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Maritime Link Alternatives Study Input Assumptions

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Study Objective

To determine the relative economic benefit of the Maritime Link project by comparing the net present value of costs to that of two other alternatives.

The database model was developed by NSPI under Non-disclosure Agreement (NDA) with NSPML. This database model is based on existing databases that were used in the 2007 and 2009 integrated resource plans with updates to reflect current forecasts and recent changes to the power system.

Analysis Plan

Study years 2015 to 2040

One set of emission conditions was considered:

1) established emissions targets to 2020 (SO_2, No_x, Hg) or 2030 (CO_2) followed by an assumption of continued reductions in air emissions limits out to 2040

Three alternatives have been assessed:

1) Maritime Link

2) Other Import (via transmission upgrades)

3) Indigenous Wind + gas

For each alternative the following scenarios have been run:

1) base load

2) low load

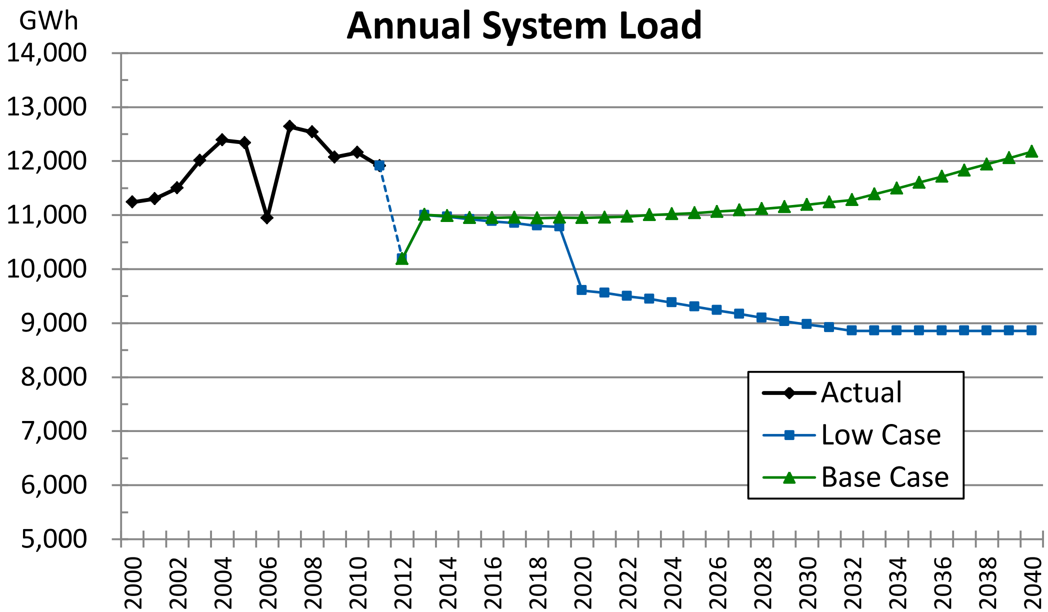
Sensitivities have been run against base case with high market/high gas prices and low market/low gas prices

Long-term Load Forecast - Base Load

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

- Assumption for growth of economic indicators was increased by 50% in the forecast models over low load case.
  i.e. 2% annual growth was increased to 3%
- The rate of growth in residential electric heating was increased by 1% every 5 years.
  – double the current growth rate
- It was assumed that Electric Vehicles (EV's) would grow to become 1% of annual auto sales in 10 years.
  This would add an estimated 15 GWh in year 10.

- It was assumed that the Port Hawkesbury paper mill would operate for the duration of the forecast (to 2040).
- The base forecast assumes Demand Side Management (DSM) will continue at current rate of change.
- This approach assumes significant load growth tempered by significant DSM achievements. The same result could be achieved with attenuated load and DSM assumptions.



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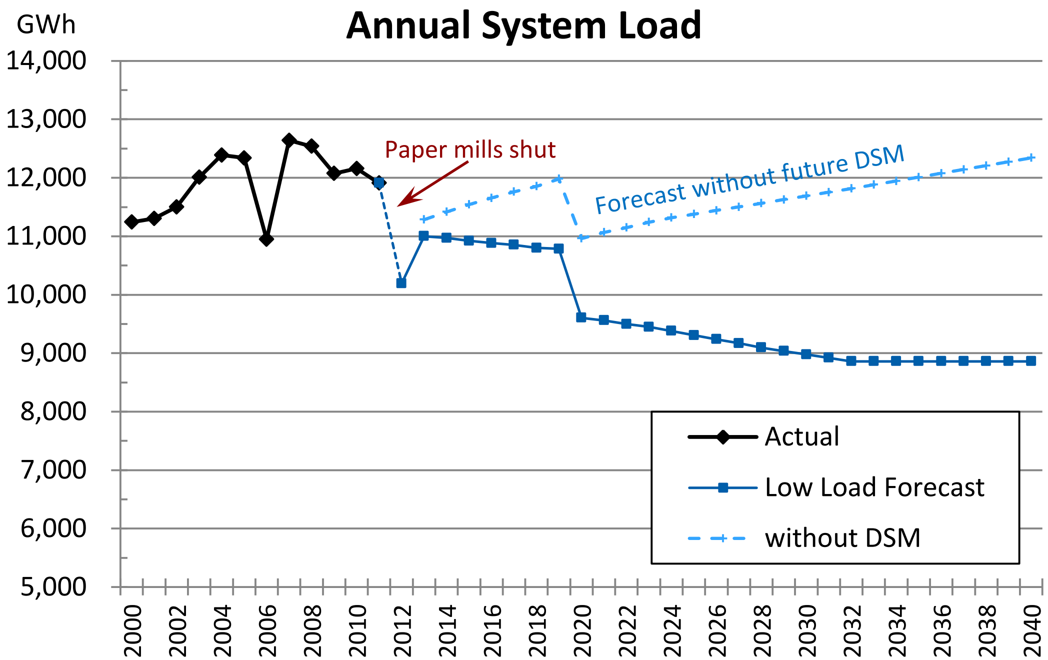
Long-term Load Forecast – Low Load

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



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Long-term Load Forecast Values

	Low Load			Base Load	
	Annual Energy GWh	Firm Peak MW		Annual Energy GWh	Firm Peak MW
2015	10,922	1885		10,952	1891
2016	10,884	1877		10,950	1890
2017	10,852	1870		10,959	1892
2018	10,802	1860		10,944	1888
2019	10,783	1857		10,954	1890
2020	9,605	1849		10,950	1889
2021	9,560	1840		10,958	1890
2022	9,499	1827		10,972	1891
2023	9,448	1817		11,002	1895
2024	9,380	1803		11,022	1897
2025	9,306	1788		11,039	1898
2026	9,237	1775		11,064	1901
2027	9,169	1761		11,091	1904
2028	9,096	1746		11,114	1906
2029	9,034	1734		11,150	1911
2030	8,977	1722		11,193	1917
2031	8,920	1711		11,239	1924
2032	8,859	1698		11,281	1930
2033	8,859	1698		11,386	1948
2034	8,859	1698		11,494	1968
2035	8,859	1698		11,603	1987
2036	8,859	1698		11,714	2007
2037	8,859	1698		11,828	2028
2038	8,859	1698		11,941	2048
2039	8,859	1698		12,057	2069
2040	8,859	1698		12,174	2090

Includes the effects of DSM

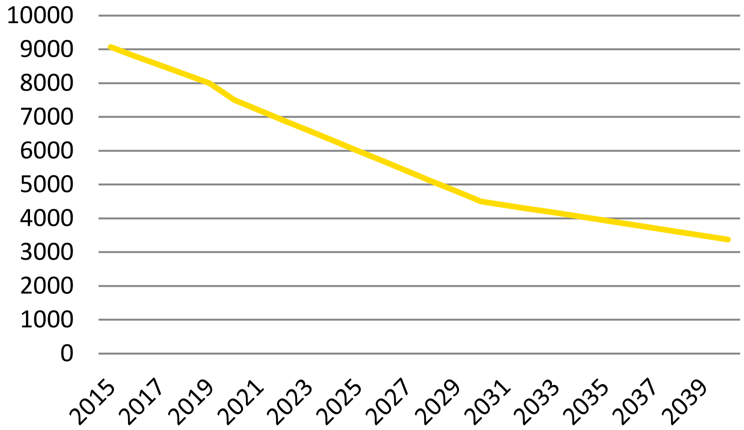
Long-term DSM Forecast Values

	Incremental DSM Energy Savings GWh	Cumulative DSM Energy Savings GWh
2015	175	175
2016	149	324
2017	139	463
2018	144	607
2019	144	751
2020	159	910
2021	149	1059
2022	144	1203
2023	144	1347
2024	145	1492
2025	135	1627
2026	130	1757
2027	130	1887
2028	135	2022
2029	125	2147
2030	120	2267
2031	120	2387
2032	125	2512
2033	64	2576
2034	65	2641
2035	65	2706
2036	65	2771
2037	66	2837
2038	66	2903
2039	67	2969
2040	67	3036

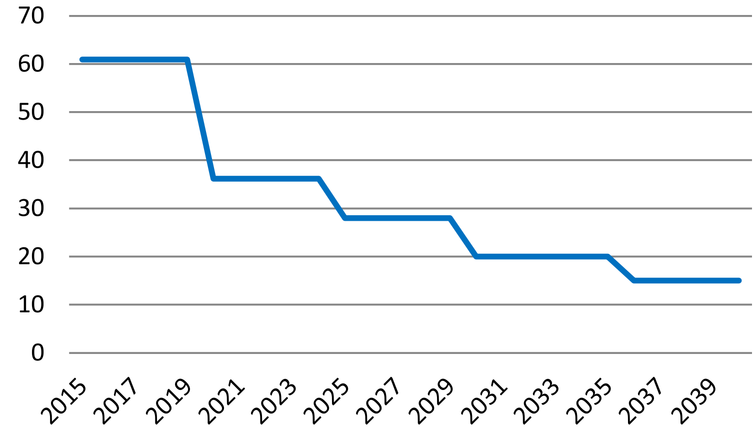
- 2015 - As per the ENSC plan for 2013-2015
- 2016- 2032 - Based upon a long-term outlook provided by ENSC
- 2032 – 2040 - Assumed that DSM effects would be equal to load growth in low load case (essentially keeping load growth to zero)

Emission Limits

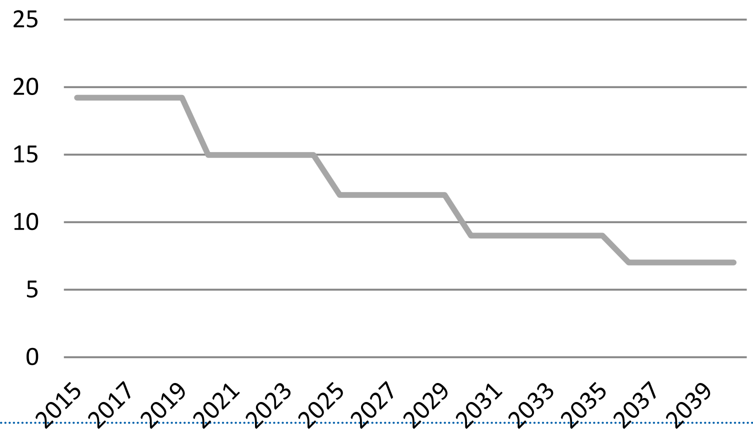
Carbon Dioxide (CO_2) [kt]



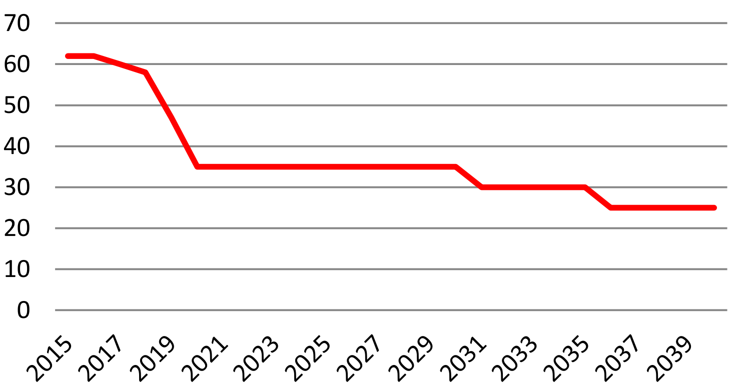
Sulphur Dioxide (SO_2) [kt]



Nitrogen Oxides (NOx) [kt]



Mercury (Hg) [kg]



Emission Limit Values-Declining Post 2030

	CO2 ktonnes	SO2 ktonnes	NOx ktonnes	Hg kg
2015	9064	60.9	19.2	62
2016	8796	60.9	19.2	62
2017	8528	60.9	19.2	60
2018	8261	60.9	19.2	58
2019	7993	60.9	19.2	47
2020	7500	36.2	14.96	35
2021	7200	36.2	14.96	35
2022	6900	36.2	14.96	35
2023	6600	36.2	14.96	35
2024	6300	36.2	14.96	35
2025	6000	28.0	12.0	35
2026	5700	28.0	12.0	35
2027	5400	28.0	12.0	35
2028	5100	28.0	12.0	35
2029	4800	28.0	12.0	35
2030	4500	20.0	9.0	30
2031	4388	20.0	9.0	30
2032	4275	20.0	9.0	30
2033	4163	20.0	9.0	30
2034	4050	20.0	9.0	30
2035	3938	15.0	7.0	25
2036	3825	15.0	7.0	25
2037	3713	15.0	7.0	25
2038	3600	15.0	7.0	25
2039	3488	15.0	7.0	25
2040	3375	15.0	7.0	25

Renewables

2015 - 25% of sales from renewable energy

2020 - 40% of sales from renewable energy

REA Contribution

- Assume in-service Jan/2015
- Installed capacity of projects 115.8 MW
- Annual Energy 353 GWh/yr
- Assumed firm planning capacity contribution of 20%.

Existing and Future wind projects have an assumed capacity contribution as follows:

- Energy Resource Interconnection Service (ERIS) projects - 0% of installed capacity
- Network Resource Interconnection Service (NRIS) projects - 20% of installed capacity
- This includes existing wind, contracted wind, COMFIT, and REA Wind projects.

(capacity contribution affects planning reserve margin calculations which influences unit retirement decisions)

Renewables *cont'd*

Port Hawkesbury (PH) biomass plant (when PH paper mill assumed in-service)

45 MW, 357 GWh/year, firm capacity starting March 2015

PH biomass (when PH paper mill assumed shut)

53 MW, 418 GWh/year, firm capacity

Small Biomass PPA In-service July/2015 – 55 GWh/yr @ 10 MW

Marshall hydro not included - project on hold

COMFIT: 100MW of primarily wind

- 5-year phase in 2014-2018
- Capacity Factor (CF) 34% (Provincial government derived estimate)
- Assumed firm planning capacity contribution of 20%
- As per amendments to the RES regulations, COMFIT contribution will not be included as a resource in planning to meet the RES.

Thermal Assumptions

Base Assumptions Coal unit retirements:

- **Lingan 2** retires in March 2015, assuming
  - Burnside #4 is back in service
  - PH Biomass is firm capacity
  - Wind firm capacity contribution is 20% (NRIS projects 20%; ERIS projects 0%)

- **Lingan 1** unit retires in October 2017 when Maritime Link /Other Import comes in-service. In the Indigenous Wind Alternative, the unit retires in January 2019, with the addition of 50 MW of firm capacity and when new wind comes in-service. This is consistent with the ML/Other Import alternatives which assume two units retired by 2020.

Long term maintenance schedule from 2009 IRP

Unit heat rates, Derating Adjusted Forced Outage Rate (DAFOR), min/max capacities as per July-2012 GRA-Refresh

Thermal and Fuel

Unit operating instructions:

- Lingan 3 is a must run unit all year until Maritime Link is operational in 2017
- Forced Gas burn 115 GWh/mth Dec-Jan-Feb due to transmission constraints and Metro voltage support
- All coal units & Tufts Cove 1 are non-cycling, i.e.(unavailable for two shifting)
- Tufts Cove (TUC) units 2, 3, 4, 5 & 6 are available for two-shifting
- Lingan #1 and #2 seasonal shut down Mar 1 through Nov 30 until retirement

Coal prices – as per NSPI Fuels Group long-term update July 2012 (assume Mid Sulphur (MS) and Low Sulphur (LS) low BTU available)

Heavy Fuel Oil (HFO), Light Fuel Oil (LFO), natural gas – as per NSPI Fuels Group long term update July/Aug 2012

Comparison of Alternatives- Base Load

	Maritime Link		Other Import	Indigenous Wind
Cost	$1.52 billion		$676 M Capital Cost. Energy Cost is market based (includes energy, capacity and a long term rate)	Capital plus O&M costs to give a levelized cost of $80/MWh ($2012)
In-service	Oct 2017		Oct 2017	Jan 2019
Capacity	153.3 MW firm (NS)		159.6 MW firm (NS)	425 MW of wind in 2019, 3 x 50 MW in 2028, 2034, 2037
Energy	NS Block: 895 GWh/yr on-peak, 16hrs/day, 365 days (153.3 MW) Supplemental: 240 GWh/yr, off-peak, Nov-Mar (5 years)		932 GWh/yr on-peak	425 MW @ 35% 50 MW @ 32% 425 MW - 1300 GWh 50 MW - 140 GWh
Retirements	Lingan #2 Mar/2015 Lingan #1 Oct/2017 Coal Unit Jan/2030 Coal Unit Jan/2035		Lingan #2 Mar/2015 Lingan #1 Oct/2017 Coal Unit Jan/2033	Lingan #2 Mar/2015 Lingan #1 Jan/2019 Coal Unit Jan/2026 Coal Unit Jan/2030 Coal Unit Jan 2035 Coal Unit Jan/2039
	NB Tie	**NFLD tie**	**NB tie**	**NB tie**
Imports	100 MW	300 MW less on-peak and off peak NS Block and Supplemental Block demand	500 MW less 159.6 MW firm on-peak 500 MW off-peak	0 MW
Exports	0 MW	0 MW	0 MW	300 MW

Note: Unit retirements shown are for modeling purposes only. Future unit retirements will be reviewed and evaluated based on system requirements and regulatory compliance.

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Comparison of Alternatives- Low Load

	Maritime Link		Other Import	Indigenous Wind
Cost	$1.52 billion		$676 M Capital Cost. Energy Cost is market based (includes energy, capacity and a long term rate)	Capital plus O&M costs to give a levelized cost of $80/MWh ($2012)
In-service	Oct 2017		Oct 2017	Jan 2019
Capacity	153.3 MW firm (NS)		159.6 MW firm (NS)	Low Load: 250 MW of wind; 50 MW firm contribution
Energy	NS Block: 895 GWh/yr on-peak, 16hrs/day, 365 days (153.3 MW) Supplemental: 240 GWh/yr, off-peak, Nov-Mar (5 years)		932 GWh/yr on-peak	30% Capacity Factor (~657 GWh/yr)
Retirements	Lingan #2 Mar/2015 Lingan #1 Oct/2017 Gas/HFO Unit Jan/2020 Coal Unit Jan/2029		Lingan #2 Mar/2015 Lingan #1 Oct/2017 Gas/HFO Unit Jan/2020 Coal Unit Jan/2029	Lingan #2 Mar/2015 Lingan #1 Jan/2019
Imports	**NB Tie** 100 MW	**NFLD tie** 300 MW less on-peak and off peak NS Block and Supplemental Block demand	**NB tie** 500 MW less 159.6 MW firm on-peak 500 MW off-peak	**NB tie** 0 MW
Exports	0 MW	0 MW	0 MW	300 MW

Note: Unit retirements shown are for modeling purposes only. Future unit retirements will be reviewed and evaluated based on system requirements and regulatory compliance.

Alternatives- Maritime Link

Financial assumptions:

- $1.52B Capital Cost
- 70% Debt
- 4% Debt rate
- 9.5% ROE during construction, 10% thereafter
- Start date: October 1, 2017
- Annual energy (before Supplemental) 895 GWh per year
- Supplemental Energy of 240 GWh per year for the 1st 5 years year)

Alternatives – Other Import

Financial assumptions:

- $663M (2015$) capital = $676M As spent, nominal capital
- NB OATT Charges $22M in year 1, escalates at ~1% per year
- 60% Debt
- 10% ROE
- 5% Debt rate
- Start date: October 1, 2017
- Assumes firm purchase of 165MW from others at market + adders for firm capacity/long term nature
- Annual firm purchase energy 932 GWh per year

Alternatives- Indigenous Wind

	Low Load	Base Load
Incremental Wind (installed) Required to meet 40% RES	250 MW in 2019	425 MW in 2019; 50 MW block added in 2028, 2034 & 2037; Total incremental wind 575 MW
Assumed Capacity Factor	30%	425 MW @ 35% 50 MW @ 32%
Energy per year	650 GWh	425 MW - 1300 GWh 50 MW - 140 GWh
Assumed Firm Capacity Contribution	20%	20%
Assumed Firm Capacity	50 MW	425 MW - 85 MW firm 50 MW - 10 MW firm

- Capital plus O&M costs equal to a levelized cost of $80/MWh ($2012)
  - Capital Cost = $988 M
  - Variable O&M = $1/MWh escalated at 2% annum, 2011$
  - Fixed O&M = $30/MW/YR escalated at 2% annum, 2011$
- 62.5% Debt
- 9.4% ROE
- 6% Debt rate
- Start date: January 1, 2019

Resource Options in the Model

Natural Gas Resource Options

	CT 50 MW	CT 100 MW	CC 150 MW	CC 250 MW
Technology	Simple cycle Combustion Turbine	Simple cycle Combustion Turbine	LM6000 based Combined Cycle	CT based Combined Cycle
Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Net Capacity Increase (MW)	49	103	147	250
Capital Cost ($/kW) (2012$)	$1,160	$1,070	$1,500	$1,500
Variable O&M ($/MWh) (2015$)	$5.83	$9.34	$2.75	$3.06
Fixed O&M ($k) (2015$)	$123	$199	$1,300	$3,784