NON-CONFIDENTIAL

Request IR-272:

Please provide transmission planning studies conducted for Nova Scotia in the last five years including but not limited to the NSPI 10 Year System Outlook 2012-2021 Report.

Response IR-272:

Please refer to Attachments 1-8.

Note that Attachment 6 and Attachment 7 are two parts of the same transmission planning report that has been split into two parts due to file size limitations. Attachment 6 is the main body of the report plus Appendices A through D, and Attachment 7 contains the Appendices E through AA.

Nova Scotia Power Inc.

10 Year System Outlook

2008-2017

June 2008

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EXECUTIVE SUMMARY

On February 1, 2007 the *Electricity Act* came into effect, opening the Nova Scotia electricity market to wholesale competition. To direct the operation and administration of this competitive market, wholesale market rules were also introduced by the Province through the *Wholesale Market Rules Regulations*.

Per the Wholesale Market Rules, the Nova Scotia Power System Operator[1] (NSPSO) is responsible for the safe and reliable operation of the Bulk Electricity Supply System and administration of the competitive wholesale market. One requirement of this role is to file with the Nova Scotia Utility and Review Board (UARB, Board) an annual assessment of the need for investments in transmission facilities and other actions that may be required to maintain the reliability of the power grid over the next 10 years.

This is the annual 10 Year System Outlook. The foundation for this report is the Integrated Resource Plan (IRP) filed with the UARB by Nova Scotia Power Inc. (NSPI) in July 2007.

The 10-year load forecast which formed the basis of the IRP predicts that electrical energy will increase from 12,338 GWh in 2005 to 15,028 GWh in 2015. This represents an annual energy growth rate of 2% per year over the period. The load forecast for the hourly peak demand shows an increase from 2143 MW in 2005 to 2639 MW in 2015, which represents an annual growth rate of 2.1%. These numbers are exclusive of any Demand Side Management (DSM) program effects.

Subsequent to the filing of the IRP, Nova Scotia Power has received UARB approval of a DSM (Energy Efficiency and Conservation) Program which identifies initiatives for implementation in 2008 and 2009 and includes demand and energy savings of 8.85 MW and 66.32 GWh respectively.

As of May 6, 2008, Nova Scotia Power has 1348 MW of potential new projects in the generation interconnection queue at various stages of interconnection studies. The results of these studies will determine the effect on the NSPI electric power system in terms of any substation configurations and transmission line additions or upgrades that may be required to support the addition of this generation.

Generation additions under the Renewable Energy Standard (RES) are required in order to meet Provincial legislation. To date Nova Scotia Power has 60 MW of renewable energy operational and contracts for a further 244 MW of wind generation to meet its RES requirement for 2010. These generation projects are included in the interconnection queue.

In its 2008 Wind Integration Study, the Nova Scotia Department of Energy identified that the 2010 RES target for renewable supply can be met. The 2013 RES (assuming a total of 581 MW of wind power capacity) can be met, but more detailed impact studies are required to fully understand the cost and technical implications related to possible transmission upgrades and new

[1] The NSPSO is a functional responsibility within the Customer Operations Division of Nova Scotia Power Inc.

operational demands on existing infrastructure. Future study will be needed to fully understand the cost and stability issues of increasing wind supply beyond the 2013 RES.

Given that Nova Scotia remains in the early stages of renewable generation expansion and DSM implementation, this report identifies near-term transmission projects necessary to maintain supply reliability to customers served from the 138 kV and 69 kV systems. As renewables and DSM development move forward, the need for additional transmission-related additions will be determined. This information will be included in future 10 Year System Outlooks.

1.0 INTRODUCTION

This 10 Year Outlook fulfills NSPSO's obligations under Market Rule 3.4, Section 3.4.3.1 of which provides:

> "The purpose of the plan is to set out planned system developments, and to identify particular major investment decisions and other investment plans which are expected to be subject to Board approval, and that would require to be approved by the Board within 18 months of plan completion date, within the context of the system requirements over at least the next 10 years."

The scope of the Plan described in Section 3.4.2.1 is as follows:

> "The NSPSO system plan will address:
>
> a) transmission investment planning;
>
> b) DSM programs operated by NSPI Customer Service division or others;
>
> c) NSPI 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 NSPI, and
>
> f) requirements for additional DSM programs and / or generating capability (for energy or ancillary services).

Per Section 3.4.6.1.:

> "Subject to any contrary order of the Board, the NSPSO shall submit the draft NSPSO system plan to the Board for the Board's public comment process and for any Board review, and shall Publish the draft plan each year [meaning post on the OASIS public web site] by the end of June."

In fulfillment of this requirement, the enclosed provides:

1. A summary of the NSPI load forecast employed;
2. A discussion of DSM programs under development;
3. A summary of generation expansion anticipated for facilities owned by NSPI and others;

4. A discussion of transmission planning issues; and
5. Identification of transmission-related projects currently in the Transmission Expansion Plan.

The basis for this report is the NSPI Integrated Resource Plan filed with the UARB in July, 2007. The IRP was developed in collaboration with Board staff and in consultation with NSPI stakeholders. In the Board's Decision, dated May 7, 2008, regarding the Board's approval of NSPI's Demand Side Management Plan, the Board provided:

> "[45] … in the Board's opinion, the IRP has met the above stated TOR [Terms of Reference] objective. The Board and stakeholders now have an overall strategy within which NSPI's applications for approval of expenditures for capital projects and DSM can be assessed."

2.0 LOAD FORECAST

The NSPI load forecast provides an outlook on the energy and peak demand requirements of in-province customers. The forecast provides the basis for the financial 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 30-year average temperatures measured in the Halifax area of the Province.

The load forecast utilized in IRP development was the *"2006 IRP Load Forecast, September 2006"*. The forecast did not include Demand Side Management initiatives. (The DSM program which emerged from the IRP was presented as a demand option to meet net system requirement.)

Table 1 shows historical and forecast total annual energy requirements. The highest months of energy consumption in Nova Scotia are December through February due to the electric heating load in the Province.

NSPI also forecasts the peak hourly demand for future years. This process uses forecast energy requirements and expected load shapes (hourly consumption files) 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 (Source: 2007 IRP)

Year	Net System Requirement GWh	Growth Rate %
2000	11,240	3.4
2001	11,303	0.6
2002	11,501	1.8
2003	12,009	4.4
2004	12,388	3.2
2005	12,338	-0.4
2006F	11,784	-4.8
2007F	12,981	10.5
2008F	13,272	2.2
2009F	13,545	2.1
2010F	13,812	2.0
2011F	14,064	1.8
2012F	14,306	1.7
2013F	14,542	1.6
2014F	14,778	1.6

Year	Net System Requirement GWh	Growth Rate %
2015F	15,028	1.7
2016F	15,265	1.6
2017F	15,506	1.6

Note: Actual growth rates for 2006 and 2007 were -11.3% and 14.7% respectively, which reflects that one of NSPI's largest customers had a temporary shutdown and remained closed for nine months in 2006. For 2007 the plant returned to normal full load operations.

Table 2 – Coincident Peak Demand (Source: 2007 IRP)

Year	Net System Peak MW	Growth %	Non-Firm Peak MW	Growth %	Firm Peak MW	Growth %
2000	2009	6.6	412	33.3	1597	1.3
2001	1988	-1	369	-10.4	1619	1.4
2002	2078	4.5	348	-5.7	1730	6.9
2003	2074	-0.2	291	-16.4	1783	3.1
2004	2238	7.9	377	29.6	1861	4.4
2005	2143	-4.2	392	4.0	1751	-5.9
2006	2029	-5.3	386	-1.5	1644	-6.1
2007F	2256	11.2	381	-1.3	1876	14.1
2008F	2312	2.4	385	1.2	1927	2.7
2009F	2363	2.2	390	1.1	1973	2.4
2010F	2413	2.1	394	1.1	2019	2.3
2011F	2460	1.9	399	1.1	2061	2.1
2012F	2504	1.8	403	1.1	2102	2.0
2013F	2548	1.7	407	1.0	2141	1.9
2014F	2592	1.7	411	1.0	2181	1.9
2015F	2639	1.8	415	1.0	2224	2.0
2016F	2683	1.7	419	1.0	2265	1.8
2017F	2729	1.7	423	1.0	2306	1.8

3.0 DEMAND SIDE MANAGEMENT FORECAST

Increased investment in Demand Side Management is a main element of the IRP Reference Plan. The table below summarizes annual projected demand and energy savings included in the Reference Plan.

Table 3 – Demand Side Management Forecast (Source: 2007 IRP)

Totals	22 Year Total	Year 1 (2008)	Year 2	Year 3	Year 5	Year 10	Year 15	Year 22	Year 22
Demand Savings (MW)		11.4	18.2	30.6	46.2	57.9	56.2	57.0	60.0
Cumulative (MW)	1113	11.4	29.6	60.2	147.0	431.9	715.0	997.5	1113.0
Energy Savings (GWh)		77.8	124.5	186.8	249.2	282.1	258.2	245.8	243.4
Cumulative (GWh)	5354.9	77.8	202.4	389.2	872.0	2283.7	3617.1	4867.1	5354.9

Subsequent to the IRP filing, NSPI developed a comprehensive DSM plan and reviewed this with stakeholders. The plan was revised during the stakeholder engagement process and ultimately a Settlement Agreement was presented to the Board for its approval.

The Board approved the Settlement Agreement (SA) in April, 2008. In its Decision, released in May, 2008, the Board provided the following:

> "[21] The Board advised the parties by letter dated April 18, 2008, that the SA is approved. The Board sees the SA as consistent with the IRP and the widely accepted belief that there is a need to actively pursue DSM without delay. The Board appreciates the efforts of all parties to the SA in reaching a consensus on these issues. The Board will encourage and facilitate future collaboration/consultation."

The approved DSM Plan covers the period 2008 and 2009. The approved DSM plan includes investment of $12.9 million and demand and energy savings of 8.85 MW and 66.32 GWh respectively.

DSM development in Nova Scotia remains in its early stages. Work has not been undertaken to assign the forecast demand and energy reductions to particular areas of the Province. For transmission planning purposes, the long-term effect of DSM remains to be determined.

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 and hydro. In addition NSPI purchases energy from independent power producers located in the Province and imports power across the NSPI/NB Power intertie. Table 4 lists NSPI's generating stations/systems along with their fuel types and net operating capacities as of 2006.

Table 4 – 2006 Generating Resources (Data sourced from 2007 IRP)

Plant/System	Fuel Type	Winter Net Capacity	
Avon	Hydro	6.8	
Black River	Hydro	22.5	
Lequille System	Hydro	24.2	
Bear River System	Hydro	37.4	
Roseway	Hydro	1.8	
Tusket	Hydro	2.4	
Mersey System	Hydro	42.5	
St. Margaret's Bay	Hydro	10.8	
Sheet Harbour	Hydro	10.8	
Dickie Brook	Hydro	3.8	
Wreck Cove	Hydro	230.0	
Annapolis Tidal[1]	Hydro	3.7	
Fall River	Hydro	0.5	
Total Hydro			**397.2**
Tufts Cove	Heavy Fuel Oil	321.0	
Trenton	Coal/Pet Coke/Heavy Fuel Oil	307.0	
Point Tupper	Coal	154.0	
Lingan	Coal/Pet Coke/Heavy Fuel Oil	620.0	
Point Aconi	Coal/Pet Coke & Limestone Sorbent (CFB)	171.0	
Total Steam			**1573.0**
Tufts Cove	Natural Gas	98.0	
Burnside	Light Fuel Oil	132.0	
Tusket	Light Fuel Oil	24.0	
Victoria Junction	Light Fuel Oil	66.0	
Total Combustion Turbine			**320.0**
Contracts	Independent Power Producers	25.6	
Renewables		18.3	
Total IP Ps & Renewables			**43.9**
Total Capacity			**2334.1**

[1]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.

4.2 Changes in Capacity

Table 5 provides a schedule of firm supply and Demand Side Management capacity additions included in the IRP Reference Plan over the IRP planning period. (For DSM, the amounts shown are forecast reductions in demand.) Amounts shown as Uprates and Hydro include relatively small capacity additions to NSPI's existing generation fleet.

Table 5 – Capacity Additions & DSM (Source: 2007 IRP)

	Reference Plan
New Resources 2008-2014	
DSM	256
Tufts Cove 6	50
Uprates	20
Hydro	4.3
RES	166*
Additional Wind	16*
Subtotal	512.3
New Resources 2015-2029	
Additional Wind	144
DSM	857
Subtotal	1001
Total Firm Supply & Demand MWs Over Planning Period	1513.3

*Reference to RES and Additional Wind reflects the assumed firm capacity value of intermittent generation (generator capacity multiplied by a capacity factor of 32%).

As is evident from the schedule, the preeminent plan elements are renewable generation and DSM. As discussed throughout this document, the ultimate effect of these sources on the power system in Nova Scotia remains to be determined.

5.0 NEW GENERATING FACILITIES

5.1 Potential New Facilities

As of May 6, 2008, NSPI's interconnection request queue includes 1348 MW of proposed generation projects at various stages of interconnection study. Sponsors of these projects have requested either Network Resource Interconnection Service (NRIS) or Energy Resource Interconnection Service (ERIS). NRIS refers to a firm 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. Results of the various interconnection studies will be incorporated into future transmission plans. Table 6 provides NSPI's interconnection request queue on May 6, 2008.

Table 6 – Generation Interconnection Queue

Nova Scotia Power - Interconnection Request Queue

Publish Date: *Tuesday, May 06, 2008*

NOVA SCOTIA POWER An Emera Company

ID #	Request Date	County	MW Summer	MW Winter	Interconnection Point Requested	Type	Inservice date YY/MM/DD	Status	Service Type	Studies Available
8	14-Oct-03	Guysborough	15	15	L-5527B	Wind	2008	Impact re-study complete	N/A	
17	23-Jul-04	Lunenburg	100	100	L-6004	Wind	Nov 1, 2008	Impact Study in Progress	NRIS	
23	10-Oct-04	Inverness	100	100	L-6549	Wind	Nov 1, 2008	Impact Study in Progress	NRIS	
42	22-Nov-04	Cape Breton	100	100	New 138kV Line	Wind	Nov 1, 2008	Impact Study in Progress	NRIS	
45	19-Jan-05	Cumberland	35	35	L-6535	Wind	2008	Optional Study in Progress	N/A	
46	25-Jan-05	Colchester	32	32	L-6513	Wind	Nov 31, 2008	Impact Study in Progress	ERIS	
56	19-Aug-05	Cumberland	34	34	L-5058	Wind	Nov 31, 2008	Impact Study in Progress	ERIS	
67	27-Apr-06	Annapolis	40	40	L-5026	Wind	Oct 31, 2010	Impact Study in Progress	ERIS	
68	27-Apr-06	Digby	35	35	L-5533	Wind	Oct 31, 2010	Impact Study in Progress	ERIS	
82	15-Nov-06	Colchester	45	45	L-5040	wind	Dec 1, 2009	Impact Study in Progress	ERIS	
84	22-Dec-06	Pictou	50	50	L-7004	wind	Dec 2008	Impact Study Agrmnt Complete	ERIS	
86	09-Jan-07	Pictou	50	50	L-7003	wind	Jan 1, 2009	Impact Study Agrmnt Complete	NRIS	

Nova Scotia Power Interconnection Request Queue: Page 1 of 2

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

ID #	Request Date	County	MW Summer	MW Winter	Interconnection Point Requested	Type	Inservice date YY/MM/DD	Status	Service Type	Studies Available
114	23-Mar-07	Pictou	60	60	L-6511	wind	Nov 30, 2009	Impact Study Agrmnt Complete	NRIS	
115	23-Mar-07	Pictou	120	120	L-7003	wind	Nov 30, 2009	Impact Study Agrmnt Complete	NRIS	
117	13-Apr-07	Shelburne	10	10	L-5027	wind	September 1, 2009	Impact Study Agrmnt Complete	ERIS	
126	16-Apr-07	Cumberland	70	70	L-6513	wind	Dec 31, 2009	Impact Study Agrmnt Complete	ERIS	
128	17-Apr-07	Cumberland	40.5	40.5	L-6535	wind	November 20, 2009	Impact Study Agrmnt Complete	ERIS	
130	17-Apr-07	Cape Breton	200	200	L-7012	wind/water pumped	December 31, 2009	Impact Study Agrmnt Complete	NRIS	
131	17-Apr-07	Cape Breton	11.5	11.5	L-5580	wind	November 30, 2009	Impact Study Agrmnt Complete	ERIS	
137	17-Apr-07	Richmond	10	10	1C	wind	Nov 30, 2009	Impact Study Agrmnt Complete	NRIS	
140	20-Apr-07	Antigonish	30	30	L-7004	wind	November 1, 2009	Impact Study Agrmnt Complete	NRIS	
141	20-Apr-07	Digby	30	30	77V	wind	November 1, 2009	Impact Study Agrmnt Complete	NRIS	
149	05-Jul-07	Cumberland	70	70	L-6536	wind	Nov 20, 2009	Feasibility Study In Progress	ERIS	
150	16-Aug-07	Richmond	10	10	1C	wind	Nov 30, 2009	Impact Study Agrmnt Complete	NRIS	
151	22-Aug-07	Halifax	50	50	91H	steam turbine	June 30, 2010	Feasibility Study In Progress	NRIS	
		Totals:	1348	1348						

Nova Scotia Power Interconnection Request Queue: Page 2 of 2

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

Included in this interconnection queue is 244 MW of projects which are under contract to NSPI as part of its Renewable Energy Standards (RES) obligations in 2010. Table 7 indicates the location and size of these planned wind generating facilities.

Table 7 – RES-committed Renewable Generation Projects

Company/Location	Capacity
Renewable Energy Services Ltd. @ Statia Terminals in the Strait area of Cape Breton	22 MW
EarthFirst Canada Inc. @ Nuttby Mountain in Colchester County	45 MW
RMSenergy @ Dalhousie Mountain in Pictou County	51 MW
RMSenergy @ Maryvale in Antigonish County	6 MW
Shear Wind Inc. @ Brown’s Mountain Range in Pictou and Antigonish Counties	60 MW
Acciona Wind Energy Canada @ Amherst	30 MW
SkyPower Corp. and Scotian WindFields Inc. @ Rossway in the Municipality of Digby	30 MW
Total Contracted Capacity	**244 MW**

5.2 Province's Wind Integration Study

In May, 2008, the Nova Scotia Department of Energy (DOE) released its Wind Integration Study which identified and assessed the effects of integrating large scale wind power generation into Nova Scotia's electric power system. Completed by Hatch Ltd., the Integrated Wind Study specifically addressed the RES requirements for 2010 and 2013 and wind energy potential beyond 2013. It identified:

> "The RES requires that by 2013, 10% of the province's electricity requirement must be supplied by new renewable energy sources post 2001 (5% by 2010 and an additional 5% by 2013). Hatch estimates the 2013 RES requirement will bring the total provincial renewable supply to approximately 22% (581 MW). DOE expects most of this supply to be met with commercial-scale wind energy projects, and estimates the number of utility wind turbines in the province may grow from the current 41 to over 300.
>
> 2010 RES (assuming a total of 311 MW of wind power capacity):
> - The 2010 RES target for renewable supply can be met
> - By 2010, electricity production from post 2001 renewables is estimated to reach 7% -- total production from renewables at 16%.
>
> 2013 RES (assuming a total of 581 MW of wind power capacity):
> - The 2013 RES target for renewable supply can be met, but more detailed impact studies are required to fully understand the cost and technical implications related to possible transmission upgrades and new operational demands on existing infrastructure.
>
> Beyond 2013 RES (assuming 781 MW and 981 MW of wind power capacity):
> - Future study will be needed to fully understand the cost and stability issues of increasing wind supply to 781 MW and 981 MW levels, after we gain more real world operational experience with increasing amounts of wind supply."

(Final Report, Nova Scotia Wind Integration Study, 2008, Hatch Ltd., p11-13.)

5.3 Other Opportunities

In addition to the above, Newfoundland and Labrador Hydro, Emera Inc. and Nova Scotia Power have signed a Memorandum of Understanding to explore the possibility of bringing energy from the Lower Churchill Project to the Maritimes and New England markets. At the conclusion of this preliminary assessment, the parties will decide if there is merit in advancing potential joint initiatives. The Lower Churchill Hydroelectric Project's two installations at Gull Island and Muskrat Falls will have a combined capacity of over 2,800 MW.

6.0 RESOURCE ADEQUACY

6.1 Operating Reserve Criteria

As a member of the Maritimes Area of the Northeast Power Coordinating Council (NPCC), NSPI meets the operating reserve requirements as outlined in NPCC Document A-6, Operating Reserve Criteria[2]. This criteria is reviewed and adjusted periodically by NPCC. The criteria notes that:

> "The ten-minute reserve available to each Area shall at least equal its first contingency loss…" and,
>
> "The thirty-minute reserve available to each Area shall at least equal one half its second contingency loss."

In the Interconnection Agreement between Nova Scotia Power Incorporated and New Brunswick System Operator (NBSO), NSPI 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% of its greatest, on-line, net single contingency," and,
>
> "NSPI shall be responsible for 50 MW of Thirty-Minute Reserve."

NSPI maintains a ten minute operating reserve of 174 MW, of which approximately 36 MW is held as spinning reserve. Additional regulating reserve is maintained to manage the variability of customer load and generation. It is anticipated that regulating reserve requirements will increase with the addition of wind generation resources due to the added variability that will be introduced.

NSPI performs an assessment of operational resource adequacy covering an 18 month period two times a year (in April and October preceding the summer and winter capability periods). These reports of system capacity and adequacy are posted on the NSPI OASIS[3] site in the Forecast and Assessments section.

[2] http://www.npcc.org/viewDoc.aspx?name=A-6.pdf&cat=regStandCriteria
[3] http://oasis.nspower.ca/index.shtml

6.2 Planning Reserve Criteria

NSPI is required to comply with the NPCC reliability criteria. This criteria is outlined in NPCC Document A-2, Basic Criteria for Design and Operation of Interconnected Power Systems[4] and states that:

> "Each Area's probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with these criteria 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 Areas and Regions, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."

NSPI maintains a capacity based planning reserve margin equal to 20% of its firm system load in order to comply with the NPCC criteria. To assess the resource adequacy of the system, the New Brunswick System Operator, 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 review, the 2007 Maritimes Area Comprehensive Review of Resource Adequacy[5], it was found that the NPCC criteria would be met with a 20% reserve margin for the Maritimes Area along with 50 MW of additional capacity provided by interconnection assistance. This confirms that the 20% planning reserve margin applied by NSPI is acceptable under the NPCC reliability criteria.

6.3 Load and Resources Review

The ten year load forecast and resources additions in the table below are based on the IRP Reference Plan. The table indicates that a planning reserve margin equal to 20% of the firm peak load is maintained from 2009 through 2018.

[4] http://www.npcc.org/viewDoc.aspx?name=A-02.pdf&cat=regStandCriteria

[5] http://www.npcc.org/viewDoc.aspx?name=2007 Maritimes Area Comprehensive Review.pdf&cat=revResource

Table 8 – NSPI 10 Year Load and Resources Outlook (Source: IRP)

	Load and Resources Outlook for NSPI – Calendar Year 2009 to 2018 (All values in MW except as noted)										
		2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
A	Firm Peak Load Forecast	1,973	2,019	2,061	2,101	2,141	2,181	2,224	2,264	2,306	2,347
B	DSM Firm	22	44	73	106	142	183	225	266	307	347
C	Peak Firm Less DSM (A-B)	1,951	1,975	1,988	1,995	1,999	1,998	1,999	1,998	1,999	2,000
D	Required Reserve (C * 20%)	390	395	398	399	400	400	400	400	400	400
E	Required Capacity (C + D)	2,342	2,371	2,386	2,395	2,399	2,398	2,399	2,397	2,399	2,399
F	Existing Resources	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334
	Total Cumulative Additions:										
G	Thermal	0	62	67	72	72	72	72	72	72	72
H	Hydro	0	4	4	4	4	4	4	4	4	4
I	Firm RES	34	61	81	109	148	148	148	148	148	148
J	Firm Wind (beyond RES)	0	0	0	0	0	16	32	32	48	48
K	Total Firm Supply Resources (F + G + H + I + J)	2368	2462	2486	2520	2558	2574	2590	2590	2606	2606
	+ Surplus / - Deficit (K - E)	26	91	100	125	160	176	191	193	208	207
	Reserve Margin % (K/C -1)	21%	25%	25%	26%	28%	29%	30%	30%	30%	30%

7.0 TRANSMISSION PLANNING

7.1 System Description

The existing transmission system has over 5,200 km of transmission lines at voltages at the 69 kV, 138 kV, 230 kV and 345 kV levels.

- 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 1627 km in length and is comprised of 12 km of steel/concrete structures and 1615 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 in USA, Nova Scotia is integrated into the NPCC power system.

7.2 Transmission Design Criteria

NSPI, 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 NSPI bulk transmission system is planned, designed and operated in accordance with single contingency criteria. NSPI is a member of the Northeast Power Coordinating Council (NPCC). Those portions of Nova Scotia 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 Basic Criteria for Design and Operation of Interconnected Power Systems.

NSPI makes extensive use of Special Protection Systems (SPS) within SCADA to maximize 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 NSPI system has several transmission corridors that are regularly operated at limits. NSPI makes use of SPS to permit these transfer limits on these corridors.

7.3 Transmission Life Extension

NSPI has in place a comprehensive maintenance program on the transmission system aimed at improving reliability and extending the useful life of transmission plant. The program is centered on detailed transmission plant inspections and associated prioritization of plant replacement (i.e., poles, crossarms, guywires, and hardware replacement).

Nova Scotia Power also has in place a pole retreatment program that aims to retreat approximately 4,800 poles per year enabling the useful life of plant to be extended.

A transmission line up-rating program has been undertaken by Nova Scotia Power such that maximum utilization can be made using existing resources to serve increasing load.

7.4 Transmission Project Approval

The transmission plan presented in this document provides a summary of the planned reinforcement of the NSPI power system. The proposed investments are required to maintain system reliability and security and comply with System Design Criteria. NSPI 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 NSPI, 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 or the UARB.

In 2008 a Maritimes Area Technical Planning Committee was established to review intra-area plans for Maritimes Area resource adequacy and transmission reliability. This Committee will also project 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 interties, including any potential new intertie between Nova Scotia and New Brunswick. The Technical Planning Committee has transmission planning representation from Nova Scotia Power, New Brunswick System Operator, Maritime Electric Company, Ltd., Northern Maine Independent System Administrator and NB Power Transmission.

8.0 TRANSMISSION DEVELOPMENT 2008 TO 2017

Annual transmission development plans are summarized below. As discussed earlier, these projects make up NSPI's current plans and are subject to change.

1. 2008

- Replace an existing 69-12 kV, 7.5/10/12.5 MVA transformer at Bridgewater East substation with a unit rated 15/20/25 MVA. This change out is required due to load growth in the Bridgewater area.

- Add a second 69-12 kV, 7.5/10/12.5 MVA transformer at an existing Waterville substation. This addition is required due to load growth in the Annapolis Valley area.

- Construct a new 138-25 kV, 25/33/42 MVA substation on the Hammonds Plains Road in the Halifax Regional Municipality. This new substation is required due to load growth in the western portion of the Halifax Regional Municipality.

- Add a second 138-69 kV, 33.6/44.8/56 MVA transformer at an existing St. Croix substation in the eastern Valley area. This project will also include the establishment of a 138 kV bus including 2 x 138 kV circuit breakers and 1 x 69 kV circuit breaker. This project is necessary to address transformer overload conditions and low voltage across the eastern Valley area under first contingency failures.

- Work will begin on uprating an existing 138 kV circuit between Port Hastings and Glen Tosh for operation at 60^{o} Celsius.

2. 2009

- Construct a new 138-25 kV, 25/33/42 MVA substation at Dartmouth Crossing. This new substation is necessary due to load growth in the Dartmouth Crossing/Burnside area.

- Add a second 138-25 kV, 25/33/42 MVA transformer at Elmsdale and a second 12 MVAR capacitor bank. This project is necessary due to increased load growth in the Elmsdale/Enfield area.

- Install a 138-25 kV, 8.4/11.2 MVA transformer at the existing Cleveland substation. This unit will replace a 69-25 kV, 7.5/10 MVA transformer that failed in 2007. Installing a 138 kV transformer at Cleveland will enable the existing 69 kV system out of Port Hastings to be retired. This will include the removal of a 138-69 kV, 22.5/33.3 MVA transformer, a 69-25 kV, 7.5/10/11.2 MVA transformer, 1 x 138 kV circuit breaker and 3 x 69 kV circuit breakers.

- Work will be completed on the uprating of a 138 kV circuit between Port Hastings and Glen Tosh.

- An existing 69 kV circuit between Trenton and Bridge Avenue is planned to be rebuilt to provide additional capacity. This project is being undertaken to avoid an overload condition for the contingency loss of a parallel 69 kV circuit during high load conditions.

- Work is planned to commence to build additional transmission capacity to the Western Annapolis Valley. This will include the construction of a 138 kV circuit between Canaan Road and Tremont, a 138 kV termination at Canaan Road and the addition of a 138-69 kV, 33.6/44.8/56 MVA transformer at Tremont along with the establishment of a 138 kV bus. This project is necessary to mitigate various contingencies that could result in transformer overload scenarios, line overload conditions and low voltage conditions.

- Wind generation projects in the interconnection queue that are advanced to meet the RES or for other purposes will require construction of interconnection facilities. Additionally, transmission expansions and/or upgrades could be required to support these new generation interconnections. This will require significant activity in 2009 the meet the RES deadlines for 2010. Transmission planning scenarios will be developed as the interconnection studies for all projects are completed.

3. 2010

- Planning studies are being conducted to determine the adequacy of transformation facilities at an existing Gannon Road 138-69 kV substation. The outcome of these studies may mean the addition of a second 138-69 kV, 33.6/44.8/56 MVA transformer.

- A second 138-25 kV, 15/20/25 MVA transformer is planned to be added at Church St. in Amherst. This project is necessary due to area load growth.

4. 2011

- Studies are being completed to determine the loading capability of the 138-69 kV transformers at Trenton following the contingency loss of one of the units. The results of these studies may focus on off loading the transformers by changing out an existing 69-25 kV transformer for a 138-25 kV unit.

- An existing 69-12 kV, 7.5/10/12.5 MVA transformer at Barrington Passage is planned to be changed out for a unit rated 15/20/25 MVA to address load growth in the area.

- The existing 138-69 kV, 20/26.7 MVA transformer at Westhaver's Elbow is planned to be changed out for a unit rated 22.5/33.3 MVA for the purpose of addressing voltage regulation in the area.

- A new 138-25 kV substation is planned to be constructed at a new site in Eastern Passage. This substation would be served by the construction of a new 138 kV circuit from an existing Dartmouth East substation to the new site. This station is required to prevent equipment overloads during contingency conditions and address load growth in the Eastern Passage area.

- Studies are underway to determine the best method of load relief in the Canaan Road area of the Annapolis Valley. The solution will be in the form of a new substation but it has not as yet been determined if the substation will be served at the 138 kV or 69 kV level.

5. 2012 – 2017

- Details of DSM initiatives, the provincially mandated Renewable Energy Standard and additional renewable energy are unknown for this timeframe. The magnitude and location of renewable resources could require significant transmission additions such that the System Design Criteria is not violated. Given this, the Company has not assessed transmission system projects beyond 2011.

9.0 REFERENCES

1. *2004 Maritimes Area Triennial Review of Resource Adequacy*, Report approved by NPCC Reliability Coordinating Council March 9, 2005.

2. *Basic Criteria for Design and Operation of Interconnected Power Systems*, Northeast Power Coordinating Council Document A-2, May 6, 2004.

3. *Final Report, Nova Scotia Wind Integration Study*, Hatch, Ltd., 2008.

4. *Integrated Resource Plan Report*, Nova Scotia Power Inc., July 2007.

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

6. 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

Nova Scotia Power's interconnected system is divided into several classifications, each of which is governed by different design criteria.

These classifications are as follows:

1. Primary Transmission
2. Secondary Transmission
3. Electrically Remote Transmission
4. Sub transmission
5. Transformation

The System Design criteria combine protection performance specifications with system dynamics and steady state performance requirements. Within any classification, system studies assume specified protection performance to determine the required number, characteristics and type of system elements, while protection design incorporates only that equipment necessary to achieve the assumed performance, assuming a single coincident protection element failure.

DEFINITIONS

1. **Primary Transmission** is defined as the 345 kV transmission system interconnecting Lakeside-Onslow-Hopewell-Woodbine, and Salisbury, New Brunswick, the 230 kV transmission system interconnecting Brushy Hill-Onslow-Lingan-and Pt. Aconi, Nova Scotia and the interconnecting 345/230 kV transformation between them.

2. **Secondary Transmission System** is defined to be that part of the system which serves mainly to interconnect miscellaneous generation and Primary Transmission with Sub transmission at major load centres.

   The lesser importance of secondary transmission relative to the Primary Transmission permits a relaxation of the design criteria from that required for the primary transmission system. This definition then governs most of the 138 kV developments plus certain 69 kV and 230 kV, other than on the Primary Transmission system.

3. **Electrically Remote Transmission** is defined by those buses at which ultimate fault levels are projected to not exceed 1500 MV.A three phase.

4. **Sub transmission System** is defined to be that part of the system which primarily serves as a source for transformation to the distribution level. This type of system is primarily characterized by radial feeds although looped sub transmission exists.

5. **Interconnected Transmission System** is defined as the combined Primary, Secondary, and Electrically Remote Transmission systems including connected generation.

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

   (a) Any load condition (this includes the full range of annually forecasted loads).

   (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.

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

8. **Local back-up clearance** is defined to be the time to clear an in-zone fault.

9. **Remote back-up clearance** is defined to be the time to clear an out-of-zone fault.

10. **Breaker back-up** is defined to be protection against local breaker failure to trip for any reason. Breaker back-up will be applied to all Primary Transmission and most of the Secondary Transmission systems.

1. PRIMARY TRANSMISSION SYSTEM

Prime clearance times are defined to be 4.5 cycles first zone and 6 cycles second zone with permissive signal for both three-phase and line-to-ground faults.

Back-up clearance times are defined to be 15 to 18 cycles for both three-phase and line-to-ground faults.

The Design Criteria[6] 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 except a generator or bus section, cleared in prime time. No cascade tripping shall occur.

[6] *Note: The Primary Transmission System Design Criteria may be superseded by the NPCC Basic Criteria for the Design and Operation of Interconnected Power Systems.*

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 except a bus section or generator, cleared in 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 their long-term thermally limited ratings.

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 voltage\s shall not be 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.

II. SECONDARY TRANSMISSION SYSTEM

Prime time clearance is defined to be 6 to 9 cycles for both three-phase and line-to-ground faults. (No additional expenditure may be made to reduce clearing times from 9 to 6 cycles without authorization from System Design.)

Local back-up clearance is defined to be less than 30 cycles (a figure of 20 cycles is desirable but where coordination so dictates, a 30 cycle figure is acceptable).

Remote back-up clearance is defined to be less than 30 cycles which in certain instances implies reduced margins of coordination.

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 except a generator or bus section 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 except a generator or bus section, cleared in 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 their thermally limited ratings in the steady state.

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 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.

III. ELECTRICALLY REMOTE TRANSMISSION

Prime time clearance is defined to be 9 cycles for both three-phase and line-to-ground faults. Note 1 and Note 2.

The Design Criteria are:

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

2. From normal system conditions following loss of any one element with or without fault, all remaining elements shall be within their thermally limited ratings.

3. From normal system conditions, for the loss of any one Electrically Remote system element with or without fault, no Interconnected transmission system bus voltage shall be less than 90% or greater than 110% of nominal following a steady state settling out of the system nor shall any bus experience a voltage change from pre-fault to post-fault condition greater than 10% before tap-changer correction.

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

NOTES:

1. No expenditure may be made to reduce clearing times to reference values without authorization from System Design.

2. Permissive tripping between an electrically remote bus and a transmission bus (or between 2 electrically remote buses) is not required, i.e., local back-up clearances are acceptable.

3. Application of the above criteria does not preclude the possibility that for loss of certain remote system elements there will be a designed loss of load. This load would be restored after operator action.

IV. SUB-TRANSMISSION SYSTEM

The Design Criteria are:

1. Sub transmission system loading shall be within the thermally limited ratings.

2. The sub transmission system voltages shall not be less than 97.5% or greater than 105% of nominal.

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

4. From normal system conditions, following the loss of any one sub transmission system element with or without a fault, any sub transmission system bus which remains connected to the system, shall maintain sufficient voltage following automatic tap-changer correction to permit operation of any affected distribution bulk supply bus at 105% of nominal following a steady state settling out of the system. In no case shall any bus experience a voltage change from pre-fault to post-fault condition greater than 10% before tap-changer correction.

(The application of the above criteria does not guarantee a continuity of supply for any single contingency. In the case of a line, since a lengthy outage is considered to have a low probability time to repair is considered adequate for restoration of service; however, in the case of transformation, since an outage is generally a prolonged one, either the use of a mobile transformer for a short-term replacement or the installation of a spare transformer and interconnections with adjacent substations at the distribution level, are considered in decisions concerning the guaranteeing, after outage, of an alternative supply.)

V. TRANSFORMATION

Design Criteria

Capacity for any individual transformation point shall, under nominal 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 as per Note 4.

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 Note 4. (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 criteria because estimated out-of-merit costs may significantly exceed the costs of capital advancement.

2. The Primary Transmission system may require additional transformation in certain instances when, although the above (a), (b) and (c) may result in satisfaction of this particular criteria, any other of several possible contingencies (transmission lines, generators or transformer(s)) could result in either frequent or prolonged outages to a widespread part of the system.

3. The result of application of these criteria may not be installation of additional transformation.

10 Year System Outlook 2009-2018 Draft Report

June 30, 2009

NOVA SCOTIA POWER
An Emera Company

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1.0 INTRODUCTION

Nova Scotia Power Inc.'s (NSPI, the Company) filing of June 30, 2008 provided the initial 10 Year System Outlook. The scope of the Outlook, as described in Section 3.4.2.1[1] of the Market Rules, included the following:

1. A summary of the NSPI load forecast employed in the Outlook;
2. A discussion of Demand Side Management (DSM) programs under development;
3. A summary of generation expansion anticipated for facilities owned by NSPI and others;
4. A discussion of transmission planning issues;
5. Identification of transmission-related projects currently in the Transmission Expansion Plan.

In response to the filing, the Nova Scotia Utility and Review Board (UARB, Board), in its letter dated November 12, 2008, provided the following:

> The Board finds the Outlook to be satisfactory. However, the Board has identified several issues which should be addressed in the next filing of the Outlook report, due by June 30, 2009. The issues to be addressed in the next Outlook are:
>
> a) Most of the information contained in the Outlook is based on the Integrated Resource Plan ("IRP") filed with the Board in July 2007, even though more recent information was available. The NSPSO should ensure that the latest available data and forecasts are used when preparing its analyses and the Outlook report.
>
> b) Throughout the report, several Inconsistencies have been noted regarding the time period being addressed. The NSPSO should ensure that all assessments are consistently based on the same 10-year period covered by the Outlook.

1 The NSPSO system plan will address: a) transmission investment planning; b) DSM programs operated by NSPI Customer Service division or others; c) NSPI 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 NSPI, and f) requirements for additional DSM programs and / or generating capability (for energy or ancillary services).

c) The Outlook was deficient in providing information pertaining to transmission development beyond the year 2011. This was apparently attributed to uncertainty associated with DSM initiatives and the Renewable Energy Strategy (RES). The Nova Scotia Power System Operator (NSPSO) needs to ensure that system development plans extending throughout the full 10-year period covered by the Outlook are developed and clearly described in the report. These plans need to include the impact of DSM, the impact of renewable generation, and other projects, all of which should be based on the latest information that is known at the time the Outlook report is being submitted.

d) The Transmission Planning section of the Outlook should be expanded to include:

- Details on the status of electrical transfers occurring on the New Brunswick interconnections, including any anticipated reinforcements;

- The results of transmission system maintenance programs including inspections, replacements, and pole treatment; and

- Map illustrating the planned transmission projects which have been identified for the next 10-year period.

Consistent with the Market Rule requirements and the subsequent Board direction, the 2009 Outlook contains the following:

1. A summary of the NSPI load forecast employed in the Outlook;
2. An update on the DSM program undertaken by the Company;
3. A summary of generation expansion anticipated for facilities owned by NSPI 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 2009 Outlook is the assumptions employed in the 2009 Integrated Resource Plan (IRP) Update. For projected generation resources, the 2007 IRP findings have been employed as the 2009 IRP Update exercise is currently underway and expected to be completed by year end. The assumptions have been developed by NSPI and the Board's consultants, with input from IRP stakeholders. The 2009 IRP Update is scheduled to be filed with the Board in November, 2009.

2.0 LOAD FORECAST

The NSPI load forecast provides an outlook on the energy and peak demand requirements of in-province customers. The forecast provides the basis for the financial 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 do not reflect the effect of current or proposed Conservation and Demand Side Management programs

Table 1 shows historical and forecast total annual energy requirements. The highest months of energy consumption in Nova Scotia are December through February due to the electric heating load in the Province. The Net System Requirement for the province has grown at an average of 0.9 percent per year in the five year period from 2003-2008 and is forecast to grow an average of 0.6 percent annually over the next 10 years.

NSPI also forecasts the peak hourly demand for future years. This process uses forecast energy requirements and expected load shapes (hourly consumption files) 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 (Source: 2009 Load Forecast)

Year	Net System Requirement GWh	Growth Rate %
2001	11,303	0.6
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	12,639	15.5
2008	12,539	-0.8
2009F	12,478	-0.5
2010F	12,547	0.6
2011F	12,615	0.5
2012F	12,725	0.9
2013F	12,821	0.8
2014F	12,918	0.8
2015F	13,007	0.7
2016F	13,082	0.6
2017F	13,156	0.6
2018F	13,241	0.6

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

Table 2 – Coincident Peak Demand (Source: 2009 Load Forecast)

Year	Net System Peak MW	Growth %	Non-Firm Peak MW	Growth %	Firm Peak MW	Growth %
2000	2009	6.6	412	33.3	1597	1.3
2001	1988	-1	369	-10.4	1619	1.4
2002	2078	4.5	348	-5.7	1730	6.9
2003	2074	-0.2	291	-16.4	1783	3.1
2004	2238	7.9	377	29.6	1861	4.4
2005	2143	-4.2	392	4.0	1751	-5.9
2006	2029	-5.3	386	-1.5	1644	-6.1
2007	2145	5.7	381	-1.3	1764	7.3
2008	2192	2.2	352	-7.5	1840	4.3
2009F	2219	1.2	360	2.2	1859	1.0
2010F	2219	0.0	360	0.1	1858	0.0
2011F	2230	0.5	363	0.6	1867	0.5
2012F	2249	0.9	366	0.8	1883	0.9
2013F	2266	0.8	368	0.7	1898	0.8
2014F	2284	0.8	371	0.7	1913	0.8
2015F	2300	0.7	373	0.6	1927	0.7
2016F	2313	0.6	375	0.6	1938	0.6
2017F	2327	0.6	377	0.6	1949	0.6
2018F	2343	0.7	379	0.6	1963	0.7

3.0 DEMAND SIDE MANAGEMENT FORECAST

The table below summarizes annual projected demand and energy savings to be included in the 2009 Integrated Resource Plan (IRP) Update. The trajectory is consistent with the DSM profile from the 2007 IRP Reference Plan, adjusted for early year changes.

Table 3 – Demand Side Management Forecast (Source: 2009 IRP Update Assumptions)

Totals	25 Year Total	Year 1 (2008)	Year 2	Year 3	Year 6	Year 10 (2017)	Year 15	Year 20	Year 25
Demand Savings (MW)		2.1	6.8	16.9	63.5	55.8	49.6	45.5	43.0
Cumulative (MW)	1106	2.1	8.9	25.8	164.2	392.1	651.6	886.5	1105.7
Energy Savings (GWh)		16.1	50.3	82.7	305.3	268.4	238.2	217.4	204.0
Cumulative (GWh)	5317	16.1	66.3	149.0	804.9	1900.7	3147.5	4272.8	5317.0

NSPI has an application before the Board for approval of the third year of the DSM program with an estimated cost of $22.9 million. Going forward the Province has announced its intention to name a DSM Program Administrator to manage this function. It is assumed this transition will occur in 2009.

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 and hydro. In addition NSPI purchases energy from independent power producers located in the province and imports power across the NSPI/NB Power inter-tie. Table 4 lists NSPI's generating stations/systems along with their fuel types and net operating capacities based on the assumptions to be used in the 2009 IRP Update.

Table 4 – 2006 Generating Resources (Data sourced from 2009 IRP Update Assumptions)

Plant/System	Fuel Type	Winter Net Capacity	Total
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**
Tufts Cove	Natural Gas	98.0	
Burnside	Light Fuel Oil	132.0	
Tusket	Light Fuel Oil	24.0	
Victoria Junction	Light Fuel Oil	66.0	
Total Combustion Turbine			**320.0**
Contracts(pre-2001)	Independent Power Producers	25.8	
Renewables(firm) (post 2001)	Independent Power Producers	25.7	
NSPI wind (firm)**	Wind	0.3	
Total IPPs & Renewables			**51.8**
Total Capacity			**2320.9**

*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.
** The assumed firm capacity value of wind is 32 percent for long-term planning purposes. For short-term assessments (e.g. 18-month Load and Capacity Assessment) the assumed capacity factor may be less.

4.2 Changes in Capacity

Table 5 provides the firm Supply and Demand Side Management capacity additions per the 2007 IRP and to be modeled in the 2009 IRP Update, over the 2009-2018 time period. For DSM, the amounts shown are reductions in forecast firm demand for the period. Amounts shown as Uprates and Hydro include relatively small capacity additions to NSPI's existing generation fleet.

Table 5 – Capacity Additions & DSM

New Resources 2009-2018	**MW**
DSM firm	330
Tufts Cove 6	48.6
Hydro*	6.7
Firm Contracted Wind**	73.7
Firm RES (2013)***	32
Firm Wind (beyond RES)***	48
Total Firm Supply & Demand MW Required Over Planning Period	**539**

Notes:
* Hydro uprate shown is Marshall at 4.2 MW and Nictaux at 2.5 MW as per the 2009 IRP Update assumptions (versus Marshall at 1.8 MW and Nictaux at 2.5 MW which had been modeled and selected in the 2007 IRP). These uprates will be re-evaluated in the 2009 IRP Update."
** Firm Contracted wind 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 NSPI and the Renewable Energy Industry Association of Nova Scotia).
*** Reference to RES and Wind beyond the RES reflects an assumed firm capacity value of intermittent generation of 32 percent for long-term planning purposes (generator capacity multiplied by an annual capacity factor of 32 percent). For short-term assessments (e.g. 18-month Load and Capacity Assessment) the assumed capacity factor may be less. Resources to meet the 2013 RES and requirements beyond will be re-evaluated in the 2009 IRP Update.

5.0 NEW GENERATING FACILITIES

5.1 Potential New Facilities

As of May 13, 2009, NSPI's interconnection request queue includes 1266 MW of proposed generation projects at various stages of interconnection study. Sponsors of these projects have requested either Network Resource Interconnection Service (NRIS) or Energy Resource Interconnection Service (ERIS). NRIS refers to a firm 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 NSPI's interconnection request queue on May 13, 2009.

Table 6 – Generation Interconnection Queue

Nova Scotia Power - Amended Interconnection Request Queue

Publish Date: *Wednesday, May 13, 2009*

Temp Waiver Order	ID #	Request Date	County	MW Summer	MW Winter	Interconnection Point Requested	Type	Inservice date YY/MM/DD	Status	Service Type	Studies Available
1	45	19-Jan-05	Cumberland	30	30	L-6535	Wind	Nov 30, 2009	GIA Tendered	N/A	
2	82	15-Nov-06	Colchester	45	45	L-5040	wind	Dec 1, 2009	GIA Executed	ERIS	
3	84	22-Dec-06	Pictou	50	50	L-7004	wind	Nov 2009	GIA Executed	ERIS	
4	114	23-Mar-07	Pictou	60	60	L-6511	wind	Nov 30, 2009	Facilities Study in Progress	ERIS	
5	137	17-Apr-07	Richmond	10	10	1C	wind	Nov 30, 2009	Facilities Study in Progress	NRIS	
6	141	20-Apr-07	Digby	30	30	77V	wind	November 1, 2009	Facilities Study in Progress	NRIS	
7	150	16-Aug-07	Richmond	10	10	1C	wind	Nov 30, 2009	Facilities Study in Progress	NRIS	
8	8	14-Oct-03	Guysborough	15	15	L-5527B	Wind	2009	GIA Tendered	N/A	
9	56	19-Aug-05	Cumberland	34	34	L-5058	Wind	Nov 31, 2008	Facilities Study in Progress	ERIS	
10	67	27-Apr-06	Annapolis	40	40	L-5026	Wind	Oct 31, 2010	Impact Study in Progress	ERIS	
11	68	27-Apr-06	Digby	35	35	L-5533	Wind	Oct 31, 2010	Impact Study in Progress	ERIS	

Nova Scotia Power Amended GIP Priority Queue: Page 1 of 3

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

Temp Waiver Order	ID #	Request Date	County	MW Summer	MW Winter	Interconnection Point Requested	Type	Inservice date YY/MM/DD	Status	Service Type	Studies Available
12	86	09-Jan-07	Pictou	50	50	L-7003	wind	Jan 1, 2009	Impact Study in Progress	NRIS	
13	115	23-Mar-07	Pictou	120	120	L-7003	wind	Nov 30, 2009	Impact Study in Progress	NRIS	
14	117	13-Apr-07	Shelburne	10	10	L-5027	wind	September 1, 2009	Impact Study Agrmnt Complete	ERIS	
15	126	16-Apr-07	Cumberland	70	70	L-6513	wind	Dec 31, 2009	Impact Study Agrmnt Complete	ERIS	
16	128	17-Apr-07	Cumberland	40.5	40.5	L-6535	wind	November 20, 2009	Impact Study Agrmnt Complete	ERIS	
17	130	17-Apr-07	Cape Breton	200	200	L-7012	wind/water pumped	December 31, 2009	Impact Study Agrmnt Complete	NRIS	
18	131	17-Apr-07	Cape Breton	11.5	11.5	L-5580	wind	November 30, 2009	Impact Study Agrmnt Complete	ERIS	
19	140	20-Apr-07	Antigonish	30	30	L-7004	wind	November 1, 2009	Impact Study Agrmnt Complete	NRIS	
20	149	05-Jul-07	Cumberland	70	70	L-6536	wind	Nov 20, 2009	Impact Study Agrmnt Complete	ERIS	
21	151	22-Aug-07	Halifax	50	50	91H	steam turbine	June 30, 2010	Impact Study Agrmnt Complete	NRIS	
22	156	16-May-08	Antigonish	49.5	49.5	L-6511	Wind	December 31, 2010	Feasibility Study In Progress	NRIS	
23	157	16-May-08	Guysborough	100.5	100.5	L-6515	Wind	December 31, 2010	Interconnection Request Valid	NRIS	
26	160	05-Dec-08	Colchester	45	45	L-5040	Wind	01-Dec-11	Interconnection Request Valid	NRIS	
28	163	28-Jan-09	Richmond	60	60	47C	Steam	Apr 30, 2011	Interconnection Request Valid	NRIS	

Nova Scotia Power Amended GIP Priority Queue: Page 2 of 3
ERIS - Energy Resource Interconnection Service
NRIS - Network Resource Interconnection Service
N/A - Not Applicable

Temp Waiver Order	ID #	Request Date	County	MW Summer	MW Winter	Interconnection Point Requested	Type	Inservice date YY/MM/DD	Status	Service Type	Studies Available
		Totals:		1266	1266						

Nova Scotia Power Amended GIP Priority Queue: Page 3 of 3
ERIS - Energy Resource Interconnection Service
NRIS - Network Resource Interconnection Service
N/A - Not Applicable

Included in this interconnection queue is 244 MW of projects which are under contract to NSPI as part of its Renewable Energy Standards (RES) obligations in 2010. Table 7 indicates the location and size of these planned wind generating facilities.

Table 7 – RES-committed Renewable Generation Projects

Company/Location	Capacity MW
Renewable Energy Services Ltd. at Statia Terminals in the Strait area of Cape Breton	23
EarthFirst Canada Inc. at Nuttby Mountain in Colchester County *	45
RMSenergy at Dalhousie Mountain in Pictou County	50
RMSenergy at Maryvale in Antigonish County	6
Shear Wind Inc. at Brown's Mountain Range in Pictou and Antigonish Counties	60
Acciona Wind Energy Canada at Amherst	30
SkyPower Corp. and Scotian WindFields Inc. at Rossway in the Municipality of Digby	30
Total Contracted Capacity	**244**

* Project development rights purchased by NSPI in 2009. Decision to move forward to develop project is under consideration.

NSPI also has an application before the Board for approval of a 60 MW purchase of biomass generation located in the Port Hawkesbury area. The System Impact Study required to determine the transmission effects of this project has not been completed.

The requirement for additional generation-related and demand options will be assessed as part of the 2009 IRP Update.

5.2 Province's Wind Integration Study

In May, 2008, the Nova Scotia Department of Energy (DOE) released its Wind Integration Study which identified and assessed the effects of integrating large scale wind power generation into Nova Scotia's electric power system. Completed by Hatch Ltd., the Integrated Wind Study specifically addressed the RES requirements for 2010 and 2013 and wind energy potential beyond 2013. The Hatch report states:

> "The RES requires that by 2013, 10 percent of the province's electricity requirement must be supplied by new renewable energy sources post 2001 (5 percent by 2010 and an additional 5 percent by 2013). Hatch estimates the 2013 RES requirement will bring the total provincial renewable supply to approximately 22 percent (581 MW). DOE expects most of this supply to be met with commercial-scale wind energy projects, and estimates the number of utility wind turbines in the province may grow from the current 41 to over 300.

2010 RES (assuming a total of 311 MW of wind power capacity):

- The 2010 RES target for renewable supply can be met.
- By 2010, electricity production from post 2001 renewables is estimated to reach 7 percent -- total production from renewables at 16 percent.

2013 RES (assuming a total of 581 MW of wind power capacity):

- The 2013 RES target for renewable supply can be met, but more detailed impact studies are required to fully understand the cost and technical implications related to possible transmission upgrades and new operational demands on existing infrastructure.

Beyond 2013 RES (assuming 781 MW and 981 MW of wind power capacity):

- Future study will be needed to fully understand the cost and stability issues of increasing wind supply to 781 MW and 981 MW levels, after we gain more real world operational experience with increasing amounts of wind supply."[2]

5.3 Other Opportunities

In addition to the above, potential developments outside of Nova Scotia (e.g. Lower Churchill and Point Lepreau II), 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.

[2] Final Report, Nova Scotia Wind Integration Study, 2008, Hatch Ltd., p.11-13.

6.0 RESOURCE ADEQUACY

6.1 Operating Reserve Criteria

As a member of the Maritimes Area of the Northeast Power Coordinating Council (NPCC), NSPI meets the operating reserve requirements as outlined in *NPCC Document A-6, Operating Reserve Criteria*. This criteria is reviewed and adjusted periodically by NPCC. The criteria note that:

> The ten-minute reserve available to each Area shall at least equal its first contingency loss…and,
>
> The thirty-minute reserve available to each Area shall at least equal one half its second contingency loss.

In the *Interconnection Agreement between Nova Scotia Power Incorporated and New Brunswick System Operator (NBSO)*, NSPI 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.

NSPI maintains a ten minute operating reserve of 174 MW, of which approximately 36 MW is held as spinning reserve. Additional regulating reserve is maintained to manage the variability of customer load and generation. It is anticipated that regulating reserve requirements will increase with the addition of wind generation resources due to the added variability that will be introduced.

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

6.2 Planning Reserve Criteria

NSPI is required to comply with the NPCC reliability criteria. These criteria are outlined in *NPCC Document A-2, Basic Criteria for Design and Operation of Interconnected Power Systems*[3] and states that:

> Each Area's probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with these criteria 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 Areas and Regions, transmission transfer capabilities, and capacity and/or load relief from available operating procedures.

NSPI 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 New Brunswick System Operator, 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 *2007 Maritimes Area Comprehensive Review of Resource Adequacy*[4], it was found that the NPCC criteria would be met with a 20 percent reserve margin for the Maritimes Area along with 50 MW of additional capacity provided by interconnection assistance. This confirms that the 20 percent planning reserve margin applied by NSPI is acceptable under the NPCC reliability criteria.

[3] http://www.npcc.org/viewDoc.aspx?name=A-02.pdf&cat=regStandCriteria

[4] http://www.npcc.org/viewDoc.aspx?name=2007 Maritimes Area Comprehensive Review.pdf&cat=revResource

6.3 Load and Resources Review

The ten year load forecast and resources additions in the table below are based on the capacity additions and DSM forecast in Table 5. Table 8 below indicates that a planning reserve margin equal to 20 percent of the firm peak load is maintained from 2009 through 2018.

Table 8 – NSPI 10 Year Load and Resources Outlook (Source: 2007 IRP and 2009 IRP Update Assumptions)

Load and Resources Outlook for NSPI – Calendar Year 2009 to 2018 (All values in MW except as noted)											
		2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
A	Firm Peak Load Forecast	1,859	1,858	1,867	1,883	1,898	1,913	1,927	1,938	1,949	1,963
B	DSM Firm	7	19	43	77	124	165	207	249	290	330
C	Peak Firm Less DSM (A-B)	1,851	1,839	1,824	1,806	1,774	1,748	1,720	1,689	1,660	1,634
D	Required Reserve (C * 20%)	370	368	365	361	355	350	344	338	332	327
E	Required Capacity (C + D)	2,222	2,207	2,189	2,167	2,129	2,097	2,064	2,027	1,992	1,960
F	Existing Resources	2,321	2,321	2,321	2,321	2,321	2,321	2,321	2,321	2,321	2,321
	Total Cumulative Additions:										
G	Thermal	0	0	49	49	49	49	49	49	49	49
H	Hydro	0	0	4	4	4	4	4	4	4	4
I	Firm Contracted Wind*	0	24	74	74	74	74	74	74	74	74
J	Firm RES*	0	0	0	0	32	32	32	32	32	32
K	Firm Wind (beyond RES)*	0	0	0	0	0	16	32	32	48	48
L	Total Firm Supply Resources (F + G + H + I + J + K)	2,321	2,345	2,448	2,448	2,480	2,496	2,512	2,512	2,528	2,528
	+ Surplus / - Deficit (L - E)	99	138	259	281	351	398	448	485	536	567
	Reserve Margin % (L/C -1)	25	28	34	36	40	43	46	49	52	55

*Reflects an assumed firm capacity value of intermittent wind generation of 32 percent for long-term planning purposes (generator capacity multiplied by an annual capacity factor of 32 percent). For short-term assessments (e.g. 18-month Load and Capacity Assessment) the assumed capacity factor may be less.

7.0 TRANSMISSION PLANNING

7.1 System Description

The existing transmission system has over 5,200 kilometres of transmission lines at voltages at the 69 kV, 138 kV, 230 kV and 345 kV levels.

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

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

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

- The 69 kV transmission system is approximately 1627 kilometres in length and is comprised of 12 kilometres of steel/concrete structures and 1615 kilometres 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 in USA, Nova Scotia is integrated into the NPCC power system.

7.2 Transmission Design Criteria

NSPI, 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 NSPI bulk transmission system is planned, designed and operated in accordance with single contingency criteria. NSPI is a member of the Northeast Power Coordinating Council (NPCC). Those portions of Nova Scotia 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 *Basic Criteria for Design and Operation of Interconnected Power Systems*.

NSPI makes extensive use of Special Protection Systems (SPS) within SCADA to maximize 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 NSPI system has several transmission corridors that are regularly operated at limits. NSPI makes use of SPS to permit these transfer limits on these corridors.

7.3 Transmission Life Extension

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

The following indicates maintenance performed on the NSPI transmission system over the past two years along with proposed planned maintenance for 2009:

2007	2008	2009
L5003(Farrell St.-Sackville)	L5003 (Farrell St.-Sackville)	L5003(Farrell St.-Sackville)
L5004(Sackville-Geizer Hill)	L5014 (St. Croix-Burlington)	L5004(Sackville-Geizer Hill)
L5011(Farrell St.-Imperial Oil)	L5015 (St. Croix-Avon #1)	L5017(Canaan-Five Points)
L5016(St. Croix-Five Points)	L5019 (CanaanRd.-Hollow Bridge)	L5039(Spryfield-Geizer Hill)
L5024(Tremont-Kingston)	L5020 (Hollow Bridge-Methals)	L5500(Trenton-Stellarton)
L5039(Spryfield-Geizer Hill)	L5023 (Waterville Tap-Waterville)	L5510(Stellarton-Malay Falls)
L5527(Salmon River Lk.-Canso)	L5029 (Maccan-Springhill)	L5511(Trafalgar-Malay Falls)
L5537(Tusket-Tusket)	L5031 (Mill Lake-Robinson's Corner)	L5512(Malay Falls-Ruth Falls)
L5540(Onslow-Tatamagouche)	L5033 (Canaan Rd.-Hillaton)	L5521(Onslow-Truro)
L5549(Maccan-Amherst)	L5040 (Onslow-Tatamagouche)	L5573(VJ-Lingan Mine)
L5560(VJ-Townsend St.)	L5055 (Tap to Rio Algom)	L6003(Tufts Cove-Sackville)
L5563(VJ-Townsend St.)	L5506 (Abercrombie-Pictou)	L6004(Sackville-Canaan Road)
L5569(Terrace St.-Townsend St.)	L5534 (Tusket-Hebron)	L6006(Bridgewater-Milton)
L6002(Sackville-Bridgewater)	L5537 (Tusket-Gas Turbine)	L6013(Canaan Road-Tremont)
L6003(Tufts Cove-Sackville)	L5538 (Sissiboo-Weymouth)	L6014(Kempt Road-Tufts Cove)
L6006(Bridgewater-Milton)	L5550 (Maccan-Parrsboro)	L6035(Water St.-Kempt Road)
L5025(Paradise-Tremont)	L5551 (Lunenburg-Riverport)	L6038(Lakeside-Kearney Lake)
L6043(Dartmouth East-Musquodoboit)	L5561 (VJ-Seaboard)	L6515(Lochaber Road-Hastings)

L6535(Maccan-NB Border)	L5563 (VJ-Townsend St.)	L6516(Hastings-VJ)
L7005(Onslow-Port Hastings)	L5564 (VJ-Keltic Drive)	L6517(Hastings-Tupper)
L7008(Brushy Hill-Bridgewater)	L5565 (Seaboard-Albert Bridge)	L6518(Hastings-NewPage)
L7011(Hastings-Lingan)	L5572 (VJ-Seaboard)	L6523(Tupper-NewPage)
L8003(Onslow-Hopewell)	L5579 (Cheticamp-S.W. Margaree)	L6540(VJ-Sysco)
L5541(Milton-Big Falls)	L6004 (Sackville-Canaan Rd.)	L6545(Wreck Cove-Glen Tosh)
L6536(Springhill-NB Border)	L6008 (Sackville-Lakeside)	L6549(Wreck Cove-Glen Tosh)
L6538(Glen Tosh-Gannon Road)	L6013 (Canaan Rd.-Tremont)	L7001(Onslow-Brushy Hill)
L6539(Gannon Road-VJ)	L6024 (Milton-Tusket)	L7002(Onslow-Brushy Hill)
L7005(Onslow-Hastings)	L6518 (Pt. Hastings-Stora)	L7011(Hastings-Lingan)
L7015(Aconi-Woodbine)	L6527 (Onslow Tie Line)	L8001(Onslow-NB Border)
L7018(Onslow-Brushy Hill)	L6533 (VJ-Lingan)	L6005A(Brushy Hill-Sackville)
L5503(Hastings-Cleveland)	L6536 (Springhill-NB Border)	L6005B(Brushy Hill-Sackville)
L5533(Gulch-Conway)	L6538 (Glen Tosh-Gannon Rd.)	L5560(VJ-Townsend Street)
L5539(Milton-Liverpool)	L5032(Rockingham-Rockingham Tap)	
L6006(Bridgewater-Milton)	L6515(Antigonish-Lochaber Road)	
L6020(Milton-Souriquois)	L5004(Sackville-Geizer Hill)	
L6021(Souriquois-Tusket)	L5011(Farrell St.-Imperial Oil)	
L6513(Onslow-Springhill)	L7009 (Brushy Hill-Bridgewater)	
L6515(Lochaber Road-Hastings)	L5024B (Tremont-Greenwood)	
L7001(Onslow-Brushy Hill)	L5031A (Mill Lake-Middle River)	
L7002(Onslow-Brushy Hill)	L5536A (Tusket-Pleasant St.)	
L7012(Hastings-Lingan)	L5536B (Pleasant St.-Hebron)	
L7014(Lingan-Woodbine)	L6012B (St. Croix-Canaan Rd.)	
L7003(Onslow-Hastings)	L5539 (Milton-Liverpool)	
L7004(Onslow-Hastings)	L5541 (Milton-Big Falls)	
L8003(Onslow-Hopewell)	L6003 (Tuft's Cove-Sackville)	
L5012(Tufts Cove-Imperial Oil)	L6503 (Onslow-Trenton)	
L5027(Tusket-Souriquois)	L7002 (Onslow-Brushy Hill)	
L5028(Onslow-Stewiacke)	L7008 (Brushy Hill-Bridgewater)	
L5042(Farrell St.-Albro Lake)	L8002 (Lakeside-Onslow)	
L5503(Hastings-Cleveland)	L5579 (Cheticamp-SW Margaree)	
L6008(Sackville-Lakeside)	L5027 (Tusket-Souriquois)	
L6033(Water St.-Lakeside)	L6002 (Sackville-Bridgewater)	
L6516(Hastings-VJ)	L6020 (Milton-Souriquois)	
L6521(Tupper-Statia)	L7005 (Onslow-Pt. Hastings)	
L6035(Water St.-Kempt Road)	L7014 (Lingan-Woodbine)	
L5575(Whitney Pier-Lingan Mine)	L5535 (Sissiboo-Tusket)	
	L5576 (Gannon RD-Keltic Drive)	
	L7011 Pt. Hastings-Lingan)	

	L5004 (Sackville-Geizer Hill)	
	L5573 (VJ-Lingan Mine)	
	L6035 (Water St.-Kempt Rd.)	
	L6537 (Hastings-Glen Tosh)	
	L8004 (Hopewell-Woodbine)	
	L5532 Gulch-Big Falls)	
	L7003(Onslow-Hastings)	
	L7004(Onslow-Hastings)	
	L8003(Onslow-Hopewell)	

Nova Scotia Power also has in place a pole retreatment program that enables the useful life of plant to be extended.

The following indicates maintenance in the form of pole retreatment on the NSPI transmission system over the past two years along with the proposed pole retreatment for 2009.

2007	2008	2009
L5527(Salmon River Lake-Canso)	L5031(MillLake-Robinsons Corner)	L5036(Berwick Tap-Berwick)
L5579(Cheticamp-S.W. Margaree)	L5033(Canaan Rd.-Hillaton)	L5037(East River-Louisiana Pacific)
L6005(Brushy Hill-Sackville)	L5053(Michelin-Tremont)	L5046(5017 Tap-Wolfville Ridge)
L6011(Brushy Hill-St. Croix)	L5540(Milton-Deep Brook)	L5047(5026 Tap-Bridgetown)
L6012(Brushy Hill-CanaanRoad)	L5544(Big Falls-Upper Lake Falls)	L5056(5026 Tap-Annapolis)
L6013(CanaanRd.-Tremont)	L5545(Bridgewater-High St.)	L5521(Onslow-Willow Lane)
L6016(Brushy Hill-Lakeside)	L5555(Gannon Rd.-Prince)	L5536(Tusket-Hebron)
L6021(Souriquois-Tusket)	L5560(VJ-Townsend St.)	L6005(Brushy Hill-Sackville)
L6043(E.Dartmouth–Musquodoboit)	L5563(VJ-Townsend St.)	L6024(Milton-Tusket)
L6510(Whycocomagh-Aberdeen)	L5564(VJ-Keltic Dr.)	L6025(Bridgewater-Milton)
L6523(Tupper-Stora)	L5565(Seaboard-Albert Br.)	L6047(Milton-Bowater)
L6545(WreckCove-Glen Tosh)	L5571(VJ-Whitney Pier)	L6048(Milton-Bowater)
L6549(WreckCove-Glen Tosh)	L5572(VJ-Seaboard)	L6515(Lochaber Road-Hastings)
L7001(Onslow-Brushy Hill)	L5573(VJ-Lingan Mine)	L6539(Gannon Road-VJ)
L7004(Onslow-Hastings)	L6002(Sackville-Bridgewater)	L6548(Hastings-Sub Tie Line)
L7008(BrushyHill-Bridgewater)	L6006(Bridgewater-Milton)	L7014(Lingan-Woodbine)
	L6012(Brushy Hill-St. Croix)	
	L6050(Aerotech Park)	
	L6503(Onslow-Trenton)	

7.4 Transmission Project Approval

The transmission plan presented in this document provides a summary of the planned reinforcement of the NSPI power system. The proposed investments are required to maintain system reliability and security and comply with System Design Criteria. NSPI 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 NSPI, 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 or the UARB.

In 2008 a Maritimes Area Technical Planning Committee was established to review intra-area plans for Maritimes Area resource adequacy and transmission reliability. This Committee will also project 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, New Brunswick System Operator, Maritime Electric Company, Ltd., Northern Maine Independent System Administrator and NB Power Transmission.

7.5 NSPI/NB Interconnection Overview

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

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

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

Import and export limits on the inter-tie have been established to ensure the Nova Scotia system can survive a single contingency loss. The limits have been described as up to 350MW export and up to 300MW import. These figures represent limits under pre-defined system conditions. Conditions which determine the actual limit of the interconnection are:

Export	**Import**
Number of thermal units armed for generation rejection (maximum two)	NS system load level (Import less than 22% of total system load)
Reactive Power Support level in the Halifax Regional Municipality	Percentage of dispatchable generation
Arming of Special Protection Systems	NB export level to PEI and/or New England
Real time line ratings (climatological conditions in northern NS)	Real time line ratings (climatological conditions in northern NS)
NS System load level	Load level in Moncton area
Largest single load contingency in NS	Largest single generation contingency in NS

If the NSPI system is separated during export (i.e. the inter-tie trips) system frequency (cycles/second) will rise, risking unstable plant operation and possible damage. To address this NSPI uses fast-acting Special Protection Systems to reject generation and stabilize the system.

If the NSPI system is separated during import, system frequency will drop. Depending on the system characteristics at the time of disruption and the size of the import generation that was lost, the system will respond and re-balance. It does this by rejecting load through under-frequency load shedding (UFLS) protection systems as required.

The loss of the 345kV line between Onslow, NS and Memramcook, NB 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 New Brunswick System Operator restricts export to Nova Scotia to a level such that any single contingency does not cause adverse impacts on NB or PEI load. Any transmission reinforcement proposed to improve reliability, increase import 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.

<u>NSPI Capital Item CI# 29009 Right of Way Purchase Northern NS</u>

In jurisdictions across North America it is becoming more 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 cost approximately $200 million and require at least 5 years to procure the required permits and complete construction.

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, NSPI has identified a future capital item in the 2009 Annual Capital Expenditure (ACE) Plan to commence the planning and acquisition of land right of way for a second 345kV line to New Brunswick. The project cost and scope will be refined prior to applying to the Board for approval.

8.0 TRANSMISSION DEVELOPMENT 2009 TO 2018

Transmission development plans are summarized below. As discussed earlier, these projects are subject to change. For 2009, the projects listed are those included in the 2009 Annual Capital Expenditure Plan. For 2010 onward, the projects are noted in the projected year of completion.

1. 2009

- Construct a new 138-25 kV, 25/33/42 MVA substation at Dartmouth Crossing. This new substation is necessary due to load growth in the Dartmouth Crossing/Burnside area.

- Add a second 138-25 kV, 25/33/42 MVA transformer at Elmsdale and a second 12 MVAR capacitor bank. This project is necessary due to increased load growth in the Elmsdale/Enfield area.

- Install a 138-25 kV transformer at the existing Cleveland substation. This unit will replace a 69-25 kV transformer that failed in 2007. Installing a 138 kV transformer at Cleveland will enable the existing 69 kV system out of Port Hastings to be retired. This will include the removal of a 138-69 kV, 22.5/33.3 MVA transformer, a 69-25 kV, 7.5/10/11.2 MVA transformer, 1 x 138 kV circuit breaker and 3 x 69 kV circuit breakers.

- The completion of a project to add a second 138-69 kV, 33.6/44.8/56 MVA transformer at an existing St. Croix substation in the eastern Valley area. This project will also include the establishment of a 138 kV bus including 2 x 138 kV circuit breakers and 1 x 69 kV circuit breaker. This project is necessary to address transformer overload conditions and low voltage across the eastern Valley area under first contingency failures.

- The completion of a project to add a second 69-12 kV, 7.5/10/12.5 MVA transformer at an existing Waterville substation. This addition is required due to load growth in the Annapolis Valley area.

- Work will be completed on the uprating of a 138 kV circuit between Port Hastings and Glen Tosh.

- An existing 69 kV circuit between Tusket and Pleasant Street, Yarmouth is planned to be reconductored to provide additional capacity.

- A 345 kV circuit between Onslow and Lakeside is being uprated to increase the operating temperature of the line.

- Work is planned to commence to clear right of way necessary to build additional transmission capacity to the Western Annapolis Valley.

- The first phase of a transmission insulator replacement program will get underway with the reinsulation of 10 circuits. These insulators are being replaced due to cement growth issues.

- Work will begin to acquire a spare generator transformer that will be utilized in the event of a prolonged failure to certain existing generator transformers.

- A transmission reliability investment program is proposed to start with the replacement of some 69 kV circuit breakers, the addition of 69 kV circuit switchers, and the upgrading of certain 69 kV switches.

- A 69 kV circuit between St. Croix and Avon is proposed to be reconductored due to deteriorated conductor issues.

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

2. 2010

- Work will begin on the construction of additional transmission to the Western Valley area. This will include the construction of a 138 kV circuit between Canaan Road and Tremont, a 138 kV termination at Canaan Road and the addition of a 138-69 kV, 33.6/44.8/56 MVA transformer at Tremont along with the establishment of a 138 kV bus. This project is necessary to mitigate various contingencies that could result in transformer overload scenarios, line overload conditions and low voltage conditions.

- The insulator replacement program will continue with the reinsulation of 4 circuits due to cement growth issues.

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

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

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

- An existing 69 kV circuit between Trenton and Bridge Avenue is planned to be rebuilt to provide additional capacity. This project is being undertaken to avoid an overload condition for the contingency loss of a parallel 69 kV circuit during high load conditions.

- Work will continue on the uprating of a 345 kV circuit between Onslow and Lakeside for the purpose of increasing the operating temperature of the line.

- Complete the 2009 project to acquire a spare generator transformer that will be utilized in the event of a prolonged failure of certain generator transformers.

- Work will begin on right of way acquirement between Dartmouth East and Eastern Passage for the purpose of accommodating a 138 kV circuit to a proposed new 138 kV substation in the Eastern Passage area.

- Work will begin on right of way acquirement from an existing 138 kV circuit out of Canaan Road substation to a new substation site in the New Minas area for the purpose of accommodating a 138 kV circuit to a new 138 kV substation in the New Minas area.

- A 69 kV line tap will be constructed from the proposed Nuttby mountain wind farm to an existing 69 kV circuit between Onslow and Tatamagouche.

3. 2011

- The insulator replacement program will continue with the reinsulation of three circuits due to cement growth issues.

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

- In accordance with the NPCC *Classification of Bulk Power System Elements* (Document A-10), dual high-speed protection systems are required at 138 kV substations at Onslow, Brushy Hill, and Tufts Cove. In addition breaker backup will be added at the Tufts Cove 69 kV substation.

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

- A new 138-12 kV, 15/20/25 MVA substation is proposed to be constructed in New Minas for the purpose of supplying additional load growth.

- A second 138-69 kV, 33.6/44.8/56 MVA transformer and 138 kV bus modifications are proposed for Gannon Road substation to prevent overload and voltage issues for the loss of the existing 138-69 kV transformer.

- An existing 69-12 kV, 7.5/10/12.5 MVA transformer at Barrington Passage is planned to be changed out for a unit rated 15/20/25 MVA to address load growth in the area.

- The existing 138-69 kV, 20/26.7 MVA transformer at Westhaver's Elbow is planned to be changed out for a unit rated 22.5/33.3 MVA for the purpose of addressing voltage regulation in the area.

- The 138 kV SF_6 switchgear at Water Street substation is planned to be replaced in a new location. The two existing 138-25 kV transformers will also be moved to the new location.

- A new 138-25 kV substation is planned to be constructed at a new site in Eastern Passage. This substation would be served by the construction of a new 138 kV circuit from an existing Dartmouth East substation to the new site. This station is required to prevent equipment overloads during contingency conditions and address load growth in the Eastern Passage area.

4. 2012

- The insulator replacement program will continue with the reinsulation of 2 circuits due to cement growth issues.

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

- In accordance with the NPCC *Classification of Bulk Power System Elements* (A-10), dual high speed protection systems are required at 138 kV substations at Sackville, Kempt Road, and New Page (Port Hawkesbury).

- Load will be transferred from the 2 x 138-69 kV autotransformers at Trenton. This will be accomplished by changing out an existing 69-25 kV transformer at Trenton with a 138-25 kV unit.

- The double-circuit towers that carry L-7008 and L-7009 for 5.5 km out of the Brushy Hill 230 kV substation will be re-configured to accommodate the normal contingency loss of both towers.

- A 69 kV circuit between St. Croix and Five Points substations will be rebuilt.

5. 2013

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

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

- A second 138-25 kV, 25/33/42 MVA transformer will be added at the existing Hammonds Plains Road substation.

6. 2014

- An existing 69-12 kV transformer at Hillaton will be changed out for a unit rated 15/20/25 MVA.

- The 138 kV bus at Milton will be rearranged to avoid loss of the bus due to a bus tie breaker failure.

- The 345 kV bus at Hopewell will be developed into a ring bus configuration.

7. 2016

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

8. 2018

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

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 remains unknown with respect to the form, location and scope of future generation, as emission regulations and Renewable Energy Standards evolve and projects required to maintain compliance are studied.

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

It should be reinforced that this work remains preliminary and is 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 unfold as projected will be determined by a host of factors unknown today including:

- The location, size and configuration of generation developments across Nova Scotia;
- The emergence of new generation sources and markets outside of Nova Scotia;
- Ongoing change to power system industry engineering and operating standards.

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

- Transmission system reinforcement will 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 plans should be robust to accommodate changes in area and provincial load and generation;

- Transmission system plans will be subject to change in response to opportunities, inside and outside of Nova Scotia; and
- Further work on this is required.

10.0 CONCLUSION

It is likely that the NSPI transmission system will require significant reinforcement in the coming decade and that this reinforcement will occur across the province and at the provincial inter-tie. The specific form of this reinforcement is not understood in detail today. Work to understand this is proceeding in accordance with the underlying market drivers.

NSPI has advised the UARB of its intent to apply to the Board in 2009 for approval of the purchase of right of way to accommodate a second provincial inter-tie. Additional transmission applications will be forthcoming once the design, cost and business cases necessary to support these investments are complete.

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

11.0 REFERENCES

1. *2004 Maritimes Area Triennial Review of Resource Adequacy*, Report approved by NPCC Reliability Coordinating Council March 9, 2005.

2. *Basic Criteria for Design and Operation of Interconnected Power Systems*, Northeast Power Coordinating Council Document A-2, May 6, 2004.

3. *Final Report, Nova Scotia Wind Integration Study*, Hatch, Ltd., 2008.

4. *Integrated Resource Plan Report*, Nova Scotia Power Inc., July 2007.

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

6. 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

Nova Scotia Power's interconnected system is divided into several classifications, each of which is governed by different design criteria.

These classifications are as follows:

1. Primary Transmission
2. Secondary Transmission
3. Electrically Remote Transmission
4. Sub-transmission
5. Transformation

The System Design criteria combine protection performance specifications with system dynamics and steady state performance requirements. Within any classification, system studies assume specified protection performance to determine the required number, characteristics and type of system elements, while protection design incorporates only that equipment necessary to achieve the assumed performance, assuming a single coincident protection element failure.

DEFINITIONS

1. **Primary Transmission** is defined as the 345 kV transmission system interconnecting Lakeside-Onslow-Hopewell-Woodbine, and Salisbury, New Brunswick, the 230 kV transmission system interconnecting Brushy Hill-Onslow-Lingan-and Pt. Aconi, Nova Scotia and the interconnecting 345/230 kV transformation between them.

2. **Secondary Transmission System** is defined to be that part of the system which serves mainly to interconnect miscellaneous generation and Primary Transmission with Sub transmission at major load centres.

The lesser importance of secondary transmission relative to the Primary Transmission permits a relaxation of the design criteria from that required for the primary transmission system. This definition then governs most of the 138 kV developments plus certain 69 kV and 230 kV, other than on the Primary Transmission system.

3. **Electrically Remote Transmission** is defined by those buses at which ultimate fault levels are projected to not exceed 1500 MV.A three phase.

4. **Sub transmission System** is defined to be that part of the system which primarily serves as a source for transformation to the distribution level. This type of system is primarily characterized by radial feeds although looped sub transmission exists.

5. **Interconnected Transmission System** is defined as the combined Primary, Secondary, and Electrically Remote Transmission systems including connected generation.

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

   (a) Any load condition (this includes the full range of annually forecasted loads).

   (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 percent to 105 percent of nominal, unless otherwise noted.

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

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

8. **Local back-up clearance** is defined to be the time to clear an in-zone fault.

9. **Remote back-up clearance** is defined to be the time to clear an out-of-zone fault.

10. **Breaker back-up** is defined to be protection against local breaker failure to trip for any reason. Breaker back-up will be applied to all Primary Transmission and most of the Secondary Transmission systems.

I. PRIMARY TRANSMISSION SYSTEM

Prime clearance times are defined to be 4.5 cycles first zone and 6 cycles second zone with permissive signal for both three-phase and line-to-ground faults.

Back-up clearance times are defined to be 15 to 18 cycles for both three-phase and line-to-ground faults.

The Design Criteria[5] 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 except a generator or bus section, 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.

[5] Note: The Primary Transmission System Design Criteria may be superseded by the NPCC Basic Criteria for the Design and Operation of Interconnected Power Systems.

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 except a bus section or generator, cleared in 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 their long-term thermally limited ratings.

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 voltage shall not be less than 90 percent or greater than 110 percent 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 percent 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.

II. SECONDARY TRANSMISSION SYSTEM

Prime time clearance is defined to be 6 to 9 cycles for both three-phase and line-to-ground faults. (No additional expenditure may be made to reduce clearing times from 9 to 6 cycles without authorization from System Design.)

Local back-up clearance is defined to be less than 30 cycles (a figure of 20 cycles is desirable but where coordination so dictates, a 30 cycle figure is acceptable).

Remote back-up clearance is defined to be less than 30 cycles which in certain instances implies reduced margins of coordination.

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 except a generator or bus section 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 except a generator or bus section, cleared in 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 their thermally limited ratings in the steady state.

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 less than 90 percent or greater than 110 percent 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 percent 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.

III. ELECTRICALLY REMOTE TRANSMISSION

Prime time clearance is defined to be 9 cycles for both three-phase and line-to-ground faults. Note 1 and Note 2.

The Design Criteria are:

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

2. From normal system conditions following loss of any one element with or without fault, all remaining elements shall be within their thermally limited ratings.

3. From normal system conditions, for the loss of any one Electrically Remote system element with or without fault, no Interconnected transmission system bus voltage shall be less than 90 percent or greater than 110 percent of nominal following a steady state settling out of the system nor shall any bus experience a voltage change from pre-fault to post-fault condition greater than 10 percent before tap-changer correction.

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

NOTES:

1. No expenditure may be made to reduce clearing times to reference values without authorization from System Design.

2. Permissive tripping between an electrically remote bus and a transmission bus (or between 2 electrically remote buses) is not required, i.e., local back-up clearances are acceptable.

3. Application of the above criteria does not preclude the possibility that for loss of certain remote system elements there will be a designed loss of load. This load would be restored after operator action.

IV. SUB-TRANSMISSION SYSTEM

The Design Criteria are:

1. Sub transmission system loading shall be within the thermally limited ratings.

2. The sub transmission system voltages shall not be less than 97.5 percent or greater than 105 percent of nominal.

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

4. From normal system conditions, following the loss of any one sub transmission system element with or without a fault, any sub transmission system bus which remains connected to the system, shall maintain sufficient voltage following automatic tap-changer correction to permit operation of any affected distribution bulk supply bus at 105 percent of nominal following a steady state settling out of the system. In no case shall any bus experience a voltage change from pre-fault to post-fault condition greater than 10 percent before tap-changer correction.

5. The application of the above criteria does not guarantee a continuity of supply for any single contingency. In the case of a line, since a lengthy outage is considered to have a low probability time to repair is considered adequate for restoration of service; however, in the case of transformation, since an outage is generally a prolonged one, either the use of a mobile transformer for a short-term replacement or the installation of a spare transformer and interconnections with adjacent substations at the distribution level, are considered in decisions concerning the guaranteeing, after outage, of an alternative supply.

V. TRANSFORMATION

Design Criteria

1. Capacity for any individual transformation point shall, under nominal 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 as per Note 4.

2. 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 Note 4. (This is in conjunction with (a) and (b) above as applicable.)

    (d) Largest available **suitable** mobile transformer loaded to its nameplate rating. (This is 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 criteria because estimated out-of-merit costs may significantly exceed the costs of capital advancement.

2. The Primary Transmission system may require additional transformation in certain instances when, although the above (a), (b) and (c) may result in satisfaction of this particular criteria, any other of several possible contingencies (transmission lines, generators or transformer(s)) could result in either frequent or prolonged outages to a widespread part of the system.

3. The result of application of these criteria may not be installation of additional transformation.

APPENDIX B

TRANSMISSION ADDITIONS FOR GENERATION DEVELOPMENT SCENARIOS

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

In lieu of this certainty, NSPI 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.

The 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. 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 NSPI supports.

Renewable Generation Additions

a) Wind Development Scenarios (2013 - 2019)

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

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

ii) Mainland (South Nova) wind generation (100MW-150MW) 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 will 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.

iii) Mainland (Lower Annapolis Valley) wind generation(100-150MW) development scenario

This scenario requires the completion of a 138kV line L-6617 from Tremont to Canaan Rd currently scheduled for construction along with a new ring bus configuration at Tremont, including a second 138-69 kV transformer, and substation modifications at Canaan Road. 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. This would include the development of a 138 kV ring bus configuration at Paradise. In addition new 138 kV circuits would be constructed from Gulch to Tremont and Tusket substations. Two 230 kV circuits currently occupying double circuit towers towards the Bridgewater area would be separated.

iv) Mainland (Upper Annapolis Valley) wind generation (100-150MW) development scenario

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

v) Mainland (Northern Nova Scotia) wind generation (100-150MW) development scenario

Construct a new 138kV line from Onslow to Springhill and install a 100 MVAR static 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.

vi) Cape Breton Wind generation (150MW -250MW) 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 – 138 kV substation would be established at Spider Lake that would terminate 3 x 138 kV circuits in the Dartmouth area. In addition 100 MVAR of reactive compensation would be established in the Dartmouth area.

b) 60MW Biomass - Cape Breton Strait Area Scenario

An additional line crossing of the Strait of Canso would be constructed to eliminate the double circuit contingency limit. A bus reconfiguration at NSPI's Onslow 345kV EHV substation, an upgrade of a 138kV line terminal at NSPI's Trenton substation, and the addition of switched capacitors at NSPI's Brushy Hill substation would also be required.

Large External Imports (300MW) or Export development scenario

a) To facilitate a large import or export via NB interconnect

To enable import, a new 345 kV transmission circuit would be required between Onslow to the New Brunswick system. An existing 230 kV circuit would be uprated to 345 kV to provide a 345 kV transmission interconnection between Onslow and Brushy Hill along with increased reactive compensation at Brushy Hill. In addition a 345 kV ring bus would be established at Hopewell and a 345 kV circuit would be constructed from Hopewell to the Metro area. Joint planning studies are required with New Brunswick to determine upgrades to the New Brunswick system that would be required to support a firm import of this magnitude.

For additional firm export from NS to NB, added further study may also be required.

b) Newfoundland Submarine Cable Import (300MW) or Export development scenario

A 300 MW DC to AC terminal would be required at Onslow or Brushy Hill along with a DC submarine cable from Newfoundland to Cape Breton along with overhead DC transmission from Cape Breton to Onslow or Brushy Hill. An existing 230 kV circuit would be converted to 345 kV to provide a 345 kV transmission connection between Onslow and Brushy Hill. A 345 kV ring bus would be established at Hopewell and a new 345 kV transmission circuit would be constructed between Hopewell and the Metro Halifax area.

Additional export of energy from Newfoundland through Nova Scotia would require further study in order to determine the additional transmission investment required.

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

For contingency loss of a large generator scenario the NS-NB inter-tie may require reinforcement depending on potential unit size.

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 345/230 kV transformer at Port Hastings. A 345/138 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

Development of a 138 kV substation 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 will be required from Spider Lake to Sackville as well as a high capacity line from Tufts Cove to Brushy Hill. In addition substation modifications will take place at Tufts Cove and Brushy Hill.

10 Year System Outlook
2010-2019
Draft Report

June 30, 2010

NOVA SCOTIA
POWER
An Emera Company

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Appendicies

1.0 INTRODUCTION

Nova Scotia Power Inc.'s (NSPI, the Company) filing of June 30, 2008 provided the initial 10 Year System Outlook. Following NSPI's second annual 10 Year System Outlook filing on June 30, 2009, the Nova Scotia Utility and Review Board (UARB, Board), in its letter dated January 11, 2010 provided the following:

> Recognizing the direct relationship among the Outlook, the IRP, and the ACE Plan, the Board anticipates that any significant recommendations resulting from these briefings will be incorporated by NSPI into its 2010 Outlook report.

Consistent with the 3.4.2.1[1] Market Rule requirements and the subsequent Board direction, the 2010 Outlook contains the following:

1. A summary of the NSPI load forecast employed in the Outlook;
2. An update on the DSM program undertaken by the Company;
3. A summary of generation expansion anticipated for facilities owned by NSPI 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 2010 Outlook is the assumptions employed in the 2009 Integrated Resource Plan (IRP) Update. The assumptions have been developed by NSPI and the Board's consultants, with input from IRP stakeholders.

1 The NSPSO system plan will address: a) transmission investment planning; b) DSM programs operated by NSPI Customer Service division or others; c) NSPI 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 NSPI, and f) requirements for additional DSM programs and / or generating capability (for energy or ancillary services).

2.0 LOAD FORECAST

The NSPI load forecast provides an outlook on the energy and peak demand requirements of in-province customers. The forecast provides the basis for the financial 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 Conservation and Demand Side Management programs.

Table 1 shows historical and forecast total annual energy requirements. The highest months of energy consumption in Nova Scotia are December through February due to the electric heating 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 due to the economic recession. With the exception of 2010 when the NSR is expected to increase by 2.7% due to economic recovery, NSR is forecast to decline an average of 0.8 percent annually over the next 10 years with the effects of Conservation and Demand Side Management programs. Without the effects of these programs, the NSR is forecast to grow an average of 1.1 percent annually.

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

NSPI also forecasts the peak hourly demand for future years. This process uses forecast energy requirements and expected load shapes (hourly consumption files) 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
(Source: 2010 NSPI Load Forecast)

Year	Net System Requirement (GWh)	Growth Rate (%)
2001	11,303	0.6
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[2]	12,539	-0.8
2009[3]	12,073	-3.7
2010F	12,397	2.7*
2011F	12,444	0.4
2012F	12,471	0.2
2013F	12,382	-0.7
2014F	12,255	-1.0
2015F	12,138	-1.0
2016F	11,994	-1.2
2017F	11,844	-1.3
2018F	11,704	-1.2
2019F	11,560	-1.2
2020F	11,394	-1.4

Note:
Actual growth rates for 2006 and 2007 were -11.3 percent and 15.5 percent respectively, which reflects one of NSPI'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.
*Increase is the result of forecasted economic recovery.

[2] Actual results include the effects of 2008 DSM programs on 2008 load estimated at 4.6 GWh
[3] Actual results include the effects of 2008 and 2009 DSM programs on 2009 load estimated at 41.2 GWh

Table 2 – Coincident Peak Demand with Future DSM Program Effects

(Source: 2010 NSPI Load Forecast)

Year	Net System Peak MW	Growth %	Non-Firm Peak MW	Growth %	Firm Peak MW	Growth %
2000	2,009	6.6	412	33.3	1,597	1.3
2001	1,988	-1	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	1,824	-0.8
2010F	2,290	9.5*	324	21.0*	1,966	7.8
2011F	2,301	0.5	326	0.7	1,975	0.4
2012F	2,302	0.0	325	-0.4	1,977	0.1
2013F	2,282	-0.9	318	-2.1	1,964	-0.7
2014F	2,254	-1.2	310	-2.7	1,945	-1.0
2015F	2,229	-1.1	302	-2.5	1,927	-0.9
2016F	2,197	-1.4	294	-2.6	1,903	-1.2
2017F	2,165	-1.5	286	-2.6	1,879	-1.3
2018F	2,134	-1.4	279	-2.5	1,855	-1.2
2019F	2,103	-1.5	272	-2.4	1,831	-1.3
2020F	2,066	-1.7	266	-2.3	1,800	-1.7

*Increase is the result of forecasted economic recovery.

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. The trajectory is consistent with the DSM profile from the 2009 IRP Update adjusted for early year changes.

Table 3 – Demand Side Management Forecast *

Year	Cumulative Demand Savings (MW)	Cumulative Energy Savings (GWh)
2010	12	66
2011	33	179
2012	73	354
2013	126	610
2014	187	900
2015	245	1176
2016	302	1452
2017	358	1724
2018	414	1989
2019	467	2247
2020	520	2499

Note: Cumulative Demand Savings include interruptible customers

*<u>The DSM Forecast values represent the difference between the “With DSM” and “Without DSM” load forecast values of the April 2010 Load Forecast.</u>

On June 7, 2010, the Board approved the $41.9 million overall expenditure associated with NSPI’s application for the 2011 DSM Plan. Going forward the new DSM Administrator, Efficiency Nova Scotia Corporation, will manage this function. This process is expected to be in operation by February 2011.

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 and hydro. In addition NSPI purchases energy from independent power producers located in the province and imports power across the NSPI/NB Power inter-tie. Table 4 lists NSPI'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 2010.

Table 4 – 2010 Generating Resources

(Data sourced from 2009 IRP Update Assumptions)

Plant/System	Fuel Type	Winter Net Capacity
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**
Tufts Cove	Natural Gas	98.0
Burnside**	Light Fuel Oil	132.0

Plant/System	Fuel Type	Winter Net Capacity
Tusket	Light Fuel Oil	24.0
Victoria Junction	Light Fuel Oil	66.0
Total Combustion Turbine		**320.0**
Contracts (pre-2001)	Independent Power Producers	25.8
Renewables(firm) (post 2001)***	Independent Power Producers	42.3
NSPI wind (firm)***	Wind	0.3
Total IPPs & Renewables		**68.4**
Total Capacity		**2337.5**

*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 can be returned to service in a relatively short time period. It continues to be included as a resource; however, it has not been returned to service yet as asset management plans for the Burnside fleet are being re-assessed.
*** The assumed firm capacity value of wind reflects the assumed 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 NSPI and the Renewable Energy Industry Association of Nova Scotia and as employed in NSPI 2009 IRP Update modeling). For short-term assessments (e.g. 18-month Load and Capacity Assessment) the assumed capacity factor may be less.

4.2 Changes in Capacity

Table 5 provides the firm Supply and Demand Side Management capacity additions per the Port Hawkesbury (PH) Biomass Project Base Case Plan (as filed with UARB in P-128.10 April 9, 2010) over the 2010-2020 time period. This Plan is based on the 2009 IRP Update assumptions and analysis, modified to include the PH Biomass Project. For DSM, the amounts shown are reductions in forecast firm demand for the period. Amounts shown as Hydro include relatively small capacity additions to NSPI's existing generation fleet. The PH Biomass Project is configured as an Energy Resource Interconnection Service (ERIS) (refer to Section 5.1) and is not included in the Table.

Table 5 – Capacity Additions & DSM

New Resources 2010-2020	MW
DSM firm*	434
Tufts Cove 6	48.9
Hydro**	4.2
Firm Contracted Wind***	51.0
Nuttby Wind Project***	15.8
Firm RES (2015)****	40
Total Firm Supply & Demand MW Projected Over Planning Period	**593.9**

Notes:
* DSM Firm does not include interruptible customers
** Hydro shown is Marshall at 4.2 MW as per the 2009 Update assumptions.
*** Firm Contracted wind and Nuttby wind 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 NSPI and the Renewable Energy Industry Association of Nova Scotia and as employed in NSPI 2009 IRP Update modeling).
**** Firm RES (2015) represents an addition of renewable energy to comply with the 2015 RES recently announced in the Province's Renewable Electricity Plan in April 2010. The value in the table reflects an assumed firm capacity value of intermittent wind generation of approximately 40 percent based on the winter capacity factor for long-term planning purpose (generator capacity multiplied by the winter capacity factor of 40 percent). An annual capacity factor of 32 percent was assumed for determining annual energy from the wind installation. For short-term assessments (e.g. 18-month Load and Capacity Assessment) the assumed capacity factor may be less.

5.0 NEW GENERATING FACILITIES

5.1 Potential New Facilities

As of late June 2010, NSPI's interconnection request queue includes 1,382 MW of proposed generation projects at various stages of interconnection study. Sponsors of these projects have requested either Network Resource Interconnection Service (NRIS) or Energy Resource Interconnection Service (ERIS). NRIS refers to a firm 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 NSPI's interconnection request queue as of June 23, 2010.

Table 6 – Generation Interconnection Queue

Nova Scotia Power - Interconnection Request Queue

NOVA SCOTIA POWER An Emera Company

Publish Date: *Wednesday, June 23, 2010*

Queue Order	IR #	Request Date DD-MMM-YY	County	MW Summer	MW Winter	Interconnection Point Requested	Type	Inservice date DD-MMM-YY	Status	Service Type	Studies Available
1	45	19-Jan-05	Cumberland	30	30	L-6535	Wind	01-Oct-12	Unexecuted GIA Filed	N/A	
2	82	15-Nov-06	Colchester	45	45	L-5040	wind	01-Dec-10	GIA Executed	ERIS	
3	114	23-Mar-07	Pictou	60	60	L-6511	wind	30-Oct-10	Unexecuted GIA Filed	ERIS	
4	141	20-Apr-07	Digby	30	30	77V	wind	31-Aug-10	GIA Executed	NRIS	
5	8	14-Oct-03	Guysborough	13.8	13.8	L-5527B	Wind	20-Sep-12	GIA in Progress	N/A	
6	56	19-Aug-05	Cumberland	34	34	L-5058	Wind	30-Nov-08	Facilities Study in Progress	ERIS	
7	151	22-Aug-07	Halifax	50	50	91H	steam turbine	30-Jun-10	Impact Study in Progress	NRIS	
8	67	27-Apr-06	Annapolis	40	40	L-5026	Wind	31-Oct-10	Impact Study Agrmnt Complete	ERIS	
9	68	27-Apr-06	Digby	35	35	L-5533	Wind	31-Oct-10	Impact Study Agrmnt Complete	ERIS	
10	86	09-Jan-07	Pictou	50	50	L-7003	wind	01-Jan-09	Impact Study Agrmnt Complete	NRIS	
11	115	23-Mar-07	Pictou	120	120	L-7003	wind	30-Nov-09	Impact Study Agrmnt Complete	NRIS	

Nova Scotia Power - Interconnection Request Queue: Page 1 of 3

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

Queue Order	IR #	Request Date DD-MMM-YY	County	MW Summer	MW Winter	Interconnection Point Requested	Type	Inservice date DD-MMM-YY	Status	Service Type	Studies Available
12	117	13-Apr-07	Shelburne	10	10	L-5027	wind	01-Sep-09	Impact Study Agrmnt Complete	ERIS	
13	126	16-Apr-07	Cumberland	70	70	L-6513	wind	31-Dec-09	Impact Study Agrmnt Complete	ERIS	
14	128	17-Apr-07	Cumberland	40.5	40.5	L-6535	wind	20-Nov-09	Impact Study Agrmnt Complete	ERIS	
15	130	17-Apr-07	Cape Breton	200	200	L-7012	wind/water	31-Dec-09	Impact Study Agrmnt Complete	NRIS	
16	131	17-Apr-07	Cape Breton	11.5	11.5	L-5580	wind	30-Nov-09	Impact Study Agrmnt Complete	ERIS	
17	140	20-Apr-07	Antigonish	30	30	L-7004	wind	01-Nov-09	Impact Study Agrmnt Complete	NRIS	
18	149	05-Jul-07	Cumberland	70	70	L-6536	wind	20-Nov-09	Impact Study Agrmnt Complete	ERIS	
19	156	16-May-08	Antigonish	49.5	49.5	L-6511	Wind	31-Dec-10	Impact Study Agrmnt Complete	NRIS	
20	157	16-May-08	Guysborough	49.5	49.5	L-6515	Wind	31-Dec-10	Impact Study Agrmnt Complete	NRIS	
21	163	28-Jan-09	Richmond	60	60	47C	Steam	30-Apr-11	Impact Study Agrmnt Complete	NRIS	
22	213	29-Jul-09	Cumberland	15	15	37N	Tidal	31-Dec-10	Impact Study Agrmnt Complete	ERIS	
23	219	08-Apr-10	Richmond	64	64	47C	Steam	31-Dec-12	Feasibility Study In Progress	ERIS	
24	222	26-Apr-10	Pictou	48	48	L-5508	Steam	31-Aug-12	Feasibility Study In Progress	NRIS	
25	223	30-Apr-10	Cape Breton	16	16	L-6540	Biomass	15-Dec-12	Feasibility Study In Progress	NRIS	

Nova Scotia Power - Interconnection Request Queue: Page 2 of 3

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

Queue Order	IR #	Request Date DD-MMM-YY	County	MW Summer	MW Winter	Interconnection Point Requested	Type	Inservice date DD-MMM-YY	Status	Service Type	Studies Available
26	225	03-May-10	Pictou	70	70	L-7004	Wind	31-Dec-12	Feasibility Study In Progress	NRIS	
27	226	03-May-10	Kings	70	70	L-6013	Wind	31-Dec-12	Feasibility Study In Progress	NRIS	
		Totals:		1381.8	1381.8						

Nova Scotia Power - Interconnection Request Queue: Page 3 of 3

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

Included in this interconnection queue is 165 MW of wind energy projects which are part of NSPI's Renewable Energy Standards (RES) commitment for 2011. In addition to these wind projects, the queue contains a 50 MW, NSPI-owned steam project (NSUARB Approved), a 60 MW Biomass Project, a 15 MW wind project that is at the GIA negotiation stage and a 34 MW wind project that is at the Facilities Study stage. All remaining projects in the queue are considered to be at the initial queue stage as they have not yet proceeded to the System Impact Study stage of the Revised Generator Interconnection Procedures. Table 7 indicates the location and size of the planned generating facilities.

Table 7 – RES-committed Renewable Generation Projects

Company/Location	**Nameplate Capacity MW**
Acciona Wind Energy Canada at Amherst	30
Shear Wind Inc. at Brown's Mountain Range in Pictou and Antigonish Counties	60
NSPI at Nuttby Mountain in Colchester County	45
NSPI/Emera at Gulliver's Cove in the Municipality of Digby	30
NSPI at Tuft's Cove, Dartmouth	50
Total New Facilities Nameplate Capacity	**215**

NSPI also has an application before the Board for approval of a 60 MW biomass generation project located in the Port Hawkesbury area. A draft of the System Impact Study required to determine the transmission effects of this project has been completed.

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 target of 25 percent by 2015, as well as a goal of 40 percent by 2020.

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

Implementation timelines and uptake rates for the programs remain to be determined and will be monitored.

5.3 Province's Wind Integration Study

The 2008, Hatch Ltd. Wind Integration Study identified and assessed the effects of integrating large scale wind power generation into Nova Scotia's electric power system. This study confirmed that "more detailed impact studies are required to fully understand the cost and technical implications related to possible transmission upgrades and new operational demands on existing infrastructure."[4]

NSPI has begun monitoring the effects of variable energy sources of an intermittent nature, such as wind, to be better prepared to forecast and schedule production loads and hence determine possible implications to system stability and availability.

5.4 Other Opportunities

In addition to the above, potential developments outside of Nova Scotia (e.g. Lower Churchill and Point Lepreau II), 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.

[4] Final Report, Nova Scotia Wind Integration Study, 2008, Hatch Ltd., p.11-13.

6.0 RESOURCE ADEQUACY

6.1 Operating Reserve Criteria

As a member of the Maritimes Area of the Northeast Power Coordinating Council (NPCC), NSPI meets the operating reserve requirements as outlined in *NPCC Document A-6, Operating Reserve Criteria*. This criteria is reviewed and adjusted periodically by NPCC. The criteria note that:

> The ten-minute reserve available to each Area shall at least equal its first contingency loss…and,
>
> The thirty-minute reserve available to each Area shall at least equal one half its second contingency loss.

In the *Interconnection Agreement between Nova Scotia Power Incorporated and New Brunswick System Operator (NBSO)*, NSPI 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.

NSPI maintains a ten minute operating reserve of 171 MW, of which approximately 36 MW is held as spinning reserve. Additional regulating reserve is maintained to manage the variability of customer load and generation. It is anticipated that regulating reserve requirements will increase with the addition of wind generation resources due to the added variability that will be introduced.

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

6.2 Planning Reserve Criteria

NSPI is required to comply with the NPCC reliability criteria. These criteria are outlined in *NPCC Reliability Reference Directory #1 – Design and Operation of the Bulk Power System*[5] 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.

NSPI 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 New Brunswick System Operator, 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 *2007 Maritimes Area Comprehensive Review of Resource Adequacy*,[6] it was found that the NPCC criteria would be met with a 20 percent reserve margin for the Maritimes area along with 50 MW of additional capacity provided by interconnection assistance. This confirms that the 20 percent planning reserve margin applied by NSPI is acceptable under the NPCC reliability criteria.

[5] http://www.npcc.org/viewDoc.aspx?name=A-02.pdf&cat=regStandCriteria
[6] http://www.npcc.org/viewDoc.aspx?name=2007 Maritimes Area Comprehensive Review.pdf&cat=revResource

6.3 Load and Resources Review

The ten year load forecast and resources additions in Table 8 below are based on the capacity additions and DSM forecast in Table 5. Table 8 indicates that a planning reserve margin equal to 20 percent of the firm peak load is maintained.

Table 8 – NSPI 10 Year Load and Resources Outlook

Load and Resources Outlook for NSPI - Winter 2010/2011 to 2019/2020 (All values in MW except as noted)											
		2010/2011	2011/2012	2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019	2019/2020
A	Firm Peak Load Forecast	2,000	2,039	2,071	2,102	2,132	2,156	2,178	2,200	2,220	2,234
B	DSM Firm	26	62	107	157	205	252	299	345	390	434
C	Peak Firm Less DSM (A - B)	1,975	1,977	1,964	1,945	1,927	1,903	1,879	1,855	1,831	1,800
D	Required Reserve (C * 20%)	395	395	393	389	385	381	376	371	366	360
E	Required Capacity (C + D)	2,370	2,372	2,356	2,334	2,313	2,284	2,254	2,226	2,197	2,160
F	Existing Resources	2338	2338	2338	2338	2338	2338	2338	2338	2338	2338
	Total Cumulative Additions:										
G	Thermal	49	49	49	49	49	49	49	49	49	49
H	Hydro	0	4	4	4	4	4	4	4	4	4
I	Firm Contracted Wind*	43	51	51	51	51	51	51	51	51	51
J	Nuttby Wind Project (firm)*	16	16	16	16	16	16	16	16	16	16
K	Firm RES (2015)**	0	0	0	0	40	40	40	40	40	40
L	Total Firm Supply Resources (F + G + H + I + J + K)	2445	2458	2458	2458	2498	2498	2498	2498	2498	2498
	+ Surplus / - Deficit (L - E)	75	85	101	124	185	213	243	271	301	337
	Reserve Margin % (L/C -1)	24%	24%	25%	26%	30%	31%	33%	35%	36%	39%

*Firm Contracted wind and Nuttby Wind 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 NSPI and the Renewable Energy Industry Association of Nova Scotia and as employed in NSPI 2009 IRP Update modeling).
**Firm RES (2015) represents an addition of renewable energy to comply with the 2015 RES recently announced in the Province's Renewable Electricity Plan in April 2010. The value in the table reflects an assumed firm capacity value of intermittent wind generation of approximately 40 percent based on the winter capacity factor for long-term planning purposes (generator capacity multiplied by the winter capacity factor of 40 percent). For short-term assessments (e.g. 18-month Load and Capacity Assessment) the assumed capacity factor may be less.

7.0 TRANSMISSION PLANNING

7.1 System Description

The existing transmission system has over 5,200 kilometres of transmission lines at voltages at the 69 kV, 138 kV, 230 kV and 345 kV levels.

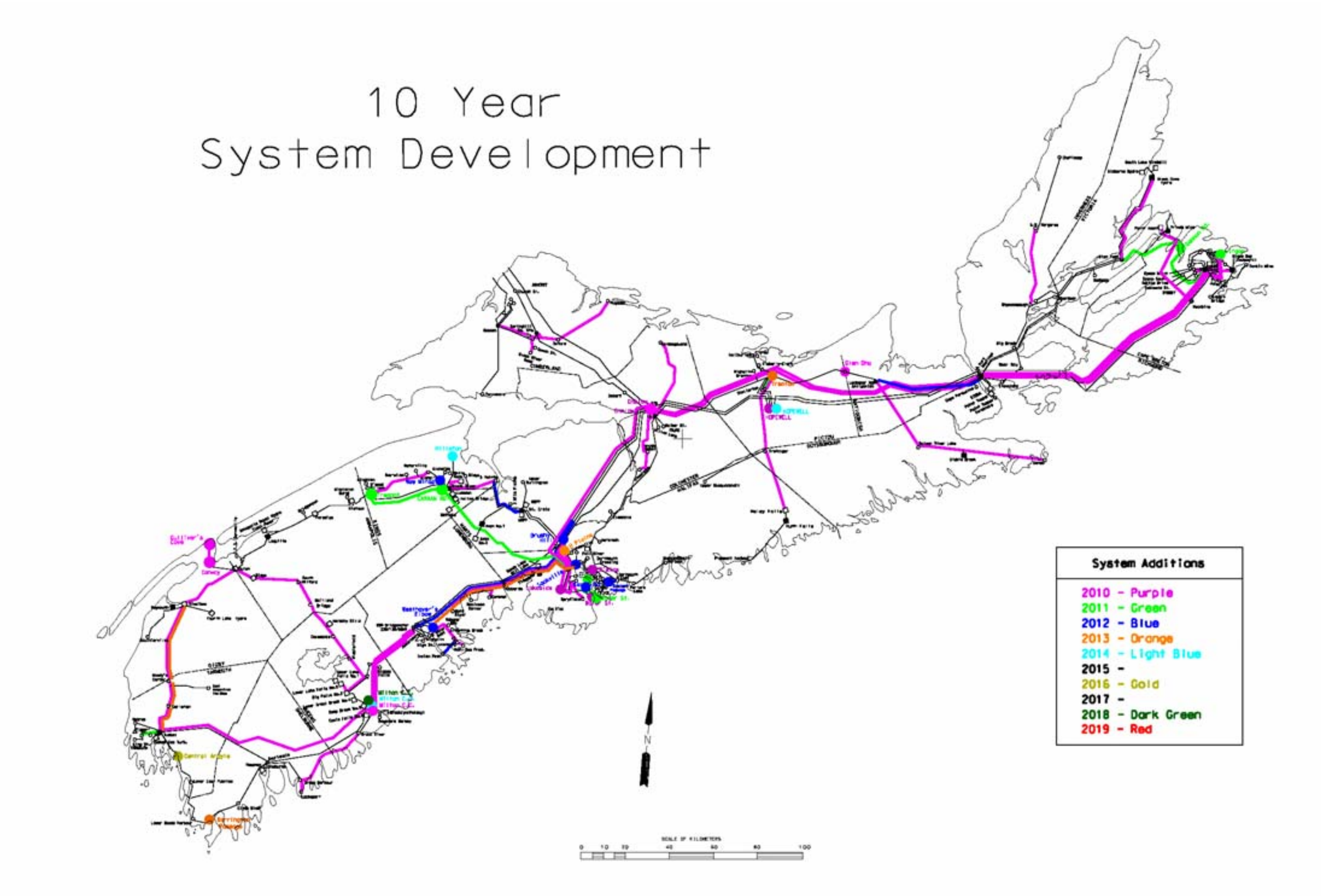
- The 345 kV transmission system is approximately 468 kilometres in length and is comprised of 372 kilometres of steel tower lines and 96 kilometres of wood pole lines.

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

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

- The 69 kV transmission system is approximately 1627 kilometres in length and is comprised of 12 kilometres of steel/concrete structures and 1615 kilometres 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 in USA, Nova Scotia is integrated into the NPCC power system.



7.2 Transmission Design Criteria

NSPI, 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 NSPI bulk transmission system is planned, designed and operated in accordance with single contingency criteria. NSPI is a member of the Northeast Power Coordinating

Council (NPCC). Those portions of Nova Scotia 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 *Basic Criteria for Design and Operation of Interconnected Power Systems*.

NSPI makes extensive use of Special Protection Systems (SPS) within SCADA to maximize 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 NSPI system has several transmission corridors that are regularly operated at limits without incident due to these SPS's.

7.3 Transmission Life Extension

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

The table below lists the lines within the NSPI transmission system which have undergone maintenance over the past two years along with proposed planned maintenance for 2010:

2008	2009	2010
L5003 (Farrell St.-Sackville)	L5003(Farrell St.-Sackville)	L5017(5 Points-Canaan)
L5014 (St. Croix-Burlington)	L5004(Sackville-Geizer Hill)	L5029(Maccan-Springhill)
L5015 (St. Croix-Avon #1)	L5017(Canaan-Five Points)	L5030(Aberdeen-Black River)
L5019 (CanaanRd.-Hollow Bridge)	L5039(Spryfield-Geizer Hill)	L5035(Hells Gate-Canaan)
L5020 (Hollow Bridge-Methals)	L5500(Trenton-Stellarton)	L5037(East River-Canexel)
L5023 (Waterville Tap-Waterville)	L5510(Stellarton-Malay Falls)	L5039(Lakeside-Spryfield)
L5029 (Maccan-Springhill)	L5511(Trafalgar-Malay Falls)	L5040(Onslow-Tatamagouche)

2008	2009	2010
L5031 (Mill Lake-Robinson's Corner)	L5512(Malay Falls-Ruth Falls)	L5048(Green Harbour-Lockport)
L5033 (Canaan Rd.-Hillaton)	L5521(Onslow-Truro)	L5058(Springhill-Pugwash)
L5040 (Onslow-Tatamagouche)	L5573(VJ-Lingan Mine)	L5527(Antigonish-Canso)
L5055 (Tap to Rio Algom)	L6003(Tufts Cove-Sackville)	L5532(Gulch-Big Falls)
L5506 (Abercrombie-Pictou)	L6004(Sackville-Canaan Road)	L5535(Sissiboo-Tusket)
L5534 (Tusket-Hebron)	L6006(Bridgewater-Milton)	L5544(Big Falls-Upper Lake Falls)
L5537 (Tusket-Gas Turbine)	L6013(Canaan Road-Tremont)	L5547(Westhavers Elbow-Lunenburg)
L5538 (Sissiboo-Weymouth)	L6014(Kempt Road-Tufts Cove)	L5559(Whycocomagh-SW Margaree)
L5550 (Maccan-Parrsboro)	L6035(Water St.-Kempt Road)	L5560(VJ-Townsend St.)
L5551 (Lunenburg-Riverport)	L6038(Lakeside-Kearney Lake)	L5561(VJ-Seaboard)
L5561 (VJ-Seaboard)	L6515(Lochaber Road-Hastings)	L5569(Terrace-Townsend)
L5563 (VJ-Townsend St.)	L6516(Hastings-VJ)	L6006(Bridgewater-Milton)
L5564 (VJ-Keltic Drive)	L6517(Hastings-Tupper)	L6010(Brushy Hill-Sackville)
L5565 (Seaboard-Albert Bridge)	L6518(Hastings-NewPage)	L6016(Brushy Hill-Lakeside)
L5572 (VJ-Seaboard)	L6523(Tupper-NewPage)	L6024(Milton-Tusket)
L5579 (Cheticamp-S.W. Margaree)	L6540(VJ-Sysco)	L6025(Bridgewater-Milton)
L6004 (Sackville-Canaan Rd.)	L6545(Wreck Cove-Glen Tosh)	L6516(Hastings-VJ)
L6008 (Sackville-Lakeside)	L6549(Wreck Cove-Glen Tosh)	L6531(Milton-Bridgewater)
L6013 (Canaan Rd.-Tremont)	L7001(Onslow-Brushy Hill)	L6545(Glentosh-Wreck Cove)
L6024 (Milton-Tusket)	L7002(Onslow-Brushy Hill)	L7012(Hastings-Lingan)
L6518 (Pt. Hastings-Stora)	L7011(Hastings-Lingan)	L7015(Pt. Aconi-Woodbine)
L6527 (Onslow Tie Line)	L8001(Onslow-NB Border)	L5530B(Broad River-East Green Harbour)
L6533 (VJ-Lingan)	L6005A(Brushy Hill-Sackville)	L5547A(Mahone Bay Tap-Mahone Bay)
L6536 (Springhill-NB Border)	L6005B(Brushy Hill-Sackville)	L5564A(Terrace St. Tap)
L6538 (Glen Tosh-Gannon Rd.)	L5560(VJ-Townsend Street)	L7003(Onslow-Hastings)
L5032(Rockingham-Rockingham Tap)		L7011(Lingan-Hastings)

2008	2009	2010
L6515(Antigonish-Lochaber Road)		L6002(Sackville-Gold River)
L5004(Sackville-Geizer Hill)		Various Insulator Replacements
L5011(Farrell St.-Imperial Oil)		
L7009 (Brushy Hill-Bridgewater)		
L5024B (Tremont-Greenwood)		
L5031A (Mill Lake-Middle River)		
L5536A (Tusket-Pleasant St.)		
L5536B (Pleasant St.-Hebron)		
L6012B (St. Croix-Canaan Rd.)		
L5539 (Milton-Liverpool)		
L5541 (Milton-Big Falls)		
L6003 (Tuft's Cove-Sackville)		
L6503 (Onslow-Trenton)		
L7002 (Onslow-Brushy Hill)		
L7008 (Brushy Hill-Bridgewater)		
L8002 (Lakeside-Onslow)		
L5579 (Cheticamp-SW Margaree)		
L5027 (Tusket-Souriquois)		
L6002 (Sackville-Bridgewater)		
L6020 (Milton-Souriquois)		
L7005 (Onslow-Pt. Hastings)		
L7014 (Lingan-Woodbine)		
L5535 (Sissiboo-Tusket)		
L5576 (Gannon RD-Keltic Drive)		
L7011 Pt. Hastings-Lingan)		
L5004 (Sackville-Geizer Hill)		
L5573 (VJ-Lingan Mine)		
L6035 (Water St.-Kempt Rd.)		
L6537 (Hastings-Glen Tosh)		
L8004 (Hopewell-Woodbine)		
L5532 Gulch-Big Falls)		
L7003(Onslow-Hastings)		
L7004(Onslow-Hastings)		

2008	2009	2010
L8003(Onslow-Hopewell)		

Nova Scotia Power also has in place a pole retreatment program that enables the useful life of plant to be extended.

The table below lists the lines within the NSPI transmission system which have undergone pole retreatment over the past two years along with proposed pole retreatment for 2010.

2008	2009	2010
L5031(MillLake-Robinsons Corner)	L5036(Berwick Tap-Berwick)	L5014(St. Croix-Burlington)
L5033(Canaan Rd.-Hillaton)	L5037(East River-Louisiana Pacific)	L5015(St. Croix-Avon)
L5053(Michelin-Tremont)	L5046(5017 Tap-Wolfville Ridge)	L5020(Hollow Bridge-Methals)
L5540(Milton-Deep Brook)	L5047(5026 Tap-Bridgetown)	L5021(Canaan Rd.-Klondike)
L5544(Big Falls-Upper Lake Falls)	L5056(5026 Tap-Annapolis)	L5506(Abercrombie-Pictou)
L5545(Bridgewater-High St.)	L5521(Onslow-Willow Lane)	L5510(Stellarton-Malay Falls)
L5555(Gannon Rd.-Prince)	L5536(Tusket-Hebron)	L5511(Trafalgar-Upper Musquodoboit)
L5560(VJ-Townsend St.)	L6005(Brushy Hill-Sackville)	L5512(Malay Falls-Ruth Falls)
L5563(VJ-Townsend St.)	L6024(Milton-Tusket)	L5531(Gulch-Sissiboo)
L5564(VJ-Keltic Dr.)	L6025(Bridgewater-Milton)	L5535(Sissiboo-Tusket)
L5565(Seaboard-Albert Br.)	L6047(Milton-Bowater)	L5546(Bridgewater-Westhavers Elbow)
L5571(VJ-Whitney Pier)	L6048(Milton-Bowater)	L5547(Westhavers Elbow-Lunenburg)
L5572(VJ-Seaboard)	L6515(Lochaber Road-Hastings)	L5548(Maccan-Amherst)
L5573(VJ-Lingan Mine)	L6539(Gannon Road-VJ)	L5561(Victoria Junction-Seaboard)
L6002(Sackville-Bridgewater)	L6548(Hastings-Sub Tie Line)	L6009(Sackville-Burnside)
L6006(Bridgewater-Milton)	L7014(Lingan-Woodbine)	L6020(Milton-Souriquois)
L6012(Brushy Hill-St. Croix)		L6536(Springhill-NB Border)
L6050(Aerotech Park)		L6538(Glentosh-Gannon Rd.)
L6503(Onslow-Trenton)		

7.4 Transmission Project Approval

The transmission plan presented in this document provides a summary of the planned reinforcement of the NSPI power system. The proposed investments are required to maintain system reliability and security and comply with System Design Criteria. NSPI 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 NSPI, 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 or the UARB.

In 2008 a Maritimes Area Technical Planning Committee was established to review intra-area plans for Maritimes Area resource adequacy and transmission reliability. This Committee will also project 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, New Brunswick System Operator, Maritime Electric Company Ltd., Northern Maine Independent System Administrator and NB Power Transmission.

7.5 NSPI/NB Interconnection Overview

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

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

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

Import and export limits on the inter-tie have been established to ensure the Nova Scotia system can withstand a single contingency loss. The limits are up to 350MW export and up to 300MW import. These figures represent limits under pre-defined system conditions. Conditions which determine the actual limit of the interconnection are:

Export	**Import**
Number of thermal units armed for generation rejection (maximum two)	NS system load level (Import less than 22% of total system load)
Reactive Power Support level in the Halifax Regional Municipality	Percentage of dispatchable generation
Arming of Special Protection Systems	NB export level to PEI and/or New England
Real time line ratings (climatological conditions in northern NS)	Real time line ratings (climatological conditions in northern NS)
NS System load level	Load level in Moncton area
Largest single load contingency in NS	Largest single generation contingency in NS

If the NSPI system is separated from New Brunswick during export (i.e. the inter-tie trips), system frequency (cycles/second) will rise, risking unstable plant operation and possible damage. To address this NSPI uses fast-acting Special Protection Systems to reject generation and stabilize the system.

If the NSPI system is separated during import, system frequency will drop. Depending on the system characteristics at the time of disruption and the magnitude of the import electricity flow that was lost, the system will respond and re-balance. It does this by rejecting load through under-frequency load shedding (UFLS) protection systems as required.

The loss of the 345kV line between Onslow, NS and Memramcook, NB 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 New Brunswick System Operator restricts export to Nova Scotia to a level such that any single contingency does not cause adverse impacts on NB or PEI load. Any transmission reinforcement proposed to improve reliability, increase import and export 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. As noted earlier, NS and NB are working together to evaluate transmission needs in the areas noted.

<u>NSPI Capital Item CI# 29009 Right of Way Purchase Northern NS</u>

In jurisdictions across North America it is becoming more 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 cost approximately $200 million and require at least 5 years to procure the required permits and complete construction.

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, NSPI has identified a future capital item in the 2010 Annual Capital Expenditure (ACE) Plan to commence the planning and acquisition of land right of way for a second 345kV line to New Brunswick. The project cost and scope will be submitted to the Board for approval by June 30, 2010.

8.0 TRANSMISSION DEVELOPMENT 2010 TO 2018

Transmission development plans are summarized below. As discussed earlier, these projects are subject to change. For 2010, the majority of the projects listed are included in the 2010 Annual Capital Expenditure Plan. For 2010 onward, the projects are noted in the projected year of completion.

1. 2010

- Work will begin on the construction of additional transmission to the Western Valley area. This will include the construction of a 138 kV circuit between Canaan Road and Tremont, a 138 kV termination at Canaan Road and the addition of a 138-69 kV, 33.6/44.8/56 MVA transformer at Tremont along with the establishment of a 138 kV bus. This project is necessary to mitigate various contingencies that could result in transformer overload scenarios, line overload conditions and low voltage conditions.

- The insulator replacement program will continue with the reinsulation of 5 circuits due to cement growth issues. Insulator cement growth has been identified on certain types of insulators that will result in the circuit experiencing an unplanned outage. This results in either customer outages or an outage to a circuit on the transmission system that could result in an uneconomic generation dispatch until the issue is rectified.

- The transmission reliability investment program will continue targeting transmission switches and circuit breakers. This program is intended to replace equipment that has encountered operational issues or those in which spare parts are no longer available.

- A program will commence to replace porcelain cutouts and some insulators at various transmission substations. NSPI has encountered issues with porcelain cutouts on the distribution system. These cutouts are similar to those used on certain equipment in substations. A failure of a cutout in a transmission substation could result in an outage to all customers supplied from that substation.

- Work will take place on a 230 kV circuit between Onslow and Port Hastings 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.

- In accordance with the NPCC *Classification of Bulk Power System Elements* (Document A-10), dual high-speed protection systems are required at 138 kV substations at Hopewell, Tufts Cove, and Burnside.

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

- Work will continue on the uprating of a 345 kV circuit between Onslow and Lakeside for the purpose of increasing the operating temperature of the line.

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

- Work will begin on right of way acquirement between Dartmouth East and Eastern Passage for the purpose of accommodating a 138 kV circuit to a proposed new 138 kV substation in the Eastern Passage area.

- Work will begin on right of way acquirement from the existing 138 kV Canaan Road substation to a new substation site in the New Minas area for the purpose of accommodating a 138 kV circuit to a new 138 kV substation in the New Minas area.

- The 69 kV transmission interconnection to the Nuttby mountain wind farm will be placed in service.

- The Digby wind farm will be placed in service. This will include at 69-34.5 kV substation at the wind farm, a 17.5 km 69 kV circuit from the wind farm to an existing substation in Digby (Conway), and a 69 kV circuit breaker at Conway Substation along with various system upgrades.

- Work will commence on replacing the 138 kV Gas Insulated Switchgear at the existing Water St. substation.

- The Glen Dhu wind farm is scheduled to go in service. This will include the establishment of a 138 kV ring bus on an existing 138 kV circuit between Trenton and Antigonish.

2. 2011

- The insulator replacement program will continue with the reinsulation of three circuits due to cement growth issues.

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

- In accordance with the NPCC *Classification of Bulk Power System Elements* (Document A-10), dual high-speed protection systems are required at 138 kV substations at Onslow, Brushy Hill, and Lakeside. In addition breaker backup will be added at the Tufts Cove 69 kV substation.

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

- The Canaan Road to Tremont transmission upgrade is scheduled to be placed in service.

- The project to replace the 138 kV Gas Insulated Switchgear at Water St. will be completed.

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

- An existing 69 kV circuit between Trenton and Bridge Avenue is planned to be rebuilt to provide additional capacity. This project is being undertaken to avoid an overload condition for the contingency loss of a parallel 69 kV circuit during high load conditions.

- An existing 69 kV circuit between Tusket and Pleasant Street, Yarmouth is planned to be reconductored to provide additional capacity.

3. 2012

- The insulator replacement program will continue with the reinsulation of 2 circuits 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.

- In accordance with the NPCC *Classification of Bulk Power System Elements* (A-10), dual high speed protection systems are required at 138 kV substations at Sackville, Kempt Road, and New Page (Port Hawkesbury).

- The existing 138-69 kV, 20/26.7 MVA transformer at Westhaver's Elbow is planned to be changed out for a unit rated 22.5/33.3 MVA for the purpose of addressing voltage regulation in the area.

- A new 138-12 kV, 15/20/25 MVA substation is proposed to be constructed in New Minas for the purpose of supplying additional load growth.

- A new 138-25 kV substation is planned to be constructed at a new site in the Eastern Passage area. This substation would be served by the construction of a new 138 kV circuit from an existing Dartmouth East substation to the new site. This station is required to prevent equipment overloads during contingency conditions and address load growth in the Eastern Passage area.

- The double-circuit towers that carry L-7008 and L-7009 for 5.5 km out of the Brushy Hill 230 kV substation will be re-configured to accommodate the normal contingency loss of both towers.

- A 69 kV circuit between St. Croix and Five Points substations will be rebuilt.

4. 2013

- The insulator replacement program will continue with the reinsulation 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.

- An existing 69-12 kV, 7.5/10/12.5 MVA transformer at Barrington Passage is planned to be changed out for a unit rated 15/20/25 MVA to address area load growth.

- Load will be transferred from the 2 x 138-69 kV autotransformers at Trenton. This will be accomplished by changing out an existing 69-25 kV transformer at Trenton with a 138-25 kV unit.

- A second 138-25 kV, 25/33/42 MVA transformer will be added at the existing Hammonds Plains Road substation.

5. 2014

- An existing 69-12 kV transformer at Hillaton will be changed out for a unit rated 15/20/25 MVA.

- The 138 kV bus at Milton will be rearranged to avoid loss of the bus due to a bus tie breaker failure.

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

- The 345 kV bus at Hopewell will be developed into a ring bus configuration.

6. 2016

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

7. 2018

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

- There is a possibility of an additional supply to the Halifax downtown area. This could take the form of a 138 kV underwater cable from Dartmouth to Water St. or another route that has not as yet been determined. This evaluation will commence in the near future.

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 remains unknown with respect to the form, location and scope of future generation, as emission regulations and Renewable Energy Standards evolve and projects required to maintain compliance are studied including the implications of large amounts of intermittent generation such as wind.

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

It should be reinforced that this work remains preliminary and is 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 unfold as projected will be determined by a host of factors unknown today including:

- The location, size and configuration of generation developments across Nova Scotia;
- The emergence of new generation sources and markets outside of Nova Scotia;
- Ongoing change to power system industry engineering and operating standards;
- Changes in customer demand or emergent technologies dependant on electricity.

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

- Transmission system reinforcement will 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 plans should be robust to accommodate changes in area and provincial load and generation;
- Transmission system plans will be subject to change in response to opportunities, inside and outside of Nova Scotia; and
- Further work on this is required.

10.0 CONCLUSION

It is likely that the NSPI transmission system will require reinforcement in the coming decade and that this reinforcement will occur across the province and at the provincial inter-tie. The specific form of this reinforcement is not understood in detail today. Work to understand this is proceeding in accordance with the underlying market drivers.

On June 30, 2010, NSPI will apply to the UARB for approval of the purchase of right of way to accommodate a second provincial inter-tie. Additional transmission applications will be forthcoming once the design, cost and business cases necessary to support these investments are complete.

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

11.0 REFERENCES

1. *2004 Maritimes Area Triennial Review of Resource Adequacy*, Report approved by NPCC Reliability Coordinating Council March 9, 2005.

2. *Basic Criteria for Design and Operation of Interconnected Power Systems*, Northeast Power Coordinating Council Document A-2, May 6, 2004.

3. *Final Report, Nova Scotia Wind Integration Study*, Hatch, Ltd., 2008.

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

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

6. 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

Nova Scotia Power's interconnected system is divided into several classifications, each of which is governed by different design criteria.

These classifications are as follows:

1. Primary Transmission
2. Secondary Transmission
3. Electrically Remote Transmission
4. Sub-transmission
5. Transformation

The System Design criteria combine protection performance specifications with system dynamics and steady state performance requirements. Within any classification, system studies assume specified protection performance to determine the required number, characteristics and type of system elements, while protection design incorporates only that equipment necessary to achieve the assumed performance, assuming a single coincident protection element failure.

DEFINITIONS

1. **Primary Transmission** is defined as the 345 kV transmission system interconnecting Lakeside-Onslow-Hopewell-Woodbine, and Salisbury, New Brunswick, the 230 kV transmission system interconnecting Brushy Hill-Onslow-Lingan-and Pt. Aconi, Nova Scotia and the interconnecting 345/230 kV transformation between them.

2. **Secondary Transmission System** is defined to be that part of the system which serves mainly to interconnect miscellaneous generation and Primary Transmission with Sub transmission at major load centres.

The lesser importance of secondary transmission relative to the Primary Transmission permits a relaxation of the design criteria from that required for the primary transmission system. This definition then governs most of the 138 kV developments plus certain 69 kV and 230 kV, other than on the Primary Transmission system.

3. **Electrically Remote Transmission** is defined by those buses at which ultimate fault levels are projected to not exceed 1500 MV.A three phase.

4. **Sub transmission System** is defined to be that part of the system which primarily serves as a source for transformation to the distribution level. This type of system is primarily characterized by radial feeds although looped sub transmission exists.

5. **Interconnected Transmission System** is defined as the combined Primary, Secondary, and Electrically Remote Transmission systems including connected generation.

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

   a) Any load condition (this includes the full range of annually forecasted loads).

   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 percent to 105 percent of nominal, unless otherwise noted.

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

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

8. **Local back-up clearance** is defined to be the time to clear an in-zone fault.

9. **Remote back-up clearance** is defined to be the time to clear an out-of-zone fault.

10. **Breaker back-up** is defined to be protection against local breaker failure to trip for any reason. Breaker back-up will be applied to all Primary Transmission and most of the Secondary Transmission systems.

I. PRIMARY TRANSMISSION SYSTEM

Prime clearance times are defined to be 4.5 cycles first zone and 6 cycles second zone with permissive signal for both three-phase and line-to-ground faults.

Back-up clearance times are defined to be 15 to 18 cycles for both three-phase and line-to-ground faults.

The Design Criteria[7] 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 except a generator or bus section, 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.

[7] Note: The Primary Transmission System Design Criteria may be superseded by the NPCC Basic Criteria for the Design and Operation of Interconnected Power Systems.

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 except a bus section or generator, cleared in 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 their long-term thermally limited ratings.

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 voltage shall not be less than 90 percent or greater than 110 percent 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 percent 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.

II. SECONDARY TRANSMISSION SYSTEM

Prime time clearance is defined to be 6 to 9 cycles for both three-phase and line-to-ground faults. (No additional expenditure may be made to reduce clearing times from 9 to 6 cycles without authorization from System Design.)

Local back-up clearance is defined to be less than 30 cycles (a figure of 20 cycles is desirable but where coordination so dictates, a 30 cycle figure is acceptable).

Remote back-up clearance is defined to be less than 30 cycles which in certain instances implies reduced margins of coordination.

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 except a generator or bus section 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 except a generator or bus section, cleared in 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 their thermally limited ratings in the steady state.

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 less than 90 percent or greater than 110 percent 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 percent 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.

III. ELECTRICALLY REMOTE TRANSMISSION

Prime time clearance is defined to be 9 cycles for both three-phase and line-to-ground faults. Note 1 and Note 2.

The Design Criteria are:

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

2. From normal system conditions following loss of any one element with or without fault, all remaining elements shall be within their thermally limited ratings.

3. From normal system conditions, for the loss of any one Electrically Remote system element with or without fault, no Interconnected transmission system bus voltage shall be less than 90 percent or greater than 110 percent of nominal following a steady state settling out of the system nor shall any bus experience a voltage change from pre-fault to post-fault condition greater than 10 percent before tap-changer correction.

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

NOTES:

1. No expenditure may be made to reduce clearing times to reference values without authorization from System Design.

2. Permissive tripping between an electrically remote bus and a transmission bus (or between 2 electrically remote buses) is not required, i.e., local back-up clearances are acceptable.

3. Application of the above criteria does not preclude the possibility that for loss of certain remote system elements there will be a designed loss of load. This load would be restored after operator action.

IV. SUB-TRANSMISSION SYSTEM

The Design Criteria are:

1. Sub transmission system loading shall be within the thermally limited ratings.

2. The sub transmission system voltages shall not be less than 97.5 percent or greater than 105 percent of nominal.

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

4. From normal system conditions, following the loss of any one sub transmission system element with or without a fault, any sub transmission system bus which remains connected to the system, shall maintain sufficient voltage following automatic tap-changer correction to permit operation of any affected distribution bulk supply bus at 105 percent of nominal following a steady state settling out of the system. In no case shall any bus experience a voltage change from pre-fault to post-fault condition greater than 10 percent before tap-changer correction.

5. The application of the above criteria does not guarantee a continuity of supply for any single contingency. In the case of a line, since a lengthy outage is considered to have a low probability time to repair is considered adequate for restoration of service; however, in the case of transformation, since an outage is generally a prolonged one, either the use of a mobile transformer for a short-term replacement or the installation of a spare transformer and interconnections with adjacent substations at the distribution level, are considered in decisions concerning the guaranteeing, after outage, of an alternative supply.

V. TRANSFORMATION

Design Criteria

1. Capacity for any individual transformation point shall, under nominal 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 as per Note 4.

2. 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 Note 4. (This is in conjunction with (a) and (b) above as applicable.)

    d) Largest available suitable mobile transformer loaded to its nameplate rating. (This is 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 criteria because estimated out-of-merit costs may significantly exceed the costs of capital advancement.

2. The Primary Transmission system may require additional transformation in certain instances when, although the above (a), (b) and (c) may result in satisfaction of this particular criteria, any other of several possible contingencies (transmission lines, generators or transformer(s)) could result in either frequent or prolonged outages to a widespread part of the system.

3. The result of application of these criteria may not be installation of additional transformation.

APPENDIX B

TRANSMISSION ADDITIONS FOR GENERATION DEVELOPMENT SCENARIOS

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

In lieu of this certainty, NSPI 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.

The 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 NSPI supports.

Renewable Generation Additions

1) Wind Development Scenarios (2013 - 2019)

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

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

b) Mainland (South Nova) wind generation (100MW-150MW) 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 (Lower Annapolis Valley) wind generation (100-150MW) development scenario

This scenario requires the completion of a 138kV line L-6617 from Tremont to Canaan Rd currently scheduled for construction along with a new ring bus configuration at Tremont, including a second 138-69 kV transformer, and substation modifications at Canaan Road. 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. This would include the development of a 138 kV ring bus configuration at Paradise. In addition new 138 kV circuits would be constructed from Gulch to Tremont and Tusket substations. Two 230 kV circuits currently occupying double circuit towers towards the Bridgewater area would be separated.

d) Mainland (Upper Annapolis Valley) wind generation (100-150MW) development scenario

An existing 69 kV circuit between Sissiboo and Tusket would be rebuilt to a higher capacity. Substation modifications would be required at Canaan Road and Milton along with changing out two 138-69 kV autotransformers at Canaan Road for 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 (100-150MW) development scenario

Construct a new 138kV line from Onslow to Springhill and install a 100 MVAR static 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 (150MW -250MW) 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 – 138 kV substation would be established at Spider Lake that would terminate 3 x 138 kV circuits in the Dartmouth area. In addition 100 MVAR of reactive compensation would be established in the Dartmouth area.

2) Port Hawkesbury 60MW Biomass- Cape Breton Strait Area Scenario

An additional line crossing the Strait of Canso would be constructed to eliminate the double circuit contingency limit. A bus reconfiguration at NSPI’s Onslow 345kV EHV substation, an upgrade of a 138kV line terminal at NSPI’s Trenton substation, and the addition of switched capacitors at NSPI’s Brushy hill substation would also be required.

Large External Imports (300MW) or Export development scenario

a) To facilitate a large import or export via NB interconnect

To enable import, a new 345 kV transmission circuit would be required between Onslow to the New Brunswick system. An existing 230 kV circuit would be uprated to 345 kV to provide a 345 kV transmission interconnection between Onslow and Brushy Hill along with increased reactive compensation at Brushy Hill. In addition a 345 kV ring bus would be established at Hopewell and a 345 kV circuit would be constructed from Hopewell to the Metro area. Joint planning studies are required with New Brunswick to determine upgrades to the New Brunswick system that would be required to support a firm import of this magnitude.

For additional firm export from NS to NB, added further study may also be required.

b) Newfoundland Submarine Cable Import (300MW) or Export development scenario

A 300 MW DC to AC terminal would be required at Onslow or Brushy Hill along with a DC submarine cable from Newfoundland to Cape Breton along with overhead DC transmission from Cape Breton to Onslow or Brushy Hill. An existing 230 kV circuit would be converted to 345 kV to provide a 345 kV transmission connection between Onslow and Brushy Hill. A 345 kV ring bus would be established at Hopewell and a new 345 kV transmission circuit would be constructed between Hopewell and the Metro Halifax area.

Additional export of energy from Newfoundland through Nova Scotia would require further study in order to determine the additional transmission investment required.

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

For contingency loss of a large generator scenario the NS-NB inter-tie may require reinforcement depending on potential unit size.

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 345/230 kV transformer at Port Hastings. A 345/138 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

Development of a 138 kV substation 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 will be required from Spider Lake to Sackville as well as a high capacity line from Tufts Cove to Brushy Hill. In addition substation modifications will take place at Tufts Cove and Brushy Hill.

Nova Scotia
POWER
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energy everywhere.

March 14, 2012

Ms. Nancy McNeil
Regulatory Affairs Officer/Clerk
Nova Scotia Utility and Review Board
1601 Lower Water Street, 3rd Floor
PO Box 1692, Unit "M"
Halifax, NS B3J 3S3

Re: Nova Scotia Power Inc. Final 10 Year System Outlook

Dear Ms. McNeil,

On June 30, 2011, NS Power submitted to the UARB its 10 Year System Outlook report. The Board issued Information requests which NS Power provided responses to on August 25, 2011. Subsequently, the Board issued a letter on August 30 requesting that Section 3.0 of the report regarding Demand Side Management be further elaborated.

NS Power has worked with UARB staff to revise the 10 Year System Outlook report in order to address the Board's directive. Please find enclosed the revised and final 10 Year System Outlook Report.

Concurrent with this filing, NSPI will post this report on the NSPSO OASIS site at:

http://oasis.nspower.ca/en/home/default/forecastsandassessments.aspx

Yours truly,

J. René Gallant
Vice President Regulatory Affairs

Encl.

10 Year System Outlook
2011-2020
Final Report

March 14, 2012

NOVA SCOTIA POWER
An Emera Company

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1.0 INTRODUCTION

Nova Scotia Power Inc. (NS Power, the Company) submitted the first 10 Year System Outlook report on June 30, 2008. Following NS Power's second annual 10 Year System Outlook filing on June 30, 2009, the Nova Scotia Utility and Review Board (UARB, Board), in its letter dated January 11, 2010 provided the following:

> Recognizing the direct relationship among the Outlook, the IRP, and the ACE Plan, the Board anticipates that any significant recommendations resulting from these briefings will be incorporated by NSPI into its 2010 Outlook report.

Consistent with the 3.4.2.1[1] Market Rule requirements and the subsequent Board direction, the 2011 Outlook contains the following:

1. A summary of the NS Power load forecast employed in the Outlook;
2. An update on the DSM program undertaken by the Company;
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 2011 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.

1 The NSPSO system plan will address: a) transmission investment planning; b) DSM programs operated by NS Power Customer Service division 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 forecast informs 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 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. Warmer than average weather kept load growth to 0.7 percent in 2010 but 2011 is forecast to grow at 4.4 percent growth with some expected economic rebound and the expected return to more typical temperatures. NSR is forecast to decline an average of 1.3 percent annually over the next 10 years with the effects of Demand Side Management (DSM) programs. Without the effects of these DSM programs, the NSR is forecast to grow an average of 0.8 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 (%)
2001	11,303	0.6
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
2011F	12,688	4.4
2012F	12,647	-0.3
2013F	12,507	-1.1
2014F	12,339	-1.3
2015F	12,180	-1.3
2016F	12,008	-1.4
2017F	11,832	-1.5
2018F	11,651	-1.5
2019F	11,492	-1.4
2020F	11,333	-1.4
2021F	11,173	-1.4

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 2010 contain the effects of DSM programs.

[2] Data sourced from the 2011 NS Power Load Forecast, filed with the UARB on April 28, 2011.

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
2011F	2,310	9.3	316	7.3	1,994	9.6
2012F	2,308	-0.1	309	-2.4	2,000	0.3
2013F	2,277	-1.4	308	-0.3	1,970	-1.5
2014F	2,242	-1.6	304	-1.3	1,938	-1.6
2015F	2,208	-1.5	298	-1.9	1,910	-1.4
2016F	2,173	-1.6	292	-1.9	1,880	-1.5
2017F	2,135	-1.7	287	-2.0	1,849	-1.7
2018F	2,096	-1.9	281	-1.9	1,815	-1.8
2019F	2,061	-1.7	276	-1.8	1,785	-1.6
2020F	2,026	-1.7	271	-1.7	1,755	-1.7
2021F	1,991	-1.7	267	-1.7	1,725	-1.7

*Results for the years 2008 to 2010 contain the effects of DSM programs.

[3] Data sourced from the 2011 NS Power Load Forecast, filed with the UARB on April 28, 2011.
[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. The trajectory is consistent with the DSM profile from the 2009 IRP Update adjusted for early year changes.

Table 3 – Demand Side Management Forecast *

Year	Cumulative Demand Savings (MW)	Cumulative Energy Savings (GWh)
2011	22	120
2012	60	306
2013	113	570
2014	173	869
2015	231	1,154
2016	288	1,439
2017	345	1,715
2018	400	1,980
2019	454	2,238
2020	506	2,490
2021	557	2,736

Note: Cumulative Demand Savings include interruptible customers

*The DSM Forecast values represent the difference between the "With DSM" and "Without DSM" load forecast values of the April 2011 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 2011, ENSC filed an application with the Board seeking approval for an overall expenditure of $43.7 million associated with the 2012 DSM Plan. A decision from the UARB was issued June 30, 2011.

The comparable DSM numbers submitted by ENSC in its 2012 DSM application can be found in Figure 4.2 of their application:

Figure 4.2 Cumulative Savings Targets and Results 2008-2012

Year	IRP Target GWh	Result GWh	IRP Target MW	Result MW
2008	16	21[a]	2	5[a]
2009	66	86[a]	9	15[a]
2010	149	171[b]	26	31[b]
2011	295	329[c]	57	62[c]
2012	500	543[d]	101	100[d]

[a] verified results
[b] estimate based on evaluated but not verified results
[c] estimate based on approved Plan
[d] estimate based on proposed Plan and includes savings outside DSM programs

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:

- Only the effects of future DSM programs are shown as load forecast adjustments in NS Power's model. The effects of past DSM programs are embedded in the model trends (i.e. the base load forecast). In contrast, ENSC's model includes the cumulative savings of past DSM programs into its figures. The ENSC figures demonstrate the accumulated DSM savings from the beginning of the programs in 2008, whereas the NS Power forecast is concerned with the DSM effects on load for the year 2011 and onward.

- At the time of the development of NS Power's load forecast, ENSC's 2012 DSM plan was not complete. Therefore, NS Power applied the 2009 IRP target savings in its 2012 load forecast. This incremental energy savings was 205 GWh[5] instead of the 214 GWh[6] that was developed in the completed ENSC 2012 plan.

- For the year 2010, the load forecast employed the DSM savings estimates from the 2010 plan that was also slightly different than the final verified 2010 results. The incremental DSM savings numbers were 81 GWh and 13 MW, instead of the numbers used in ENSC's Fig 4.2 which were 85 GWh and 16 MW.

[5] Year 2012 incremental DSM savings from the 2009 IRP filing.
[6] Year 2012 incremental DSM savings as per the ENSC 2012 DSM filing.

- Another difference is due to the method that NS Power uses to account for these annual incremental DSM plan savings in the load forecast. It is based on the assumption that the planned DSM measures, for any given year, are implemented throughout that calendar year and are not entirely active on the first day of the year. For this reason, NS Power's load forecast assumes that 50 percent of the planned savings will occur in the first year the program is implemented, and the remaining 50 percent will occur in the following year. This approach to calculating the "realized" savings results in different cumulative DSM savings, particularly in the ramp-up phase of DSM programs.

The table below shows the annual DSM adjustments using ENSC's results from Figure 4.2, 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.

Year	DSM Result (from Figure 4.2) Cumulative Savings (GWh)	Calculated incremental DSM Savings from Figure 4.2 **Result** (GWh)	Forecast Adjustments calculated using ENSC results in the NS Power method: Increment (50% of current year + 50% of prior year)	Forecast Adjustments calculated using ENSC results in the NS Power method: Cumulative Savings (GWh)	NS Power Load Forecast: DSM Increment (GWh)	NS Power Load Forecast: DSM Cumulative Savings (GWh)
2008	21	21	DSM embedded in actual load		DSM embedded in actual load	
2009	86	64				
2010	171	85				
2011	329	158	122	122	120	120
2012	543	214	186	**308**	186	**306**

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 Figure 4.2

Year	DSM Result (from Figure 4.2) Cumulative Savings (MW)	Calculated incremental DSM Savings from Figure 4.2 **Result** (MW)	Forecast Adjustments calculated using ENSC results in the NS Power method: Increment (50% of current year + 50% of prior year)	Forecast Adjustments calculated using ENSC results in the NS Power method: Cumulative Savings (MW)	NS Power Load Forecast: DSM Increment (MW)	NS Power Load Forecast: DSM Cumulative Savings (MW)
2008	5	5	DSM embedded in actual load		DSM embedded in actual load	
2009	15	10				
2010	31	16				
2011	62	31	24	24	22	22
2012	100	38	34	**58**	38	**60**

Once adjusted for methodological differences, the results of both NS Power and ENSC are similar.

GENERATION RESOURCES

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 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 2011.

Table 4 – 2011 Generating Resources[7]

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**

[7] Data sourced from 2009 IRP Update Assumptions

Plant/System	Fuel Type	Winter Net Capacity (MW)
Tufts Cove	Natural Gas	98.0
Burnside**	Light Fuel Oil	99.0
Tusket	Light Fuel Oil	24.0
Victoria Junction	Light Fuel Oil	66.0
Total Combustion Turbine		**287.0**
Contracts (pre-2001)	Independent Power Producers	25.8
Renewables(firm) (post 2001)***	Independent Power Producers	72.2
NS Power wind (firm)***	Wind	28.5
Total IPPs & Renewables		**126.5**
Total Capacity		**2362.6**

*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 the future. Asset management plans for the Burnside fleet are currently being re-assessed.

*** The assumed firm capacity value of wind reflects the assumed 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.

Changes in Capacity

Table 5 provides the firm Supply and Demand Side Management capacity additions per the Port Hawkesbury (PH) Biomass Project Base Case Plan (as filed with the UARB in P-128.10 April 9, 2010) over the 2010-2020 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 configured as an Energy Resource Interconnection Service (ERIS) (refer to Section 5.1) and is not included in the Table.

Table 5 – Capacity Additions & DSM

New Resources 2011-2021	MW
DSM firm*	495
Tufts Cove 6	48.9
Hydro**	4.2
Firm Contracted Wind***	5.7
Firm RES (2015)****	50.6
Community Feed-in-Tariff*****	20.0
Total Firm Supply & Demand MW Projected Over Planning Period	**624.4**

Notes:

* DSM Firm does not include interruptible customers.

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

*** Firm Contracted wind 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).

**** Firm RES (2015) represents an addition of renewable energy to comply with the 2015 RES announced in the Province's Renewable Electricity Plan in April 2010. The value in the table includes the firm contribution of dispatchable generation as well as an assumed firm capacity value of intermittent wind generation. For long-term planning purposes the firm capacity value of wind is based on the winter capacity factor (generator capacity multiplied by the winter capacity factor). For short-term assessments (e.g. 18-month Load and Capacity Assessment) the assumed capacity factor may be less. Legislation has recently received Royal Assent for RES (2020) with a target of 40%. NS Power is currently determining the capacity additions associated with this.

*****The Community Feed-in-Tariff represents distribution-connected renewable energy projects as outlined in the Province's Renewable Electricity Plan in April 2010. 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 20% capacity factor. For short-term assessments (e.g. 18-month Load and Capacity Assessment) the assumed capacity factor may be less.

4.0 NEW GENERATING FACILITIES

Potential New Facilities

As of June 27, 2011, NS Power's interconnection request queue includes 1461 MW of proposed generation projects at various stages of interconnection study. Sponsors of these projects have requested either Network Resource Interconnection Service (NRIS) or Energy Resource Interconnection Service (ERIS). 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 interconnection request queue as of June 27, 2011.

Table 6 – Generation Interconnection Queue

Nova Scotia Power - Interconnection Request Queue

NOVA SCOTIA POWER An Emera Company

Publish Date: *Monday, June 27, 2011*

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	45	19-Jan-05	Cumberland	31.5	31.5	L-6535	Wind	15-Jan-12		GIA Executed	N/A	N/A
2	8	14-Oct-03	Guysborough	13.8	13.8	L-5527B	Wind	20-Sep-12		GIA Executed	N/A	N/A
3	56	19-Aug-05	Cumberland	34	34	L-5058	Wind	01-Nov-14		GIA Executed	ERIS	N/A
4	151	22-Aug-07	Halifax	50	50	91H	Steam	30-Jun-10		GIA Tendered	NRIS	N/A
5	219	08-Apr-10	Richmond	64	64	47C	Steam	31-Dec-12		FAC in Progress	ERIS	N/A
6	227	26-Aug-10	Hants	10.2	10.2	L-4048	Steam	01-Jul-12		FAC in Progress	NRIS	N/A
7	225	03-May-10	Pictou	60	60	L-6503	Wind	31-Dec-12		FAC in Progress	ERIS	N/A
8	233	14-Jan-11	Colchester	50.6	50.6	L-5040	Wind	31-Dec-14		SIS in Progress	ERIS	N/A
9	234	14-Jan-11	Pictou	41.4	41.4	L-6503	Wind	31-Dec-14		SIS in Progress	ERIS	N/A
10	67	27-Apr-06	Annapolis	40	40	L-5026	Wind	31-Oct-10		SIS Agrmnt Complete	ERIS	N/A

Nova Scotia Power - Interconnection Request Queue: Page 1 of 3

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

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
11	68	27-Apr-06	Digby	35	35	L-5533	Wind	31-Oct-10		SIS Agrmnt Complete	ERIS	N/A
12	86	09-Jan-07	Pictou	50	50	L-7003	wind	01-Jan-09		SIS Agrmnt Complete	NRIS	N/A
13	115	23-Mar-07	Pictou	120	120	L-7003	wind	30-Nov-09		SIS Agrmnt Complete	NRIS	N/A
14	117	13-Apr-07	Shelburne	10	10	L-5027	wind	01-Sep-09		SIS Agrmnt Complete	ERIS	N/A
15	126	16-Apr-07	Cumberland	70	70	L-6513	wind	31-Dec-09		SIS Agrmnt Complete	ERIS	N/A
16	128	17-Apr-07	Cumberland	40.5	40.5	L-6535	wind	20-Nov-09		SIS Agrmnt Complete	ERIS	N/A
17	130	17-Apr-07	Cape Breton	200	200	L-7012	wind/water	31-Dec-09		SIS Agrmnt Complete	NRIS	N/A
18	131	17-Apr-07	Cape Breton	11.5	11.5	L-5580	wind	30-Nov-09		SIS Agrmnt Complete	ERIS	N/A
19	149	05-Jul-07	Cumberland	70	70	L-6536	wind	20-Nov-09		SIS Agrmnt Complete	ERIS	N/A
20	163	28-Jan-09	Richmond	60	60	47C	Steam	30-Apr-11		SIS Agrmnt Complete	NRIS	N/A
21	213	29-Jul-09	Cumberland	15	15	37N	Tidal	31-Dec-10		SIS Agrmnt Complete	ERIS	N/A
22	222	26-Apr-10	Pictou	48	48	L-5508	Steam	31-Aug-12		SIS Agrmnt Complete	NRIS	N/A

Nova Scotia Power - Interconnection Request Queue: Page 2 of 3
ERIS - Energy Resource Interconnection Service
NRIS - Network Resource Interconnection Service
N/A - Not Applicable

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
23	232	14-Jan-11	Antigonish	50.6	50.6	L-6511	Wind	31-Dec-14		SIS Agrmnt tendered	ERIS	N/A
24	235	19-Jan-11	Halifax	50	50	L-6043	Wind	1-Jul-14		SIS Agrmnt tendered	ERIS	N/A
25	238	28-Jan-11	Yarmouth	50	50	9W	Wind	01-Jul-14		FEAS In Progress	NRIS	N/A
26	241	14-Feb-11	Colchester	1	1	L-5040	Wind	30-Mar-11		IR Valid	NRIS	N/A
27	242	24-Nov-11	Cumberland	49.6	49.6	L-5550	Wind	31-Dec-12		FEAS In Progress	ERIS	N/A
28	244	14-Mar-11	Cumberland	34.5	34.5	30N	Wind	31-Dec-14		SIS Agrmnt tendered	ERIS	N/A
29	273	27-May-11	Cumberland	100	100	L-5550	Wind	31-Dec-12		IR Valid	NRIS	N/A
		Totals:		1461.2	1461.2							

Nova Scotia Power - Interconnection Request Queue: Page 3 of 3
ERIS - Energy Resource Interconnection Service
NRIS - Network Resource Interconnection Service
N/A - Not Applicable

Included in this interconnection queue is:

- a 31.5 MW wind project that has completed the GIP process and is at the design stage;

- 47.8 MW of wind projects that have completed the GIP process but have yet to secure a PPA;

- a 50 MW, NS Power owned steam project (UARB approved) with GIA tendered;

- 60 MW of wind and 74.2 MW of biomass projects at the Facilities Study stage which are part of NS Power's Renewable Energy Standards (RES) commitment for 2013; and

- 92 MW of wind projects that are at the System Impact Study stage.

All remaining projects in the 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 committed generating facilities.

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Table 7 – Committed Renewable Generation Projects

Company/Location	**Nameplate Capacity MW**
SP Amherst Wind Power LP in Cumberland County	31.5
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 #233 Wind in Colchester County	50.6
IR #234 Wind in Pictou County	41.4
Total New Facilities Nameplate Capacity	**305.5**

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 (IPPs) and Nova Scotia Power. IPPs will compete for 300 GWh in a bidding process managed by the Renewable Electricity Administrator, who will oversee the competition by calling for bids, evaluating bid submissions and selecting winning projects.

In addition to these targets, the plan includes a Community-Based Feed-in-Tariff (COMFIT) for up to 100MW 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 is expected to be initiated in July of this year. Implementation of the COMFIT program is also anticipated to occur in 2011, although uptake rates for this program remain to be determined and will be monitored.

Province's Wind Integration Study

The 2008, Hatch Ltd. Wind Integration Study identified and assessed the effects of integrating large scale wind power generation into Nova Scotia's electric power system. This study confirmed that "more detailed impact studies are required to fully understand the cost and technical implications related to possible transmission upgrades and new operational demands on existing infrastructure."[8]

NS Power has begun monitoring the effects of variable energy sources of an intermittent nature, such as wind, to be better prepared to forecast and schedule production loads and

[8] Final Report, Nova Scotia Wind Integration Study, 2008, Hatch Ltd., p.11-13.

hence determine possible implications to system stability and availability. In 2011 a wind integration study will be commenced.

Other Opportunities

In addition to the above, potential developments outside of Nova Scotia (e.g. Lower Churchill), 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 OATT Transmission Service Queue as of April 7, 2011.

Table 8 – OATT Transmission Service Queue

OATT Transmission Service
Queued System Impact Studies
Revised April 7, 2011

Number	Project	Date & Time of Service Request	Project Type	Project Location	Project size (MW)	Status
1	TSR 100	June 4, 2010 10:50 AM	Point to Point	NB/NS border to Lingan, NS	320	SIS Study initiated
2	TSR 200	November 16, 2010 2:44 PM	Point to Point	Lingan, NS to NS/NB border	500	SIS Study initiated
3	TSR 300	February 14, 2011 11:15 AM	Point to Point	Wreck Cove, NS to NS/NB border	300	Withdrawn

5.0 RESOURCE ADEQUACY

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, of which approximately 36 MW is held as spinning reserve. Additional regulating reserve is maintained to manage the variability of customer load and generation. It is anticipated that regulating reserve requirements will increase with the addition of wind generation resources due to the added variability that will be 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 capacity periods). These reports of system capacity and adequacy are posted on the NS Power OASIS site in the Forecast and Assessments section.

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*[9] 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 New Brunswick System Operator, 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*,[10] 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.

[9] http://www.npcc.org/viewDoc.aspx?name=A-02.pdf&cat=regStandCriteria
[10] http://www.npcc.org/viewDoc.aspx?name=2010_Maritimes_Area_Comprehensive_Review_of_Resource_Adequacy_RCC.pdf&cat=revResource

Load and Resources Review

The ten year load forecast and resources additions in Table 9 below are based on the capacity additions 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 2011/2012 to 2020/2021
(All values in MW except as noted)

		2011/2012	2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019	2019/2020	2020/2021
A	Firm Peak Load Forecast	2,058	2,076	2,099	2,120	2,141	2,159	2,172	2,190	2,205	2,220
B	DSM Firm	58	107	161	210	260	310	358	404	450	495
C	Firm Peak Less DSM (A - B)	2,000	1,970	1,938	1,910	1,880	1,849	1,815	1,785	1,755	1,725
D	Required Reserve (C x 20%)	400	394	388	382	376	370	363	357	351	345
E	Required Capacity (C + D)	2,400	2,364	2,325	2,292	2,256	2,219	2,178	2,142	2,106	2,070
F	Existing Resources	2363	2363	2363	2363	2363	2363	2363	2363	2363	2363
	Total Cumulative Additions:										
G	Thermal*	49	82	82	82	82	82	82	82	82	82
H	Hydro	0	0	4	4	4	4	4	4	4	4
I	Firm Contracted Wind**	0	6	6	6	6	6	6	6	6	6
J	Firm RES (2015)***	0	10	10	51	51	51	51	51	51	51
K	Community Feed-in-Tariff****	0	0	2	4	10	16	20	20	20	20
L	Total Firm Supply Resources (F + G + H + I + J + K)	2412	2460	2466	2509	2515	2521	2525	2525	2525	2525
	+ Surplus - Deficit (L - E)	12	97	141	217	259	302	347	383	419	455
	Reserve Margin % (L/C -1)	21%	25%	27%	31%	34%	36%	39%	41%	44%	46%

*Thermal includes Burnside #4 (winter capacity 33 MW) assumed to be returned to service in 2013.

**Firm Contracted wind 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).

***Firm RES (2015) represents an addition of renewable energy to comply with the 2015 RES announced in the Province's Renewable Electricity Plan in April 2010. The value in the table includes the firm contribution of dispatchable generation as well as an assumed firm capacity value of intermittent wind generation. For long-term planning purposes the firm capacity value of wind is based on the winter capacity factor (generator capacity multiplied by the winter capacity factor). For short-term assessments (e.g. 18-month Load and Capacity Assessment) the assumed capacity factor may be less. Legislation has recently received Royal Assent for RES (2020) with a target of 40%. NS Power is currently determining the capacity additions associated with this.

****The Community Feed-in-Tariff represents distribution-connected renewable energy projects as outlined in the Province's Renewable Electricity Plan in April 2010. 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 20% capacity factor. For short-term assessments (e.g. 18-month Load and Capacity Assessment) the assumed capacity factor may be less.

6.0 TRANSMISSION PLANNING

System Description

The existing transmission system has approximately 5,150 kilometres of transmission lines at voltages at the 69 kV, 138 kV, 230 kV and 345 kV levels.

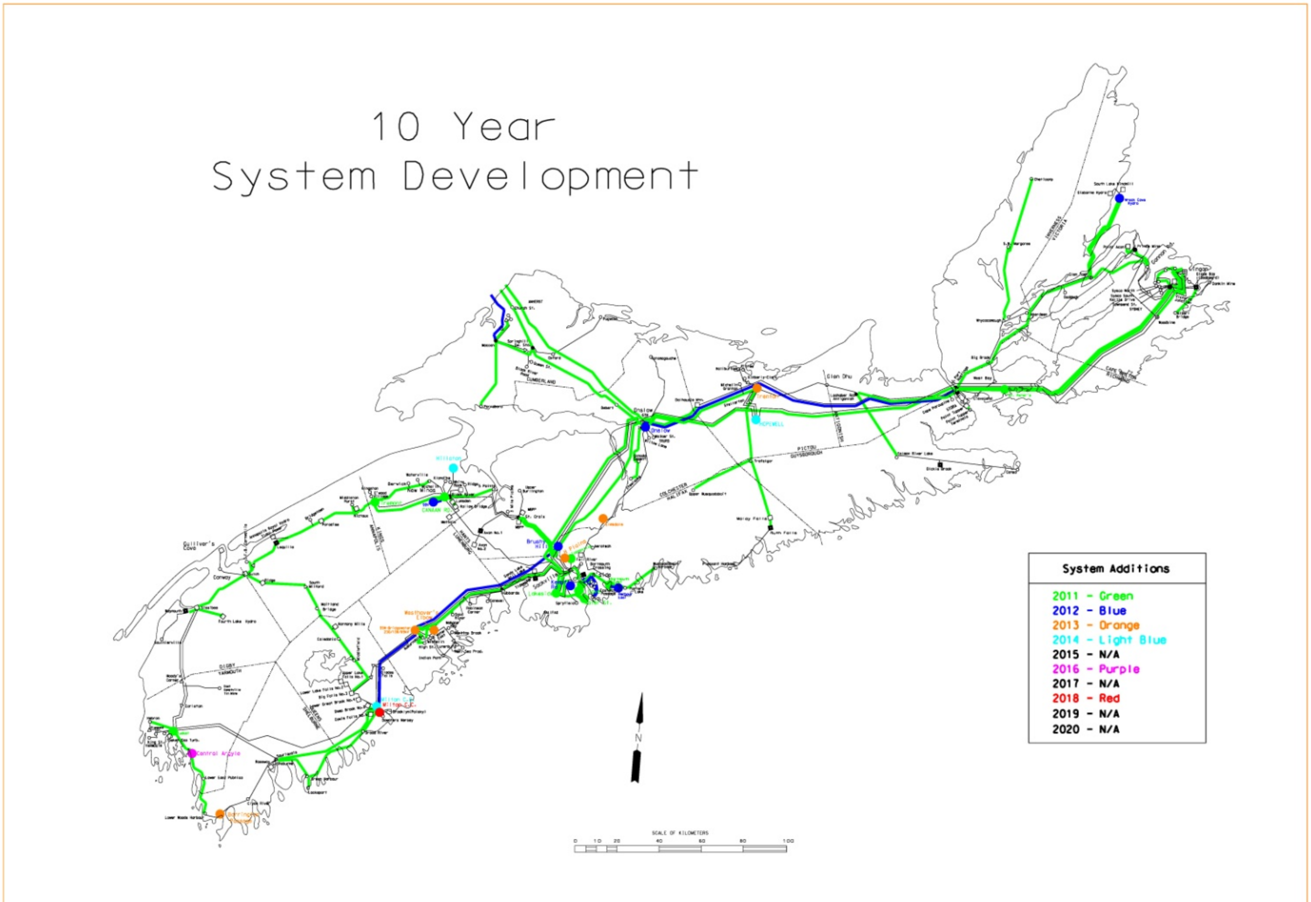
- The 345 kV transmission system is approximately 468 kilometres in length and is comprised of 372 kilometres of steel tower lines and 96 kilometres of wood pole lines.

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

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

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



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 single contingency criteria. NS Power is a member of the Northeast Power Coordinating Council. Those portions of Nova Scotia 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 *Basic Criteria for Design and Operation of Interconnected Power Systems*.

NS Power makes extensive 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.

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 2011:

2009	2010	2011
L5003(Farrell St.-Sackville)	L5017(5 Points-Canaan)	L5003(Sackville-Akerley)
L5004(Sackville-Geizer Hill)	L5029(Maccan-Springhill)	L5004(Sackville-Rockingham)
L5017(Canaan-Five Points)	L5030(Aberdeen-Black River)	L5011(Farrell-Imperial)
L5039(Spryfield-Geizer Hill)	L6002(Sackville-Gold River)	L5019(Canaan-Hollow Bridge)
L5500(Trenton-Stellarton)	L5037(East River-Canexel)	L5028(Onslow-Stewiacke)
L5510(Stellarton-Malay Falls)	L5039(Lakeside-Spryfield)	L5044(Tap-Middleton)
L5511(Trafalgar-Malay Falls)	L5040(Onslow-Tatamagouche)	L5053(Tremont-Michelin)
L5512(Malay Falls-Ruth Falls)	L5048(Green Harbour-Lockport)	L5510(Bridge Ave.-Malay Falls)

2009	2010	2011
L5521(Onslow-Truro)	L5058(Springhill-Pugwash)	L5511(Trafalgar-Upper Musquodoboit)
L5573(VJ-Lingan Mine)	L7011(Lingan-Hastings)	L5512(Malay Falls-Ruth Falls)
L6003(Tufts Cove-Sackville)	L5532(Gulch-Big Falls)	L5524(Antigonish-Salmon River)
L6004(Sackville-Canaan Road)	L5535(Sissiboo-Tusket)	L5531(Gulch-Sissiboo)
L6006(Bridgewater-Milton)	L5544(Big Falls-Upper Lake Falls)	L5532(Big Falls-Gulch)
L6013(Canaan Road-Tremont)	L7003(Onslow-Hastings)	L5534(Tusket-Hebron)
L6014(Kempt Road-Tufts Cove)	L5559(Whycocomagh-SW Margaree)	L5538(Sissiboo-Weymouth)
L6035(Water St.-Kempt Road)	L5560 (VJ-Townsend St.)	L5546(Bridgewater-Westhavers)
L6038(Lakeside-Kearney Lake)	L5561(VJ-Seaboard)	L5549(Maccan-Hickman)
L6515(Lochaber Road-Hastings)	L5569(Terrace-Townsend)	L5550(Maccan-Parrsboro)
L6516(Hastings-VJ)	L6006(Bridgewater-Milton)	L5555(Gannon Road-Aconi)
L6517(Hastings-Tupper)	L6010(Brushy Hill-Sackville)	L5559(Whycocomaugh-SW Margaree)
L6518(Hastings-NewPage)	L6016(Brushy Hill-Lakeside)	L5565(Seaboard-Albert Bridge)
L6523(Tupper-NewPage)	L6024(Milton-Tusket)	L5571(VJ-Whitney Pier)
L6540(VJ-Sysco)	L6025(Bridgewater-Milton)	L5575(Whitney Pier-Lingan)
L6545(Wreck Cove-Glen Tosh)	L6516(Hastings-VJ)	L5579(SW Margaree-Cheticamp)
L6549(Wreck Cove-Glen Tosh)	L6531(Milton-Bridgewater)	L6008(Sackville-Lakeside)
L7001(Onslow-Brushy Hill)	L6545(Glentosh-Wreck Cove)	L6011(Brushy Hill-St. Croix)
L7002(Onslow-Brushy Hill)	L7012(Hastings-Lingan)	L6020(Milton-Sourquois)
L7011(Hastings-Lingan)	L7015(Pt. Aconi-Woodbine)	L6033 (Lakeside-Water St.)
L8001(Onslow-NB Border)	L5530B(Broad River-East Green Harbour)	L6042(Tufts Cove-Dartmouth East)
L6005A(Brushy Hill-Sackville)	L5564A(Terrace St. Tap)	L6043(Dartmouth-Musquodoboit)
L6005B(Brushy Hill-Sackville)	Various Insulator Replacements	L6051(Brushy Hill-St. Croix)
L5560(VJ-Townsend Street)		L6503(Onslow-Trenton)
		L6513(Onslow-Springhill)
		L6514(Maccan-Springhill)
		L6515(Antigonish-Port Hastings)

2009	2010	2011
		L6527(Onslow Substation Tie)
		L6533(Victoria Junction-Lingan)
		L6536(Springhill-NB Border)
		L6537(Port Hastings-Glen Tosh)
		L6538(Glen Tosh-Gannon-Road)
		L6545(Glen Tosh-Wreck Cove)
		L6549(Glen Tosh-Wreck Cove)
		L7002(Onslow-Brushy Hill)
		L7005(Onslow-Port Hastings)
		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)
		Various

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 2011.

2009	2010	2011
L5036(Berwick Tap-Berwick)	L5014(St. Croix-Burlington)	L5017 (Five Points-Canaan Rd.)
L50179	L5015(St. Croix-Avon)	L5025(Paradise-Tremont)
L5046(5017 Tap-Wolfville Ridge)	L5020(Hollow Bridge-Methals)	L5026(Gulch-Paradise)
L5047(5026 Tap-Bridgetown)	L5021(Canaan Rd.-Klondike)	L5035 (Hells Gate-Canaan Rd.)
L5056(5026 Tap-Annapolis)	L5506(Abercrombie-Pictou)	L5042(Farrell-Albro Lake)
L5521(Onslow-Willow Lane)	L5510(Stellarton-Malay Falls)	L5048(East Green Harbour-Lockport)
L5536(Tusket-Hebron)	L5511(Trafalgar-Upper Musquodoboit)	L5050(Sissiboo-Fourth Lake)
L6005(Brushy Hill-Sackville)	L5512(Malay Falls-Ruth Falls)	L5057(Tap-Cornwallis)
L6024(Milton-Tusket)	L5531(Gulch-Sissiboo)	L5500 (Trenton-Bridge Ave.)
L6025(Bridgewater-Milton)	L5535(Sissiboo-Tusket)	L5530(Milton-Souriquois)
L6047(Milton-Bowater)	L5546(Bridgewater-Westhavers Elbow)	L5538(Sissiboo-Weymouth)
L6048(Milton-Bowater)	L5547(Westhavers Elbow-Lunenburg)	L6516(Hastings-Victoria Junction)
L6515(Lochaber Road-Hastings)	L5548(Maccan-Amherst)	L6521(Point Tupper-Point Tupper Terminal)
L6539(Gannon Road-VJ)	L5561(Victoria Junction-Seaboard)	L6543(Hastings 138kV-230kV)
L6548(Hastings-Sub Tie Line)	L6009(Sackville-Burnside)	L7011(Hastings-Lingan)
L7014(Lingan-Woodbine)	L6020(Milton-Souriquois)	
	L6536(Springhill-NB Border)	
	L6538 (Glentosh-Gannon Rd.)	

Transmission Project Approval

The transmission plan presented in this document provides a summary of the planned reinforcement of the NS Power power 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 a Maritimes Area Technical Planning Committee was established to review intra-area plans for Maritimes Area resource adequacy and transmission reliability. This Committee will also estimate 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, New Brunswick System Operator, Maritime Electric Company Ltd., Northern Maine Independent System Administrator and NB Power Transmission.

NS Power/NB 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. The primary function of the interconnection is to support system reliability.

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 the largest element) 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, Nova Scotia.

Import and export limits 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. Conditions which determine the actual limit of the interconnection are:

Export	**Import**
Number of thermal units armed for generation rejection (maximum two)	NS system load level (Import must be less than 22% of total system load)
Reactive Power Support level in the Halifax Regional Municipality	Percentage of dispatchable generation
Arming of Special Protection Systems	NB export level to PEI and/or New England
Real time line ratings (climatological conditions in northern NS)	Real time line ratings (climatological conditions in northern NS)
NS System load level	Load level in Moncton area
Largest single load contingency in NS	Largest single generation contingency in NS

If the NS Power system is separated from the New Brunswick system during export (i.e. the inter-tie trips), 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 generation and stabilize the system.

If the NS Power system is separated during import, 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 load through under-frequency load shedding (UFLS) protection systems as required.

The loss of the 345 kV line between Onslow, NS and Memramcook, NB 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 New Brunswick System Operator restricts power export to Nova Scotia to a level such that any single contingency does not cause adverse impacts on NB 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. As noted earlier, NS and NB are collaborating to evaluate transmission needs in the areas previously noted.

In jurisdictions across North America it is becoming increasingly difficult to obtain access to the land and the right-of-ways 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 completing construction.

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.

7.0 TRANSMISSION DEVELOPMENT 2011 TO 2020

Transmission development plans are summarized below. As highlighted earlier, these projects are subject to change. For 2011, the majority of the projects listed are included in the 2011 Annual Capital Expenditure Plan. For 2011 onward, the projects are noted in the projected year of completion.

1. 2011

- Work will be completed on the construction of additional transmission to the Western Valley area. This will include the construction of a 138 kV circuit between Canaan Road and Tremont, a 138 kV termination at Canaan Road and the addition of a 138-69 kV, 33.6/44.8/56 MVA transformer at Tremont along with the establishment of a 138 kV bus. This project was necessary to mitigate various contingencies that could result in transformer overload scenarios, line overload conditions and low voltage conditions.

- The transmission insulator replacement program will continue with the reinsulation of 3 circuits (L-6002 from Gold River to Bridgewater, L-5532 from Big Falls to Gulch, and L-5524 from Antigonish to Salmon River Lake) due to identified cement growth issues. Insulator cement growth has been identified on certain types of insulators that will result in the circuit experiencing an unplanned outage. This results in either customer outages or an outage to a circuit on the transmission system that could result in an uneconomic generation dispatch until the issue is resolved.

- The transmission reliability investment program will continue targeting transmission switches and circuit breakers. This program is intended to replace equipment that has encountered operational issues, those in which spare parts are no longer available or have reached the end of life.

- The program to replace porcelain cutouts and some insulators at various transmission substations will continue. NS Power has encountered issues with porcelain cutouts on the distribution system. These cutouts are similar to those used on certain equipment in substations. A failure of a cutout in a transmission substation could result in an outage to all customers supplied from that substation.

- The structures on a water crossing on a 230 kV transmission circuit between Lingan and Port Hastings will be replaced with steel towers.

- In accordance with NS Power's implementation plan for requirements of the NPCC *Classification of Bulk Power System Elements* (Document A-10), dual high-speed protection systems are required at 138 kV substations at Tufts Cove and Lakeside. In addition, breaker control backup will be added at the Tufts Cove 69 kV substation.

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

- Work will continue on the uprating of a 345 kV transmission circuit between Onslow and Lakeside for the purpose of increasing the rated operating temperature limit of the line.

- 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.

- Work will begin on right-of-way acquisition from the existing 138 kV Canaan Road substation to a new substation site in the New Minas area for the purpose of accommodating a 138 kV transmission circuit to a new 138 kV substation in the New Minas area.

- The project to replace the 138 kV Gas Insulated Switchgear at the existing Water St. substation will be completed in 2011.

- A third 138-25 kV transformer is proposed for Water St. along with the refurbishment/replacement of a portion of the 25 kV switchgear.

- Work will be completed in 2011 on system modifications required to accommodate the Digby wind farm.

- 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 138 kV transmission circuit between Sackville and Bridgewater will undergo some structure replacements to meet ground clearance requirements.

- 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 commence on a multi-year re-furbishment program to prevent metal deterioration on transmission line steel towers. The 2011 program scope will focus on four steel towers associated with the 138 kV Halifax Harbour Crossing circuit.

- Work will be completed to upgrade conductor and replace deteriorated structures on a 69 kV circuit between Trenton and Bridge Avenue for the purpose of increasing circuit capacity. This project is being undertaken to avoid an overload condition for the contingency loss of a parallel 69 kV circuit during high load conditions.

- A project will be initiated to install a 138-25 kV transformer for each of Kempt Road and Dartmouth East substations for reliability purposes in the event of transformer failures at these substations.

2. 2012

- The insulator replacement program will continue with the reinsulation 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 Dartmouth East substations, initiated in 2011, will be completed.

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

- 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 are required on the transmission system to accommodate a new wind farm in the Amherst area.

- Work will continue on right-of-way acquisition between Dartmouth East and the Harbour East area for the purpose of accommodating a 138 kV circuit to a proposed new 138 kV substation in the Harbour East area.

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

- It is planned to purchase a 69 – 25/12 kV transformer and a 138 – 25 kV transformer as system spares.

- 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 138-12 kV, 15/20/25 MVA substation is proposed to be constructed in New Minas for the purpose of supplying additional load growth. This project will also include 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 138-25 kV substation is planned to be started at a new site in the Harbour East area. This project will also include a new 138 kV circuit from an existing Dartmouth East substation and the 138 kV line terminal at Dartmouth East.

- An existing 138 – 25 kV transformer at the Kempt Road substation is proposed to be rewound due to suspected damage as the result of repeated through faults.

- 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, and a 138 kV circuit between Maccan and the New Brunswick border 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.

- A project will be initiated to install a 138-25 kV transformer for each of Lucasville and Lochaber Road substations for reliability purposes in the event of transformer failures at these substations.

3. 2013

- The insulator replacement program will continue with the reinsulation 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.

- Transformer installations at Lucasville Road and Lochaber Road substations, initiated in 2012, will be completed.

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

- The existing 138-69 kV, 20/26.7 MVA transformer at Westhaver's Elbow is planned to be changed out for a unit rated 22.5/33.3 MVA for the purpose of addressing voltage regulation in the area.

- An existing 69-12 kV, 7.5/10/12.5 MVA transformer at Barrington Passage is planned to be changed out for a unit rated 15/20/25 MVA to address area load growth.

- Load will be transferred from the 2 x 138-69 kV autotransformers at Trenton. This will be accomplished by changing out an existing 69-25 kV transformer at Trenton with a 138-25 kV unit.

- An existing 138 – 25 kV transformer at Elmsdale is proposed to be rewound due to suspected damage as the result of repeated through faults.

- A second 138-25 kV, 25/33/42 MVA transformer will be added at the existing Hammonds Plains Road substation.

- At Bridgewater, a second 36 MVAR capacitor bank is proposed to be added on the 138 kV bus.

4. 2014

- An existing 69-12 kV transformer at Hillaton will be changed out for a unit rated 15/20/25 MVA.

- The 138 kV bus at Milton will be rearranged to avoid loss of the bus due to a bus tie breaker failure.

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

5. 2016

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

6. 2018

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

- There is a possibility of an additional supply to the Halifax downtown area. This could take the form of a 138 kV underwater cable from Dartmouth to Water St. or another route that has not as yet been determined. This evaluation will commence in the near future.

There are no additions indicated in 2015, 2017, 2019 and 2020. This will most likely change as those time periods draw closer and local planning studies could indicate system modifications or additions.

8.0 UNCERTAINTY

The Nova Scotia Power 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 Energy Standards evolve and projects required to maintain compliance are studied including the implications of large amounts of intermittent generation such as wind.

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 initial work to project 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 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;

- 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 dependant on electricity.

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

- Transmission system reinforcement will 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.

9.0 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 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.

10.0 REFERENCES

1. *2004 Maritimes Area Triennial Review of Resource Adequacy*, Report approved by NPCC Reliability Coordinating Council March 9, 2005.

2. *Basic Criteria for Design and Operation of Interconnected Power Systems*, Northeast Power Coordinating Council Document A-2, May 6, 2004.

3. *Final Report, Nova Scotia Wind Integration Study*, Hatch, Ltd., 2008.

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

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

6. 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 and new in-province thermal generation all have a potential role in serving Nova Scotia's future electricity needs. Each will likely 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 Generation Additions

1) Wind Development Scenarios (2013 - 2019)

   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 (100MW-150MW) 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 (Lower Annapolis Valley) wind generation (100-150MW) development scenario

This scenario requires the completion of a 138 kV line from Tremont to Canaan Road currently in construction along with a new ring bus configuration at Tremont, including a second 138-69 kV transformer, and substation modifications at Canaan Road. 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. This would include the development of a 138 kV ring bus configuration at Paradise. In addition new 138 kV circuits would be constructed from Gulch to Tremont and Tusket substations. Two 230 kV circuits currently occupying double circuit towers towards the Bridgewater area would be separated.

d) Mainland (Upper Annapolis Valley) wind generation (100-150MW) development scenario

An existing 69 kV circuit between Sissiboo and Tusket would be rebuilt to a higher capacity. Substation modifications would be required at Canaan Road and Milton along with replacing two 138-69 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 (100-150MW) development scenario

Construct a new 138 kV line from Onslow to Springhill and install a 100 MVAR static 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 (150MW -250MW) 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 345-138 kV substation would be established at Spider Lake that would terminate 3 x 138 kV circuits in the Dartmouth area. In addition 100 MVAR of reactive compensation would be established in the Dartmouth area.

2) NewPage 60MW Biomass- Cape Breton Strait Area Scenario

The NewPage 60 MW Biomass project has been approved. This generation has been assigned a capacity factor of zero and is meant to displace some existing Cape Breton generation. No transmission upgrades are required for this project as this is ERIS service.

Large External Imports (300MW) or Export development scenario

a) To facilitate a new large import or export via NB interconnect

To enable import, a new 345 kV transmission circuit would be required between Onslow and the New Brunswick system. Additional studies would be required, taking into consideration the potential for new generation sources, to determine transmission modifications or additions required on the Nova Scotia System. Joint planning studies are required with New Brunswick to determine upgrades to the New Brunswick system that would be required to support a firm import of this magnitude.

For additional firm export from NS to NB, further study would also be required.

b) Newfoundland Submarine Cable Import (300MW) or Export development scenario

System studies are currently underway to determine the transmission required across Nova Scotia to accommodate a 300 MW or higher import from Newfoundland. The import from Newfoundland will be via a DC submarine cable from Newfoundland to Cape Breton.

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

For contingency loss of a large generator scenario the NS-NB inter-tie may require reinforcement depending on potential unit size.

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 345/230 transformer at Port Hastings. A 345/138 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

Development of a 138 kV substation 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 will be required from Spider Lake to Sackville as well as a high capacity line from Tufts Cove to Brushy Hill. In addition substation modifications will take place at Tufts Cove and Brushy Hill.

10 Year System Outlook
2012-2021
Report

June 29, 2012

Nova Scotia
POWER
An Emera Company

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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:

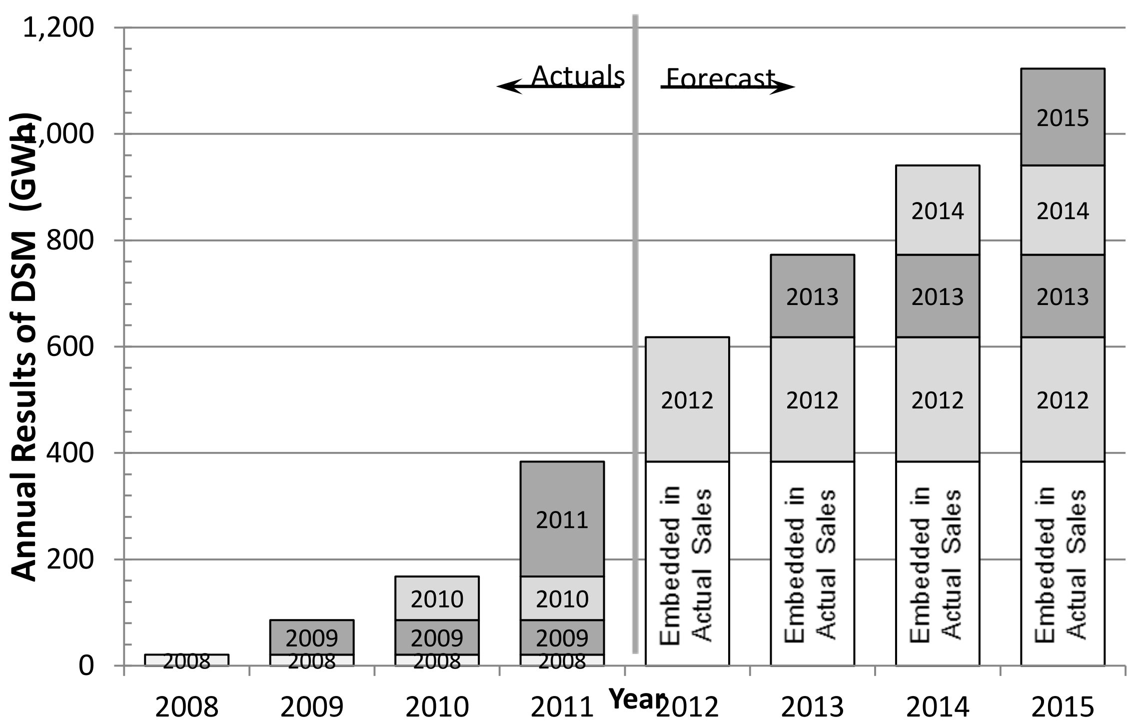
- Since this is a forecast, the effects of past DSM programs are embedded in the actual sales trend. This forecast describes only the influence of future DSM programs on projected load. Other related documents may present the accumulated DSM savings beginning with the program inception in 2008, rather 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.

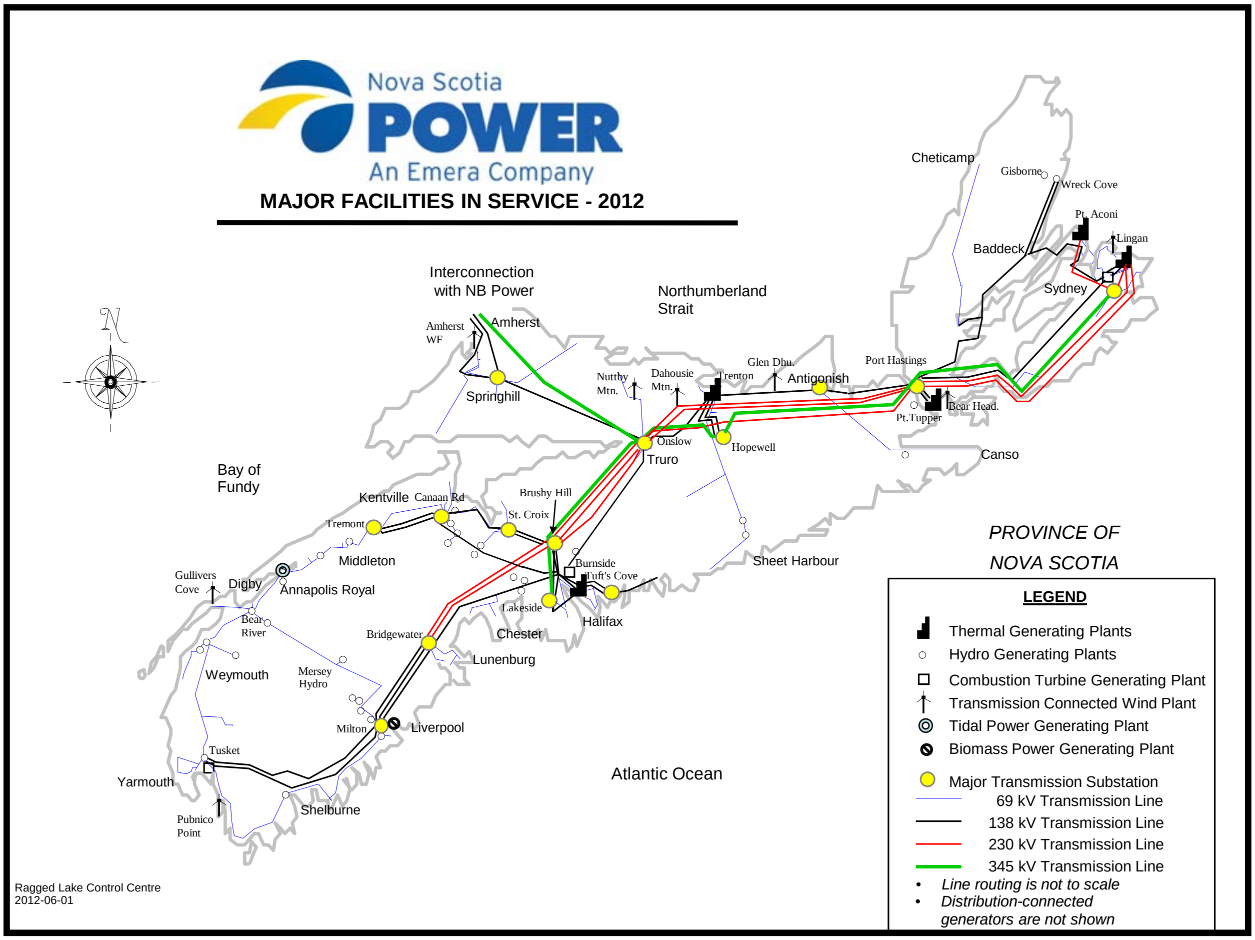
**** Maritime Link Import and the forecast retirement of a solid fuel unit are assumed to coincide. The assumed retirement dates of solid fuel unit(s) are for planning purposes in order to comply with federal environmental regulations, and are subject to adjustment due to equivalency with provincial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