NON-CONFIDENTIAL

Request IR-1:

REFERENCE: M-2 (APPLICATION), P. 18-19

CITATION:

> **Since 1999, Nova Scotia has had the ability to use natural gas to produce electricity when economically advantageous for customers. The utility captured opportunities to use natural gas to benefit customers through additional economic generation and, for a time, by selling excess gas in order to lower overall costs to customers. In 2011, 20 percent of NS Power's electricity was generated from natural gas.**

(a) Please provide a document that presents in detail the electric generation assets in service in Nova Scotia and their dispatch.

(b) Please explain what is meant by the expression « when economically advantageous for customers ». Under what circumstances are the natural gas generation assets used, and not used?

Response IR-1:

(a) Please refer to CanWEA IR-001 Attachment 1.

(b) Natural gas prices are volatile, and fluctuate daily and seasonally. NS Power optimizes the dispatch of the fleet daily, using the current market prices. Some day's coal is cheaper than gas and therefore coal would be base loaded, with gas units running at lower levels to meet generation requirements. Other day's gas is less expensive than coal and gas would be base loaded and coal dispatched down. In addition, the Tufts Cove steam units can burn either Heavy Fuel Oil (HFO) or gas. As the price of these two commodities moves, the decision is made daily which fuel is less expensive to consume in these units.

NSPI 2013- Summary of Installed Generation

Thermal Units	Nameplate Installed (MW)	Net Operating (MW)	Fuel Type	In-service Year
Tufts Cove 1	100	81	HFO/ N Gas	1965
Tufts Cove 2	100	93	HFO/ N Gas	1972
Tufts Cove 3	150	147	HFO/ N Gas	1976
Pt Aconi	165	171	Petcoke/ Coal	1994
Lingan 1	150	153	Coal/ Petcoke	1979
Lingan 2	150	153	Coal/ Petcoke	1980
Lingan 3	150	153	Coal/ Petcoke	1983
Lingan 4	150	153	Coal/ Petcoke	1984
Trenton 5	150	150	Coal/ Petcoke	1969
Trenton 6	160	157	Coal/ Petcoke	1991
Tupper 2	150	152	Coal/ Petcoke	1987
Port Hawkesbury Biomass	61	53	Biomass	2013
		1616		
Combustion Turbines				
Burnside 1	30	33	Lt. Oil	1976
Burnside 2	30	33	Lt. Oil	1976
Burnside 3	30	33	Lt. Oil	1976
Burnside 4	30	33	Lt. Oil	1976
Victoria Junction 1	30	33	Lt. Oil	1975
Victoria Junction 2	30	33	Lt. Oil	1975
Tusket	24	24	Lt. Oil	1971
Tufts Cove 4	47	49	N Gas	2003
Tufts Cove 5	47	49	N Gas	2005
Tufts Cove 6	49	49	N Gas	2012
		369		

Hydro	Net Operating (MW)
Wreck Cove	212.0
Annapolis Tidal	19.0
Avon	6.8
Black River	22.5
Nictaux	8.3
Lequille	11.2
Paradise	4.7
Mersey	42.5
Sissiboo	24.0
Bear River	13.4
Tusket	2.4
Roseway	1.8
St Margarets	10.8
Sheet Harbour	10.8
Dickie Brook	3.8
Fall River	0.5
	394.5

Total NSPI Thermal and Hydro		**2379**		
NSPI Wind		**Net Operating (non firm)**		
Little Brook	0.6	0.60		2002
Grand Etang	0.66	0.66		2002
Nutby Mountain	49.5	50.6		2010
Digby	30	30		2010
Total NSPI Wind	**80.8**	**81.9**		
NSPI Total		**2461**		
Total IPP Contracts (Pre-2001)	24.8	25.8	Wood/Hydro	
Total Existing IPP contracts (Post -2001)	60	61.8	Wind/Biomass/Landfill gas	
Total Incremental IPP 2010	139.0	141.1		
Total Incremental IPP 2011	1.5	1.5		
Total Incremental IPP 2012	36.4	39.2		
Total Incremental IPP 2013	8.0	8.0		
Total Net Operating Capacity		**2739**		

Hydro Capacity and In-Service Year

Unit/System	Net Operating (Firm MW)	In-service Year
Avon 1	3.75	1958
Avon 2	3	1929
Avon	**6.75**	
Gulch	6.2	1952
Ridge	4.1	1957
Fourth Lake	3.1	1983
Bear	**13.4**	
Sissiboo	5	1961
Weymouth 1	9.5	1961
Weymouth 2	9.5	1967
Sissiboo	**24**	
Methals	3.5	1949
Hollow Bridge	5.5	1942
Lumsden	2.9	1940
Hell's Gate 1	3.5	1930
Hell's Gate 2	3.7	1949
White Rock	3.4	1952
Black River	**22.5**	
Dickie Brook 1	1.2	1948
Dickie Brook 2	2.6	1948
Dickie Brook	**3.8**	
Fall River	**0.5**	1985
Roseway 1	0.45	1974
Roseway 2	0.6	1949
Harmony	0.75	1943
Roseway	**1.8**	
Nictaux	**8.3**	1954
Paradise	**4.7**	1950
Lequille	**11.2**	1968
Upper Lake Falls 1	2.7	1929
Upper Lake Falls 2	2.7	1929
Lower Lake Falls 3	3.7	1929
Lower Lake Falls 4	3.7	1929
Big Falls 5	4.5	1929
Big Falls 6	4.5	1929
Lower Great Brook 7	2.25	1955
Lower Great Brook 8	2.25	1955
Deep Brook 9	4.5	1950
Deep Brook 10	4.5	1950
Cowie Falls 11	3.6	1938
Cowie Falls 12	3.6	1938
Mersey	**42.5**	
Mill Lake 1	1.3	1922
Mill Lake 2	1.3	1922
Sandy Lake 3	1.8	1928
Sandy Lake 4	1.8	1928
Tidewater 1	2.3	1922
Tidewater 2	2.3	1922
St Margarets	**10.8**	
Malay Falls 4	1.15	1924
Malay Falls 5	1.15	1924
Malay Falls 6	1.1	1924
Ruth Falls 1	2.3	1925
Ruth Falls 2	2.8	1925
Ruth Falls 3	2.3	1936
Sheet Harbour	**10.8**	
Tusket 1	0.8	1929
Tusket 2	0.8	1929
Tusket 3	0.8	1929
Tusket	**2.4**	
Gisborne	3.5	1982
Wreck Cove 1	113.25	1978
Wreck Cove 2	113.25	1978
Wreck Cove	**212**	
Annapolis	**19**	1984
Total	**394.5**	

Breakdown of IPPs

	Nameplate Installed (MW)	Net Operating (MW)	Fuel Type	In-service Year
Renewables Contracts (Pre-2001)				
Taylor Lumber	0.75	0.8	Biomass (wood)	1996
Morgan Falls	0.50	0.5	Hydro	1996
Black River Hydro	0.23	0.2	Hydro	1996
Brooklyn Power Corp	23.37	24.3	Biomass (wood)	1996
Total IPP Contracts (Pre-2001)	**24.85**	**25.8**		
Existing Renewables (Post -2001)				
Halifax Renewable Energy (*Mt. Uniacke Landfill*)	2.00	2.00	Biogas	2006
Atlantic Wind Power				
Pubnico Point Wind Farm	30.60	30.60	Wind	2005
Cape Breton Power				
LIngan	14.00	15.80	Wind	2006
Glace Bay 1B	0.80	0.80	Wind	2005
Donkin	0.80	0.80	Wind	2005
Confederation				
Springhill	2.10	2.10	Wind	2006
Higgins Mtn.	3.60	3.60	Wind	2007
Tiverton	0.90	0.90	Wind	2009
RESL (Renewable Energy Services Ltd)				
Goodwood	0.60	0.60	Wind	2005
Brookfield	0.60	0.60	Wind	2005
Pt. Tupper 1	0.80	0.80	Wind	2006
Tatamagouche (Marshville / River John)	0.80	0.80	Wind	2006
Digby	0.80	0.80	Wind	2006
Sheerwind North				
Fitzpatrick Mountain	1.60	1.60	Wind	2007
Subtotal - Existing IPP wind (Post-2001)	**58**	**59.8**		
Total Existing IPP Renewables (Post-2001)	**60.0**	**61.8**		
Total Existing renewables Pre and Post 2001	**84.8**	**87.6**		
Incremental Additions in 2010				
RESL (Renewable Energy Services Ltd)				
Pt. Tupper 3 (Bear Head)	22.00	22.00	Wind	2010
Sheerwind North				
Barney's River (Glen Dhu North)	60.00	62.10	Wind	2010
RMS Energy				
Dalhousie Mountain	51.00	51.00	Wind	2010
Maryvale	6.00	6.00	Wind	2010
Total Incremental IPP Renewables 2010	**139.0**	**141.1**		
Incremental Additions in 2011				
Watts Wind Energy				
Watts Section	1.5	1.5	Wind	2011
Total Incremental IPP Renewables 2011	**1.5**	**1.5**		
Total cumulative IPP wind 2011	**198.5**	**202.4**		
Incremental Additions in 2012				
Amherst Wind LP (Sprat)				
Amherst	**30**	**31.5**	Wind	2012
Wind Prospect Inc				
Fairmont	4.0	4.6	Wind	2012
Colchester-Cumberland Wind Field				
Spiddle Hill	0.8	0.8	Wind	2012
Confederation Power				
Donkin (Lingan II - distribution)	1.6	2.3	Wind	2012
Total Incremental IPP Renewables 2012	**36.4**	**39.2**		
Total cumulative IPP wind 2012	**234.9**	**241.6**		
Incremental Additions in 2013				
Scotian Windfields				
Granville ferry	2.0	2.0	Wind	2013
Black River Wind				
Creignish Rear	2.0	2.0	Wind	2013
Irish Mountain	2.0	2.0	Wind	2013
South Cape Mabou	2.0	2.0	Wind	2013
Total Incremental IPP Renewables 2013	**8.0**	**8.0**		
Total cumulative IPP wind 2013	**242.9**	**249.6**		
Total IPP nameplate capacity	**269.7**	**277.4**		

NON-CONFIDENTIAL

Request IR-2:

REFERENCE: M-2 (APPLICATION), FIGURE 1-4, PAGE 21

Do these limits apply to coal-fired generation only? If not, please indicate to what types of greenhouse gas emissions they apply.

REFERENCE: M-2 (APPLICATION), PAGE 22 CITATION:

> On December 17, 2012, Emera and Nalcor entered into a Sanction Agreement (Appendix 2.15) enabling both parties to advance their respective projects, and a Project Oversight Agreement (Appendix 2.16).
>
> This now sets the stage for construction to begin on the Muskrat Falls generating station, the Labrador Transmission Assets and the Labrador-Island Transmission Link, as well as, this regulatory filing with the UARB for the Maritime Link Project.

Response IR-2:

The limits referred to in Figure 1-4 of the Application apply to greenhouse gases (including Carbon Dioxide, Methane, Nitrogen Oxide, Sulphur hexafluoride, Hydrofluorocarbons and Perfluorocarbons) from any facility supplying electricity for sale on the grid that emits greater than 10,000 metric tonnes of carbon dioxide equivalent greenhouse gases in a calendar year.

NON-CONFIDENTIAL

Request IR-3:

(a) Will the construction of the Muskrat Falls generating station, the Labrador Transmission Assets and the Labrador-Island Transmission Link continue in the event that the UARB does not approve the Maritime Link Project?

(b) In the affirmative, has Nalcor provided any explanation of how it would dispose of surplus energy in the event that the Maritime Link is not built? If so, please provide it. If not, please explain your reasoning for believing that the remaining components of the Muskrat Falls Project would go ahead.

(c) Is your response based on public statements by Nalcor? If so, please provide them.

(d) Is your response based on direct communications from Nalcor? If so, please provide them.

(e) Inversely, in the event that either one of the Muskrat Falls generating station, the Labrador Transmission Assets or the Labrador-Island Transmission Link is delayed or cancelled, would the Maritime Link Project go ahead on the announced schedule?

(f) In the affirmative, please describe in detail the uses to which the Maritime Link would be put in the event that power from the Muskrat Falls generating station, transmitted via the Labrador-Island Transmission Link, were not available?

NON-CONFIDENTIAL

Response IR-3:

(a-f) NSPML is not prepared to speculate on the outcome of the UARB hearing. Please refer to the Sanction Agreement at Appendix 2.15, which addresses the Sanction of the Maritime Link, the Labrador-Island Link, the Labrador Transmission Assets and the Muskrat Falls Plant.

NON-CONFIDENTIAL

Request IR-4:

REFERENCE: M-2 (APPLICATION), PAGE 33

CITATION 1 (p. 33):

> **The NS Block is dispatchable, which means the utility can schedule and optimize when the energy is to be delivered to Nova Scotia within the terms of the Energy and Capacity Agreement.**

(a) Please describe in detail, making reference to the Energy and Capacity Agreement, to what extent the NS Block is "dispatchable".

(b) Please describe in detail the mechanism by which dispatch will be carried out between the Nova Scotia system and the Muskrat Falls project, identifying the system operators for each control area and explaining the role of each.

(c) Please describe in detail the mechanisms for day-ahead commitments and dispatch, hourly dispatch and expected minute by minute dispatch instructions.

CITATION 2 (p. 35):

> **In the short term, Emera will provide the path through New Brunswick to the US border, using transmission rights attached to its Bayside Generating Station in Saint John.**

(d) Please describe the transmission rights « attached to » Emera's Bayside Generating Station.

NON-CONFIDENTIAL

Response IR-4:

(a) Please refer to Schedule 5 Section 2 of the Energy and Capacity Agreement (ECA) for the detailed rights to schedule and optimize energy deliveried to Nova Scotia.

(b) Nova Scotia will have the rights set out in the ECA (refer to Appendix 2.03 of the application) as outlined in Schedule 5 Section 2 of the agreement. The structure of the agreements has Nalcor responsible for all details and operational coordination to assure that the energy is delivered to the delivery point.

Schedule 5 presents the scheduling protocol and dispatch parameters which include, but not limited to; ramping period for the start and end of each day of 90 minutes either way, scheduling delivery in 30-minute increments in a plus or minus 40 MW band and 20 MW of regulation service.

(c) Please refer to Schedule 5 Section 2 of the ECA. Please also refer to Appendix 2.09 of the Application, the Interconnection Operators Agreement between NLH and NS Power for the roles of the system operators.

(d) Please refer to McMaster IR-12.

NON-CONFIDENTIAL

Request IR-5:

REFERENCE: M-2 (APPLICATION), P. 40

CITATION:

> **The Muskrat Falls Generation Station will be capable of producing up to 824 MW of electricity (4.93 TWh annual energy production). Nalcor requires part of this supply for Newfoundland's own needs, but up to 500 MW will be available for export from Newfoundland to Nova Scotia.**

In order to better understand the meaning of « up to 500 MW » in the citation, please indicate:

(a) The power losses, at full output of 824 MW, between Muskrat Falls and Soldier's Point in Newfoundland as well as at the connection point on the existing Nova Scotia grid

(b) Newfoundland's anticipated power requirements for Muskrat Falls power, on a seasonal basis (including upper and lower bounds, on peak and off-peak), in the first year of operation, and at 5-year intervals thereafter. Please indicate precisely the source of this information.

(c) Taking into account losses and Newfoundland's anticipated power requirements for Muskrat Falls power, please provide anticipated capacity availability to Nova Scotia on a seasonal basis (including upper and lower bounds, on peak and off-peak), in the first year of operation, and at 5-year intervals thereafter.

NON-CONFIDENTIAL

(d) For greater clarity, please summarize the responses to Questions 5b and 5c in tables similar to the following:

	2017	2023	2027	2032	2037	2042	2047	2052
Winter on-peak (upper bound)								
Winter on-peak (lower bound)								
Winter off-peak (upper bound)								
Winter off-peak (lower bound)								
Summer on-peak (upper bound)								
Summer on-peak (lower bound)								
Summer off-peak (upper bound)								
Summer off-peak (lower bound)								

Response IR-5:

(a-d) Please refer to CanWEA IR-51, NSUARB IR-13, NSUARB IR-65 and CA IR-73.

NON-CONFIDENTIAL

Request IR-6:

REFERENCE: M-2 (APPLICATION), P. 40-41

CITATION:

> **Of the 500 MW export capacity, Nova Scotia will receive at least 170 MW, less the losses to deliver it to Bottom Brook and then through the Maritime Link to Woodbine, plus a supplemental block of energy that NSPML will receive during the first five years of Project operation. This will allow NS Power to retire one or two coal units. The balance of the 500 MW export would be available for sale to NS Power by Nalcor, or it could pass through Nova Scotia to buyers beyond the NS border.**

(a) Please quantify the energy and capacity losses to Bottom Brook and to Woodbine.

(b) Given that the Supplemental Block consists of off-peak energy during the first five years of operation, please explain in what sense, if any, this Supplemental Block consists of capacity additional to the 170 MW mentioned at the beginning of the citation.

(c) Please explain in detail how "this will allow NS Power to retire one or two coal units", indicating:

(i) The capacity (or capacities) of the unit(s) to which you refer

(ii) The conditions that will determine whether it allows the retirement of one or two units.

Response IR-6:

(a) Please refer to Grand Riverkeeper IR-2(b).

(b) The Supplemental Energy will provide additional capacity during the off-peak hours as it is flowing at a different time of day than the initial 170 MW block.

(c) (i) NS Power plans for a 20 percent margin of firm capacity over firm load. The addition of the Maritime Link provides firm energy above the NS Block, thus will allow the retirement of other firm capacity in the province whenever the 20 percent margin is exceeded in long term planning.

(ii) Please refer to Grand Riverkeeper IR-3.

Request IR-7:

REFERENCE: M-2 (APPLICATION), page 47 AND 49

CITATION (P. 47):

> The HVDC portion of the Maritime Link will have two separate cables, a negative pole and a positive pole, together capable of carrying 500 MW. Asymmetrical bipolar and dual-monopolar DC transmission systems require a solid return path in addition to the pole conductors. During bipolar operation, unbalanced currents between the poles (approximately 12.5 A or 1 percent of full load current) will flow through the return path. During monopolar operation, full load current of 1,250 A may flow through the return path; it must maintain that power level even during planned or unplanned outages on either of the poles. In the event of such an interruption, the return path will be a primary path for the reduced power transmission. The return path must achieve very low resistance to ensure stable and reliable performance of the AC/DC converters.

CITATION (P. 49):

> As a rule, the grounding sites will carry very little current, based only on minor unbalance between the positive and negative poles. Only a sustained outage of a pole conductor will require sustained use of the earth return path. As rare as these events may be, the ground sites must be designed to carry full rated system current for an extended period of time without incident.

(a) Please clarify the syntax of the underlined sentence in the citation from p. 47.

(b) Please explain the use of the phrase "the reduced power transmission", given that full load current … may flow through the return path.

(c) Please elaborate on the meaning of « for an extended period of time » (2nd citation, p.49). What is the longest time that such an outage could last? Please provide references or documents to support your answer.

(d) What are the types of events that could cause such an outage? For each one, please indicate the likelihood that it would affect only one of the two poles.

(e) In the event of an outage at the Muskrat Falls generating station or on the Labrador-Island Transmission Link, is Nalcor obliged under the Agreements to continue to provide the Nova Scotia Block? In your response, please refer to specific provisions of the Agreements.

Response IR-7

(a) The underlined text explains the fact that a current of up to 1250 A can flow between the two converter stations for as long as the planned or unplanned pole outage persists. During an unplanned outage (fault or forced outage on one pole), the current will initially flow through the grounding sites and the earth. The earth return system must be designed for operation in this mode for an extended period of time. As indicated in SBA IR-166, the impacts of stray currents in the earth are cumulative over time, so system operators will seek to bypass the earth return system when a pole outage persists. If the outage was caused by a failure within one pole converter, and the pole conductors and cables for that pole are healthy, switching activities can be undertaken to divert the return current through those pole conductors, as a means of bypassing the earth return system. Similarly, during planned (maintenance) outages of pole converters, the metallic return path can be used to bypass the earth return system. The system must perform reliably throughout the duration of such planned or unplanned outages.

(b) Throughout the duration of planned or unplanned pole outages, on either pole converters, overhead HVdc transmission lines or submarine cables, the system must be capable of carrying 1250 A continuously, although the amperage can be lower depending upon the MW transfer rating required. Since one pole will be out of service during these outage conditions, the power delivery available at 200 kV and 1250 A will be 250 MW.

(c) The duration of outages will vary significantly depending on cause and location. Planned outages for maintenance will generally last only for a matter of a few hours to a maximum of a few days. Outages due to equipment failures could last a few days if the failures occur in the valve halls of the converter stations or on the overhead lines, as these are typical time durations for repairs of such failures. For equipment failures on the submarine cables, the outages can last much longer, as the repair activities require hiring of specialized cable repair vessels to travel to the project site and lift the damaged cable from the ocean bottom for repair. Depending on availability of such vessels at the time of the equipment failure, the repair time could range from a few weeks to several months. Finally, for failures of the converter transformers at the converter stations, replacement is typically the only practical option, and with spare transformers at site, the replacement time for a failed transformer will be 1-2 weeks.

(d) Unplanned outages on the Maritime Link Project are anticipated to be rare. The types of events that could give rise to a single-pole failure include component failures within the converter stations, failures of converter transformers, failures of insulators on the overhead transmission lines, and insulation failures on the submarine cables. All of these events are highly unlikely to affect both poles of the system, and single-pole outages would be the most likely outcome. In spite of design practices focused on cable protection, cable damage due to marine vessels/anchors, or pack ice is a possibility, and the objective of cable system design is to minimize the risk of damage to both cables. Another important factor in failure events is adverse weather and climatic conditions, and these factors will have their greatest impact on the overhead transmission lines and the overhead/underground transition compounds. Even in the event of a failure due to weather or climatic conditions, only one pole of the transmission system is usually affected.

(e) Please refer to SBA IR-109.

NON-CONFIDENTIAL

Request IR-8:

REFERENCE: M-2 (APPLICATION), PAGE 73

CITATIONS:

> The Regulations contemplate that once the UARB has approved the Maritime Link Project, NSPML will then be entitled to recover all costs that it incurs in connection with the Project (Project Costs) from NS Power from time to time in accordance with the mechanism prescribed by the Regulations.[22]
>
> [22] See: Section 2, subsection4(2) and Section 8

Regulations, Section 4:

> **Requirement for Review Board approval**
>
> **4** **(1)** To obtain a rate, toll, charge or other compensation for services as defined under the *Public Utilities Act*, an applicant must first obtain an approval of the Maritime Link Project under Section 5.
>
> **(2)** Once approved under Section 5, an applicant is entitled to recover Project costs through a rate, toll, charge or other compensation from Nova Scotia Power Incorporated in accordance with Section 8.
>
> **(3)** An applicant who makes an application under this Section is not required to make a separate application under Section 35 or 35A of the *Public Utilities Act*, but once the Review Board has approved an assessment under Section 8, the applicant is subject to Sections 35 and 35A of the *Public Utilities Act* with respect to any new expenditures.

NON-CONFIDENTIAL

Regulations, Section 8:

Assessment and costing approval

8 **(1)** Before receiving energy under the Nalcor Transactions, an applicant must set an assessment against Nova Scotia Power Incorporated for the recovery of the all approved Project costs, and must apply to the Review Board for an approval of the assessment under Section 64 of the *Public Utilities Act*.

(2) Nova Scotia Power Incorporated is entitled to recover through its rates any assessment approved by the Review Board in respect of the Maritime Link Project.

(a) **Will the Board retain discretion as to what incurred costs can be passed on to consumers? Please explain your response in detail.**

(b) **What is the understanding of NSPI and of NSPMLI of the expression « to set an assessment », used in the Regulations?**

(c) **Is this term defined in either the Public Utilities Act or its Regulations? If not, please justify your interpretation.**

Response IR-8:

(a-c) The UARB will retain discretion for approval of costs that will be recovered by NSPML from NS Power, and thereafter by NS Power from the customers of NS Power, pursuant to applications from time to time that are made under section 64 of the Public Utilities Act, which states:

> 64(1) No public utility shall charge, demand, collect or receive any compensation for any service performed by it until such public utility has first submitted for the approval of the Board a schedule of rates, tolls and charges and has obtained the approval of the Board thereof.

Applications pursuant to section 64 of the Public Utilities Act establish the revenue requirement and resulting rates for the public utility that makes the application. An application by NSPML to set an assessment that will recover costs from NS Power as provided by section 8 of the Maritime Link Cost Recovery Process Regulations is comparable to an application by NS Power to set its revenue requirement and electric rates for customers. NSPML agrees that the phrase “to set an assessment” is not a defined term in the Public Utilities Act or Regulations.

NON-CONFIDENTIAL

Request IR-9:

REFERENCE: M-2 (APPLICATION), PAGE 75-77

PREAMBLE:

A number of transmission upgrades are identified in NSPI's 2013 Annual Capital Expenditure plan.

(a) Are any of the transmission upgrades included in NSPI's 2013 Annual Capital Expenditure plan included as part of the Maritime Link costs? In the affirmative, please indicate in detail which ones, and their costs.

(b) Of the transmission upgrades included in NSPI's 2013 Annual Capital Expenditure plan, please indicate which, if any, are necessary to facilitate the integration of the Maritime Link, specifying the description and costs of any such upgrades.

Response IR-9:

(a) No.

(b) None.

NON-CONFIDENTIAL

Request IR-10:

REFERENCE: M-2 (APPLICATION), P. 77

CITATION:

Figure 4-2

Total Maritime Link Project Estimated Capital Costs (before AFUDC)			
	ML cost $1.4 billion	ML cost $1.5 billion	ML cost $1.7 billion
LCP Phase 1 at DG3 (fixed)	$6.2	$6.2	$6.2
Maritime Link facilities range at DG2	$1.4	$1.5	$1.7
Total	$7.6	$7.7	$7.9
	x 20%	x 20%	x 20%
Twenty percent of total being Maritime Link Project capital costs to be included in NSPML rate base	$1.52	$1.54	$1.58

CITATION:

> **An allowance for funds used during construction (AFUDC) of approximately $230 million will be added to this base cost [of $1.52 billion]. AFUDC represents the capitalization of financing costs during the construction phase of the Project.**

PREAMBLE:

> **The citations suggest that the AFUDC of approximately $230 million is not included in the amount of $1.52 billion (plus a variance of $60 million) to be included in the « NSPML rate base ».**

NON-CONFIDENTIAL

(a) Please specify if the amount for which inclusion in the NSPML rate base is requested consists of $1.52 billion + $0.06 billion (variance) + $0.23 billion (AFUDC) = $1.81 billion. In the negative, please explain your answer in detail.

(b) If the actual cost of constructing the Maritime Link exceeds the amounts indicated in the third column of Figure 4-2 ($1.7 billion), will the NSPML rate base reflect the actual amounts, or those described in the application?

Response IR-10:

(a) Correct.

(b) If the UARB approves NSPML's Application for a capital cost of $1.52 billion plus $60 million variance, and if NSPML's Decision Gate 3 cost estimate later this year is $1.7 billion, the total amount that will be included in rate base will be $1.58 billion plus AFUDC. If the actual cost incurred to construct the Maritime Link exceeds $1.7 billion, NSPML will apply to the UARB for approval to include such prudently incurred costs in rate base. If the actual cost is less than $1.7 billion, only the actual amount will be added to rate base.

NON-CONFIDENTIAL

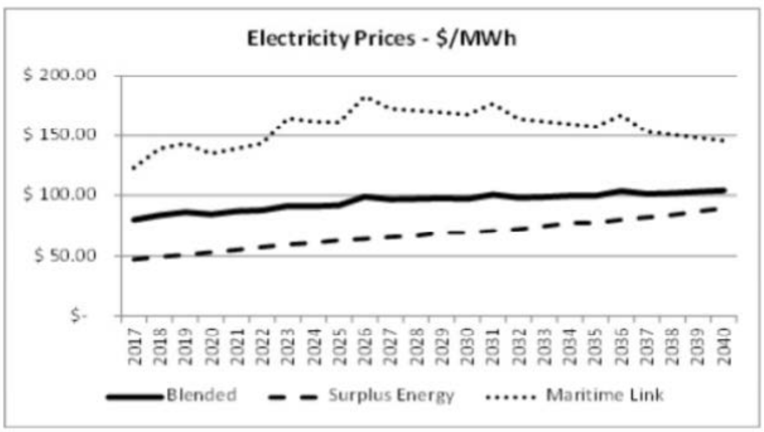
Request IR-11:

REFERENCE: M-2 (APPLICATION), P. 92

CITATION:

Figure 4-4 illustrates the stable pricing of this blended cost of electricity arising from the Maritime Link Project. It does not include the additional benefit of fuel cost savings which will be experienced by NS Power.

Figure 4-4 Weighted Average Electricity Prices Per MWh



(a) **Please provide, in a Microsoft Excel worksheet, the data used to produce Figure 4-4.**

(b) **Please specify, in a Microsoft Excel worksheet, for each year from 2017 to 2040, the respective quantities of Maritime Link energy and of « surplus » energy used to calculate the “Blended” price indicated in Figure 4-4.**

(c) **Please provide, in a Microsoft Excel worksheet, the detailed calculations used to define the annual price of Maritime Link energy in Figure 4-4.**

(d) **Please provide a detailed narrative explanation of the approach used to estimate the price of purchased Surplus Energy in Figure 4-4.**

(e) **Please provide, in a Microsoft Excel worksheet, the detailed calculations used to estimate the price of purchased Surplus Energy in Figure 4-4.**

(f) **Please indicate whether Figure 4-4 represents real or nominal dollars.**

(g) **Please indicate if the Surplus Energy prices used in preparing Figure 4-4 correspond to one of these three price forecasts.**

(h) **Please provide alternate versions of Figure 4-4, along with (in Excel format) the underlying data, for all three of the MassHub price forecasts contained on page 6 of Appendix 6.04.**

Response IR-11:

(a-b) Please refer to NSUARB IR-37 Attachment 1.

(c) Please refer to NSUARB IR-37 Attachment 1 and the Financial Model Appendix 4.01 of the regulatory filing.

(d) It was assumed that Surplus Energy would be based on MassHub pricing. Please refer to NSUARB IR-37 Attachment 1.

(e) Please refer to NSUARB IR-37 Attachment 1.

(f) Nominal dollars.

(g) Yes. Please refer to NSUARB IR-37 Attachment 1, Base Case.

(h) Please refer to NSUARB IR-37 Attachment 1.

NON-CONFIDENTIAL

Request IR-12:

PREAMBLE:

Redacted Appendix 6.04 (p. 6) includes forecasts of Base, High and Low MassHub Energy Prices from 2015 to 2040.

(a) **Please provide the amount of on-peak and off-peak Surplus Energy, on a year-by-year basis, used in the preparation of Figure 4-4.**

(b) **Please provide a detailed narrative justification for the annual quantities of Surplus Energy used to prepare Figure 4-4.**

(c) **Please describe in detail the transmission charges for delivery of Surplus Energy from Muskrat Falls which have been taken into account in estimating the Surplus Energy prices used in preparing Figure 4-4. Please ventilate these charges per operating area and charges in each jurisdiction.**

(d) **Has Nalcor Energy provided year-by-year estimates of the annual quantities of Surplus Energy that it expects to be available? In the affirmative, please provide these estimates.**

(e) **Has Nalcor Energy provided seasonal and hourly estimates of the quantities of Surplus Energy that it expects to be available, on a year-by-year basis? In the affirmative, please provide these estimates.**

(f) **Has Nalcor Energy provided any estimate of the prices it intends to obtain for its onpeak and off-peak Surplus Energy? In the affirmative, please provide these estimates.**

NON-CONFIDENTIAL

(g) Has Nalcor Energy made any commitment to NSPML or to NSPMI to provide these quantities of Surplus Energy at the prices used in preparing Figure 4-4? In the affirmative, please provide details and copies of relevant documents.

(h) Have NSPML or to NSPMI undertaken any discussions with Nalcor Energy or with any other authorized agent for the sale of Muskrat Falls power with respect to the sale of Surplus Energy? In the affirmative, please describe in detail the exchanges that have taken place and copies of relevant documents.

(i) Do NSPML or NSPI have any knowledge as to whether or not Nalcor Energy has undertaken commercial negotiations with any other potential buyers of its surplus energy from the Muskrat Falls project? If so, please provide details and copies of relevant documents, should they exist.

Response IR-12:

(a) Please refer to NSUARB IR-37 Att 1.

(b) The amounts of Surplus Energy are based on the Ventyx economic dispatch model, which uses the market prices outlined in NSUARB IR-37 Att 1. The amount of electricity purchased is the result of the model choosing energy purchases over other options such as domestic generation. The higher amounts of purchased electricity mean it was more beneficial for customers, lowering the total cost.

(c) Not applicable. The model is based upon market price not a cost plus transmission estimate.

(d-i) Please refer to response to CanWEA IR-26.

NON-CONFIDENTIAL

Request IR-13:

REFERENCE: M-2 (APPLICATION), P. 97-98

CITATION:

> **5.2 NSPML Due Diligence**
>
> An essential part of NSPML's risk management approach involves ongoing due diligence reviews of LCP Phase 1 activities. NSPML has been working with the Nalcor project team and representatives on key aspects of the LCP Phase1; including environmental assessment and planning, land rights, project controls, cost estimation labour planning, system design, engineering and project execution. This has included regular and special meetings to review project elements, as well as, workshops, where common elements of the projects are reviewed and assessed by representatives of NSPML and Nalcor. NSPML and its representatives have been provided direct access to information necessary for due diligence purposes, including individual interviews with Nalcor Project representatives to review the design and budget. Reports were reviewed by the NSPML team. These reports covered all aspects of the project design and estimate and include their findings, recommendations and conclusions.

(a) Has NSPML's Due Diligence included a review of Nalcor's estimates of the annual, seasonal and hourly energy availability of the Muskrat Falls project? In the affirmative, please provide a detailed description of the questions asked and the answers obtained.

(b) Please provide copies of any documents received by NSPML from Nalcor Energy with respect to estimates of the annual, seasonal and hourly energy availability of the Muskrat Falls project.

(c) Has NSPML's Due Diligence included a review of the Water Management Agreement that was put in place by the NL PUB with respect to Churchill River? In

the affirmative, please providea detailed description of the questions asked and the answers and supporting documents obtained.

(d) In the context of its Due Diligence, has NSPML attempted to obtain a commitment from Hydro-Quebec, either directly or through Nalcor that it would not launch a legal challenge to the Water Management Agreement? In the affirmative, please provide a detailed description of the questions asked and the answers and supporting documents obtained.

(e) Has NSPML's Due Diligence included a review of Nalcor's estimates of the annual, seasonal and hourly energy availability of the Muskrat Falls project? In the affirmative, please provide a detailed description of the questions asked and the answers and supporting documents obtained.

Response IR-13:

(a) Yes, annual energy estimates are referenced in the MHI report mentioned in Section 5 and are also available publicly at http://www.nr.gov.nl.ca/energyplan/energyreport.pdf.

(b) Please refer to CanWEA IR-013 Attachment 1.

(c) Please refer to NSUARB IR-70.

(d) No.

(e) Please refer to (a) above.

NON-CONFIDENTIAL

Request IR-14:

REFERENCE: M-2 (APPLICATION), P. 106-107

CITATION:

> Tidal energy is a promising resource in Nova Scotia, but remains under development. Scientific studies have shown that the Bay of Fundy resource alone could provide over 2,000 MW of power through extraction of kinetic energy from tidal currents. There remains limited experience regarding the costs associated with tidal energy deployments. Early estimates range from $440 – 510/MWh. With economies of scale and technology innovation, it is estimated that these costs should eventually fall within the range of $100 –150/MWh, making tidal power a competitive option to other renewable energy technologies. Emera expects that tidal power could become commercial, on a modest scale, in 2020. Tidal energy projects will likely develop incrementally over time from this point forward before eventually achieving large scale installations. The early stage of commercialization is not expected to provide the quantity of energy and capacity required. Furthermore, an expectation that tidal energy will be available commercially in 2020 is not sufficient guarantee to forego other options that will be available in 2020. For this reason, tidal has been excluded as a viable alternative to the Maritime Link Project.

(a) Please provide the source(s) for the cost estimates mentioned for tidal power. If the source documents are not available on the internet, please provide copies.

(b) Given that NSPML and NSPI expects that tidal energy will be available commercially starting around 2020, why was it not evaluated as a possible contributor to meeting NSPI's needs in the later part of the planning period?

Response IR-14:

(a) Please refer to UARB IR-48.

(b) The technology has not been demonstrated at a utility scale and reliability which would allow Nova Scotia to rely upon it for planning purposes, even in the timeframe beyond 2020, at this time. The legislative and regulatory standards relating to emissions reductions and the renewable electricity portfolio, require a certain and reliable source of energy and capacity. The customers of NS Power need to be certain that these obligations can be achieved, and maintained throughout the planning period. Organizations in the United Kingdom such as the Carbon Trust and RenewablesUK, currently estimate that tidal energy could be considered commercial around the 2020 timeframe. These forecasts are based on multiple presumptions, including expectations that there will be a significant growth in development given that the global installed capacity for tidal current energy today is approximately less than 10 MW.[1] Due to the uncertainty, tidal was not included during the planning period.

[1] Ocean Energy Systems, International Energy Agency, 2011 Annual Report. Available on website: http://www.ocean-energy-systems.org/

NON-CONFIDENTIAL

Request IR-15:

REFERENCE: M-2 (APPLICATION), PAGE 113, NOTE 41

CITATION:

[41] COMFIT expectations include 100 MW but are not included for purposes of planning to meet the RES. COMFIT projects that are built will be used as a margin of safety in meeting the future RES requirements.

Please explain why the 100 MW of wind power expected to be installed under COMFIT is not included for purposes of planning to meet the RES.

Response IR-15:

Currently under the Regulations, COMFIT projects are eligible for the purpose of RES compliance. However, it is our understanding that revisions to the Regulations are currently underway that, if granted approval by government, will prohibit COMFIT projects for consideration in renewable electricity planning. Given this uncertainty, NS Power has excluded COMFIT projects for the purpose of RES compliance planning.

NON-CONFIDENTIAL

Request IR-16:

REFERENCE: M-2 (APPLICATION), PAGE 115

CITATION:

> **The hydro resources of the province total 400 MW, and there is no pumped storage.**

Has NSPI explored the possibility of adding pumped storage to the province's existing hydro resources? In the affirmative, please provide a detailed summary of the conclusions, and a copy of the analysis.

Response IR-16:

Please refer to CA IR-44.

NON-CONFIDENTIAL

Request IR-17:

REFERENCE: M-2 (APPLICATION), P. 118

CITATION:

> Based on the screening analysis described in Section 6.1, other alternatives were eliminated for the reasons described. Two alternatives to the Maritime Link required further analysis: Indigenous Wind and Other Import. These alternatives are described in Sections 6.3.2 and 6.3.3 respectively.

PREAMBLE:

In NSPI's 2009 Integrated Resource Plan Update Report (November 30, 2009), Carbon Capture and Storage was included as a supply option with an associated range of costs (p. 11).

(a) Was Ventyx asked to examine any alternatives combining different alternate resources (e.g. some additional wind power and some additional imports) ?

(b) In the affirmative, please describe in detail the combined alternatives examined by Ventyx and the results.

(c) In the negative, please explain why no such alternatives were examined.

(d) Was Ventyx asked to examine any scenarios which included Carbon Capture and Storage? If so, please provide the assumptions and results. If not, why not?

NON-CONFIDENTIAL

Response IR-17:

Please refer to SBA IR-70.

Ventyx was provided the input assumptions for various alternatives. The Carbon capture and storage was not carried as an alternative because the cost and reliability of the technology for utility scale was not deemed sufficient to meet reliability standards at NS Power.

NON-CONFIDENTIAL

Request IR-18:

REFERENCE: M-2 (APPLICATION), P. 120, FIGURE 6-2

CITATION:

9.2% Transmission losses

(a) **Please specify the path for which the transmission losses are 9.2%. For greater clarity, please specify is these losses are from Muskrat Falls, from Soldiers' Pond, from Bottom Brook, or from some other point.**

(b) **Please specify the expected transmission losses from Muskrat Falls, from Soldiers' Pond and from Bottom Brook, including both capacity losses (at full loading) and average energy losses.**

Response IR-18:

(a) Losses are from Muskrat Falls to Woodbine and based on the agreed upon methodology.

(b) Please refer to NSUARB IR-13.

Request IR-19:

REFERENCE: M-2 (APPLICATION), P. 121, FIGURE 6-3

CITATION:

Figure 6-3 Indigenous Wind Key Assumptions

Value	Assumption
$988M	Capital Cost [derived from a levelized cost of $80/MWh for 425 MW using the assumptions below]
62.5%	Percentage of rate base funded by debt
6%	Debt rate
9.4%	Average Rate of ROE
Jan 1 2019	Commercial Operation Date
$1/MWh	Variable O&M escalated at 2%/annum, 2011$
$30/MW/yr	Fixed O&M escalated at 2%/annum, 2011$
30-35%	Capacity Factor* * Base Load: 425 MW @ 35% & 150 MW @ 32% Low Load: 250 MW @ 30% Capacity factors for incremental wind take into account estimated curtailment. An hourly profile of the forecasted system load net of wind production was produced. Curtailment was assumed in any given hour if the resulting load net of wind was less than the minimum steam generation requirement. Capacity factors were reduced to include the decrease in wind production due to the estimated curtailment.
20 years	Expected Useful Life
80%	Redevelopment Costs as a percentage of original project cost

(a) Please provide the source(s) and justification for the choice of a levelized cost of $80/MWh.

(b) Please provide the capacity cost per installed MW of wind power used in your modeling.

(c) Please provide the rational for establishing the capital cost of wind using a reverse calculation of the levelized cost per MWh.

(d) Please indicate which elements are included in the price used (equipment, construction (BOP), interconnection, required network upgrades, etc.)

(e) Is it assumed that the incremental wind development will be carried out by NSPI, or by independent wind developers under PPAs? If the latter, please explain the use of the term, "Percent of rate base funded by debt".

(f) Please provide source(s) and justify the values chosen for: 1) debt rate, 2) average rate of ROE, 3) variable O&M rate, 4) fixed O&M rate, and 5) expected useful life.

(g) Was it NSPI that produced the hourly profile of forecasted system load net of wind production? In the negative, please identify the consultant that produced this study, and provide his or her report.

(h) Please provide (in format Excel) 1) the hourly load profile net of wind production, 2) the hourly load profile (without wind production), 2) the hourly profile of wind production used, 3)the hypotheses concerning the placement and wind speeds used to produce this hourly profile of wind production.

(i) Please specify the "minimum steam generation requirement" used in the analysis, and identify the plants to which it refers.

(j) Please provide a list of the generating stations available to NSPI to serve load in Nova Scotia, indicating for each one the installed capacity, the annual fixed costs and the operating costs per MWh.

(k) **Please provide a list of NSPI's power purchase agreements, indicating for each one the principal terms.**

(l) **Please provide the justification for the choice of 80% as Redevelopment Costs, as a percentage of original project cost.**

(m) **Please provide the detailed justification for the choice of the capacity factors of 425 MW @ 35% and 150 MW @ 32% (base load) and 250 MW @ 30% (low load).**

(n) **Please provide the wind speeds used for the calculation of capacity factors.**

(o) **Please provide the wind capacity factors used, before curtailment.**

Response IR-19:

(a) Please refer to Synapse IR- 1 (b).

(b) $1985/kW 2011$.

(c) It is assumed that there is no "real" (that is no effect of inflation) change in the price of wind in the future.

(d) The price used represents the cost of installing a wind farm in Nova Scotia and connecting it to the grid. It does not include any system upgrades or back-up gas generation.

(e) It is assumed that the wind plants are developed by NS Power.

(f) Please refer to Synapse IR-14 (l).

NON-CONFIDENTIAL

(g) NSPI generated load-net-wind shape based on historical Nova Scotia load and wind generation data. Please refer to Synapse IR-2 for details.

(h) Please see answer in section (g). Please refer to SBA IR-225 (b).

(i) Please refer to SBA IR-52 (b).

(j) Please refer to CanWEA IR-1 Att 1 for the list of NS Power generating stations. Fixed and operating costs only make sense for specific scenarios and with specific fuel costs. Fuel costs can be found in the Maritime Link Project Application Appendix 6.04. Thermal fleet heat rates needed to calculate average variable costs can be found in the answer to CA IR-23.

(k) Please refer to CanWEA IR-1 for the list of Independent Power Producers. The terms of Power Purchase Agreements are confidential.

(l) There would be savings on initial development costs, utility interconnections, data gathering systems, foundations, building, access roads. It is estimated that these could be 20 percent in savings. Please refer to NSUARB IR-55 Att 1. We have not attempted to forecast the escalation in price of wind generation if demand for the machines increases.

(m) Please refer to Synapse IR-2.

(n) NS Power did not use wind speed data to calculate wind capacity factors. NS Power used historical wind generation data. Please refer to Synapse IR-5 for hourly historical wind generation data.

(o) Please refer to Synapse IR-2.

NON-CONFIDENTIAL

Request IR-20:

REFERENCE: M-2 (APPLICATION), P. 123

CITATION:

> **The results of this run showed that for the Study Period, the Maritime Link Project was less expensive than the Indigenous Wind alternative in all sensitivity cases.**

Please provide the results of this run, in Excel format, with narrative explanation adequate to understand the results.

Response IR-20:

Please refer to ELECTRONIC Attachment 1 that shows the Study period costs for the Maritime Link Project and the Indigenous Wind alternative (with and without integration costs) for all sensitivities. The Study Period costs for the Indigenous Wind alternative cases are an output from the Strategist model. Attachment 1 shows that the Maritime Link Project net present value (NPV) benefit varies between $475 million to $2.2 billion compared to the Wind alternative without integration costs added. The NPV benefit of the Maritime Link Project increases to between $1.0 billion and $3.0 billion when wind integration costs are included.

Base Load Cases	Maritime Link (ML)	Indigenous Wind No Integration Costs	Additional Cost versus ML Alternative	Indigenous Wind With Integration Costs	Additional Cost versus ML Alternative
Study Period NPV $M	16,209	17,365	1,156	18,182	1,973

Low Load Cases	Maritime Link (ML)	Indigenous Wind No Integration Costs	Additional Cost versus ML Alternative	Indigenous Wind With Integration Costs	Additional Cost versus ML Alternative
Study Period NPV $M	12,221	12,779	558	13,244	1,023

Base Load, High Power and Gas Prices	Maritime Link (ML)	Indigenous Wind No Integration Costs	Additional Cost versus ML Alternative	Indigenous Wind With Integration Costs	Additional Cost versus ML Alternative
Study Period NPV $M	18,238	20,479	2,241	21,296	3,058

Base Load, Low Power and Gas Prices	Maritime Link (ML)	Indigenous Wind No Integration Costs	Additional Cost versus ML Alternative	Indigenous Wind With Integration Costs	Additional Cost versus ML Alternative
Study Period NPV $M	14,767	15,242	475	16,059	1,292

Request IR-21:

REFERENCE: M-2 (APPLICATION), SECTION 6.4 (PAGES 128 TO 135)

PREAMBLE:

Figures 6-6, 6-9, 6-12 and 6-13 include the expression "Study Period ($M PV)", and the headings in Figure 6-14 (Summary of Alternative Costs) include the expression ($M NPV).

(a) Please explain in detail the distinction (if any) between the expression « PV » used in Figures 6-6, 6-9, 6-12 and 6-13, and the expression « NPV » used in Figure 6-14.

(b) Please explain the relationship between the data displayed in Figures 6-7, 6-8, 6-10 and 6-11 and the figures presented in Fig. 6-14 (Summary of Alternative Costs) in sufficient detail to allow the calculation of the figures in Fig. 6-14 from the data presented in Figures 6-7, 6-8, 6-10 and 6-11.

Response IR-21:

(a) The expression present value (PV) and net present value (NPV) in the cases presented have the same meaning. They are both the sum of the present values of the annual costs in 2015 dollars.

(b) Figures 6-7, 6-8, 6-10 and 6-11 show the calculation of the planning period NPV benefit of the Maritime Link Project versus the Other Import and Indigenous Wind alternatives.

Figure 6-14 shows the NPV benefit in the study period. The study period costs are the planning period costs plus end effects. Strategist calculates the end effects as a single net

NON-CONFIDENTIAL

present value to represent the operating and capital costs beyond 2040. Please refer to Synapse IR-11 (a) for the supporting spreadsheets.

NON-CONFIDENTIAL

Request IR-22:

REFERENCE: M-2 (APPLICATION), PAGE 135

CITATION:

> The sensitivity analysis provides further assurance that if the load forecast is lower than anticipated today, the Maritime Link Project is still the lowest long-term cost option for customers. Similarly, if power and gas prices are higher or lower than predicted today, the Maritime Link Project is still the lowest cost option for customers.

(a) Please provide the year-by-year power and gas prices used in the « high market price conditions » and « low market price conditions » sensitivity analyses.

(b) Please provide comparative costs for the different scenarios studied under conditions of low load growth, combined with high and low market price conditions.

(c) Were any sensitivity analyses performed to understand the implications of various levels of DSM? If so, please provide the assumptions and results. If not, why not?

(d) Were any sensitivity analyses performed to understand the implications of various cost scenarios for wind power? If so, please provide the assumptions and results. If not, why not?

(e) Were any sensitivity analyses performed to understand the implications of various cost scenarios for imported power? If so, please provide the assumptions and results. If not, why not?

PREAMBLE:

Appendix 6.03 (page 5) indicates that the Low Load forecast was based on the July-2012 GRARefresh load forecast as the starting point.

(f) Were any scenarios run with loads substantially lower than those in the July-2012 GRA-Refresh load forecast? In the affirmative, please present detailed information concerning these scenarios. In the negative, please explain why no such scenarios were studied.

Response IR-22:

(a) Please refer to Appendix 6.04 pages 3 and 5 of the Application.

(b) This analysis was not undertaken as part of the Application. Please refer to SBA-IR-233.

(c) As DSM is a component of the amount of load, the range of load scenarios studied was reflective of different levels of DSM.

(d) No. The cost used for wind power was reflective of a low price scenario. A higher price scenario was not required because Indigenous Wind was not the lowest long-term cost option at the lower price. Please refer to Synapse IR-14(i) for details to support the cost used for wind power.

(e) Yes. Please refer to Appendix 6.04 page 5 of the Application for the assumptions and Figure 6-12 and 6-13 of the Application for the results.

(f) No. Please refer to Synapse IR-13 (a).

NON-CONFIDENTIAL

Request IR-23:

REFERENCE: M-2 (APPLICATION), PAGE 135

CITATION:

> NSPML anticipates that, by 2025, it will be possible to increase the amount of electricity that can remain within Nova Scotia, which is presently modelled at a 300 MW limit. By increasing the limitation assumption from 300 MW to 500 MW, and based on NSPML's expectation that additional Nalcor energy will be available by 2025, the benefit to customers of the Maritime Link Project increases by a further $495 million, after the cost of potential transmission upgrades.

(a) Please explain why NSPML believes that, by 2025, it will be possible to increase the amount of electricity that can « remain within Nova Scotia » from 300 to 500 MW.

(b) Please explain the basis for NSPML's expectation that additional Nalcor energy will be available by 2025.

Response IR-23:

(a) Please refer to refer to EAC IR-22.

(b) The 2025 date is driven by the estimated time to study and complete the required transmission upgrades after the Maritime Link is in service. This is the constraint limiting the amount of energy that can remain in Nova Scotia prior to 2025. The constraint is not the availability of Nalcor Surplus Energy.

NON-CONFIDENTIAL

Request IR-24:

REFERENCE: M-2 (APPLICATION), PAGE 135

(a) Please provide, in an Excel worksheet, the amount of electricity that NSPML expects to be available for purchase from Nalcor for each year of the study period.

(b) Please explain, in detail, the justification for the amounts of electricity that NSPML expects to be available for purchase from Nalcor for each year of the study period.

(c) Were any sensitivity analyses performed to explore the consequences if the amounts of electricity made available by Nalcor are less than those forecast by NSPML? If so, please provide the assumptions and the detailed results of these sensitivity analyses. If not, please explain why such studies were not carried out.

Response IR-24:

(a) Please refer to NSUARB IR-37 Attachment 1.

(b) The amounts are based on economic dispatch in the Ventyx analysis. Please refer to CA IR-62. The price of the Surplus Energy Assumptions is found in NSUARB IR-37 Attachment 1.

(c) The analysis limited imports from the Maritime Link to a maximum of 300 MW (including the NS Block) during all times of the year. A lower limit was not tested because this is a conservative assumption given the expected energy availability. Please refer to CanWEA IR-26 for information about energy availability from Nalcor.

NON-CONFIDENTIAL

Request IR-25:

REFERENCE: M-2 (APPLICATION), PAGE 142

CITATION:

8.1 Energy and Capacity Agreement

Through the ECA, NS Power's customers will benefit from a new source of reliable, dispatchable, clean, renewable energy at a stable price for 35 years. The Nova Scotia Block will provide eight to ten percent of Nova Scotia's total energy requirement in a way that can be planned and dispatched to serve customers in a manner not much different from NS Power's existing hydro systems. This energy source will further diversify the portfolio of energy options available to the Province and help NS Power provide long-term rate stability for customers.

(a) Please indicate, in $/MWh, the stable price at which NS Power's customers will obtain energy through the ECA for 35 years.

(b) Please indicate in detail to what extent the Nova Scotia Block can be dispatched to serve customers, specifying all limitations to its dispatchability. Also indicate any non-energy payments (ie: capacity or reserve payments) that will be made and describe their structure.

Response IR-25:

(a) Please refer to LPRA IR-1.

(b) Please refer to the Energy and Capacity Agreement Schedule 5 Section 2 for the details on dispatching the NS Block. There are no separate payments for the capacity or reserve in the Agreements.

NON-CONFIDENTIAL

Request IR-26:

REFERENCE: M-2 (APPLICATION), P. 143-144

CITATION:

> As the system operator in Nova Scotia, NS Power is in the best position to fulfill the transmission obligations set out in the NSTUA, which include firm and contingent firm NSPML transmission service for the Nalcor Surplus Energy. Based on NSTUA requirements and expected quantities of Nalcor Surplus Energy, NS Power is expected to incur capital upgrade, maintenance and redispatch costs associated with providing a path for the Nalcor Surplus Energy from the interconnection point with the Maritime Link at Woodbine through to the Nova Scotia/New Brunswick border.
>
> Pending more detailed study and evolution of transmission infrastructure, Figure 8-1 lists the capital projects associated with the transit of Nalcor Surplus Energy through Nova Scotia, and for which NS Power has indicated it will seek regulatory approval consistent with current rules for capital filings.

(a) Please specify the expected annual quantities of Nalcor Surplus Energy, in both MW and MWh per year, for each year of the agreements.

(b) Were these expected annual quantities of Nalcor Surplus Energy provided by Nalcor Energy? In the affirmative, please provide copies of the documents and/or communications in which these amounts were provided. In the negative, please explain in detail the methodology used by NSPI or NSPML to estimate these quantities.

(c) **Are the capital projects mentioned in Figure 8-1 sufficient to allow the transmission of all of the Nalcor Surplus Energy to the New Brunswick border**?

Response IR-26:

(a) The following table represents the total energy (MWh) of imports from the Maritime Link in the Base Load case to 2040. For modeling purposes, the ML was limited to no more than 300 MW purchase capability from the ML and therefore no hour exceeds 300 MW less the NS Block.

ML Case - Economy Energy Purchases from NFLD and NB

	ML Base Load Case Economy Energy from NFLD
	GWh
2015	0.0
2016	0.0
2017	282.2
2018	1287.9
2019	1289.5
2020	1281.4
2021	1307.5
2022	1391.5
2023	1528.7
2024	1540.6
2025	1583.3
2026	1583.2
2027	1597.5
2028	1597.5
2029	1653.1
2030	1607.7
2031	1624.8
2032	1640.5
2033	1672.4
2034	1709.7
2035	1664.0
2036	1705.9
2037	1708.8
2038	1716.7
2039	1724.0
2040	1732.0

(b) Nalcor has available the Surplus Energy from the Muskrat Falls project, which is 40 percent of the 4.93 TWh annual production, which is approximately 2TWh. In

NON-CONFIDENTIAL

addition, Nalcor has available 300 MW of recall energy from the Upper Churchill, which it will now have access to market through existing routes and the Maritime Link. In 2041, the Upper Churchill reverts to ownership of Newfoundland and Labrador.

(c) Yes, there are no further upgrades expected to be required.

NON-CONFIDENTIAL

Request IR-27:

REFERENCE: M-2 (APPLICATION), P. 145

CITATION:

> **The NSTUA requires Nalcor to pay the applicable NSTUA tariff rate for transmission of the Nalcor Surplus Energy, which tariff rate is a proxy for the NS Power OATT tariff rate, but billed on an as used basis. Based on projections of Nalcor Surplus Energy, it is expected that the transmission fees paid by Nalcor (which will be provided to NS Power pursuant to the NS Power-NSPML Agreement) during the term will offset the associated capital expenditures, redispatch costs, and anticipated system maintenance costs resulting from the Nalcor Surplus Energy flowing through Nova Scotia. Due to transmission constraints in the early years of the transactions, the costs of providing the transmission services may not initially be fully covered by the transmission revenues, though they are expected to cover the capital expenditures, redispatch costs, and anticipated system maintenance costs over the term of the agreement.**

(a) Please describe in detail the transmission constraints in the early years of the transactions.

(b) Please indicate in detail when and how these transmission constraints will be alleviated.

(c) Please indicate the capital costs of the investments that will be required to alleviate these transmission constraints.

(d) Please indicate in detail how, and to what extent, these capital costs have been integrated into the Alternatives Analysis.

(e) Please indicate in detail whether, and to what extent, these or similar investments would be required for the Other Import scenario.

(f) Please indicate in detail whether, and to what extent, the capital costs of these investments have been integrated into the costs of the Other Import scenario.

Response IR-27:

(a) Current limits:

Transmission Corridors	**Summer**		**Winter**	
Arm is the non-SPS Limit	Arm	Limit	Arm	Limit
Hastings From (150 MW unit targeted on SPS)	575	705	575	705
Main At Hastings (150 MW unit targeted on SPS)	550	680	550	680
Cape Breton Export (120 MW unit targeted on SPS)	500	600	tba	tba
Cape Breton Export (150 MW unit targeted on SPS)	500	900	600	900
Onslow Import (150 MW unit targeted on SPS)	875	975	875	975
Cape Breton Export (2nd 120 MW unit targeted on SPS)	600	700	tba	tba
Onslow Import (2nd 150 MW unit targeted on SPS)	975	1025	975	1025

(b-c) Nova Scotia is subject to declining air emissions limits across its generating fleet, the effect of these caps will be to limit the dispatch of coal generation as a source of energy in the future. The Lingan units are forecast to run less in the future leaving the transmission system that provides a path through Nova Scotia free more often.

(d-f) Please refer to SBA IR- 118. Capital costs associated with the Nalcor Surplus Energy are anticipated to be covered by the associated transmission revenues. Known forecast costs, including system upgrades and capital costs, associated with the Other Import case have been included in the Alternatives Analysis.

NON-CONFIDENTIAL

Request IR-28:

REFERENCE: M-2 (APPLICATION), P. 146

CITATION:

> As contained in the NBTUA and MEPCO TRA, Emera has an obligation to provide a transmission path through New Brunswick for the Nalcor Surplus Energy. If Emera is unable to provide this path through New Brunswick in accordance with the terms of these agreements, Nalcor can require Emera to purchase the energy that Nalcor cannot get through the New Brunswick Transmission system. Due to the flow of this energy (via the Maritime Link), Nova Scotia is in the best position to provide an outlet for this potentially stranded energy.
>
> As part of the Maritime Link Project and subject to system reliability considerations, NS Power will take such energy at a cost equivalent to the avoided cost of backing down the applicable amount of generation and/or turning back an alternate import supply. This

(a) Please explain in detail what steps Emera is obligated to take to attempt to provide a transmission path through New Brunswick for the Nalcor Surplus Energy.

(b) Please indicate in detail the steps Emera has taken, and intends to take, in order to provide a transmission path through New Brunswick for the "potentially stranded" Nalcor Surplus Energy.

(c) Please confirm that, if NS Power takes « potentially stranded energy » at the avoided cost of backing down generation or or turning back an alternate import supply, this price could be lower than the price that could have been obtained in New England or New York. If this statement is incorrect, please explain in detail why it is incorrect.

NON-CONFIDENTIAL

(d) Are there provisions in the Agreements to ensure that, by failing to provide a transmission path through New Brunswick, Emera cannot obtain access to stranded Nalcor Surplus Energy at a price lower than the price Nalcor could have obtained in New England or New York? If so, please identify the relevant provisions.

Response IR-28:

(a-b) The specific obligations assumed by Emera with respect to the transmission rights through New Brunswick are set out in detail in the New Brunswick Transmission Utilization Agreement (NBTUA) as found in Appendix 2.07 of the Application**.** Under the NBTUA, Emera has agreed to make available to Nalcor certain transmission rights (220 MW to 260 MW during the months of April to October, inclusive) held by it in connection with the ownership of the Bayside Generating Station in Saint John, N.B., which rights expire in 2021, at which time Emera has renewal rights for an additional five years to March 31, 2026. If those rights are not available to Nalcor, and in any event upon expiry of the Bayside Rights, Emera has agreed to use commercially reasonable efforts to obtain transmission rights that are equivalent in all material respects to the Bayside Rights.

(c) The statement is correct.

(d) Nalcor has the right to require Emera to purchase such stranded energy at defined market prices if Emera doesn’t provide the transmission service for any reason other than force majeure. However, there are no specific provisions prohibiting Nalcor from selling the energy to Emera at a price lower than the market prices set out in the NBTUA.

NON-CONFIDENTIAL

Request IR-29:

REFERENCE: M2(vi), App. 6.02, p. 9

CITATION 1:

> **While NSPI has not attempted to forecast renewable electricity produced under enhanced net metering,it has been provided with an estimate by government for 100 MW of COMFIT generation. NSPI foreseesCOMFIT projects coming online between 2014 and 2018, <u>which will aid in achieving the 2015 and 2020 RES requirements</u>. Additionally, tidal generation could contribute to the renewables mix in the coming decades.**

CITATION 2:

> **[41] COMFIT expectations include 100 MW but are not included for purposes of planning to meet the RES. COMFIT projects that are built will be used as a margin of safety in meeting the future RES requirements.**

(a) Please explain the apparent contradiction between the statement that COMFIT projects « will aid in achieving the 2015 and 2020 RES requirements » and the statement in the Application that they « are not included for purposes of planning to meet the RES ».

(b) Please explain why, if « tidal generation could contribute to the renewables mix in the coming decades », no tidal generation is included in either the base case or any of the alternatives studied.

Response IR-29:

(a) Please refer to CanWEA IR-15, and refer to the January 17, 2013 amendments to the Nova Scotia Renewable Electricity Standard Sections 6 (3) and 6A(3) at the provided link:

http://gov.ns.ca/just/regulations/regs/elecrenew.htm

(b) NSPML and NS Power remain optimistic about the future of tidal generation. The commercialization of tidal technology is progressing. Present forecasts for the cost of tidal generation suggest that some improvement is necessary before tidal could be expected to compete with other options. Please refer to CanWEA IR-14 and NSUARB IR-47.

NON-CONFIDENTIAL

Request IR-30:

REFERENCE: M2(vi), App. 6.02, Table 2.3, p. 10

PREAMBLE:

The table presents installed wind capacity and additional wind capacity required in MW.

Please present Table 2.3 in terms of annual energy.

Response IR-30:

Table 2.3 of Appendix 6.02 expressed as annual energy.

	No ML	**No ML**	**ML**	**No ML**	**ML**
Scenario	**Low Load**	**Base Load**	**Base Load**	**Base Load**	**Base Load**
	RES 2020	**RES 2020**	**RES 2020**	**RES 2040**	**RES 2040**
Existing NSPI & IPP Wind (GWh)	972	972	972	972	972
REA Procurement (GWh)	353	353	353	353	353
COMFIT (GWh)	300	300	300	300	300
Additional Wind Capacity Required (GWh)	644	1207	0	1665	0
Total Wind Generation (GWh)	**2269**	**2832**	**1625**	**3290**	**1625**

NON-CONFIDENTIAL

Request IR-31:

REFERENCE: M2(vi), App. 6.02, p. 12

CITATION:

> **The Nova Scotia Environment Act and The Canadian Environmental Protection Act have imposed increasingly stringent emission restrictions that limit the emission of carbon dioxide, sulphur dioxide, nitrogen oxides and mercury from power plants. These restrictions limit the dispatch of coal fired units and reducing unit capacity factors to below 10% in comparison with historical operating capacity factor of 80% to 90% for these units.**

(a) Please provide a list of Nova Scotia's coal fired units, indicating for each its nameplate capacity and its most recent capacity factor.

(b) Why would NSPI choose to operate all of its coal units at a capacity factor of 10%, rather than retiring some of them in order to operate the others at a higher capacity factor?

Response IR-31:

(a) Please refer to CanWEA IR-1 Attachment 1 for coal fired unit capacities.

Unit capacity factors:

	2009 (%)	**2010 (%)**	**2011 (%)**	**2012 (%)**
Lingan 1	78	64	71	62
Lingan 2	67	65	59	32
Lingan 3	70	69	57	47

NON-CONFIDENTIAL

	2009 (%)	2010 (%)	2011 (%)	2012 (%)
Lingan 4	80	72	64	66
Tufts Cove 1	38	82	76	65
Tufts Cove 2	57	76	77	53
Tufts Cove 3	53	51	68	51
Tufts Cove 6	-	-	1	45
Trenton 5	54	57	50	21
Trenton 6	86	77	89	83
Point Aconi	85	81	77	78
Point Tupper 2	82	88	49	64

(b) The statement was a reflection of the forecasted trend for coal units out into the future. NS Power would not run all of its coal units at 10 percent capacity factor and would as suggested retire low capacity factor units to make way for higher utilization, lower emitting, firm capacity, or in the case of the Maritime Link, firm capacity imports. NS Power is required to meet firm load plus a 20 percent planning reserve margin. Accordingly, retirement of firm generation will trigger the need for replacement capacity.

NON-CONFIDENTIAL

Request IR-32:

REFERENCE: M2(vi), App. 6.02, p. 15

CITATION:

> **It has been estimated that the cost of providing additional reserves because of wind generation is around $8-$16 per MWh of wind generation16. (Note 16: Committee on Climate Change 2011)**

Please file a copy of the Committee on Climate Change report referred to, and provide a page reference for footnote 16.

Response IR-32:

A hyperlink is provided for this report in the Bibliography of Appendix 6.02. Please refer to CA IR-28 for the requested page reference.

Request IR-33:

REFERENCE: M2(vi), App. 6.02, Figure 3.3, p. 24

(a) Was the sample 48-hour period shown (Feb. 9-10, 2012) randomly selected, or is it a period specifically chosen to highlight the ramping issue?

(b) Are the system load and wind generation curves in Figure 3.3 drawn to the same scale?

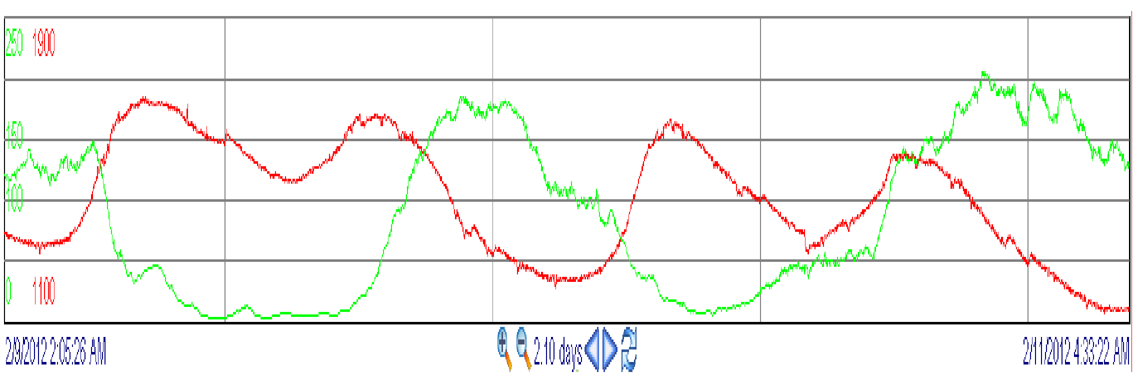
(c) Please provide a copy of this figure indicating the scale(s) of the y-axis.

Response IR-33:

(a) The period was selected to show the full range of interaction between load and wind generation trends, both complementary and contrary.

(b) No.

(c) Wind Generation (Green Curve): Scale 0 – 250 MW
System Load (Red Curve): Scale 1100 MW – 1900 MW



NON-CONFIDENTIAL

Request IR-34:

REFERENCE: M2(vi), App. 6.02, p. 24-25

CITATION:

> **Increased ramp rates and the uncertainty associated with wind generation forecasts can make the task of balancing demand and supply very challenging. NSPI conducted an analysis to better understand the possible system ramp rates that could be encountered under high levels of wind penetration, and found that the load net of wind ramping requirements are consistently higher than the load before modification by wind.**

Please provide a copy of the full NSPI analysis of ramp rates under high levels of wind penetration.

Response IR-34:

Please refer to SBA IR-225 Attachment 1, filed electronically.

NON-CONFIDENTIAL

Request IR-35:

REFERENCE: M2(vi), App. 6.02, p. 27

CITATION 1:

> **The fleet of hydro power plants (381 MW as of 201224) in Nova Scotia, which play an important role in serving the ramping needs and providing operating reserve, may not be sufficient to fill the ramping deficit created by marginalization of the coal fleet. Almost all of the hydro power facilities are run-of-river systems with limited storage, and none have sufficient storage (with the possible exception of the Mersey) to guarantee year round operation. In years where runoff from precipitation is below average, many of the hydro systems will be shut down as operators protect remaining storage in headponds for emergency use (reserve). Moreover, operational flexibility is limited on some hydro systems by stringent operating licenses which impose restrictions on dispatch for periods up to six months. In addition, hydro power plants will also need to be used for providing energy towards meeting the RES requirements. Due to all of these factors, the ability of hydro power plants to provide ramping support will be significantly limited. (Note 24: Nova Scotia Power Inc. 2012)**

CITATION 2 (M-2, p. 142):

> **8.1 Energy and Capacity Agreement**
>
> **Through the ECA, NS Power's customers will benefit from a new source of reliable, dispatchable, clean, renewable energy at a stable price for 35 years. The Nova Scotia Block will provide eight to ten percent of Nova Scotia's total energy requirement in a way that can be planned and dispatched to serve customers in a manner not much different from NS Power's exisiting hydro system. This energy source will further diversify the portfolio of energy options available to the Province and help NS Power provide long-term rate stability for customers.**

(a) Please file a copy of NSPI's « 10 Year System Outlook Report 2012-2021 » (note 24) and provide a page reference for the footnote.

(b) Please quantify the ramping capability of the hydro fleet (on a seasonal basis, if appropriate).

(c) Please specify which hydro systems are subject to the « stringent operating licences described, and indicate to the licence's effect on ramping capability for each.

(d) Please explain why the fact that energy from hydro plants is used to meet RES requirements affects their ramping capabilities.

PREAMBLE:

Citation 2 states that the Nova Scotia Block "can be planned and dispatched to serve customers in a manner not much different from NS Power's existing hydro systems, but Citation 1 indicates that the dispatchability of NS Power's existing hydro systems is extremely limited.

(e) Please reconcile the statements in Citation 1 and Citation 2 with respect to the dispatchability of the Nova Scotia Block.

Response IR-35:

(a) Please refer to Attachment 1, Section 4.

(b) Please refer to CA IR-36 Attachment 2 CONFIDENTIAL for hydro system ramping capability.

(c) Please refer to CA IR-36 Attachment 2 CONFIDENTIAL for hydro system parameters including key operational constraints.

(d) The traditional use of hydro facilities has been to peak, shave or reduce on peak cost of service by delivering the electricity at the most advantageous time to reduce the cost of generation, however that has limitations when the same resources are being used to provide back up for intermittent sources or is restricted due to operating permit limitations or water levels being maintained. The ramp capability of a hydro unit is quite favorable when not restricted due to one of these reasons. The ramping or load following versus peak-shaving mode of operation is a less efficient mode of operation for hydro (although still the lowest cost when utilized) and will produce lower levels of output for the same volume of water.

(e) The NS Block will have dispatch and regulation capability and act similar to a hydro unit which does not have the same operating restrictions. The VSC converter technology provides a fast responsive control capability for system operators.

10 Year System Outlook
2012-2021
Report

June 29, 2012

Nova Scotia
POWER
An Emera Company

Table of Contents

List of Tables

Page

Appendices

1.0 INTRODUCTION

Consistent with the 3.4.2.1[1] Market Rule requirements and Nova Scotia Utility and Review Board (Board, UARB) direction provided following Nova Scotia Power (NS Power, the Company) annual filings of its 10 Year System Outlook Report, the 2012 Outlook contains the following:

1. A summary of the NS Power load forecast employed in the Outlook;
2. An update on the Demand Side Management (DSM) program undertaken by Efficiency Nova Scotia Corporation (ENSC) and included in the Company's forecasts;
3. A summary of generation expansion anticipated for facilities owned by NS Power and others;
4. A discussion of transmission planning issues, including comment on related issues raised in the Board's letter;
5. Identification of transmission-related capital projects currently in the Transmission Expansion Plan;
6. An overview of potential transmission development scenarios pending the outcome of generation development, inside and outside of Nova Scotia.

The basis for the 2012 Outlook is the assumptions employed in the 2009 Integrated Resource Plan (IRP) Update. The assumptions were developed by NS Power and the Board's consultants, with input from IRP stakeholders and subsequently modified to reflect legislative or regulatory certainties which have arisen since then.

1 The NSPSO system plan will address: a) transmission investment planning; b) DSM programs operated by ENSC or others; c) NS Power generation planning for existing Facilities, including retirements as well as investments in upgrades, refurbishment or life extension; d) new Generating Facilities committed in accordance with previous approved NSPSO system plans; e) new Generating Facilities planned by Market Participants or Connection Applicants other than NS Power, and f) requirements for additional DSM programs and / or generating capability (for energy or ancillary services).

2.0 LOAD FORECAST

The NS Power load forecast provides an outlook on the energy and peak demand requirements of in-province customers. The load forecast forms the basis for the investment planning and overall operating activities of the Company.

The forecast is based on analyses of sales history, economic indicators, customer surveys, technological and demographic changes in the market and the price and availability of other energy sources. Weather conditions, in particular temperature, affect electrical energy and peak demand. The forecast is based on the 10-year average temperatures measured in the Halifax area of the Province. The values presented in the tables below reflect the effects of current and proposed efficiency and Demand Side Management programs.

Table 1 shows historical and forecast net annual energy requirements. NS Power remains a winter peaking utility and accordingly, the highest period of energy consumption in Nova Scotia is December through February due to the electric heating load and relatively light air conditioning load in the Province. The Net System Requirement (NSR) for the province had grown at an average of 0.9 percent per year in the five year period from 2003-2008 and declined by 3.7 percent in 2009 primarily due to the economic recession that affected sales, primarily in the industrial sector. Load growth began to recover in 2010. However, it dropped by 2.1 percent in 2011 largely due to production changes at two paper mills. The forecast load for 2012 and onward is lower than recent years due to the assumption that the largest paper mill will remain closed indefinitely, removing over 1,500 GWh from the annual load. NSR is forecast to decline an average of 0.3 percent annually over the next 10 years with the effects of Demand Side Management programs. Without the effects of these DSM programs, the NSR is forecast to grow an average of 1.0 percent annually.

NS Power is also cognizant in its planning of the potential for new load which could emerge from shifts away from fossil fuels for transportation and other economic uses of electricity which could increase in time.

NS Power also forecasts the peak hourly demand for future years. This process uses forecast energy requirements and expected load shapes (hourly consumption data) for the various customer classes. Load shapes are derived from historical analysis, adjusted for expected changes (e.g. customer plans to add major equipment). Table 2 shows the historical and forecast net system peak.

Table 1 – Total Energy Requirement with Future DSM Program Effects[2]

Year	Net System Requirement (GWh)	Annual Change (%)
2002	11,501	1.8
2003	12,009	4.4
2004	12,388	3.2
2005	12,338	-0.4
2006	10,946	-11.3
2007	12,640	15.5
2008*	12,539	-0.8
2009*	12,073	-3.7
2010*	12,158	0.7
2011*	11,908	-2.1
2012F	10,840	-9.0
2013F	10,721	-1.1
2014F	10,710	-0.1
2015F	10,694	-0.1
2016F	10,668	-0.2
2017F	10,646	-0.2
2018F	10,617	-0.3
2019F	10,624	0.1
2020F	10,624	0.0
2021F	10,604	-0.2
2022F	10,562	-0.4

Note:
Actual growth rates for 2006 and 2007 were -11.3 percent and 15.5 percent respectively, which reflects one of NS Power's largest customers having a temporary shutdown and remaining closed for nine months in 2006. In 2007 the plant returned to normal full load operations.

*Results for the years 2008 to 2011 contain the effects of past DSM programs.

[2] Data sourced from the 2012 NS Power Load Forecast, filed with the UARB on April 30, 2012.

Table 2 – Coincident Peak Demand with Future DSM Program Effects[3]

Year	Net System Peak MW	Annual Change %	Non-Firm Peak MW	Annual Change %	Firm Peak MW	Annual Change %
2000	2,009	6.6	412	33.3	1,597	1.3
2001	1,988	-1.0	369	-10.4	1,619	1.4
2002	2,078	4.5	348	-5.7	1,730	6.9
2003	2,074	-0.2	291	-16.4	1,783	3.1
2004	2,238	7.9	377	29.6	1,861	4.4
2005	2,143	-4.2	392	4.0	1,751	-5.9
2006	2,029	-5.3	386	-1.5	1,644	-6.1
2007	2,145	5.7	381	-1.3	1,764	7.3
2008*	2,192	2.2	352	-7.5	1,840	4.3
2009*	2,092	-4.5	268	-23.9[4]	1,824	-0.8
2010*	2,114	1.0	295	10.0	1,820	-0.3
2011*	2,168	2.5	265	-10.2	1,903	11.4
2012F	2,117	-2.4	146	-44.8	1,971	-2.7
2013F	2,098	-1.1	141	-3.8	1,958	-0.9
2014F	2,093	-0.2	140	-0.4	1,953	-0.2
2015F	2,084	-0.4	139	-0.7	1,945	-0.4
2016F	2,073	-0.5	138	-0.6	1,935	-0.5
2017F	2,070	-0.1	137	-0.9	1,933	-0.1
2018F	2,064	-0.3	136	-0.7	1,928	-0.3
2019F	2,065	0.0	135	-0.8	1,930	0.1
2020F	2,064	0.0	134	-0.7	1,930	0.0
2021F	2,060	-0.2	133	-0.9	1,928	-0.1
2022F	2,053	-0.4	132	-0.7	1,921	-0.4

* Results for the years 2008 to 2011 contain the effects of DSM programs.
* Figures for the year 2012 have been updated since the 2012 Load Forecast was filed with the Board on April 30, 2012.

[3] Data sourced from the 2012 NS Power Load Forecast, filed with the UARB on April 30, 2012.
[4] Decrease due to economic recession affecting primarily industrial customers.

3.0 DEMAND SIDE MANAGEMENT FORECAST

The table below summarizes annual projected demand and energy savings included in the Load Forecast in Section 2.0.

Table 3 – Demand Side Management Forecast *

Year	Cumulative Demand Savings (MW)	Cumulative Energy Savings (GWh)
2012	27	150
2013	50	293
2014	73	435
2015	98	580
2016	125	728
2017	153	873
2018	181	1015
2019	209	1156
2020	237	1298
2021	265	1440
2022	293	1581

Note: Cumulative Demand Savings include interruptible customers and includes the effects of the LED Streetlight Program

*The DSM Forecast values represent the difference between the "With DSM" and "Without DSM" load forecast values of the April 2012 Load Forecast.

In 2010, the responsibility for energy efficiency and conservation programs was transferred from NS Power to the new DSM Administrator, Efficiency Nova Scotia Corporation (ENSC). In early 2012, ENSC filed an application with the Board seeking approval for an overall expenditure of $42.3 million in 2013 and $43.1 million in 2014 associated with the 2013-2014 DSM Plan. A decision from the UARB was issued June 4, 2012.

The comparable DSM numbers submitted by ENSC in its 2013 DSM application can be found in Figure 4.8 of its application:

Table 3A – Cumulative Load Reduction Targets and Results 2008-2017

Year	Result GWh	Result MW
2008[a]	21	5
2009[a]	86	15
2010[a]	168	31
2011[b]	384	65
2012[c]	618	109
2013[d]	773	139
2014[d]	941	170
2015[d]	1123	203
2016[e]	1306	236
2017[e]	1486	269

[a] verified results

[b] verified results and includes reductions outside DSM programs

[c] estimate based on approved Plan and includes reductions outside DSM programs

[d] estimate based on approved Plan and includes savings outside DSM programs

[e] estimate based on outlook beyond approved Plan and includes reductions outside DSM programs (from the adoption of new codes and standards)

As can be seen, NS Power's forecasted DSM savings differ from those found in ENSC's filing. The resulting differences between NS Power's forecasting methodology and ENSC's DSM savings are described below:

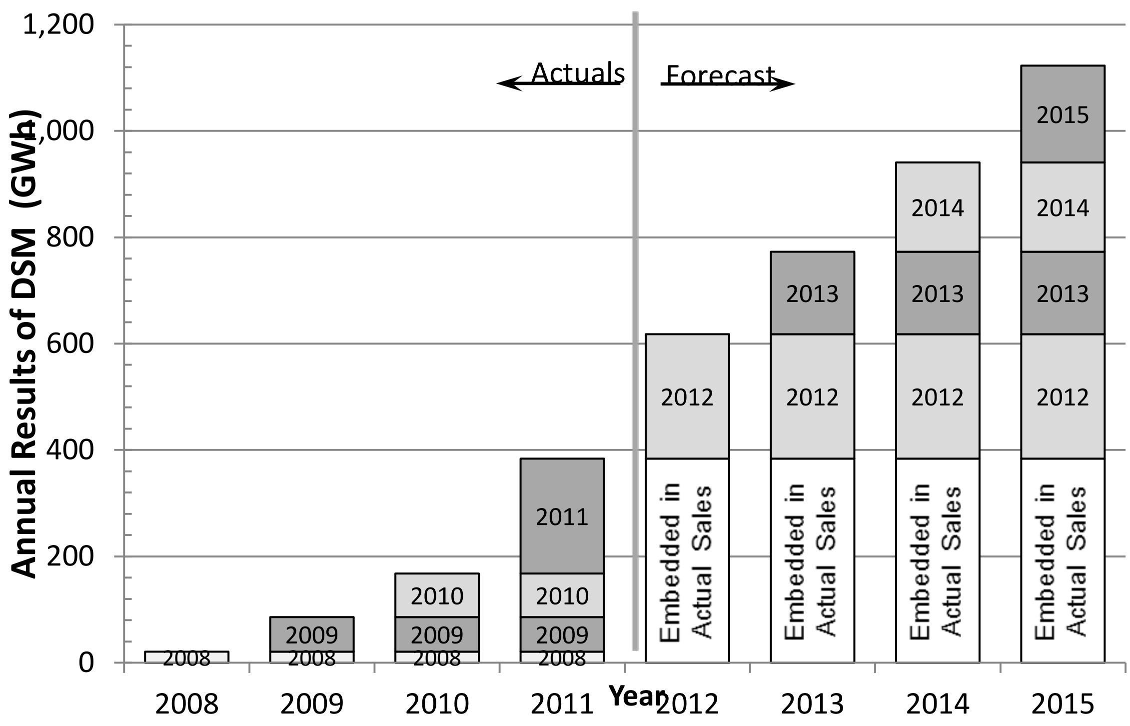
- Since this is a forecast, the effects of past DSM programs are embedded in the actual sales trend. This forecast describes only the influence of future DSM programs on projected load. Other related documents may present the accumulated DSM savings beginning with the program inception in 2008, rather than from the present as this forecast describes. This difference in approach is demonstrated in Figure 1 which shows the cumulative results of the annual DSM programs for historical and forecast periods.

- Since the DSM programs cannot all be implemented in the first day of the year, but will instead be gradually implemented throughout the calendar year, this forecast makes an allowance for this installation rate. The forecast assumes that 50 percent of the DSM target will be attained by year-end and the remaining 50 percent of that plan will be achieved in the following year. These calculations are shown below in Figure 2. NS Power does assume that the DSM target will be fully achieved, but that there will be a slight delay before the savings are fully realized.

- At the time of preparation of this load forecast, the 2013 DSM plan from ENSC was not yet complete. To proceed with this forecast development, draft DSM targets from preliminary discussions with ENSC were used. These DSM numbers will differ slightly from the final DSM conservation targets filed by ENSC.

The figures below show the annual DSM adjustments using ENSC's results from Table 3A, and the methodology employed with the NS Power load forecast assumptions. It results in a year 2012 adjustment that is different from the NS Power adjustment by only 2 GWh (once the assumed savings attributable to the LED Streetlight Program are included). For the DSM demand calculation, the results are similar, with the NS Power forecast savings within 2 MW of the savings calculated using the ENSC results of Table 3A. Once adjusted for methodological differences, the results of both NS Power and ENSC are similar.

Figure 1 Cumulative Effects of Annual DSM Savings



**Based on results data from Figure 4.8 ENSC 2013-2015 DSM Filing (E-ENSC-R-12)*

The DSM targets and calculated 2012 load forecast adjustments are shown in Figure 2 below.

Figure 2 DSM Adjustments for 2012 Load Forecast

Source	Calendar Year	DSM Target GWh	NS Power Forecast DSM Methodology: 50% of current Year Plan GWh	50% of prior Year Plan GWh	Realized Annual Increment GWh	Cumulative Future DSM Savings GWh
2011 DSM Plan	2011	158				
2012 DSM Plan	2012	134	67	79	146	**146**
Preliminary 2013 DSM Plan Estimates	2013	133	67	67	134	**280**
	2014	133	67	67	133	**413**
	2015	138	69	67	136	**549**
	2016	140	70	69	139	**688**
	2017	142	71	70	141	**828**
	2018	142	71	71	142	**970**
	2019	142	71	71	142	**1112**
	2020	142	71	71	142	**1253**
	2021	142	71	71	142	**1395**
	2022	142	71	71	142	**1537**

Note: Does not include the effects of assumed savings attributable to the LED Streetlight Program.

4.0 GENERATION RESOURCES

4.1 Existing Generation Resources

Nova Scotia's generation portfolio is comprised of a mix of fuel types that includes coal, petroleum coke, light and heavy oil, natural gas, wind, tidal and hydro. In addition, NS Power purchases energy from independent power producers located in the province and imports power across the NS Power/NB Power inter-tie. Table 4 lists NS Power's generating stations/systems along with their fuel types and net operating capacities based on the assumptions used in the 2009 IRP Update. It has been updated to include changes and new additions effective January 2012.

Table 4 – 2012 Generating Resources[5]

Plant/System	Fuel Type	Winter Net Capacity (MW)
Avon	Hydro	7.6
Black River	Hydro	23
Lequille System	Hydro	26
Bear River System	Hydro	39.5
Roseway	Hydro	1.6
Tusket	Hydro	2.7
Mersey System	Hydro	42
St. Margaret's Bay	Hydro	10
Sheet Harbour	Hydro	10
Dickie Brook	Hydro	2.5
Wreck Cove	Hydro	212
Annapolis Tidal*	Hydro	3.7
Fall River	Hydro	0.5
Total Hydro		**381.1**
Tufts Cove	Heavy Fuel Oil/Natural Gas	321.0
Trenton	Coal/Pet Coke/Heavy Fuel Oil	307.0
Point Tupper	Coal/Pet Coke/Heavy Fuel Oil	152.0
Lingan	Coal/Pet Coke/Heavy Fuel Oil	617.0
Point Aconi	Coal/Pet Coke & Limestone Sorbent (CFB)	171.0
Total Steam		**1568.0**

[5] Data sourced from 2009 IRP Update Assumptions

Plant/System	Fuel Type	Winter Net Capacity (MW)
Tufts Cove Units 4,5 & 6	Natural Gas	146.7
Total Combined Cycle		**146.7**
Burnside**	Light Fuel Oil	99.0
Tusket	Light Fuel Oil	24.0
Victoria Junction	Light Fuel Oil	66.0
Total Combustion Turbine		**189.0**
Pre-2001 Renewables	Independent Power Producers (IPPs)	25.8
Post-2001Renewables (firm)***	Independent Power Producers	72.9
NS Power wind (firm)***	Wind	28.8
Total IPPs & Renewables		**127.4**
Total Capacity		**2412.2**

*Capacity of Annapolis Tidal Unit is based on an average performance level at peak time. Nameplate capacity (achieved at low tide) is 19.4 MW.

**Burnside unit #4 (winter capacity of 33 MW) is presently unavailable but it is assumed to be returned to service in 2015.

*** The assumed firm capacity value of wind reflects the firm capacity contribution based on a three year average of actual capacity factor during peak hours and the annual forecasted value (as per formula agreed on by NS Power and the Renewable Energy Industry Association of Nova Scotia and as employed in NS Power 2009 IRP Update modeling). For short-term assessments (e.g. 18-month Load and Capacity Assessment) the assumed capacity factor may be less. These assumed capacity values are being re-evaluated in the Renewables Integration Study presently underway.

4.2 Changes in Capacity

Table 5 provides the firm Supply and Demand Side Management capacity changes per the Port Hawkesbury (PH) Biomass Project Base Case Plan (as filed with the UARB in P-128.10 April 9, 2010) over the 2012-2022 time period. This Plan is based on the 2009 IRP Update assumptions and analysis, modified to include the PH Biomass Project. Capacity additions have been further updated to reflect renewable energy requirements set forth in the Province’s Renewable Electricity Plan in April 2010. For DSM, the amounts shown are reductions in forecast firm demand for the period which makes additional capacity available. Amounts shown as Hydro include relatively small capacity additions to NS Power’s existing generation fleet. The PH Biomass Project is currently registered for Energy Resource Interconnection Service (ERIS) but will be transitioned to firm capacity as a network resource through an application under the GIP coincident with the proposed retirement of a solid fuel unit in 2015. The Maritime Link Project will enable import of RES compliant hydro energy from the Muskrat Falls project in Newfoundland and Labrador which will largely achieve the incremental requirements of the 2020 Renewable Electricity Standard (RES) target of 40% renewable energy as a percentage of sales. This firm capacity import includes the assumed retirement of solid fuel unit(s) for planning purposes in order to comply with federal environmental regulations, and is subject to adjustment due to equivalency with provincial regulations.

Table 5 – Capacity Changes & DSM

New Resources 2012-2022	Net MW
DSM firm [1]	282
Contracted Wind (Firm) [2]	15.4
Community Feed-in Tariff (Firm) [3]	34.1
Hydro [4]	4.2
Biomass [5]	63
Maritime Link Import	155
Assumed Unit Retirements	-306
Total Firm Supply & Demand MW Change Projected Over Planning Period	**247.7**

Notes:

[1] DSM Firm does not include interruptible customers and differs from the Cumulative Demand Savings shown in Table 3.

[2] Contracted Wind (Firm) reflects the assumed firm capacity contribution based on a combined three year average of actual capacity factor during peak hours and the annual forecasted value (as per formula agreed on by NS Power and the Renewable Energy Industry Association of Nova Scotia and as employed in NS Power 2009 IRP Update modeling). These assumed capacity values are being re-evaluated in the Renewables Integration Study presently underway.

[3] The Community Feed-in-Tariff represents distribution-connected renewable energy projects as outlined in the Province's Renewable Electricity Plan in April 2010. The projects are assumed to be phased-in over 5 years starting in 2014. The value in the table is the assumed firm capacity value of intermittent generation for small-scale projects. For long-term planning purposes the firm capacity value in the table is based on a 34% capacity factor as estimated by the provincial government. For short-term assessments (e.g. 18-month Load and Capacity Assessment) the assumed capacity factor may be less. These assumed capacity values are being re-evaluated in the Renewables Integration Study presently underway.

[4] Hydro shown is Marshall Falls at 4.2 MW as per the 2009 IRP Update assumptions.

[5] Biomass shown includes the PH Biomass Project and a small IPP expected in-service within the 10 year period.

5.0 NEW GENERATING FACILITIES

5.1 Potential New Facilities

As of June 12, 2012, NS Power has 27 Active Transmission Interconnection Requests (1103 MW) and 128 Active Distribution Interconnection Requests (406 MW) at various stages of interconnection study. Of these, there are 9 transmission projects and 34 distribution projects that have advanced to the Combined T/D Advanced Stage Interconnection Request Queue.

Sponsors of the transmission projects have requested either Network Resource Interconnection Service (NRIS) or Energy Resource Interconnection Service (ERIS) (Distribution projects do not receive an NRIS or ERIS designation). NRIS refers to a firm transmission capacity request with the potential for transmission reinforcement upon completion of the System Impact Study (SIS). ERIS refers to a requested capacity but only to the point where transmission reinforcement will not be required. The effect of this on installed firm capacity will continue to be monitored. Results of the various interconnection studies will be incorporated into future transmission plans. Table 6 provides NS Power's Advanced Stage Interconnection Request queue as of June 12, 2012.

Table 6 – Generation Interconnection Queue

Combined T/D Advanced Stage Interconnection Request Queue

Publish Date: *Tuesday, June 12, 2012*

Nova Scotia POWER An Emera Company

Queue Order*	IR #	Request Date DD-MMM-YY	County	MW Summer	MW Winter	Interconnection Point Requested	Type	Inservice date DD-MMM-YY	Revised Inservice date	Status	Service Type	IC Identity
1 -T	8	14-Oct-03	Guysborough	13.8	13.8	L-5527B	Wind	20-Sep-12		GIA Executed	N/A	N/A
2 -T	56	19-Aug-05	Cumberland	34	34	L-5058	Wind	01-Nov-14		GIA Executed	ERIS	N/A
3 -D	153	13-Dec-07	Cumberland	4	4	37N-412	Tidal	15-May-12		GIA Executed	N/A	N/A
4 -D	168	06-Feb-09	Inverness	3.6	3.6	2C-402	Wind	12-May-13		GIA Executed	N/A	N/A
5 -D	169	06-Feb-09	Inverness	1.2	1.2	67C-411	Wind	12-May-13		GIA Executed	N/A	N/A
6 -D	170	06-Feb-09	Pictou	1.2	1.2	62N-413	Wind	12-May-13		GIA Executed	N/A	N/A
7 -D	184	13-Feb-09	Antigonish	4	4	4C-424	Wind	13-Jul-12		GIA Executed	N/A	N/A
8 -D	215	22-Oct-09	Cape Breton	2	2	81S-303	Wind	15-Sep-11		GIA Executed	N/A	N/A
9 -D	216	01-Dec-09	Annapolis	2	2	12V-302	Wind	2-Jul-12		GIA Executed	N/A	N/A
10 -D	217	01-Dec-09	Richmond	2	2	22C-404	Wind	2-Jul-12		GIA Executed	N/A	N/A
11 -D	218	01-Dec-09	Inverness	2	2	58C-403	Wind	2-Jul-12		GIA Executed	N/A	N/A
12 -D	164	30-Jan-09	Victoria	0.65	0.65	85S-401	Wind	n/a		GIA in Progress	N/A	N/A
13 -T	219	08-Apr-10	Richmond	64	64	47C	Steam	31-Dec-12		GIA Executed	ERIS	N/A
14 -T	227	26-Aug-10	Hants	10.2	10.2	L-4048	Steam	01-Sep-14		GIA in Progress	NRIS	N/A
15 -T	225	03-May-10	Pictou	60	60	L-6503	Wind	3-Mar-17		GIA Executed	ERIS	N/A
16 -T	234	14-Jan-11	Pictou	41.4	41.4	L-6503	Wind	3-Mar-17		FAC in Progress	ERIS	N/A
17 -D	236	14-Jan-11	Pictou	0.8	0.8	62N-413	Wind	12-May-13		GIA in Progress	N/A	N/A
18 -D	237	14-Jan-11	Inverness	0.5	0.5	67C-411	Wind	12-May-13		GIA in Progress	N/A	N/A
19 -D	274	10-May-11	Cape Breton	2.35	2.35	15S-303	Wind	31-Aug-12		GIA Executed	N/A	N/A
20 -D	271	24-May-11	Pictou	0.6	0.6	4C-424	Wind	13-Jul-12		GIA Executed	N/A	N/A
21 -T	131	17-Apr-07	Cape Breton	10.25	10.25	109S	wind	31-Dec-12		SIS Complete	ERIS	N/A
22 -T	360	20-Oct-11	Annapolis	18	18	70V	Wind	31-Dec-12		SIS Complete	ERIS	N/A
23 -T	362	21-Oct-11	Cumberland	12.6	12.6	92N	Wind	31-Oct-13		SIS Complete	NRIS	N/A
24 -D	288	15-Jul-11	Lunenburg	2	2	84W-301	Wind	1-Aug-13		SIS in Progress	N/A	N/A
25 -D	389	19-Dec-11	Queens	3.4	3.4	50W-412	Steam	01-Mar-13		SIS in Progress	N/A	N/A
26 -D	254	28-Mar-11	Cape Breton	4	4	3S-301	Wind	01-Jan-13		SIS in Progress	N/A	N/A
27 -D	262	11-May-11	Colchester	6	6	15N-403	Wind	31-Jul-13		SIS in Progress	N/A	N/A
28 -D	290	15-Jul-11	Lunenburg	6	6	89W-303	Wind	31-Dec-13		SIS in Progress	N/A	N/A
29 -D	319	17-Aug-11	Hants	6	6	79V-403	Wind	01-Jul-13		SIS in Progress	N/A	N/A
30 -D	346	16-Sep-11	Victoria	2	2	104S-311	Wind	01-Dec-12		SIS in Progress	N/A	N/A
31 -D	348	16-Sep-11	Yarmouth	2	2	88W-323	Wind	01-Dec-12		SIS in Progress	N/A	N/A
32 -D	341	16-Sep-11	Hants	5	5	82V-423	Wind	01-Sep-13		SIS in Progress	N/A	N/A
33 -D	333	06-Sep-11	Pictou	6.4	6.4	62N-414	Wind	31-Dec-13		SIS in Progress	N/A	N/A
34 -D	334	06-Sep-11	Pictou	1.6	1.6	56N-414	Wind	31-Dec-13		SIS in Progress	N/A	N/A
35 -D	312	08-Aug-11	Pictou	4.6	4.6	50N-410	Wind	01-Jan-13		SIS in Progress	N/A	N/A
36 -D	332	30-Aug-11	Halifax	10	10	113H-444	Wind	01-Oct-13		SIS in Progress	N/A	N/A
37 -D	256	11-Apr-11	Colchester	0.8	0.8	4N-313	Wind	31-Oct-12		SIS in Progress	N/A	N/A
38 -D	240	09-Feb-11	Halifax	3.2	3.2	20H-303	Wind	04-Apr-11		SIS in Progress	N/A	N/A
39 -D	388	02-Dec-11	Pictou	6.4	6.4	62N-413	Wind	01-Oct-13		SIS in Progress	N/A	N/A
40 -D	162	22-Dec-08	Halifax	8	8	103H-434	Wind	30-Jun-12		SIS in Progress	N/A	N/A
41 -D	282	09-Jun-11	Inverness	0.8	0.8	103C-314	Wind	01-Nov-13		SIS in Progress	N/A	N/A
42 -D	283	09-Jun-11	Guysborough	2	2	100C-422	Wind	01-Nov-13		SIS in Progress	N/A	N/A
43 -D	306	02-Aug-11	Cape Breton	0.8	0.8	15S-303	Wind	01-Jul-13		SIS in Progress	N/A	N/A
		Totals:		372.15	372.15							

Nova Scotia Power - Interconnection Request Queue: Page 4 of 4

ERIS - Energy Resource Interconnection Service
NRIS - Network Resource Interconnection Service
N/A - Not Applicable

T - Transmission Interconnection Request
D - Distribution Interconnection Request

* Note: Queue reflects current list of IR's which have established an advanced queue position per GIP/DGIP Section 4.1

All active transmission and distribution requests not appearing in the Combined T/D Advanced Stage Interconnection Request Queue are considered to be at the initial queue stage as they have not yet proceeded to the System Impact Study stage of the Generator Interconnection Procedures. Table 7 indicates the location and size of the generating facilities currently in the Generation Interconnection Queue.

Table 7 – Renewable Generation Projects Currently in the Generation Interconnection Queue

Company/Location	**Nameplate Capacity MW**
Canso Wind Energy Centre ULC in Guysborough County	13.8
Pugwash Wind Farm Inc. in Cumberland County	34
NS Power Biomass at NewPage Port Hawkesbury in Richmond County	64
IR #227 Biomass in Hants County	10.2
IR #225 Wind in Pictou County	60
IR #234 Wind in Pictou County	41.4
IR #131 Wind in Cape Breton County	10.25
IR #360 Wind in Annapolis County	18
IR #362 Wind in Cumberland County	12.6
Distribution Interconnection Requests (IRs)	107.9
Total New Facilities Nameplate Capacity	**372.15**

Included in the Advanced Stage Request Interconnection Queue is:

- 47.8 MW of wind projects that have completed the GIP process but have yet to secure a PPA;
- a 64 MW Biomass project that has completed the GIP process and is under construction;
- 60 MW of wind and 10.2 MW of biomass projects with GIA's executed or in progress and 41.4 MW of wind at the Facilities Study stage;
- 40.8 MW of wind with SIS's complete; and
- 107.9 MW of distribution wind and biomass projects that are at the System Impact Study stage (81 MW of these are COMFIT related).

5.2 Renewable Electricity Plan

In April 2010, the Nova Scotia Department of Energy (DOE) released its Renewable Electricity Plan, which sets out the Province's commitment to renewable electrical energy supply. This plan includes a legislated renewable energy requirement of 25 percent of net energy sales by 2015, as well as a goal of 40 percent by 2020. The legislation for the 2020 target received Royal Assent in May 2011. The 2015 renewable energy requirement will be met through equal participation by independent power producers and Nova Scotia Power.

In addition to these targets, the plan includes a Community-Based Feed-in-Tariff (COMFIT) for approximately 100 MW of community-owned projects connected to the distribution system and provides for enhanced net-metering for renewable projects up to 1 MW in capacity.

The Enhanced Net Metering program was initiated in July of 2011, and the implementation of the COMFIT program occurred in September of 2011. Uptake rates for the COMFIT program have been strong (over 150 Interconnection Requests > 100 kW Evaluated), while uptake for Enhanced Net Metering > 100kW has resulted in the evaluation of two Interconnection Requests.

5.3 Renewables Integration Study

NS Power has contracted GE Energy to conduct a study of the numerous possibilities for renewables integration on its electric power system to identify operational and planning challenges associated with compliance with the provincial RES. This work builds from the 2008 Nova Scotia Wind Integration Study[6] completed by Hatch Ltd. for the Nova Scotia Department of Energy. Now that the range of possibilities for RES compliance is better understood, GE can study the implications for the power system at greater granularity to identify load following and regulation needs and to better understand curtailment or other operational requirements. GE has also been requested to re-examine the capacity value assumptions that have been adopted for wind generation projects. This assessment, based on actual operating data, should provide direction for the purpose of long-term capacity planning and daily operations planning. System simulation work is presently underway and a final report is due by year end.

5.4 Other Opportunities

In addition to the above, potential developments outside of Nova Scotia (e.g. large imports), if implemented, would influence the Company's long-term resource plan in general and transmission system development, in particular. These developments continue to be monitored. Table 8 shows NS Power's Open Access Transmission Tariff (OATT) Transmission Service Queue as of April 16, 2012.

Table 8 – OATT Transmission Service Queue

OATT Transmission Service
Queued System Impact Studies
Revised June 12, 2012

Number	Project	Date & Time of Service Request	Project Type	Project Location	Requested In-Service Date	Project size (MW)	Status
4	TSR 400	July 22, 2011 1:56 PM	Point to Point	NS-NB	Jan 1, 2017	330	SIS Study in progress

5.5 Atlantic Energy Gateway

Throughout the past year, NS Power has participated in the work of the Atlantic Energy Gateway (AEG). The AEG project is a regional initiative of the federal government, the Atlantic provincial governments, electric utilities of Atlantic Canada and the system operators in New Brunswick and Nova Scotia. The objective of the AEG project is an examination of the opportunities for greater regional cooperation in the planning and operation of the Atlantic region's electric power system and what that might contribute to the promotion of renewables within the region.

6.0 RESOURCE ADEQUACY

6.1 Operating Reserve Criteria

As a member of the Maritimes Area of the Northeast Power Coordinating Council (NPCC), NS Power meets the operating reserve requirements as outlined in *NPCC Regional Reliability Reference Directory #5, Reserve.* This Criteria is reviewed and adjusted periodically by NPCC. The Criteria require that:

> Each Balancing Authority shall have ten-minute reserve available that is at least equal to its first contingency loss…and,
>
> Each Balancing Authority shall have thirty-minute reserve available that is at least equal to one half its second contingency loss.

In the *Interconnection Agreement between Nova Scotia Power Incorporated and New Brunswick System Operator (NBSO)*, NS Power and the NBSO have agreed to share the reserve requirement for the Maritimes Area on the following basis:

> The Ten-Minute Reserve Responsibility, for contingencies within the Maritimes Area, will be shared between the two Parties based on a 12CP [coincident peak] Load-Ratio Share…. Notwithstanding the Load-Ratio Share the maximum that either Party will be responsible for is 100 percent of its greatest, on-line, net single contingency, and,
>
> NSPI shall be responsible for 50 MW of Thirty-Minute Reserve.

NS Power maintains a ten minute operating reserve of 171 MW (equivalent to Point Aconi net output when on-line), of which approximately 33 MW is held as spinning reserve on the system. Additional regulating reserve is maintained to manage the variability of customer load and generation. Regulating reserve requirement has increased over the past five years with the addition of wind generation resources due to the added variability that has been introduced.

NS Power performs an assessment of operational resource adequacy covering an 18 month period twice a year (in April and October preceding the summer and winter peak capacity periods). These reports of system capacity and adequacy are posted on the NS Power OASIS site in the Forecast and Assessments section.

6.2 Planning Reserve Criteria

NS Power is required to comply with the NPCC reliability criteria. These criteria are outlined in *NPCC Regional Reliability Reference Directory #1 – Design and Operation of the Bulk Power System*[6] and states that:

> The probability (or risk) of disconnecting firm load due to resource deficiencies shall be, on average, not more than once in ten years as determined by studies conducted for each Resource Planning and Planning Coordinator Area. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation [LOLE] of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures.

NS Power maintains a capacity based planning reserve margin equal to 20 percent of its firm system load in order to comply with the NPCC criteria. To assess the resource adequacy of the system, the NBSO, as Reliability Coordinator, submits a resource adequacy review to NPCC on behalf of the Maritimes Area. This review is completed every three years with interim reviews completed annually. In the most recent comprehensive review, the *2010 Maritimes Area Comprehensive Review of Resource Adequacy*,[7] it was confirmed that the NPCC criteria would be met with a 20 percent reserve margin for the Maritimes area along with 70 MW of additional capacity provided by interconnection assistance. This confirms that the 20 percent planning reserve margin applied by NS Power is acceptable under the NPCC reliability criteria.

[6] https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx
[7] https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx

6.3 Load and Resources Review

The ten year load forecast and resources additions in Table 9 below are based on the capacity changes and DSM forecast in Table 5. Table 9 indicates that a planning reserve margin equal to 20 percent of the firm peak load is maintained.

Table 9 – NS Power 10 Year Load and Resources Outlook

Load and Resources Outlook for NSPI - Winter 2012/2013 to 2021/2022
(All values in MW except as noted)

		2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022
A	Firm Peak Load Forecast	2,006	2,024	2,040	2,056	2,081	2,102	2,131	2,158	2,183	2,203
B	DSM Firm	49	71	95	121	147	174	201	228	255	282
C	Firm Peak Less DSM (A - B)	1,958	1,953	1,945	1,935	1,933	1,928	1,930	1,930	1,928	1,921
D	Required Reserve (C x 20%)	392	391	389	387	387	386	386	386	386	384
E	Required Capacity (C + D)	2,349	2,344	2,334	2,322	2,320	2,314	2,316	2,316	2,313	2,305
F	Existing Resources	2412	2412	2412	2412	2412	2412	2412	2412	2412	2412
	Total Cumulative Additions:										
G	Thermal*	0	0	0	-120	-120	-273	-273	-273	-273	-273
H	Hydro	0	0	0	0	0	4	4	4	4	4
I	Contracted Wind (Firm capacity)**	15	15	15	15	15	15	15	15	15	15
J	Biomass	0	10	10	63	63	63	63	63	63	63
K	Community Feed-in-Tariff***	0	6	11	17	26	34	34	34	34	34
L	Maritime Link Import ****	0	0	0	0	0	155	155	155	155	155
M	Total Firm Supply Resources (F + G + H + I + J + K + L)	2428	2443	2449	2388	2396	2411	2411	2411	2411	2411
	+ Surplus / - Deficit (M - E)	79	99	115	65	76	97	95	95	98	106
	Reserve Margin % (M/C -1)	24%	25%	26%	23%	24%	25%	25%	25%	25%	26%

*Thermal includes Burnside #4 (winter capacity 33 MW) assumed to be returned to service in 2015. Also includes assumed retirement dates of solid fuel unit(s) for planning purposes in order to comply with federal environmental regulations, and are subject to adjustment due to equivalency with provincial regulations.

** Contracted Wind (Firm capacity) reflects the assumed firm capacity contribution based on a combined three year average of actual capacity factor during peak hours and the annual forecasted value (as per formula agreed on by NS Power and the Renewable Energy Industry Association of Nova Scotia and as employed in NS Power 2009 IRP Update modeling). These assumed capacity values are being re-evaluated in the Renewables Integration Study presently underway.

*** The Community Feed-in-Tariff represents distribution-connected renewable energy projects as outlined in the Province's Renewable Electricity Plan in April 2010. The projects are assumed to be phased-in over 5 years starting in 2014. The value in the table is the assumed firm capacity value of intermittent generation for small-scale projects. For long-term planning purposes the firm capacity value is based on an assumed 34% capacity factor as estimated by the provincial government. For short-term assessments (e.g. 18-month Load and Capacity Assessment) the assumed capacity factor may be less. These assumed capacity values are being re-evaluated in the Renewables Integration Study presently underway.

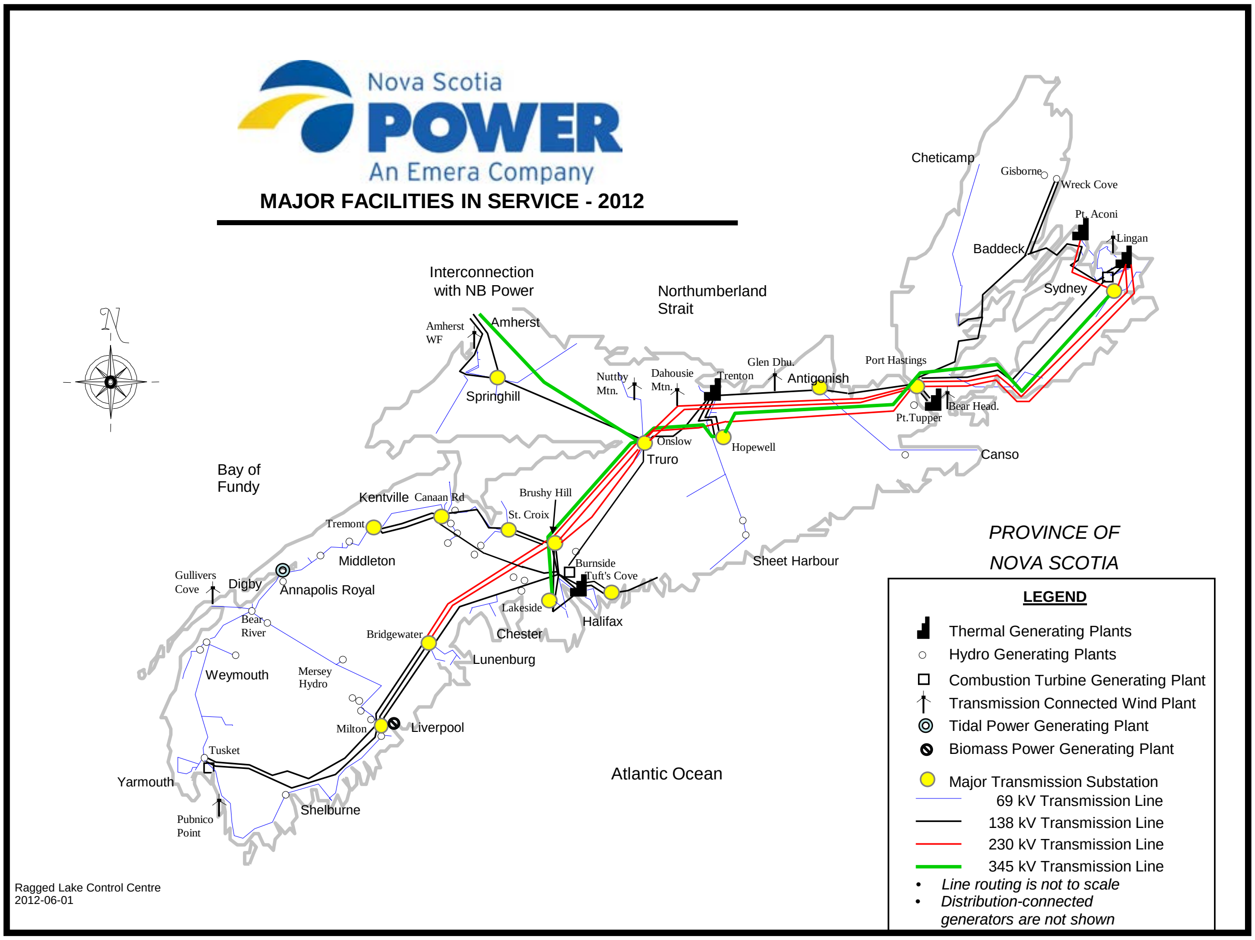
**** Maritime Link Import and the forecast retirement of a solid fuel unit are assumed to coincide. The assumed retirement dates of solid fuel unit(s) are for planning purposes in order to comply with federal environmental regulations, and are subject to adjustment due to equivalency with provincial regulations.

7.0 TRANSMISSION PLANNING

7.1 System Description

The existing transmission system has approximately 5200 km of transmission lines at voltages at the 69 kV, 138 kV, 230 kV and 345 kV levels. The configuration of the NS Power transmission system and major facilities is shown in Figure 3.

Figure 3 NS Power Major Facilities in Service 2012



- The 345 kV transmission system is approximately 468 km in length and is comprised of 372 km of steel tower lines and 96 km of wood pole lines.

- The 230 kV transmission system is approximately 1253 km in length and is comprised of 47 km of steel/laminated structures and 1206 km of wood pole lines.

- The 138 kV transmission system is approximately 1786 km in length and is comprised of 303 km of steel structures and 1483 km of wood pole lines.

- The 69 kV transmission system is approximately 1668 km in length and is comprised of 12 km of steel/concrete structures and 1656 km of wood pole lines.

Nova Scotia is interconnected with the New Brunswick electric system through one 345 kV and two 138 kV lines providing up to 350 MW of transfer capability to New Brunswick and up to 300 MW of transfer capability from New Brunswick, depending on system conditions. As the New Brunswick system is interconnected with the province of Quebec and the state of Maine, Nova Scotia is integrated into the NPCC bulk power system.

7.2 Transmission Design Criteria

NS Power, consistent with good utility practice, utilizes a set of deterministic criteria for its interconnected transmission system that combines protection performance specifications with system dynamics and steady state performance requirements.

The approach used has involved the subdivision of the transmission system into various classifications each of which is governed by distinct design criteria (see Appendix A). In general, the criteria require the overall adequacy and security of the interconnected power system to be maintained following a fault on and disconnection of any single system component.

The NS Power bulk transmission system is planned, designed and operated in accordance with North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council (NPCC) criteria. NS Power is a member of the Northeast Power Coordinating Council. Those portions of NS Power's bulk transmission network wherein single contingencies can potentially adversely affect the interconnected NPCC system are designed and operated in accordance with the NPCC *Regional Reliability Directory 1 Design and Operation of the Bulk Power System*.

NS Power makes use of Special Protection Systems (SPS) within the Supervisory Control and Data Acquisition (SCADA) system to enhance the utilization of transmission assets. These systems act to maintain system stability and remove equipment overloads, post contingency, by rejecting generation and/or shedding load. The NS Power system has several transmission corridors that are regularly operated at limits without incident due to these Special Protection Systems.

7.3 Transmission Life Extension

NS Power has in place a comprehensive maintenance program on the transmission system focused on maintaining reliability and extending the useful life of transmission assets. The program is centered on detailed transmission asset inspections and associated prioritization of asset replacement (i.e., poles, crossarms, guywires, and hardware replacement).

The table below lists the lines within the NS Power transmission system which have undergone maintenance over the past two years along with proposed planned maintenance for 2012:

2010	2011	2012
L5017(5 Points-Canaan)	L5003(Sackville-Akerley)	L5004 (Sackville-Rockingham)
L5029(Maccan-Springhill)	L5004(Sackville-Rockingham)	L5012 (Tufts Cove-Imperial Oil)
L5030(Aberdeen-Black River)	L5011(Farrell-Imperial)	L5025 (Paradise-Tremont)
L6002(Sackville-Gold River)	L5019(Canaan-Hollow Bridge)	L5031 (Hubbards-Robinsons Corner)
L5037(East River-Canexel)	L5028(Onslow-Stewiacke)	L5035 (Hells Gate-Canaan Road)
L5039(Lakeside-Spryfield)	L5044(Tap-Middleton)	L5054 (Weymouth-Saulnierville)
L5040(Onslow-Tatamagouche)	L5053(Tremont-Michelin)	L5057 (Tap to Cornwallis)
L5048(Green Harbour-Lockport)	L5501(Trenton-Bridge Ave)	L5510 (Bridge Ave-Malay Falls)

2010	2011	2012
L5058(Springhill-Pugwash)	L5510(Bridge Ave.-Malay Falls)	L5511 (Trafalgar-Musquodoboit)
L7011(Lingan-Hastings)	L5511(Trafalgar-Upper Musquodoboit)	L5521 (Onslow- Willow Lane)
L5532(Gulch-Big Falls)	L5512(Malay Falls-Ruth Falls)	L5027A(Tusket-Lower Woods Harbour)
L5535(Sissiboo-Tusket)	L5524(Antigonish-Salmon River)	L5536B(Pleasant St to Hebron)
L5544(Big Falls-Upper Lake Falls)	L5531(Gulch-Sissiboo)	L5539 (Milton-Liverpool)
L7003(Onslow-Hastings)	L5532(Big Falls-Gulch)	L5544 (Big Falls-Upper Lower Lake Falls)
L5559(Whycocomagh-SW Margaree)	L5534(Tusket-Hebron)	L5547 (Westhavers Elbow-Lunenburg)
L5560 (VJ-Townsend St.)	L5546(Bridgewater-Westhavers)	L5560 (Victoria Junction-Townsend St)
L5561(VJ-Seaboard)	L5549(Maccan-Hickman)	L5563 (Victoria Junction-Townsend St)
L5569(Terrace-Townsend)	L5550(Maccan-Parrsboro)	L5564 (Victoria Junction-Keltic Dr)
L6006(Bridgewater-Milton)	L5555(Gannon Road-Aconi)	L5572 (V J-Seaboard)
L6010(Brushy Hill-Sackville)	L5559(Whycocomaugh-SW Margaree)	L5575(Whitney Pier-New Waterford)
L6016(Brushy Hill-Lakeside)	L5565(Seaboard-Albert Bridge)	L5576(Gannon Road-Keltic Dr)
L6024(Milton-Tusket)	L5571(VJ-Whitney Pier)	L6003(Tufts Cove-Sackville)
L6025(Bridgewater-Milton)	L6002(Sackville-Bridgewater)	L6004(Sackville-Canaan Rd)
L6516(Hastings-VJ)	L6008(Sackville-Lakeside)	L6012(St. Croix-Canaan Rd)
L6531(Milton-Bridgewater)	L6011(Brushy Hill-St. Croix)	L6021(Souriquois-Tusket)
L6545(Glentosh-Wreck Cove)	L6020(Milton-Sourquois)	L6024(Milton-Tusket)
L7012(Hastings-Lingan)	L6033 (Lakeside-Water St.)	L6025(Milton-Bridgewater)
L7015(Pt. Aconi-Woodbine)	L6042(Tufts Cove-Dartmouth East)	L6510(Whycocomagh-Aberdeen)
L5530B(Broad River-East Green Harbour)	L6051(Brushy Hill-St. Croix)	L6511(Trenton-Glen Dhu)
L5564A(Terrace St. Tap)	L6503(Onslow-Trenton)	L6521(Tupper-Tupper Terminals)
Various Insulator Replacements	L6513(Onslow-Springhill)	L6535(Maccan-NB)
	L6514(Maccan-Springhill)	L6523(Tupper-New Page)
	L6515(Antigonish-Port Hastings)	L6539(Gannon Rd-VJ)
	L6527(Onslow Substation Tie)	L6545(Glen Tosh-Wreck Rd)

2010	2011	2012
	L6536(Springhill-NB Border)	L6552(Glen Dhu-Lochaber Rd)
	L6538(Glen Tosh-Gannon-Road)	L7001(Onslow-Brushy Hill)
	L6545(Glen Tosh-Wreck Cove)	L7002(Onslow-Brushy Hill)
	L6549(Glen Tosh-Wreck Cove)	L7005(Onslow-Port Hastings)
	L7002(Onslow-Brushy Hill)	L7009(Bridgewater-Brushy Hill)
	L7005(Onslow-Port Hastings)	L7012(Port Hastings-Lingan)
	L7012(Port Hastings-Lingan)	L8004(Onslow-Lakeside)
	L7014(Lingan-Woodbine)	
	L7019(Onslow-Dalhousie Mountain)	
	L5027A(Tusket-Lower Woods Harbour)	
	L5540A(Tap-Deep Brook Hydro)	
	L5545A/5545B (Bridgewater-Auburndale/High St.)	
	L8001(Onslow-New Brunswick)	
	L8002 (Onslow-Lakeside)	

Nova Scotia Power also has in place a wooden pole retreatment program that enables the useful lives of these assets to be extended.

The table below lists the lines within the NS Power transmission system which have undergone wooden pole retreatment over the past two years along with proposed wooden pole retreatment for 2012.

2010	2011	2012
L5014(St. Croix-Burlington)	L5017 (Five Points-Canaan Rd.)	L5003(Farrell St-Sackville)
L5015(St. Croix-Avon)	L5025(Paradise-Tremont)	L5010(Imperial Oil-Imperial Oil Res)
L5020(Hollow Bridge-Methals)	L5026(Gulch-Paradise)	L5016(St Croix-Five Points)
L5021(Canaan Rd.-Klondike)	L5035 (Hells Gate-Canaan Rd.)	L5029(Maccan-Springhill)
L5506(Abercrombie-Pictou)	L5042(Farrell-Albro Lake)	L5501(Trenton-Stellarton)
L5510(Stellarton-Malay Falls)	L5048(East Green Harbour-Lockport)	L5502(Trenton-Abercrombie Pt)
L5511(Trafalgar-Upper Musquodoboit)	L5050(Sissiboo-Fourth Lake)	L5503(Port Hastings-Cleveland)
L5512(Malay Falls-Ruth Falls)	L5057(Tap-Cornwallis)	L5537(Tusket 9W-Tusket 102W)
L5531(Gulch-Sissiboo)	L5500 (Trenton-Bridge Ave.)	L5551(Lunenburg-Indian Path)
L5535(Sissiboo-Tusket)	L5530(Milton-Souriquois)	L6004(Sackville-Canaan Rd)
L5546(Bridgewater-Westhavers Elbow)	L5538(Sissiboo-Weymouth)	L6511(Trenton-Lochaber Rd)
L5547(Westhavers Elbow-Lunenburg)	L6516(Hastings-Victoria Junction)	L6514(Maccan-Springhill)
L5548(Maccan-Amherst)	L6521(Point Tupper-Point Tupper Terminal)	L6518(Port Hastings-Stora)
L5561(Victoria Junction-Seaboard)	L6543(Hastings 138kV-230kV)	L7002(Onslow-Brushy Hill)
L6009(Sackville-Burnside)	L7011(Hastings-Lingan)	L7018(Onslow-Brushy Hill)
L6020(Milton-Souriquois)		L8001(Onslow -NB Border)
L6536(Springhill-NB Border)		L8002(Lakeside- Onslow
L6538 (Glentosh-Gannon Rd.)		

7.4 Transmission Project Approval

The transmission plan presented in this document provides a summary of the planned reinforcement of the NS Power transmission system. The proposed investments are required to maintain system reliability and security and comply with System Design Criteria. NS Power has sought to upgrade existing transmission lines and utilize existing plant capacity, system configurations, and existing rights-of-way and substation sites where economic.

Major projects included in the plan have been included on the basis of a preliminary assessment of need. The projects will be subjected to further technical studies, internal approval by NS Power, and final funding approval by the Nova Scotia Utility and Review Board. Projects listed in this plan may change because of final technical studies, changes in the load forecast, changes in customer requirements or other matters determined by the Company, NPCC/NERC Reliability Standards or the UARB.

In 2008 the Maritimes Area Technical Planning Committee was established to review intra-area plans for Maritimes Area resource integration and transmission reliability. The Committee forms the core resource for coordinating input to studies conducted by each member organization and presenting study results, such as evaluation of transmission congestion levels in regards to the total transfer capabilities on the utility interfaces. This information will be used as part of assessments of potential upgrades or expansions of the inter-ties, including any potential new inter-tie between Nova Scotia and New Brunswick. The Technical Planning Committee has transmission planning representation from Nova Scotia Power, NBSO, Maritime Electric Company Ltd., Northern Maine Independent System Administrator and NB Power (Transmission).

7.5 Nova Scotia – New Brunswick Interconnection Overview

The power systems of Nova Scotia and New Brunswick are interconnected via three overhead transmission lines; one 345 kV line from Onslow, Nova Scotia to Memramcook, New Brunswick, and two 138 kV lines from Springhill, Nova Scotia to Memramcook, New Brunswick (note however that there is only a single 138 kV line from Springhill to Onslow). The primary function of the interconnection is to support system reliability.

Access to the Nova Scotia – New Brunswick Interconnection is controlled by the terms of the respective OATT of NS Power and NBSO. As previously mentioned in Table 8, there is currently one active Transmission Service request for Long-Term Firm Point-to-Point Transmission Service (TSR-400) from Nova Scotia to New Brunswick.

Electricity is imported or exported over the inter-tie in proportion to the electrical characteristics of the transmission lines. The 345 kV line carries approximately 80 percent of the total power transmitted.

Power systems are designed to accommodate a single contingency loss (i.e. loss of any single element and certain multiple elements) and since the 345 kV line carries the majority of the power flow, loss of the 345 kV line becomes the limiting factor. Power flow on the 138 kV lines is also influenced by the loads in Prince Edward Island; Sackville, New Brunswick; and Amherst, Springhill and Debert, Nova Scotia

Import and export limits (both firm and non-firm) on the inter-tie have been established to allow the Nova Scotia and the New Brunswick system to withstand a single contingency loss. The limits are up to 350 MW export and up to 300 MW import. These figures represent limits under pre-defined system conditions, and differ for Firm versus Non-Firm Transmission Service. Conditions which determine the actual limit of the interconnection are:

Export	**Import**
Amount of generation in Nova Scotia that can be rejected or run-back via SPS action	Nova Scotia system load level (Import must be less than 22% of total system load)
Reactive Power Support level in the Metro Area	Percentage of dispatchable generation in Nova Scotia
Arming status of SPS	New Brunswick export level to Prince Edward Island and/or New England
Real time line ratings (climatological conditions in northern Nova Scotia)	Real time line ratings (climatological conditions in northern Nova Scotia)
Nova Scotia System load level	Load level in Moncton area
Largest single load contingency in Nova Scotia	Largest generation contingency in Nova Scotia

If the 345 kV Nova Scotia - New Brunswick inter-tie trips while exporting, the parallel 138 kV lines can be severely overloaded and potentially trip, causing Nova Scotia to separate from New Brunswick. If this happens, the Nova Scotia system frequency (cycles/second) will rise, risking unstable plant operation and possible equipment damage. To address this, NS Power uses fast-acting Special Protection Systems to reject sufficient generation to prevent separation.

If the NS Power system is separated during heavy import, Nova Scotia system frequency will drop. Depending on the system configuration at the time of separation and the magnitude of the import electricity flow that was interrupted, the system will respond and re-balance. The system does this by automatically rejecting firm load through under-frequency load shedding (UFLS) protection systems as required. The degree of load shedding will be impacted as an increasing percentage of in-province generation is supplied by wind power, due to the technical characteristics of that source.

The loss of the 345 kV line between Onslow, Nova Scotia and Memramcook, New Brunswick is not the only contingency that can result in Nova Scotia becoming separated from the New Brunswick Power system while importing power. All power imported to Nova Scotia flows through the Moncton/Salisbury area of New Brunswick. Since there is no generation in the Moncton/Salisbury area, and only a limited amount of generation in Prince Edward Island, power flowing into Nova Scotia is added and shares transmission capacity with the entire load of Moncton, Memramcook, and PEI.

The NBSO restricts power export to Nova Scotia to a level such that any single contingency does not cause adverse impacts on New Brunswick or PEI load. Any transmission reinforcement proposed to improve reliability, increase import and export power capacity or prevent the activation of UFLS in Nova Scotia must also consider the reinforcement of the southeast area of the New Brunswick transmission system.

In jurisdictions across North America it is becoming increasingly difficult to obtain access to the land and the rights-of-way necessary to undertake transmission projects. It is estimated that the addition of a second inter-tie will require at least 5 years to secure the required permits and complete construction.

Although joint studies have been conducted, at this time the timing and configuration of an expansion to the provincial inter-tie has yet to be determined. However, given the dynamic nature of the provincial and regional electricity markets it is likely that an upgrade may be required over the next decade. Similarly, it is possible to identify the preferred route of the new line.

To this end, NS Power has been granted approval by the Nova Scotia Utility and Review Board to proceed with the acquisition of a right-of-way to accommodate a second 345 kV circuit between Nova Scotia and New Brunswick.

8.0 TRANSMISSION DEVELOPMENT 2012 TO 2021

Transmission development plans are summarized below. As highlighted earlier, these projects are subject to change. For 2012, the majority of the projects listed are included in the 2012 Annual Capital Expenditure Plan. For 2012 onward, the projects are noted in the projected year of completion.

2012

- The insulator replacement program will continue with the re-insulation of two circuits due to cement growth issues.

- The transmission reliability investment program will continue targeting transmission switches and circuit breakers.

- Transformer installations at Kempt Road and Lucasville Rd. will be completed.

- The installation of a third 138 kV – 25 kV transformer will commence at Water St. along with the refurbishment/replacement of a portion of the 25 kV switchgear.

- Work will be completed to upgrade steel transmission towers on two 138 kV transmission circuits on the Halifax Peninsula that terminate in the Water St. 138 kV substation.

- Work will continue on acquiring a spare generator transformer that will be utilized to prevent a prolonged outage resulting from a failure of certain generator transformers.

- In accordance with the NPCC *Classification of Bulk Power System Elements* (Document A-10), dual high-speed protection systems are required at Onslow 138 kV and Tuft's Cove 69 kV.

- The program to replace porcelain cutouts and some insulators at various transmission substations will continue.

- Work will continue on acquiring a right-of-way for a second 345 kV tie to New Brunswick.

- Network upgrades to accommodate a new wind farm in the Amherst area will be completed.

- Two 69 kV circuits in the Dartmouth area (L-5011 and L-5012) will be uprated to ensure proper ground clearances are met.

- A 69 kV – 25/12 kV transformer and a 138 – 25 kV transformer will be purchased as system spares for delivery in 2013.

- Work will continue on the removal and replacement of transmission substation devices with 500 mg/kg or more of PCBs, to be in compliance with Federal Environmental PCB Regulations.

- A new 138 kV - 12 kV, 15/20/25 MVA substation is approved for Highbury Rd. in New Minas for the purpose of supplying additional load growth. This project also includes a 138 kV line terminal at Canaan Road and a 138 kV transmission circuit between Canaan Road and the new substation.

- The construction of a new 138 kV - 25 kV substation is planned for a new site at Harbour East. This project will also include a new 138 kV circuit and right-of-way from the existing Dartmouth East substation as well as the line terminal at Dartmouth East.

- The spar arms on a 138 kV circuit between Bridgewater and Milton will be reinforced.

- Work will take place on a 230 kV circuit between Onslow and Port Hastings, a 230 kV circuit between Brushy Hill and Bridgewater, for the purpose of increasing ground clearances. A recent transmission line survey indicated that certain spans of this transmission line required that the conductor be raised to comply with operating temperature ground clearances.

- Work will continue to prevent metal deterioration on transmission steel towers.

- The 138 kV cables at the Wreck Cove Hydro site are proposed to be replaced.

- To accommodate the interconnection of generation at the Fundy Ocean Research Centre for Energy, a 138 kV class transmission line is being built from the facility to the Parrsboro substation.

- Transmission structure footings on the 345 kV line from Onslow to Lakeside have shown signs of fatigue and will be inspected and repaired.

2013

- The insulator replacement program will continue with the re-insulation of one circuit due to cement growth issues.

- The transmission reliability investment program will continue targeting transmission switches and circuit breakers.

- The program to replace porcelain cutouts and some insulation at various transmission substations will continue.

- A second 138 kV - 25 kV transformer will be installed at Lochaber Road substation for reliability purposes in the event of transformer failure.

- The 138 kV - 25 kV substation at Harbour East and associated transmission line to the existing Dartmouth East substation along with the 138 kV line terminal at Dartmouth East substation will be completed.

- Load will be transferred from the 69 kV bus to the 138 kV bus at Trenton, relieving load on the two 138 kV – 69 kV autotransformers. This will be accomplished by changing out an existing 69 kV- 25 kV transformer at Trenton with a 138 kV- 25 kV unit.

- A second 36 MVAR capacitor bank is proposed to be added on the 138 kV bus at Bridgewater.

- In accordance with the NPCC *Classification of Bulk Power System Elements* (Document A-10), dual high-speed protection systems are required at Lakeside 138 kV and Brushy Hill 138 kV.

- In accordance with a directive from NPCC, Bulk Power System elements which previously fell within the "grandfather clause" of NPCC Directory 04 *System Protection Criteria* must have duplicate high-speed protection systems and duplicate station batteries by the end of 2016. Brushy Hill 230 kV will be uprated in 2013.

- Ground-clearance issues which have been identified for L-5510, L-6513, L-6535, L-6536 and L-6514 will be addressed.

- Transmission lines which share a common circuit breaker at Tuft's Cove will be re-arranged, and a 69 kV cable will be uprated to permit higher net output from generation in the Dartmouth area during light load.

- Load at the Cleveland substation will be moved to a new 138 kV- 25 kV transformer, and the existing 69 kV line from Port Hastings to Cleveland will be retired.

2014

- The insulator replacement program will continue with the re-insulation of various circuits due to cement growth issues.

- The transmission reliability investment program will continue targeting transmission switches and circuit breakers.

- The existing 138 kV - 69 kV, 20/26.7 MVA transformer at Westhaver's Elbow is reaching end-of-life, and is planned to be changed out for a unit rated 22.5/33.3 MVA, which will also address the lack of voltage regulation in the area.

- In accordance with a directive from NPCC, Bulk Power System elements which previously fell within the "grandfather clause" of NPCC Directory 04 *System Protection Criteria* must have duplicate high-speed protection systems and duplicate station batteries. Onslow 230 kV will be uprated in 2014.

- 69 kV lines from Tusket to Pleasant St and St. Croix to Upper Burlington will be re-built.

- Ground clearance issues with the 230 kV circuit L-7003 between Port Hastings and Onslow will be addressed.

2015

- In accordance with a directive from NPCC, Bulk Power System elements which previously fell within the "grandfather clause" of NPCC Directory 04 *System Protection Criteria* must have duplicate high-speed protection systems and duplicate station batteries. Port Hastings 230 kV will be uprated in 2015.

- The 230 kV bus at Lingan will be re-configured to eliminate single contingencies which trip two generators or two lines.

- The 69 kV line between Victoria Junction and Townsend Street will be re-conductored.

- In accordance with a directive from NPCC, Bulk Power System elements which previously fell within the “grandfather clause” of NPCC Directory 04 *System Protection Criteria* must have duplicate high-speed protection systems and duplicate station batteries. Lingan 230 kV will be uprated in 2016.

2016

- An existing 69 kV - 12 kV transformer at Central Argyle will be changed out for a unit rated 7.5/10/12.5 MVA.

2018

- An existing 69 kV - 25 kV transformer at Milton will be changed out for a unit rated 15/20/25 MVA.

NS Power is currently studying the impact of a proposed 500 MW high-voltage direct-current (HVDC) cable from the province of Newfoundland and Labrador (NL) to a terminal in Cape Breton, with a proposed in-service date of 2017. In association with this project, Table 8 shows a 330 MW Point-to-Point Transmission Service Request from Nova Scotia to New Brunswick. As these studies are not yet finalized, any associated transmission reinforcements will be identified in subsequent 10-Year System Outlook reports.

9.0 UNCERTAINTY

The Nova Scotia power system is dynamic, complex to plan and operate, and influenced by developments inside and outside of our Province. Much uncertainty remains with respect to the form, location and scope of future generation, as emission regulations and Renewable Electricity Standards evolve and projects required to maintain compliance are studied including the implications of large amounts of variable generation such as wind and tidal.

Once determined, development and implementation of the appropriate transmission plan to address these challenges will require a timely and effective response from NS Power and stakeholders. Recognizing this, NS Power has begun work to determine the transmission system reinforcement required to support various generation scenarios, inside and outside of the Province. This work is summarized in Appendix B, Generation Development Scenarios.

It should be reinforced that scenario transmission studies remain preliminary and are included in this report to provide insight to the potential nature of transmission reinforcement across the Province over the next decade (beyond that described earlier in this report). Whether the scenarios materialize as projected will be determined by a host of factors unknown today including:

- The location, size and configuration of generation developments across Nova Scotia, including distribution-based projects such as COMFIT;

- The emergence of new generation sources and markets outside of Nova Scotia;

- Ongoing evolution of power system industry engineering, operating standards and NPCC/NERC reliability standards;

- Changes in customer demand or emergent technologies dependent on electricity.

What can be drawn from the information presented in Appendix B is that:

- Transmission system reinforcement may be required to accommodate the addition of renewable generation across Nova Scotia;
- The design of the transmission system reinforcement will be determined by the location and scope of the generation development;
- Transmission system expansion plans should be robust to accommodate changes in area and provincial load and generation;
- Transmission system expansion plans will be subject to change in response to opportunities, inside and outside of Nova Scotia; and
- Transmission system planning remains an ongoing evolution as evidenced by other jurisdictions.

Section 4.0 provided the Generation Interconnection Request Queue for new generation, or increases in the capacity of existing generation. As proposed projects, known as Interconnection Requests move through the various stages of the Generation Interconnection Procedure, studies are conducted to determine the impact of the IR on the transmission system, and/or determine the required system upgrades. Each of the IR's listed in Table 6 has been the subject of either a Feasibility Study or a System Impact Study. However, since the GIP offers "Energy Resource Interconnection Service", which allows for generation to be eligible to deliver the output using the existing firm or non-firm capacity of the Transmission Provider's Transmission System on an as available basis, no significant transmission reinforcement projects have committed at this time.

10.0 CONCLUSION

It is likely that the NS Power transmission system will continue to require reinforcement in the coming decade and that this reinforcement will occur across congested corridors and at the provincial inter-tie. Studies to understand the reinforcement scope is proceeding in accordance with the underlying market drivers, primarily RES requirements and other provincial and federal legislation.

In 2010 the UARB approved NS Power's application for the purchase of right-of-way to accommodate a second provincial inter-tie. Additional transmission capital investment applications will be forthcoming once the design, cost and business cases necessary to support these investments are complete.

It is NS Power's objective to develop and maintain a timely, effective and robust transmission expansion plan. This process will require the Board's support and the participation of stakeholders. NS Power will continue to keep the Board and stakeholders apprised as this work moves forward.

11.0 REFERENCES

1. *2011 Maritimes Area Interim Review of Resource Adequacy*, Report approved by NPCC Reliability Coordinating Council November 29, 2011.

2. *NPCC Regional Reliability Reference Directory #1: Design and Operation of the Bulk Power System*, Northeast Power Coordinating Council Directory #1, December 1, 2009.

3. *Final Report, Nova Scotia Wind Integration Study for Nova Scotia Department of Energy*, Hatch Ltd., 2008.

4. Nova Scotia Power Open Access Same Time Information System (OASIS). http://oasis.nspower.ca

5. *Integrated Resource Plan Report*, Nova Scotia Power Inc., November 30, 2009.

6. *Nova Scotia Wholesale Electricity Market Rules*, February 1, 2007.

7. Regulations Respecting Renewable Energy Standards made under Section 5 of Chapter 25 of the Act of 2004, the *Electricity Act.*

APPENDIX A

SYSTEM DESIGN CRITERIA

PURPOSE

The purpose of this document is to establish the Nova Scotia Power Inc. (NS Power) planning and development criteria to be applied to new additions to NS Power transmission system planned or constructed after the effective date of this document. NS Power's transmission system is divided into four classifications, each of which is governed by different design criteria. Where and when applicable, NS Power criteria will be superseded by the Northeast Power Coordinating Council (NPCC) criteria.

The NS Power classifications are as follows:

1. Primary Transmission
2. Secondary Transmission
3. Electrically Remote Transmission
4. Transformation

The NS Power System Design Criteria combine protection performance specifications with system dynamics and steady state performance requirements. When system expansions are undertaken, facilities are to be constructed such that the criteria are met. The specified speed of protection systems must be achieved unless faster speeds are specified or slower speeds are accepted based on system studies. System studies to determine adequacy and investment requirements must be conducted using the actual characteristics (setting and operating time) of existing protection systems.

DEFINITIONS

1. *Normal system conditions* are defined to include all of the following:

   a. Expected load conditions.
   b. All transmission facilities in service (no line or transformer maintenance).

c. Economically scheduled and dispatched generation allowing for planned generator maintenance outages (non-firm generation is not included as economically dispatched generation).

d. Stable steady-state operation of the Interconnected Transmission System.

e. All system voltages within 95% to 105% of nominal, unless otherwise noted.

f. All system elements operating within their continuous thermal ratings, unless otherwise noted.

2. A *system element* is defined to be any one generator, transmission line, transformer or bus section.

3. *Breaker back-up* is defined to be protection against a local breaker's failure (mechanical or electrical) to trip when initiated by an associated protection operation.

4. *Single contingency* is defined as loss of one *system element* with or without a fault.

1. PRIMARY TRANSMISSION SYSTEM

Primary Transmission is defined as 230 kV and above.

The protection system must be designed with redundancy to cater to any single element failure, in keeping with good utility practice and conform to industry standards.

Unless otherwise specified, and determined appropriate by transient stability studies, the goal for fault clearing times will be 4 cycles or less for near end fault and 6 cycles or less for remote end fault with permissive signal for both three-phase and line-to-ground faults (or less).

a. Fault clearance for a near end fault with a breaker failure (fault cleared by breakers local to the line terminal) will be *12* cycles or less.

b. Fault clearance for a near end fault with a breaker failure (for lines that will also require breaker operation at the remote bus on the non-faulted line to clear the fault) will be *13* cycles or less.

c. Fault clearance for a remote end fault with a breaker failure (fault cleared by breakers local to the line terminal) will be *14* cycles or less.

d. Fault clearance for a remote end fault with a breaker failure (for lines that will also require breaker operation at the remote bus on the non-faulted line to clear the fault) will be *15* cycles or less.

e. *Breaker back-up* will be applied to all Primary Transmission.

The design criteria are:

1. From normal system conditions, the Interconnected Transmission System dynamic response shall be stable and positively-damped following a permanent three-phase fault on any one system element cleared in prime time. No cascade tripping shall occur.

2. From normal system conditions, the Interconnected Transmission System dynamic response shall be stable and positively-damped following a permanent line-to-ground fault on any one system element cleared in prime time. No cascade tripping shall occur.

3. From normal system conditions, the Interconnected Transmission System dynamic response shall be stable and positively-damped following a permanent line-to ground fault on any one system element cleared in breaker back-up time. No cascade tripping beyond elements cleared by the operative back-up protection shall occur.

4. From normal system conditions, following loss of any one system element with or without fault, all system elements shall be within 110% of their thermally limited ratings under the condition that the System Operator can take action within a 10 minute period to reduce load on the element.

5. From normal system conditions, for the loss of any one system element with or without fault, steady-state post-contingency Interconnected Transmission System bus voltages shall be not less than 90% or greater than 110% of nominal following correction by automatic tap-changers. In addition no bus shall experience a voltage change from pre-fault to post-fault condition greater than 10% before movement of tap-changers.

6. As far as possible, provision should be made to ensure that no fault is left permanently on the system.

7. The maximum net generation that may be rejected by a Special Protection Scheme (SPS) for normal contingency is 310 MW.

2. SECONDARY TRANSMISSION SYSTEM

This category includes all other loop transmission facilities, operating higher than 100 kV, which are not included in the Primary Transmission nor the Electrically Remote Transmission categories.

The protection system must be designed with sufficient redundancy to cater to any single element failure, in keeping with good utility practice and conform to industry standards. The clearing time will be 6 cycles or less (near end) and 8 cycles or less (remote end) for both three-phase and line-to-ground faults.

a. Fault clearance for a near end fault with a breaker failure (fault cleared by breakers local to the line terminal) will be **14** cycles or less.

b. Fault clearance for a near end fault with a breaker failure (for lines that will also require breaker operation at the remote bus on the non-faulted line to clear the fault) will be **15** cycles or less.

c. Fault clearance for a remote end fault with a breaker failure (fault cleared by breakers local to the line terminal) will be **16** cycles or less.

d. Fault clearance for a remote end fault with a breaker failure (for lines that will also require breaker operation at the remote bus on the non-faulted line to clear the fault) will be **17** cycles or less.

e. *Breaker back-up* will be applied to Secondary Transmission if system studies determine the requirement.

The design criteria are:

1. From *normal system conditions*, the Interconnected Transmission System dynamic response shall be stable and positively-damped following a permanent three-phase fault on any one *system element* cleared in prime time. No cascade tripping shall occur.

2. From *normal system conditions*, the Interconnected Transmission System dynamic response shall be stable and positively-damped following a permanent line-to-ground fault on any one *system element* cleared in prime time. No cascade tripping shall occur.

3. From *normal system conditions*, the Interconnected Transmission System dynamic response shall be stable and positively-damped following a permanent line-to ground fault on any one *system element* cleared in *breaker back-up* time. No cascade tripping beyond elements cleared by the operative back-up protection shall occur.

4. From *normal system conditions*, following loss of any one system element with or without fault, all system elements shall be within 110% of their thermally limited ratings in steady state, under the condition that the System Operator can take action within a 10 minute period to reduce load on the element.

5. From normal system conditions, for the loss of any one system element with or without fault, steady-state post-contingency Interconnected Transmission System bus voltages shall be not less than 90% or greater than 110% of nominal following correction by automatic tap-changers. In addition no bus shall experience a voltage change from pre-fault to post-fault condition greater than 10% before movement of tap-changers.

6. As far as possible, provision should be made to ensure that no fault is left permanently on the system.

3. ELECTRICALLY REMOTE TRANSMISSION SYSTEM

This category is defined by the buses at which the ultimate fault levels will not exceed 1,500 MVA three-phase.

1. The Interconnected Transmission System dynamic response shall be stable and positively-damped following a fault on any one *system element*.

2. From *normal system conditions* following any *single contingency* with or without a fault, all system elements shall be within their thermally limited ratings in the steady state.

3. From *normal system conditions*, for any *single contingency* with or without a fault, steady-state post-contingency system bus voltages shall not be less than 90% and not be greater than 110% of nominal following correction by automatic tap-changers. In addition, no bus shall experience

a voltage change from pre-fault to post-fault condition greater than 10% before movement of tap changers.

4. As far as possible, provision should be made to ensure that no fault is left permanently on the system.

5. *Breaker back-up* will be applied to Electrically Remote Transmission if system studies determine the requirement.

4. TRANSFORMATION

Capacity for any individual transformation point shall, under *normal system conditions*, be sufficient to meet the daily load requirements after due consideration is given to the following:

a. Economic dispatch or outage of generation.

b. Loading of transformer(s) to their (or their associated equipment) thermally limited ratings.

Reinforcement is required in all cases when, for a single contingency, there will result either, thermal damage to equipment in attempting to continue to supply the load, or, inability to meet the daily load requirements in whole or in part after due consideration is given to the following:

a. The capacity of the underlying interconnection(s) with another supply point(s) when applicable.

b. Out-of-merit running of generation when applicable.

c. Loading of remaining station(s) transformer(s) to their (or their associated equipment) thermally-limited ratings as per the Notes below. (This in conjunction with (a) and (b) above as applicable.)

d. Largest available *suitable* mobile transformer loaded to its nameplate rating. (This in conjunction with (a) and (b) above as applicable.)

Notes:

1. Reinforcement may be the economic choice even if (a), (b) and (c) or (d) result in satisfaction of the load supply criterion because estimated out-of-merit costs may significantly exceed the costs of capital advancement.

2. In accordance with methods accepted within North America, and particularly with reference to "C57.91-1995 IEEE Guide for Loading Mineral-Oil-Immersed Transformers", it is NS Power practice to permit the loading of transformers to exceed the nominal or nameplate value.

3. For distribution load serving transformers to exceed the nominal or nameplate value, where calculations are not specifically conducted, overload capability assumptions based on normal cyclic daily loading may be made, but shall not exceed 133% of top nameplate rating. In any case the maximum overload capability is not to exceed the current NS Power SCADA Alarm limits. In special circumstances, such as *single contingency* situations where some means of reducing the overload exists, a thermal rating based on a loss of life of 2 1/2% may be applied to distribution load serving transformers, in accordance with the above and engineering judgment. The loss of life permitted is measured over the time required to reduce the loading on the transformers. This may be done by switching low voltage circuits or relieving load by use of a mobile transformer.

4. System power transformers (not distribution load serving transformers) with a nameplate rating of less than 200MVA are rated at 100% of the 65^{o}C manufacturer nameplate MVA for summer and 110% of the 65^{o}C manufacturer nameplate MVA for winter under

normal operating conditions. For winter conditions, under contingency, transformers are limited to 120% of the 65^{o} C manufacturer nameplate MVA.

5. Where calculations are not specifically conducted, overload capability assumptions for system transformers greater than 200 MVA (65 deg C nameplate rating) will be based on 100% for both summer and winter under system normal.

6. When no means of reducing the overload exists, a 0% loss of life is used.

APPENDIX B

GENERATION DEVELOPMENT SCENARIOS

Dispersed large-scale renewable generation, large-scale imports and exports, new in-province thermal generation, and even small-scale embedded generation have a potential role in serving Nova Scotia's future electricity needs. Each will potentially require reinforcement of the current transmission system. However the form of this reinforcement cannot be defined in advance of a determination of the location and scope of generation sources.

In lieu of this certainty, NS Power has undertaken preliminary transmission scenario planning regarding alternative generation sources. This exercise provides insight to the constraints which currently exist on the provincial transmission system and provides perspective as to the investments that will be required to realize various generation opportunities.

This information remains largely conceptual. It is not intended to describe the future plans of the utility but rather the nature of decisions facing the Company with respect to transmission system expansion where network resource interconnection service is required. The scenarios are helpful in highlighting transmission projects that appear under numerous scenarios, and as such, may form the foundation for a robust long-term transmission expansion plan. These expansion plans could help to enable a higher degree of renewable energy in Nova Scotia, which NS Power supports.

Renewable Energy Development Scenarios (2013 - 2020)

a) Mainland (Metro) wind generation (100 MW - 150 MW) development scenario:

Establish a new 138 kV substation in the Dartmouth area along with rebuilding/reconductoring two existing circuits and building a new 138 kV circuit between Fall River and Sackville.

b) Mainland (South Nova) wind generation (100 MW - 150 MW) development scenario:

Re-conductor an existing 138 kV circuit between Milton and Tusket along with an existing 69 kV circuit between Tremont and Michelin. A 138 kV substation would be established in the Tusket area along with substation bus modifications at Canaan Road, Milton and Bridgewater. Two 230 kV circuits currently occupying double circuit towers towards the Bridgewater area would be separated.

c) Mainland (Western Annapolis Valley) wind generation (100 MW – 150 MW) development scenario:

An existing 69 kV circuit between Tremont and Gulch would be uprated to 138 kV and the 69 kV substations currently connected to this circuit would be converted to 138 kV. In addition new 138 kV circuits would be constructed from Gulch to Tremont and Tusket substations. This would include the development of 138 kV ring buses at Paradise, Gulch, and Tusket. Two 230 kV circuits currently occupying double circuit towers towards the Bridgewater area would be separated.

d) Mainland (Eastern Annapolis Valley) wind generation (100 MW – 150 MW) development scenario:

An existing 69 kV circuit between Sissiboo and Tusket would be rebuilt to a higher capacity. Substation modifications would be required at Bridgewater and Milton along with replacing two 138 kV - 69 kV autotransformers at Canaan Road with higher capacity units. Two 230 kV circuits currently occupying double circuit towers towards the Bridgewater area would be separated.

e) Mainland (Northern Nova Scotia) wind generation (100 MW – 150 MW) development scenario:

Construct a new 138 kV line from Onslow to Springhill and install a 100 MVAR Static Var compensator on the Onslow 230 kV bus along with increasing reactive power compensation at Brushy Hill. An existing 230 kV circuit would be uprated to 345 kV to provide a 345 kV transmission connection between Onslow and Brushy Hill.

f) Cape Breton Wind generation (150 MW – 250 MW) development scenario:

An existing 230 kV circuit would be uprated to 345 kV to provide a 345 kV transmission connection between Onslow and Brushy Hill and reactive power compensation would be increased at Brushy Hill. A 345 kV substation would be established at Port Hastings and 345 kV circuits would be constructed from Port Hastings to both Woodbine and Spider Lake including a new Canso crossing. A new 345 kV - 138 kV substation would be established at Spider Lake that would terminate three 138 kV circuits in the Dartmouth area. In addition, 100 MVAR of reactive compensation would be installed in the Dartmouth area.

Large External Imports (300 MW – 500 MW) or Export development scenario

a) To facilitate large import or export via New Brunswick:

To enable firm import, a new 345 kV transmission circuit would be required between Onslow and the New Brunswick system. Studies have been conducted which indicate the need for significant transmission reinforcement in the Moncton area to support firm transfers from New Brunswick to Nova Scotia and Prince Edward island. If the imported energy displaces generation in the Halifax Metro area, additional transmission reinforcement inside Nova Scotia would be required, including uprating an existing 230 kV line to 345 kV between Onslow and Brushy Hill, a 100 MVAR Static Var Compensator at Onslow, and switched capacitor banks at Brushy Hill 138 kV.

For additional firm export from Nova Scotia to New Brunswick, further study would be required.

b) Newfoundland and Labrador Submarine Cable Import (500MW) or Export development scenario:

System studies are currently underway to determine the transmission required across Nova Scotia to accommodate a 500 MW import from Newfoundland. The import from Newfoundland and Labrador will be via a DC submarine cable from Newfoundland to Cape Breton, with part of the energy exported from Nova Scotia via New Brunswick.

Large Natural Gas Generator (250 MW – 350 MW) expansion scenario

For contingency loss of a large generator scenario in Nova Scotia, the Nova Scotia - New Brunswick inter-tie, as well as transmission in the Moncton area of New Brunswick, may require reinforcement.

a) Eastern Shore/Point Tupper Natural Gas Generator Scenario

Substation expansions would take place at Point Tupper and Port Hastings including the addition of a 345 kV - 230 kV transformer at Port Hastings. A 345 kV - 138 kV substation would be established at Spider Lake. A new 230 kV circuit would be required from Point Tupper to Port Hastings and a 345 kV circuit would be required between Port Hastings and Spider Lake.

b) Metro Large Natural Gas Generator Scenario

A 138 kV substation would be developed at Spider Lake to terminate two existing Dartmouth 138 kV circuits along with increasing the conductor size on two existing Dartmouth circuits. A new 138 kV circuit would be required from Spider Lake to Sackville as well as a high capacity line from Tuft’s Cove to Brushy Hill. An additional 138 kV circuit across the Halifax Harbour would be required. In addition, substation modifications would be required at Tuft’s Cove and Brushy Hill.

Request IR-36:

REFERENCE: M2(vi), App. 6.02, p. 31

CITATION:

> **NSPI is engaged in the PowerShift Atlantic project to test new opportunities to control customer load through a virtual power plant approach to respond to wind variability or other operational upsets. Additionally, voluntary load shedding programs such as the program used in the Alberta market called the Load Shed Service for Imports (LSSi)28 can be instituted to help the system operator in maintaining demand and supply balance if sufficient conventional generation resources are not available.**

(a) Please describe in detail the « virtual power plant approach".

(b) Please indicate whether or not there is a voluntary load shedding program in place in Nova Scotia. If not, is there one under consideration?

(c) Please quantify the potential for voluntary load shedding in Nova Scotia.

Response IR-36:

(a) The Virtual Power Plant (VPP) is an intelligent energy management system. It works with the system operator to direct shifting of customer load demand. By smoothing the overall shape of required load demand, and analysing wind generation forecasts, the VPP informs the system operator of the amount of load that cannot be powered by wind power generation, and must be handled with conventional generation. The PowerShift Atlantic project studies acceptable ways to shift electricity flows to homes and businesses, without inconveniencing customers. Through a combination of intelligent hardware and software solutions, and improved wind forecasting tools, Maritime utilities are regulating specific electrical equipment at participating customers' homes and businesses to better align supply with wind generation availability.

(b) This is currently a load shedding program available to Industrial customers under the Interruptible Rider To The Large Industrial Tariff (Rate Code 25). Under this tariff, the customers will reduce their available interruptible system load by the amount required by NS Power within ten (10) minutes of NS Power initiating and sending notice to the customer.

There currently is not a load shedding program at NS Power for Residential or Commercial customers. NS Power's participation in the PowerShift Atlantic project represents its consideration for a load shedding or load management program. Research under the PowerShift Atlantic project is providing NS Power experience with hardware and software solutions that could be used for load shedding or load management purposes.

(c) Full load shedding potential in Nova Scotia is not yet quantified. Details regarding the residential and commercial customer classes need to be evaluated, such as the willingness of these customers to participate, the most valuable types of customer load, and availability of those customer loads.

To achieve customer acceptance of load shedding or load shifting, such a program must be able to avoid inconveniencing the participating customers.

Research through the PowerShift Atlantic project has identified that the best end-uses (appliances) for load shedding and load shifting are those with some energy storage capability such as water heaters, electronic thermal storage (ETS) heaters or commercial heating, ventilation and air-conditioning systems (HVAC).

It will be important to determine the availability of the individual appliances to be turned off (or turned on) when required by the System Operator. Research through the PowerShift Atlantic project is providing data around the degree of availability of these appliances and whether it aligns with the timing of any load shedding or shifting needs of the System Operator. Commercial load availability is still to be determined, with audits and enrollment of sites for participation in the PowerShift project beginning in March 2013.

NON-CONFIDENTIAL

Request IR-37:

REFERENCE: M2(vi), App. 6.02, p. 32

CITATION:

Recommendations

1. Energy Storage31,32: Energy storage systems can help in reducing thermal generator cycling by absorbing (charging) energy during excess wind generation and supplying (discharging) energy when wind generation is low. Pumped hydro energy storage, battery storage and Compressed Air Energy Storage (CAES) systems are some examples of systems that have the potential to store large amounts of energy. These technologies however, have certain limitations. Pumped hydro and CAES systems are location constrained while large scale battery storage can be extremely expensive.

(a) Has NSPI evaluated the possibilities for pumped hydro and CAES in Nova Scotia? If so, please provide details of these reviews.

(b) Has NSPI estimated the potential and cost of emerging storage technologies (CAES, capacitors, flywheels, etc.) for use after 2020? If so, please provide copies of these reviews.

Response IR-37:

(a) Please refer to CA IR-44 (a) on pumped storage; CAES was reviewed but not investigated in detail.

(b) NS Power has no additional studies to offer on these subjects.

NON-CONFIDENTIAL

Request IR-38:

REFERENCE: M2(vi), App. 6.02, p. 32-33

CITATION:

Challenge

As system load reduces in the off peak overnight hours, generation must be turned down to follow load. With wind generation added to the system, conventional generation must be turned down even further or de-committed to limit curtailment of wind generation in order to meet the RES requirements. With approximately 300 MW of wind generation installed, NSPI is already encountering the challenges of minimum unit turndown and commitment. However, the amount of conventional generation that can be de-committed is limited by the high morning load. This problem of minimum unit commitment is further complicated by possible unit contingencies and uncertainties introduced by errors in wind forecasts. To demonstrate the magnitude of the issue, Figure 3.9 presents an excerpt of <u>actual system load data and actual wind generation data scaled up to emulate the output of 785MW of installed wind capacity</u> (the installed wind capacity that would be required to meet the 2020RES under low load conditions). The black circled portion on Figure 3.9 shows that for the five hour period between midnight and early morning, high wind generation (blue line) causes the modified load (actual load less wind generation, shown by the orange line) to become significantly lower than the minimum generation that is online. Such an event would necessitate wind curtailment due to low load conditions and the potential inability to de-commit conventional generation on short notice.

(a) In scaling up the actual wind generation data to emulate the output of 785 MW of installed wind capacity, did NSPI make any effort to account for the effect of increased geographic diversity? If so, please specify the methodology used. If not, please explain why not.

NON-CONFIDENTIAL

(b) Has NSPI simulated the performance of this emulated wind fleet to estimate the amount of curtailment that would be required? If so, please provide a detailed description and detailed results of the simulation.

Response IR-38:

(a) NS Power used the information that has been posted on the OASIS for the Generator Interconnection Queue for guidance on prospective projects that could contribute future requirements. The analysis was predominantly a scaling exercise to give an estimate of the range of curtailment that could be expected from futher development of wind resources.

(b) NS Power has not performed wind fleet simulations for this purpose.

Request IR-39:

REFERENCE: M2(vi), App. 6.02, p. 37

CITATION:

> **Should it be necessary for NSPI to meet the 2020 RES requirements predominantly with wind, significant integration costs will be incurred over and above the costs associated with building wind generation and associated interconnection facilities. While NSPI is continuing to detail these costs the following system requirements have been identified to date which would require some level of capital investment depending on the penetration levels of variable wind generation:**
>
> - **Investment in new conventional generating capacity to maintain planning reserves and address needs for two shifting or fast acting generation. Simple-cycle combustion turbines in various multiples of 50MW ($60M) and 100MW ($100M) were assumed to address this requirement across the range of wind options.**
>
> - **Investment in transmission upgrades within NSPI and developing stronger links with neighboring utilities to enhance system stability and reduce thermal generator cycling. Transmission investments with a mid-range of $250M were assumed to represent these costs.**
>
> - **Deploying energy storage and load shifting programs to complement conventional generation for managing wind variability and wind ramps. In cases where energy storage/load shifting was assumed necessary, costs were forecasted at $200 to $400M.**

Please provide a copy of the NSPI report from which these data are drawn.

Response IR-39:

Please refer to Synapse IR-18 Attachment 1, filed electronically, for the related worksheet.

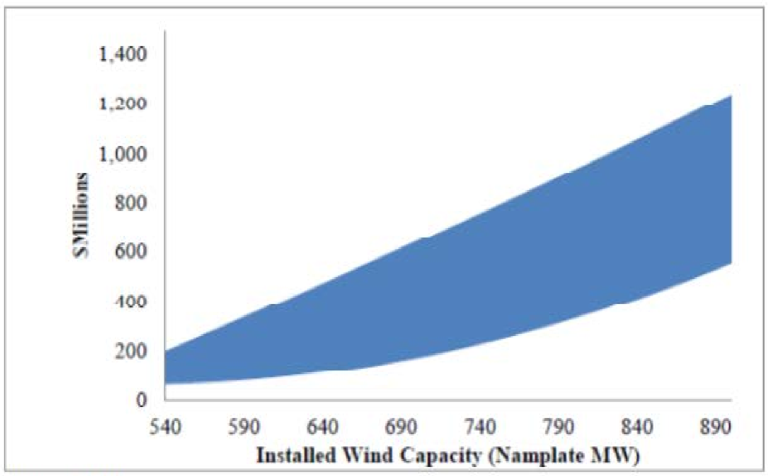
NON-CONFIDENTIAL

Request IR-40:

REFERENCE: M2(vi), App. 6.02, Figure 4.1, p. 38

CITATION:

Figure 4.1 Estimated Range of Capital Investments to Support Large Scale Wind Integration



Source: NSPI

(a) **Please provide the data used to prepare this graph, accompanied by a detailed narrative explanation.**

(b) **Please indicate a precise source for this graph.**

(c) **Please provide a copy of the document from which this graph was drawn.**

(d) **Please indicate in detail to what extent, if any, these costs were included in the Alternatives Analysis.**

Response IR-40:

(a-d) Please refer to Synapse IR-18.

Request IR-41:

REFERENCE: M2(vi), App. 6.03, p. 2

CITATION:

> **This database model is based on existing databases that were used in the 2007 and 2009 integrated resource plans with updates to reflect current forecasts and recent changes to the power system.**

(a) Please identify in detail the elements that were updated with respect to the 2009 IRP.

(b) Please provide a document indicating in detail the updates, in relation to the 2009 IRP.

(c) Please file a copy of the 2009 IRP Update.

Response IR-41:

(a-b) Please refer to Synapse IR-12.

(c) The 2009 IRP Update is available on the UARB website under matter M03441: http://www.nsuarb.ca/index.php?option=com_content&task=view&id=73&Itemid=82

NON-CONFIDENTIAL

Request IR-42:

REFERENCE: M2(vi), App. 6.03, p. 3

CITATION:

> **For each alternative the following scenarios have been run:**
> **1) base load**
> **2) low load**

Please explain why no high scenario was run.

Response IR-42:

Please refer to Synapse IR-13 (a).

Request IR-43:

REFERENCE: M2(vi), App. 6.03, p. 4

CITATION:

A base load case was developed for modeling and analysis and included the following assumptions:

- **Assumption for growth of economic indicators was increased by 50% in the forecast models over low load case. i.e. 2% annual growth was increased to 3%.**

- **The rate of growth in residential electric heating was increased by 1% every 5 years. – double the current growth rate.**

- **It was assumed that Electric Vehicles (EV's) would grow to become 1% of annual auto sales in 10 years. This would add an estimated 15 GWh in year 10.**

(a) Please justify the choice to increase by 50% the load growth rate from NSPI's July 2012-GRA-Refresh load forecast for a « base load forecast ».

(b) Please justify the choice to increase the rate of growth in residential electric heating by double the current growth rate in a base load forecast.

(c) Please indicate the forecast residential electric heating load, both in GWh and in penetration rate, for each year 2015-2040.

(d) Please justify the assumption that the Port Hawkesbury paper mill would continue to operate to 2040 in a base load forecast.

NON-CONFIDENTIAL

(e) Please specify the « current rate of change » assumed for DSM, and provide GWh savings for each year 2015-2040.

(f) Please provide historical data for Nova Scotia load and load growth since 2000.

(g) Please explain the assumption of "significant load growth" in a base load scenario, in light of Nova Scotia's recent history.

(h) Please justify the assumption, in a base load forecast, that Electric Vehicles (EV's) would grow to become 1% of annual auto sales in 10 years, adding 15 GWh in year 10, making reference to forecasts in neighbouring jurisdictions.

Response IR-43:

(a-b) Please refer to CA-IR-49.

(c) Please refer to Table 1 below for electric heat saturation from 2015 to 2040 for both the low and base scenarios. The econometric model uses variables like heating degree days, appliance efficiency improvement, customer counts, and electric heat saturation, rather than calculating the total space heat requirement in estimating residential load. Due to the impact of future DSM programs it is difficult to predict the total energy requirement associated with electric space heating.

Table 1:

Electric Heat Saturation		
Year	**Low Load**	**Base Load**
2015	31.15	31.75
2016	31.39	32.19
2017	31.66	32.66
2018	31.93	33.13
2019	32.18	33.58
2020	32.44	34.04
2021	32.70	34.50
2022	32.94	34.94
2023	33.16	35.36
2024	33.38	35.78
2025	33.56	36.16
2026	33.71	36.51
2027	33.83	36.83
2028	33.93	37.13
2029	34.01	37.41
2030	34.07	37.67
2031	34.13	37.93
2032	34.19	38.19
2033	34.26	38.46
2034	34.32	38.72
2035	34.38	38.98
2036	34.44	39.24
2037	34.51	39.51
2038	34.57	39.77
2039	34.63	40.03
2040	34.69	40.29

(d) Please refer to Synapse IR-13 a.

(e) Please refer to CA-IR-53.

NON-CONFIDENTIAL

(f)

Year	Net System Requirement (Gwh)	Change (%)
2000	11,240.1	-
2001	11,303.2	0.6
2002	11,501.0	1.8
2003	12,009.1	4.4
2004	12,387.6	3.2
2005	12,338.2	-0.4
2006	10,946.2	-11.3
2007	12,639.5	15.5
2008	12,538.9	-0.8
2009	12,073.4	-3.7
2010	12,157.7	0.7
2011	11,907.9	-2.1
2012	10,474.3	-12.0

(g) Please refer to Synapse IR-13.

(h) Please refer to CA-IR-49 (b).

NON-CONFIDENTIAL

Request IR-44:

REFERENCE: M2(vi), App. 6.03, p. 5

CITATION:

- **A long-term low load forecast (to the year 2040) was developed using the July-2012 GRA-Refresh load forecast as the starting point.**
- **Econometric models extended to 2025, and for the remaining 15 years, load was projected at the 2025 growth rate for each sector : (Residential, Commercial, Industrial)**
- **Large industrial load for 2013 and beyond was assumed to offer little growth potential, so was kept flat throughout the forecast. The Port Hawkesbury paper mill is assumed to return to operation for 2013 until 2019, however the Bowater Mersey paper mill remains closed.**
- **DSM affects were as per the efficiency Nova Scotia Corporation (ENSC) plan for 2013-2015, then based upon a long-term outlook provided by ENSC up to 2032. For the years beyond 2032, it was assumed that DSM effects would be equal to load growth, essentially keeping load growth to zero.**

(a) Please provide a copy of the July-2012 GRA-Refresh load forecast.

(b) Please justify the choice to use the current load forecast for the <u>low load</u> scenario.

(c) Please indicate whether in a) its recent General Rate Applications, and b) its 2007 and 2009 IRP proceedings, NSPI has used its detailed load forecast for the low load or for the base load scenario.

NON-CONFIDENTIAL

(d) Please provide the input assumptions for the econometric models, and justify their use in a low load forecast.

(e) Please indicate whether or not there is any possibility of further loss of industrial load in Nova Scotia.

(f) Please provide a copy of the long-term DSM outlook provided by ENSC up to 2032.

(g) Please explain why NSPI chose to limit DSM after 2032, in a low load scenario, to be equal to load growth, essentially keeping load growth to zero. For greater clarity, please explain why NSPI excludes the possibility that DSM effects will be greater than load growth in the period 2032-2040.

Response IR-44:

(a) Please reference CA IR-49.

(b) Please reference Synapse IR-13.

(c) In the most recent GRA application and in the 2007 and 2009 IRPs, the Company's current load forecast was referred to as the base load forecast and low and high scenarios were provided as alternatives.

(d) Details on the input assumptions in the econometric model can be found in the April 2012 NSPI Load Forecast filed as SR-02 in the 2013 General Rate Application.

(e) There is both the possibility of the expansion of industrial load in the future and reduction.

NON-CONFIDENTIAL

(f) The 2016-2032 long term outlook is available publicly in response to Multeese IR-6b from ENSC's application to the UARB for approval of its Demand Side Management Plan 2013-2015.

(g) Please reference CA-IR-53.

NON-CONFIDENTIAL

Request IR-45:

REFERENCE: M2(vi), App. 6.03, p. 7

CITATION:

Long-term DSM Forecast Values

(a) Please indicate if the values provided in the table of Long-term DSM Forecast Values apply to all load growth scenarios, or only to the low load scenario.

(b) If the values provided in the table of Long-term DSM Forecast Values apply only to the low load scenario, please provide a similar table for the base load scenario.

Response IR-45:

(a-b) DSM is included in both scenarios and the same load bounds were used to examine all alternatives.

NON-CONFIDENTIAL

Request IR-46:

REFERENCE: M2(vi), App. 6.03, p. 11

CITATION:

> **As per amendments to the RES regulations, COMFIT contribution will not be included as a resource in planning to meet the RES.**

Please explain, to the best of NSPI's knowledge, why an amendment was adopted to the RES regulations specifying that the COMFIT contribution will not be included as a resource in planning to meet the RES?

Response IR-46:

NS Power cannot speculate on the reasons for the amendment.

NON-CONFIDENTIAL

Request IR-47:

REFERENCE: M2(vi), App. 6.03, p. 14

(a) Please provide the estimated levelized unit cost ($/MWh) in 2012 dollars for the Maritime Link and Other Import options.

(b) Please provide an Excel workbook including the assumptions and calculations used to estimate the levelized unit cost for the Maritime Link and Other Import options.

(c) Please explain in detail why the Indigenous Wind scenario is designed to produce substantially more annual energy than the Maritime Link or the Other Import scenarios.

PREAMBLE:

No imports over the NB Tie are included in the Indigenous Wind scenario, but 100 MW over this tie are included in the Maritime Link scenario.

(d) In NSPI and NSPML's opinion, is it possible that the costs of the Indigenous Wind scenario could be lowered by including some imports over the NB Tie? In the affirmative, please explain why no such scenario was presented. In the negative, please explain the reasons for your view.

(e) Please explain why 100 MW of imports over the NB Tie are included in the Maritime Link scenario.

(f) Please specify the reduction in wind and other resources that would result if the Indigenous Wind scenario included 100 MW of imports over the NB Tie.

(g) Please specify the implications in terms of annual cost and NPV if the Indigenous Wind scenario included 100 MW of imports over the NB Tie.

(h) Please explain the 300 MW of exports in the Indigenous Wind scenario, as well as the export prices used in the economic analysis.

PREAMBLE:

On page 18 of App. 6.03, a capital cost of $988M is provided, without indication as to whether it applies to the Low Load or Base Load scenario.

(i) Please indicate clearly the capital cost for wind investments under the Low Load and Base Load scenarios.

Response IR-47:

(a-b) The levelized costs are not part of the analysis. The ML and Alternatives all have different effects on the existing electrical generation in Nova Scotia. The Alternatives analysis encompasses the costs of the particular alternative along with the resulting costs of the generation for the balance of the electrical system in Nova Scotia.

(c) The amount of energy required is consistent between the three alternatives.

(d) Please refer to SBA IR-70.

(e) Up to 100 MW of energy is available from New Brunswick in the model. This is reflective of the increased import capability on the NB/NS tie because of the Nalcor energy flowing from the Maritime Link.

NON-CONFIDENTIAL

(f-g) This specific sensitivity was not conducted as part of the analysis. Please refer to SBA IR-70.

(h) Please refer to NSUARB IR-37 for the export prices. Reflective of current transmission limitations, up to 300 MW of exports to NB were available to the model.

(i) Please refer to Synapse IR-1 Attachment 1. The same capital cost basis was used for both the Base load and Low load scenarios.

NON-CONFIDENTIAL

Request IR-48:

REFERENCE: M2(vi), App. 6.05, p. 5 of 27

CITATION:

> The mandate of WKM Energy for this paper is limited to the identification of costs and issues associated with delivery of a purchase from Hydro Quebec. The information provided dos not constitute a full economic evaluation of Hydro Quebec purchase. It provides cost estimates for transmission and the means by which those costs could be recovered through the OATTs of NB Power and NS Power. As such it is information that can be used by Emera to complete a full economic analysis of a Hydro Quebec Purchase which would need to include the cost of capacity and energy.

(a) Has Emera completed an economic analysis of a Hydro Quebec Purchase?

(b) In the affirmative, please provide a copy of Emera's economic analysis of a Hydro Quebec Purchase.

Response IR-48:

(a) Emera has completed an analysis of alternative import which is the Other Import scenario. For the purpose of the alternative, to avoid relying upon one particular supply alternative or source, the Other Import is based upon market prices and factors which represent a supply from whomever could provide the renewable energy and capacity required, through the electrical connection to the northwest of Nova Scotia.

(b) Please refer to the modeling input and results for Other Import.

NON-CONFIDENTIAL

Request IR-49:

REFERENCE: M2(vi), App. 6.05, p. 6 of 27

CITATION:

> The Nova Scotia Power 2009 Integrated Resource Plan Update[8] that was filed and reviewed by the Utility and Review Board (UARB) sets out a future for Nova Scotia within which a capacity and energy purchase from an imported renewable resource will fit. The key points of that plan are: …
>
> - Beyond 2020 uncertainty in emission limits remains[9], though further physical reductions are expected, and NS Power will continue to explore opportunities for a large (300MW) non-emitting Power Purchase Agreement (PPA) as an option to respond to the larger-scale future need.

Did the 2009 IRP Update identify the purchase of a large non-emitting PPA as the least-cost option? If not, why not?

Response IR-49:

Yes, the 2009 IRP Update did anticipate a large non-emitting import with a timeline in the 2020s. Subsequent changes in greenhouse gas and air pollutant regulations and RES regulations have led to the advancement of this alternative.

NON-CONFIDENTIAL

Request IR-50:

REFERENCE: M2(vi), App. 6.05, p. 8 of 27, Figure 2

CITATION:

Figure 2
NBSO Transmission Capabilities in MW[14]

	Quebec Interface				NS Interface	
	------HVDC------		-----Radial-----			
Firm	Summer	Winter	Summer	Winter	Summer	Winter
TTC	742	773	150	200	405	405
Less TRM	50	50	150	200	305	325
Less Existing LT Firm	691	691	0	0	80	80
Firm ATC	1	32	0	0	20	0
Non Firm						
TTC	742	773	150	200	405	405
Less TRM (Reserve Share)	0	0	0	0	105	105
Less Existing LT Firm	691	691	0	0	0	0
Non Firm ATC	51	82	150	200	300	300

(a) Please explain in detail the distinction between the HVDC and Radial categories for the Quebec interface.

(b) Please confirm that the TRM capacity is available on a non-firm basis.

Response IR-50:

(a) The Radial Transmission portion is the ability to supply load in New Brunswick directly from Quebec by connecting that load to the Quebec side of the HVDC stations. The HVDC Transmission portion is the ability to transmit power through the HVDC stations.

(b) Yes, the TRM is available on a non-firm basis.

NON-CONFIDENTIAL

Request IR-51:

REFERENCE: M2(vi), App. 6.05, p. 8 of 27

CITATION:

> In order to have a capacity purchase from Hydro Quebec be accredited as valid capacity in Nova Scotia and contribute to NS Power's adequacy obligations under NERC[15] reliability standards and NPCC[16] reliability criteria it is necessary that it be delivered via firm transmission.

Please specify the amount of firm capacity provided by Nalcor under the Agreements.

Response IR-51:

The amount of firm capacity for the Nova Scotia Block is 20 percent of the Muskrat Falls capacity divided by the number of days per years then divided by 16 hours per day, net of transmission losses. This calculation results in approximately 153 MW at the delivery point at Woodbine substation.

NON-CONFIDENTIAL

Request IR-52:

REFERENCE: M2(vi), App. 6.05, p. 9 of 27

CITATION:

> **Under the NB OATT, if a Transmission Customer requests service and there is not sufficient capability to provide the requested service (as is the case currently at the NB-NS and HQ-NB interfaces), then the Transmission Provider, NBSO, is obligated to conduct any requested system impact studies and facilities studies to determine upgrades that may be required to provide it. NS Power or Hydro Quebec as the prospective customer would be responsible for the cost of the studies. If either decided to go forward with the reservation then the NBSO is obligated under the current regulatory structure in New Brunswick to have the transmission upgrades constructed[18].**
>
> **To protect other customers from rate increases and avoid cross subsidization of the new customer by existing customers, the new customer will pay the higher of the posted tariff or the cost of the facility upgrades (ie, the tariff plus additional direct assignment costs for the upgrades not funded through the tariff).**

(a) Please provide references to the provisions of the NBSO OATT referred to in the Citation.

(b) Are the provisions referred to here identical to those of the FERC pro forma tariff? If not, please summarize any significant differences between them.

Response IR-52:

(a) The Transmission Provider (NBSO) has the obligation to provide Transmission Service that requires expansion of the transmission system and the Eligible Customer (NS Power, Hydro Quebec or NB Power) has the obligation to pay for System Impact Studies, Facilities Studies and the cost of the expansion. OATT references setting out these obligations are as follows:

"15.4 Obligation to Provide Transmission Service that Requires Expansion or Modification of the Transmission System
If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to have a Transmitter expand or modify its Transmission System to provide the requested Firm Transmission Service, provided the Transmission Customer agrees to compensate the Transmission Provider and Transmitters for such costs pursuant to the terms of Section 27. The Transmission Provider and Transmitters will conform to Good Utility Practice in determining the need for new facilities and in the design and construction of such facilities. The obligation applies only to those facilities that the Transmission Provider has the right to have expanded or modified".

"19.1 Notice of Need for System Impact Study
After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. In such cases, the Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study".

"19.4 Facilities Study Procedures
If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study".

"27 COMPENSATION FOR NEW FACILITIES AND REDISPATCH COSTS
Whenever a System Impact Study performed by the Transmission Provider in connection with the provision of Firm Point-To-Point Transmission Service identifies the need for new facilities, the Transmission Customer shall be responsible for such costs to the extent consistent with the Transmission Provider's policy. Whenever a System Impact Study performed by the Transmission Provider identifies capacity constraints that may be relieved more economically by redispatching

resources than by building new facilities or upgrading existing facilities to eliminate such constraints, the Transmission Customer shall be responsible for the redispatch costs to the extent consistent with the Transmission Provider's policy".

(b) No, the provisions are not identical to the current post-Order 890 FERC pro forma tariff. However, they are identical to the pre-Order 890 FERC pro forma tariff with a single wording change from "Commission Policy" in the FERC pro forma tariff to "Transmission Providers Policy" in the NB OATT. It should be noted that NBSO made application to the NB EUB to upgrade its tariff to be compatible with the Order 890 pro forma in 2011. However, after release of the NB Energy Blueprint in October, 2011, arguments were made by interveners to suspend the hearings until after planned updates to the NB Electricity Act were made.

NON-CONFIDENTIAL

Request IR-53:

REFERENCE: M2(vi), App. 6.05, p. 9 of 27

CITATION:

> **[18]This is the current requirement under the NB OATT, the NB Market Rules and the NB electricity Act (2004). However it is proposed not to be the case in the future unde the NB Energy Bluepirnt which would put control of transmission construction in the hands of NB Power. Under the Blueprint proposal, access to Hydro Quebec by NS Power may likely by subject to the agreement of NB Power.**

(a) Please provide references to the sections of the NB Energy Blueprint to which you refer.

(b) In your opinion, should the Blueprint proposal be adopted, would the NBSO OATT remain in conformity with FERC's reciprocity requirements?

(c) In the negative, please describe the implications, if any, for New Brunswick Power if its OATT should be found in non-conformity with FERC's reciprocity requirements.

Response IR-53:

(a) The NB Energy Blueprint is publicly available: http://www2.gnb.ca/content/gnb/en/departments/energy.html

Sections of the NB Energy Blueprint that indicate the reintegration of NBSO into NB Power and the total control of transmission ownership and development are provided below:

> *"In order to improve transparency and the opportunity for meaningful cost reductions, NB Power will be reintegrated into a vertically integrated utility and the* ***Electricity Act*** *will be updated to reflect this simplified structure. In addition, Government will review New Brunswick's electricity market policies and implement structural and operational changes to improve efficiencies and cost effectiveness, including the reintegration of the system operation functions of the NBSO within NB Power".(Page 14)*

> *"In addition to taking over the system operation function, NB Power will become the sole developer and owner of the transmission system in New Brunswick, thus maximizing our geographic advantage in the international northeast region. Reserving the right for NB Power to provide new interconnection transmission capacity, rather than market participants from outside New Brunswick, will maximize the benefits to New Brunswick on energy deals being transacted through the province. This will not however inhibit NB Power from seeking partners in the construction of new transmission lines".(Page 16)*

(b-c) Yes, that is the expressed intent of the NB Energy Blueprint as stated below:

> *"By establishing and enforcing proper functional separation and codes of conduct within the organization, a fully integrated utility (including system operator functions) can maintain the adequacy and reliability of the integrated electricity system and meet NERC/FERC requirements relating to reliability and open, non-discriminatory transmission access and reciprocity, thereby preserving our access to U.S. electricity export markets. Recognizing that it may not be desirable for NB Power to take over certain functions that the NBSO currently carries out - such as monitoring and enforcing reliability standards - these responsibilities will be moved to, or independently reviewed by, appropriate organizations outside of NB Power." (Page 15)*

NON-CONFIDENTIAL

Request IR-54:

REFERENCE: M2(vi), App. 6.05, p. 10-11 of 27

CITATION 1:

> **To be able to provide transmission for a purchase from Hydro Quebec that is similar to that provided by the Maritimes Link (<u>165 MW for a firm purchase</u> plus up to 335 MW for surplus energy or future firm purchases) it is necessary to complete upgrades to both the NB-NS interconnection and the HQ-NB interconnection.**

CITATION 2:

> **At the NB-NS interconnection the supply of <u>500 MW of firm transmission capability</u> to NS Power requires that the NB Power system must be reinforced back to Coleson Cove.**

(a) **Do all of the scenarios explored in your report include the « NB-NS#1 » option, which provides 500 MW of firm transmission capacity?**

(b) **Please explain why 500 MW of firm transmission capability from New Brunswick to Nova Scotia is required to provide transmission for a purchase from Hydro Quebec that is similar to that provided by the Maritimes Link, which includes only 165 MW of firm power.**

(c) **Does your report present an NB-NS alternative which provides 165 MW instead of 500 MW of firm transmission capacity? If not, why not?**

(d) Please estimate the capital costs associated with making 165 MW of firm transmission capability available on the NB-NS interface.

Response IR-54:

(a) Yes.

(b) A 345 kV line is capable of 500 MW. Consistent with past planning, even prior to the Maritime Link being considered the size of the interconnection was determined to be 345 kV (please refer to NS Power 10 Year System Outlook from 2008 found at: http://oasis.nspower.ca/site-nsp/media/Oasis/2012%2010%20Year%20System%20Outlook%20Report%20June%2029%202012.pdf) and more recently the AEG Transmission Modelling Study (SBA IR-256 Attachment 2).

(c) No. Please refer to (b).

(d) Please refer to CA/SBA IR-70.

NON-CONFIDENTIAL

Request IR-55:

REFERENCE: M2(vi), App. 6.05, p. 18 of 27

CITATION :

> **In addition to improved reliability, this second interconnection provides an opportunity for an expanded balancing area which can assist in the integration of the amount of wind committed to be added to the NS Power system. While a larger balancing area is also possible with NBSO it would not have the amount of hydro storage that exists in Newfoundland and Labrador. While Hydro Quebec has large hydro storages, they have, as yet, not provided any balancing services to any adjacent markets. This does not mean that they would not but the complexity of a balancing deal two systems away would make it less attractive.**

(a) Please explain in detail the methodology by which hydro storage in Newfoundland and Labrador would be used to assist in the integration of wind power added to the NS Power system.

(b) Please specify the hydro storage in Newfoundland and Labrador to which you are referring, and indicate your reasons for believing that NSPI will have access to this storage.

(c) Please explain in detail « the complexities of a balancing deal two systems away », to which you refer.

(d) Please indicate whether or not Newfoundland and Labrador consist of a single balancing area. In the affirmative, please identify the system operator. In the

NON-CONFIDENTIAL

negative, please indicate the names of the two system operators and explain in detail the way that they are coordinated.

(e) Does Hydro Quebec provide balancing services to wind power in Quebec?

(f) In the affirmative, please provide a summary of the terms under which Hydro-Quebec provides balancing services to wind power in Quebec.

(g) Please indicate whether or not the hydro storage in Labrador is currently available to Hydro-Quebec to provide balancing services for wind power.

(h) In the affirmative, please explain how use of the Churchill Falls hydro storage for providing balancing services to Hydro-Quebec and to Nalcor Energy would be coordinated.

Response IR-55:

This response provided by WKM Energy Consultants Inc.

(a) The HVDC station at the NS end of the Maritime Link could be placed on AGC to provide 20 MW of Regulation Service for NS Power. As the HVDC changed its delivered electricity to balance Nova Scotia, the change would be passed back to the Newfoundland side of the Maritime Link and cause an imbalance in Newfoundland. This imbalance would be sensed and corrected by hydro units in Newfoundland that are on AGC. This same arrangement would be activated between Newfoundland and Labrador across the Island Link so that mutual balancing support can be provided across the region. Hence, the hydro storage in Newfoundland and Labrador would help balance the wind in Nova Scotia. Please also see the responses to CA/SBA IR-261(a) and CA/SBA IR-261(h).

(b) The likely hydro storages that can provide the balancing are Muskrat Falls in Labrador and Bay d'Espoir plus smaller hydro stations in Newfoundland. NS Power will have access to some of this storage through its planned agreement with Nalcor to have 20 MW of Regulating Service provided via the Maritime Link as set out in Schedule 5 of the Energy and Capacity Agreement (Appendix 2.04 of the Application). Please also see the responses to CA/SBA IR-261 (a) and CA/SBA IR-261 (h).

(c) To provide balancing services from Quebec to Nova Scotia requires that dynamic scheduling be instituted between Quebec and Nova Scotia. To do so requires that firm transmission be reserved from Quebec to Nova Scotia for the full range of the balancing changes. For example, to provide plus or minus 30 MW of balancing it would be necessary to reserve 60 MW of firm transmission. An initial energy flow of 30 MW would need to be scheduled and control signals put in place such that this energy flow would be modulated to off-set the Area Control Error (ACE) in the Nova Scotia Balancing Area. In addition to continuous coordination between the Quebec and Nova Scotia system operators, the New Brunswick system operator would need to be involved and would need to have over-riding control in order to sustain reliability of the New Brunswick system. At present, there is no firm transmission available from Quebec to Nova Scotia so such an arrangement is not possible.

(d) Newfoundland and Labrador are electrically isolated from each other today so must operate as two separate balancing areas. WKM Energy has no knowledge of the specific operational coordination of either system. After the Muskrat Falls project (including the Labrador and Island Link transmission) is completed, it is expected that the entire Newfoundland and Labrador system would be operated as a single balancing area with a single system operator.

(e) Yes.

NON-CONFIDENTIAL

(f) Hydro Quebec Production (HQP) provides wind balancing services to Hydro Quebec Distribution (HQD) under the ENTENTE D'INTÉGRATION ÉOLIENNE (EDIE) dated June 9, 2005. In it, HQP accept all wind energy as it is produced by the wind farms under contract to HQD and provides in return to HQD a steady flow of energy at 35 percent of the nameplate capacity of the wind farms. The original agreement had a term of five years and was approved by the Regie to be in force until Dec 31, 2011. HQD applied to have a new agreement approved in 2011 but it was not approved and neither was an alternative arrangement in 2012 approved. The EDIE included escalation on the pricing terms so it has continued to be in force. When a new balancing arrangement will be in force is not known.

(g) It is understood that the interface between Labrador and Quebec operates on an hourly schedule with imbalances considered as inadvertent energy. As such, the Churchill Falls hydro storage in proportion to Hydro Quebec's contract capacity is available to be used by Hydro Quebec for hourly balancing.

(h) Within Labrador, the recall capacity from Churchill Falls should be available to be placed on AGC to provide intra hour balancing for loads and wind in Labrador today, and for loads and wind in a combined Newfoundland and Labrador balancing area after the Muskrat Falls project is completed.

NON-CONFIDENTIAL

Request IR-56:

REFERENCE: M2(vi), App. 6.06

(a) Please provide an Excel workbook containing the data and graphs presented on pages 2, 3, 5 and 6 of Appendix 6.06.

(b) Please justify the choice of a discount rate of 6.56%.

(c) Please specify the investments and the costs included in the « capital investments for wind integration » applied in 2019 in the Base Load Indigenous Wind plan (page 1) and in the Low Load Indigenous Wind plan (page 4).

(d) Please explain in detail the mechanism used for determining annual capital costs for a) the Other Import and b) the Indigenous Wind scenarios.

(e) Please explain in detail how the operating and capital costs of the Indigenous Wind scenario would change if the wind investments were treated as part of NSPI's rate base.

(f) Please provide the year-by-year modelling outputs for the scenarios described on pages 1 and 4 of Appendix 6.06, in sufficient detail to make it possible to duplicate the calculations of Planning NPV and Study NPV for each scenario.

Response IR-56:

(a) Please refer to Synapse IR-11 (a).

(b) The discount rate of 6.56 percent is the 2014 discount rate from the 2013 GRA.

NON-CONFIDENTIAL

(c) Please refer to Synapse IR-18 Att 2.

(d) Please refer to Synapse IR-14 (i).

(e) The wind investments were treated as part of NS Power's rate base in the modeling.

(f) Please refer to Synapse IR-11 (a).