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.

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