REDACTED

Request IR-1:

With respect to GRA Exhibit No. SR-03, the exhibit describes sources for the fuel price information used to develop the fuel forecast. For the natural gas price information, please provide the following:

(a) **For each contract used in developing the gas price specified to the dispatch model, provide the adjustment to the contract price that was used to obtain a price at the Tufts Cove Generating Station for each month of the forecast period (calendar year 2012).**

(b) **For any amounts of gas that are forecast to be required, but are not yet contracted, please provide the various components used to obtain prices at the Tufts Cove Generating Station for specification to the dispatch model for each month of the forecast period.**

(c) **Please describe the sources of each of the adjustments and components used.**

(d) **If contracts were not used, please describe the method used to develop the prices used in specifying the price of natural gas to the dispatch model used for preparing the forecast. Describe the method, and provide all numerical values used to implement the method.**

Response IR-1:

(a) The [redacted] contract has a delivery point of [redacted] to obtain the price at Tufts Cove. The [redacted] contract has a delivery point of [redacted] to obtain a price at Tufts Cove.

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(b) [redacted] has been contracted.

(c) Please refer to part (a).

(d) Contract pricing was used.

REDACTED

Request IR-2:

With respect to GRA Exhibit No. SR-03, the exhibit describes sources for the fuel price information used to develop the fuel forecast. For the heavy fuel oil price information, please provide:

(a) the amount of any adjustment required to get the fuel from the location for which NSPI obtained broker quotes to the location at which it would be consumed; and

(b) the source of the adjustment.

Response IR-2:

(a-b) The following adjustments are made to the heavy fuel oil pricing to arrive at a plant delivered price from a [redacted] (the broker quotes location referred to above):

- [redacted] spread over forward prices to adjust for the bid/ask spread that NSPI encounters in the market. The price is derived from the most recent trading experience.

- [redacted] spread over index price charged by [redacted]. The current contract price [redacted].

- [redacted] handling costs incurred by Tufts Cove. This is based on historic experience.

- Delivery costs to the solid fuel plants: Lingan [redacted], [redacted] and Point Tupper [redacted]. These are historic numbers.

REDACTED

Request IR-3:

With respect to GRA Exhibit No. SR-03, the exhibit describes sources for the fuel price information used to develop the fuel forecast. For the light fuel oil price information, please provide:

(a) **the amount of any adjustment required to get the fuel from the location for which NSPI obtained broker quotes to the location at which it would be consumed; and**

(b) **the source of the adjustment.**

Response IR-3:

(a-b) The following adjustments are required to adjust the light fuel oil pricing from [redacted] (the broker quotes location referred to above) to a plant delivered price:

- [redacted] spread over forward prices to adjust for Nova Scotia pricing relative [redacted]. These are historic numbers.

- Delivery costs to the plants (historic numbers):

Lingan	[redacted]
Point Aconi	
Trenton	
Tupper	
Tufts Cove	
Burnside	
Tusket/VJ	

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Request IR-4:

With respect to GRA Exhibit No. SR-03, the exhibit lists Wood MacKenzie Quarterly Price Forecast as one of the sources of industry information used to develop the fuel forecast. What information is used from this forecast?

Response IR-4:

The 2012 fuel forecast used the Wood MacKenzie Short Term Outlook – Q4 2010, for low sulphur Colombian coal and petroleum coke for each of quarters 1 through 4 of the year 2012, following the Fuel Forecasting Methodology in the FAM POA.

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Request IR-5:

With respect to GRA Exhibit No. SR-03, the exhibit lists Indicative Offers as one of the sources of industry information used to develop the fuel forecast. What information was obtained from this source?

Response IR-5:

The 2012 fuel forecast did not use Indicative Offers and thus the reference to Indicative Offers was an error. In the past, as provided in the FAM POA, indicative offers have been used when contract negotiations were still underway for coal that would be purchased during the forecast period.

REDACTED

Request IR-6:

With respect to GRA Exhibit No. OP-06, the exhibit shows estimated production from Tufts Cove Unit 1 [redacted] and Tufts Cove Unit 2 [redacted], yet Tufts Cove 2 has a [redacted] heat rate. Please explain why the unit with the [redacted] heat rate is forecast to run [redacted].

Response IR-6:

Please refer to Partially Confidential Attachment 1.

2011 Fuel Adjustment Mechanism Base Cost of Fuel (NSUARB P-887(2))
NSPI Responses to Liberty Information Requests

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Request IR-6:

With respect to NSPI 2011 FAM Base Cost of Fuel Filing, Appendix A, Requirement OE-01A, Attachment 1, page 24,

Tufts Cove Unit 1 [redacted].

Please explain.

Response IR-6:

[redacted].

Consistent with the method used in past FAM fuel and purchased power forecasts, [redacted].

REDACTED

Request IR-7:

With respect to GRA Exhibit No. OR-08, the requirement includes, "For transportation paid for by NSPI, provide the name of the transporter, nature of the transportation service (firm, interruptible, released firm, etc.), and price paid."

(a) For the transactions listed in Attachment 2 to that exhibit, no transportation information is provided. Does that mean that NSPI did not pay for transportation for any of those transactions?

(b) The location of title transfer for most of the transactions is [redacted]. If the Company paid for no transportation, how did the Company get the gas to [redacted], [redacted]?

(c) For one of the transactions, the location of title transfer is given as [redacted] (which we interpret to be the gas trading hub at [redacted]). How did the Company get the gas that it sold there to that location?

(d) Where did the Company receive the gas that it sold at the locations listed in Attachment 2?

Response IR-7:

(a-c) The table filed in GRA Exhibit No. OR-08 was incorrect. Please refer to Confidential Attachment 1 for a corrected version. The delivery locations for all of the sales were on [redacted]. Deliveries were made using [redacted]. The cost of the transportation is included in the price. This does not affect the amount of the fuel forecast.

REDACTED

(d) For delivery locations [redacted] the Company received the gas at [redacted]. For those sales with a delivery point of [redacted], the Company received the gas at [redacted].

REDACTED

Request IR-8:

With respect to GRA Exhibit No. OR-08, for most of the transactions listed in Attachment 2, the Company gave a location [redacted] as the transaction point.

(a) What did the Company do to obtain authority to export the gas from Canada?

(b) For each such transaction, who obtained authority from the U. S. Government for importing the gas into the U. S.?

Response IR-8:

(a-b) The table filed in GRA Exhibit No. OR-08 was incorrect. Please refer to Liberty IR-7.

REDACTED

Request IR-9:

With respect to GRA Exhibits DE-03 and 04, the middle paragraph of page 28 discusses the Canaport LNG facility at Saint John, New Brunswick. With respect to that facility,

(a) How much gas is being imported through that facility?

(b) Has NSPI sought gas supplies from the gas being imported there?

(c) If so, how much, and in what time frames?

(d) If not, why not?

Response IR-9:

(a) Since the facility began operating, in July 2009, Repsol has imported 4,121,126 thousand M^3 of LNG. The amount of LNG imported through the facility is available on the NEB website thru the following link:

http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/sttstc/mprtlqufdntrlgs/mprtlqufdntrlgs.xls

(b) Yes.

(c-d) The Company sought to have LNG supply in all of its negotiations with [redacted]. Specifically, [redacted] MMBtu/day [redacted] Transaction Confirmation that was negotiated from [redacted] and the [redacted] MMBtu/day [redacted] Transaction Confirmation that was negotiated [redacted]. Additionally, the Company sought LNG from [redacted] in its September 2008 RFP for gas supply in 2010 and beyond and its August 2009 RFP for gas supply in

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2010 and beyond. Please refer to FAM Data Room confidential binders NG0010, NG0012, NG0007 and NG0009 respectively available for viewing at NSPI offices.

Discussions with [redacted], seeking LNG supply, began as early as May 2008 when NSPI issued an Expression of Interest for gas supply in 2010 and beyond. At the time of the September 2008 RFP, [redacted] was not prepared to commit to LNG sales and [redacted]. In July 2009, [redacted]. Neither [redacted] offered LNG in response to the August 2009 RFP. Throughout 2010 and 2011 NSPI has had discussions with [redacted] about LNG supply. Discussions with [redacted] occurred from [redacted] during the negotiation of [redacted] of gas supply. Discussions with [redacted] occurred in June 2010 at the Boston LDC Forum and in August 2010 at an M&NP-CA Customer Event. Discussions were held with [redacted] again in October during negotiation of [redacted] of gas supply. Discussion with [redacted] occurred again in January 2011. Discussion with [redacted] occurred again in March 2011. The most recent conversation with [redacted] regarding LNG supply was in early May 2011. The most recent conversation with [redacted] regarding LNG supply was in mid-May 2011. To date, [redacted] has been willing to contract for LNG. The response from [redacted]. [redacted]. NSPI will continue to seek LNG supplies from [redacted].

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Request IR-10:

With respect to GRA Exhibits DE-03 and 04, the middle paragraph of page 28 discusses the Canaport LNG facility at Saint John, New Brunswick. The discussion in the paragraph notes that "The facility has a one billion cubic feet (Bcf) per day output capacity", and that "Repsol had previously secured most of the M&NP-US capacity from Baileyville, Maine to Dracut, Massachusetts, approximately 730,000 MMBtu per day, in order to be able to supply regasified … LNG from Canaport to U. S. markets."

(a) What does NSPI know about the LNG terminal's owners' plans for the capacity of the LNG terminal (one Bcf/day) that is in excess of Repsol's contracted capacity to move gas from Baileyville to Dracut?

(b) Please summarize the discussions that NSPI has had with either or both of the owners of the terminal about those plans.

Response IR-10:

(a) Irving Oil and Repsol are negotiating an agreement for Repsol to supply LNG to Irving Oil. Irving Oil is the exclusive marketer of LNG in Canada and therefore until Irving Oil has supply to sell, LNG is not being marketed in Canada. Once an agreement is reached, it is logical to expect that some of the excess LNG terminal and pipeline send-out capacity on the Brunswick Pipeline would be used to supply LNG to Canada. NSPI is not aware of any expansion plans on M&NP-US to accommodate additional volume.

(b) Please refer to Liberty IR-9 (c).

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Request IR-11:

With respect to GRA Exhibits DE-03 and 04, the second paragraph on page 40 contains the following statement:

> **When reselling natural gas, the portion of market-price indexed (floating) gas volumes available under *the existing gas contract* are sold at matching or similar indices for no material cost or benefit to us and our customers. (Emphasis added.)**

(a) Which gas contract is being referenced in that statement?

(b) Please explain the statement further.

Response IR-11:

(a) The gas contract being referenced is the applicable purchase contract for the gas being re-sold at the time. It is not meant to refer to a specific contract.

(b) The statement is meant to differentiate the margins experienced on gas sales in the past compared to current gas sale margin expectations. Specifically it is meant to identify that there is no longer a material gain anticipated on gas sales because purchase and sale contracts are both structured with matching price indices. Additionally, it is meant to convey that there will not be a material cost because both contracts are structured with matching price indices.

CONFIDENTIAL (Attachment Only)

Request IR-12:

With respect to GRA Exhibit OE-01A Attachment 1, pages 2 and 3, please provide tables in the same format, but using the fuel prices and load forecast from NSPI's latest forecast for 2011; *i.e.*, the same tables, but with actual generation and production through the latest month available (April?) , and NSPI's current forecast for the remainder of 2011. (Liberty expects that this response will include the requested tables from the Company's second-quarter update of its fuel forecast.)

Response IR-12:

Please refer to Confidential Attachment 1. The most recent forecast has been included. NSPI has not yet completed the Q2 forecast.

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Request IR-13:

With respect to GRA Exhibit OE-01A Attachment 1, page 3,

(a) Please confirm (or correct) our interpretation that the row in the table labeled "$ per MMBtu" for each fuel is the price on which each fuel is dispatched in the simulation model (Strategist?) run that produces the forecast; and

(b) Please confirm (or correct) our interpretation that the row in the table labeled "MTM on HFO and Natural Gas" is the forecasted effect of hedges on HFO and gas that were in place when the forecast was prepared, but will settle in each of the indicated months.

(c) Please explain what costs are included in the row labeled "Adjustments".

Response IR-13:

(a) The rows in this table labeled "$ per MMBtu" are not the prices used for dispatch. These are the accounting costs which include open, contracted and hedged amounts. Unit dispatch is based on replacement energy costs.

(b) This item relates to the transitional provision associated with the change in accounting policy, Accounting for Financial Instruments and Hedges - 6960, effective January 1, 2011. The ineffectiveness booked prior to January 1st, 2011 is being reversed as the related hedges settle.

(c) Total Adjustments are $4,990,245.

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	($)
Fuel Handling [1]	[redacted]
Water Royalties	[redacted]
Provincial Emissions Fee	[redacted]
Fuel Tech [2]	[redacted]
Rail Car Lease	[redacted]
Volume Adjustments [3]	[redacted]
Total	**4,990,245**

Notes:

1. Fuel handling includes expenses to move the fuel to the generating stations' reclaim hoppers from the inventory piles, largely labour.

2. Fuel Tech Targeted In-Furnace Injection is an additive used at Point Aconi generating station.

3. Volume adjustments are related to contracts for an agreed level of throughput.

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Request IR-14:

With respect to GRA Exhibit OE-01A Attachment 1, page 6,

(a) Please explain why the Company expects to make gas sales.

(b) Please explain how the Company estimated the amount of gas that it forecasts selling in each month of the forecast period.

(c) Please explain how the Company estimated the purchase prices and resale prices for the gas that it forecasts selling in each month of the forecast period.

(d) Please identify the sources of the gas that the Company forecasts selling in each month of the forecast period.

Response IR-14:

(a) The Company expects to make gas sales when it is an overall lower cost to the customer to purchase lower price term gas, and occasionally re-sell it, than it is to purchase higher-priced spot gas to match daily requirements.

(b) The Company estimates the amount of gas it forecasts selling each month by subtracting the amount of gas required, according to Strategist, from the amount of gas contracted. The remainder is the amount of gas to be re-sold.

(c) The purchase and re-sale pricing specified in existing contracts is used for the purchase and re-sell price for the forecast.

(d) The sources of the gas are [redacted].

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Request IR-15:

With respect to GRA Exhibit OE-01A Attachment 1, pages 23 and 25, please explain the differences between the gas prices shown for the steam units (page 23) and the prices shown for the LM6000 (page 25). Please explain the differences both with and without hedges.

Response IR-15:

The difference between gas prices (both with and without hedges) results from the modeling method. The total gas commitments (contracts) are allocated to the units sequentially based on volumes. Due to the price differences between contracts, this results in differences in gas prices between the individual units. It is important to note the total annual gas requirements in both dollars and volume is unique to a forecast and does not change based on this allocation.

For further details, please refer to FAM Data Room confidential binder GE0022 (Financial Modeling section, page labeled Tufts) available for viewing at NSPI offices.

REDACTED

Request IR-16:

Given the significant [redacted] as described throughout OE-01N, please explain and justify the rationale for the significant [redacted] solid fuel transportation forecast costs from $[redacted] in 2011 to [redacted] in 2012, as forecast in OE-01C. In addition, please also explain why the significant [redacted] for 2011 as predicted in OE-01N, Attachment 3, page 12 of 21, would not [redacted] into 2012, or [redacted], and consequently [redacted] on NSPI 2012 transportation prices, given that [redacted]

Response IR-16:

Freight rates with [redacted] are contractually limited to [redacted] In 2011, a number of solid fuel suppliers [redacted] In addition, the open (un-contracted) positions for solid fuel are greater in 2012 than in 2011. The cost of transportation associated with the open position tonnage [redacted] As we enter into new contracts to close the open position, [redacted]

Our shipping contracts contain a provision that allows for increases, or decreases, in shipping costs based on the shippers' fuel costs. As a result of forecast [redacted] the price of bunker, the total adjustment provision for 2012 is forecast [redacted] by approximately [redacted]. This change accounts for [redacted] in 2012 relative to 2011. Also in 2012, there are [redacted] forecasted to be imported in total than in 2011.

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Request IR-17:

Please explain the [redacted] capacity factor of [redacted] for Trenton #5 in 2012, as shown in OE-01A, Attachment 3, page 5 of 9, including responses to the following:

(a) Please provide the forecast availability of this unit for 2012.

(b) If [redacted] capacity factor is due to maintenance, please explain the nature and duration of maintenance.

(c) If [redacted] capacity factor is due to [redacted] fuel costs, please explain why fuel costs are [redacted], especially as related to Trenton #6.

(d) If [redacted] capacity factor is due to other reasons, please explain.

Response IR-17:

(a) The forecast availability for Trenton Unit 5 in 2012 is approximately [redacted], based on the forecast thermal maintenance schedule, DAFOR and deration factors.

(b-d) [redacted] capacity factor is due to the cost of fuel for Trenton Unit 5, relative to the other thermal steam units. The fuel cost for Trenton Unit 5 [redacted] the natural gas units and the other coal units due to [redacted]. Therefore, the other units are dispatched [redacted] Trenton Unit 5 in the Strategist model for 2012. Trenton Unit 6 is designed to burn a higher ash coal blend and therefore consumes [redacted], [redacted].

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Request IR-18:

Please provide a brief summary of the planned maintenance activities for each of the generating units scheduled for maintenance in 2012, as shown on OP-05, Attachment 1, page 1 of 1.

Response IR-18:

Please refer to Attachment 1.

Project Title
Burnside1 - Routine Maintenance & Inspections
Burnside2 - Routine Maintenance & Inspections
Burnside3 - Routine Maintenance & Inspections
LIN1 - Condenser Upgrade - Plastocor Sheets
LIN1 - Burner Shut Off Valves Improvements
LIN1 - Steam Drum Level Controls
LIN2 - Rotor Rewind
LIN2 - High Temperature Fastener Replacement
LIN2 - LSB Replacement
LIN2 - L-1 Turbine Blade Replacement
LIN2 - Boiler Refurbishment
LIN2 - Boiler Feedpump Check Valve Replacement
LIN2 - Burner Shut Off Valves
LIN3 - Automatics Voltage Regulator Replacement
LIN3 - Condenser Large Bore Pipe and Valving Replacement
LIN3 - Division Wall Replacement
LIN3 - HVB Refurbishment
LIN3 - Condenser Upgrade - Plastocor Sheet Installation
LIN3 - Economizer Outlet Duct Improvements
LIN3 - Ash Conveyer Structure Replacement & upgrade
LIN3 - Burner Shut Off Valves
LIN3 - Boiler Division Wall Replacement
LIN4 - Battery & Charger Replacement
LIN4 - Upgrade Boiler Feedwater Instrumentation
LIN4 - Govenor Replacement
LIN4 - Burner Shut Off Valves
LIN4 - Precip Outduct Structural Steel replacement
POA - BA Drag Chain Replacement
POA - Turbine Supervisor Run-up Improvements
POA - Generator Automatic Voltage Regulator (AVR) Replacement
POA - 2012 Refractory Refurbishment
POA - Structural Steel Coating
POA - Turbine Vibration Monitoring System Upgrade
POA - Sidewall Feeder Replacements
POA - Turbine By-Pass Decommissioning
POA - Boiler Expansion Joint Replacements
POA - 4KV Motor Refurbishment
POT - 4KV, 600V Motor Refurbishment
POT - Control Room Upgrade
POT - Vibratory feeder for coal crusher refurbishment

Project Title
POT - Flame Scanner Replacement
POT - 129V Battery Charger Replacement
POT - Replace Sternson PLC
POT - Automatic Voltage Regulator Replacement
TRE5 - Coal Feeders Conversion to Gravometric Feeders
TRE5 - Precip Refurbishment
TRE5 - Waterwall Panel Replacements
TRE5 - Condenser Pipe Replacements
TRE5 - Turbine/Generator Sprinkler System Upgrades
TRE5 - Conveyor System Upgrades
TRE5 - Blowdown Tank Replacement
TRE5 - Boiler Alignment (Phase 2)
TRE5 - CW Inlet Pipes and Valves Replacement
TRE5 - High Pressure Piping Upgrades
TRE5 - Seal Oil Piping Upgrades
TRE6 - Turbine/Generator Sprinkler System Upgrades
TRE6 - High Pressure Piping Upgrades
TRE6 - Stack Breaching Inlet Ductwork Repairs
TRE6 - Stack Lighting System Upgrades
TRE6 - Condenser Actuator Replacements
TRE6 - Turbine Controls Power Supply
TRE6 - 6B Fly Ash Compressor/Dryer Upgrades
TRE6 - Ignitor Replacements
TRE6 - Coal Feeder Valve Replacement
TRE6 - MCC Component Replacements
Tusket Overhaul
TUC1 - Turbine Supervisory Equipment Upgrade
TUC1 - Precip Heater Control Replacement
TUC2 - Replace Excitation & AVR System
TUC2 - H2 Dryer Replacement
TUC2 - ACW Strainer Replacement
TUC2 - Turning Gear Worm Shaft Replacement
TUC3 - Excitation & AVR System Replacement
TUC3 - Turbine HP Impulse Blades Replacement
TUC3 - Cooling Water (CW) Piping Internal Lining Replacement
TUC3 - Turbine Bolting Replacement
TUC3 - Generator Protection Relay Replacement
TUC4 - Routine Maintenance and Inspections
TUC5 - Routine Maintenance and Inspections

Project Title
TUC 6-4 - Routine Maintenance and Inspections
TUC 6-5 - Routine Maintenance and Inspections
VJ1 - Routine Maintenance and Inspections
VJ2 - Routine Maintenance and Inspections
WC1 - Routine Maintenance and Inspections
WC2 - Routine Maintenance and Inspections

Does not include a listing of the extensive inspection programs which occurs during each outage

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Request IR-19:

Please provide the date of preparation of the fuel forecast shown in OE-01A.

Response IR-19:

The effective forecast date for the 2012 GRA is December 31, 2010.

CONFIDENTIAL (Attachment Only)

Request IR-20:

Please explain why the generating unit heat rates for 2012 as shown on OP-06, Attachment 1, page 1 of 2 do not agree with the heat rates for 2012 as shown on OE-01A, attachment 1. Also please identify which heat rates are correct for 2012, as well as why the heat rates from OE-01A are those being used in the Strategist model, OE-01A, Attachment 3.

Response IR-20:

Attached is a revised version OP-06 using the heat rates shown in OE-01A and in strategist.

Standardized Filing Requirements for Fuel - Generating Units by Type
Year 2012

	Fuel Type	In Service Year	Net Operating Capacity (MW)	Net Avg. Heat Rate (Btu/kwh)	2012 Annual Energy (GWh)
Thermal Units					
Tufts Cove 1	Oil / Natural Gas	1965	81	[redacted]	290
Tufts Cove 2	Oil / Natural Gas	1972	93	[redacted]	68
Tufts Cove 3	Oil / Natural Gas	1976	147	[redacted]	376
Trenton 5	Coal / Petcoke	1969	150	[redacted]	328
Trenton 6	Coal / Petcoke	1991	157	[redacted]	1145
Pt. Tupper 2	Coal / Petcoke	1973	152	[redacted]	1244
		Coal Conv. 1987		[redacted]	
Lingan 1	Coal / Petcoke	1979	153	[redacted]	1149
Lingan 2	Coal / Petcoke	1980	153	[redacted]	927
Lingan 3	Coal / Petcoke	1983	158	[redacted]	1119
Lingan 4	Coal / Petcoke	1984	153	[redacted]	1211
Pt. Aconi 1	Petcoke / Coal	1994	171	[redacted]	1305
		Total Thermal	**1568**		**9162**
Combustion Turbines					
Tufts Cove 4	Natural Gas	2003	49	[redacted]	
Tufts Cove 5	Natural Gas	2005	49	[redacted]	
Tufts Cove 6	Natural Gas Combined Cycle	2011	50	[redacted]	999
Tusket 1	Light Oil	1971	24	[redacted]	1
Burnside 1	Light Oil	1976	33	[redacted]	6
Burnside 2	Light Oil	1976	33	[redacted]	4
Burnside 3	Light Oil	1976	33	[redacted]	3
Burnside 4	Light Oil	1976	33	[redacted]	0
Victoria Junction 1	Light Oil	1976	33	[redacted]	1
Victoria Junction 2	Light Oil	1975	33	[redacted]	1
		Total CT's	**371**		**1015**
Hydro and Wind Systems	**Installed Capacity (MW)**		**Firm Capacity (MW)**		**Energy (GWh)**
Wreck Cove		1978	230		301
Annapolis Tidal		1984	3.7		27
Other Hydro			163.5		647
Little Brook	0.60		0.2		2
Grand Etang	0.66		0.2		2
Digby	30		9.9		107
Nuttby Mountain	45		14.9		140
Total Hydro/ Wind			**422**		**1226**
Independent Power Producers	**Installed Capacity (MW)**		**Firm Capacity (MW)**		**Energy (GWh)**
Independent Power Producers - Other	36.8		26.8	Contract IPPs (pre 2001)	198
Independent Power Producers - Wind	217.7		71.8	Renewables IPPs (post 2001)	597
Imported Power				Import Purchases	484
NS Power Total Firm Capacity (MW)			**2460**	**Total Purchases**	**1279**
				Total Annual Energy	**12681**

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Request IR-21:

Please explain in detail what coal costs for 2012 are used in unit dispatch calculations. Include in this discussion how these coal costs are calculated in the following situations:

(a) If coal consumed comes from inventory,

(b) If there is currently an excess of coal on order, and no purchases are forecast in the near term (no open positions),

(c) If there is currently a shortage of coal on order, and purchases are being made on a regular monthly basis to fill continuing open positions.

(d) How the coal cost for dispatch in 2012 varies on a monthly basis, and to what variables such variation is related.

Response IR-21:

(a) The order of dispatch of the coal units used in the 2012 forecast was based on the replacement price of low-sulphur coal for each unit. The replacement price of low-sulphur coal was calculated as of December 31, 2010, and included published forward price strips for 2012, as described by the Fuel Forecasting Methodology in the FAM POA. The dispatch prices also included the 2012 contract price for domestic coal which makes up a portion of the normal blend at [redacted] and [redacted], as well as the forecast price for petroleum coke following the Fuel Forecasting Methodology in the FAM POA. Once the dispatch of the coal units is established using replacement solid fuel prices, the forecast generation cost of each plant is determined using the forecast solid fuel inventory for each plant. The forecast cost of solid fuel in inventory includes

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the cost of solid fuel that was contracted for 2012 as of December 31, 2010, as well as the forecast cost of open positions for 2012.

(b) If there had been no open positions in the 2012 forecast, the unit dispatch would be based on replacement price of coal for the year of the next open position. The cost of generation would then be determined using the 2012 contract cost of the coal in inventory for each plant.

(c) There were open positions in the 2012 forecast as of December 31, 2010, and the unit dispatch for the 2012 forecast was based on the replacement price of coal as described in part (a).

(d) The replacement coal prices used to determine the dispatch in the 2012 forecast were calculated as described in part (a) and do not vary on a monthly basis.