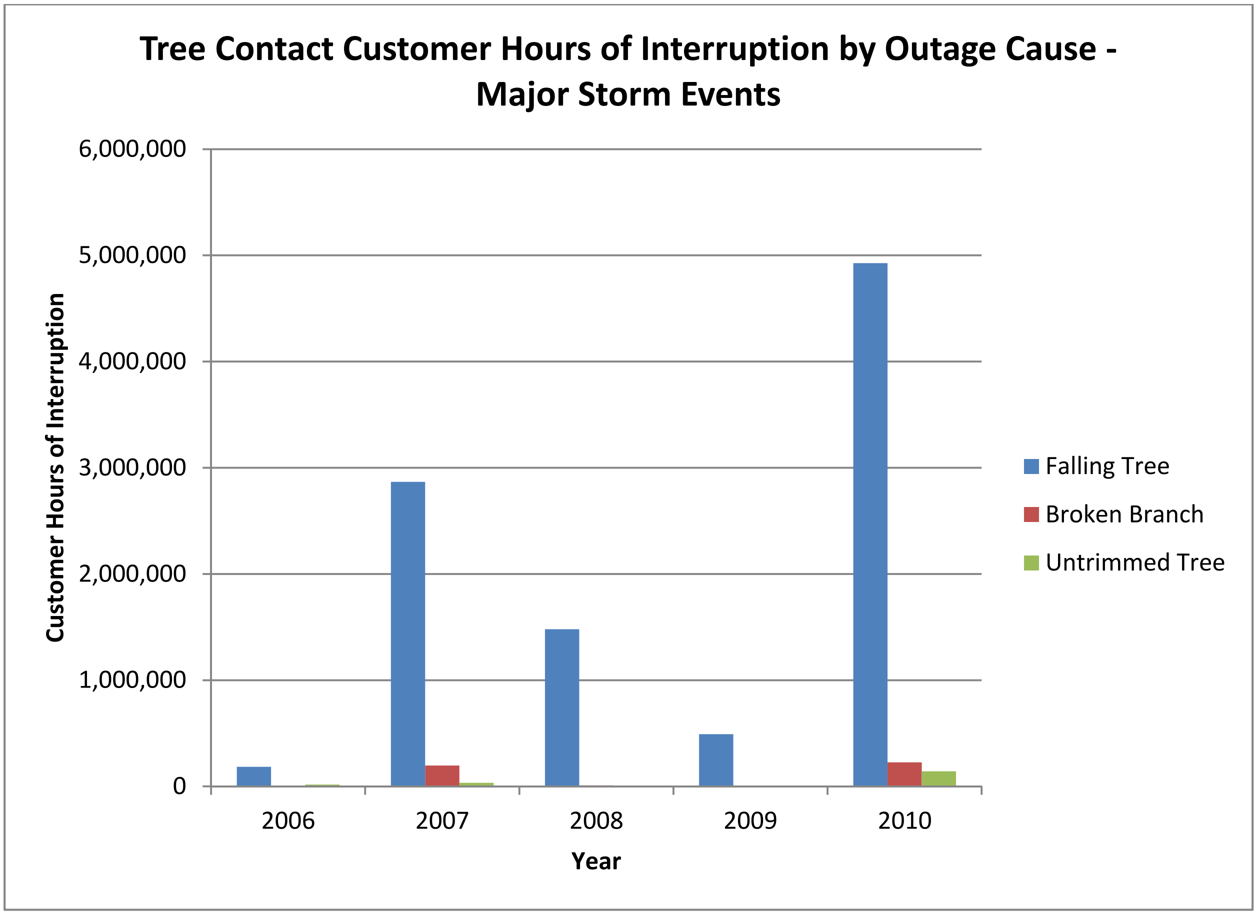

(c) Please refer to Attachment 1, filed electronically.

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Request IR-145:

Referring to 2012 GRA Application Exhibit OP-06, Attachment 1, page 2, the contribution of power imports at the time of the peak is given as 288 MW; please

(a) provide the capacity of the tie line between New Brunswick and Nova Scotia and the portion of that capacity reasonably expected to be available to support imports as it changes across a typical year,

(b) confirm, or explain if not, that all power imports must come through the interface between the New Brunswick and Nova Scotia power systems,

(c) identify all other sources of imports and describe generally their capability to support imports across a typical year, and

(d) provide and explain how long can imports remain at the 288 MW level.

Response IR-145:

(a) The maximum commercial interchange capacity between New Brunswick and Nova Scotia available for imports is 300 MW. This number may be reduced depending on availability of reserve and the transmission system configuration in Nova Scotia, New Brunswick, and northern New England. Other than the small reductions due to regulation, reductions are dependent on the need for maintenance on the transmission system and can vary from year to year.

(b) The interface between Nova Scotia and New Brunswick is currently the only source for import power deliveries to Nova Scotia.

(c) There no other sources of imports.

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(d) Imports can remain at the stated 288 MW level as long as the interface remains in service and unconstrained. The import level is also dependent on available transmission in the neighboring control area(s) which influences the ability to transmit power to the Nova Scotia interface. When we are importing at this level of import, system reliability standards require that we have load shedding system protection armed. We would not want to import at this level on a continuous basis as it exposes customers to outages if the transmission interconnection between Nova Scotia and New Brunswick trips.

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Request IR-146:

Referring to 2012 GRA Application Exhibit OE-01A, Attachment 1, page 9, please describe

(a) **how the hydro availability data is distributed across the months (e.g., is each month averaged separately),**

(b) **explain how the hydro-sourced power is dispatched for modeling purposes,**

(c) **state and describe whether it is it possible to determine what the hydro-sourced power is displacing in the dispatch, and**

(d) **if it is possible, describe how.**

Response IR-146:

(a) The total annual hydro generation forecast is calculated using a 23-year average. The monthly profile is then based on the most recent three-year average of monthly profiles.

(b) Hydro dispatch is modeled in Strategist as a load modifier using a load peak shave algorithm.

(c-d) In order to determine exactly what generation resources are displaced by hydro generation, and to what extent, a re-run of Strategist would be required with hydro generation removed.

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Request IR-147:

Referring to 2012 GRA Application Exhibit OE-01A, Attachment 1, page 9, please describe and quantify to the extent possible how dispatch of NSPI's hydro resources will change as a result of wind integration.

Response IR-147:

With the integration of additional wind generation into the NSPI system, it is expected that the hydro resources will be used to a greater extent to follow short-term changes in the wind generation. This is because hydro units have a much quicker response time (ramp rate) than the larger thermal units.

NSPI is in the process of selecting a consultant to assist with a comprehensive study of the impacts of additional wind integration on the dispatch of the generating units and on the system as a whole. The analysis of wind characteristics is scheduled for completion in the fourth quarter of this year with the final report expected to be completed in the second quarter of 2012. Once this study is complete, NSPI will be in a position to more definitively comment on the impacts of wind integration on the dispatch of hydro generating units.

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Request IR-148:

Referring to 2012 GRA Application Exhibit OE-01A, Attachment 1, page 9, please describe

(a) how wind energy from each generator is distributed across the months, and

(b) how wind energy is modeled for fuel-cost estimation purposes.

Response IR-148:

(a) The annual wind generation forecast for each project is calculated using a three-year average of historical data. Where this data does not exist, the contract amount is used until three years of history is available. A monthly profile is then applied to the three year average generation (or contract amount) for each wind project.

(b) Wind energy in Strategist is modeled as a load modifier according to hourly wind shape and forecasted monthly energy. In terms of cost, wind energy is modeled as "must take at specified cost" and it is neither dispatched nor curtailed based on economics. Wind energy displaces either more expensive or less expensive generation depending on load and wind shape profiles.

REDACTED

Request IR-149:

Referring to 2012 GRA Application Exhibit OE-01A, Attachment 1, page 9, please describe whether the production is supposed to be exactly the same month after month for each of the following projects: [redacted].

Response IR-149:

The same monthly profile is used across all wind projects, therefore projects with the same forecasted annual generation will have matching monthly forecasts. None of these projects have been in service long enough to develop the three year historical data set that would otherwise be used for forecasting. In the case of [redacted], the projects use the same number, size and manufacturer of wind turbines. In the case of [redacted], the forecast is based on contracted amount of wind energy.

REDACTED

Request IR-150:

For natural gas, please:

(a) describe in detail what gas cost is used in calculating <u>dispatch</u>, not estimated fuel costs,

(b) list and describe the components of the cost used (price at Henry Hub, basis differential to the Northeast U. S., M&NP transportation charges, etc.),

(c) list and explain the sources of the values for each component (for the dispatch calculation, where does the Henry Hub price come from, where does the basis differential come from, etc.?),

(d) explain how these values differ from the ones used to estimated fuel costs for (1) The General Rate Application and (2) NSPI's internal updated fuel costs, and

(e) provide the values of the various components used in the economic dispatch calculation for May 1, 2011.

Response IR-150:

(a) [redacted]. Any gain/loss on financial hedges is not taken into consideration.

(b) The components are: [redacted].

REDACTED

(c) [redacted] price comes from the most recent issue of Platts Gas Daily. The [redacted] website under the Rate And Fuel Summary section. The [redacted].

(d) The only difference between these values and the ones used to estimate fuel costs is that the dispatch values are based off of current market conditions, not forecast prices.

(e) For May 1, 2011 [redacted]. The price used for dispatch was [redacted].

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Request IR-151:

Referencing the Company's response to Liberty IR-32, Attachment 1, please provide estimates of the changes in fuels consumption and fuels costs if the average of the most-recent five years' hydro production were used rather than the most-recent 23 years.

Response IR-151:

In order to provide the estimate proposed, NS Power would be required to run the entire set of fuel forecasting models (Strategist, the coal model and then the fuels finance model). The estimate would be based upon an assumption that does not comply with the FAM fuels forecasting methodology contained in the POA. NS Power has not undertaken the analysis necessary to provide such an estimate.

Request IR-152:

With respect to application Figure 5.1, which shows a $3.7 million increase in storm costs, please:

(a) update the year to date costs through the most recent month available, and

(b) provide your analysis of how storm experience to date this year validates/alters/etc. the proposed increase.

Response IR-152:

(a) Please refer to Attachment 1, filed electronically.

(b) As can be seen on Page 2 of Attachment 2, filed electronically, the actual storm costs for the first five months of 2011 are 13 percent or $314,053 higher than they were for the inflation-adjusted average storm costs of the previous six years. Page 1 of Attachment 2 demonstrates that, if the proposed increase were to be recalculated using the actual costs for the end of 2010 (these costs were not available at the time of the preparation of the rate case application), and the actual and estimated costs for 2011, the average storm costs would have actually been $9.6 million, or $0.9 million more than the requested increase. The storm costs of the past year are consistent with the analysis presented in Liberty IR-58, and applying the most recent experience results in an amount that exceeds the 2012 test year forecast amount.

REDACTED

Request IR-153:

With respect to the non-recurring costs described in the response to IR 62, please

(a) state whether any adjustments to 2012 costs have been made to reflect that such costs will not be expended,

(b) if not, explain why,

(c) if so, describe and quantify the adjustments made, and

(d) if so, provide supporting workpapers demonstrating the adjustments made.

Response IR-153:

Please see the table below for a reconciliation of the 2012 Forecast versus the 2011 Forecast. As can be seen, there are $2.9 million in costs projected to occur in 2011 that have been excluded from the 2012 Forecast.

Adjustments from 2011 Forecast to 2012 Forecast (in $ Thousands)	
2011 Forecast	[redacted]
One-Time Initiatives As Identified in Liberty IR-62	[redacted]
Service Levels	[redacted]
Redesign of Customer Experience Processes	[redacted]
Training	[redacted]
Total One-Time Initiatives	[redacted]
Escalation	[redacted]
Pension	[redacted]
Other	[redacted]
2012 Forecast	**32,459**

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Request IR-154:

With respect to the response to IR-66, please:

(a) describe who performs the activities in each area listed for the parent and other subsidiaries,

(b) identify all entities (parent and subsidiaries) for which the group performs activities in each of area listed, and

(c) identify the percentages and amounts of group costs charged, assigned, or allocated to other than NSPI.

Response IR-154:

(a-c) Please refer to Liberty IR-142.