**SUPPLEMENTAL**
**CONFIDENTIAL (Attachment Only)**

**Request DR-14:**

**Wind Integration Study (status, draft results?)**

Response DR-14:

The wind integration study commissioned by NS Power and being conducted by GE Energy is expected to be available in April 2013.

Supplemental Response:

Please refer to Partially Confidential Attachment 1.

GE
Energy Consulting

**Final Report**

# Nova Scotia Renewable Energy Integration Study

**Prepared for:**

**Nova Scotia Power, Inc.**

**Prepared by:**

**GE Energy Consulting**

June 28, 2013

imagination at work

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# Table of Contents

# List of Figures

# List of Tables

# Acronyms and Nomenclatures

| | |
|---|---|
| AGC | Automatic Generation Control |
| AMI | Advanced Metering Infrastructure |
| AWS | AWS Truepower |
| AWST | also AWS Truepower |
| Bowater | Bowater Paper Mill |
| CAISO | California Independent System Operator |
| CC | Combined Cycle |
| CO2 | Carbon Dioxide |
| COMFIT | Community Feed-in-Tariff |
| DAH | Day-Ahead |
| DR | Demand Response |
| DSM | Demand Side Management |
| ELCC | Effective Load Carrying Capability |
| EMS | Energy Management System |
| ERCOT | Electricity Reliability Council of Texas |
| EUE | Expected Unserved Energy |
| GE | General Electric International, Inc. |
| GE MAPS | GE Multi Area Production Simulation |
| GE MARS | GE Multi Area Reliability Simulation |
| GT | Gas Turbine |
| GW | Gigawatt |
| GWh | Gigawatt Hour |
| HAN | Home Area Network |
| IPP | Independent Power Producers |
| ISO-NE | Independent System Operator of New England |
| LMP | Locational Marginal Prices |
| LOLE | Loss of Load Expectation |
| MAE | Mean Absolute Error |

| | |
|---|---|
| ML | Maritime Link |
| MW | Megawatts |
| MWh | Megawatts Hour |
| NB | New Brunswick |
| NCAR | National Center for Atmospheric Research |
| NOx | Nitrogen Oxides |
| NREL | National Renewable Energy Laboratory |
| NS | Nova Scotia |
| NSPI | Nova Scotia Power, Inc. |
| NS Power | Nova Scotia Power, Inc. |
| PPA | Power Purchase Agreement |
| PH PM2 | Port Hawkesbury PM2 Paper Mill |
| PV | Photovoltaic |
| REA | Renewable Energy Administrator |
| REIS | Renewable Energy Integration Study |
| RES | Renewable Energy Standard |
| RT | Real Time |
| SCUC/EC | Security Constrained Unit Commitment / Economic Dispatch |
| SOx | Sulfur Oxides |
| ST | Steam Turbine |
| TW | Terawatts |
| TWh | Terawatts Hour |
| UARB | Nova Scotia Utility and Review Board |
| VOC | Variable Operating Cost |
| WAN | Wide Area Network |
| WC | Wreck Cove Hydro |

# Executive Summary

General Electric International, Inc. (GE) was engaged by Nova Scotia Power, Inc. (NSPI) to perform a renewable energy integration study (REIS) in order to quantify the impacts of increasing renewable energy penetration on the operation and reliability of the Nova Scotia power system, to evaluate performance and operating costs, and to consider methods and approaches to mitigate the adverse impacts of renewable energy integration. The intent is to provide guidance and quantitative metrics to aid NSPI in future development decisions.

Four primary analytical methods were used to meet this objective; statistical analysis, hourly production simulation analysis, sub-hourly production simulations, and reliability and wind capacity valuation analysis.

NSPI requested consideration of nine study cases covering years 2012, 2013, 2015, and 2020. Two different outlooks on the system load were considered for future years, namely, one without large industrial load from Port Hawkesbury Paper, and one including this load. Furthermore, the 2020 cases considered the impact of meeting the 40% renewable energy target with and without the Maritime Link.

A summary of the nine base cases is shown in Table S 1.

**Table S 1: Summary of the Study Base Cases**

| Case ID | Year | Industrial Load | Maritime Link | Wind Capacity | Available Wind Energy |
|---|---|---|---|---|---|
| **Case 1** | 2012 | No | No | 335 MW | 1,148 GWh |
| **Case 2** | 2013 | Yes | No | 335 MW | 1,148 GWh |
| **Case 3** | 2013 | No | No | 335 MW | 1,148 GWh |
| **Case 4** | 2015 | Yes | No | 488 MW | 1,661 GWh |
| **Case 5** | 2015 | No | No | 488 MW | 1,661 GWh |
| **Case 6** | 2020 | Yes | No | 916 MW | 3,102 GWh |
| **Case 7** | 2020 | No | No | 796 MW | 2,685 GWh |
| **Case 8** | 2020 | Yes | Yes | 551 MW | 1,871 GWh |
| **Case 9** | 2020 | No | Yes | 551 MW | 1,871 GWh |

GE performed a large number of sensitivities in order to evaluate the robustness of the system to handle uncertainty and variability of the wind power, and to appraise the impact of various drivers and variables on system performance, both operational and economic. A complete listing of the sensitivities performed is included in Section 7.3 of this report.

## S.1 CONTEXT AND LIMITATIONS

### S.1.1 This Study is not an Integrated Resource Plan (IRP)

The focus of this project was to determine the various impacts of renewable energy additions as part of meeting the overall renewable energy policy of the province. It was not intended to be an overall integrated resource plan. The study makes no effort to establish the overall adequacy of the Nova Scotia system, nor does it attempt to determine exactly what resources are necessary to meet system performance and reliability objectives. The study does not look beyond 2020. Nevertheless, additional wind and the Maritime Link were modeled to function in the Nova Scotia power system as it currently exists and is expected to exist over the period of this study. As such, the study endeavored to establish how increased levels of renewable energy could work within the existing and future infrastructure, and it provides insights into various mitigating options, including changes in the generation portfolio that could improve system performance, reliability and economy. The results of this work will be useful to future integrated resource planning undertaken by NSPI.

### S.1.2 Production Simulation Is Still Simulation

The modeling used is highly sophisticated, and the tools (GE MAPS and PLEXOS) are industry standards - widely used for economic and operational evaluation of power systems. Nevertheless, they are still simulations. Reality is even more complex, and successful grid operation includes the action of experienced, sophisticated humans. There are limits to our ability to exactly replicate present, and even more so, to accurately project possible future operations of the Nova Scotia grid. GE has extensive experience and has exercised care and applied engineering judgment to make sure that the simulations are reasonably accurate, and that they provide the quantitative insight necessary for NSPI to make good investment and operational decisions. Perfect accuracy is neither possible, nor necessary.

### S.1.3 Industry and World Experience Perspectives

In cases where wind energy penetration reaches approximately 25%, Nova Scotia would be joining a small number of systems worldwide that are at these levels. Instantaneous penetration of wind power would exceed 50% for 1,200 hours each year in 2020 Case 7. The fact that ERCOT set a new record of 26% instantaneous wind penetration on November 10, 2012, and that this was worthy of front page news in an experienced renewable energy state, should give pause. On the other hand, Portugal (REN) has had many hours of operation in 2012, during which total wind power exceeded the entire country's load – more than 100% penetration. They are coping well.

While this study concludes that it is technically feasible to integrate large amounts of wind power in Nova Scotia, it would not be without significant impact to Nova Scotia Power's customers. In high wind penetration cases, wind power would be curtailed much more often than it is today. NSPI generating facilities would maneuver more, with less warning and more urgency. Operating practices would need to change; rescheduling would also need to occur more frequently. Operating and maintenance costs on thermal and hydro plants would increase. New operating practices would be needed; new information gathered, archived and digested. Investment in existing NSPI plant and equipment, and people, would also be needed.

### S.1.4 Power versus Energy Penetration

Typically, when developing renewable energy targets, the focus is on the fraction of total annual system load energy that is to be supplied from renewable resources. That is the case here: NSPI has renewable energy requirements for 25% by 2015, and 40% by 2020. In the language of the industry, this is "energy penetration". From a grid operations perspective, energy is much less important than power: NSPI must maintain reliable operation every hour of the year, including when it is very windy and also when it is calm. At any instant of time, the wind power being generated serves the load at that instant. The fraction of the total load that is served by wind is the instantaneous penetration. This difference in perspective is important.

Figure S 1 presents two sets of modeled "duration curves" of wind penetration for different windows of time. For example, the hourly trace is wind MW/load MW for that hour – sorted from maximum to minimum. On the left, the present system, Case 1 (2012), is shown, and on the right Case 7 (2020).

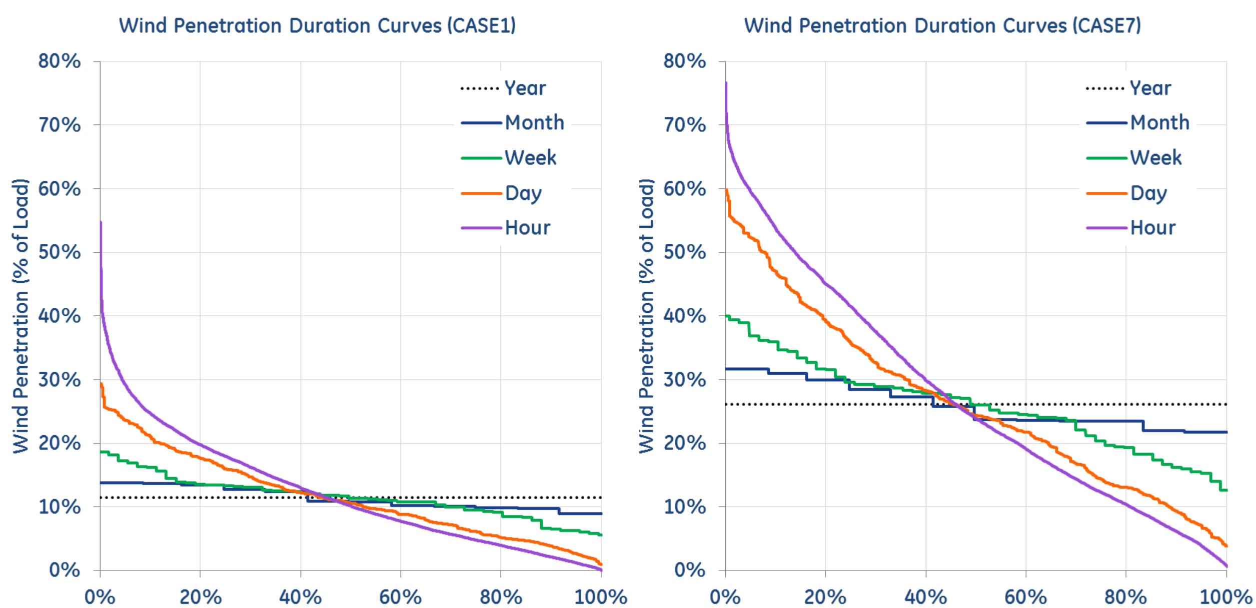



**Figure S 1: Wind Penetration Duration Curve (Cases 1 & 7)**

The increases in penetration help illustrate the changes for which NSPI must be prepared. In the 2020 Case 7 curve, the maximum single hourly wind penetration is over 75%, the minimum close to zero – providing an overall average of about 27% (the annual wind energy penetration). In one week (green trace) the system gets 40% of its energy from wind. In the event that high levels of wind penetration were employed to meet renewable energy requirements, NSPI would need to be able to operate at these extremes. A considerable amount of the work performed in this study is aimed at understanding and meeting those extremes.

### S.1.5 Wind Data and Validation

The penetration duration curves highlight the necessity for good wind power production data to make meaningful simulations and projections about future system operations. Data used in this study was developed using state-of-the-art atmospheric computer models to determine the amount of power every wind plant in the system would make at ten-minute intervals for the study year. Since weather affects both load and wind power data, the same weather year was used for both. Extensive checking and calibration of the future wind power data was performed against detailed historical wind power production from existing Nova Scotia wind plants. Hence, the fidelity of the wind data used in this study is high.

### S.1.6 Variable Operating Cost as the Critical Economic Metric

Throughout the work reported here, the focus is on "variable operating cost", also known as "production cost". Production cost is NOT the total cost incurred to serve load, but rather it is the component of cost that varies with operation, and which can be affected by operating decisions. Production costs reported in this study include the following:

- Fuel expense (the largest component by far)
- The costs of starting and stopping plants
- The costs of operation and maintenance that vary with energy produced (variable O&M).

Other costs are fixed and do not count towards production cost. Examples of fixed costs include:

- The cost of capital for all plant and equipment
- The cost of capital for all grid investment
- The cost of operation and maintenance independent of energy production (i.e. the cost that a plant incurs just to stay able to produce power)

While these costs play a role in whether to invest in a new plant or keep a plant in service, they play no role in operational decision making. The cost of NSPI producing hydroelectric power is also fixed. This is less intuitive, but the fuel is free and the other costs don't vary with energy produced. Consequently, the operational consideration for hydro power is how to use it to its best advantage to reduce the operational costs that *are* variable.

This logic applies to wind power as well: the "fuel" has no cost. Although there is a cost for payments to some independent power producers, PPA (power purchase agreement) price has no impact on system operations as wind will always be accepted by the grid, unless it needs to be curtailed or exported when there is surplus wind energy generated. This study did not examine PPA price levels for wind. The study reports the cost of purchased energy from wind IPPs for each study case based on the PPA prices provided by NSPI and the capital carrying cost for the NSPI share of the Maritime Link, also provided by NSPI

## S.2 OPERATIONAL IMPACTS AND CONSIDERATIONS

The results of this study provide insight into a number of key operational areas and the impact that integrating increasing levels of wind energy could have on NSPI and its customers.

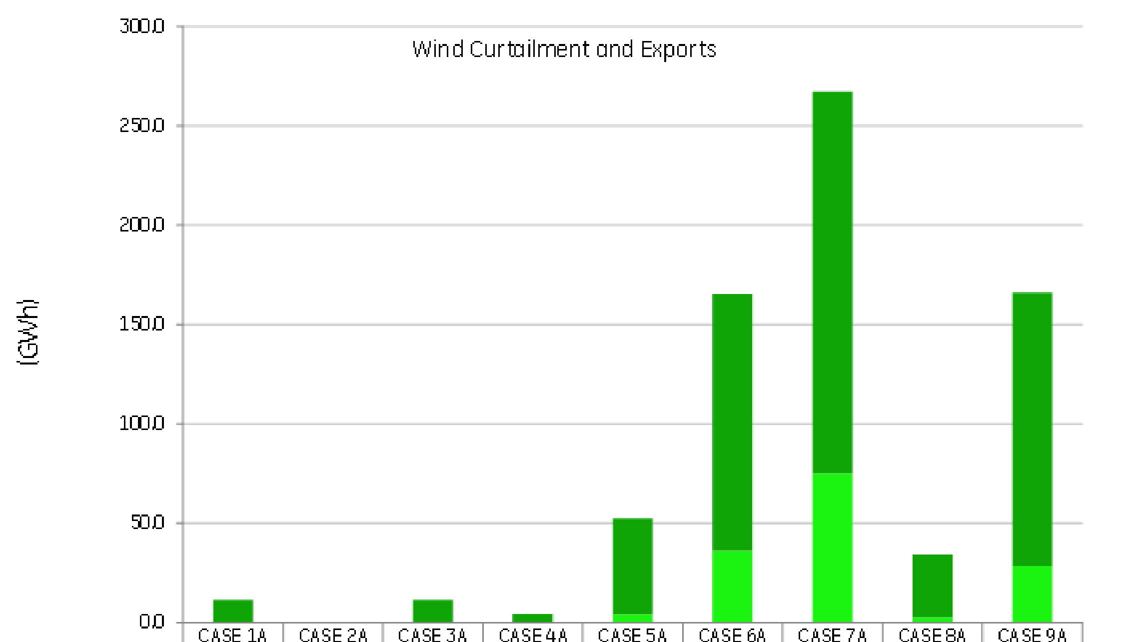
### S.2.1 Exports and Imports

The existing tie with New Brunswick (NB) and proposed Maritime Link interconnecting Nova Scotia (NS) and Newfoundland and Labrador (NL) were found to be beneficial and important elements in system operation. The variability of wind power increases the need to maneuver NSPI generation to balance the system. The study found that interconnections with NB and NL provide NSPI with resources that allow the Nova Scotia power system to adapt to variable wind power.

The NB tie was modeled with a 15% forced outage rate in the base cases. This forced outage rate is based on NSPI's operational experience and is indicative of the amount of scheduled energy that has been cut or curtailed. There are cases where NSPI's ability to schedule energy on the tie line is much less than 85% of the tie line's capacity. This is particularly evident during high load conditions in the winter months. As a result, NSPI considers modeling of the tie line with a 15% forced outage rate to be optimistic relative to the ability to import power to Nova Scotia during high load periods.

Under circumstances in which the tie line was modeled with a 15% forced outage rate, it is estimated that the presence of the NB / NS tie is worth [redacted]/year in avoided operating costs in the 2020 scenarios. In high wind penetration cases, this would provide an alternative to aggressive cycling of the coal plants. Unavailability of the NB / NS tie increases coal plant maneuvering (mileage) by about 10%. Operational flexibility of the NB / NS tie, both physical and contractual, can have a significant impact on operating costs, and on the frequency with which demand response reserves (last resort) must be invoked. Sensitivities bounding these costs indicate that highly flexible operation of the NB / NS tie – i.e., that which can be scheduled on very short notice without scheduled energy being cut or curtailed – can reduce variable operating costs by about [redacted]/year, compared to long lead (day-ahead) scheduling.

In the high wind later years of the study, there are many hours when the NSPI system cannot accept any more wind power, given the present physical and reliability constraints on the system. During those hours, the excess wind power must be either exported or curtailed (spilled). The feasibility of exporting excess wind power is a function of the ability of markets beyond Nova Scotia's border to accept this energy at a time when Nova Scotia would be looking to sell it. Figure S 2 depicts wind curtailment and export by case.




| | CASE 1A | CASE 2A | CASE 3A | CASE 4A | CASE 5A | CASE 6A | CASE 7A | CASE 8A | CASE 9A |
|---|---|---|---|---|---|---|---|---|---|
| Exports (GWh) | 11.2 | 0.4 | 11.2 | 4.4 | 48.5 | 129.3 | 192.2 | 31.7 | 137.5 |
| Curtailment (GWh) | 0.3 | 0.0 | 0.3 | 0.0 | 4.1 | 36.1 | 75.0 | 2.6 | 28.6 |

**Figure S 2: Exports and Curtailment by Case**

Case 7A requires the most export - with about 10% of total wind energy production (~200 GWh) that must be exported. This represents an increase of approximately 20 times the current levels of exported wind energy. The price received for exports will be a complex function of resources, operations and policy in New Brunswick and beyond. Consideration of that complexity is beyond the scope of this study, but the base case assumption is that times of high wind and low demand in Nova Scotia will coincide with those in the neighboring systems. Thus, the price received for exported wind power would be low. Some further investigation of revenues from exports is included in the report. Any excess wind power that cannot be exported will need to be curtailed.

### S.2.2 Curtailments and Wind Plant Operations

Curtailment of wind power occurs when the system cannot accept or export all of the wind power being generated at that time. In our analyses, we have assumed that wind generation is always accepted if possible, and is only exported or curtailed when all the committed thermal generation is on its minimum load. This means that wind plants must be able (and willing) to be curtailed in small increments and on very short notice. This approach minimizes the amount of wind energy spilled, but at the cost of imposing significant operational expectations and constraints on the wind plants. If the wind plants are unable or unwilling to be active participants in balancing when the system is operating under these low load and high wind conditions, then preemptive curtailment will be required – raising the amount of wind that must be exported and/or curtailed. Increases on the order of 20 GWh/year or more than what are shown in Figure S 2 could be expected, if NSPI carries a moderate amount of extra down reserve to cover most intra-hour wind variability. The impact of this on variable operating cost is small, but wind generators could see reduced revenues due to increased curtailments (assuming they are not paid for spilled power). Since any excess wind power that cannot be exported will be curtailed, a significant fraction (up to 10%) of total wind generation in the later years is at issue. The ability and willingness of neighboring systems to accept this power, warrants further investigation. The issue of who would bear the cost of curtailed wind is a separate policy question, beyond the scope of this study.

### S.2.3 Demand Response

When load, conventional generation outages and unanticipated changes or shortfalls in predicted wind occur, the system can find itself with insufficient conventional generation and import capability to meet load and satisfy reserve requirements. For this study, demand response is used as a resource of last resort, which is consistent with NPSI's operating practices.

This study found that the number of hours that NSPI's Large Industrial Interruptible customers could be interrupted increases significantly in the 2020 cases. As illustrated in the demand response duration curves of Figure S 3, there were approximately 30 hours (blue arrow) in 2012 where NSPI's Large Industrial Interruptible customers were interrupted (minimum interruption is 10MW here) when a forced outage rate of 15% was used for the NB / NS tie line (Case 1A). If the NB tie is assumed to be completely unavailable (Case 1D), that could increase to nearly 90 hours (purple arrow). Having the NB tie perfectly available (Case 1I) would have essentially no impact on demand response.

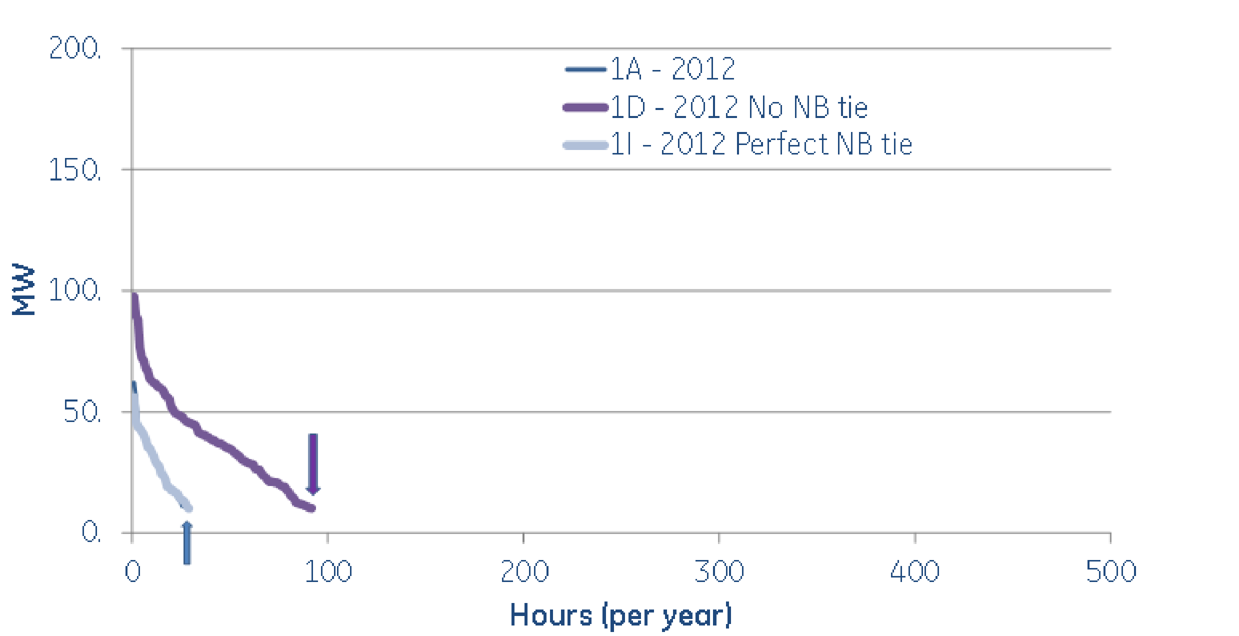



**Figure S 3: Demand Response Duration vs. Availability of NB Tie - 2012**

Figure S 4 shows the same information for the four possible 2020 cases. In the high-wind penetration case that includes large industrial load and 915 MW of installed wind capacity (case 6), the impact on Large Industrial Interruptible customer interruptions increases substantially relative to the 2012 base case (from 30 to 90 hours now, increasing to 80 to 420 hours). NSPI's Large Industrial Interruptible customers would be interrupted three to four times as many hours as they are in the 2012 base case. In both cases (6 and 7) that rely only on in-province wind additions (without the Maritime Link), the availability of the NB tie has a large impact on frequency and amount of demand response required.

In Case 8, which includes the Maritime Link, large industrial load, and 550 MW of installed wind capacity, the number of hours that NSPI's Large Industrial Interruptible customers would be interrupted is reduced to nearly zero in the case where the NB / NS tie line is modeled at a 15% forced outage rate (Case 8A in Figure S 4). In the absence of the NB / NS tie line (Case 8D) the number of hours that NSPI's Large Industrial Interruptible customers would be interrupted would be approximately 60% less than the 2012 base case without the NB / NS tie line (Case 1D).

In the absence of large industrial load in 2020 (Cases 7 and 9), the impact is somewhat similar. As illustrated in Figure S 4, the number of hours that Large Industrial Interruptible customers would be interrupted in Case 7 would increase by at least 30% relative to the 2012 base case, whereas the number of hours Large Industrial Interruptible customers would be interrupted in Case 9 is nearly 80% less than the 2012 base case.

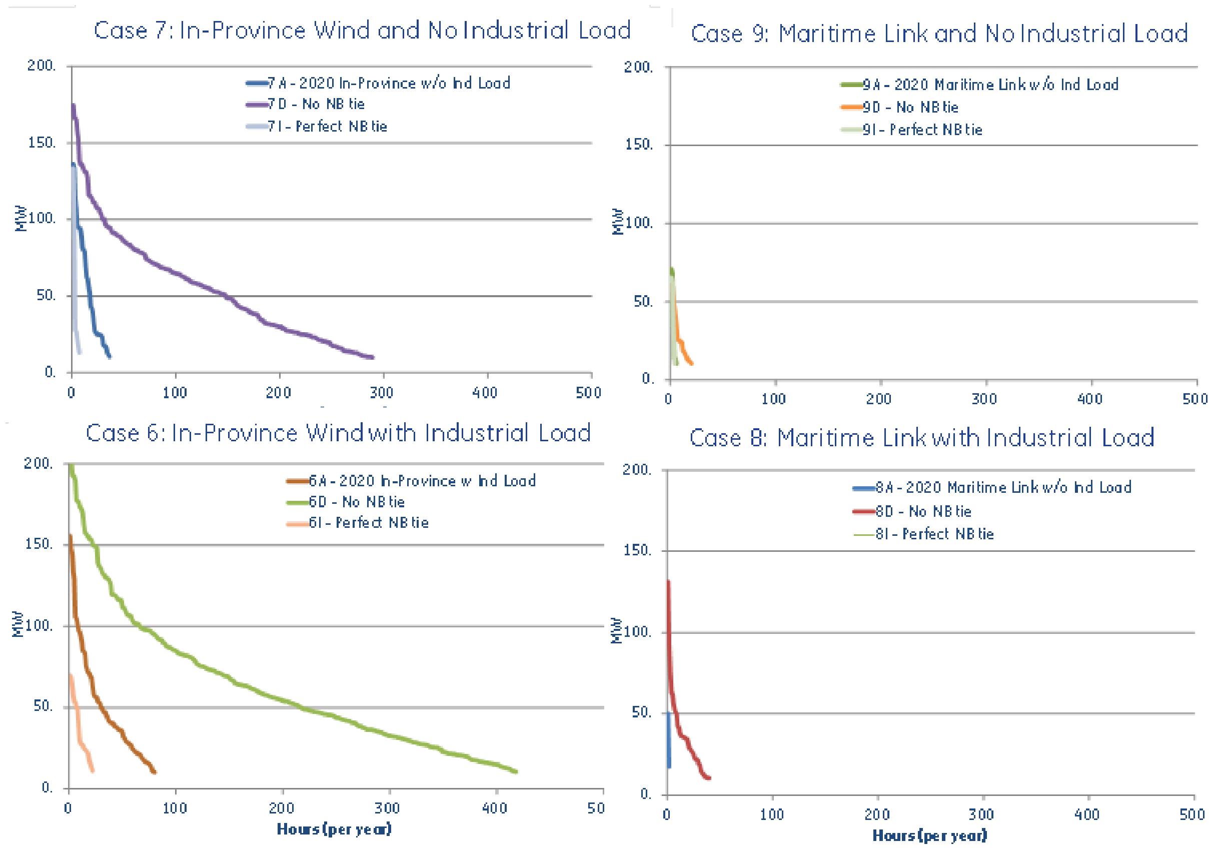



**Figure S 4: Demand Response Duration vs. Availability of NB Tie - 2020**

Demand response is a valuable resource, especially in high wind systems. Other studies have shown demand response to be highly economical for helping systems handle occasional extremes caused by wind power. Nova Scotia should pursue development of more and more agile, demand response resources. If this proves to be challenging for NSPI and its customers and it is found that there is not enough new interruptible customer base in Nova Scotia to address the increase in calls on demand response in the high wind penetration cases, there are a number of options available to mitigate the risk of increased levels of customer interruptions. The Maritime Link, investments in new generation capacity (in-province) and improving the ability for Nova Scotia to import through the NB / NS tie line are all options that NSPI should consider in parallel with pursuing development of more and more agile demand response.

### S.2.4 Thermal Cycling, Maneuvering and Mileage

The variability of wind power increases the maneuvering of NSPI power plants. As the level of wind penetration increases, the thermal plants experience more starts and stops and their dispatch adjusted more frequently and by more MWs. In high wind penetration cases, the count of coal plants starts can nearly double relative to 2012, but would still be less than 120 per year for the entire fleet. Starts and stops of other thermal resources can increase or decrease depending on the resource and study case.

One measure of operational maneuvering is "mileage" – the sum of the absolute value of the total hourly MW changes in dispatch. Relative to the 2012 base case (case 1A), the mileage on the coal plants increases about 20% in Case 7A and about 30% in Case 9A. Increased coal plant cycling has a cost in terms of wear-and-tear. This is the subject of fierce debate and investigation in the industry today. Estimates of these costs vary wildly. Recent work sponsored by National Renewable Energy Laboratory (NREL) [20], that includes current state-of-the-art estimates for these costs showed that they would be expected to reduce the variable cost savings from wind energy between $0.06 and $2.0 per MWh of wind energy. Based on the amount of wind energy that could be operating on the Nova Scotia power system in the high wind penetration cases in 2020, the cycling costs could possibly be as high as $6 million annually over and above the production costs summarized below in Figure S 6. These estimated costs are based on the NREL work referenced here. Further study would be required to provide a more accurate estimate for cycling costs for NSPI's thermal fleet.

### S.2.5 Hydro Operation

With the exception of Wreck Cove, the hydro generation in Nova Scotia is assumed to have relatively little operational flexibility, and is assumed to be scheduled well in advance of real-time operation. Wreck Cove is a valuable asset from a flexibility perspective, and we have approximated the sophisticated human operation of this plant, using it to both shave peak load and cover for errors in wind forecasts. Experience with operation under high wind scenarios will almost certainly result in improvements beyond our ability to model at this point. The critical observation is that NSPI must have operational flexibility. Any operational flexibility that can be obtained from the hydro plants will offset the need for maneuvering of thermal plants and the need to depend on the NS / NB tie line. Investments in all of the NSPI hydro facilities to increase operational flexibility may prove to be highly cost effective and should be a high priority in NSPI's investment planning.

### S.2.6 Maritime Link Operation

As already discussed in sections S.2.1 and S.2.3, the Maritime Link (ML) would provide operational benefits in terms of reducing the volume of exported and curtailed wind energy as well as significantly reduce the number of hours that Large Industrial Interruptible customers would be interrupted relative to the 2012 base case and high wind penetration cases.

The Maritime Link, as specified for this study, was modeled using three separate blocks. The assumptions used are detailed in Section 6.3. As these assumptions highlight, the 35-year block and supplemental 5-year block have tight daily energy delivery targets and a relatively narrow range of power operation. There could be as much as 1.3 TWh per year of surplus energy available to Nova Scotia with a third, discretionary block that would be more flexible. It has been assumed that the first two blocks of energy associated with the Maritime Link will be given hourly schedules that are determined during the day-ahead commitment and scheduling process, with the intent of net load peak shaving (forecasted hourly net load is forecasted system load minus forecasted hourly wind power). The third discretionary block was examined in several sensitivity cases, as an option to meet hourly variability of wind with day-of-operation dispatch, and as an option for economic imports. If fast, real-time changes in scheduling of power and energy through the Maritime Link is possible (still subject to power and daily energy limits), it could be a valuable source of operational flexibility. For example, relying on the Maritime Link for just 10 MW of fast reserve would save about $[redacted]/year in variable operating cost.

### S.2.7 Wind Forecasting

All major power systems with substantial penetration of wind power rely on wind forecasting for operations. The industry consensus is that forecasting improves reliability and economy of operation in high wind systems. Most debate today surrounds discussions of how to make wind forecasting even better: more accurate, more usable by grid operators, with more information. Forecasting of big wind ramp events is the current hottest topic. All of the base cases presented in this study assume that NSPI has access to, and uses, a day-ahead wind forecast at the time of day-head unit commitment and scheduling. Failure to use wind forecasts has been found to be cripplingly expensive in other large system studies. Surprisingly, this study found a much lower value to wind forecasting. The existing generation portfolio in Nova Scotia, combined with the projected fuel prices, make the marginal cost of generation look different than in most systems that GE has studied. The operational cost penalty of over-forecasting (predicting more wind power than actually shows up – i.e., being caught short) is high compared to the operational penalty of under-estimating wind production. This is because the cost of running quick start peakers is very high compared to base load coal. Consequently, unlike other systems studied, NSPI will tend to operate conservatively, with a bias towards discounting the wind forecast. Nevertheless, savings from using wind forecasting would be on the order of $[redacted]/year, with more savings possible with better forecasts. Changes in NSPIs generating fleet mix may also increase the value of forecasting. The forecasting community is also developing tools for handling extreme weather, which will likely prove valuable for NSPI. Steps to further develop wind data collection, archiving and mining are likely to pay dividends in the future.

## S.3 RELIABILITY IMPACTS AND CONSIDERATIONS

### S.3.1 Reserves

The amount and type of reserves that high wind systems must carry is the subject of intense and ongoing investigation and debate in the industry. There is some consensus that some incremental synchronous reserves must be running and have the necessary speed and maneuvering range to cover the majority of short term variation in wind output. In this study, statistical analysis was used to establish the expected variability of wind power over 10-minute intervals. The variation is dependent on the amount of actual wind production, rather than just the total MW rating of wind installed. The physical reality is that wind power is more variable at moderate power levels (e.g. around ½ of turbine rating) than at full power. The production simulations force the NSPI system to carry incremental reserves capable of handling more than 99% (3 standard deviations - 3σ) of all wind power drops that are expected to occur in any 10-minute period. This is a relatively conservative approach. For example, Texas (ERCOT) uses 2.5σ ~ 98%), but NSPI has a less expansive thermal fleet and is significantly smaller and therefore a more conservative approach to reserves is warranted - similarly conservative approaches have been recommended in smaller, completely islanded systems. This approach results in about 22 MW of extra reserves being carried, *on average*, in the earlier years, and rising to around 36 MW in the highest wind case (Case 6). As noted above, demand response, use of the Maritime Link, and use of other hydro, are all potential resources from which NSPI can get reserves to cover the inter-hour variability of wind power. The marginal cost of providing these reserves is on the order of $[redacted]/MW per year, although the study indicates a relatively wide range, depending on assumptions and boundary conditions. These costs are included in the variable operating costs reported throughout this report. Refinements in reserve strategy could produce reductions in the amount carried and in the costs associated with carrying them. The cost of providing these reserves is high enough that other technologies to achieve this functionality, including energy storage, might be economically justified.

### S.3.2 Reliability and Capacity Value

The addition of wind generation to the NSPI system, as with the addition of any new generation resource, has a beneficial impact on the ability of the system to serve load. The difference with variable wind generation is that the capacity added to the system from incremental wind generation is much less than other forms of generation.

This aspect of system reliability is normally measured in terms of "loss-of-load-expectation" (LOLE). This metric is calculated using a given annual hourly load profile (8760 hours per year) and generation portfolio which includes individual power plant MW rating and forced outage rates. It establishes the frequency with which a system, through a combination of high load and generator unavailability, has insufficient generation to serve load. Typical industry practice for large systems targets a value of 0.1, meaning one incident in 10 years. A measure of an individual generator contribution to improving LOLE is the "capacity value" (this has different names in different places). For example, a 200 MW thermal plant with a 5% forced outage rate, will have a 190 MW or 95% capacity value – from a reliability perspective it is "worth" 95% of a theoretical "perfect" generator. This industry standard method applies to the addition of wind (and other renewable resources, such as hydro, solar and tidal) generation as well.

The capacity value of the wind additions in this study were found to be in the range of 12-30% of rating. For example, the first block of wind generation totaling 336 MW that will be in place in 2013, provides the equivalent reliability value of 105 MW of "perfect" capacity (31%). Incremental additions of wind plants in the same location have diminishing returns, due to loss of spatial and temporal diversity. This means that the last blocks of wind added - those necessary to meet the 2020 renewable requirements with only in-province wind additions (Case 6) – have capacity values of around 12%.

Looking out to 2020, at cases where the PH PM2 industrial load and Lingan 1 & 2 are retired, there is a significant difference between the In-province (Case 7) and the Maritime Link (Case 9) LOLE. In order to meet a LOLE target of 0.1, Case 7 is short about 150 MW of capacity. Case 9 is about 8 MW short. If the PH PM2 industrial load returns, the In-province Case 6 is about 290 MW short of capacity. These results do not give existing demand response any credit toward capacity or towards reducing the LOLE. The contribution of the NB tie to these LOLE calculations is based on the 85% availability number discussed above.

Great care must be exercised in using these absolute figures, as this study was not intended to be an overall resource adequacy study. Required capacity additions, unlike the wind capacity values reported here, are extremely sensitive to resource, grid interconnectivity, and load level assumptions. However, it can be concluded from this work that additional capacity may be required in cases where coal units are retired and large industrial interruptible load remains on the system. Depending on the load, the extent of unit retirements, and wind energy penetration (and therefore capacity that can be counted from additional wind), NSPI could require in the range of approximately zero to 200MW of additional capacity. Further study that incorporates a carefully crafted assumption set and a multiple year outlook would be required to determine how much additional capacity would be required.

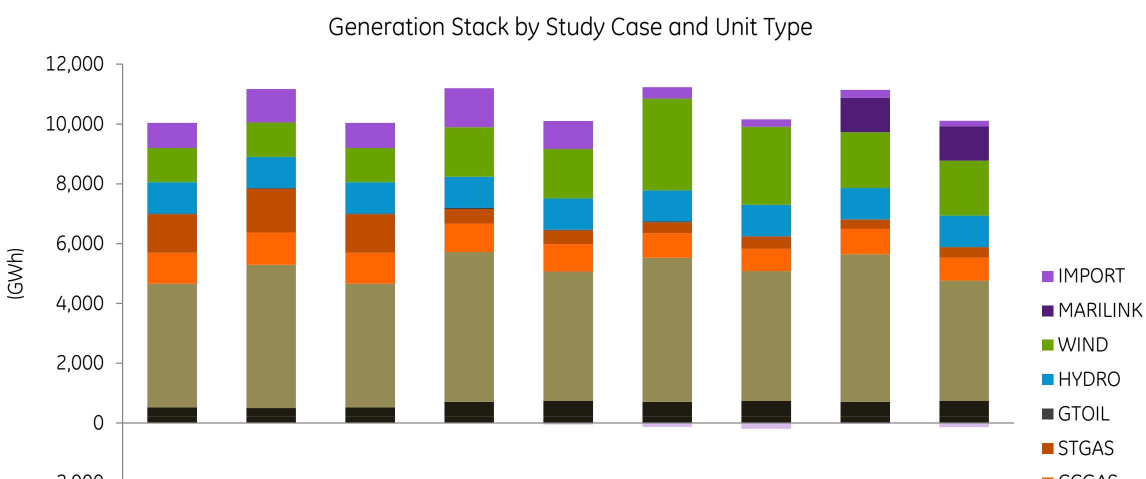
### S.3.3 Advanced Grid Code

As wind generation displaces synchronous generation, the features of the displaced generation that have made power systems stable, and have provided controlled system frequency and voltage to serve load must continue to be provided. Early wind turbine technologies were considered simple energy sources, incapable of even providing reactive power. Wind farms on the NS power system today can produce reactive power to control system voltage and their output can be curtailed on demand, but they are still incapable of controlling system frequency, provide operating reserve and system inertia, tie-line control and black-start capability. All of these functions, except black-start, can be provided by some commercially available wind technology, but they are not presently in widespread use. The North American Electric Reliability Corporation (NERC) has initiated a project to ensure that future renewable generation technologies, including wind, can provide the ancillary services traditionally provided by synchronous generators. This will mean that grid codes, the set of requirements for interconnection of new generation, must be enhanced and standardized. It is expected that the provision of ancillary services will come at a cost, so the industry must find encourage the development of markets and price signals for the services.

## S.4 ECONOMIC IMPACTS AND CONSIDERATIONS

### S.4.1 Energy Mix and Variable Operating Costs

In general, each MWh of wind energy displaces approximately one MWh of thermal generation, if the system can accept that wind power at that time. The total generation for each of the nine cases is shown in Figure S 5. The height of each bar represents the total load served (plus losses) in each case. There is essentially no net load growth expected up to 2020, so the comparable cases across the years are essentially the same height. The energies plotted are shown in the table below the chart. Odd numbered cases have the large industrial load at Port Hawkesbury retired, and therefore are lower.




| | CASE1 A | CASE2 A | CASE3 A | CASE4 A | CASE5 A | CASE6 A | CASE7 A | CASE8 A | CASE9 A |
|---|---|---|---|---|---|---|---|---|---|
| IMPORT | 843 | 1,119 | 843 | 1,303 | 938 | 386 | 253 | 265 | 175 |
| MARILINK | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1,153 | 1,153 |
| WIND | 1,148 | 1,148 | 1,148 | 1,661 | 1,657 | 3,066 | 2,610 | 1,868 | 1,842 |
| HYDRO | 1,044 | 1,044 | 1,044 | 1,044 | 1,044 | 1,045 | 1,045 | 1,045 | 1,045 |
| GTOIL | 21 | 26 | 21 | 32 | 25 | 27 | 13 | 5 | 7 |
| STGAS | 1,294 | 1,460 | 1,294 | 487 | 458 | 367 | 412 | 316 | 349 |
| CCGAS | 1,036 | 1,082 | 1,036 | 952 | 917 | 816 | 745 | 844 | 769 |
| STCOAL | 4,135 | 4,791 | 4,135 | 5,014 | 4,329 | 4,821 | 4,343 | 4,939 | 4,028 |
| BIOMASS | 291 | 270 | 291 | 475 | 506 | 477 | 507 | 477 | 507 |
| STOTHER | 230 | 230 | 230 | 230 | 230 | 230 | 230 | 230 | 230 |
| EXPORT | -11 | 0 | -11 | -4 | -49 | -129 | -192 | -32 | -138 |

**Figure S 5: Base Case (Sensitivity A) Generation Energy (GWh) by Type**

The variable costs of operation for the nine base cases are provided in Figure S 6, which show the components of that cost by generation type. Over the planning horizon of the study, the price of fossil fuel increases as does the amount of renewable energy. Throughout the study, sensitivity tests have been performed to determine the impact of various assumptions - such as changes in resources and changes in operating practice - on these variable costs. Fixed costs, while they add to the total cost of serving load, are not dependent on operating strategy.

[redacted]

| | CASE | CASE | CASE | CASE | CASE | CASE | CASE | CASE | CASE |
|---|---|---|---|---|---|---|---|---|---|
| **UNIT TYPE** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** |
| **CCGAS** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **GTOIL** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **IMPORT** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **STCOAL** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **STGAS** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **TOTAL** | 359.8 | 417.2 | 359.8 | 446.8 | 384.1 | 457.4 | 409.2 | 436.6 | 373.2 |

**Figure S 6: Production Costs by Study Case and Unit Type**

**THIS FIGURE IS CONFIDENTIAL, WITH THE EXCEPTION OF THE TOTAL COST**

This study did not examine PPA price levels for wind. The PPA prices do not influence the dispatch of wind. But they determine the cost of purchased energy from IPPs for each study case. Figure S 7 provides the cost of purchased energy from IPPs for each study case using the PPA prices and Maritime Link capitalization costs provided by NSPI.

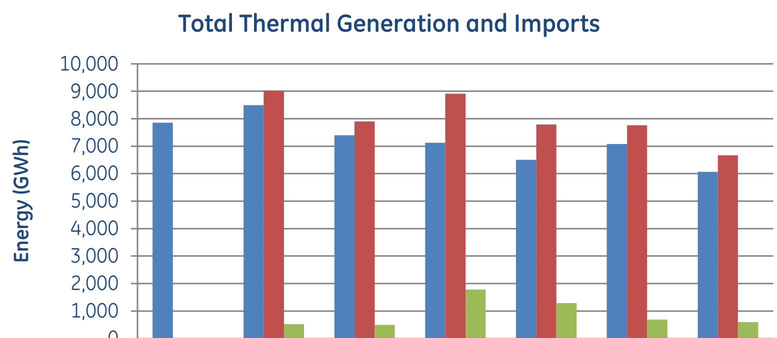

| | CASE1 A | CASE2 A | CASE3 A | CASE4 A | CASE5 A | CASE6 A | CASE7 A | CASE8 A | CASE9 A |
|---|---|---|---|---|---|---|---|---|---|
| MARILINK | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 155.0 | 155.0 |
| WIND | 63.7 | 63.7 | 63.7 | 115.3 | 114.9 | 266.7 | 223.3 | 152.9 | 150.4 |

**Figure S 7: IPP PPA Cost of Wind and Maritime Link**

### S.4.3 Comparison against Business-as-usual (from 2013 on)

The system study cases were designed to provide a picture of future operations. All of the future cases include not only added wind generation, but also a wide range of other changes: different fuel prices, unit retirements, load projections, etc.

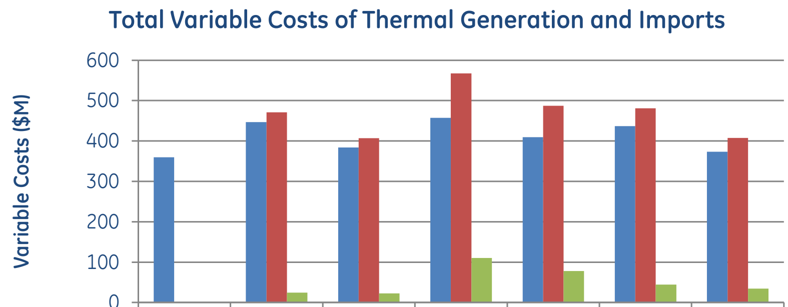
Comparing system operations in these future scenarios that include all of the assumed changes *with exception to the addition of any new wind generation beyond the level that exists in the 2013 base* case is termed "business-as-usual" (BAU), and provides some interesting insights. In Figure S 8, the red bars show an increase in thermal generation and imports (GWh) for each of the base cases. The red bars show an increase in thermal generation in the 2015 and 2020 years over the study base cases (without the incremental wind energy that is assumed to be added after 2013, the thermal plant generation and imports increase to cover the energy that is provided by wind in the base cases). The difference between the blue bars and red bars is shown in green. These differences are mostly due to the difference in wind energy, but also reflect the fact that more wind is exported and curtailed in the base cases compared to the business-as-usual cases. It is important to remember that Maritime Link energy is included in the BAU numbers for cases 8 and 9. By way of example, Case 4 of Figure S 8 illustrates that if the wind that is assumed to be added to the system between 2013 and 2015 is not added, then 525 GWh more energy would be required from NSPI's thermal generators and imports made by NSPI.




| | CASE 1 | CASE 4 | CASE 5 | CASE 6 | CASE 7 | CASE 8 | CASE 9 |
|---|---|---|---|---|---|---|---|
| Base Case | 7,850 | 8,493 | 7,402 | 7,124 | 6,503 | 7,075 | 6,065 |
| BAU Case | | 9,018 | 7,896 | 8,911 | 7,789 | 7,762 | 6,665 |
| Delta | | 525 | 494 | 1,787 | 1,286 | 687 | 600 |

**Figure S 8: Thermal Generation Comparison with Business-as-usual**

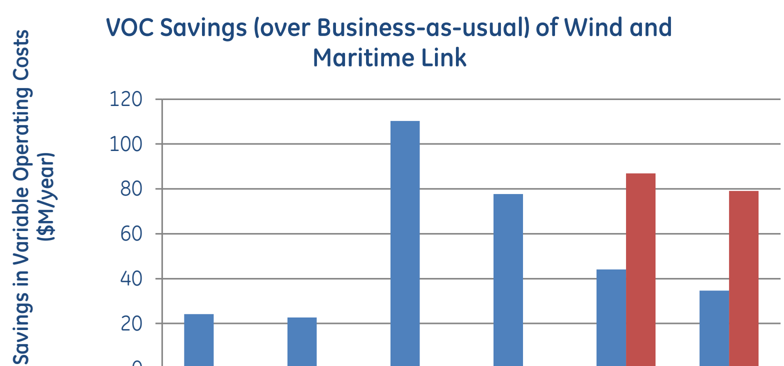
The need to generate more with thermal plants (the hydro energy is unchanged between the cases) and to import more, adds to the variable cost. The total variable cost, and the difference between the cases is shown in Figure S 9. The BAU cases also allow for a calculation of the value of the Maritime Link energy.




| | CASE 1 | CASE 4 | CASE 5 | CASE 6 | CASE 7 | CASE 8 | CASE 9 |
|---|---|---|---|---|---|---|---|
| Base Case | 360 | 447 | 384 | 457 | 409 | 437 | 373 |
| BAU Case | | 471 | 407 | 568 | 487 | 481 | 408 |
| Delta | | 24 | 23 | 110 | 78 | 44 | 35 |

**Figure S 9: Variable Cost Comparison with Business-as-usual**

In Figure S 10, the differences between BAU Case 8 and Case 6, and between Case 9 and Case 7, show the savings from the Maritime Link, if no new wind was added after 2013. The wind savings in this figure are the same as the "delta" in the preceding one. Thus, these show the savings for the Maritime Link *without* wind additions past 2013. The savings for wind are *with* the Maritime Link in operation.




| | CASE 4 | CASE 5 | CASE 6 | CASE 7 | CASE 8 | CASE 9 |
|---|---|---|---|---|---|---|
| Wind | 24 | 23 | 110 | 78 | 44 | 35 |
| Maritime Link | | | | | 87 | 79 |

**Figure S 10: Variable Cost Savings Comparison with Business-as-usual**

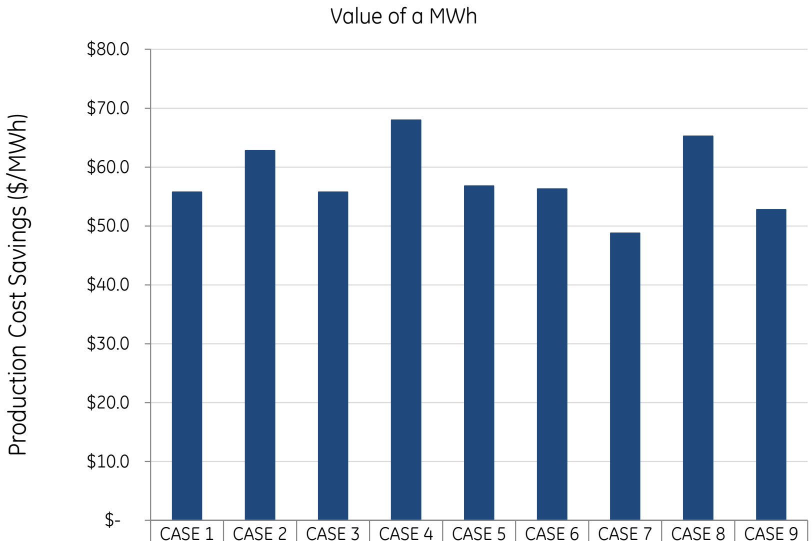
The reduction in variable costs is mostly fuel cost savings from reduced production by the thermal plants. The changes reflect the net impact of the wind added after 2013, and include impacts on the thermal plants such as running at different heat rates, starts and stops, and all the other factors that are included in the production simulations. These savings can be assigned to the wind energy.

In Figure S 11, the production cost (variable operating cost) reductions are shown distributed uniformly across all of the incremental wind energy. Thus, for example in Case 8, all of the wind energy added after 2013 is "worth" $62/MWh in avoided variable operating cost. This does not reflect any value that might be realized from the exported excess wind power. Similarly, the energy from the Maritime Link is "worth" $75/MWh in avoided variable operating costs.

**Figure S 11: Average Avoided Variable Operating Cost due to Wind or Maritime Link Energy**

### S.4.4 Marginal Values

It is also illuminating to examine the "marginal value" of the wind and Maritime Link energy. In this context, the question is slightly different from the comparison with Business-as-usual. Here the *marginal* value shows how much variable operating cost is reduced (or avoided) by the addition of wind or Maritime Link imports. This is determined by removing a small amount of the wind generation, and calculating the incremental cost of operation. These marginal values are shown in Figure S 12.




| | CASE 1 | CASE 2 | CASE 3 | CASE 4 | CASE 5 | CASE 6 | CASE 7 | CASE 8 | CASE 9 |
|---|---|---|---|---|---|---|---|---|---|
| Savings ($/MWh) | $55.8 | $62.8 | $55.8 | $68.0 | $56.8 | $56.3 | $48.8 | $65.3 | $52.8 |

**Figure S 12: Marginal Value of Wind in terms of Production Cost Savings**

The marginal values for wind energy range from a low (Case 7) of $49/MWh to a high of $68/MWh (Case 4). This marginal value could be considered an "entitlement" against which the cost of the wind power (in total, including PPAs) is evaluated. So, for example, the next MWh of wind power added in Case 7 (2020 In-province wind with retired large industrial load) will save $49/MWh in variable operating cost. A PPA that paid $49/MWh would be production cost neutral. From a policy and cost perspective, the critical observation is that the PPA price level will have no impact on the production cost savings. Close scrutiny of the PPA prices is warranted, but is not part of the scope of this study.

A similar approach was used to calculate the value of energy imported on the Maritime Link. The marginal value of that energy ranges from $58/MWh (Case 9 – No large industrial load) to $72/MWh (Case 8 with PH load). In Figure S 13 the marginal value of the last MWh of Maritime Link energy is shown in comparison to the last MWh of wind energy in the Maritime Link cases.

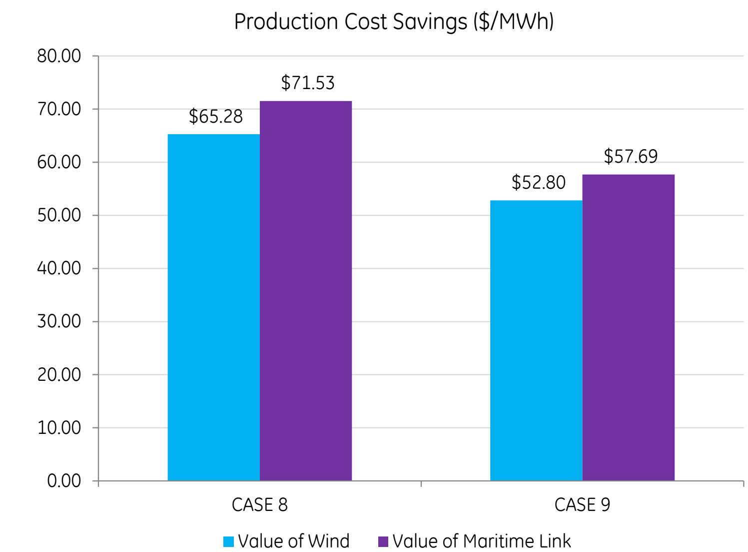



**Figure S 13: Marginal Value of Maritime Link and Wind in terms of Production Cost Savings**

## S.5 ENVIRONMENTAL IMPACTS

There are other benefits to adding renewable energy that are not reflected in the variable operating cost. The impact on carbon and sulfur emissions can be similarly calculated. The marginal reductions in $CO_2$ from wind energy range from about ½ to ¾ of a metric ton/MWh of wind, as shown in Figure S 14.

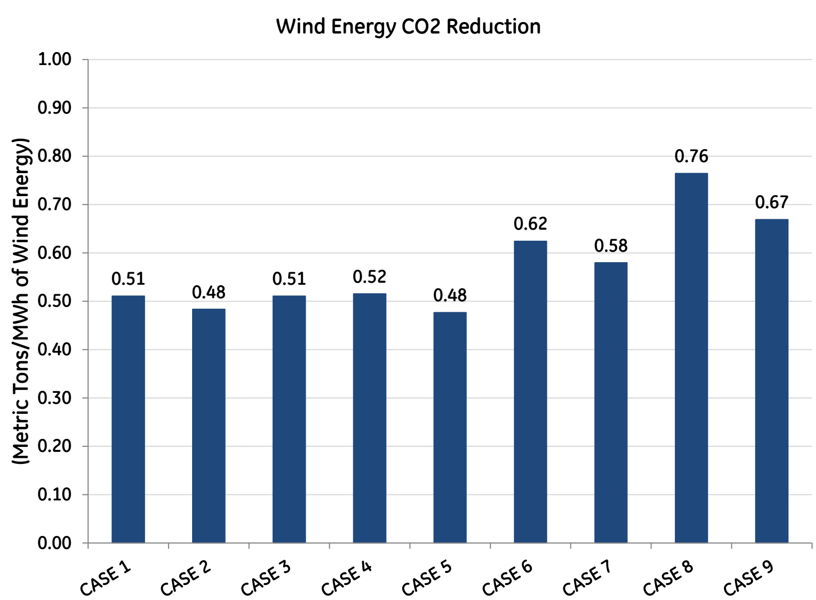



**Figure S 14: Marginal CO2 Reduction from Wind Energy**

The Maritime Link marginal reductions in $CO_2$ range from 0.84 to 0.92 of a metric ton/MWh as shown in Figure S 15. SOx emissions drop about 1.5 to 3 kg/MWh in cases where wind power is added to the system and 4.2 to 4.3 kg/MWh for energy from the Maritime Link. All of the cases studied achieve the emission cap assumptions provided by NSPI.

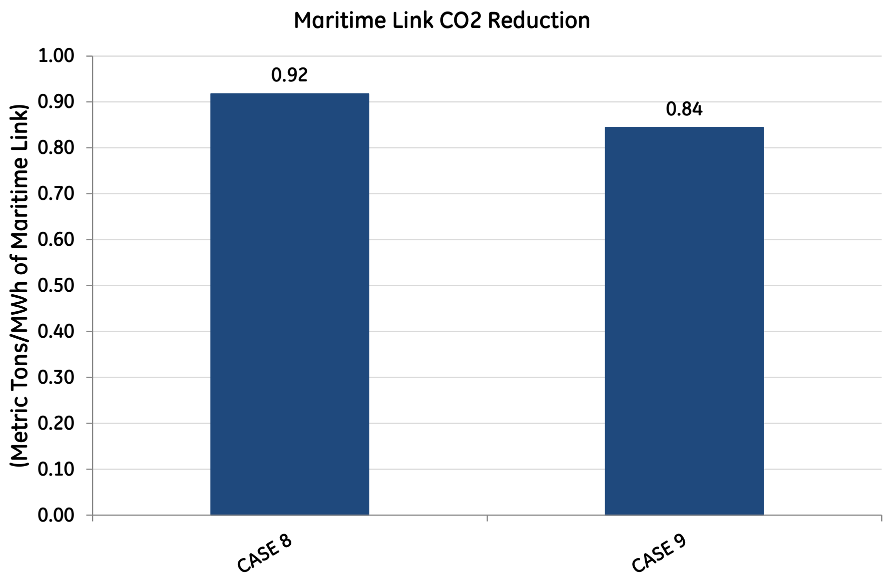



**Figure S 15: Marginal CO2 Reduction from Maritime Link**

## S.6 CONCLUSIONS AND RECOMMENDATIONS

While this study concludes that it is technically feasible to integrate large amounts of wind power in Nova Scotia, it would not be without significant impact to Nova Scotia Power's customers and the utility. In the high-wind penetration cases, there are a number of risks and potential outcomes that require careful consideration, and may warrant mitigation. Some of these include:

- The number of hours that NSPI's Large Industrial Interruptible customers would be interrupted would increase by approximately 50 to 330 hours (about 150 to 400 percent) relative to 2012, depending on the case. The cases including the Maritime Link would see the level of potential Large Industrial Interruptible customer interruptions reduced by 60 to nearly 100 percent of the levels experienced in 2012.
- Curtailment of wind energy would increase dramatically over the level experienced in 2012. Low levels of wind curtailment necessary to provide intra-hour balancing when other NSPI resources are at minimum will occur often. Wind generators could see reduced revenues due to increased curtailments if they are not paid for curtailed energy.

- Export of excess wind energy would increase by approximately 120 to 180 GWh (10 to 16 times) relative to 2012. Total forced curtailment and export of wind energy can approach 10% of total wind energy, in the most extreme wind penetration case. The cases including the Maritime Link would see export of excess wind generation increase by approximately 20 to 130 GWh (two to 12 times) relative to 2012. The modeling completed in this study assumes that there would always be a market outside of Nova Scotia to export this excess wind energy to, but NSPI would need to further evaluate this potential. Inability to export excess wind energy would result in higher levels of curtailment than those found in this study. The variable costs reported throughout this report assume that exported wind power has zero value, and therefore neither curtailed nor exported wind power produces any benefit in terms of avoided variable cost of operation.
- NSPI's existing thermal generating plants would experience higher levels of cycling than they do today. In 2012, each coal plant would have approximately 10 starts per year. By 2020, the average number of starts for each coal unit increases to 17 in case 6A and the number of starts and stops on each gas-fired steam units could increase to as much as 36 per year in case 6A; which is an increase of approximately 200% over the number of starts and stops in 2012 (case 1A). The mileage (the sum of the absolute value of the total hourly MW changes in dispatch) on coal generating units would increase by 20% to 30%. NSPI may wish to undertake further study to evaluate if its existing thermal generating fleet can sustain the impact of these increases in cycling and operational maneuvering.
- Maintenance costs for thermal plants would increase. Although it was not in the scope of this study to quantify this cost, work sponsored by NREL shows that incremental wear and tear could reduce the variable cost savings due to the wind power between \$0.06 and \$2.0 per MWh of wind. Thus, the savings summarized in Figure S 12 might be reduced as much as \$2.
- Operating practices would need to change.

Achieving 2020 renewable electricity requirements in the high wind energy cases would require much more than increasing the installed wind capacity to the levels shown in Table S 1, which in some cases are nearly three times the present-day capacity. In order to integrate this amount of wind energy and continue to operate and manage the power system in a reliable, economical and effective manner, a number of additional investments and changes to existing operating practices and procedures would be required. This study examined a wide variety of options for improving the ability of the system to accommodate high levels of wind energy. A combination of some or all of these options will be needed. Some of these include:

- Add dispatchable, high-efficiency, fast-acting generation for capacity reasons and operational flexibility.

- Investigate the physical limits on the operational flexibility of existing hydro and thermal resources and develop strategies and make investments to maximize the operational flexibility of these generating resources.
- Invest in maximizing the flexibility of the interconnection with New Brunswick to improve the availability of this tie and also increase the capacity for both import and export. Also work with New Brunswick to address any constraints on the NB system that currently limit the capability to import firm energy into Nova Scotia.
- Investigate the ability of New Brunswick and markets further afield to accept (and pay for) excess wind power from Nova Scotia.
- Require all wind plants to have the capability to participate in real-time balancing by having the capability to accept and impose curtailments immediately and at frequent (sub-hourly) intervals.
- Require wind plants to have the capability to provide primary frequency response, especially when curtailed.
- Invest in advanced wind forecasting tools and capabilities. All systems with high wind energy penetration world-wide have reached this conclusion. Investments in physical and personnel expansions in both operations and planning will be required.
- Further develop and consider incentivizing responsive, agile demand side resources to address the significant increases in customer interruptions that are expected.
- Investigate and consider adding short-term energy storage.
- Carefully consider reserves and refine the reserve strategy. Consider all of the resources that can provide reserve as part of a refined strategy to ensure the higher reserve requirements are met in the most reliable and economic manner.
- Re-examine system stability in high-wind penetration cases and make the investments required in the transmission system to mitigate any system stability risks.

It should be noted that some of the mitigating actions will still be required for the lower, but still substantial, levels of wind penetration that would still exist in the Maritime Link cases, and the corresponding costs should be accounted for in any planning cost-benefit analysis.

## S.7 FUTURE ANALYSIS:

This study, while extensive, does not cover all issues. In particular, addition of large amounts of wind and addition of the Maritime Link will substantively alter the dynamics of the system. Investigation into the NSPI system stability, and stability constraints, is warranted. The investigation should include consideration of wind plant functionality that is being required by other grid operators around the world to help cope with high wind penetration levels. These investigations may impact must-run limitations imposed on our model, as well as reserve requirements. Changes in those limits could impact economy and curtailment. Delivery of reserves may be affected.

The operation of the Maritime Link could be a resource for operational flexibility that will significantly aid in operations. Further analysis of possible characteristics of the tie and the contractual commitments that accompany it are warranted. This analysis may need to include some modeling or more information about the exporting system (In Newfoundland and Labrador). Similarly, the behavior of not only the New Brunswick tie, but the entire Northeast region, both Maritimes and New England, warrants closer investigation. Questions of technical and market ability to accept excess wind power will substantively impact the economics and practicality of large wind additions in Nova Scotia and economic imports on the Maritime Link.

As noted above, this study forms an essential foundation to future integrated resource planning. A comprehensive, multi-year IRP would aid in establishing the total cost impact for years beyond 2020 and the most economic long range plan for the system.

# 1 Introduction

## 1.1 Study Background

Nova Scotia Power Incorporated (NSPI) is a regulated, vertically-integrated, electric utility. NSPI has produced and supplied electricity to Nova Scotia for over 80 years. The company supplies over 97% of the generation, transmission and distribution of electrical power to more than 460,000 customers in Nova Scotia. NSPI owns 2,293 megawatts (MW) of generation capacity, fuelled by a mix of renewable energy sources and fossil fuels. NSPI manages 5,200 km of transmission lines which move electricity from its generating plants to the 25,000 km of distribution wires that supply power to customers' homes and businesses. Together, they make up the transmission and distribution system that connects NSPI to the North America electricity grid through New Brunswick.

Nova Scotia Renewable Energy Standard (RES) Regulations require that NSPI supply its customers with renewable electricity in an amount equal to or greater than 25% of its total energy sales by 2015. It is also expected that by 2020, NSPI will be required by an amended RES to supply its customers with renewable electricity in the amount equal to or greater than 40% of its total sales. In order to comply with RES regulations, NSPI has made significant contractual commitments with Independent Power Producers (IPPs) and utility capital investment in the past few years to add wind generation and is planning to move forward with projects that will add additional wind generation between 2012 and 2020.

General Electric International, Inc. (GE) was engaged by Nova Scotia Power, Inc. (NSPI) to perform a renewable energy integration study (REIS) in order to quantify the impacts of increasing renewable energy penetration on the operation and reliability of the Nova Scotia power system, to evaluate performance and operating costs, and to consider methods and approaches to mitigate the adverse impacts of renewable energy integration. The intent is to provide guidance and quantitative metrics to aid NSPI in future development decisions.

Four primary analytical methods were used to meet this objective; statistical analysis, hourly production simulation analysis, sub-hourly production simulations, and reliability and wind capacity valuation analysis.

The study considers nine study cases covering years 2012, 2013, 2015, and 2020. Two different outlooks on the system load were considered for future years, namely, one without two major industrial loads, and one with only one of those two loads. Furthermore, the 2020 cases considered the impact of meeting the 40% renewable energy target with and without the Maritime Link.

GE performed a large number of sensitivities in order to evaluate the robustness of the system to handle uncertainty and variability of the wind power, and to appraise the impact of various drivers and variables on system performance, both operational and economic. A complete listing of the sensitivities performed is included in Section 7.3 of this report.

## 1.2 Study Objectives

The principal objectives of the REIS study were to:

1. Narrow options for future system development plans that would enable increasing renewable energy penetration in Nova Scotia.
2. Determine the feasibility and quantify the impacts of increasing penetration of wind power, in some cases to very high levels, on the operation, reliability and operating costs of the Nova Scotia power system.
3. Evaluate and recommend possible methods and options to mitigate reliability, power system performance and operational economic risks associated with high levels of wind penetration.

To meet these objectives, GE performed a number of detailed security constrained unit commitment and economic dispatch (SCUC/ED) modeling simulations of the Nova Scotia power system for current and a number of future years under different load and resource conditions.

NSPI will determine capital costs of selected mitigation methods, combine that information with system performance and operating cost results from this study, and determine the best options for future system investments to meet Nova Scotia's renewable energy requirements.

## 1.3 Analytical Methods

The primary objective of this study was to identify and quantify any system performance or operational problems with respect to load following, regulation, operation during low-load periods, etc. Four primary analytical methods were used to meet this objective; statistical analysis, hourly production simulation analysis, sub-hourly production simulations, and reliability analysis.

- **Statistical analysis** was used to quantify variability due to system load, as well as wind generation over multiple time frames (annual, seasonal, daily, hourly, and 10 minute). The power grid already has significant variability due to periodic and random changes to system load. Typically wind generation (and solar generation, in power systems with significant deployment) add to that variability, and increase what must be accommodated by load following and regulation with other generation resources. The statistical analysis quantified the grid variability due to load alone over several time scales, as well as the changes in grid variability due to wind generation for each scenario. The statistical analysis also characterized the forecast errors for wind generation.

- **Production simulation** analysis with GE MAPS was used to evaluate hour-by-hour grid operation of each scenario with different wind and load profiles. The production simulation results quantified numerous impacts on grid operation including:
    - Amount of maneuverable generation on-line during a given hour
    - Effects of day-ahead (DAH) wind forecast alternatives in unit commitment
    - Changes in dispatch of conventional generation resources due to the addition of new renewable generation
    - Changes in emissions (SOx and CO2) due to renewable generation
    - Changes in costs and revenues associated with grid operation, and changes in net cost of energy
    - Changes in intertie loadings
    - Changes in use of hydro resources
    - Changes in use and economic value of demand response resources
    - Number of unit start-ups and hours on line during the year
- **Sub-hourly simulation** analysis with PLEXOS was used to quantify grid performance trends and to investigate potential mitigation measures in the 10-minute time frame. The sub-hourly analysis simulated the operation of dispatchable generation resources as well as variable wind generation in the study footprint using 10-minute time steps for selected days, while enforcing constraints related to unit ramp rates, ramp range, and intertie flow schedules. These simulations enabled examination of the responsiveness of NSPI resources in mitigating impact of wind generation in sub-hourly periods.
- **Wind Capacity valuation** involved loss of load expectation (LOLE) calculations for the study footprint using the GE MARS software. The analysis quantified the impact of wind generation on overall reliability measures, as well as the capacity values of the wind generation resources.

Impacts on system-level operating reserves were also analyzed using a variety of techniques including statistics and production simulation. This analysis quantified the effects of variability and uncertainty, and related that information to the system's increased need for operating reserves to maintain reliability and security.

The results from these analytical methods complemented each other, and provided a basis for developing observations, conclusions, and recommendations with respect to the integration of wind generation into the NSPI power grid.

## 1.4 Major Tasks

The work was divided into six tasks. A brief overview of each task is presented here. Detailed task descriptions are included in the next section of this report.

- Statistical Analysis and Wind Profile Development: This task developed wind profiles for the NSPI REIS with sufficient accuracy and flexibility to enable simulation of power system and renewable generation operation over the time scales of interest; hourly operations for multiple years and sub-hourly operations for selected days. The wind production and DAH forecast profiles were derived from a combination of NSPI historical wind plant output data and meso-scale wind data for Nova Scotia originally developed by AWS Truepower (referred to as "AWS" or "AWST" in the remainder of this report) for the New England Wind Integration Study performed by GE for the ISO-NE. Permission has been granted by the ISO-NE to GE to use this data source, and AWST assisted GE in extracting the necessary plant-specific wind profile data for the study scenarios.
- Modeling of the NSPI Power System: This activity focused on the development of various study cases developed in accordance with the NSPI specifications, and finalized in consultation with NSPI. GE worked with NSPI to identify specific details (e.g. transmission and generation changes) necessary for each of the scenarios. This task also included statistical analysis to establish preliminary requirements for regulation, load-following, spinning reserve and other criteria necessary to provide meaningful boundary conditions for subsequent time-domain simulations. This task also identified "challenging" time periods to consider for detailed sub-hourly analysis (e.g., periods with large ramp events, or high variability, or low net load).

  This task entailed performing a detailed evaluation of the impact of renewable energy generation variability and uncertainty on NPSI's operations for each study case. This work included extensive time simulations, for full years of operation as well as more detailed, sub-hourly examination of challenging periods. This task quantified a wide range of system performance and cost parameters, including:

  - Regulation and reserve requirements
  - Load-following performance
  - Undelivered wind/renewable energy (curtailment)

- Load not served (Demand Side Management (DSM), Demand Response (DR), and involuntary interruptions)
- Control performance or reliability violations
- Variable operating costs
- Starts, stops, peaking unit utilization
- Changes in emissions
- Impacts of DAH forecast utilization
- Changes in demand response utilization
- Changes in energy exchange with neighboring systems

The results of this task also identified, and quantified to the extent possible, performance impacts that may require mitigation – which fed into the next task.

GE's proprietary Concorda Software Suite's Multi-Area Production Simulation (GE MAPS) model, which is a chronological hourly security constrained unit commitment and economic dispatch (SCUC/ED) model, was used to simulate the hourly operation of the NSPI system for the study years using production cost data (generator, load and transmission topology) and the regulation and load following requirements identified in the statistical analysis. In addition, the GE MAPS hourly simulations were used to identify challenging days to be analyzed in more detail using Energy Exemplar's PLEXOS power system modeling model for sub-hourly simulations. PLEXOS was used to simulate near real-time operations of the NSPI system, with 10-minute time-steps, close to the economic dispatch update period used in power system operations. The PLEXOS analysis was intended to provide more detailed view of the ability of the NSPI system resources to accommodate the variability and uncertainty associated with the levels of wind generation in selected study scenarios.

- Sensitivity Analysis and Mitigation Measures: This task examined several alternative methods to mitigate unacceptable or undesirable impacts of increased wind energy penetration, including:

  Examples of candidate measures that were investigated included:

  - Power plant modifications such as: change in plant minimum load and change in steam unit collective operations
  - New generation resources
  - Flexible operation of Wreck Cove
  - Flexibility in scheduling of NB imports
  - Wind forecast accuracy

- Change in spin reserve requirements
- Role of demand response

The impacts, efficacy, and benefits of these and other mitigation alternatives were quantified by performing a long list of sensitivity analysis.

- Wind Capacity Evaluation: This task evaluated the capacity value of the wind resources in Nova Scotia, using rigorous Loss of Load Expectation (LOLE) methods. The LOLE analysis determined the Effective Load Carrying Capability (ELCC) of the incremental wind generation additions.

  This task utilized GE's proprietary Concorda Software Suite's Multi-Area Reliability Simulation (GE MARS) software to perform the analysis.

- Reporting: This task involved the development of this document as the final project report documenting the analytical results of Tasks 1-5, including, (a) quantifying the impacts of increasing penetration of wind power on the operation and reliability of the Nova Scotia power system, and (b) evaluating possible mitigation methods, including system performance and variable cost impacts. The results are expected to help NSPI narrow "least regret" options for future system development that enable increasing levels of renewable generation. Figure 16 provides a flow chart representation of the project tasks. More detailed exposition of each task is provided in the next section.

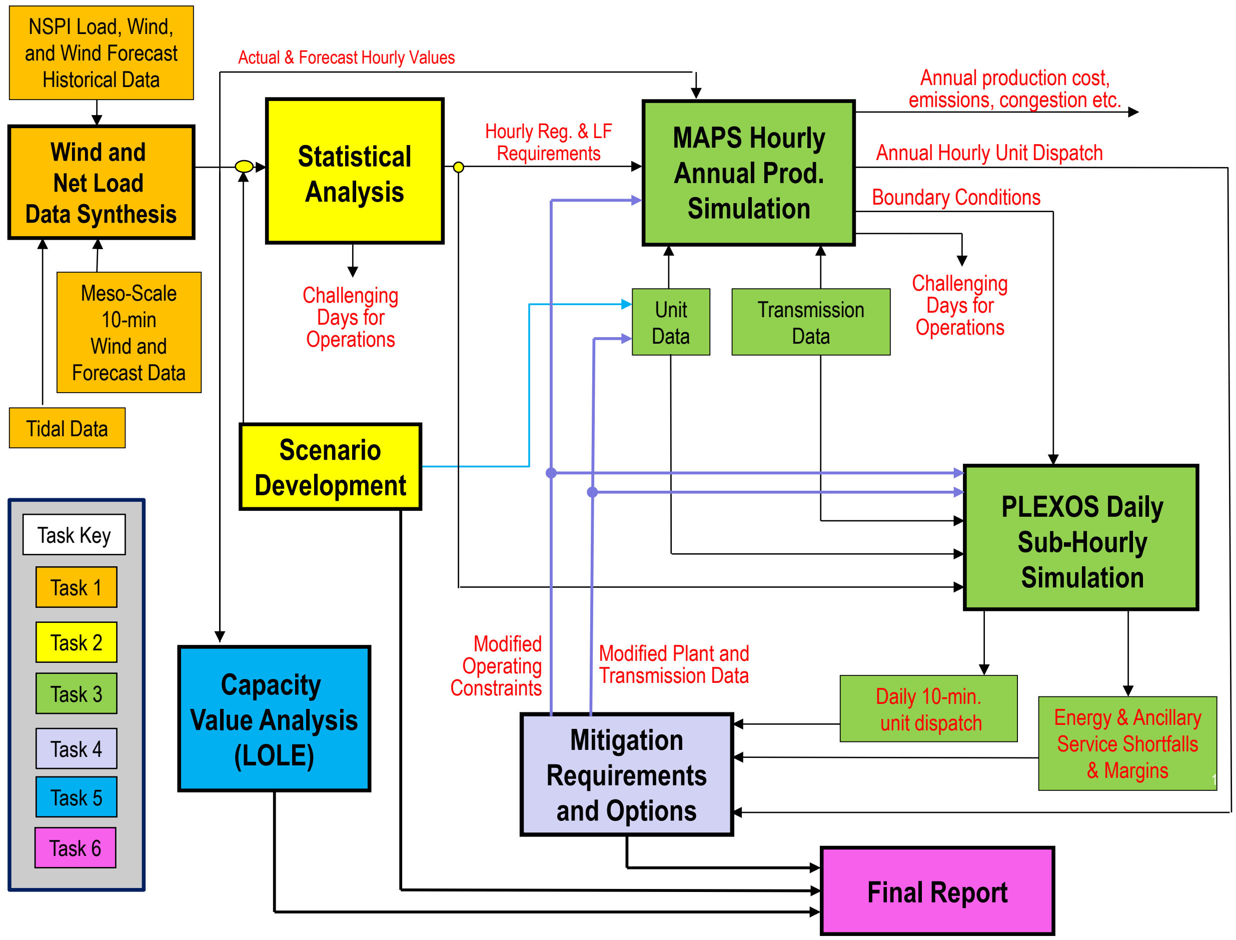



**Figure 16: Project Task Flowchart**

## 1.5 Study Cases

The final study considered nine cases (also called scenarios) which covered different years including 2012 (base case), 2013, 2015, and 2020; and different outlooks on future load, i.e., with and without some industrial loads; and in the case of year 2020, with and without the Maritime Link.

The two future outlooks on load considered two possibilities:

a) a future load outlook without the two major industrial loads of Bowater paper mill (Bowater) and Port Hawkesbury PM2 paper mill (PH PM2)

b) a future load outlook with only PH PM2 in operation

The nine cases are listed herein:

- Case 1: Year 2012 No Large Industrial Load, With 335 MW of Wind, No Maritime Link
- Case 2: Year 2013 With Large Industrial Load, With 335 MW of Wind, No Maritime Link

- Case 3: Year 2013 No Large Industrial Load, With 335 MW of Wind, No Maritime Link
- Case 4: Year 2015 With Large Industrial Load, With 488 MW of Wind, No Maritime Link
- Case 5: Year 2015 No Large Industrial Load, With 488 MW of Wind, No Maritime Link
- Case 6: Year 2020 With Large Industrial Load, With 916 MW of Wind, No Maritime Link
- Case 7: Year 2020 No Large Industrial Load, With 796 MW of Wind, No Maritime Link
- Case 8: Year 2020 With Large Industrial Load, With 551 MW of Wind, With Maritime Link
- Case 9: Year 2020 No Large Industrial Load, With 551 MW of Wind, With Maritime Link

More detail on each study case is provided in Section 4.

# 2 Study Approach

The section describes the approaches used to perform various tasks in this study.

## 2.1 Statistical Analysis and Wind Profile Development

One of the first tasks was to develop wind and load profiles for the NSPI REIS with sufficient accuracy and flexibility to enable simulation of power system and renewable generation operation over the time scales of interest, namely, hourly operations for multiple years, and sub-hourly operations for selected days. The wind production and DAH forecast profiles were derived from a combination of NSPI historical wind plant output data and meso-scale wind data for Nova Scotia originally developed by AWST for the New England Wind Integration Study performed by GE for the ISO-NE. Permission was granted by the ISO-NE to GE to use this data source, and AWST assisted GE in extracting the necessary plant-specific wind profile data for the study scenarios.

### 2.1.1 Collecting Wind Plant Output Data

GE has considerable experience in development of wind output and forecast data for systems studies, which guided the wind profile development for this project. The vast majority of the data used in this project originates from the AWST meso-scale modeling.

Extensive meso-scale modeling of wind in the Maritimes, including Nova Scotia, had been performed in support of the GE's New England Wind Integration Study performed for the ISO-NE. Meso-scale data on 2 $km^2$ cell resolution for the province was provided by AWST to GE covering years 2004, 2005, and 2006. This AWST data included production by cell at 10-minute resolutions, and synthetic forecasts. Synthetic four-hour, six-hour, and next-day wind power forecasts were generated for each site.

The process of creating synthetic forecasts combines the AWST eWind® forecasting system with observed output at actual wind plants to develop a set of transition probabilities. The probabilities are applied to simulated plant output data, stepping forward in time using a Markov chain approach. This process results in a synthetic forecast that imitates the statistical behavior of a real forecast.

NSPI also supplied a large amount of high fidelity measured and historical data from their existing wind plants, which were used for comparison with and verification of the suitability of the AWST data for the analysis.

### 2.1.2 Verification of Wind Plant Output and Forecast Data

Although actual production records exist for actual wind farms in the NSPI system, available data is for more recent periods than the meso-scale data. Since this period of record is misaligned with synthetic wind plant output data (which requires alignment/coincidence of the year of load data and the year of wind data to account for wind energy and weather correlations), and data exists only for existing wind farms, meso-scale production and forecasts are needed for all hypothetical sites for the same period as the study data.

The analysis used the actual NSPI plant forecast data to calibrate and validate the synthetic AWST real-time and forecast wind data, but considering both hourly and 10-minute data. The main tasks included the following:

- Identification of valid and invalid NSPI and AWST data.
- Smoothing and sampling of actual NSPI production data to create 10-minute periodicity profiles.
- Selection of sites within the AWST data set to approximate, as closely as possible, existing and future Nova Scotia wind plant sites.
- Matching of AWST data to existing and future NSPI wind plant locations.
- Scaling of production (and forecast) data for selected sites to match the MW rating of the existing Nova Scotia wind plants.
- Comparison of hourly and 10-minute NSPI and AWST wind shapes for similarity.
- Performing a sequence of hourly and 10-minute variability analysis (based on hourly and 10-minute delta, i.e., change, in the level of wind).
- Development of critical metrics of variability for the two sequences for comparison, including 10-minute sigma (i.e., standard deviation of delta), extreme variability outliers, and others.
- Comparison of the statistical measures of variability of NSPI and AWST data.
- Verification of suitability of AWST data to represent the wind power generation in Nova Scotia.
- Establishment of wind driven ancillary reserve requirements based on the calculated wind variability measures.

Details of the analysis are provided in Section 3.

## 2.2 Modeling of the NSPI Power System

### 2.2.1 GE MAPS Based Hourly Analysis

GE used its proprietary Concorda Suite's Multi-Area Production Simulation (GE MAPS) software to simulate the hourly operation of the NSPI system for the study years using production cost data (generator, load and transmission data) provided by NSPI and the hourly regulation and load following requirements identified in the statistical analysis. GE MAPS is a chronological hourly security constrained unit commitment and economic dispatch (SCUC/ED) model. GE MAPS is ideally suited to this study since it simulates a power system from the point of view of a system operator – performing an N-1 security constrained system dispatch with complete and detailed transmission modeling. GE MAPS has been continuously developed, refined and benchmarked for over 30 plus years and has been applied for system economic analyses for the entire U.S., Canada and many parts of the world. Additional information about GE MAPS is provided in the Appendix.

The simulation outputs include, but not limited, the following:

- Annual production cost (variable operating cost)
- Locational Marginal Prices (LMP)
- Transmission congestion
- Changes in emissions (SOx, and CO2)
- Undelivered (i.e., curtailed or spilled) renewable energy
- Demand response deployed and load not served
- Unit performance
- Starts, online hours, peaking unit utilization, cycling, etc.
- Impacts of Wind Forecast error
- Tie-Line Utilization with neighboring system
- Others

The GE MAPS production simulations employed in this study were conducted chronologically at one-hour time steps. Consequently, the real-time adjustments of generation to compensate for variations in the balancing area net demand were not modeled explicitly. Instead, the responsive generation that would be necessary in a given hour to regulate and balance was represented as constraints on the unit commitment and economic dispatch algorithms in the production model. The determination of the appropriate constraints that reflect the additional variability and short-term uncertainty introduced by wind generation was the objective of the statistical analysis. Those "operating rules", which used current hour values of load and wind generation along with forecasts of those quantities, were entered into the model as reserve constraints for each hour of the production simulation. The commitment, dispatch and cost implications of those reserves were reflected in the GE MAPS results.

GE MAPS was also used to quantify the hourly operation of each individual generator in NSPI. This information was fed into the overall analysis of simulation results to help identify and quantify performance that might require or benefit from mitigation options. In addition, the GE MAPS simulation also identified challenging days for further PLEXOS analysis.

In addition to the detailed representation of the NSPI power grid modeled in the GE MAPS, the New Brunswick (NB) and the outside world, including Maritime Link (ML), were represented as equivalent load and resource elements with corresponding price curves.

The final cases defined by NSPI were used to develop a database of profile data for load and wind generation. The resulting database contained multiple tables of information including:

- Raw profile data at the highest available resolution.
- Average hourly values, computed from the raw profile data.
- Scaling information to project to 2020 and intervening study years load from historical profiles.
- Scenario definitions identifying renewable generation project capacities and corresponding injection bus for the power-flow and production simulations models.
- Any other information, as necessary for constructing the study cases.

### 2.2.2 Development of Study Cases

The study utilized a case-based analysis for analyzing future growth in renewable energy penetration for the NSPI system. After GE performed a number of preliminary model runs based on the initial selected study cases and reviewed the results with NSPI, a final set of study cases were identified by NSPI covering different years into the future.

**Table 2: Summary of the Study Cases**

| Case ID | Year | Industrial Load | Maritime Link | Wind Capacity | Available Wind Energy |
|---|---|---|---|---|---|
| **Case 1** | 2012 | No | No | 335 MW | 1,148 GWh |
| **Case 2** | 2013 | Yes | No | 335 MW | 1,148 GWh |
| **Case 3** | 2013 | No | No | 335 MW | 1,148 GWh |
| **Case 4** | 2015 | Yes | No | 488 MW | 1,661 GWh |
| **Case 5** | 2015 | No | No | 488 MW | 1,661 GWh |
| **Case 6** | 2020 | Yes | No | 916 MW | 3,102 GWh |
| **Case 7** | 2020 | No | No | 796 MW | 2,685 GWh |
| **Case 8** | 2020 | Yes | Yes | 551 MW | 1,871 GWh |
| **Case 9** | 2020 | No | Yes | 551 MW | 1,871 GWh |

For the purpose of this proposal, a “case” or a “scenario” is defined as a specific combination of system topology, generation fleet, and ratings/locations of wind, tidal and biomass plants, and a load outlook with and without selected industrial loads for a given year. A “sensitivity” is defined as a change to some parameter in a case (e.g., load, fuel cost, etc.) while keeping the topology, generation fleet, and ratings/locations of wind and new renewable plants the same. A study "case" or "scenario" requires significant effort to set up the system configuration, while a "sensitivity" analysis requires much less effort as only one (or a few) data item is changed.

A major effort entailed identification of specific wind projects consistent with the cases. The locations of these wind facilities were based on proposed wind plants in the NSPI generation queue and resource plan, augmented by additional resources as needed to reach the levels listed by NSPI, and other forecast changes to the NSPI portfolio. The underlying system transmission grid topology was based on transmission system model provided by the NSPI transmission team, consistent with this level of wind generation, as well as non-conforming year 2020 loads (i.e. possible large discrete loads that are not typically captured by scaling of historical load profiles) and other planned new generation facilities.

As shown in Table 2, the study cases for each selected future year. i.e., 2013, 2015, and 2020, consider two distinct possibilities, namely:

a) a future load outlook without the two large industrial loads of Bowater paper mill (Bowater) and Port Hawkesbury PM2 paper mill (PH PM2)

b) a future load outlook with only PH PM2 in operation

The study cases for year 2020 also consider the impact of future power imports from the Lower Churchill Project through the Maritime Transmission Link (Maritime Link). More detailed descriptions of study cases are provided later.

GE worked with NSPI to define all the necessary assumptions for each scenario, including amount of renewable energy (type, rating, and location), energy interchange with New Brunswick (NB), and any new NSPI infrastructure that defined each scenario. Characterization of the new biomass generation, including operational characteristics and constraints were provided. Similarly, Community Feed-in-Tariff (COMFIT) resources were characterized in terms of size and distribution.

### 2.2.3 Simulation and Analysis

After selection of case studies a detailed evaluation of the impact of renewable energy generation variability and uncertainty on NPSI's operations for each study case was performed. The evaluation included extensive GE MAPS simulations for full years of operation as well as more detailed, sub-hourly PLEXOS examination of challenging periods.

The new biomass, small hydro, COMFIT and transmission resources were added to the GE MAPS and PLEXOS production simulation models. These new resources were characterized and modeled as hourly load modifiers, i.e., with fixed generation pattern and not subject to being dispatched by the operator's instructions. It was also assumed that small hydro resources are scheduled "must take" generation. The curtailments of these resources were set to occur only after wind curtailment.

NSPI provided the transmission model (with changes in the future) that was built into the GE MAPS database. NSPI also provided a list of transmission interfaces to monitor (and limit) based on operating experience and present stability constraints. In addition to transmission constraints, GE also modeled other market and operational procedures in the GE MAPS program based on consultation with NSPI.

### 2.2.4 PLEXOS Based Sub-Hourly Analysis

The GE MAPS hourly simulations were used to identify challenging days to be analyzed in more detail using Energy Exemplar's PLEXOS power system modeling model for sub-hourly simulations. PLEXOS was used to simulate near real-time operations of the NSPI system, with 10-minute time-steps, close to the economic dispatch in actual system operations. The PLEXOS analysis was intended to provide more detailed view of the ability of the NSPI system resources to accommodate the variability and uncertainty associated with the levels of wind generation in selected study scenarios.

The maintenance, wind and hydro schedules from the GE MAPS simulation were entered into the PLEXOS model for the selected days of interest in selected study cases. The PLEXOS simulation analyzed sub-hourly thermal dispatch and potential short-term operational issues in the selected case.

## 2.3 Sensitivity Analysis and Mitigation Measures

### 2.3.1 Sensitivity Analysis

In addition to the different combinations of renewable energy penetration and siting, the analysis considered a range of sensitivities. As described in more detail later, sensitivity analysis was used to examine impacts of wind forecast accuracy, fuel prices, wind plant characteristics, and other drivers on selected cases. These sensitivities were analyzed across all of the study cases, except for years or cases where the underlying sensitivity driver was not applicable. For instance, a sensitivity related to Maritime Link, was applied only to 2020 cases with Maritime Link.

Through sensitivity analysis, changes to NSPI infrastructure and operations that could improve system performance were investigated. Extensive analysis of the performance based on the present baseline trajectory was performed, and a range of options were tested for effectiveness in relieving problems or improving performance.

### 2.3.2 Mitigation Measures

This activity examined the performance of the system with intent of providing focus on candidate measures for improvement of system performance. These were broadly termed mitigation measures, since the highest priority was to identify means of correcting inadequacies, particularly violations of reliability or other rules. Most importantly, violations of firm reserve criteria, unserved load, and other serious problems were of greatest concern. However, the issue was taken to be rather broader than that, and included measures that could improve otherwise acceptable performance, to shift or rebalance the criteria, or make performance more robust. For example, while curtailment of renewable production may allow the system to meet operating and reliability criteria, means to reduce renewable curtailment were also considered. Similarly, the most economic operation of the system may be shown to have consequences such as less reduction of carbon dioxide or other emissions than expected with large amounts of wind.

The performance issues that were identified by examination of Base Case results cover a broad spectrum. Various classes of concerns, similar to experiences in other renewables integration studies, included (not in a specific order of severity or priority):

- Load Impacts: Unserved load and use of demand response
- Reserve Impacts: Reserve costs
- Energy Impacts: High wind curtailment
- Emissions Impacts: $CO_2$ and $SO_2$ emissions
- Operations Impacts: High thermal plant cycling
- Economic Impacts: High variable cost of operations (VOC)

The sensitivity based mitigation analysis was explicitly designed to allow for addition of, but also prioritization of, concerns for further mitigation investigation.

Examples of candidate measures that were investigated included:

- Power plant modifications such as: change in plant minimum load and change in steam unit collective operations
- New generation resources
- Flexible operation of Wreck Cove
- Flexibility in scheduling of NB imports
- Wind forecast accuracy and use
- Change in spin reserve requirements
- Role of demand response

Investigations were structured around specific performance concerns, rather than specific mitigation technologies. The systemic benefits of competing mitigation measures can be evaluated against costs of implementation. The simulation work provided quantitative insight into the benefits of selected technologies and approaches, which was the primary objective of this effort. However, to get a clear picture of the *efficacy* of different approaches, the cost information of those approaches must be considered. This information will be primarily the responsibility of NSPI, but GE will be available to work with NSPI to provide additional inputs in areas involving new technology with which NSPI may have less familiarity.

Since some options will produce benefits for more than one performance concern, the evaluation of mitigation measures cannot be solely based on individual issues, but rather must look across the spectrum (rows) as well. Since it is unlikely that a single technology or approach will be sensible for addressing all performance concerns, the structure of this analysis was intended to provide meaningful quantitative and comparable results without resorting to the impossible approach of evaluating all possible combinations of measures.

## 2.4 Capacity Value Analysis

The objective of this task was to quantify the capacity value of wind generation in Nova Scotia using loss of load expectation (LOLE) calculation methods, and to benchmark/calibrate approximate capacity value calculation methods against the rigorous LOLE method. Since the capacity value of wind power declines with increasing penetration, the analysis considered several wind penetration levels in Nova Scotia based on the study cases.

### 2.4.1 LOLE Analysis

A Loss of Load Expectation (LOLE) reliability evaluation was performed for each of the scenarios. GE Energy Consulting used its proprietary Concorda Suite Multi-Area Reliability Simulation Software (GE MARS) to calculate the daily Loss of Load Expectation (LOLE), (in days per year) for each Case. In addition to the daily LOLE, GE MARS also calculated hourly LOLE (hours per year) and Expected Unserved Energy (EUE) in megawatt hours (MWh) per year.

The LOLE analysis determined the Effective Load Carrying Capability (ELCC) of the incremental wind generation additions.

The daily LOLE determines the number of days on which an outage is expected to occur. Since typical generation outages are equally likely at any time of the day this index is historically calculated at the time of the system daily peak load. However, wind generation varies throughout the day. In recent work with the California ISO (CAISO [17]), GE Energy Consulting has expanded the GE MARS program to determine the daily LOLE while looking at every hour of the day. In this way any off-peak outages caused by significant drops in the wind generation will be fully accounted for.

### 2.4.2 Capacity Value and Loss-of-Load Expectation

Wind generation was divided into blocks, and each of the GE MARS cases quantified the incremental capacity value for each block of wind generation.

Based on the ratios of capacity among the areas in the target block, perfect capacity was added to the system to develop a capacity value curve. Perfect capacity is an ideal unit that has a fixed output for all hours of the year, with no outages. An advantage of perfect capacity over other methodologies is that it is independent of forced outage rate, unit size and load profiles which affect other measures. Perfect capacity can be converted into the capacity of a conventional thermal unit based on the forced outage rate of that unit.

Each block was modeled to determine the reliability of the system with that block installed. The equivalent perfect capacity was then determined by finding the amount of added capacity brought the system to the same level of reliability. Further, for most situations analyzed, we determined the amount of perfect capacity that could be needed to meet one-in-ten-year interruption reliability targets.

# 3 Statistical Analysis and Characterization of Wind Data

## 3.1 Wind Generation Variability

Wind generation cannot be perfectly forecast over any time horizon, since it is variable across time scales ranging from seconds to seasons. System load also exhibits variability and uncertainty across many operational time frames, and therefore, the impacts of wind generation on Nova Scotia Power operations are a function of the degree to which the wind variability and uncertainty increases the overall variability and uncertainty of the net load.

The general objective of the analysis in this section is to provide familiarity with the chronological load and wind data that are the primary inputs to the technical analysis described in later sections. It is generally not possible to extract quantitative conclusions about operating impacts directly from statistics of wind and load data.

While certain features may stand out from the perspective of system operations – such as lower net loads during off-peak hours – a range of other factors must be considered to determine the magnitude of the impact. Production simulations take a great number of these other factors into account as they seek to mimic the actual operation of the system against the array of operating constraints, and therefore are the better framework for drawing operational conclusions.

In the GE MAPS production simulations, individual plants were assigned to existing or planned network buses in the Nova Scotia grid model. In this statistical analysis and characterization, the aggregate production, i.e., the total generation of all wind is analyzed.

Operationally, the net of load and wind generation (i.e., the net load) will drive the decisions and algorithms for deployment of dispatchable resources (e.g., conventional generating units, energy transactions with neighboring markets and areas, and demand response). The net load analysis does not consider energy transactions with neighboring markets and systems, so the minimum hourly net load values for each study case cannot be used directly to assess implications for the Nova Scotia generation fleet. The price of the excess energy during these periods would be very low, and therefore possibly attractive to outside purchasers; energy sales might add to the demand served by Nova Scotia resources, but only if external purchasers are available.

Maximum net loads are also of interest, since wind generation would be expected to reduce the Nova Scotia peak load. The amount of this reduction would vary by study case and year, as would be expected from the differing generation makeup of each study case and the variability between years in terms of both load and wind resources.

Considering only minimum or maximum net load hours to draw some conclusions about the wind capacity values is not appropriate and is potentially misleading. The capacity value analysis described later in the report will consider not just the single minimum and maximum net load hours, but all hours of an annual period along with the important system risks to determine wind generation capacity contributions with a much higher degree of confidence. The rigorous analytical methodology used in this study to determine the capacity value of each wind scenario is much less prone to being influenced by a single hour of the chronological data.

The initial part of this section focuses on the variability of wind generation as defined by the study scenarios and how it combines with the inherent variability of Nova Scotia load.

Wind information were constructed by selecting grid cells and then the Individual cells were then grouped into "plants" for which chronological production data at ten-minute resolution over the calendar years 2004, 2005, and 2006 (years for which data were available) were extracted. The analysis first looks at hourly data over the entire three years of the available wind and load data. Variability and uncertainty are then examined with the 10-minute interval data.

Finally, the uncertainty and error characteristics of various forecasts available for the chronological wind production data are analyzed including the DAH and 4-hour-ahead forecasts. Other techniques important to the analysis presented later in the report, such as persistence forecasts, are also examined. The analysis here is conducted on an aggregate basis for the entire footprint; that is, the total generation for each time interval (10-minute, 1-hour, as appropriate) is considered, independent of where the individual virtual plants may be located.

The time horizons for which wind generation variability is important for power system operations range from tens of seconds to seasons. Over shorter horizons, the variability appears as almost random due to the extremely large number of factors that can influence production over this time frame. Over longer horizons, such as weeks or seasons, patterns reflecting the underlying meteorological drivers for wind generation can usually be discerned. Over longer time scales such as years, varying production is driven by even larger meteorological patterns that were first identified a few decades ago, e.g., the El Nino/La Nina cycle in the Pacific, and closer to New England, the North Atlantic Oscillation.

## 3.2 Validation of AWST Data by NSPI Data

### 3.2.1 Selection of Wind Data

The approach was built in part on the meso-scale models and 10-minute wind profile data (years 2004-2006) for the Canadian Maritimes that AWST had already developed for the New

England Wind Integration Study. ISO-NE granted GE permission to use this data source for the NSPI REIS and AWST assisted GE in extracting the necessary plant-specific wind profile and forecast data for the NSPI study scenarios.

The project team developed wind profiles and forecasts to enable simulation of power system and renewable generation operation over the time scales of interest; hourly operations for multiple years and sub-hourly operations for selected days.

The wind production and DAH forecast profiles were derived from a combination of NSPI historical wind plant output data and meso-scale wind data for Nova Scotia originally developed by AWST for the New England Wind Integration Study.

Since the main idea was to use the AWST data to represent the Nova Scotia wind sites, and to ensure the suitability of the ASWT data, we compared the NSPI wind sites with corresponding AWST sites, and verified the similarities of the AWST data characteristics with actual historical NSPI data. These comparisons and analysis are provided in the following sections.

### 3.2.2 NSPI Wind Sites and Corresponding AWST Sites

Eight (8) NSPI sites were matched with closest AWST sites. The AWST sites were scaled with the corresponding NSPI site ratings according to the following formula:

$$\textit{Wind Profile } x \, [MW_{NSPI} / MAX(MW_{AWST})]$$

Figure 17 provides an example of a comparative look at the NSPI and AWST wind data.

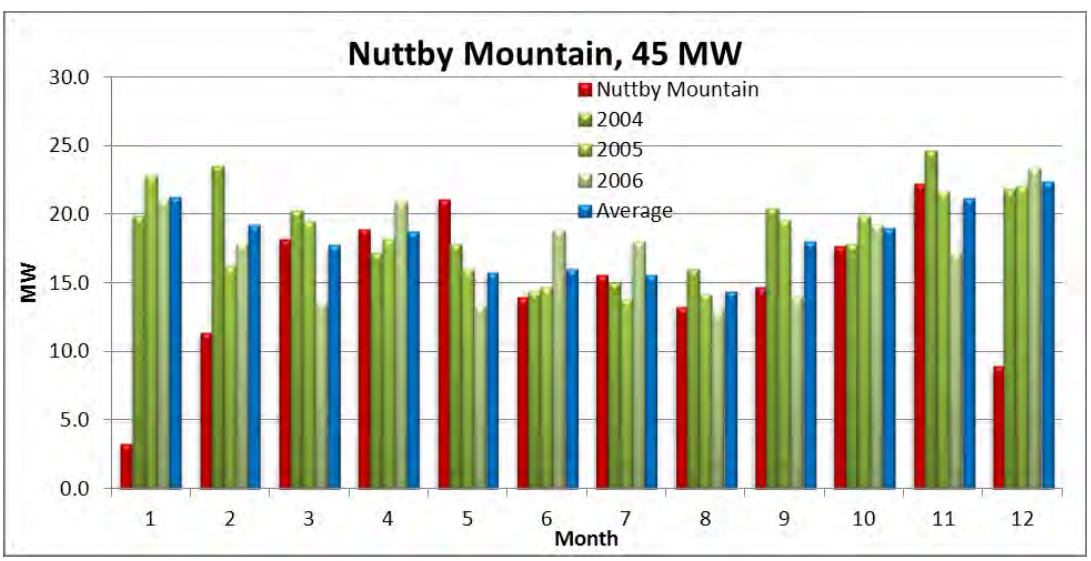



**Figure 17: Comparison of Maximum of AWST Wind with NSPI Historical Wind (Example of Nuttby Mountain)**

The blue and green bars are AWST data. The Average is across the three years of AWST data. The data set provided by NSPI did not include data points for all hours of the year. Some of the reasons for actual wind production being so much different in some months, particularly in January and December, are related to cold-weather operation. While the comparison is not ideal for all months, there are many months where the comparison is meaningful.

Figure 18 shows the maximum MW output of the Nuttby Mountain plant for each day during each month (hence a 12 x 31 table). The color spectrum represents the deviation of the monthly maximums from the plant MW rating:

- White: Plant MW rating
- Green: Values below the plant MW rating (darker green for higher deviation)
- Red: Values above the plant MW rating (darker red for higher deviation)

| Month/Day | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 | Max |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | 2 | 4 | 7 | 11 | 9 | 7 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 32 | 1 | 3 | 29 | 30 | 27 | 20 | 9 | 33 | 8 | 6 | 9 | 24 | 33 |
| 2 | 14 | 29 | 26 | 21 | 37 | 36 | 24 | 34 | 41 | 18 | 30 | 35 | 41 | 37 | 42 | 32 | 36 | 33 | 14 | 10 | 1 | 1 | 0 | 12 | 37 | 32 | 18 | 35 | | | | 42 |
| 3 | 33 | 37 | 32 | 27 | 36 | 36 | 36 | 34 | 23 | 21 | 37 | 37 | 43 | 43 | 38 | 38 | 33 | 41 | 39 | 34 | 13 | 19 | 11 | 37 | 41 | 39 | 41 | 30 | 31 | 66 | 7 | 66 |
| 4 | 37 | 30 | 27 | 45 | 46 | 42 | 32 | 15 | 23 | 20 | 50 | 50 | 50 | 50 | 45 | 49 | 50 | 46 | 35 | 22 | 22 | 43 | 50 | 48 | 28 | 24 | 31 | 50 | 50 | 50 | | 50 |
| 5 | 49 | 50 | 19 | 50 | 50 | 47 | 45 | 38 | 44 | 42 | 50 | 47 | 32 | 17 | 35 | 43 | 39 | 21 | 31 | 41 | 45 | 13 | 51 | 51 | 40 | 32 | 47 | 35 | 50 | 43 | 34 | 51 |
| 6 | 50 | 44 | 23 | 21 | 29 | 13 | 33 | 27 | 45 | 45 | 34 | 15 | 50 | 31 | 43 | 40 | 21 | 48 | 45 | 34 | 33 | 42 | 6 | 22 | 46 | 23 | 20 | 13 | 28 | 28 | | 50 |
| 7 | 18 | 27 | 33 | 46 | 31 | 34 | 37 | 14 | 42 | 45 | 43 | 49 | 47 | 50 | 50 | 47 | 31 | 34 | 11 | 45 | 50 | 47 | 45 | 32 | 18 | 24 | 33 | 18 | 39 | 49 | 27 | 50 |
| 8 | 16 | 48 | 46 | 15 | 41 | 11 | 19 | 46 | 36 | 31 | 16 | 24 | 15 | 26 | 16 | 22 | 41 | 32 | 27 | 39 | 26 | 50 | 35 | 42 | 50 | 44 | 24 | 48 | 41 | 11 | 17 | 50 |
| 9 | 9 | 11 | 32 | 38 | 50 | 46 | 46 | 19 | 38 | 45 | 42 | 48 | 39 | 42 | 47 | 50 | 41 | 14 | 6 | 30 | 21 | 31 | 14 | 4 | 37 | 31 | 33 | 40 | 48 | 51 | | 51 |
| 10 | 45 | 29 | 17 | 19 | 49 | 46 | 39 | 47 | 39 | 48 | 40 | 36 | 27 | 38 | 48 | 48 | 50 | 26 | 28 | 49 | 47 | 20 | 6 | 6 | 25 | 45 | 43 | 38 | 33 | 46 | 42 | 50 |
| 11 | 19 | 39 | 45 | 38 | 47 | 46 | 48 | 37 | 17 | 47 | 50 | 46 | 39 | 51 | 45 | 47 | 42 | 47 | 51 | 51 | 37 | 19 | 49 | 49 | 31 | 4 | 9 | 14 | 10 | 23 | | 51 |
| 12 | 26 | 28 | 20 | 26 | 24 | 26 | 24 | 20 | 11 | 22 | 24 | 28 | 28 | 16 | 16 | 11 | 9 | 14 | 14 | 20 | 20 | 22 | 24 | 20 | 10 | 0 | 10 | 12 | 1 | 0 | 0 | 28 |
| Max | 50 | 50 | 46 | 50 | 50 | 47 | 48 | 47 | 45 | 48 | 50 | 50 | 50 | 51 | 50 | 50 | 50 | 48 | 51 | 51 | 50 | 50 | 51 | 51 | 50 | 45 | 47 | 50 | 50 | 66 | 42 | |

**Figure 18: Variation of Daily Maximum MW (Example of the Nuttby Mountain Plant, with Rating of 45 MW)**

We performed a number of similar comparisons to establish the suitability of the scaled AWST data for representation of the Nova Scotia wind plants, both existing, and those that will be potentially built, including wind capacity build-ups for the future years in our simulations.

### 3.2.3 NSPI Data Conditioning and AWST Data Validation

The NSPI 4-second wind data covered periods from November 1, 2010 - 12:00 AM to January 1, 2012 - 12:00 AM, and for analysis we used the full year data from January 1, 2011 to December 31, 2011. The 4-second MW wind data were averaged over the appropriate periods in order to develop the hourly and 10-minute data used in the analysis.

Again, in this case, there were a number of data points that were missing or invalid and more detailed analysis was required to evaluate the impact of this missing or invalid data. Some missing data are shown as zeros in Figure 19, Figure 20, and Figure 21.

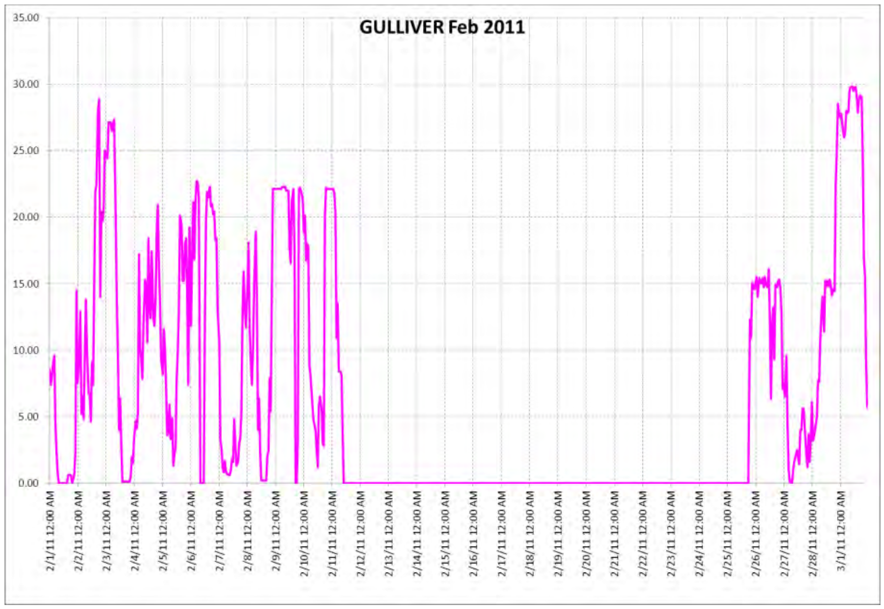



Figure 19: Hourly Gulliver Data for February 2011

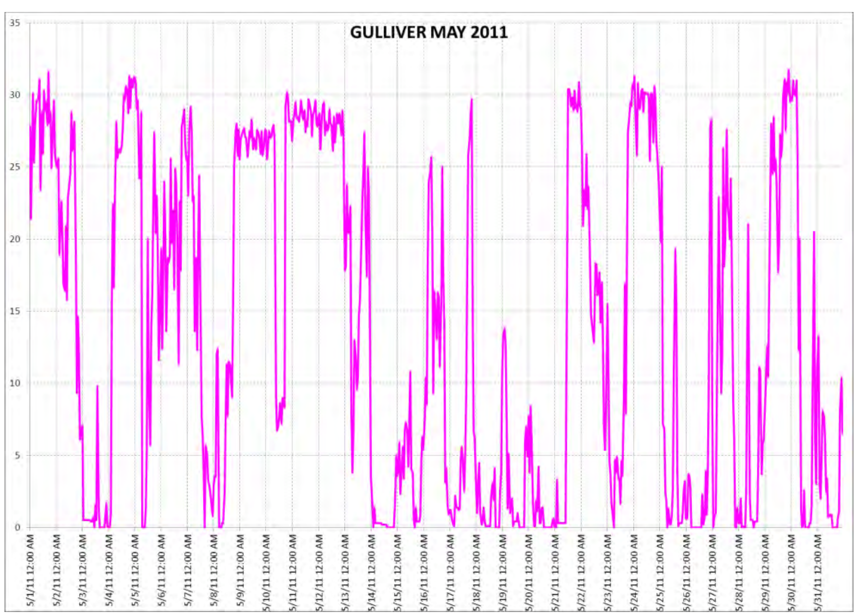



Figure 20: Hourly Gulliver Data for May 2011

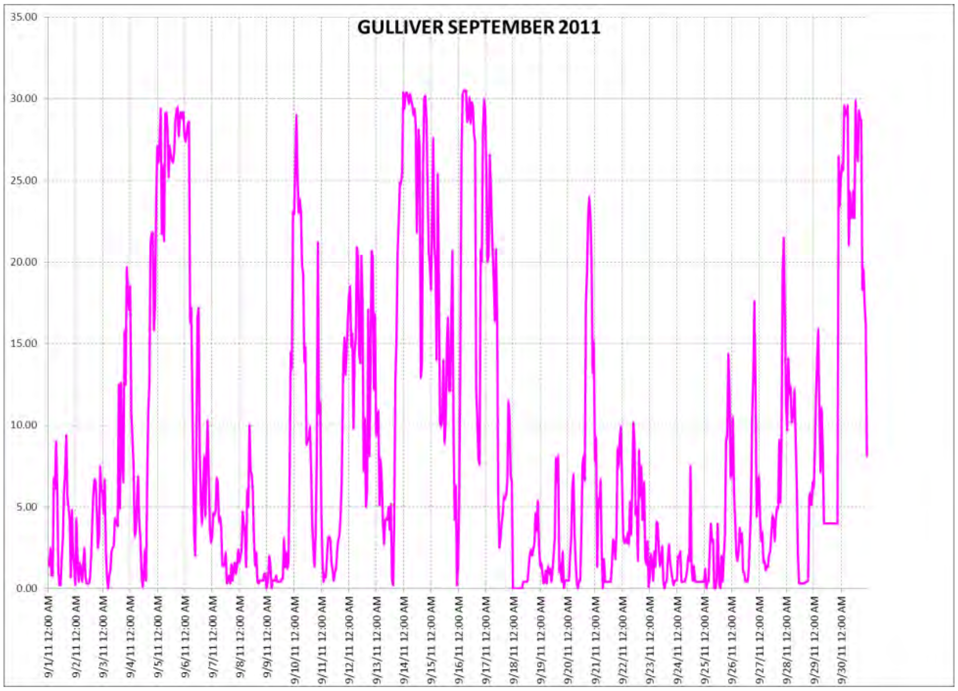



**Figure 21: Hourly Gulliver Data for September 2011**

We developed so-called "carpet charts" to illustrate the valid and non-zero data points in 2011 data as shown in the Figure 22 and Figure 23.

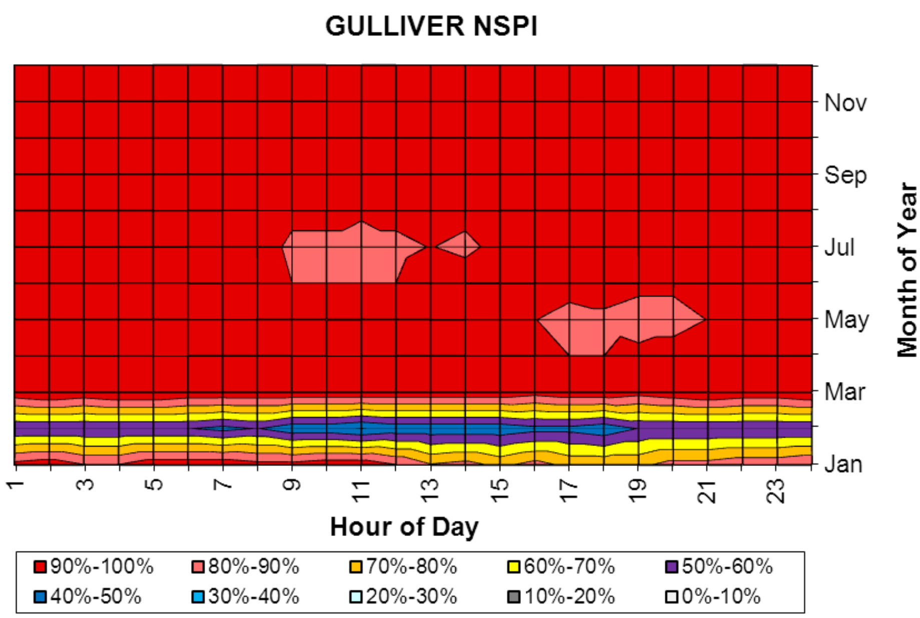



**Figure 22: Carpet Figure Showing Percent of Valid and Non-Zero Data Points**

The color coding represents the percent of the time each of the days across a month has valid (non-zero) data points. As an example, the number of valid data points at hour 10 during the month of July (July has 31 days and therefore there are 31 such hours in the month) is between 80% and 90%. Higher quality data are available mostly between March and December. The data in February was poor.

Similarly, the following carpet chart illustrates the quality of the data for the Nuttby wind site. For the months of March through December, the number of valid data points is between 80% and 100%, whereas the number of valid data points for the months of January and February ranges from 50% to 80%.

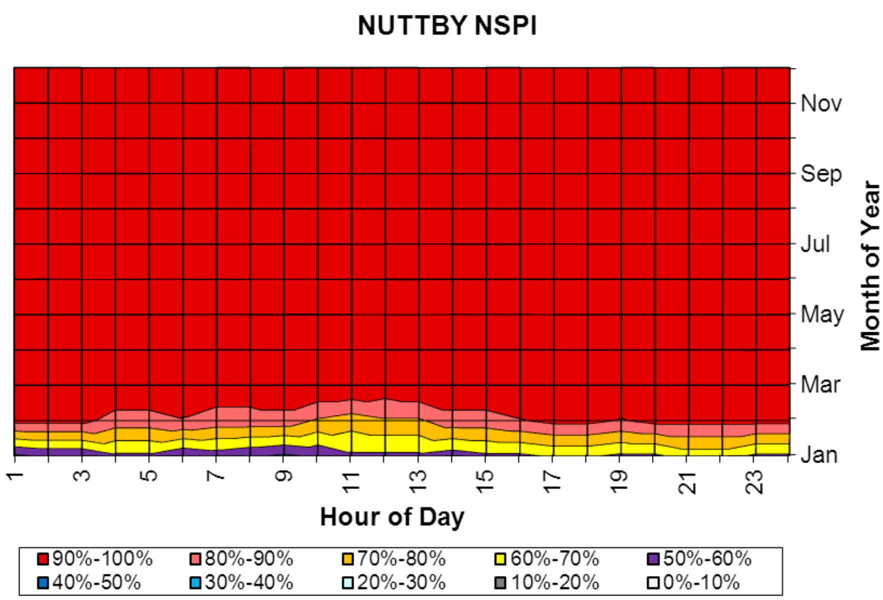



**Figure 23: Carpet Figure Showing Percent of Valid and Non-Zero Data Points**

Next we looked at plant generation on a month by month basis, as shown in Figure 24 and Table 3.

[redacted]

Figure 24: 2011 Monthly Generation of NSPI Wind Plant (MWh)

THIS FIGURE IS CONFIDENTIAL

Table 3: Monthly Average Power of NSPI Wind Plants (MW)

| | Pubnico (30.6 MW) | Gulliver (30 MW) | Nuttby (45 MW) | Dalhousie (51 MW) | Maryvale (6 MW) | Glen Dhu (60 MW) | Bear Head (22 MW) | Lingan (22 MW) |
|---|---|---|---|---|---|---|---|---|
| Jan | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Feb | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Mar | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Apr | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| May | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Jun | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Jul | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Aug | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Sep | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Oct | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Nov | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Dec | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

As can be observed in Figure 24 on monthly generation, the least windy months appear to be [redacted], and [redacted]. Same monthly high and low wind pattern is also reflected in maximum capacity as shown in the above table. However, as shown later in comparison with AWST data, we believe that the data underrepresents how much energy was actually generated in the early months of the year. By way of example, NSPI has more wind generation in the month of [redacted] than any other month in its history.

Next we attempted to validate the AWST data by the NSPI data and performed statistical analysis to guide the development of the reserve requirements needed to mitigate the wind variability.

Data sources included:

- NSPI: 4-sec wind output for2011, 2011 load data
- AWST: 10-min wind output for 2004 - 2006

We corrected anomalies (bad data) in NSPI 4-second data and then integrated the 4-second data to 10-minute and 1-hour timeframe.

We examined and charted data integrity which delineated suspiciously long periods of zeros, as shown in Figure 25 and Figure 26 in the comparison of NSPI and AWST data. The NSPI data in January (top row) shows more zeros than reasonable, suggesting a data problem. The frequency of zeros in the rest of the year is higher than in the AWST data, suggesting it is slightly more volatile.

**Glendhu (NSPI-avg hourly)**

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 24 | 24 | 24 | 20 | 24 | 7 | 0 | 14 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 12 | 5 | 15 | 24 | 8 | 0 | 0 | 16 | 7 | 0 | 0 | 1 | 5 | 24 | 3 |
| 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 21 | 24 | 24 | 24 | 24 | 1 | 0 | 14 | 6 | | | |
| 3 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 7 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 5 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 7 | 0 | 0 | 1 | 7 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 6 | 0 | 0 | 0 | 1 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 7 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 0 |
| 8 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 7 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 2 | 0 |
| 9 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3 | 0 | 0 | 0 | 0 | 4 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 2 | 0 | 0 | 0 | |
| 10 | 0 | 0 | 0 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 13 | 24 | 24 | 24 | 24 | 10 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 11 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 7 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 12 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 1 | 0 | 0 | 0 | 0 |

**Figure 25: Number of Zero Data Points for Each hour Within a Month in NSPI Average Hourly Data**

| Glendhu (AWS-avg hourly) | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 |
| 1 | 0 | 0 | 1 | 0 | 0 | 4 | 0 | 4 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 1 | 0 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| 2 | 0 | 0 | 1 | 5 | 0 | 0 | 0 | 1 | 1 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 6 | 0 | 2 | 0 | 0 | 0 | 0 | | | |
| 3 | 0 | 0 | 0 | 0 | 0 | 0 | 10 | 0 | 4 | 0 | 0 | 1 | 0 | 2 | 0 | 0 | 1 | 7 | 9 | 0 | 1 | 9 | 4 | 0 | 5 | 0 | 0 | 0 | 1 | 1 | 2 |
| 4 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 3 | 0 | 2 | 1 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 4 | 0 | 0 | 1 | 0 | 8 | 0 | 2 | |
| 5 | 0 | 0 | 0 | 0 | 5 | 2 | 2 | 1 | 0 | 0 | 0 | 1 | 2 | 9 | 17 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 12 | 0 | 0 | 9 | 0 | 7 | 2 |
| 6 | 0 | 5 | 2 | 0 | 0 | 6 | 0 | 0 | 0 | 0 | 0 | 2 | 8 | 15 | 5 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 3 | 0 | 0 | 0 | 0 | 0 | |
| 7 | 0 | 1 | 1 | 0 | 0 | 0 | 1 | 2 | 0 | 0 | 0 | 0 | 0 | 8 | 1 | 0 | 0 | 0 | 1 | 1 | 0 | 4 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | 8 | 1 | 3 | 0 | 0 | 4 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 4 | 0 | 14 | 0 | 3 | 0 | 0 | 2 | 3 | 0 | 0 | 0 | 0 | 0 | 4 | 0 |
| 9 | 0 | 0 | 6 | 0 | 3 | 3 | 5 | 2 | 0 | 0 | 0 | 4 | 0 | 0 | 7 | 0 | 2 | 6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 1 | |
| 10 | 6 | 0 | 0 | 5 | 0 | 0 | 5 | 1 | 0 | 0 | 1 | 0 | 1 | 4 | 0 | 0 | 3 | 0 | 0 | 0 | 0 | 0 | 3 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 11 | 1 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 4 | 4 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 1 | 0 | |
| 12 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Figure 26: Number of Zero Data Points for Each hour Within a Month in AWST Average Hourly Data**

We spent extensive effort to align the NSPI and AWST data, and matching the 8 NSPI sites with the closest AWST Sites.

### 3.2.4 Wind Data Validation in Hourly Timeframe

For the analysis of hourly average data we considered the following time periods of data:

- NSPI: 1/1/2011 - 12:00:00 AM to 12/31/2011 - 11:00PM
- AWST: 1/1/2006 - 12:00:00 AM to 12/31/2006 - 11:00 PM

Figure 27 compares the total monthly energy from 8 plants. The early month totals reflect the imperfect data issues in the NSPI data.

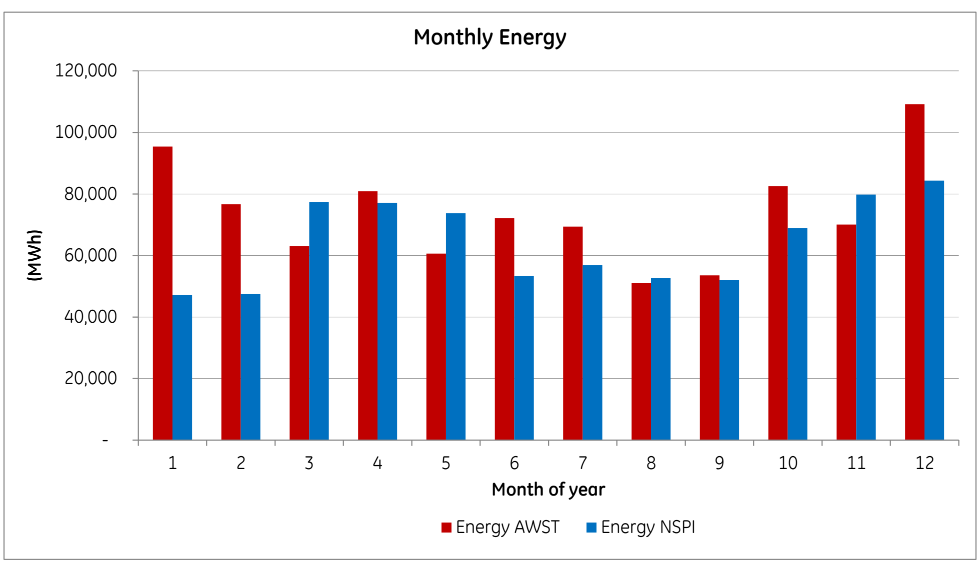



**Figure 27: Total Monthly Energy from 8 Plants**

As noted earlier and observed in the carpet charts, the NSPI data has many zero and invalid values, particularly during the earlier and later months of the year.

Figure 28 and Figure 29 depict the average hourly profiles of NSPI and AWST data by month.

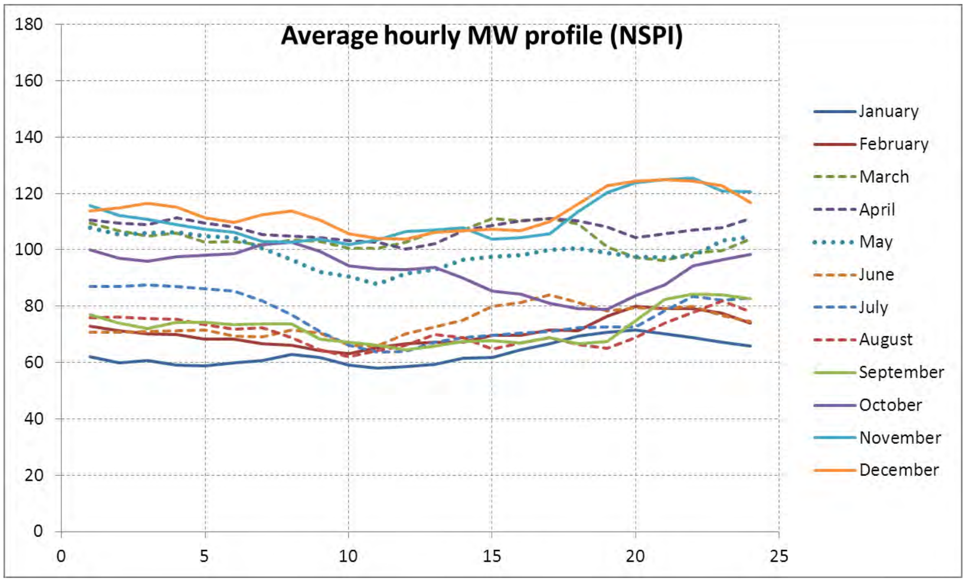



Figure 28: Average Monthly MW Profile of NSPI Data

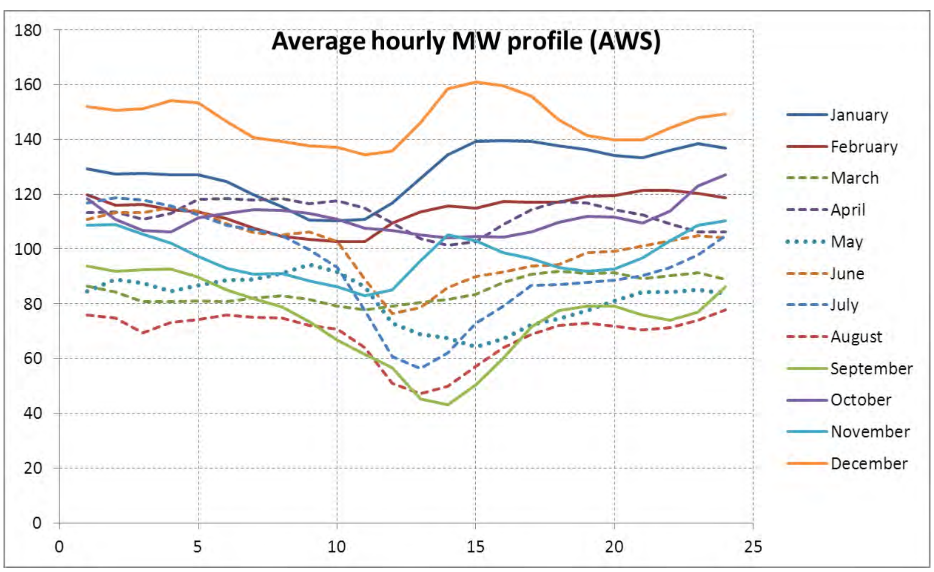



Figure 29: Average Monthly MW Profile of AWST Data

The AWST daily profiles appear to be more non-uniform compared to the NSPI data, and may be a bit pessimistic (low) at mid-day in the summer.

We next considered the hourly variable in the NSPI and AWST data in Figure 30 and Figure 31 within a selected month and week.

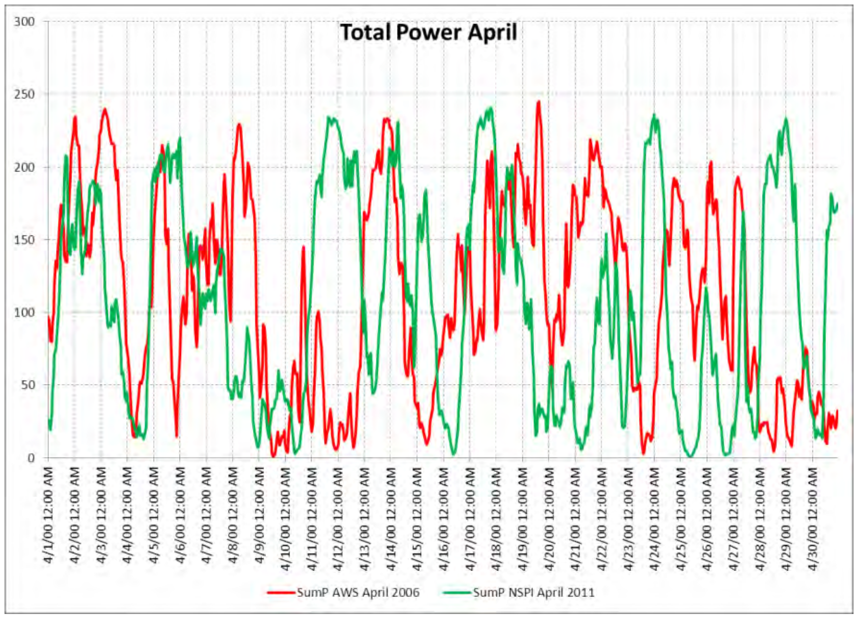



**Figure 30: Hourly Variation of ASWT and NSPI Wind Data (Month of April)**

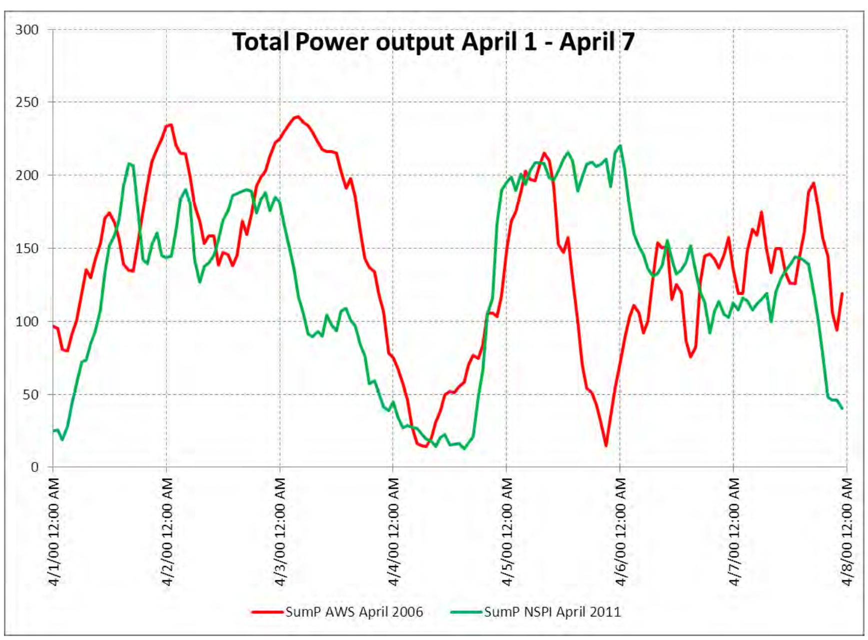



**Figure 31: Hourly Variation of ASWT and NSPI Wind Data (Week of April 1 to April 7)**

Figure 30 and Figure 31 indicate similar characteristics for fast variation between the NSPI and AWST data. Remember, there is no expectation of having the data "line up", as these are different years. The critical element is the character of the variability in total energy. In this sense, the data looks very good. The statistics presented below support this qualitative observation.

The hourly variability of the wind data is established by the statistical characteristics of hour by hour changes in wind level (so-called "Delta"). The following figures provide carpet charts of hourly variability of wind data for both NSPI and AWST data.

Figure 32 and Figure 33 show the standard deviation (so-called "Sigma") of hourly Deltas for same hour of the day during each month of NSPI and AWST data.

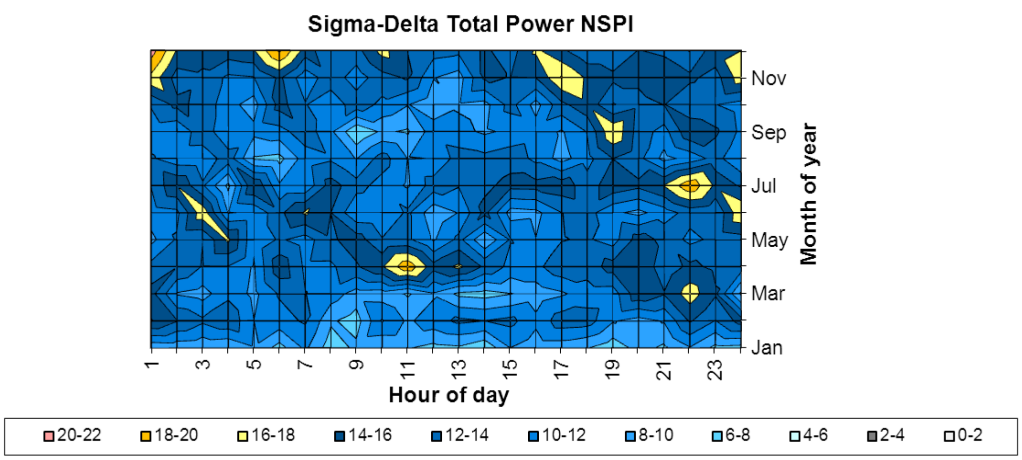



**Figure 32: Carpet Chart of Standard Deviation of Hourly Deltas of Total NSPI Wind Power**

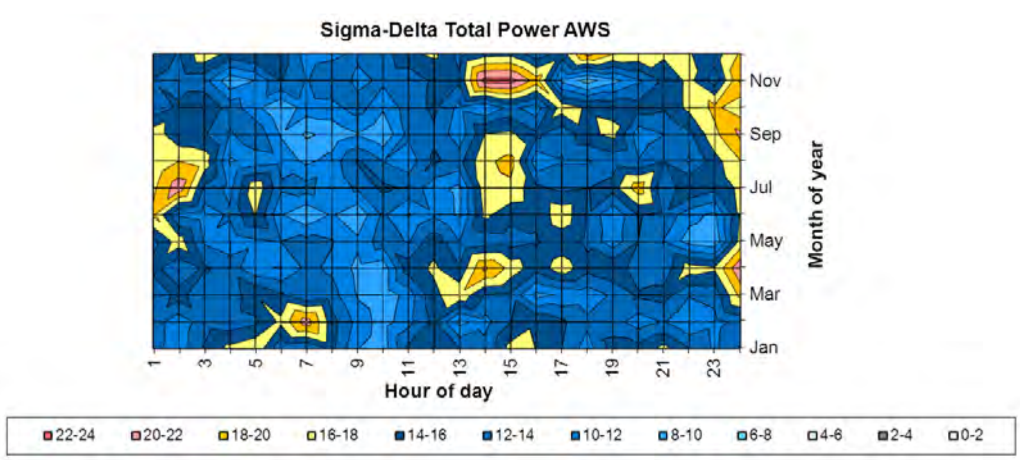



**Figure 33: Carpet Chart of Standard Deviation of Hourly Deltas of Total AWST Wind Power**

Table 4 compares the statistics of the two sets of data.

**Table 4: Statistics of Hourly NSPI and AWST Variability**

| | AWS Data | NSPI Data |
|---|---|---|
| Sigma | 14.27 | 12.39 |
| 3.0* Sigma | 42.82 | 37.18 |
| Max Pos Delta | 79.49 | 63.59 |
| Max Neg Delta | -76.12 | -85.70 |
| # of drops > 3*sigma | 41 | 50 |
| # of rises > 3*sigma | 65 | 64 |

The statistical analysis indicates that the AWST data is slightly pessimistic, in the sense that it exhibits a higher Sigma compared to the NSPI data, which is also reflected by the higher incidence of the warmer colors in the carpet chart of the AWST data.

The next two carpet charts, Figure 34 and Figure 35, compare the maximum negative delta or maximum drop in wind in the following hour of the NSPI data with the AWST data. The charts show the Maximum Negative Delta for a given hour over the month. We are checking to see if the AWST data reasonably captures the extremes of wind drop-off events that are so important to system operation.

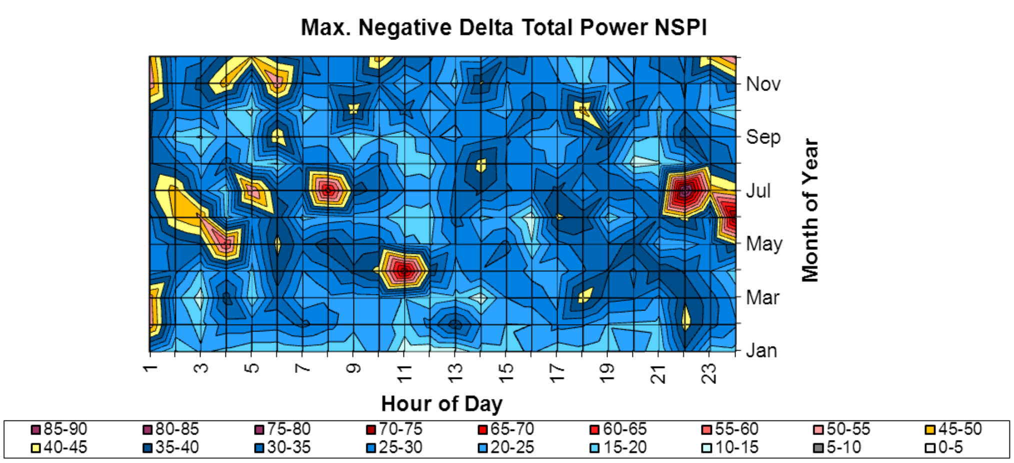



**Figure 34: Carpet Chart of Maximum Negative Deltas of Total NSPI Wind Generation**

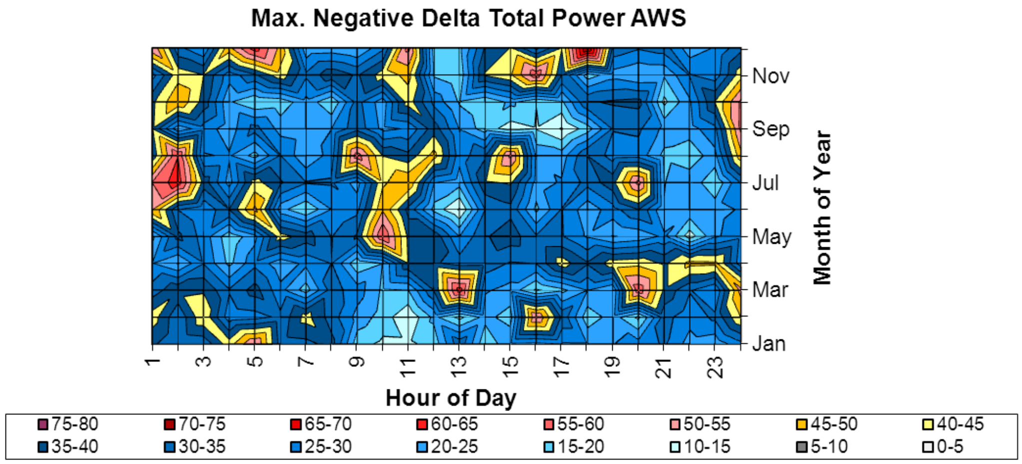



**Figure 35: Carpet Chart of Maximum Negative Deltas of Total AWST Wind Generation**

As can be seen in the NSPI data, in April the greatest drop in wind power was at hour 11 (hour 11 on one of the 30 days within April). The same happened in the AWST data in July, hour 2. We also observe slightly more variability in AWST data, which establishes the AWST data as slightly more "conservative", since the modeling results based on AWST data will be somewhat more pessimistic relative to NSPI's ability to handle the wind variability. Furthermore, as will be discussed later, more variable wind in the model (higher Sigma Delta), results in higher operating reserve requirements in the model which is more restrictive than in actual operations.

### 3.2.5 Wind Data Validation within Ten Minute Timeframe

We next investigated the 10-minute variability of the wind data, considering the following time periods of data:

- NSPI: 1/1/2011 - 12:00:00 AM to 12/31/2011 - 11:50PM
- AWST: 1/1/2006 - 12:00:00 AM to 12/31/2006 - 11:50 PM

Figure 36 and Figure 37 provide carpet charts of 10-minute Sigma Delta, similar to the approach done for the hourly data.

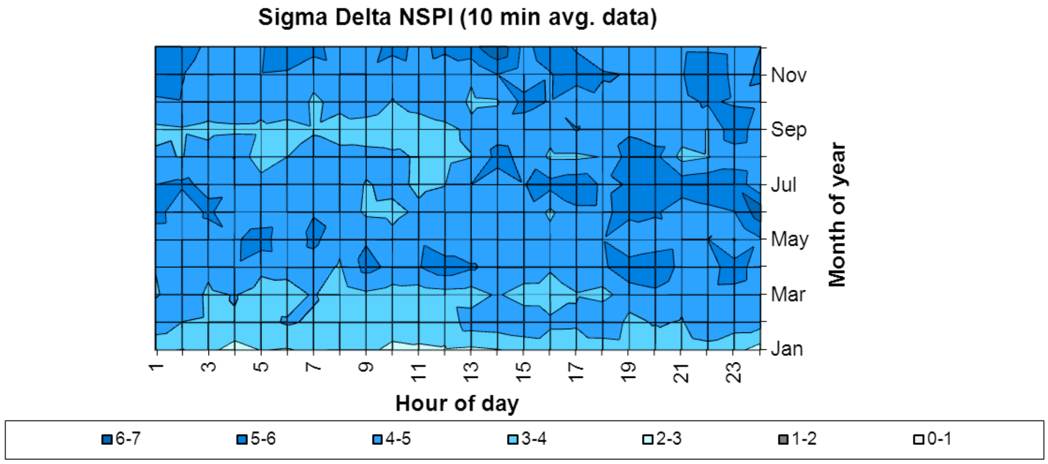



Figure 36: Carpet Chart of Standard Deviation of 10-Minute Deltas of Total NSPI Wind Power

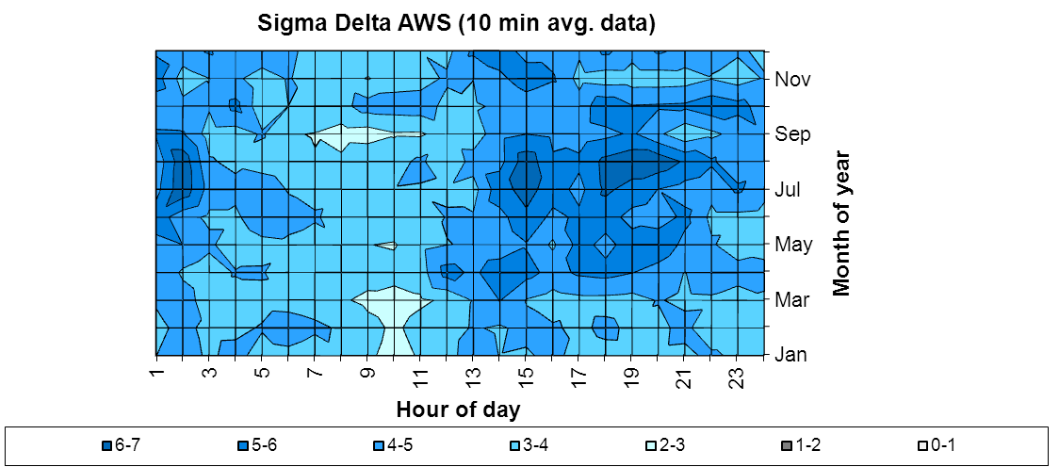



Figure 37: Carpet Chart of Standard Variation of 10-Minute Deltas of Total AWST Wind Power

As expected, the size of Deltas and Sigmas are smaller in 10-minute data compared to the hourly data. Both the hourly and 10-minute results show limited time-of-day and time-of-year dependency. Table 5 summarizes the 10-minute statistics.

**Table 5: Statistics of 10-Minute NSPI and AWST Variability**

| | AWS Data | NSPI Data |
|---|---|---|
| Sigma Delta | 4.31 | 4.46 |
| 3.0* Sigma Delta | 12.94 | 13.38 |
| Max Pos Delta | 43.12 | 36.83 |
| Max Neg Delta | -37.44 | -63.05 |
| # of drops > 3*sigma delta | 307 | 348 |
| # of rises > 3*sigma delta | 428 | 383 |

Figure 38 compares the 10-minute profiles of the NSPI and AWST data, and again both profiles show similar characteristics for fast variation, this time in 10-minute time frames. Again, the character of the variability is well captured.

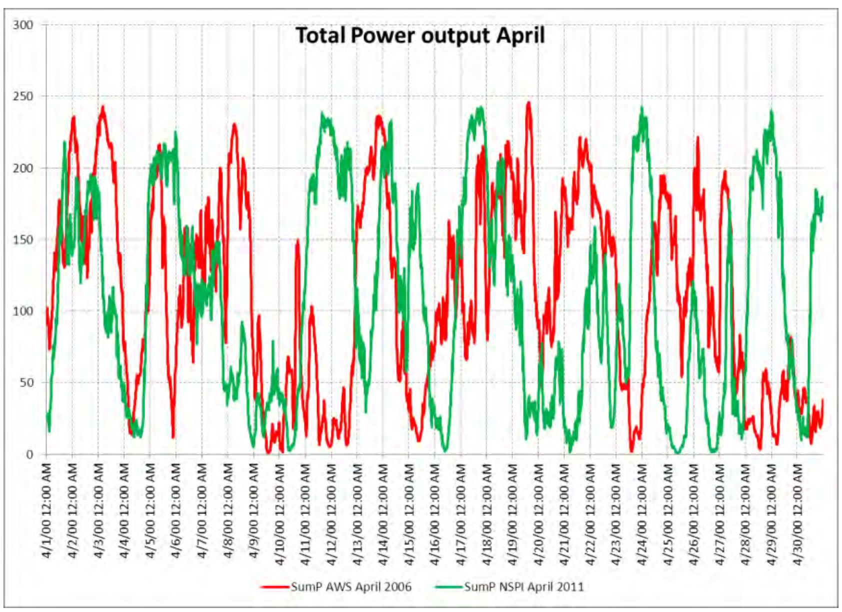



**Figure 38: 10-Minute Variations of ASWT and NSPI Wind Data (Month of April)**

### 3.2.6 Hourly Net Load and Challenging Periods

In power system operations, thermal generation is committed and dispatched against the hourly net load (load minus wind power) which is the modified load after accounting for the wind energy. The higher integration of wind resources adds to the net load variability that thermal generation and other dispatchable generation need to be balanced against.

In this section we look into the variability of Net Load. We considered a 2006 Hourly Load data that corresponds to a 2006 hourly AWST wind data (the last year for which data were available). These 2006 hourly load shapes were used in the analysis to represent the NSPI hourly load shapes, since it was essential to preserve the naturally existing inherent load/weather and wind relationship in our modeling. This is because load is correlated with weather, and weather is correlated with wind energy.

We also investigated the NSPI load and wind data - starting in 2010 and ending in 2011 - in order to establish suitability of using the AWST 2006 load shapes.

The Net Load relationships investigated include the following:

- AWST Net Load Calculation:
  - AWST Net Load = AWST Total Load – AWST Total Power Output of 8 Plants
  - AWST Load data considered: 1/1/2006 – 12/31/2006
  - AWST wind data considered: 1/1/ 2006 - 12/31/2006
- NSPI Net Load Calculation:
  - NSPI Net Load = NSPI Total Load – NSPI Total Power Output of 8 plants
  - NSPI Load data considered: 11/26/2010 - 7:00 PM – 11/25/2011 - 11:00 AM
  - NSPI wind data considered: 11/26/2010 - 7:00 PM – 11/25/2011 - 11:00 AM

The NSPI period consideration is based on starting hour with the available valid and non-zero wind data and ending with the last period of load data received from NSPI.

Figure 39 and Figure 40 show the NSPI and AWST hourly net load variations.

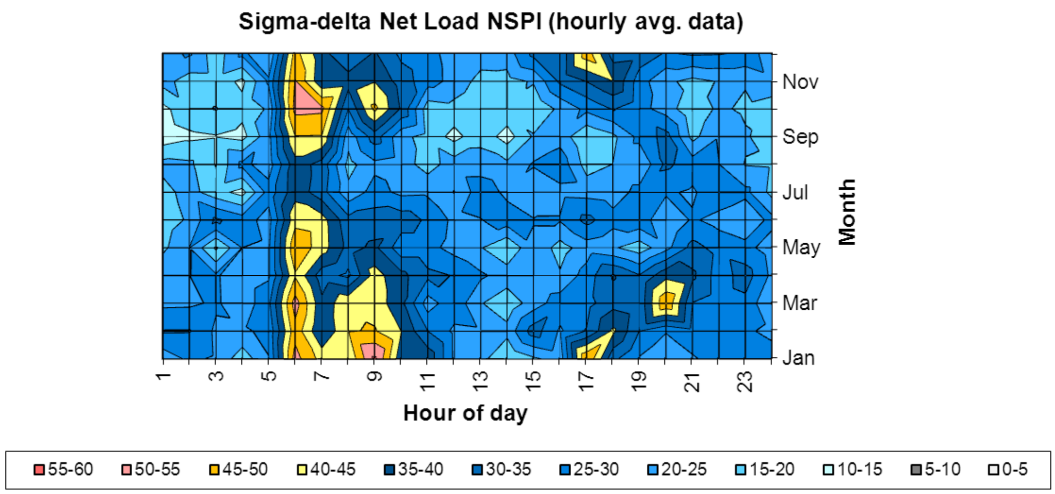



**Figure 39: Carpet Chart of Standard Deviation of Hourly Deltas of NSPI Net Load**

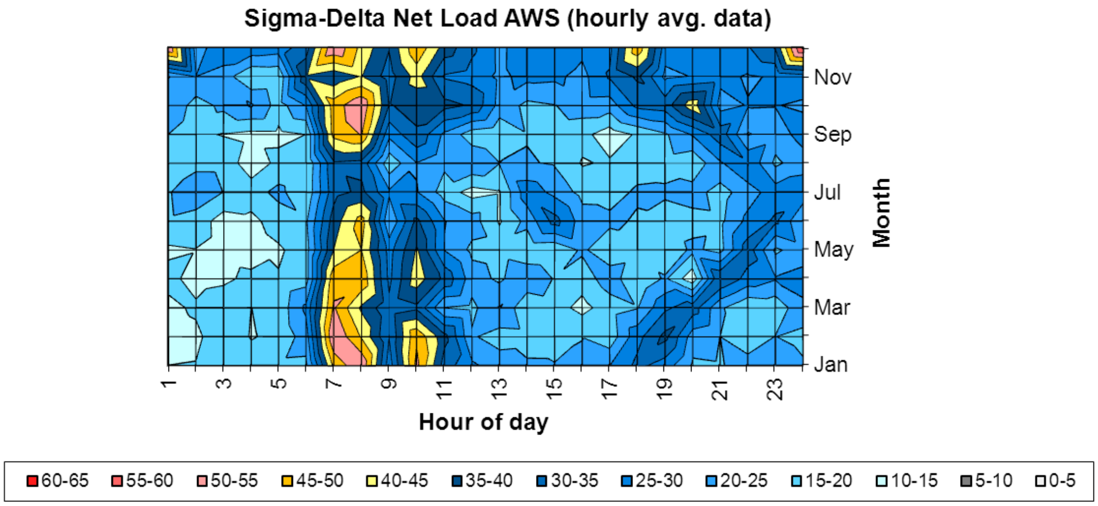



**Figure 40: Carpet Chart of Standard Deviation of Hourly Deltas of AWST Net Load**

There is a striking similarity in the variation pattern of hourly NSPI and AWST Net Loads.

Figure 41 and Figure 42 provide the carpet charts for Maximum Positive Hourly Net Load Deltas.

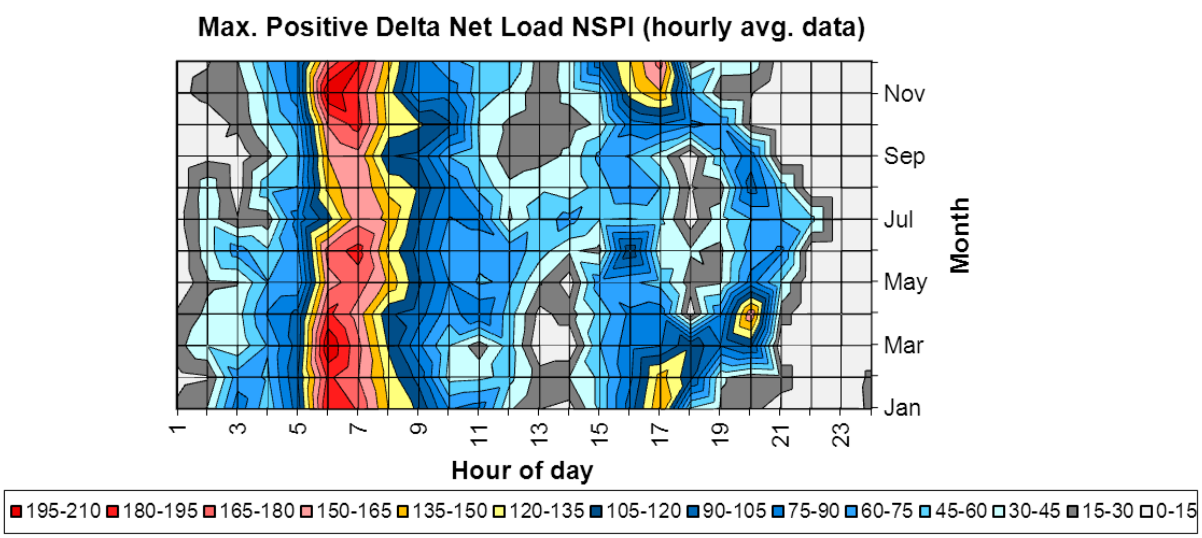



**Figure 41: Carpet Chart of Maximum Positive Deltas of Hourly NSPI Net Load**

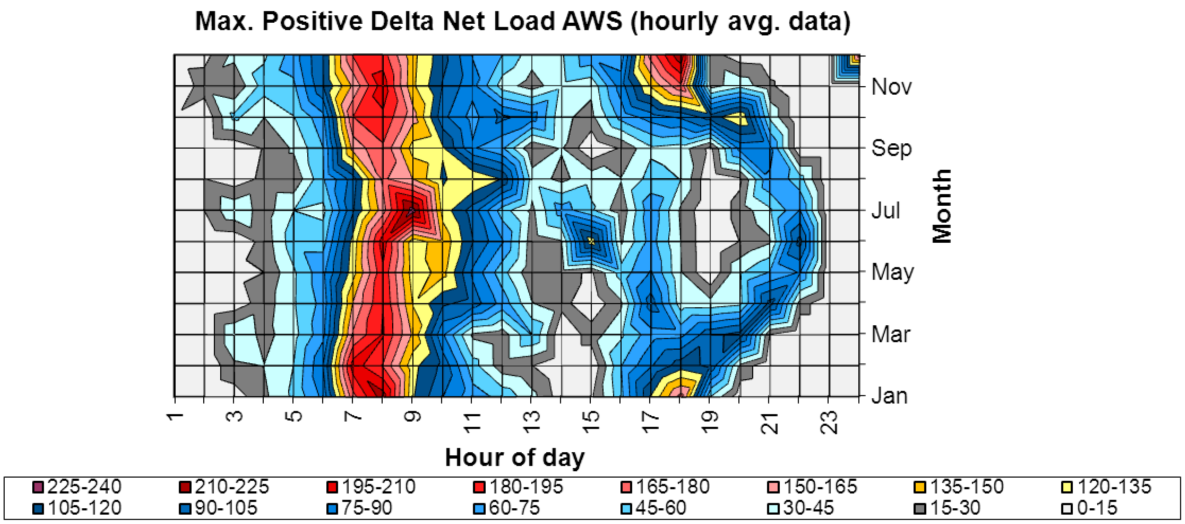



Figure 42: Carpet Chart of Maximum Positive Deltas of Hourly AWST Net Load

It can be seen that again there is a striking similarity in the Maximum Positive Deltas (increase in wind power in the following hour) of hourly NSPI and AWST Net Loads.

The challenging hours are those with extreme period to period variations. Figure 43 and Figure 44 show the number of hours where the hourly Delta is equal or greater than a certain value. The first figure includes all hours the year when Delta is equal or greater than about 10 MWs. The second figure zooms on the top 50 hours with highest Deltas.

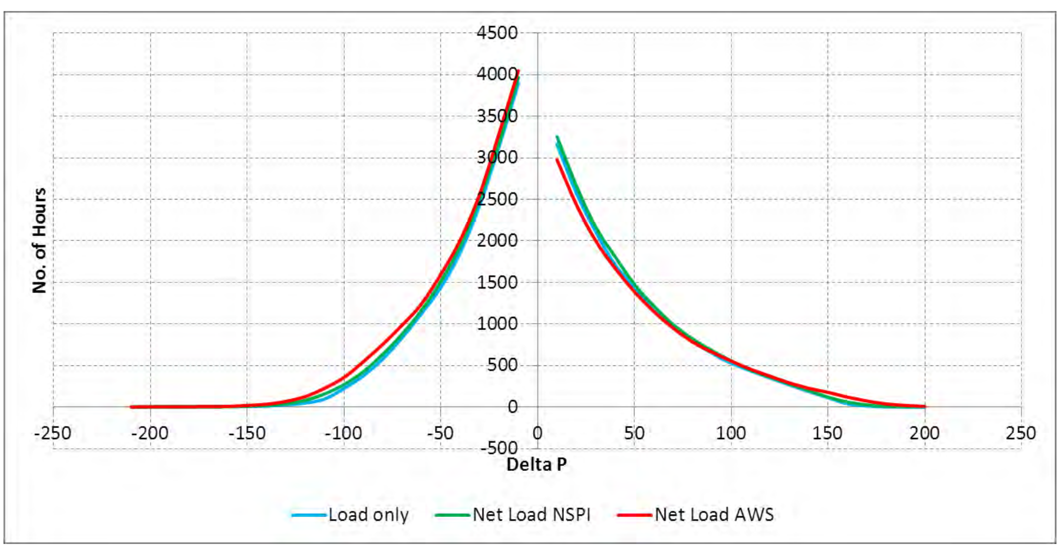



Figure 43: Number of Hours where Hourly Deltas are Equal to or Greater than a Given Value

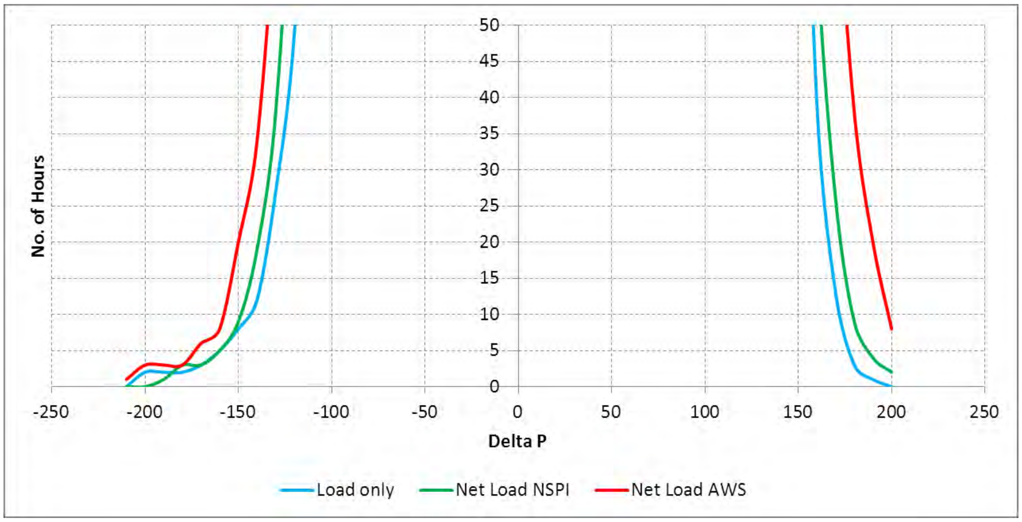



**Figure 44: Number of Hours where Hourly Deltas are Equal to or Greater than a Given Value (Zoomed)**

These figures demonstrate that the NSPI and AWST net load deltas have very similar behavior, and hence another confirmation of the suitability of using the AWST load and wind shape data as a proxy for NSPI load and wind generation.

Figure 45 illustrates the fact that Net Load variations could be more aggravating than Load alone due to the impact of additional wind variability.

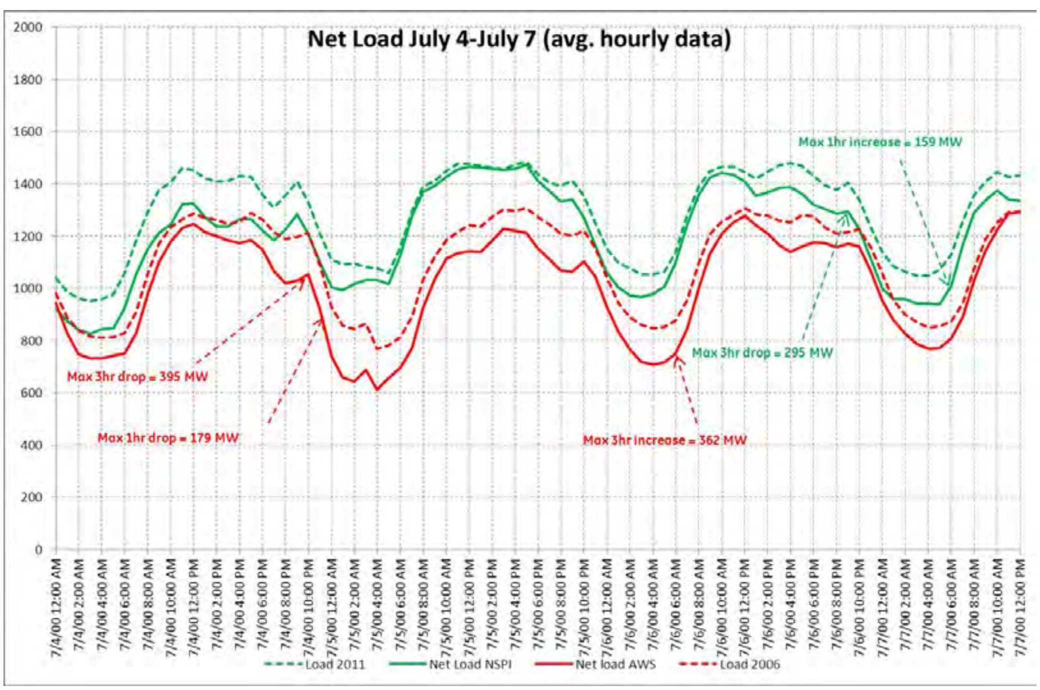



**Figure 45: Net Load Variations Compared to Load Alone**

The figure also identifies instances of maximum 3hr deltas. Sustained drops, especially ones that are not expected can exhaust available resources. Since they are 3hr, then GE MAPS modeling will "see" the problem, but these are the events that would be difficult for grid operators. For instance, the biggest worries for Alberta Electric System Operator (AESO) are the 4 hour drops.

In the above figure, a greater drop in both NSPI and AWST net loads compared to their original loads, brought about by the wind Deltas.

## 3.3 Wind Variability Related Reserve

The wind variability adds to the short-term variability of net load (load minus wind), which requires following with synchronized reserve. This additional synchronous reserve requirement is above and beyond the synchronized contingency reserves or Regulation Up and Regulation Down since most variations should not impinge on the contingency reserves. The grid operator needs guidance, in advance, to set and hold these incremental reserves.

In this analysis, we focus primarily on the 10-minute variability, since any variation within that period must be covered by synchronized reserves or 10-minute non-spinning reserves. It is also the finest resolution of our larger wind data set. Industry practice is continuing to evolve regarding incremental reserves required for wind variability [1], [2], [5], [19] and [7].

To establish a measure of 10-minute variability we investigated the relationship between variability and the level of the wind power as shown in Figure 46. We started by dividing the total wind capacity into 10% buckets of equal size (about 26 MW each), from zero MW to the maximum total wind power level in Nova Scotia. We then identified the largest 10-minute rise and drop in wind power in each bucket, which are shown as vertical lines in the figure (solid lines for NSPI data and hashed lines for AWST data). The boxes in figure show a range of ± 1σ – i.e. 1 standard deviation, Sigma, for each bucket. The statistics for wind power variation tend to be normal up to about 2 to 3 standard deviations. The outliers, as shown by the "whisker" lines in the figure are not normal (in the statistical sense). The significance of this behavior is that the host utility has the ability to cover the majority of sub-hourly deviations with a relatively modest amount of incremental reserves. But it is impractical and uneconomic to maintain *separate* reserves intended to cover very rare wind variation occurrences, i.e. to cover the ends of the whiskers.

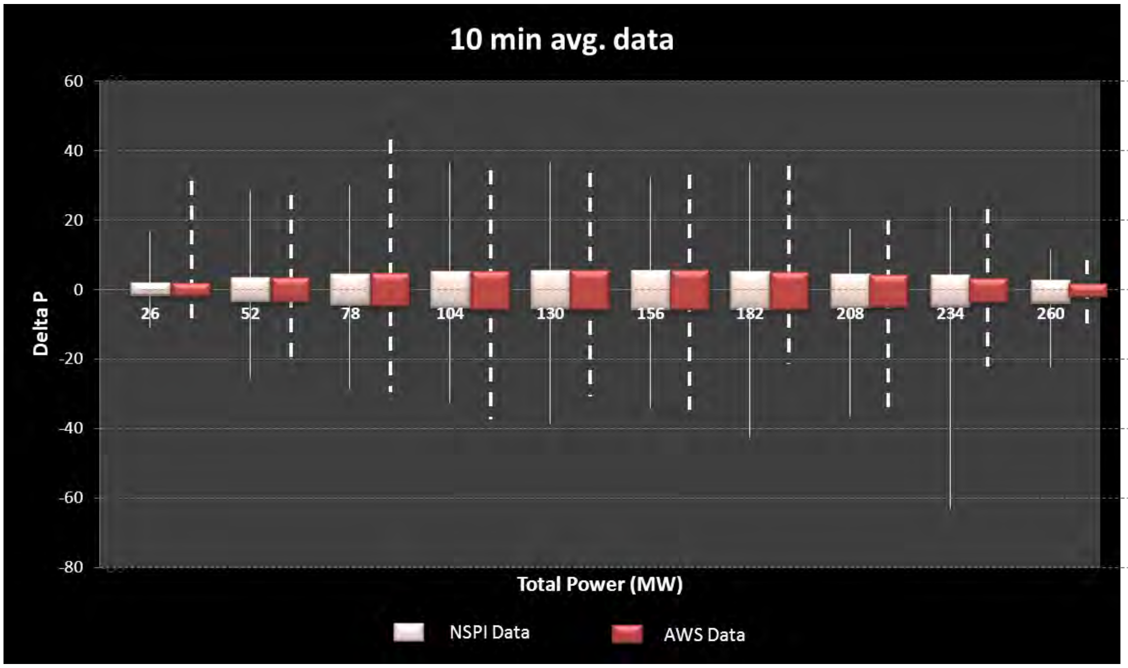



Figure 46: Wind Variability and Wind Power Level

It can be observed that the buckets in the midrange of the wind power exhibit the largest 1 σ of 10-minute variations. Figure 47 is based on zooming and enlarging the y-axis of Figure 46.

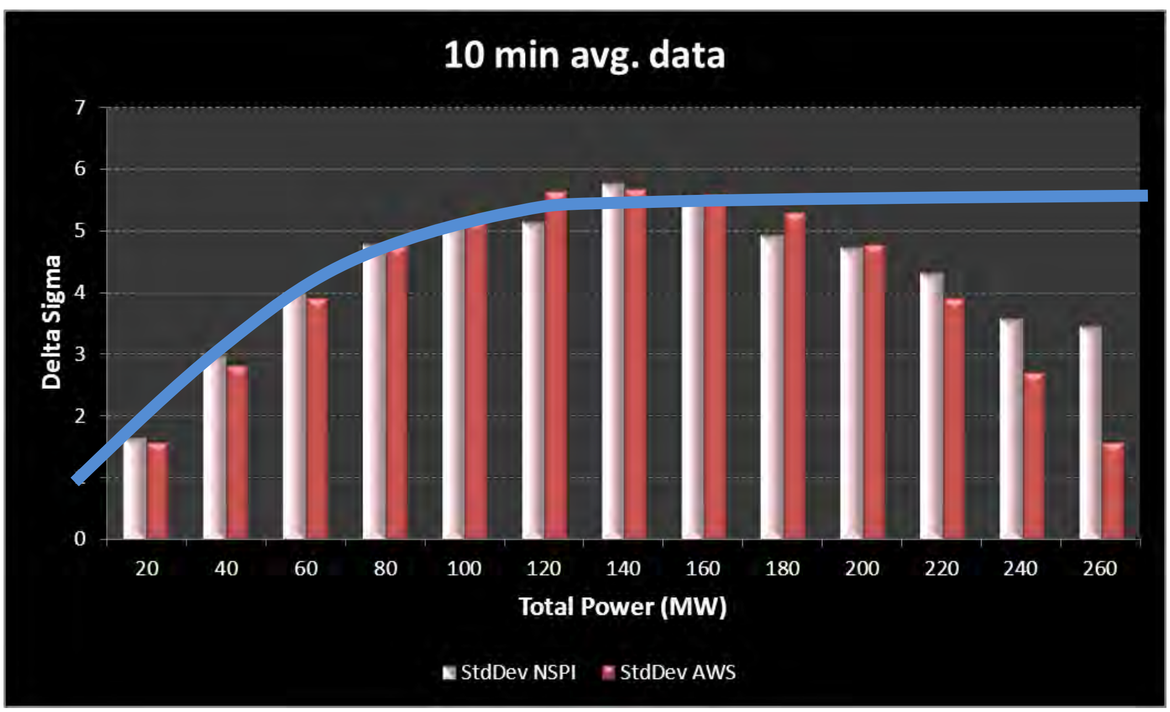



Figure 47: Wind Variability and Wind Power Level (Zoomed)

These results guide us towards establishing the additional incremental load following reserves to cover intra-hour wind variability. The added blue curve shows an increasing sigma as the wind power level rises and then stays constant at its highest level. At each power level, it simply measures the highest level of 10-minute sigma up to that level of power.

Previous studies have established that a statistically high level of confidence for reserve is achieved at about 3σ. In other words, with a reserve margin of 3σ, the chances of a 10-minute wind level drop being greater than 3σ, is highly unlikely.

Figure 48 shows curve fits for the 3σ data for NSPI (red) and AWST (green) data from Figure 47. The blue curve is an algebraic function fit that is used to set reserve in the MAPS simulations. It covers both NSPI and AWST as a measure of the wind variability related operating reserve for a given wind forecast. Notice that it increases with the wind power level until it plateaus at its maximum level as wind power increases beyond the maximum level of its variability.

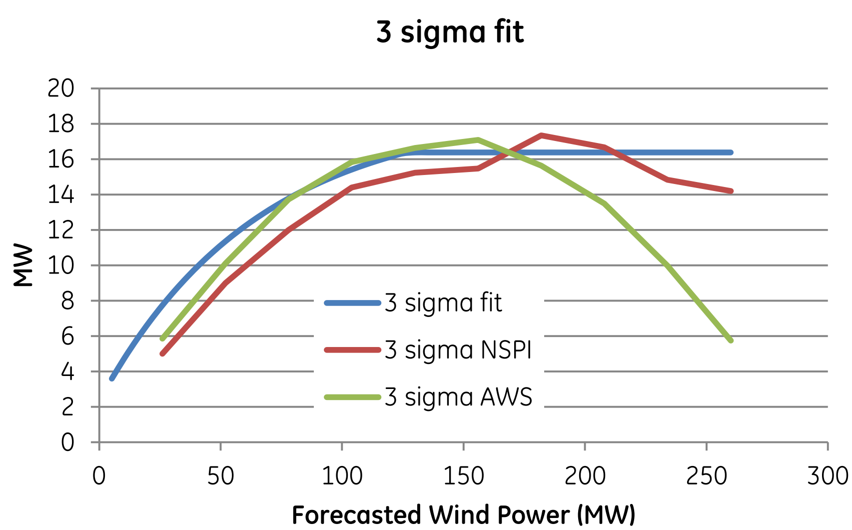



**Figure 48: 3 Sigma Levels and the Wind Variability Related Operating Reserve**

The reason for not decreasing the operating reserve as wind power level continues to increase is to ensure maintenance of reserve if the wind levels start falling, which would be accompanied by higher levels of variability. Hence, initial incremental on-line reserve will be a function of wind power level, and then stay at its highest level as wind power level increases beyond the its maximum short-term variability level. Since the variability shows little time of day or time of year dependency, the reserve strategy used in this study is based on wind power only. NSPI can use this approach in operations as well.

In systems with wind power, the wind variability related operating reserve should be scaled according to the total MW nameplate in the system. This reserve should be considered during DAH unit commitment and during real-time economic dispatch. This reserve can be supplied by both supply-side (flexible generators) and demand-side (demand response or DR) resources.

This reserve requirement is added to the contingency based NSPI operating reserve requirements. The blue curve in Figure 48 is scaled across the various cases in accordance with the total nameplate of wind power in that particular scenario. In the early years of the study, the values in the figure are close, as only a small amount of wind generation is added beyond that used in this statistical analysis. In later years, the curve is increased considerably. The annual average value of incremental reserves is summarized in Table 6. By 2020, *on* average, up to about 24 MW of incremental synchronous reserves (i.e. in Case 6, 45 MW minus 21 MW) is carried for wind variability. GE MAPS considers one type of hourly reserve and it doesn't distinguish between different types of synchronized reserves. Hence, to model different types of reserves, the maximum level of operating reserve in the operating system hierarchy can be set in GE MAPS to ensure sufficient set-aside of operating reserves in the system.

**Table 6 Average Incremental Reserves for Wind Variability**

| Case (Installed Wind Rating, MW) | Annual Average Incremental Reserves (MW) |
|---|---|
| 1,2,3 (335 MW) | **21** |
| 4,5 (448 MW) | **29** |
| 6 (916 MW) | **45** |
| 7 (796 MW) | **41** |
| 8,9 (551 MW) | **32** |

In the Study Cases, the spin requirements are satisfied based on co-optimization of energy and reserves in GE MAPS (as is the case in most ISOs in the U.S.). However, we are modeling

DR as the resource of last resort and they are called upon before violating the spin reserve requirements. Spin requirements will be violated only if all DR resources are exhausted.

# 4 Study Cases

As listed in Table 7, in the final round of modeling, the study considered nine cases (also called scenarios) which covered different years including 2012, 2013, 2015, and 2020; and different outlooks on future load, i.e., with and without some industrial loads; and in the case of year 2020, with and without the Maritime Link.

The two future outlooks on load considered two possibilities:

a) a future load outlook without the two major industrial loads of Bowater paper mill (Bowater) and Port Hawkesbury PM2 paper mill (PH PM2)

b) a future load outlook with only PH PM2 in operation

The following sections provide more details on each of the nine Study Cases.

**Table 7: Summary of the Study Cases**

| Case ID | Year | Industrial Load | Maritime Link | Wind Capacity | Available Wind Energy |
|---|---|---|---|---|---|
| **Case 1** | 2012 | No | No | 335 MW | 1,148 GWh |
| **Case 2** | 2013 | Yes | No | 335 MW | 1,148 GWh |
| **Case 3** | 2013 | No | No | 335 MW | 1,148 GWh |
| **Case 4** | 2015 | Yes | No | 488 MW | 1,661 GWh |
| **Case 5** | 2015 | No | No | 488 MW | 1,661 GWh |
| **Case 6** | 2020 | Yes | No | 916 MW | 3,102 GWh |
| **Case 7** | 2020 | No | No | 796 MW | 2,685 GWh |
| **Case 8** | 2020 | Yes | Yes | 551 MW | 1,871 GWh |
| **Case 9** | 2020 | No | Yes | 551 MW | 1,871 GWh |

## 4.1 Case 1: Year 2012 – No Large Industrial Load - No Maritime Link

This case represents the NSPI system "as is" (current state). It served as a benchmark to verify and calibrate system models and analytical techniques used in this study by comparison with NSPI operating records and experience.

Case 1 resource assumptions:

- No Bowater Load, No PH PM2 Load
- No Maritime Link
- Wind capacity of 335 MW

- Resources are projected to meet the Renewable Energy Standard (RES) requirements

## 4.2 Case 2: Year 2013 – With Large Industrial Load - No Maritime Link

Case 2 load and resource assumptions:

- No Bowater Load
- PH PM2 Load Included
- No Maritime Link
- Wind capacity of 335 MW
- Forecasted energy sales of 10,260 GWh
- Resources are projected to meet the Renewable Energy Standard (RES) requirements
- Port Hawkesbury Biomass Plant was added to the 2013 model (relative to the 2012 baseline system model)

## 4.3 Case 3: Year 2013 – No Large Industrial Load - No Maritime Link

Case 3 load and resource assumptions:

- No Bowater Load, No PH PM2 Load
- No Maritime Link
- Wind capacity of 335 MW
- Forecasted energy sales of 9,330 GWh
- Resources are projected to meet the Renewable Energy Standard (RES) requirements
- Port Hawkesbury Biomass Plant was added to the 2013 model (relative to the 2012 baseline system model)

## 4.4 Case 4: Year 2015 – With Large Industrial Load – No Maritime Link

Main features of this case are:

- Forecasted energy sales 10,280 GWh
- To meet 25% RES Regulation, require 2,570 GWh renewable energy
- Sources of renewable energy:
    - Legacy Hydro: 985 GWh
    - Post 2001 IPPs: 742 GWh
    - 2015 Wind Projects announced by the Renewable Energy Administration (REA): 345 GWh
    - Port Hawkesbury Biomass: 388 GWh
    - Existing NSPI-Owned Wind Generation (2012): 254 GWh
    - Pre 2001 IPPs: 156 GWh
    - Community Feed-In Tariff (COMFIT) Projects (assuming ~17 x 2MW wind turbines scattered throughout the province): 100 GWh
    - Minas Basin Biomass: 55 GWh
- Total Renewable Energy Available: 3,025 GWh
- Resources are projected to meet the Renewable Energy Standard (RES) requirements, with a surplus in 2015 of approximately 455 GWh.

## 4.5 Case 5: Year 2015 – No Large Industrial Load – No Maritime Link

Main features of this case are:

- Forecasted energy sales 9,350 GWh
- To meet 25% RES Regulation, require 2,340 GWh of renewable energy
- Sources of Renewable Energy:
    - Legacy Hydro: 985 GWh
    - Post 2001 IPPs:742 GWh
    - NPPH Biomass: 418 GWh
    - 2015 Wind Projects announced by the REA: 345 GWh
    - Existing NSPI-Owned Wind Generation (2012): 254 GWh
    - Pre 2001 IPPs: 156 GWh

  - COMFIT Projects (assuming ~17 x 2MW wind turbines scattered throughout the province): 100 GWh
  - Minas Basin Biomass: 55 GWh
- Total Renewable Energy Available: 3,055 GWh
- Resources are projected to meet the RES requirements with a surplus in 2015 of approximately 715 GWh

## 4.6 Case 6: Year 2020 – With Large Industrial Load – No Maritime Link

Main features of this case are:

- Approximately 915 MW of Installed Wind Capacity
- Forecasted energy sales 10,200 GWh
- To meet 40% RES requirement, require 4,080 GWh of renewable energy
- Sources of Renewable Energy:
  - Additional Wind Energy (Post-2015): 1,095 GWh
  - Legacy Hydro: 985 GWh
  - Post 2001 IPPs: 742 GWh
  - Port Hawkesbury Biomass: 388 GWh
  - 2015 Wind Projects announced by the REA: 345 GWh
  - COMFIT Projects (assuming 50 x 2MW wind turbines scattered throughout the province): 300 GWh
  - Existing NSPI-Owned Wind Generation (2012): 254 GWh
  - Pre 2001 IPPs: 156 GWh
  - Minas Basin Biomass: 55 GWh
  - New small-scale hydro: 15 GWh
- Total Renewable Energy Available: 4,335 GWh
- Resources are projected to meet the RES requirements, with a surplus in 2020 of approximately 250 GWh

## 4.7 Case 7: Year 2020 – No Large Industrial Load – No Maritime Link

Main features of this case are:

- Approximately 795 MW of Installed Wind Capacity
- Forecasted energy sales 9,270 GWh
- To meet 40% RES requirement, require 3,710 GWh of renewable energy
- Sources of Renewable Energy:
- Legacy Hydro: 985 GWh
  - Post 2001 IPPs: 742 GWh
  - Additional Wind Energy (Post-2015): 675 GWh
  - Port Hawkesbury Biomass: 418 GWh
  - 215 Wind Projects announced by the REA: 345 GWh
  - COMFIT Projects (assuming 50 x 2MW wind turbines scattered throughout the province) : 300 GWh
  - Pre 2001 IPPs: 156 GWh
  - Minas Basin Biomass: 55 GWh
  - New small-scale hydro: 15 GWh
- Total Renewable Energy Available: 3,945 GWh
- Resources are projected to meet the RES requirements, with a surplus in 2020 of approximately 235 GWh

## 4.8 Case 8: Year 2020 – With Large Industrial Load – With Maritime Link

Main features of this case are:

- Approximately 550 MW of Installed Wind Capacity
- Forecasted energy sales 10,200 GWh
- To meet 40% RES requirement, require 4,080 GWh of renewable energy
- Sources of Renewable Energy:
  - Legacy Hydro: 985 GWh

- Maritime Link (35 year block): 897 GWh
- Post 2001 IPPs: 742 GWh
- Port Hawkesbury Biomass: 388 GWh
- 2015 Wind Projects announced by the REA: 345 GWh
- COMFIT Project (assuming 50 x 2MW wind turbines scattered throughout the province): 300 GWh
- Maritime Link (Supplemental 5 year block): 261 GWh
- Existing NSPI-Owned Wind Generation (2012): 254 GWh
- Pre 2001 IPPs: 156 GWh
- Minas Basin Biomass: 55 GWh
- New small-scale hydro: 15 GWh

- Total Renewable Energy Available: 4,400 GWh
- Resources are projected to meet the RES requirements, with a surplus in 2020 of approximately 320 GWh

## 4.9 Case 9: Year 2020 - No Large Industrial Load - With Maritime Link

Main features of this case are:

- Approximately 550 MW of Installed Wind Capacity
- Forecasted energy sales 9,270 GWh
- To meet 40% RES requirement, require 3,700 GWh renewable energy
- Sources of Renewable Energy:
    - Legacy Hydro: 985 GWh
    - Maritime Link (35 year block): 897 GWh
    - Post 2001 IPPs: 742 GWh
    - NPPH Biomass: 418 GWh
    - 2015 Wind Projects announced by REA: 345 GWh
    - COMFIT Projects (assuming 50 x 2MW wind turbines scattered throughout the province): 300 GWh

  - Maritime Link (Supplemental 5 year block): 261 GWh
  - Pre 2001 IPPs: 156 GWh
  - Minas Basin Biomass: 55 GWh
  - New small-scale hydro: 15 GWh
- Total Renewable Energy Available: 4,230 GWh
- Resources are projected to meet the RES requirements, with a surplus in 2020 of approximately 720 GWh

# 5 Modeling Assumptions

## 5.1 Nova Scotia Power System

Nova Scotia Power Incorporated (NSPI) is a regulated, vertically-integrated, electric utility and has produced and supplied electricity to Nova Scotia for over 80 years. The company supplies over 97% of the generation, transmission and distribution of electrical power to 460,000 customers in Nova Scotia. NSPI owns 2,293 megawatts (MW) of generation capacity, fuelled by a mix of renewable energy sources and fossil fuels. NSPI manages 5,200 km of transmission lines which move electricity from its generating plants to the 25,000 km of distribution wires that supply power to customers' homes and businesses. Together, they make up the transmission and distribution system that connects NSPI to the North America electricity grid through New Brunswick. Figure 49 depicts a schematic overview of the Nova Scotia grid. The map below highlights key areas and transmission linkages throughout the province, but the modeling used throughout this study uses a more detailed, full transmission model that takes into account a more granular system. This includes each transmission line along with individual load and generator buses.

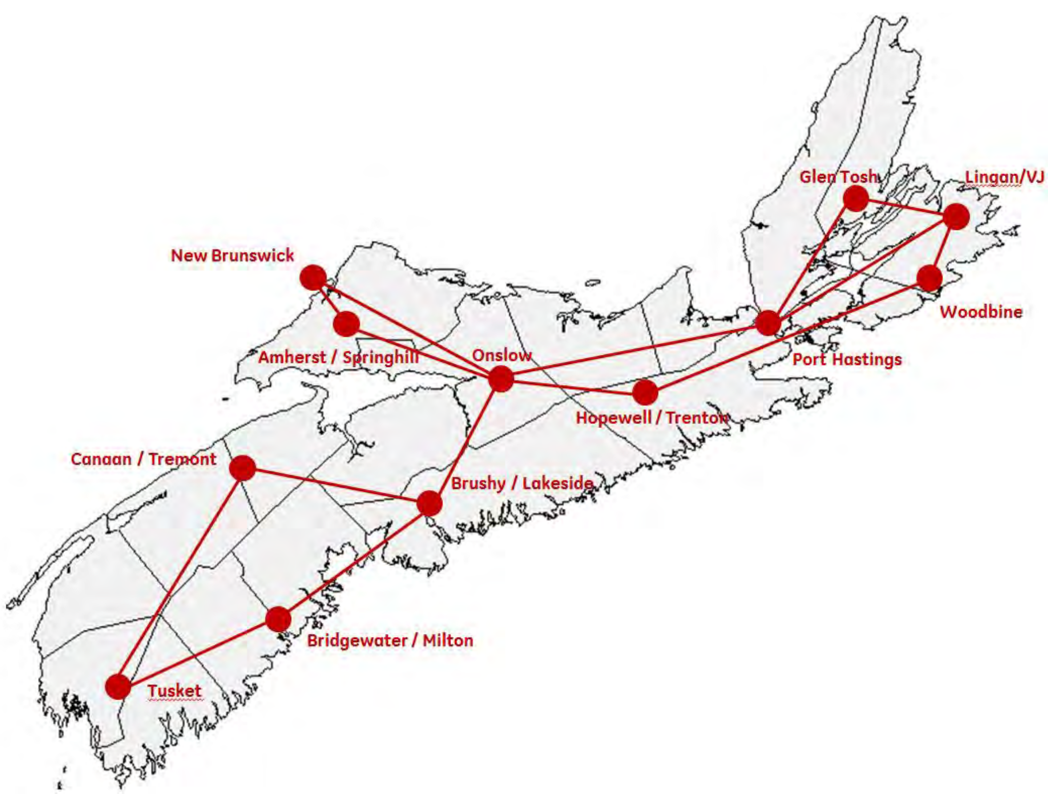



**Figure 49: Nodal Model of the Nova Scotia Power System**

## 5.2 General Modeling Assumptions

This section lists the pertinent modeling assumptions used throughout this study. GE started with the Nova Scotia portion of its GE MAPS model of the North America's Eastern Interconnect, which included the underlying transmission grid and a database of the generation resources, and projection of fuel and load data. The Nova Scotia model was then revised by the more detailed data that NSPI provided in various stages during the project, and generally encompassing all aspects of the Nova Scotia power system, including detailed information on transmission, generation, load, fuel prices, and the relevant operational constraints.

The following list includes the basic assumptions used in the modeling of the Nova Scotia Power system:

- As noted in the Study Case definitions, the modeled years include 2011, 2013, 2015, and 2020.
- Inflation rate is 1.92% per year (applied to inputs such as Variable Operations and Maintenance (VOM) costs, Fixed Operations and Maintenance (FOM) costs, etc.)
- Nova Scotia is represented as one power pool (NSP), and 11 areas (as shown in Figure 49)
- Summer season is from April 1st to October 31st, and during this period thermal units have a capacity derate and planned outages for maintenance.
- Winter season is from November 1st to March 31st, and during this time thermal units have full capacity and no planned outages for maintenance, and transmission lines also have higher ratings.
- For the hourly simulation, GE MAPS can directly model the operating reserve (i.e., Spinning Reserve). In this study we use the results of the statistical analysis to guide the on-line reserve strategy, which we incorporated into the sub-hourly PLEXOS simulations.
- The production simulation analysis assumed that all units were economically committed and dispatched while respecting existing and new transmission limits, generator cycling capabilities, and minimum turndowns, with exceptions made for any must-run unit or units with operational constraints.
- Existing available transmission capacity is accessible to renewable generation.
- Increased O&M of conventional generators due to increased ramping and cycling was not included due to lack of data.
- Renewable energy plant O&M costs were not included. Renewable energy was considered to be a price-taker.

- The hydro modeling did not reflect the specific climatic patterns of 2004, 2005, and 2006, but rather a 10-year long-term average flow per month.
- The sub-hourly modeling assumed a 10-minute economic dispatch.

## 5.3 Nova Scotia Load

NSPI provided the total Nova Scotia load projections and the proportion of the total load (load rations) by each of the 11 areas and for each of the study years. The load shape for each area is based on the 2006 load shape provided by NSPI. The reason to use the 2006 load shape is that the wind shape data is from the year 2006. Since there is a correlation between wind and weather and since load is also weather driven, it was essential to use the same year basis to align the load and the wind shapes. It was assumed that all areas followed the same load shape, scaled to reach their peak load and annual energy targets. With the annual load forecasts and load shape provided by NSPI, GE MAPS processed the information to develop hourly load profiles for each of the study areas. The hourly loads were then distributed to individual load buses within each area.

As noted previously, the Study Cases in each year include one scenario without the two major Bowater and Port Hawkesbury Paper Mill (PH PM2) industrial loads, and one with only one of the industrial loads (PH PM2) included. In cases that included the PH PM2 industrial load, the hourly load pattern was provided by NSPI and was consistent across the scenarios.

Table 8 and Table 9 present the modeled annual area peak demand and annual area energy, respectively. The data presented do not include the industrial load.

**Table 8: Annual Area Peak Demand (MW)**

| Peak Demand (MW) | | | |
|---|---|---|---|
| | **2013** | **2015** | **2020** |
| Amherst | 99 | 99 | 98 |
| Brushy | 857 | 854 | 846 |
| Canaan | 243 | 242 | 240 |
| Glentosh | 32 | 32 | 32 |
| Hastings | 29 | 29 | 29 |
| Hopewell | 215 | 214 | 212 |
| Lingan | 187 | 187 | 185 |
| Milton | 178 | 178 | 176 |
| Onslow | 110 | 110 | 109 |
| Tusket | 81 | 80 | 79 |
| Woodbine | 0 | 0 | 0 |
| Total | **2,032** | **2,025** | **2,004** |

**Table 9: Annual Area Energy (GWh)**

| Annual Energy (GWh) | | | |
|---|---|---|---|
| | **2013** | **2015** | **2020** |
| Amherst | 490 | 491 | 487 |
| Brushy | 4,232 | 4,243 | 4,206 |
| Canaan | 1,199 | 1,202 | 1,192 |
| Glentosh | 160 | 160 | 159 |
| Hastings | 143 | 143 | 142 |
| Hopewell | 1,060 | 1,063 | 1,054 |
| Lingan | 924 | 927 | 919 |
| Milton | 881 | 883 | 875 |
| Onslow | 544 | 545 | 541 |
| Tusket | 398 | 399 | 395 |
| Woodbine | 0 | 0 | 0 |
| Total | **10,031** | **10,056** | **9,969** |

Figure 50 depicts the share of total 2013 Nova Scotia coincident peak load and annual energy in each modeled area.

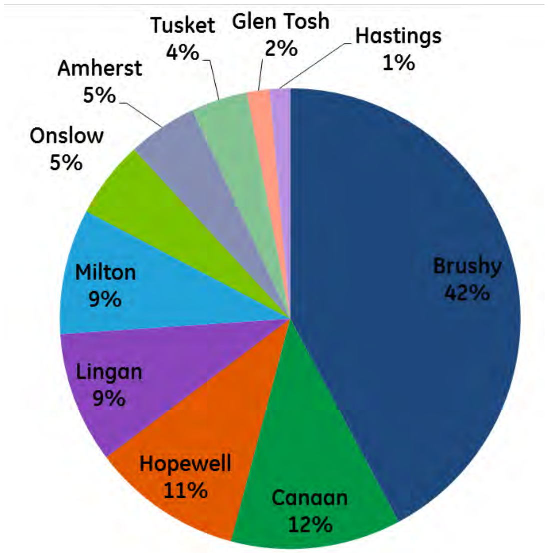



**Figure 50: Share of Total 2013 Nova Scotia Coincident Peak Load in Each Area**

Figure 51 shows the 2013 monthly Nova Scotia system peak and energy and highlights the winter-peaking seasonality of the Nova Scotia system.

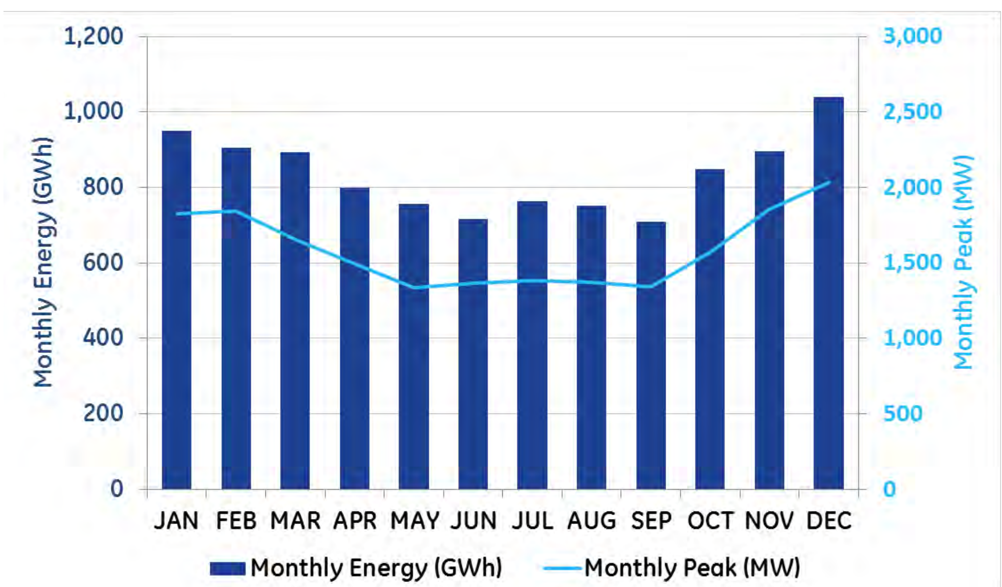



**Figure 51: 2013 Monthly Nova Scotia System Peak and Energy**

Figure 52 shows the annual load duration curve of the NSPI system. The overall load factor is 56%, maximum load is 2,032mw, minimum load is 473mw, and the median load is 1,168mw.

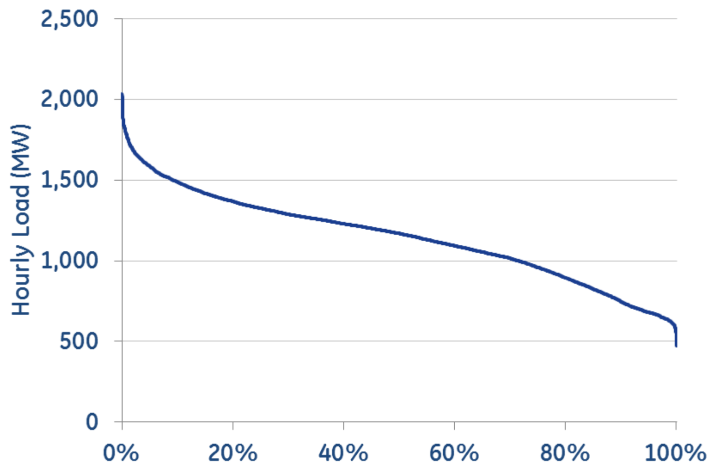



Figure 52: NSPI Annual Load Duration Curve

## 5.4 Generation Mix

As shown in Table 10 and Figure 53 Nova Scotia's 2013 generation mix is dominated by steam coal and hydro resources. Among the thermal generation, after steam coal, steam gas units have the highest share of installed capacity.

Table 10: Nova Scotia Generation Mix (2013)

| *Installed Capacity by Type* | |
|---|---|
| **Type** | **MW** |
| ST Coal | 1,203 |
| ST Gas | 305 |
| CC Gas | 148 |
| GT Oil | 190 |
| Biomass | 48 |
| IPP Other | 26 |
| Hydro | 393 |
| IPP Wind | 260 |
| NSPI Wind | 76 |
| | |
| **Total** | **2,649** |
| | |
| **Total Thermal** | **1,846** |
| **Total Renew** | **803** |
| | |
| **Total Non-Wind** | **2,313** |
| **Total Wind** | **336** |

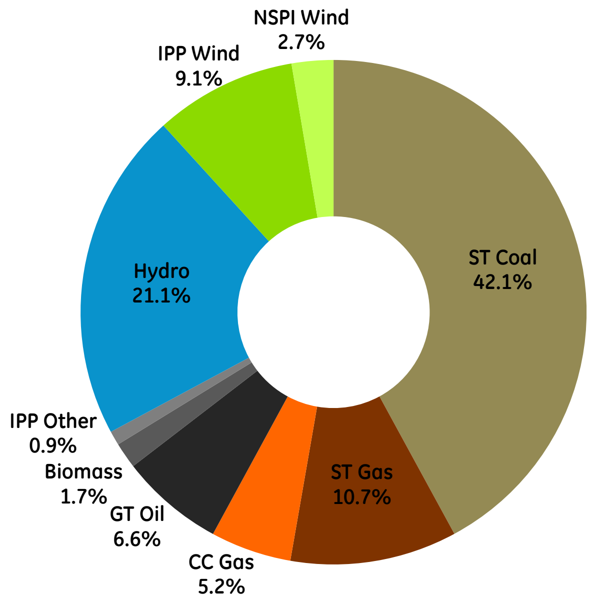



**Figure 53: Share of Nova Scotia Installed Capacity Mix by Unit Type (2013)**

Installed capacity shares of thermal and non-thermal (renewable) resources are shown in Figure 54. Renewable resources, consisting of hydro, wind, and biomass resources, account for about 35% of installed capacity in 2013.

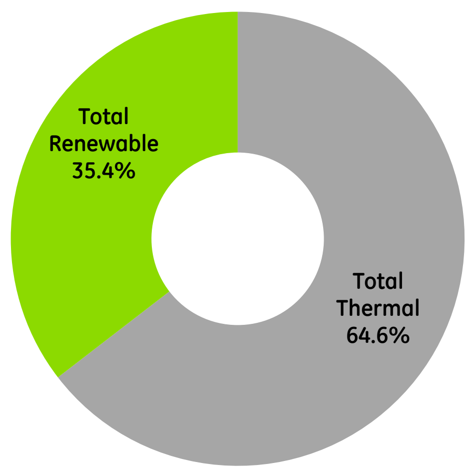



**Figure 54: Share of Nova Scotia Installed Capacity by Thermal and Renewable Resources (2013)**

## 5.5 Thermal Resources

Nova Scotia thermal resources and their unit types and locations are listed in Table 11. Some of the units required special treatment, as described below. Units designated as must-run, which include the types "ST Other (IPP)" and "Biomass" are not dispatchable, and are committed and run all the time except when on maintenance or on forced outage.

**Table 11: Thermal Resource Types and Location**

| MAPS Name | Unit Name | Unit Type | Area |
|---|---|---|---|
| LINGAN1 | Lingan #1 | ST Coal | Lingan |
| LINGAN2 | Lingan #2 | ST Coal | Lingan |
| LINGAN3 | Lingan #3 | ST Coal | Lingan |
| LINGAN4 | Lingan #4 | ST Coal | Lingan |
| PTACONI1 | Pt Aconi #1 | ST Coal | Woodbine |
| PTTUPPER | Pt Tupper #2 | ST Coal | Hastings |
| TRENTON5 | Trenton #5 | ST Coal | Hopewell |
| TRENTON6 | Trenton #6 | ST Coal | Hopewell |
| BURNSID1 | Burnside #1 | GT Oil | Brushy |
| BURNSID2 | Burnside #2 | GT Oil | Brushy |
| BURNSID3 | Burnside #3 | GT Oil | Brushy |
| BURNSID4 | Burnside #4 | GT Oil | Brushy |
| TUSKET1 | Tusket #1 CT | GT Oil | Tusket |
| VICTORI1 | Victoria Junction #1 | GT Oil | Lingan |
| VICTORI2 | Victoria Junction #2 | GT Oil | Lingan |
| TUFTSCO1 | Tufts Cove #1 | ST Gas | Brushy |
| TUFTSCO2 | Tufts Cove #2 | ST Gas | Brushy |
| TUFTSCO3 | Tufts Cove #3 | ST Gas | Brushy |
| TUFTSCO4 | Tufts Cove #4 | CC Gas | Brushy |
| TUFTSCO5 | Tufts Cove #5 | CC Gas | Brushy |
| TUFTSCO6 | Tufts Cove #6 | CC Gas | Brushy |
| TUFTSCDF | Tufts Cove Duct Fire | CC Gas | Brushy |
| SACKVILL | Sackville Landfill | ST Other (IPP)* | Brushy |
| BROOKLYN | Brooklyn Power | ST Other (IPP)* | Milton |
| TAYLORLU | Taylor Lumber | ST Other (IPP)* | Brushy |
| MINASBAS | Minas Basin PP | Biomass* | Canaan |
| PHBIOMAS | PH Biomass | Biomass* | Hastings |
| | | | |
| **Note: ST Other (IPP) and Biomass units are modeled as non-dispatchable must-run units* | | | |

Table 12 lists the thermal resource characteristics.

### Table 12: Thermal Resource Characteristics

| MAPS Name | Max Capacity (MW) | Min Capacity (MW) | FLHR (but/kwh) | Fuel Assignment | Start Cost ($) | VOM ($/MWh) | Min Down Time (Hours) | Min Up Time (Hours) | % of Capacity for Operating Reserve | Quick-Start Capable |
|---|---|---|---|---|---|---|---|---|---|---|
| LINGAN1 | 146.5 | 70 | [redacted] | Lingan Coal | [redacted] | [redacted] | 24 | 24 | 20% | N |
| LINGAN2 | 146.5 | 70 | [redacted] | Lingan Coal | [redacted] | [redacted] | 24 | 24 | 20% | N |
| LINGAN3 | 149.7 | 70 | [redacted] | Lingan Coal | [redacted] | [redacted] | 24 | 24 | 19% | N |
| LINGAN4 | 146.5 | 70 | [redacted] | Lingan Coal | [redacted] | [redacted] | 24 | 24 | 20% | N |
| PTACONI1 | 169.9 | 60 | [redacted] | PT Aconi Coal | [redacted] | [redacted] | 24 | 24 | 0% | N |
| PTTUPPER | 149.4 | 65 | [redacted] | PT Tupper Coal | [redacted] | [redacted] | 24 | 24 | 53% | N |
| TRENTON5 | 139.7 | 70 | [redacted] | Trenton 5 Coal | [redacted] | [redacted] | 24 | 16 | 37% | N |
| TRENTON6 | 155.4 | 70 | [redacted] | Trenton 6 Coal | [redacted] | [redacted] | 24 | 16 | 13% | N |
| BURNSID1 | 33.0 | - | [redacted] | Diesel | [redacted] | [redacted] | 0 | 0 | 50% | Y |
| BURNSID2 | 33.0 | - | [redacted] | Diesel | [redacted] | [redacted] | 0 | 0 | 50% | Y |
| BURNSID3 | 33.0 | - | [redacted] | Diesel | [redacted] | [redacted] | 0 | 0 | 50% | Y |
| BURNSID4 | 33.0 | - | [redacted] | Diesel | [redacted] | [redacted] | 0 | 0 | 50% | Y |
| TUSKET1 | 25.0 | - | [redacted] | Diesel | [redacted] | [redacted] | 0 | 0 | 50% | Y |
| VICTORI1 | 33.0 | - | [redacted] | Diesel | [redacted] | [redacted] | 0 | 0 | 50% | Y |
| VICTORI2 | 33.0 | - | [redacted] | Diesel | [redacted] | [redacted] | 0 | 0 | 50% | Y |
| TUFTSCO1 | 77.0 | 45 | [redacted] | Natural Gas | [redacted] | [redacted] | 16 | 16 | 0% | N |
| TUFTSCO2 | 88.4 | 30 | [redacted] | Natural Gas | [redacted] | [redacted] | 8 | 16 | 33% | N |
| TUFTSCO3 | 139.7 | 40 | [redacted] | Natural Gas | [redacted] | [redacted] | 8 | 16 | 61% | N |
| TUFTSCO4 | 49.0 | - | [redacted] | Natural Gas | [redacted] | [redacted] | 1 | 16 | 49% | Y |
| TUFTSCO5 | 49.0 | - | [redacted] | Natural Gas | [redacted] | [redacted] | 1 | 16 | 49% | Y |
| TUFTSCO6 | 26.0 | - | [redacted] | Natural Gas | [redacted] | [redacted] | 6 | 16 | 49% | N |
| TUFTSCDF | 24.0 | - | [redacted] | Natural Gas | [redacted] | [redacted] | 6 | 16 | 0% | Y |
| SACKVILL | 2.0 | - | - | - | - | - | - | - | - | - |
| BROOKLYN | 23.4 | - | - | - | - | - | - | - | - | - |
| TAYLORLU | 0.8 | - | - | - | - | - | - | - | - | - |
| MINASBAS | 10.0 | - | - | - | - | - | - | - | - | - |
| PHBIOMAS | 60.0 | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | |
| ***Note: combined heat rate for the entire plant, running in 2x1 combined cycle mode* | | | | | | | | | | |

Key thermal resource features include the following:

- Tufts Cove units 4 & 5 are modeled as a single CC unit (CCGAS) – i.e., Tufts Cove 6.
- STOTHER are IPP units modeled to run all hours of the year, i.e., with "Must-Run" designation.
- GTOIL are Diesel units are modeled as quick-start units and are available even if they were not included in the DAH commitment process.
- Winter capacity includes an average derated capacity of October through March, and summer capacity includes the average capacity of April through September.

- Full Load Heat Rate (FLHR) was calculated based on "heat input vs. net generation" curves provided by NSPI for each thermal unit.
- [redacted] is a must-run unit all year due to SPS considerations.
- [redacted] must be forced on during [redacted] outages due to SPS considerations.
- During the winter months, [redacted] of generation must occur in the Brushy (Halifax) area due to voltage support considerations. During the summer months [redacted] of generation is required. This generation can come from any combination of the [redacted].
- All coal units and Tufts Cove Unit#1 are [redacted]

## 5.6 Hydro Resources

List of Nova Scotia hydro units and their main characteristics are presented in Table 13.

**Table 13: Hydro Resource Characteristics**

| MAPS Name | Unit Name | Unit Type | Area | Max Capacity (MW) | Available for Operating Reserve |
|---|---|---|---|---|---|
| ANNAPOLI | Annapolis | Tidal** | Canaan | 16.0 | N |
| WRECKRT | Wreck Cove | Hydro | Glen Tosh | 212.0 | Y |
| AVON | Avon | Hydro | Canaan | 6.8 | Y |
| BLACKRIV | Black River | Hydro | Canaan | 22.5 | Y |
| NICTAUX | Nictaux | Hydro | Canaan | 8.3 | Y |
| LEQUILLE | Lequille | Hydro | Canaan | 11.2 | Y |
| PARADISE | Paradise | Hydro | Canaan | 4.7 | Y |
| MERSEY | Mersey | Hydro | Milton | 42.5 | Y |
| SISSIBOO | Sissiboo | Hydro | Tusket | 24.0 | Y |
| BEARRIVE | Bear River | Hydro | Canaan | 13.4 | Y |
| TUSKETHY | Tusket hydro | Hydro | Tusket | 2.4 | N |
| ROSEWAY | Roseway/Harmony | Hydro | Milton | 1.8 | N |
| STMARGAR | St. Margarets | Hydro | Hopewell | 10.8 | N |
| SHHARBOR | Sh. Harbour | Hydro | Brushy | 10.8 | N |
| DICKIEBR | Dickie Brook | Hydro | Hastings | 3.8 | N |
| FALLRIVE | Fall River | Hydro | Brushy | 0.5 | N |
| IPPBLACK | IPP Black River | Hydro | Hastings | 0.2 | N |
| MORGANFA | Morgan Falls | Hydro | Canaan | 0.5 | N |

**Note: Hydro generation is based on average of 5-years of available data (2007-2011)*
***Note: Annapolis is modeled as a tidal plant, following an hourly pattern*

Key hydro resource features include the following:

- Hydro units are characterized by a Minimum Hourly Generation and a Maximum Hourly Generation.
- Within these bounds the unit's monthly energy generation is limited to a Monthly Energy Target (provided by NSPI), and is dispatched for peak shaving purposes.
- Annapolis is a tidal unit and follows an hourly shape provided by NSPI and based off of 2006 generation profile.
- Wreck Cove is a hydro plant with special characteristics - modeled as a more flexible plant subject to certain operational limitations – that can play an important role in responding to wind forecast errors. The Wreck Cove schedule is determined based on a pre-model-run analysis, which is then fed into GE MAPS as an hourly generation schedule. More details on Wreck Cove are provided later.

## 5.7 Renewable Wind Resources

The Base Case wind resources and their characteristics are listed in Table 14.

**Table 14: Base Case Wind Resource Characteristics**

| MAPS Name | Unit Name | Unit Type | Area | Max Capacity (MW) | Available Energy (GWh) | Capacity Factor | Curtailment Order |
|---|---|---|---|---|---|---|---|
| *Base Case Wind Units* | | | | | | | |
| GLACEBAY | CBP: Glace Bay 1B | Wind | LINGAN | 0.8 | [redacted] | [redacted] | [redacted] |
| DONKIN01 | CBP: Donkin | Wind | LINGAN | 0.8 | [redacted] | [redacted] | [redacted] |
| SPRINGHI | Confederation: Springhill | Wind | ONSLOW | 2.1 | [redacted] | [redacted] | [redacted] |
| HIGGINSM | Confederation: Higgins Mt | Wind | ONSLOW | 3.6 | [redacted] | [redacted] | [redacted] |
| TIVERTON | Confederation: Tiverton | Wind | CANAAN | 0.9 | [redacted] | [redacted] | [redacted] |
| GOODWOOD | RESL: Goodwood | Wind | BRUSHY | 0.6 | [redacted] | [redacted] | [redacted] |
| BROOKFIE | RESL: Brookfield | Wind | ONSLOW | 0.6 | [redacted] | [redacted] | [redacted] |
| PTUPPER1 | IPP12-Point Tupper 1 | Wind | HASTINGS | 0.8 | [redacted] | [redacted] | [redacted] |
| TATAMAGO | RESL: Tatamagouche | Wind | ONSLOW | 0.8 | [redacted] | [redacted] | [redacted] |
| DIGBYW1 | RESL: Digby 1 | Wind | CANAAN | 0.8 | [redacted] | [redacted] | [redacted] |
| FITZPATR | Shear Wind: Fitzpatrick Mt | Wind | ONSLOW | 1.6 | [redacted] | [redacted] | [redacted] |
| MARYVALE | RMS Energy: Maryvale | Wind | HOPEWELL | 6.0 | [redacted] | [redacted] | [redacted] |
| WATTS | Watts | Wind | HOPEWELL | 1.5 | [redacted] | [redacted] | [redacted] |
| FAIRMOUN | Fairmount | Wind | HOPEWELL | 4.0 | [redacted] | [redacted] | [redacted] |
| DUNVEGAN | Dunvegan | Wind | HASTINGS | 2.0 | [redacted] | [redacted] | [redacted] |
| GRANVILL | Granville Ferry | Wind | CANAAN | 2.0 | [redacted] | [redacted] | [redacted] |
| ISLEMADA | Isle Madamme | Wind | HASTINGS | 2.0 | [redacted] | [redacted] | [redacted] |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| CRAEGNIS | Craegnish | Wind | HASTINGS | 6.0 | [redacted] | [redacted] | [redacted] |
| IRISHMOU | Irish Mountain | Wind | HOPEWELL | 6.0 | [redacted] | [redacted] | [redacted] |
| CAPEMABO | Cape Mabou | Wind | HASTINGS | 6.0 | [redacted] | [redacted] | [redacted] |
| SPIDDLEH | Spiddle Hill | Wind | ONSLOW | 0.8 | [redacted] | [redacted] | [redacted] |
| CAPENORT | Cape North | Wind | HASTINGS | 0.7 | [redacted] | [redacted] | [redacted] |
| DONKIN02 | Donkin (CP) | Wind | LINGAN | 1.6 | [redacted] | [redacted] | [redacted] |
| GRANDETA | Grand Etang | Wind | GLENTOSH | 0.6 | [redacted] | [redacted] | [redacted] |
| LITTLEBR | Little Brook | Wind | TUSKET | 0.6 | [redacted] | [redacted] | [redacted] |
| NUTTBYMT | AVP: Nuttby Mt. | Wind | ONSLOW | 45.0 | [redacted] | [redacted] | [redacted] |
| GULLIVER | Gulliver Cove | Wind | CANAAN | 30.0 | [redacted] | [redacted] | [redacted] |
| BEARHEAD | Bear Head | Wind | HASTINGS | 22.0 | [redacted] | [redacted] | [redacted] |
| LINGANW | CBP: Lingan | Wind | LINGAN | 14.0 | [redacted] | [redacted] | [redacted] |
| PUBNICOP | Pubnico Point Wind Farm | Wind | TUSKET | 30.6 | [redacted] | [redacted] | [redacted] |
| DALHOUSI | RMS Energy: Dalhousie Mt. | Wind | ONSLOW | 51.0 | [redacted] | [redacted] | [redacted] |
| GLENDHU | Glen Dhu | Wind | HOPEWELL | 60.0 | [redacted] | [redacted] | [redacted] |
| AMHERSTW | Acciona: Amherst | Wind | AMHERST | 30.0 | [redacted] | [redacted] | [redacted] |

Future wind resources that are added to the model in order to satisfy future planned and expected RES targets are listed in Table 15.

**Table 15: Future Wind Resource Characteristics**

| MAPS Name | Unit Name | Unit Type | Area | Max Capacity (MW) | Available Energy (GWh) | Capacity Factor | Curtailment Order |
|---|---|---|---|---|---|---|---|
| *2015 COMFIT Units* | | | | | | | |
| CFITTUSK | Tusket Area COMFIT Unit | Wind | Tusket | 4.0 | 13.7 | 39% | 27 |
| CFITCANA | Canaan Area COMFIT Unit | Wind | Canaan | 4.0 | 14.2 | 41% | 26 |
| CFITBRUS | Brushy Area COMFIT Unit | Wind | Brushy | 4.0 | 14.0 | 40% | 25 |
| CFITHOPE | Hopewell Area COMFIT Unit | Wind | Hopewell | 4.0 | 13.0 | 37% | 24 |
| CFITAMHE | Amherst Area COMFIT Unit | Wind | Amherst | 4.0 | 12.7 | 36% | 23 |
| CFITONSL | Onslow Area COMFIT Unit | Wind | Onslow | 4.0 | 13.6 | 39% | 22 |
| CFITHAST | Hastings Area COMFIT Unit | Wind | Hastings | 4.0 | 12.4 | 35% | 21 |
| CFITGLEN | Glen Tosh Area COMFIT Unit | Wind | Glen Tosh | 4.0 | 12.5 | 36% | 20 |
| CFITLING | Lingan Area COMFIT Unit | Wind | Lingan | 4.0 | 13.2 | 38% | 19 |
| | | | | | | | |
| *2020 COMFIT Units* | | | | | | | |
| CFITTUSK | Tusket Area COMFIT Unit | Wind | Tusket | 10.0 | 34.7 | 36% | 27 |
| CFITCANA | Canaan Area COMFIT Unit | Wind | Canaan | 10.0 | 35.9 | 37% | 26 |
| CFITBRUS | Brushy Area COMFIT Unit | Wind | Brushy | 10.0 | 35.1 | 36% | 25 |
| CFITHOPE | Hopewell Area COMFIT Unit | Wind | Hopewell | 10.0 | 32.7 | 34% | 24 |
| CFITAMHE | Amherst Area COMFIT Unit | Wind | Amherst | 10.0 | 31.8 | 33% | 23 |
| CFITONSL | Onslow Area COMFIT Unit | Wind | Onslow | 10.0 | 34.1 | 35% | 22 |
| CFITHAST | Hastings Area COMFIT Unit | Wind | Hastings | 10.0 | 31.3 | 32% | 21 |
| CFITGLEN | Glen Tosh Area COMFIT Unit | Wind | Glen Tosh | 10.0 | 31.6 | 33% | 20 |
| CFITLING | Lingan Area COMFIT Unit | Wind | Lingan | 10.0 | 33.0 | 34% | 19 |
| | | | | | | | |
| *REA Wind Units* | | | | | | | |
| REAWND78 | REA Wind #1 @ Canaan | Wind | Canaan | 78.0 | 285.7 | 42% | 8 |
| REAWND24 | REA Wind #2 @ Canaan | Wind | Canaan | 24.0 | 87.0 | 41% | 7 |
| REAWND14 | REA Wind #3 @ Port Hastings | Wind | Hastings | 13.8 | 44.3 | 37% | 6 |
| | | | | | | | |
| *Generic Wind Expansion Units to REA's 40% RES Requirement* | | | | | | | |
| XHOPE125 | Generic Wind #1 for 40% RES @ Hopewell | Wind | Hopewell | 125.0 | 414.2 | 38% | 5 |
| XHOPE60I | Generic Wind #2 for 40% RES @ Hopewell | Wind | Hopewell | 60.0 | 198.8 | 38% | 4 |
| XAMHE60I | Generic Wind #3 for 40% RES @ Amherst | Wind | Amherst | 60.0 | 192.9 | 37% | 3 |
| XONSL60I | Generic Wind #4 for 40% RES @ Onslow | Wind | Onslow | 60.0 | 207.1 | 39% | 2 |
| XCANAA60 | Generic Wind #5 for 40% RES @ Canaan | Wind | Canaan | 60.0 | 217.9 | 41% | 1 |

All wind units are modeled as hourly load modifiers in GE MAPS and follow a pre-defined hourly generation wind shape. The wind shapes used throughout the study were provided by AWST and represent modeled wind patterns based on meteorological data from the year 2006. AWST provided two shapes for each wind site location in the province. One shape represents a DAH wind forecast that is used only during the GE MAPS commitment process, while the other shape represents a real time wind availability that is used during the GE

MAPS dispatch process. Each wind plant was then assigned to a unique AWST pattern based on its location in the province and scaled according to the MW rating of the plant. It is important to note that the inputs into GE MAPS are hourly wind *availability* patterns only. The hourly generation however is an output from the GE MAPS algorithm that takes into account any necessary curtailment. Table 16 shows the available wind energy in each of the Study Cases. Wind shapes are held constant throughout the study, but changes to the installed wind capacity across the cases changes the overall available energy.

**Table 16: Available Wind Energy by Study Case**

| *Available Wind Energy (GWh)* | |
|---|---|
| Case #1 - #3 | 1,148 |
| Case #4 - #5 | 1,661 |
| Case #6 | 3,102 |
| Case #7 | 2,685 |
| Case #8 - #9 | 1,871 |

## 5.8 Generation Unit Additions and Retirements

Some generating unit additions reflect expected future plans related to actual units. Others are additions to satisfy future planned and expected RES targets, depending on the expectation of renewable capacity shortfalls in Study Cases. Table 17 lists generating unit additions by year and Study Cases.

**Table 17: Generating Unit Additions by Year and Study Case**

| *Generating Unit Additions* | | | | |
|---|---|---|---|---|
| **Unit** | **Unit Type** | **Capacity** | **Year** | **Case #** |
| ***Thermal Unit Additions*** | | | | |
| PH Biomass | ST Biomass | 60 | 2013 | #1-9 |
| Minas Basin Biomass | ST Biomass | 10 | 2014 | #4-9 |
| Burnside #4 | GT Oil | 33 | 2015 | #6-9 |
| | | | | |
| ***Wind Unit Additions*** | | | | |
| COMFIT (2015)* | Wind | 34 | 2015 | #4-5 |
| COMFIT (2020)* | Wind | 100 | 2020 | #6-9 |
| REA Wind #1 @ Canaan | Wind | 78 | 2015 | #4-9 |
| REA Wind #2 @ Canaan | Wind | 24 | 2015 | #4-9 |
| REA Wind #3 @ Port Hastings | Wind | 14 | 2015 | #4-9 |
| Generic Wind #1 for 40% RES @ Hopewell | Wind | 125 | 2020 | #6-7 |
| Generic Wind #2 for 40% RES @ Hopewell | Wind | 60 | 2020 | #6 |
| Generic Wind #3 for 40% RES @ Amherst | Wind | 60 | 2020 | #6-7 |
| Generic Wind #4 for 40% RES @ Onslow | Wind | 60 | 2020 | #6-7 |
| Generic Wind #5 for 40% RES @ Canaan | Wind | 60 | 2020 | #6 |

Table 18 lists the steam coal units that are planned to be retired. Based on information provided by NSPI,

- Lingan Unit #2
  - Retires in March 2015 assuming that:
    - Burnside Unit #4 is back in service
    - PH Biomass is firm capacity
    - Wind firm capacity contribution is 30-40%
- Lingan Unit #1
  - Retires in January 2018 when Maritime Link comes into service

**Table 18: Generating Unit Retirements by Year and Study Case**

| *Generating Unit Retirements* | | | | |
|---|---|---|---|---|
| **Unit** | **Unit Type** | **Capacity (MW)** | **Year** | **Case #** |
| Lingan 1 | ST Coal | 146.5 | 2018 | #6-9 |
| Lingan 2 | ST Coal | 146.5 | March 2015 | #4-9 |

## 5.9 Fuel Price Projections

Annual coal price and monthly Natural Gas price projections were provided by NSPI for each fuel type and for each study year.

Table 19 presents the assumed annual coal and diesel/oil prices. Coal prices are shown for different types of coal, specific for each coal plant. Coal prices used in the Base Case modeling and analysis reflect the cleanest (most expensive) fuel blend available. The clean coal was used for the Base Case to ensure that environmental emissions do not violate the emission caps. A sensitivity analysis was performed with a less expensive fuel blend to evaluate the impact of an alternative fuel blend. Results of that sensitivity analysis are provided in a later section.

**Table 19: Annual Coal and Diesel/Oil Prices**

| *Assumed Fuel Prices ($/mmBtu)* | | | |
|---|---|---|---|
| | **2013** | **2015** | **2020** |
| ***Coal Prices*** | | | |
| PT Aconi | [redacted] | [redacted] | [redacted] |
| Lingan | [redacted] | [redacted] | [redacted] |
| PT Tupper | [redacted] | [redacted] | [redacted] |
| Trenton 5 | [redacted] | [redacted] | [redacted] |
| Trenton 6 | [redacted] | [redacted] | [redacted] |
| ***Average*** | [redacted] | [redacted] | [redacted] |
| | | | |
| ***Diesel / Oil Price*** | [redacted] | [redacted] | [redacted] |

Table 20 presents the monthly natural gas prices for each year of the study.

**Table 20: Monthly Natural Gas Prices**

| *Assumed Fuel Prices ($/mmBtu)* | | | |
|---|---|---|---|
| | **2013** | **2015** | **2020** |
| ***Natural Gas Prices*** | | | |
| January | [redacted] | [redacted] | [redacted] |
| February | [redacted] | [redacted] | [redacted] |
| March | [redacted] | [redacted] | [redacted] |
| April | [redacted] | [redacted] | [redacted] |
| May | [redacted] | [redacted] | [redacted] |
| June | [redacted] | [redacted] | [redacted] |
| July | [redacted] | [redacted] | [redacted] |
| August | [redacted] | [redacted] | [redacted] |
| September | [redacted] | [redacted] | [redacted] |
| October | [redacted] | [redacted] | [redacted] |
| November | [redacted] | [redacted] | [redacted] |
| December | [redacted] | [redacted] | [redacted] |
| ***Average*** | [redacted] | [redacted] | [redacted] |

As shown in Figure 55, the monthly pattern of natural gas prices, and their value relative to annual coal prices, results in a seasonal switching of dispatch of coal-fired versus gas-fired units in 2013 and 2015. Such a switching also occurs with the improved efficiency of the CC unit.

[redacted]

**Figure 55: Comparison of Monthly Natural Gas and Annual Coal Prices**

**THIS FIGURE IS CONFIDENTIAL**

## 5.10 Transmission

GE used the 2013 Nova Scotia solved power flow data provided by NSPI transmission experts as input into the GE MAPS model. GE MAPS model includes the full configuration of the Nova Scotia transmission grid including all the major transmission lines and transmission system buses and line constraints. Also included are all the major thermal and contingency constraints with summer and winter ratings applied, and other operational constraints that can be represented by nomograms in GE MAPS. An example is the Special Protection System (SPS) arming of Lingan units for reliability contingencies.

For load and generation bus assignments:

- All load buses are assigned to the appropriate areas.
- All large generation units are assigned to the correct generation bus.
- Some small wind and hydro units with unknown bus locations are assigned to the large transmission node in the corresponding area.

Relevant operating and transmission constraints that are modeled in GE MAPS are summarized below:

1. Transmission Interface Limits:
    a. ONS West-of-Onslow Interface limited to 900mw
    b. ONI West-of-Hopewell Interface limited to 1,025mw
    c. CBX West-of-Hastings Interface limited to 900mw
2. [redacted] SPS Arming:
    a. [redacted] is a must-run at full capacity during all hours.
    b. If [redacted] is offline for maintenance, [redacted] is must-run at full capacity.
3. Halifax Voltage Support[1]:
    a. During the winter, [redacted] MW of generation must be in the Halifax area.
    b. During the summer, [redacted] MW of generation must be in the Halifax area.
    c. All Tufts Cove and Burnside units count towards Halifax generation.
4. Import Limit:
    a. Imports are [redacted]

[1] Halifax Voltage Support information is confidential and has been redacted.

5. Minimum ST units on-line:
    a. At least 4 steam turbines must be online at any given time.

## 5.11 Unit Maintenance

All thermal units and Wreck Cove hydro units have a fixed maintenance schedule for 2013, 2015, and 2020 provided by NSPI. In addition, individual thermal units have unplanned forced outage rates (between 3% and 5%) provided by NSPI, that are randomly assigned throughout the year by GE-MAPS. Table 21 shows the duration of scheduled thermal unit outages.

**Table 21: Duration of Scheduled Thermal Outages**

| | |
|---|---|
| Mini | |
| Minor | |
| Major | |
| Retired | |

| Unit | Weeks (2013) | Weeks (2014) | Weeks (2015) | Weeks (2016) | Weeks (2017) | Weeks (2018) | Weeks (2019) | Weeks (2020) |
|---|---|---|---|---|---|---|---|---|
| LIN1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LIN2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LIN3 | 8 | 3 | 4 | 5 | 4 | 3 | 4 | 6 |
| LIN4 | 3 | 8 | 3 | 4 | 3 | 4 | 3 | 4 |
| POA | 4 | 8 | 4 | 4 | 4 | 4 | 4 | 4 |
| POT | 3 | 3 | 3 | 3 | 3 | 3 | 8 | 3 |
| TRE5 | 1 | 5 | 4 | 3 | 4 | 3 | 4 | 8 |
| TRE6 | 3 | 4 | 8 | 2 | 4 | 2 | 3 | 4 |
| TUC1 | 3 | 4 | 8 | 3 | 4 | 3 | 3 | 4 |
| TUC2 | 3 | 4 | 3 | 3 | 4 | 8 | 3 | 4 |
| TUC3 | 3 | 4 | 3 | 3 | 4 | 3 | 8 | 4 |
| TUC4 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| TUC5 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| TUC6-1 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| TUC6-2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| TUC 6 T/G | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 6 |
| PH Bio | 0 | 3 | 4 | 3 | 4 | 3 | 4 | 6 |
| BDS1 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| BDS1 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| BDS3 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| BDS4 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| VJ1 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| VJ2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Tusket | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| WC1 | 3 | 4 | 6 | 8 | 2 | 2 | 2 | 2 |
| WC2 | 2 | 3 | 4 | 6 | 8 | 4 | 2 | 2 |

## 5.12 Air Emission Caps

Future annual Air Emission Caps by different emission types, including CO2, SOx, and NOx in kilo Tons (kT), and Mercury (Hg) in kilo grams (kg), were provided by NSPI, and are shown in Table 22. GE MAPS results demonstrated that these caps were not violated in any of the years as long as the cleanest (and more expensive) coal fuels were used when given the choice.

**Table 22: Air Emission Caps**

| Air Emission Caps | | | | |
|---|---|---|---|---|
| Year | **CO2 (kT)** | **SOx (kT)** | **NOx (kT)** | **Hg (kg)** |
| 2012 | 9,620 | 72.5 | 21.4 | 80 |
| 2013 | 9,435 | 72.5 | 21.4 | 70 |
| 2014 | 9,249 | 72.5 | 21.4 | 63 |
| 2015 | 9,064 | 60.9 | 19.2 | 60 |
| 2016 | 8,796 | 60.9 | 19.2 | 60 |
| 2017 | 8,528 | 60.9 | 19.2 | 60 |
| 2018 | 8,261 | 60.9 | 19.2 | 58 |
| 2019 | 7,993 | 60.9 | 19.2 | 52 |
| 2020 | 7,500 | 36.2 | 15.0 | 35 |

Table 23 includes the assumed carbon and sulfur emission rates by unit and fuel types. The carbon emission of natural gas units is close to one-half of coal-fired units, on per unit of equivalent heat basis. The sulfur emission of natural gas-fired units is negligible.

**Table 23: Emission Rates by Unit and Fuel Type**

| *Assumed Fuel Emissions (Metric Tons/mmBtu)* | | |
|---|---|---|
| | **Carbon Content** | **Sulfur Content** |
| ***Coal Emissions*** | | |
| PT Aconi | 0.105647 | 0.000490 |
| Lingan | 0.096755 | 0.000490 |
| PT Tupper | 0.096755 | 0.000490 |
| Trenton 5 | 0.096755 | 0.000490 |
| Trenton 6 | 0.096755 | 0.000490 |
| Trenton 6 (2020) | 0.096755 | 0.000490 |
| | | |
| ***Diesel / Oil Emissions*** | 0.078020 | 0.000001 |
| | | |
| ***Natural Gas Emissions*** | 0.055580 | 0.000000 |

# 6 Special Considerations

In the Nova Scotia power grid system, a number of system elements require special consideration and handling, not only for the important role they play in balancing of the system, but also for the complexity of their operational constraints. The section takes a closer look at the following system elements and discusses their modeling treatments:

- Wreck Cove Hydro Plant
- New Brunswick Imports/Exports
- Maritime Link Imports

## 6.1 Wreck Cove Hydro Plant

### 6.1.1 Role of Wreck Cove Hydro

Wreck Cove Hydro (WC) Hydro Plant is a critical resource within the Nova Scotia power system, and due to its special characteristics and operational features it is mostly utilized for short-term load balancing and contingency reserve. This short-term flexibility differentiates it from other hydro plants which mostly function as DAH peak shaving resources. WC has some considerable limitations in terms of its size and availability but also a very high degree of maneuverability. Hence, we examined the real-time dispatch capability of WC and its impact on mitigating high wind variability in our sensitivity analysis.

Special characteristics of Wreck Cove:

- It is fed by run-off hydro into an upper pond with quite limited storage, on the order of a few hours at or near rated power of the plant.
- The plant has two identical units in parallel, each with a maximum capacity of 106 MW.
- They cannot operate between the range of 0 and 45 MW. They can either be at 0 MW, or when running, operate at a minimum power of 45 MW, because of cavitation.
- Run-up/ramp-up of each unit is 10 MW/Minute.
- Maximum Energy per day:
    - JAN, FEB, MAR, MAY, DEC: 1.1 GWh /day (for both units combined)
    - JUN: 0.5 GWh /day
    - APR, JUL, AUG, SEP, OCT, NOV: 0.8 GWh/day
    - Automatic Generation Control (AGC): 90-200 MW

The units are maneuverable, but the small amount of pondage storage makes managing the resource different from most of hydro resources. It requires special, non-standard treatment in the production simulations to give reasonable results.

### 6.1.2 Wreck Cove Commitment and Dispatch

Most hydro pondage plants are typically dispatched as peak shavers, meaning that they are mostly used to smooth out the daily (or weekly) load cycles and reduce the need for peakers during on-peak periods. The hydro pondage plants are pre-scheduled before any thermal unit commitment and dispatch. The pre-scheduling of hydro plants is subject to respecting their monthly energy limits and hourly discharge limits.

The exception is WC, which due to its special characteristics it is used as a fast responding resource to mitigate wind forecast error in closer to real time. The salient features of the modeling of the WC include:

- Wreck cove can be maneuvered during the day, but still needs to respect power and energy limits as described above.
- The DAH schedule of WC was modified such that WC is a preferred resource to cover wind forecast errors according to the following rules:
    - If WC is already committed (non-zero dispatch from DAH schedule), then:
        - Respecting power limits, it will try to correct for forecast errors.
    - But, the NSPI operators will be less inclined to use that capability, depending on the level of the reservoir. Therefore,
        - If the pondage is “low”, then WC contributes less to correcting under-forecasts (and vise-versa).
- Further, the operator will tend to “bias” the schedule to return the reservoir to an optimal level.
- The result is wider swings in power and pondage, but within the reservoir limits.
- This is intended to be an algorithmic proxy for smarter human intervention (i.e., although a reasonable approach, this is still an approximation of the actual and more complex operation!)
- Results discussed later consider possible strategies that might further take advantage of WC operational flexibility. Narrative appears in the appropriate sections.

### 6.1.3 Wreck Cove Operational Algorithm

The following sequence shows the behavior of the components of the WC algorithm used in the study. As noted, this is intended to be a proxy for the smarter human operator actions.

Figure 56 illustrates the DAH schedule of WC for a selected week. As shown, in DAH, WC is scheduled to peak shave the modified net load (original load modified after scheduling of other pondage hydro and addition of DAH forecasted wind power). When on-line, any up-range or remaining capacity (difference of plant rating and current dispatch) can be counted towards meeting spin requirement. The graphic shows the WC dispatch in red, "shaving off" the daily peak of net load. Each day is scheduled subject to the daily energy target (supplied by NSPI) and subject to the power limitations of the generators. This dispatch philosophy is intended to give the best value for the limited available daily energy by helping to avoid higher priced thermal generation at the top of the dispatch stack.

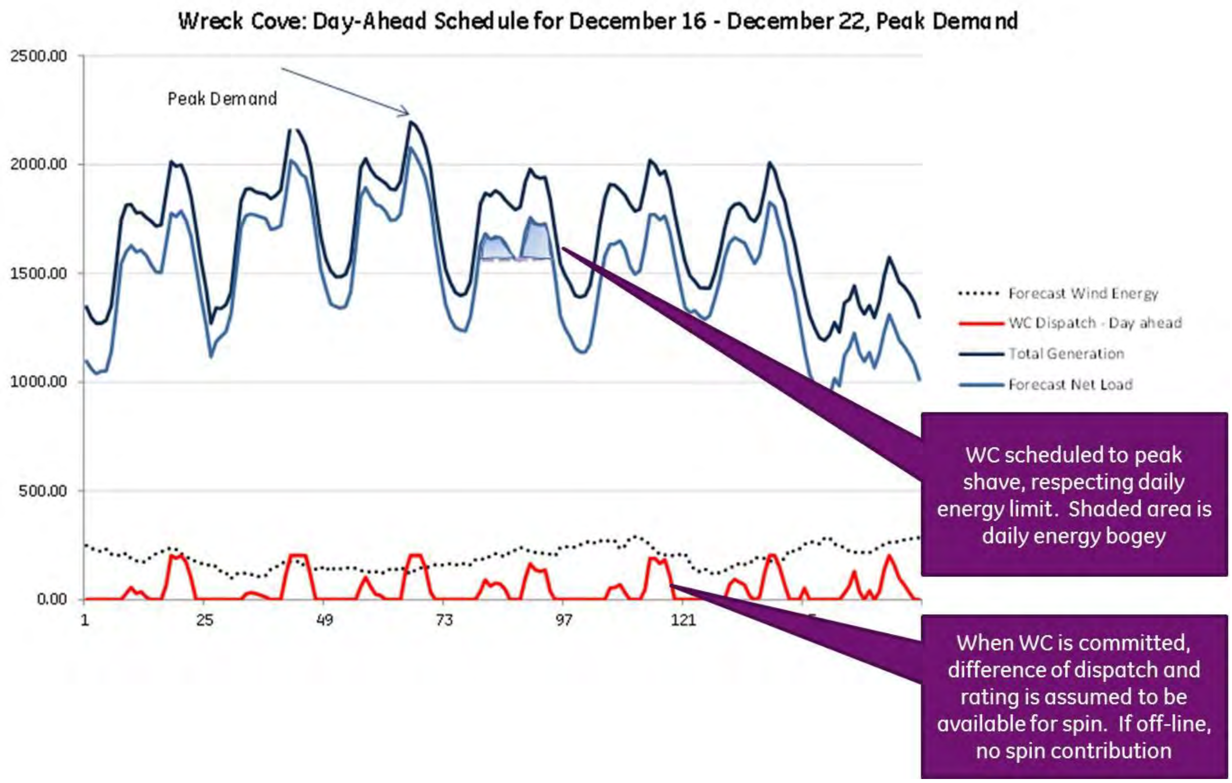



**Figure 56: Peak Shaving DAH Net Load Forecast**

Figure 57 shows the daily dispatch of WC for a whole year. The straight lines are the daily WC energy limits provided by NSPI which vary by month, but averages to about [redacted] capacity factor. The yellow curve is the daily WC energy discharge, which is at most about [redacted], since the maximum dispatch power is assumed to be [redacted] MW ([redacted] MW out of [redacted] MW is always kept available for spin). The blue curve is the running integral of energy in and out, and hence, represents the daily pondage storage level, which fluctuates daily. Note that in this figure we have used rather odd units: GWh/day for power and GW-day for energy. This is to allow the hourly dispatch (in yellow) to be plotted meaningfully with the daily energy targets – which are given in GWh each day (the black line). Notice that yellow lines (power) greatly exceed the average (black line) – this is consistent with a roughly [redacted] annual capacity factor for the plant. The blue trace is energy – the integral of power. We have labeled this "Virtual Pondage". We have no knowledge of the actual pondage, volume or head, but we know that there is a [redacted]. This is sufficient information for the purpose of scheduling the use of that available energy most effectively. The pondage variation is [redacted].

[redacted]

**Figure 57: WC Dispatch: Power and Energy**

**THIS FIGURE IS CONFIDENTIAL**

During real-time (and near real-time) operation, WC can be a valuable resource for covering wind forecast errors. As noted above, the idea is that the human operators will be more inclined to increase generation when the pond level is higher, and will be more inclined to reduce power from the scheduled power when the pond is relatively less full. The real-time schedule is modified according to the wind forecast error and the virtual pondage. Figure 58 illustrates the difference between DAH and real time (RLT) dispatch of WC. The RLT dispatch is more volatile and drives wider swings in the pondage (the light blue trace as compared with the purple trace which is reproduced in this plot from the previous figure), as the dispatch varies trying to mitigate the wind forecast error. The dispatch must be adjusted more slowly to reestablish a reasonable pondage level. There is a trade-off between managing the pondage level towards a center dead-band and aggressively mitigating the wind forecast error.

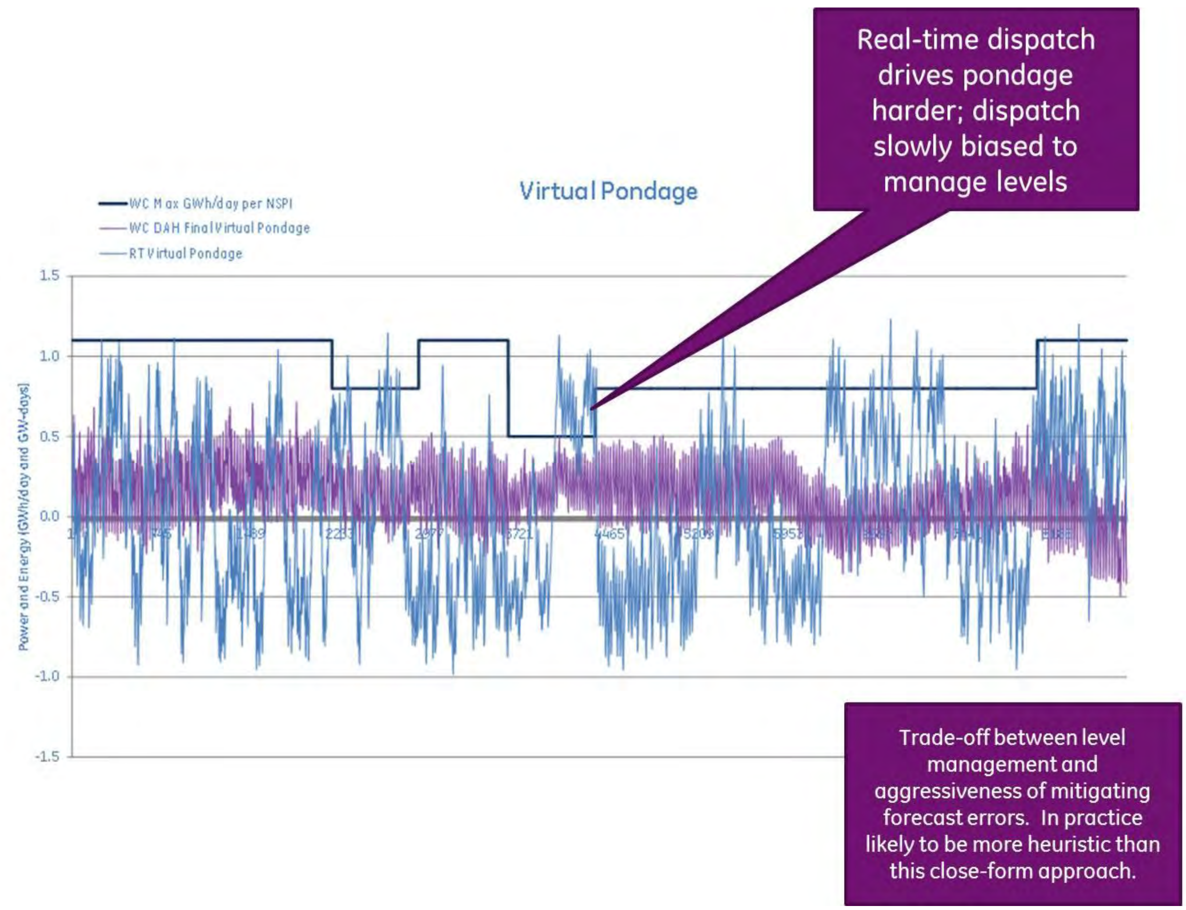



**Figure 58: Pondage Hydro Management**

As shown in Figure 59, the interplay of the direction of the wind forecast error and the pondage level influences how hard the pondage is driven to react to the forecast error (the purple trace in the figure). When the directions of the forecast error and the pondage level coincide, WC is pushed harder. But, when directions of the forecast error and the pondage level conflict, WC is pushed more moderately. The pondage reset bias (the black trace) refers to the tendency to manage and restore the pondage storage level towards a center dead-band, to ensure that the pondage does not run empty and there is continuous pondage availability to respond to the future forecast errors.

The result shown here is the result of some experimentation. In practice, the human operators will almost certainly develop heuristic methods that are at least this sophisticated. It is possible that operational tools that provide guidance based on pondage, power and forecast information could be developed to aid the human operators, and assure the NSPI gets the most operational benefit from this valuable resource. This real-time dispatch is supplied to the MAPS simulation as an input. It is therefore not sensitive to commitment and dispatch of thermal resources. This is a limitation of our modeling that will result in somewhat less ideal utilization of WC that might be expected in actual operation.

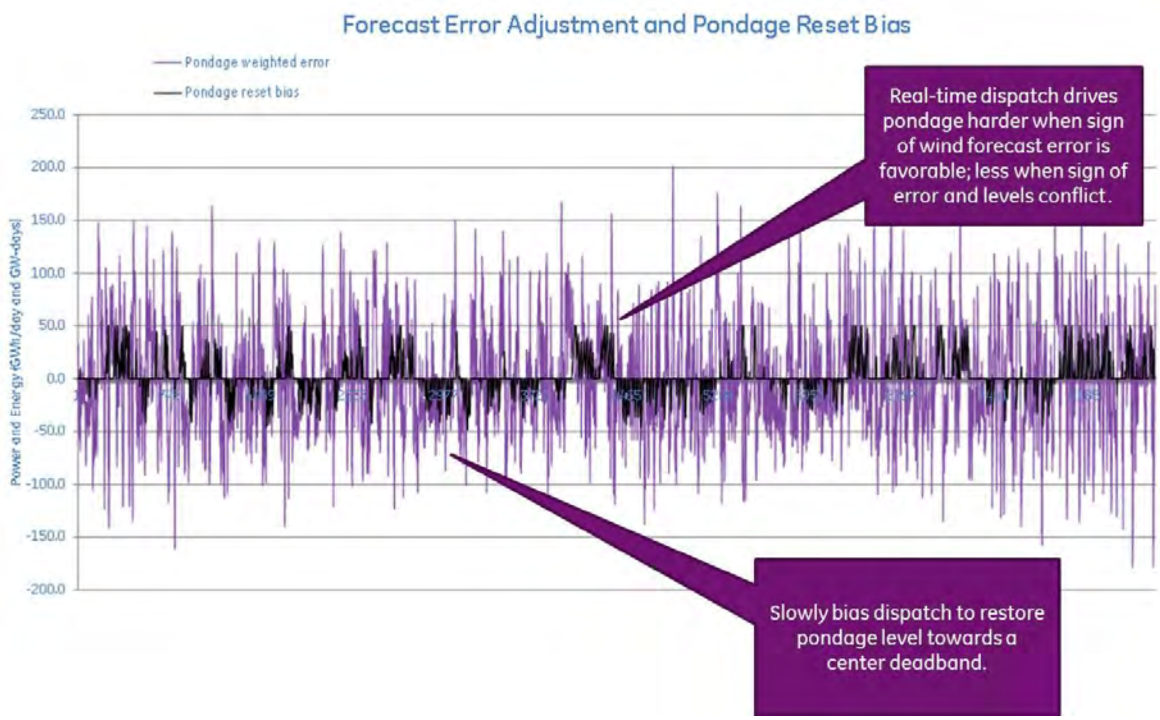



**Figure 59: Adjusting for Forecast Error and Level**

Figure 60 compares the WC DAH and RLT dispatch duration curves (i.e., sorting MW levels from high to low across all hours of the year). It can be observed that when dispatched, the [redacted] are generally [redacted]. However, there are [redacted]. It can also be seen that [redacted].

The shift in the duration curve as WC is used to partially offset forecast errors helps illustrate the energy trade-off with this approach. [redacted].

[redacted]. This shows up in the figure as the leftward shift in the vertical drop to zero. [redacted]. These effects are captured in the production simulations.

[redacted]

**Figure 60: WC Dispatch Duration Curve**

**THIS FIGURE IS CONFIDENTIAL**

The complex scheduling described above does not lend itself to exactly realizing the [redacted] Figure 61 illustrates how well the scheduling algorithm satisfied the [redacted]. The blue trace shows that [redacted]. The red trace adds in the [redacted] These traces are energy difference (in MWh) from the target daily energy provided by NSPI (which is the black trace in Figure 58). The errors are on the order of a few percent. Although this approximate approach did not exactly match [redacted], we believe it is consistent with actual practice, [redacted]. (As compared with our modeling of the Maritime link, discussed below, [redacted].

[redacted]

**Figure 61: Not Perfect … Day-to-Day Variation from NSPI Target in Total Energy Production**

**THIS FIGURE IS CONFIDENTIAL**

Figure 62 depicts the available spinning reserve from WC on an hourly basis. As noted, when on-line, the hourly reserve availability of WC is the difference between its maximum rating and its hourly loading point. However, as shown, if any of the two WC units is off-line, none of its capacity can be counted towards spin. The two visible notches in the figure correspond to periods when one of the two units is out on maintenance. The difference of this contribution and the total synchronized reserve requirement must be met by other NSPI reserves. It is that difference, on an hourly basis, that is provided to the production simulation as an input. The production simulation determines the resources that will provide that additional reserve as part of the optimization process.

[redacted]

Figure 62: WC Contribution to Spinning Reserve

THIS FIGURE IS CONFIDENTIAL

## 6.2 New Brunswick Import/Export Assumptions

### 6.2.1 Key Features of NB Imports

The New Brunswick (NB) / Nova Scotia (NS) tieline is the only current interconnection between Nova Scotia and the outside world. Nova Scotia relies on the NB imports to meet some of its electrical energy requirements throughout the year.

We represent the outside world through the NB / NS tieline as a thermal generator or combination of thermal generators with given price curves that can operate in a manner consistent with the operational characteristics that govern the current operations of the intertie and NB electrical energy imports and exports.

There are physical, economic, and contractual constraints on the importing power from and exporting power to New Brunswick. The following parameters define the NB Imports (or its generation plant equivalent), which are also represented in the modeling effort:

- Imported energy on an annual basis is 400 GWh (This projection was the expectation conveyed by NSPI earlier in the project, but is not “economically” supported by results of this study.)
- Maximum level of NB imports is the minimum of 285 MW or 22% of total in-province load – including in-side-the-fence load (or 25% of modeled out-side-the-fence load) in any hour.

- NB Import randomized forced outage rate is 15% (equivalent to 7 Week + 6 Days of outage.)
- NB Import minimum stable level is 20 MW (Although not enforced in the model, it is respected by virtue of dispatching imports in increments of 25 MW as described below.)
- Maximum ramp rate is 100MW per hour.
- Generator can be dispatched in increments of 25 MW (in the model, this constraint is loosened in the "day-of" scheduling).
- Minimum up-time is three hours.
- Minimum down-time is one hour.
- Firm Transmission Availability:
    - 20 MW firm in the summer (April through October).
    - 0 MW firm in the winter (November through March).
    - Can count toward 10-minute non-spinning reserve April through October.
- Exports to NB are allowed, but NB exports are capped at 175 MW. However, export prices are set such that only excess wind power that would otherwise be curtailed is exported – with the exception of a sensitivity case, reported later in the results section, where other export prices are considered resulting in additional generation in the province.

### 6.2.2 NB Imports and Reserve Treatments

There is a DAH reserve requirement for non-firm NB Imports, but not for day-of scheduling. The following list summarizes the key features of the import reserves in relation to other reserve requirements in the system, and how they are being modeled:

- DAH reserves for NB import are NOT "in addition to" DAH reserves required for NS in-province requirements, but rather "the greater of".
- Aside from NB imports, there needs to be 60 MW of spin PLUS 111 MW of 10-minute reserve (which comes from 171 MW worst single contingency, minus 60 for spin).
- Further, there is another 50 MW of 30-minute non-spinning reserve needed ON TOP of these reserve requirements. In DAH, the model cannot distinguish between 10- and 30- minute reserves. Hence, for modeling purposes, the additional 50 MW of reserves is added to other reserves to make up a minimum total of 221 MW reserves (or "headroom") as seen by the model.

- The NB import reserve term only applies to the DAH scheduling. Therefore, in real-time, the headroom requirement is only 171 MW (of which 60 MW is spin). There is no need to cover the NB import, nor is there a need to have the 50 MW, because the intent of DAH reserve was to cover schedule and load uncertainties, which are not an issue in real time.
- We assume that the following components of Up-Range (available reserve capacity of plants) can count towards satisfying the DAH reserve requirement on NB imports:
  - Committed Thermal Up-Range: If generation is greater than zero, the difference between capacity and generation.
  - Quick Start Up-Range: The difference between capacity and generation, i.e., available capacity counts even if not synchronized.
  - Hydro Up-Range: The difference between capacity and generation.
  - Wreck Cove Up-Range: The difference between capacity and generation (even if off-line in DAH schedule)

### 6.2.3 NB Import and Export Representations and Sensitivities

As described in the results section, we performed a number of sensitivities on NB imports, including investigation of the flexible versus inflexible import scheduling, NB time unavailability, and volatility of NB imports.

As the study results indicate, NB imports do play an important role in balancing the Nova Scotia power needs. Any [redacted].

Table 24 provides the assumed NB import prices provide by NSPI.

Table 24: New Brunswick Import Prices

| Year | 2013 | 2015 | 2020 |
|---|---|---|---|
| | | | |
| **Base Price** | | | |
| | | | |
| NB to NS (NS Imports) | | | |
| On-Peak | [redacted] | [redacted] | [redacted] |
| Off-Peak | [redacted] | [redacted] | [redacted] |
| | | | |
| NS to NB (NS Exports) | | | |
| On-Peak | [redacted] | [redacted] | [redacted] |
| Off-Peak | [redacted] | [redacted] | [redacted] |
| | | | |

## 6.3 Maritime Link Assumptions

### 6.3.1 Key Features of Maritime Link

In 2020, Maritime HVDC Transmission Link (Maritime Link or ML) is expected to provide Nova Scotia with a second access route to external resources in Newfoundland and Labrador.

The modeling assumptions used for the 35-year block, supplemental 5-year block and discretionary third block are as follows:

- Nova Scotia 35 year block:
    - 897 GWh annual import modeled as must-take energy (reflects losses up to delivery point at Lingan)
    - Seven (7) days per week, 16 hours per day, 365 days per year
    - Dispatched from HE 8 to HE 23
    - 154 MW/hour Firm
    - Dispatchable from 114 to 194 MW
    - Maximum and minimum daily energy of 2.46 GWh
- Supplemental 5 year block:
    - 261 GWh annually off-peak for five years (Jan 1, 2017 to end of 2021)
    - Delivered off-peak during winter months (November-March)
    - Dispatched from HE 00 to HE 7

- 218 MW/hour Firm
- Dispatchable from 178 to 250 MW
- Maximum and minimum daily energy of 1.74 GWh

- Discretionary Third Block:
  - Configuration A:
    - Maximum of 1.3 TWh/year
    - Seven (7) days per week, 16 hours per day, 365 days per year
    - Economically dispatched from HE 8 to HE 23
    - On peak: Not to exceed 250 MW less what is flowing in the hour on the Nova Scotia 35-year block
  - Configuration B:
    - Maximum of 1.3 TWh/year
    - Seven (7) days per week, 24 hours per day, 365 days per year
    - Economically dispatched all hours
    - Off peak: Not to exceed 300 MW less what is flowing in the hour on the 5-year supplemental block
    - On Peak: Not to exceed 300 MW less what is flowing in the hour on the Nova Scotia 35-year block

We did not include either configuration of the Discretionary Third Block in our main study cases. However we accounted discretionary economic dispatch of the Maritime Link in a number of our sensitivity cases to show a range of potential operating constraints (Section 7.3).

### 6.3.2 Observations and Modeling Considerations

Given these assumptions, the Maritime Link is conservatively modeled in the bases cases without the discretionary third block, resulting in a capacity factor of approximately 26% on the two 250 MW poles (total capacity of 500 MW):

$$26\% = (897 + 261\ \text{GWh}) / (500 \times 365 \times 24/1000\ \text{GWh})$$

The average loading of the two poles would be 50% during off-peak hours:

$$50\% = 250\ \text{MW} / 500\ \text{MW}$$

Modeling of the discretionary third block in the sensitivity cases increases the capacity factor of the two poles to as much as 39% in Configuration A:

*39% = (897 + 261 + 561 GWh) / (500 x 365 x 24/1000 GWh)*

Where 561 GWh of Discretionary Third Block is based on the 154 MW/hour of firm 35-Year Block, resulting in 250 – 154 = 96 MW of Discretionary Third Block:

*561 GWh = 96 MW x 365 x 16/1000*

With the Discretionary Third Block in Configuraiton A, the average loading of one of the two 250 MW poles would still be 50% during off-peak hours, since during anytime of the day, the maximum MW of all blocks is 250 MW.

Modeling of the discretionary third block in the sensitivity cases increases the capacity factor of the two poles to as much as 56% in Configuration B:

*56% = (897 + 261 + 1279 GWh) / (500 x 365 x 24/1000 GWh)*

Where 561 GWh of Discretionary Third Block is based on the 154 MW/hour of firm 35-Year Block, resulting in 300 – 154 = 146 MW of Discretionary Third Block:

*1,279 GWh = 146 MW x 365 x 16/1000*

With the Discretionary Third Block in Configuraiton B, the average loading of one of the two 250 MW poles would still be 60% during off-peak hours, since during anytime of the day, the maximum MW of all blocks is 300 MW.

Maritime Link – Modeling/Scheduling considerations include:

- ML imports above 154 MW (or 218 MW for the supplemental block), were treated in the same way as NB imports:
    - Assumed same DAH reserve for levels > 171 MW. However, simple arithmetic shows that maximum non-firm ML import is 40 MW (194 - 154 = 40, or 250 – 218 = 32), which is always less than 171. Hence, no impact is expected unless there is simultaneous import from NB greater than 151 MW (since 20 MW from NB is firm). That could happen, but it seems highly unlikely, since it was not observed in any of the study cases.
- The ML import scheduling is similar to the Wreck Cove algorithm:
    - There are rigid daily block energy targets:
        - 16 x 154 MW = 2.46 GWh/block for 35-Year block year-round.
        - 8 x 218 MW = 1.74 GWh/block for supplemental block between November and March.
- ML was scheduled DAH to peak shave on forecasted net load (load minus forecasted wind).

Figure 63 and Figure 64 provide examples of ML dispatch during a typical summer week and a typical winter week.

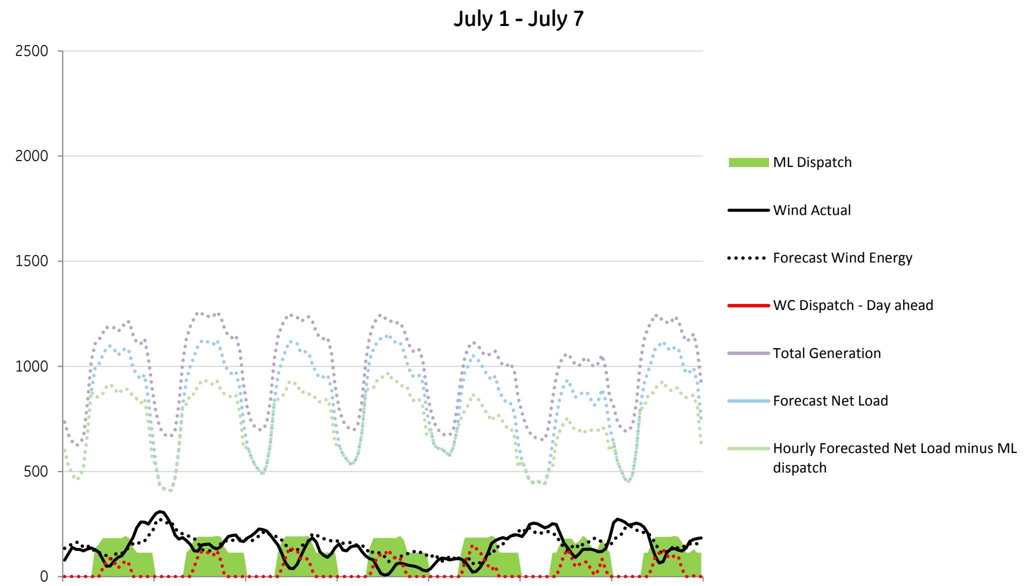



**Figure 63: Maritime Link Dispatch - Typical Summer Week**

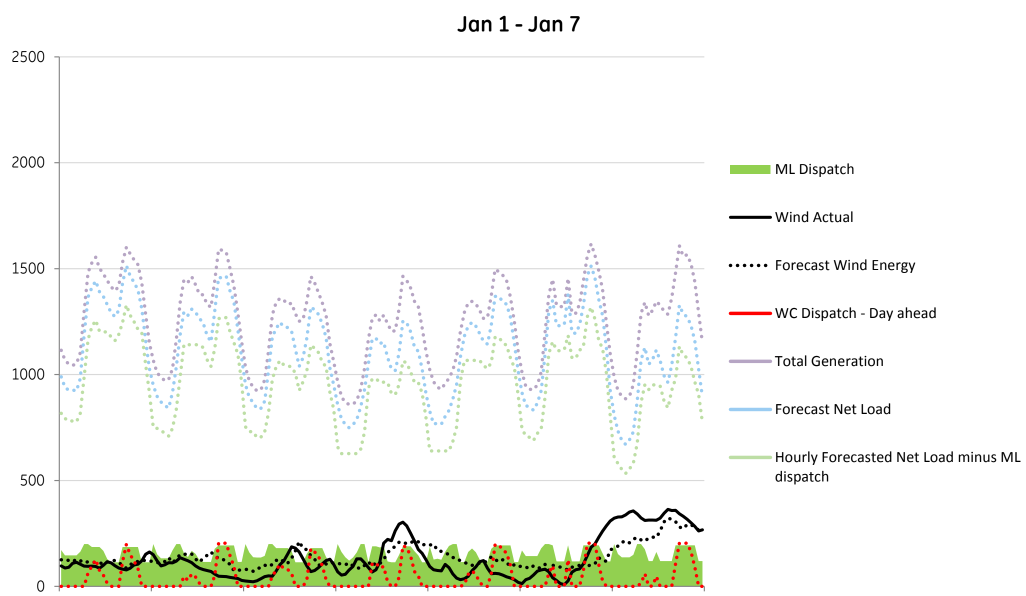



**Figure 64: Maritime Link - Typical Winter Dispatch**

# 7 Results and Analysis

## 7.1 Study Cases

We performed GE MAPS runs of all the Study Cases which cover years 2012, 2013, 2015, and 2020. The table of the Study Cases (from Section 1.5 and Section 4) is replicated in Table 25 below for ease of reference.

**Table 25: Summary of the Study Cases**

| Case ID | Year | Industrial Load | Maritime Link | Wind Capacity | Available Wind Energy |
|---|---|---|---|---|---|
| **Case 1** | 2012 | No | No | 335 MW | 1,148 GWh |
| **Case 2** | 2013 | Yes | No | 335 MW | 1,148 GWh |
| **Case 3** | 2013 | No | No | 335 MW | 1,148 GWh |
| **Case 4** | 2015 | Yes | No | 488 MW | 1,661 GWh |
| **Case 5** | 2015 | No | No | 488 MW | 1,661 GWh |
| **Case 6** | 2020 | Yes | No | 916 MW | 3,102 GWh |
| **Case 7** | 2020 | No | No | 796 MW | 2,685 GWh |
| **Case 8** | 2020 | Yes | Yes | 551 MW | 1,871 GWh |
| **Case 9** | 2020 | No | Yes | 551 MW | 1,871 GWh |

Concurrent with running each study case with base assumptions, we also performed a number of sensitivity analysis as described in Section 2.3.1. We present our findings in the following sections, with focus in a number of themes that are most relevant to the system response to volatility and intermittency of renewable energy with implications for the type of mitigating measures potentially available to NSPI.

Based on the results of the hourly GE MAPS runs we selected a number of “interesting” days that warranted a closer and more detailed look by using the sub-hourly PLEXOS model. As we present the main findings, we also include the PLEXOS results, interwoven with the GE MAPS findings, to shed more light on the sub-hourly behavior of system resources.

## 7.2 Base Case Analysis and Results

### 7.2.1 System Performance in Base Case

The Base Case - also referred to as “Sensitivity A” - covers all nine Study Cases and is the basis for comparison with other sensitivities. This sensitivity uses the base assumptions, provided by NSPI. However there are a few assumptions in the Base Case that warrant further description. For example, imports are committed and scheduled day-ahead but can be adjusted in real time to compensate for missed wind forecasts and are on outage 15% of the time (there is further discussion about this in Section 7.6). In addition, the ability to export is always available, but only used in instances to avoid curtailment. During high levels of wind penetration, excess wind energy is assumed to be exported outside of the system (i.e. to New Brunswick or beyond) up to a limit of 175 MW. To an appreciable extent, curtailment and exports are very closely intertwined: excess power that cannot be exported is curtailed. A critical difference is that exported wind power is assumed to be covered in the PPA, and therefore is included in total costs to NSPI, whereas curtailed wind power is not covered in the PPA.

Although system operation varies substantially over the nine Study Cases, there are several common system characteristics that are seen throughout the analysis. Coal is the dominant source of energy throughout the study period, producing over 40% of provincial energy. Even after the retirements of Lingan 1 and 2, coal generation remains a pivotal component of the overall energy mix. In fact, over the study period capacity factors for the coal fleet actually increases from around 40% in the 2013 scenarios, to 60% in the 2020 scenarios. Figure 65 shows the overall coal fleet capacity factor across the base case study period. Note that the increase in the even numbered cases shows the impact of the industrial load. Because the large industrial load was assumed to be relatively constant for the purpose of this study, much of the energy used to meet the increase in load is generated by the coal assets.

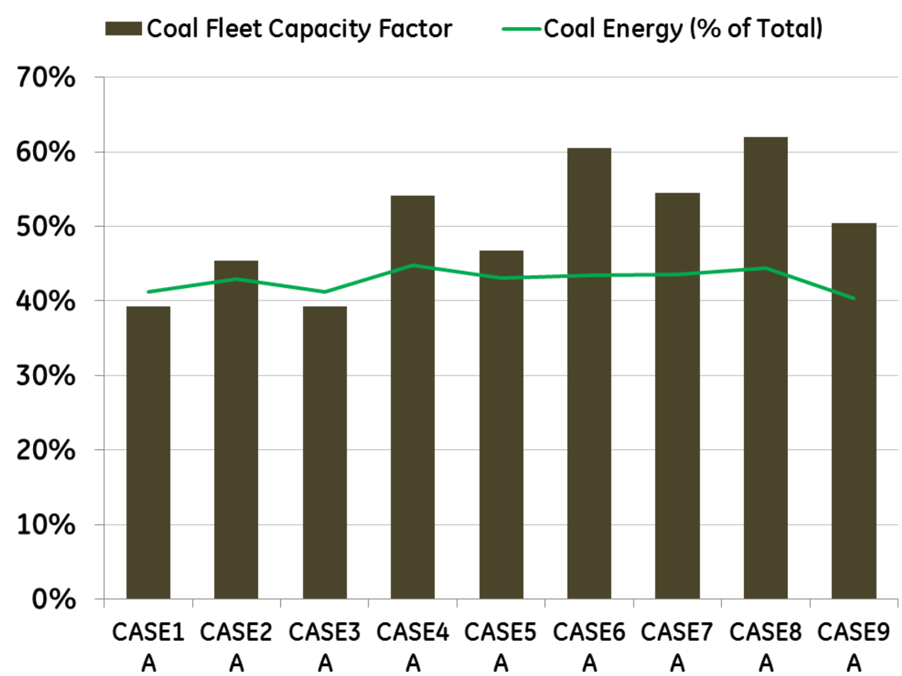



Figure 65: Coal Fleet Utilization by Case

The reasons for the increased capacity factor in the 2015 and 2020 scenarios are two-fold; the first is due the retirements of Lingan 1 and 2, much of the generation is replaced by available capacity of the other coal units. A second reason is due to changing fuel prices over the study period (See Figure 55 in the Modeling Assumptions section). During the 2013 cases, natural gas prices are relatively low and some coal generation is replaced by increased utilization of gas units. This displacement is most apparent in the early cases, before fuel prices diverge again. This is true for both the Tufts Cove #6 combined cycle unit and steam gas units (Tufts Cove #1 - #3), which have a seasonal advantage during the summer due to reduced gas prices. The decreased utilization of the CC Unit is slightly counterintuitive in the future scenarios with increased wind penetration. Higher wind penetration requires more flexible assets in the generating fleet which would tend to increase CC usage. However, the additional wind (and lower relative coal costs) tends to move down the dispatch stack and displace the gas generation. The net ends with decreasing CC utilization. Figure 66 demonstrates the gas-coal fuel switching dynamic due to fuel price changes in 2013 (Case 3), 2015 (Case 5) and 2020 (Case 7). This underscores the importance of overall economics and the underlying fuel price assumptions.

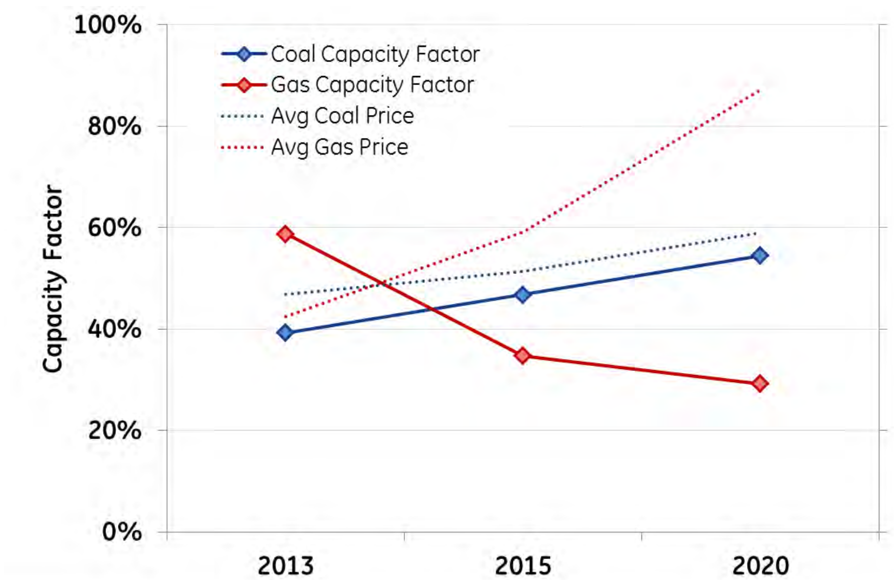



**Figure 66: Gas vs. Coal Utilization by Year**

Much of the rest of modeled thermal energy is provided by natural gas generation, comprising about [redacted] of total generation in the 2013 scenarios and about [redacted] of total generation in the 2015 and 2020 scenarios. The most efficient thermal asset in the Nova Scotia system is the newly installed combined cycle unit (Tufts Cove #4 - #6), which has a heat rate of about [redacted] Btu/kwh when operating in combined-cycle mode. This efficiency advantage is also coupled with a significant flexibility advantage, which allows the unit to respond to fluctuating wind generation. As a result, the CC unit has one of the highest annual capacity factors, of around [redacted] in the 2013 cases and [redacted] in the 2015 and 2020 cases. On the contrary, the steam gas units (Tufts Cove #1 - #3) [redacted]. As a result, these units [redacted], at around [redacted] capacity factor in 2013 scenarios, and only around [redacted] capacity factor in the 2015 and 2020 scenarios.

The oil and diesel units (Burnside #1 - #4, Victoria Junction #1 - #2 and Tusket) are rarely used throughout the study and contribute to less than 1% of total energy. This is due to a [redacted] and a prohibitively expensive fuel price at nearly [redacted]/mmBtu. Their primary role in system operation is to provide quick-start peaking generation and provide quick-start reserves. In general the assets are only used in periods of high peak loads or periods of wind variability. Despite the low levels of annual energy generation, the peaking units are of pivotal importance in the high wind scenarios. The gas, oil and diesel units are the only in-province assets that are flexible enough to react to wind forecast error where the wind available during real-time dispatch falls short of the expected wind that was used to commit units during the DAH period. As a result, the majority of this generation occurs during times of a missed wind forecast and periods of under-commitment. Figure 67 shows the annual duration curves of the total GT oil/diesel generation. Not only does the figure shows a relatively low number of hours of utilization in each case, it also shows relatively low levels of generation when the units are dispatched.

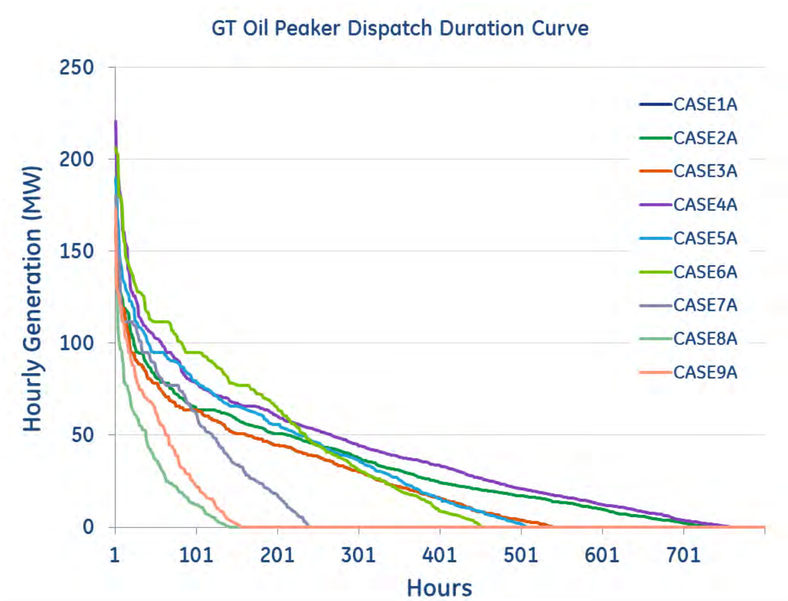



**Figure 67: GT Oil and Diesel Dispatch Duration Curve**

Hydro resources contribute about 10% of total annual generation. As discussed in Section 5.5, the hydro resources are limited to a monthly capacity rating (MW) and monthly energy (GWh) and the model scheduled according to the system hourly load profile. The hydro resources are used for "peak-shaving" and are scheduled during the DAH commitment process to reduce system peak loads.

Figure 68 shows the average hydro energy dispatch by time of day and shows the correlation of hydro generation and system load. This scheduling occurs after the DAH scheduling of the wind forecast. As a result, the monthly and annual generation and capacity factors do not change across the cases or sensitivities, however hourly utilization may change due to different levels of wind generation and forecast error. The monthly capacity rating and available energy allows the model to accurately simulate the seasonal variability of hydro resource. Although monthly generation varies on a unit specific basis, the overall monthly pattern demonstrates a significant winter peaking resource. Figure 69 shows the monthly hydro generation and monthly load shapes.

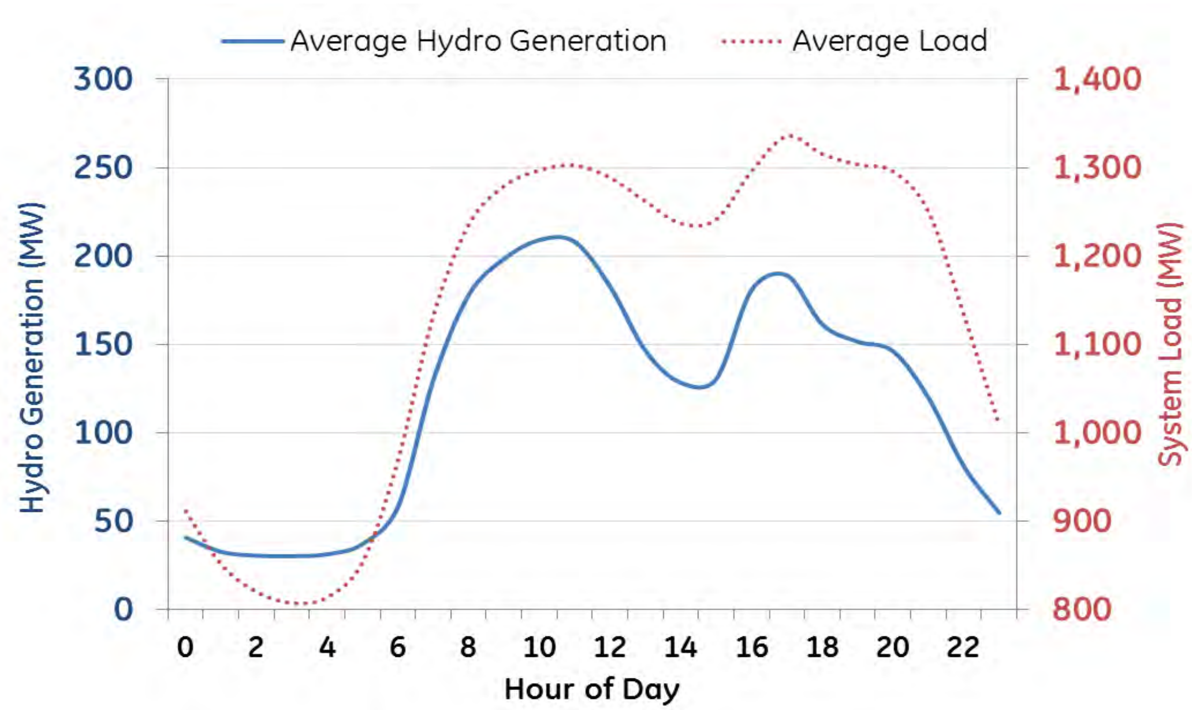



**Figure 68: Average Daily Hydro Generation**

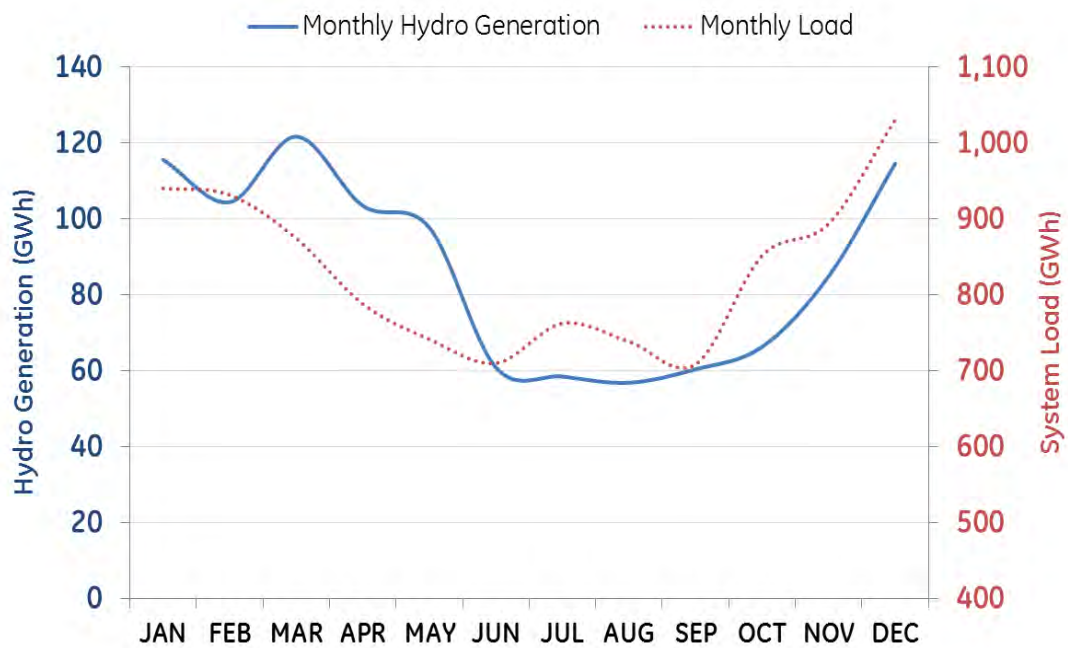



**Figure 69: Monthly Hydro Generation**

In general, the hydro resources are not used to respond to wind forecast error, the exception of which is Wreck Cove. The modeling of Wreck Cove, outlined in Section 6.1, allows the resource to be used for both peak-shaving and to cover wind variability. This is important because the unit is one of the largest units on the system, but severely constrained on an annual energy basis due to hydro resource availability and a limited storage reservoir. For example, the Wreck Cove plant provides 31% of all hydro generation, but only has a capacity factor of 18%.

Wind resources are the last significant in-province generating resource on the Nova Scotia system and of most importance during this study. As wind capacity increases from one scenario to another, the overall generation and penetration increases dramatically.

Figure 70 shows annual wind generation (GWh) and overall penetration as a percent of system load. Due to the variable nature of wind generation, the penetration of wind is often asymmetric over the year.

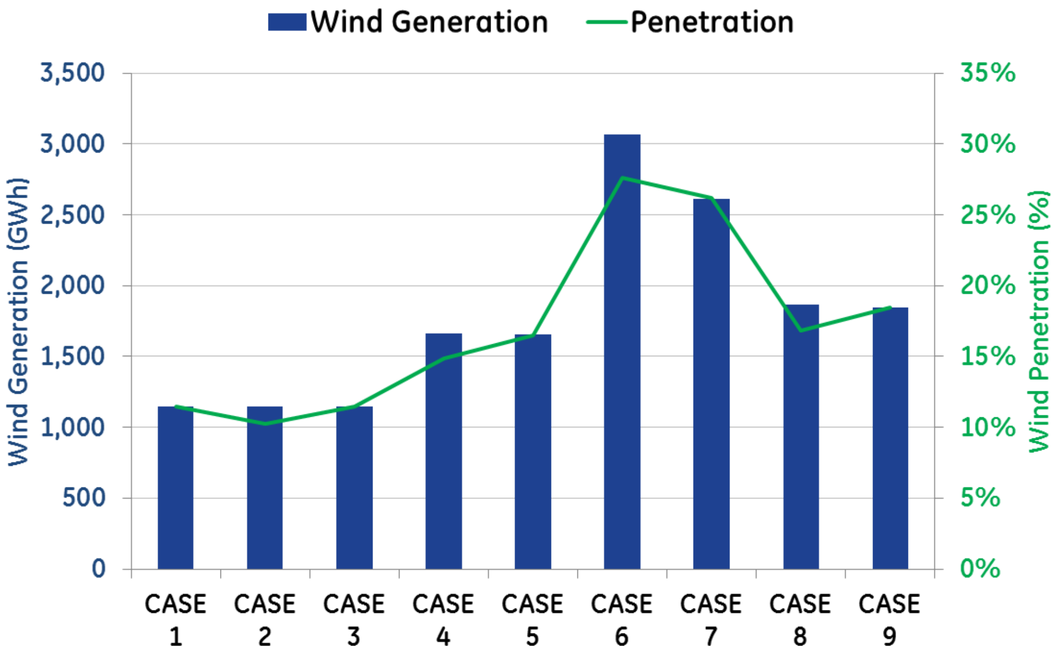



**Figure 70: Wind Generation and Penetration by Case**

The overall variability is highlighted in Figure 71 which shows wind penetration by month, week, day and hour two sets of "duration curves" of wind penetration for different windows of time. For example, the hourly trace is wind MW/load MW for that hour – sorted from maximum to minimum. On the left, the present system, Case 1 (2013), is shown, and on the right Case 7 (2020). The increases in penetration help illustrate the changes for which NSPI must be prepared. In the 2020 Case 7 curve, the maximum single hourly wind penetration is over 75%, the minimum close to zero – providing an overall average of about 27% (the annual wind energy penetration). In one week (green trace) the system gets 40% of its energy from wind.

In the event that high levels of wind penetration were employed to meet renewable energy requirements, NSPI would need to be able to operate at these extremes. A considerable amount of the work performed in this study is aimed at understanding and meeting those extremes. The duration curves show that in order to achieve annual wind penetration of over 25% (Case 7), there will be periods of very high and very low penetration.

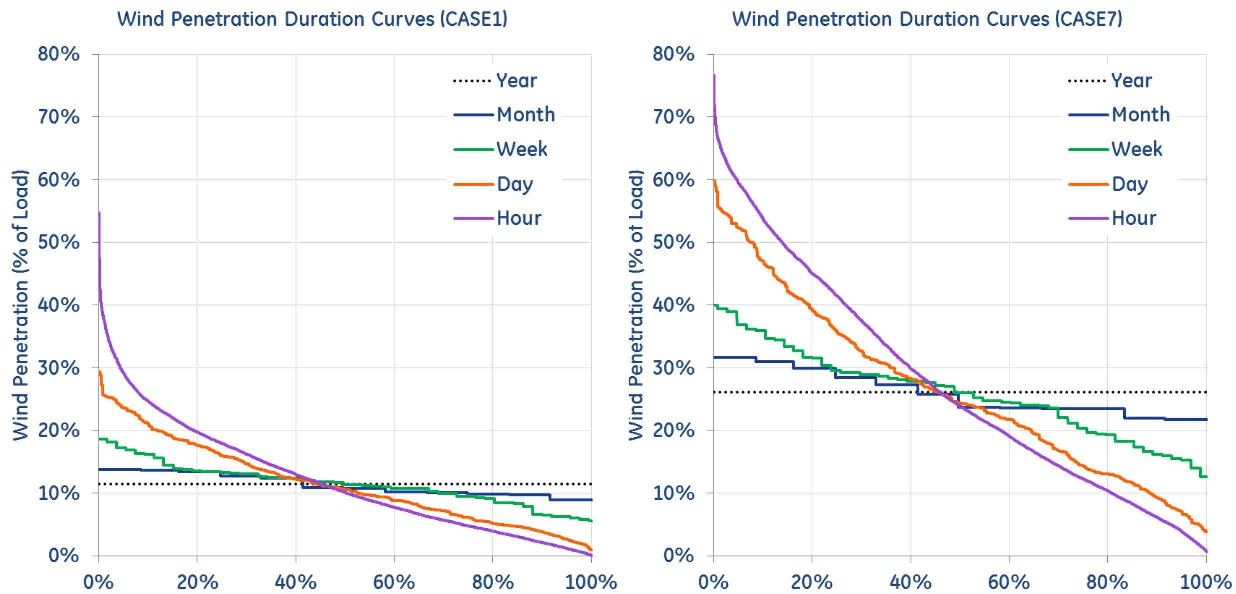



**Figure 71: Wind Penetration Duration Curves**

As discussed in Section 5.7, wind resources are modeled as hourly modifiers and price-takers. Both the forecasted and real-time wind energy is provided to the model following an hourly pattern. The forecast shape is used during the DAH commitment period, and the "actual" shape is used during the real-time dispatch process. Figure 72 shows a representative week from Case 7 and shows the variation in both the DAH forecast and real-time actual wind shapes. For a more detailed description of wind forecasting impacts, see Section 7.5. Periods where the available wind (solid line) is higher than the forecast line represent periods of under-forecast, whereas periods where the forecasted wind (dotted line) is higher than the available wind represents periods of over-forecast. Periods of large differences (forecast error) will have profound impacts on the operation of the system. When the wind is over-forecasted, only quick-start, flexible generation can turn on in the dispatch period. Thus, if there is insufficient headroom on long start time resources (which are usually cheaper to run), these expensive resources must be used. In the NSPI system the relative costs between these long start time resources and faster start resources is critical. This is reflected in many of the results presented throughout this report: in short, the economic consequences of being "short" are very high compared to those of being "long" – i.e. over committing. It is worth noting that, in the experience of the GE project team, this effect is the most pronounced we have observed in any non-island system.

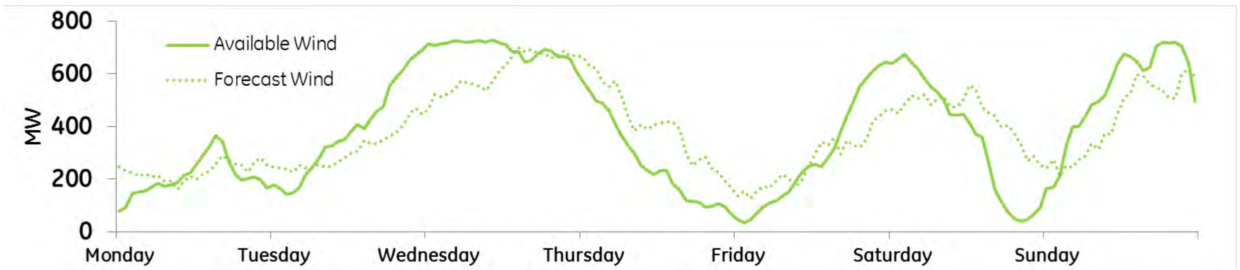



**Figure 72: Weekly Available Wind vs. Forecast Wind**

## 7.2.2 Comparisons across All Sensitivity A Cases

The system behavior is expected to be mostly driven by load, installed generation, and fuel prices. The Base Cases include with and without large industrial load scenarios in 2013 and 2015. The 2020 cases also include with and without Maritime Link for each of load scenarios in that year. The cases with the large industrial load are even numbered, and consistently have about 1100 GWh higher generation. This is illustrated in Figure 73.

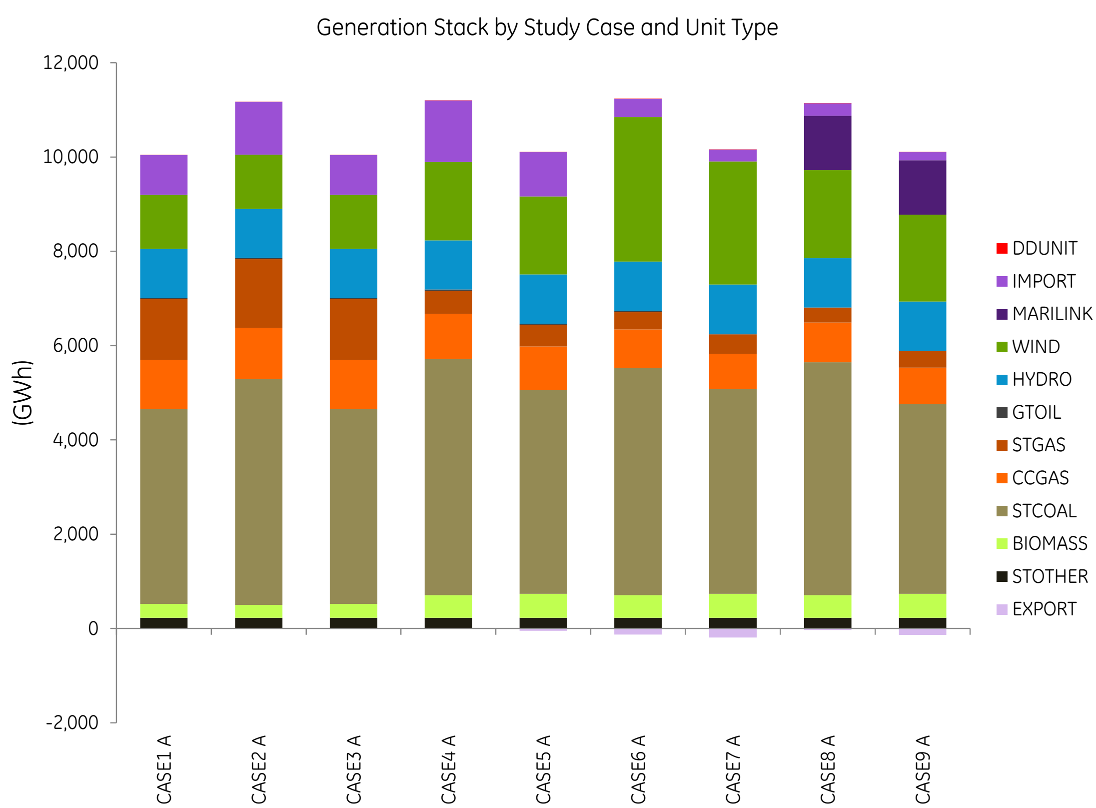



**Figure 73: Base Case (Sensitivity A) Generation by Type**

In Figure 73, exports to NB (EXPORT) are shown as negative values, since they actually increase the system generation.

In study cases with large industrial load, the total original system load is higher due to the existence of the large industrial load, requiring more generation resources to meet system load. As can be observed, additional energy needed by large industrial load is mostly provided by steam coal, wind, and NB imports.

The GE MAPS unit designated as DDUNIT is a proxy for all types of Demand Response (DR) type action or resources that would constitute the resources of last resort, after all other less expensive resources in the system have been utilized. We will provide more discussion on DR later.

Figure 74 presents the same information by individual unit types.

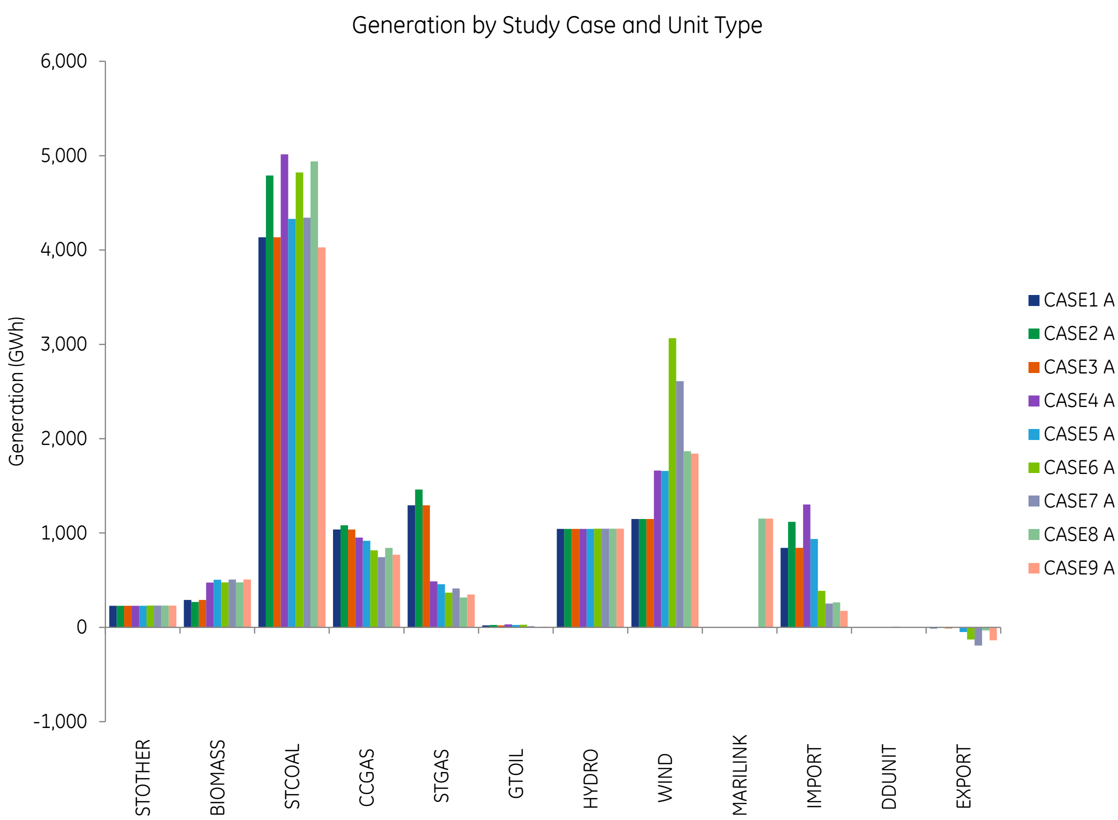



**Figure 74: Generation by Study Case and Unit Type**

Although wind energy is a price-taker there are periods when the system cannot take all of the available wind energy due to other system constraints (low system load, minimum generation, minimum up-times, minimum down-times, transmission congestion, etc.). During these periods, the model will export up to [redacted] MW of excess wind energy. Any additional generation will be curtailed and not utilized. Figure 75 shows the overall levels of exports and curtailment by scenario and Figure 76 shows the annual duration curve for combination of curtailment and exports for each of the nine base cases.

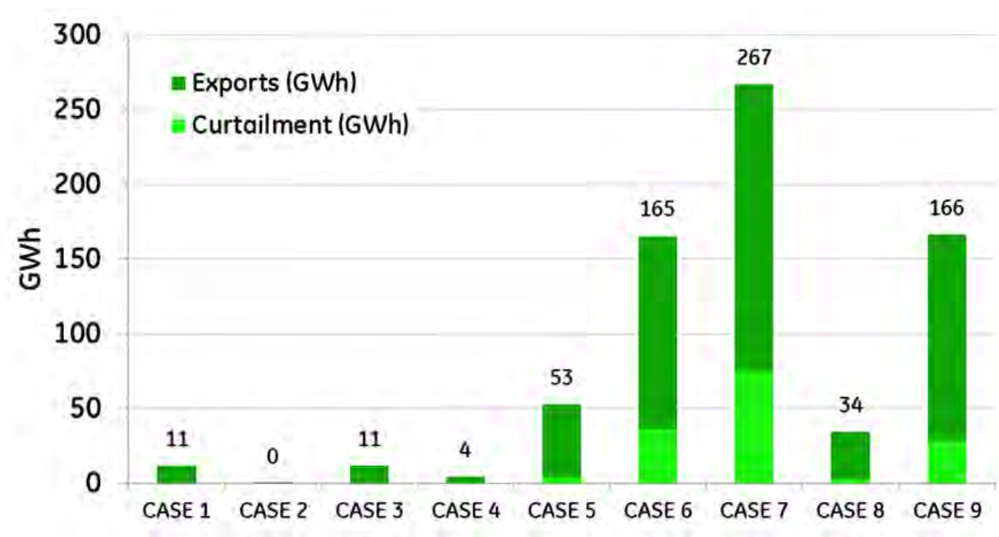



Figure 75: Exports and Curtailment by Case

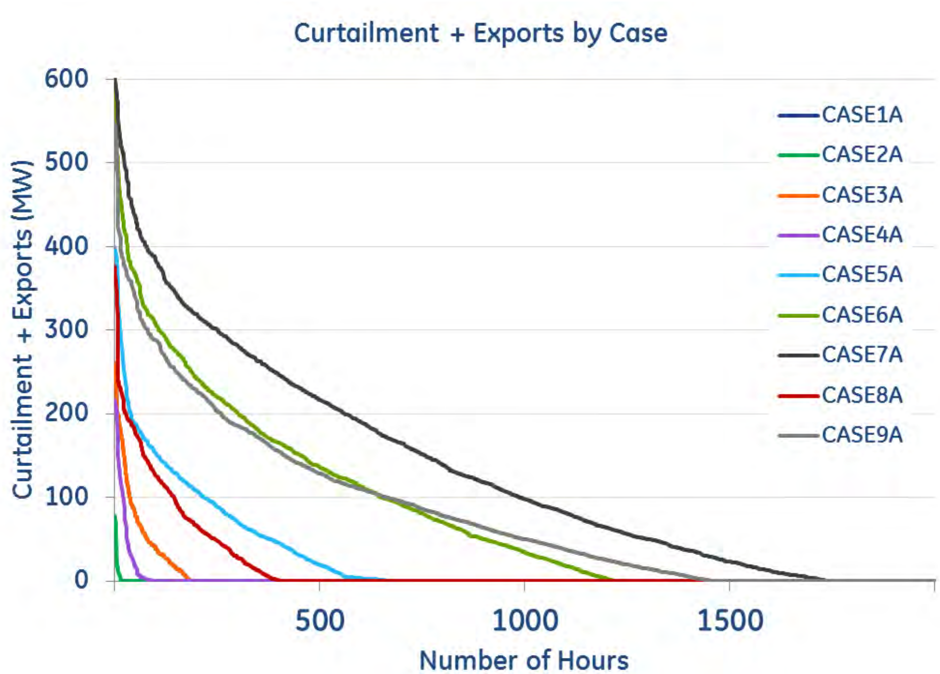



Figure 76: Exports and Curtailment Duration Curve

Figure 77 Shows curtailment only duration curves for each of the nine base cases.

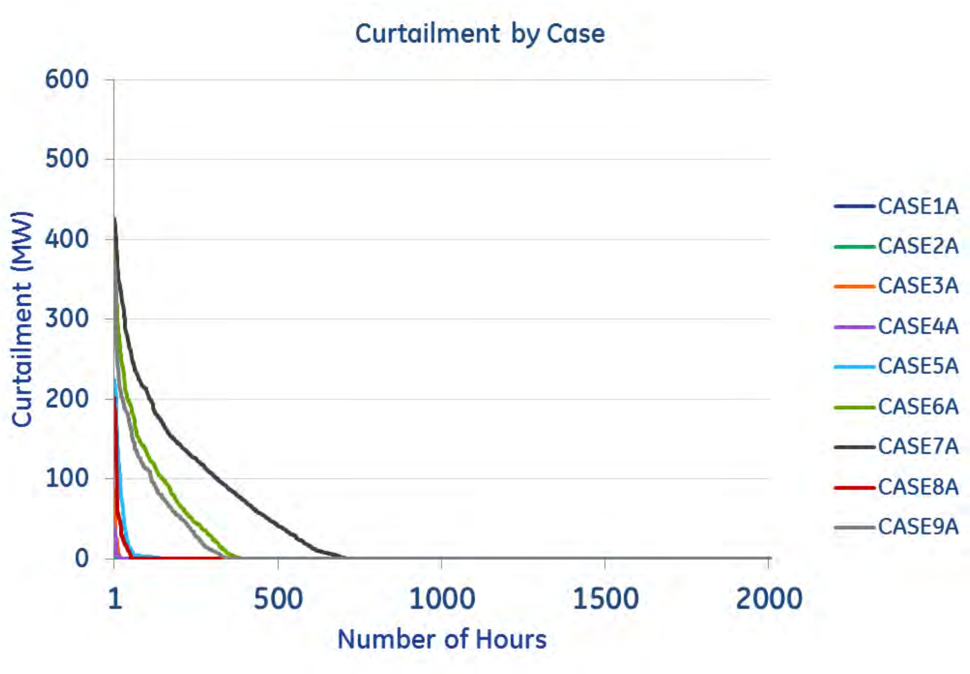



**Figure 77: Curtailment Duration Curve**

The use of demand response varies by case. The duration curves shown in Figure 78 show that, for example, in case 6 demand response of greater than 10MW may be called upon 80 times a year, with the largest event being greater than 150MW. More discussion of demand response is included in section 7.10.

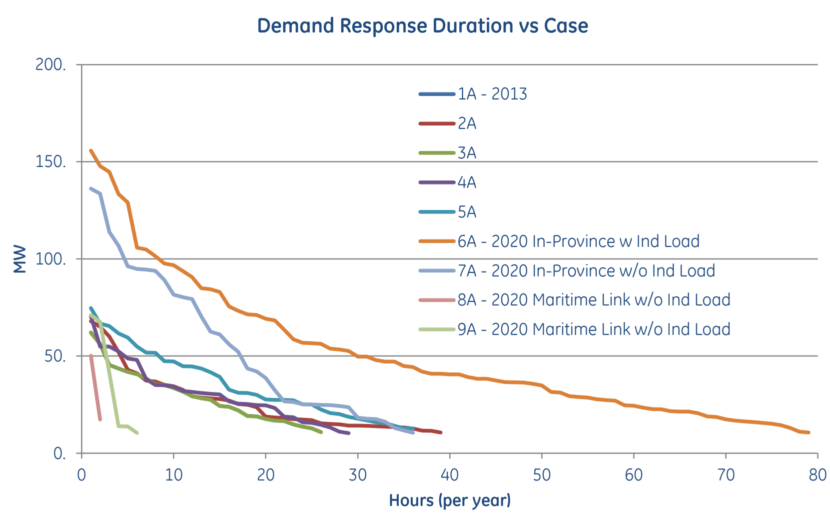



**Figure 78: Demand Response Duration Curve in Base Cases**

Figure 79 and Table 26 show the Production Costs (i.e., variable costs) by Study Case and unit type.

[redacted]

**Figure 79: Production Costs by Study Case and Unit Type**

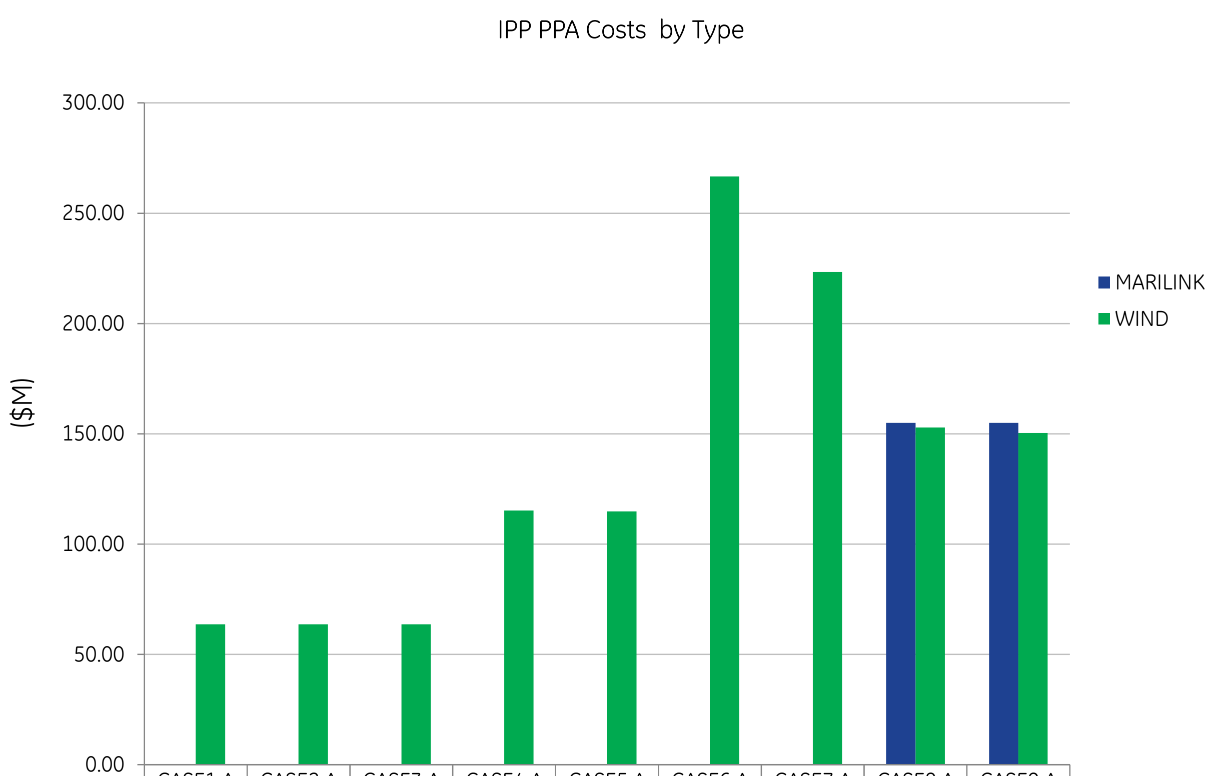
**THIS FIGURE IS CONFIDENTIAL**

**Table 26: Production Costs by Study Case and Unit Type**

| | CASE | CASE | CASE | CASE | CASE | CASE | CASE | CASE | CASE |
|---|---|---|---|---|---|---|---|---|---|
| **UNIT TYPE** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** |
| **CCGAS** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **GTOIL** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **IMPORT** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **STCOAL** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **STGAS** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **TOTAL** | 359.8 | 417.2 | 359.8 | 446.8 | 384.1 | 457.4 | 409.2 | 436.6 | 373.2 |

When PPA payments to IPPs, including wind generators, are added to the variable operating cost, the result is a quantity that we have called "Total Cost". It is important to recognize that this "Total" reflects only the payments out of NSPI to pay for energy supplied. Transfers within NSPI for fixed costs, like cost of NSPI owned hydroelectric generation, tidal and biomass power, as well all the fixed costs of owning and maintaining infrastructure are not in this total. The wind, Maritime Link, IPP biomass and IPP hydro costs are based on the annual energy production and PPA prices provided by NSPI, and would be included in any total cost calculations.

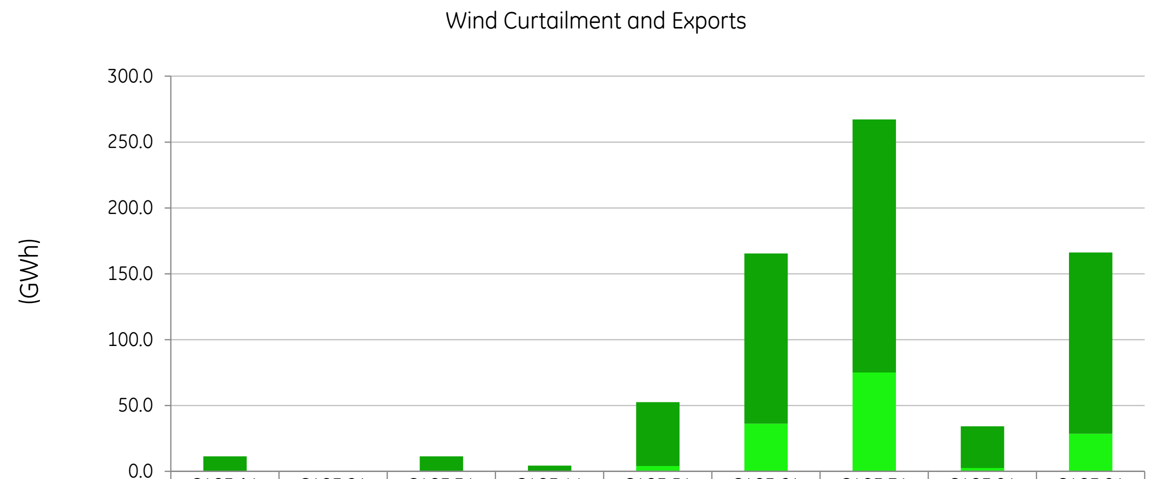
However, although there is a PPA based cost for payments to some independent power producers, PPA price has no impact on system operations as wind will always be accepted by the grid, unless it needs to be curtailed or exported when there is surplus wind energy generated. This study did not examine PPA price levels for wind, but does provide the cost of purchased energy from IPPs for each study case based on the PPA prices and Maritime Link capitalization costs provided by NSPI. Figure 80 shows the IPP related PPA costs for each of the 9 base cases.




| | CASE1 A | CASE2 A | CASE3 A | CASE4 A | CASE5 A | CASE6 A | CASE7 A | CASE8 A | CASE9 A |
|---|---|---|---|---|---|---|---|---|---|
| MARILINK | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 155.0 | 155.0 |
| WIND | 63.7 | 63.7 | 63.7 | 115.3 | 114.9 | 266.7 | 223.3 | 152.9 | 150.4 |

**Figure 80: IPP PPA Cost by Case Study and Type**

Figure 81 depicts the amount of wind curtailment and exports in the base case.




| | CASE 1A | CASE 2A | CASE 3A | CASE 4A | CASE 5A | CASE 6A | CASE 7A | CASE 8A | CASE 9A |
|---|---|---|---|---|---|---|---|---|---|
| Exports (GWh) | 11.2 | 0.4 | 11.2 | 4.4 | 48.5 | 129.3 | 192.2 | 31.7 | 137.5 |
| Curtailment (GWh) | 0.3 | 0.0 | 0.3 | 0.0 | 4.1 | 36.1 | 75.0 | 2.6 | 28.6 |

**Figure 81: Wind Curtailment and Exports in Base Cases**

Figure 82 and Figure 83 show the average number of starts in the year and also the average hours on-line by different unit types for each Study Case. The average is based on the totals for each unit in the year across all units within a unit type. So, for example, in Case 1A, each coal plant would be expected to have about 10 starts per year. By 2020, the average number of starts increases to 17 (Case 6A), as shown in Table 27. The other most salient result is that the expected frequency of starts for the GT oil plants drops in the later years, from about twice a week (~100 in Case 1A), to about once every two weeks (~25 in Case 9A). Starts of gas steam units roughly double in the later years.

**Table 27: Number of Steam Coal Starts**

| | CASE **1** | CASE **2** | CASE **3** | CASE **4** | CASE **5** | CASE **6** | CASE **7** | CASE **8** | CASE **9** |
|---|---|---|---|---|---|---|---|---|---|
| **Steam Coal Starts** | 10 | 11 | 10 | 13 | 13 | 17 | 16 | 14 | 9 |

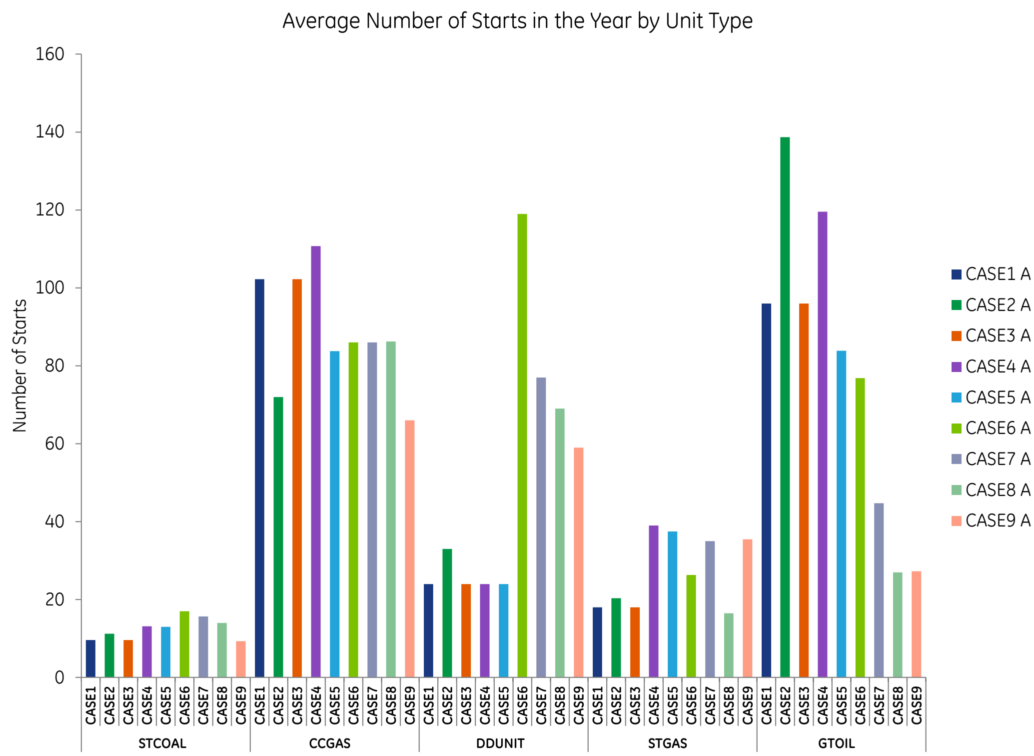



**Figure 82: Average Number of Starts in the Year by Unit Type**

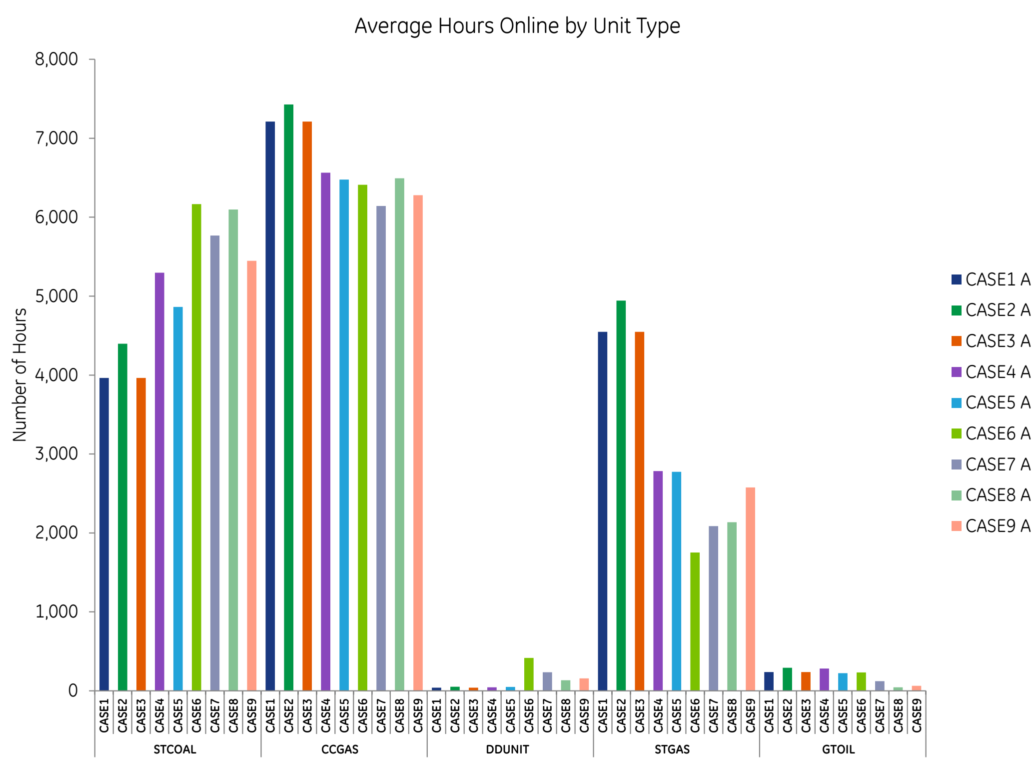



**Figure 83: Average Hours Online by Unit Type**

As expected, the CC (combined cycle) and GT (peaking gas turbine) units exhibit a greater number of starts compared to baseload units (steam coal). Also note that the BIOMASS and STOTHER units are "must run" units and run all year, and hence, have zero starts.

Even though the total annual amount of DR (DDUNIT) is not significant, there are many hours in the year when they are called on for just few hours, particularly in the 2020 Study Cases. As expected, the DR startups are greatest for the Case 6A. In contrast the number of NB imports starts is lower in 2020 due to less need for NB imports in that year.

The annual amount of SO2 and CO2 emissions by Study Case are shown in Figure 84 and Figure 85.

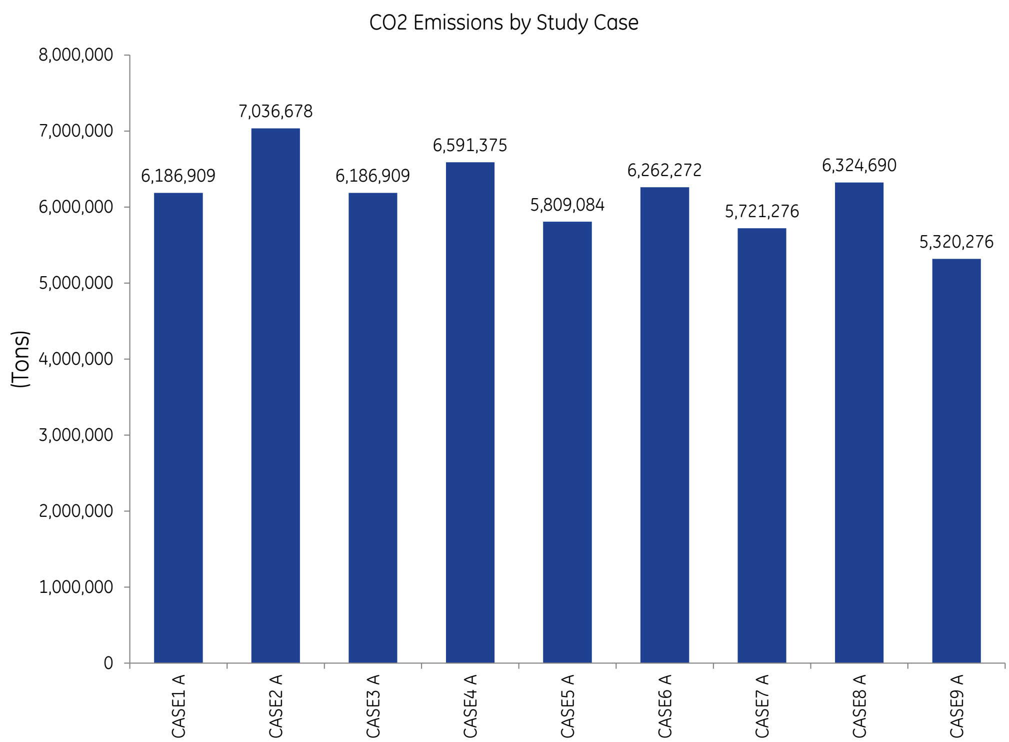



**Figure 84: CO2 Emissions by Study Case**

By 2020, the addition of wind and the Maritime link results in substantial savings in CO2. The marginal value of wind and the Maritime link on carbon emissions is reported in the next section.

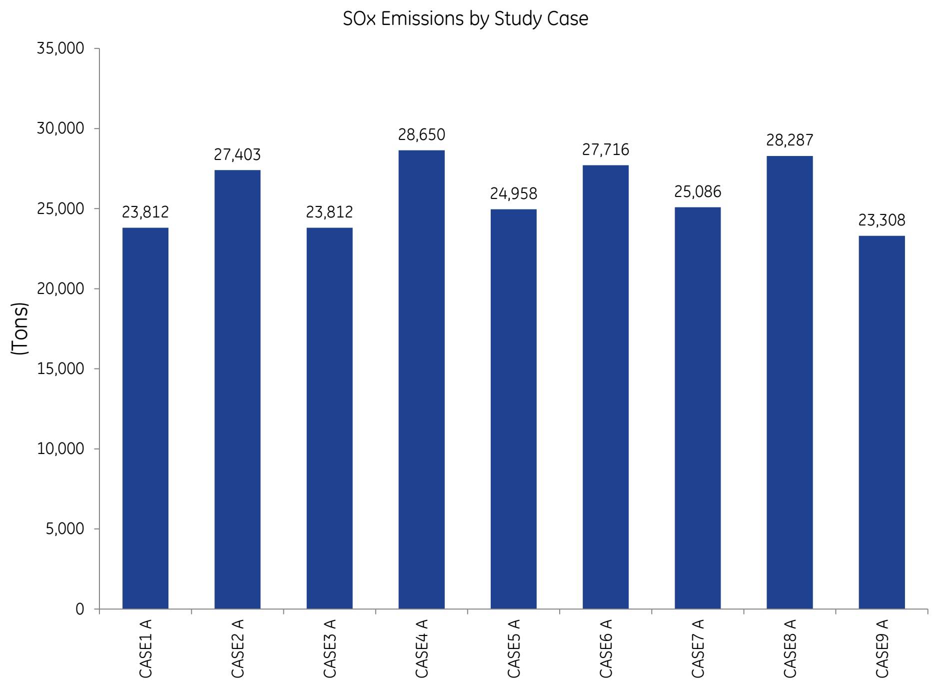



**Figure 85: SOx Emissions by study Case**

The CO2 emissions reflect the collective size of thermal generation, both coal- and gas-fueled, which is highest in Case 2 (year 2013 with industrial load). The thermal generation is lower in future years, with the slack taken up by more wind and also Maritime Link in 2020. The CO2 emission rates of coal-fueled plants are close to twice the CO2 emission rates of gas-fueled plants.

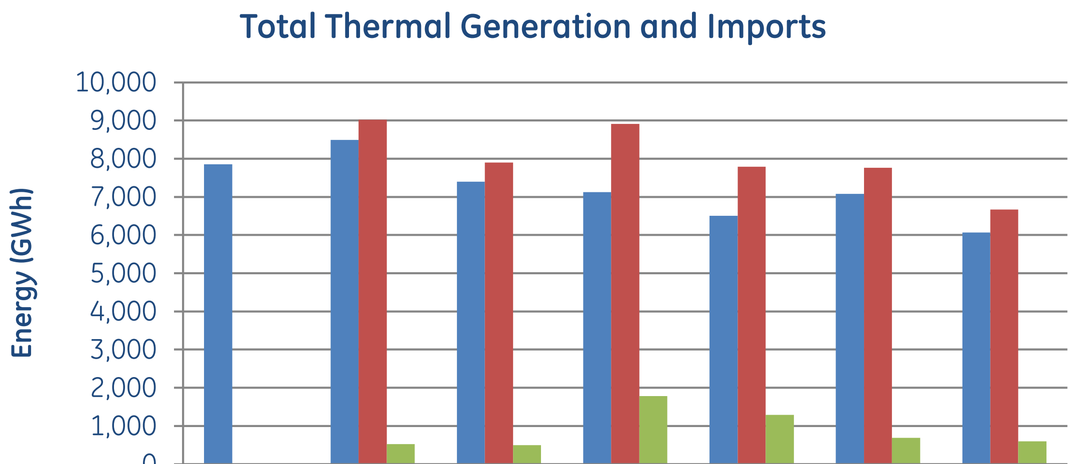
The SOx emissions (SOx or Sulfur Oxide, referring to many types of sulfur and oxygen compounds such as SO, SO2, SO3, and others) are only modeled for coal and diesel fuel plants, and therefore are proportional to their thermal generation. Gas-fueled plants have negligible SOx emissions.

### 7.2.3 Comparisons against Business-As-Usual (from 2013 on)

The system study cases were designed to provide a picture of future operations. All of the future cases include not only added wind generation, but also a wide range of other changes: different fuel prices, unit retirements, load projections, etc.

Comparing system operations in these future scenarios with all of the assumed changes - *except without the addition of any new wind generation beyond those in the 2012 and 2013* cases - is termed "business-as-usual" (BAU), and provides some interesting insights. In Figure 86, the red bars show an increase in thermal generation in the 2015 and 2020 years over the study base cases.

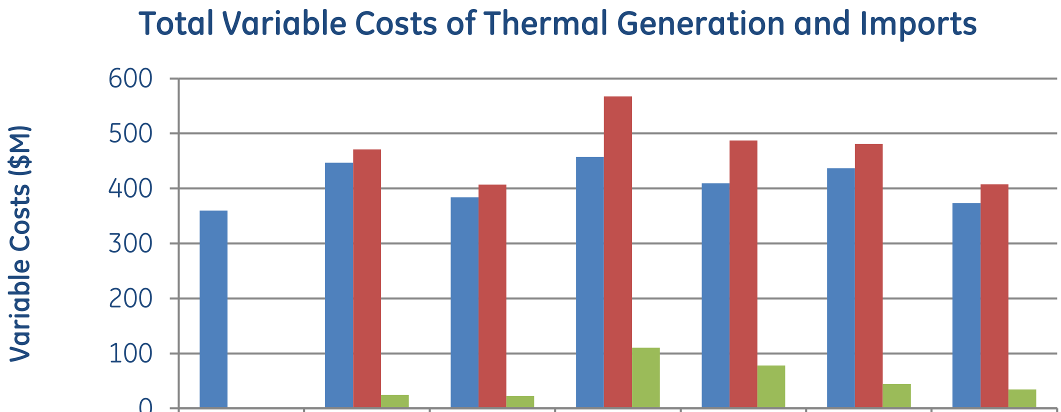
Without the incremental wind energy that is assumed to be added after 2013, the thermal plant generation and imports increase to cover the energy that is provided by wind in the base cases. The difference is shown in green. These differences are mostly due to the difference in wind energy, but also reflect the fact that more wind is exported and curtailed in the base cases compared to the business-as-usual cases. It is important to remember that Maritime Link energy is included in the BAU numbers for Cases 8 and 9.




| | CASE 1 | CASE 4 | CASE 5 | CASE 6 | CASE 7 | CASE 8 | CASE 9 |
|---|---|---|---|---|---|---|---|
| Base Case | 7,850 | 8,493 | 7,402 | 7,124 | 6,503 | 7,075 | 6,065 |
| BAU Case | | 9,018 | 7,896 | 8,911 | 7,789 | 7,762 | 6,665 |
| Delta | | 525 | 494 | 1,787 | 1,286 | 687 | 600 |

**Figure 86: Thermal Generation Comparison with Business-as-usual**

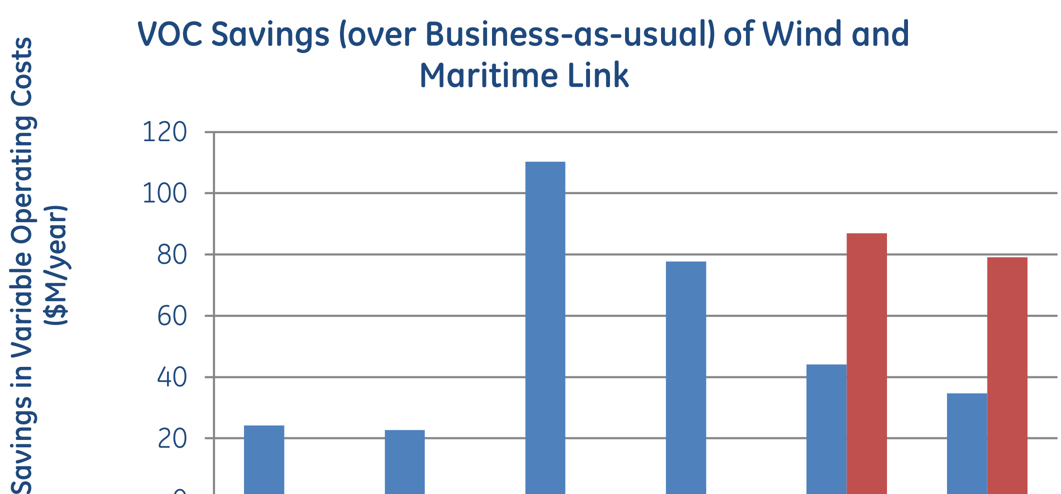
The need to generate more with thermal plants (the hydro energy is unchanged between the cases) and to import more, adds to the variable cost. The total variable cost, and the difference between the cases is shown in Figure 87. The BAU cases also allow for a calculation of the value of the Maritime Link energy.




| | CASE 1 | CASE 4 | CASE 5 | CASE 6 | CASE 7 | CASE 8 | CASE 9 |
|---|---|---|---|---|---|---|---|
| Base Case | 360 | 447 | 384 | 457 | 409 | 437 | 373 |
| BAU Case | | 471 | 407 | 568 | 487 | 481 | 408 |
| Delta | | 24 | 23 | 110 | 78 | 44 | 35 |

**Figure 87: Variable Cost Comparison with Business-as-usual**

In Figure 88, the differences between BAU Case 8 and Case 6, and between Case 9 and Case 7, show the savings from the Maritime Link, if no new wind was added after 2013. The wind savings in this figure are the same as the "delta" in the preceding one.




| | CASE 4 | CASE 5 | CASE 6 | CASE 7 | CASE 8 | CASE 9 |
|---|---|---|---|---|---|---|
| Wind | 24 | 23 | 110 | 78 | 44 | 35 |
| Maritime Link | | | | | 87 | 79 |

**Figure 88: Variable Cost Savings Comparison with Business-as-usual**

The reduction in variable costs is mostly fuel cost savings from reduced production by the thermal plants. The changes reflect the net impact of the wind added after 2013, and include impacts on the thermal plants such as running at different heat rates, starts and stops, and all the other factors that are included in the production simulations. These savings can be assigned to the wind energy.

It is important to note that we have modeled the Maritime Link as resource scheduled to shave peaks off the net load (i.e., load minus wind), and hence it is represented as a controlled resource that replaces expensive peaking units. The ability of the Maritime Link to deliver power on schedule and during periods of higher marginal cost of production makes it a more valuable resource than wind. It is important to recognize that in this calculation, the benefit of the Maritime Link is *without* the incremental wind, whereas the wind value is *with* the Maritime Link in place.

In Figure 89, the production cost (variable operating cost) reductions are shown distributed uniformly across all of the incremental wind energy. Thus, for example in Case 8, all of the wind energy added after 2013 is "worth" \$62/MWh in avoided variable operating cost. This does not reflect any value that might be realized from the exported excess wind power. Similarly, the energy from the Maritime Link is "worth" \$75/MWh.

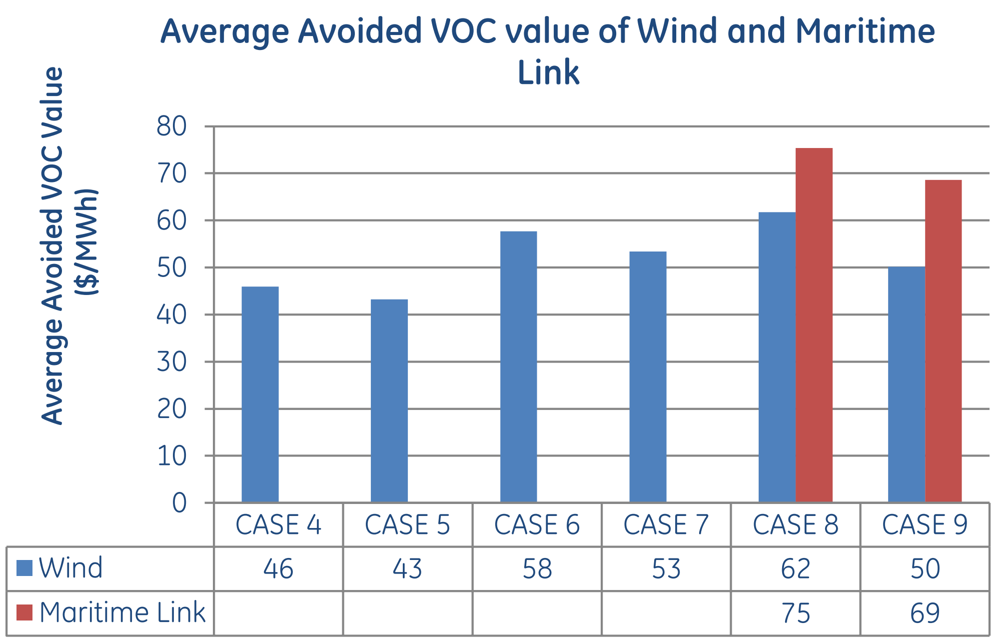



**Figure 89: Average Avoided Variable Operating Cost due to Wind or Maritime Link Energy**

### 7.2.4 Marginal Value of Wind

A set of test cases (Sensitivity V) was created for evaluation of the marginal value of wind energy. This was achieved by running this sensitivity where one wind plant was removed. To estimate the marginal value of the wind, the differences in various system attributes between Sensitivity V and Sensitivity A, such as variable costs and emissions, were divided by the capacity and energy generation of the removed plant. The resulting per MW and per MWh values of the system attributes are estimates of the marginal value of the wind.

Amherst wind is a 30 MW plant with a capacity factor of 37% and about 96 GWh of delivered energy. Energy delivered varies slightly because of leaps years (an extra day of production) and curtailment. The marginal values of Wind in terms of lowered system production costs are presented in Figure 90 and Figure 91. Figure 90 needs to be read carefully: it represents that annual variable operating cost savings that each MW of turbine hardware (or rating) would bring. So, for Case 2, the variable operating cost savings (mostly fuel and VOM costs) is $[redacted]/MW per year. If a new wind plant and any supporting capital investments to integrate the plant can be capitalized (most of the cost) and run for this revenue, then investment in the plant would be total cost neutral. It must be noted however, that a portfolio approach, that considers all future investments for each study case as well as the impact on variable operating costs and revenue requirement for recovery of fixed costs, must be taken in order to determine which option is the best option for NSPI's customers. This is beyond the scope of this study, but the results of this study can be used to inform future work that takes all of these costs into account.

Figure 91 gives the value in terms of energy delivered, which is much more understandable. It also compares the marginal value of wind to the underlying wind PPAs. As can be seen, savings from the avoided operating costs are, by themselves, insufficient to cover the PPAs.

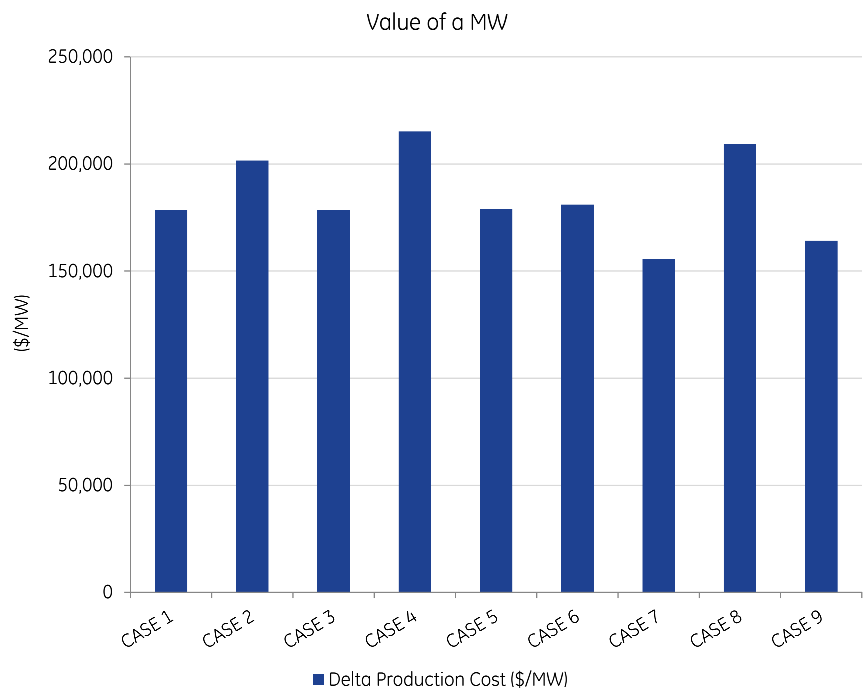



**Figure 90: Marginal Value of Wind in terms of Lower System Production Costs**

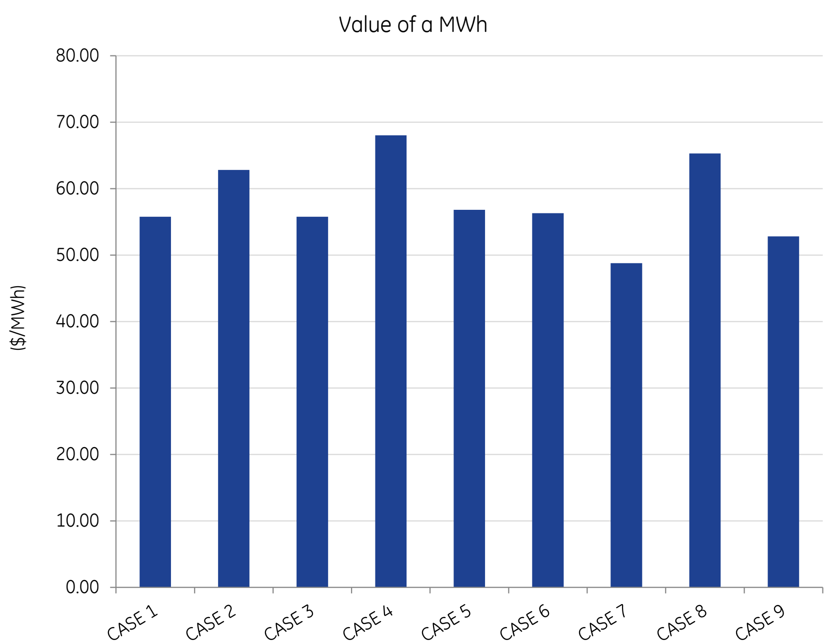



**Figure 91: Marginal Value of Wind in terms of Lower System Production Costs**

The marginal values of Wind in terms of CO2 and SOx emission reductions are presented in the Figure 92 and Figure 93. These values can be monetized if an emission allowance cost can be assigned to each emission type.

That wind power creates a CO2 savings of about ½ ton per MWh in early years is consistent with displacement primarily of gas generation. In the later years, the savings increase as the mix of displaced fuel begins to include some coal. SOx savings are about 1½ kg/MWh in the early years, rising to about 3 kg/MWh in the later years.

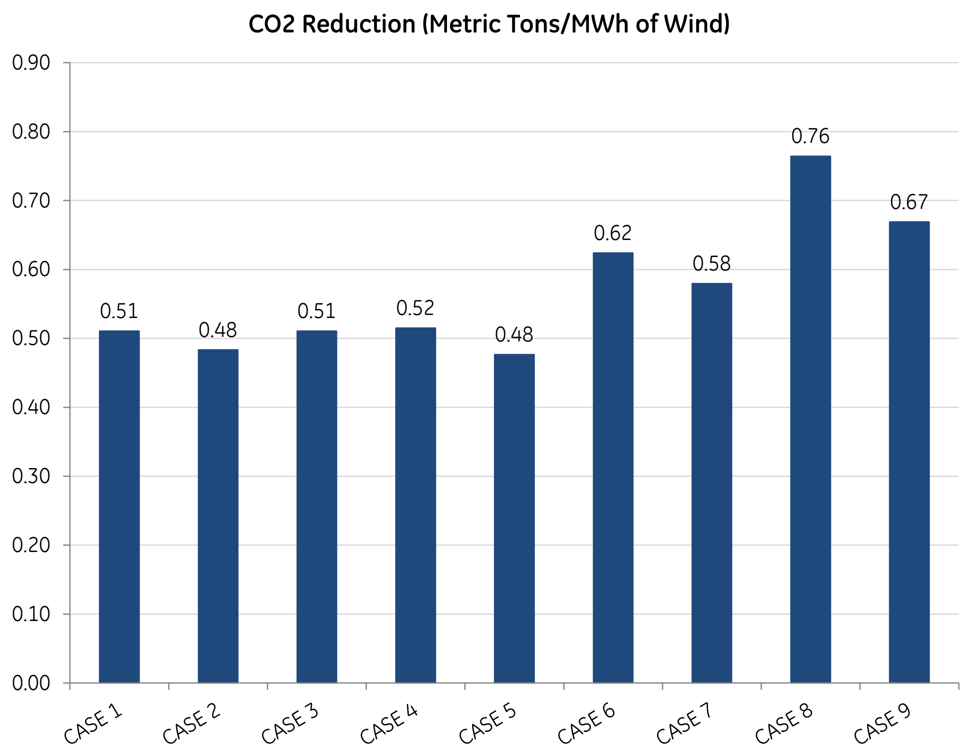



**Figure 92: Marginal Value of Wind in terms of CO2 Emissions**

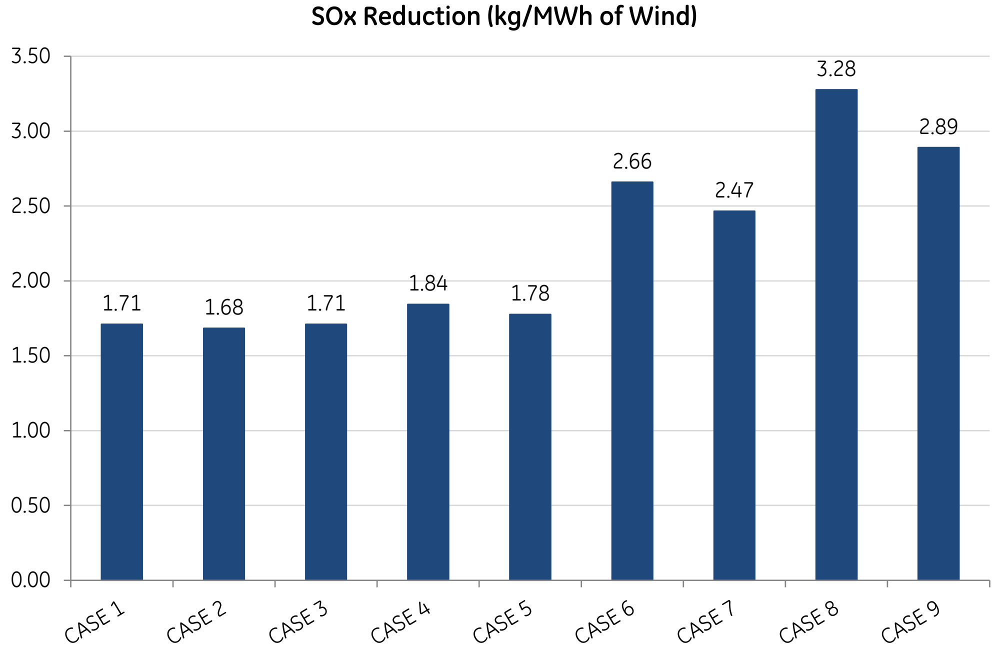



**Figure 93: Marginal Value of Wind in terms of SOx Emissions**

### 7.2.5 Marginal Value of Maritime Link

Sensitivity W was intended for evaluation of the marginal value of Maritime Link. This was achieved by running this sensitivity for Study Cases 8 and 9, with 115.3 GWh less energy from Maritime Link (i.e. about a 10% reduction in Maritime Link energy from the base cases). To estimate the marginal value of the Maritime Link, the differences in various system attributes between Sensitivity W and Sensitivity A, such as variable costs and emissions, were divided by the amount of the reduced energy imports. The resulting per MWh values of the system attributes are estimates of the marginal value of the Maritime Link. The marginal values of the Maritime Link in terms of Lower System Production Costs are presented in Figure 94.

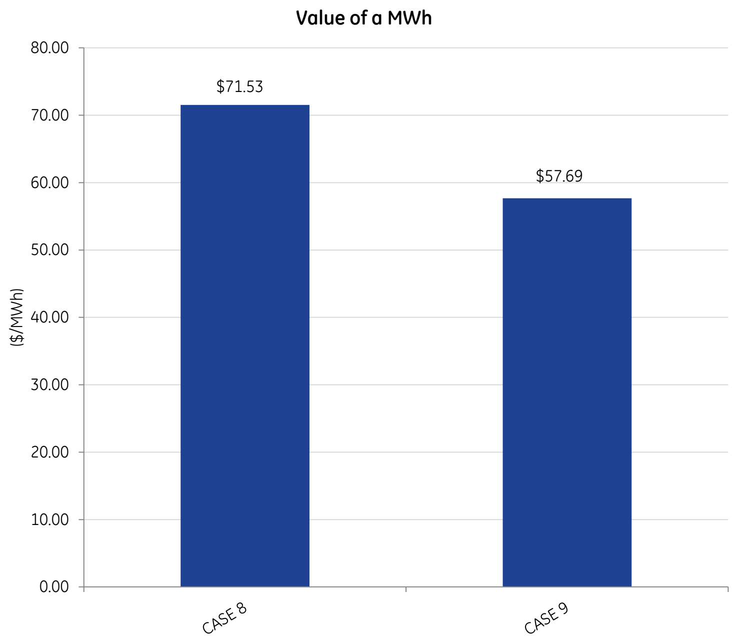



**Figure 94: Marginal Value of Maritime Link in terms of Lower System Production Costs**

The marginal values of Wind in terms of CO2 and SOx emission reductions are presented in Figure 95 and Figure 96. These values can be monetized if an emission allowance cost can be assigned to each emission type.

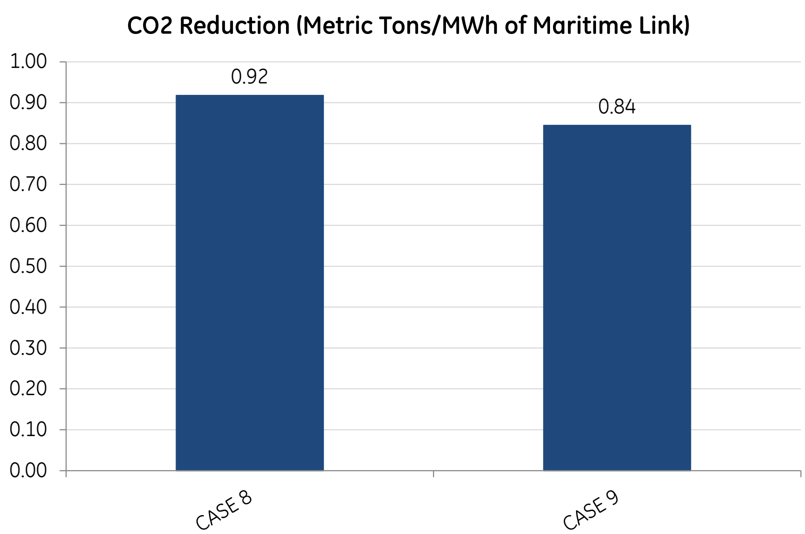



**Figure 95: Marginal Value of Maritime Link in terms of CO2 Emissions**

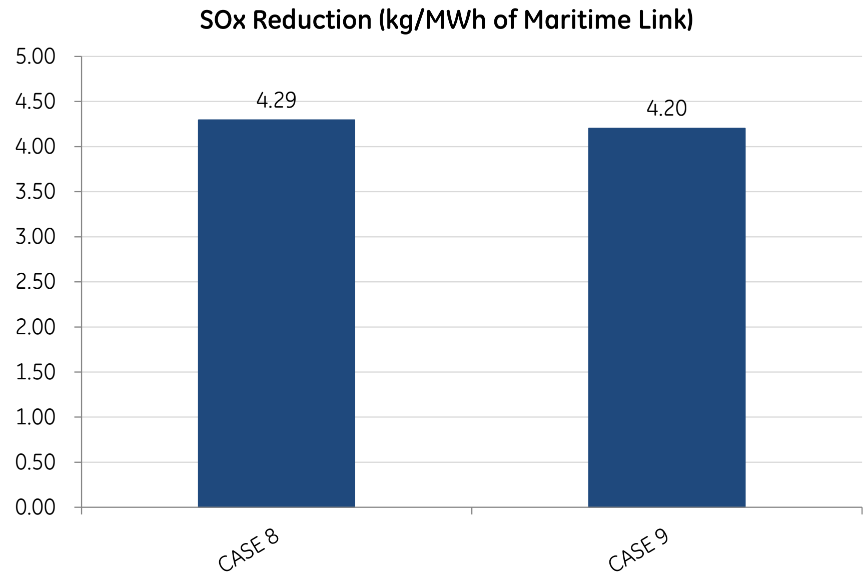



**Figure 96: Marginal Value of Maritime Link in terms of SOx Emissions**

The SOx savings for the Maritime link, of about 4 kg/MWh is better than for wind, which is in the 2.5 kg/MWh -3 kg/MWh range (as shown in Figure 93).

### 7.2.6 Marginal Value of Wind versus Maritime Link

Marginal values of Wind and Maritime Link in terms of system production costs are compared in Figure 97. Under the assumptions we used for the analysis, marginal value of an incremental MWh of Maritime Link appears to be slightly greater than that of an incremental MWh of Wind.

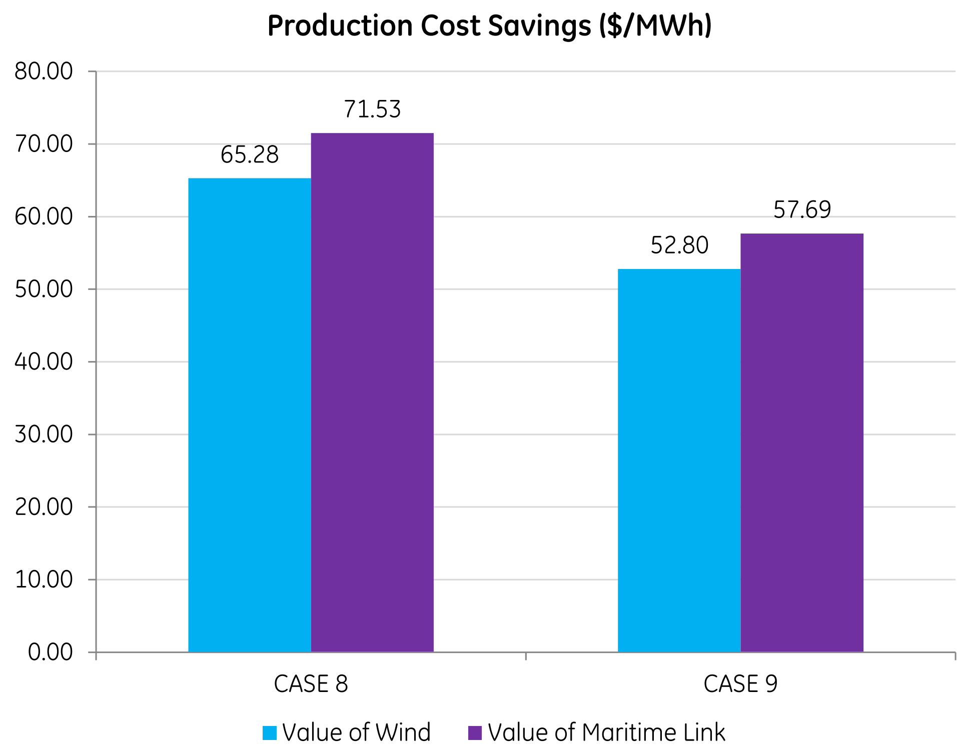



**Figure 97: Comparison of Marginal Value of Wind versus Maritime Link in terms of Production Cost Savings**

Marginal values of Wind and Maritime Link in terms of CO2 and SOx reductions are compared in Figure 98 and Figure 99. These comparisons are only for cases with the Maritime Link. Again it can be observed that under the assumptions used for the analysis, marginal value of an incremental MWh of Maritime Line is greater than that of an incremental MWh of Wind, in terms of both CO2 and SOx reductions.

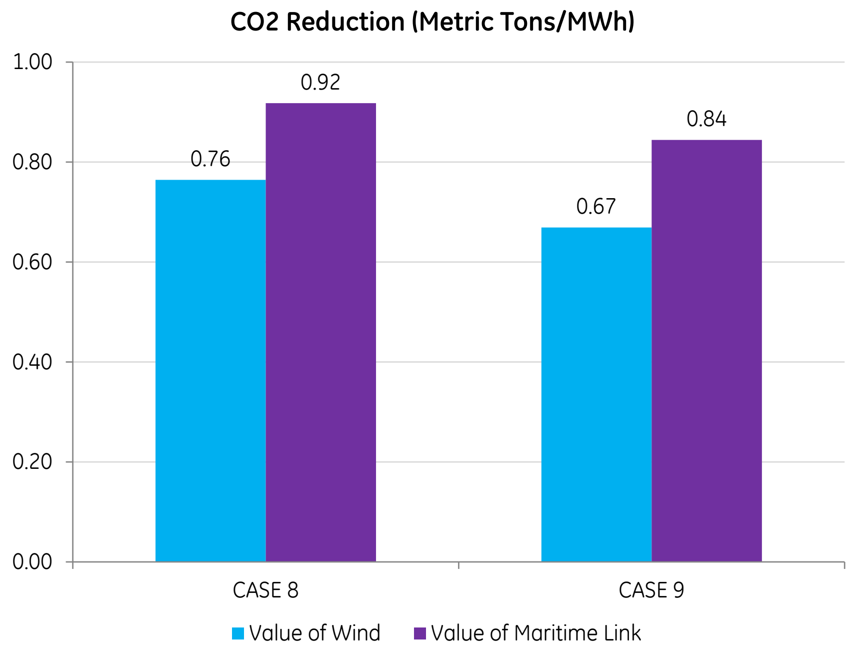



**Figure 98: Comparison of Marginal Value of Wind versus Maritime Link in terms of CO2 Reductions**

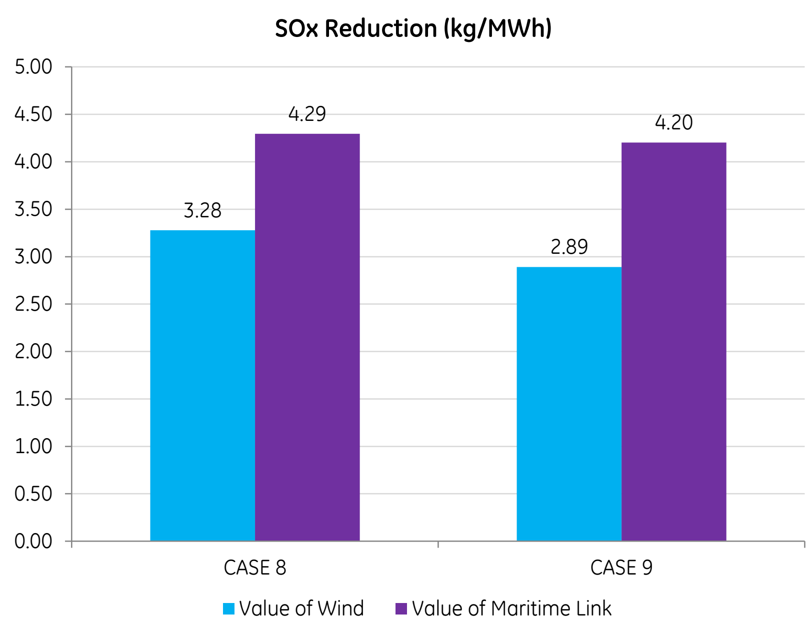



**Figure 99: Comparison of Marginal Value of Wind versus Maritime Link in terms of SOx Reductions**

### 7.2.7 Hourly Performance

This section will present hourly simulations for a range of interesting weeks. The intent is to help illustrate how the system performs from hour to hour and day-to-day during operational periods in which the behavior of the wind or wind forecast is challenging.

In Figure 100, a wide range of interesting operational aspects are apparent. All of the hourly charts presented in this report are of similar format. The color bands correspond to the dispatch of NSPI generation by type. The total system load in NSPI is the black line. Wind power delivered to the system is green. This green is the same as available wind, except when the lower trace “curtailment” is non-zero. Curtailed wind is not delivered. When the green trace is greater than the black line, excess wind power is being exported to New Brunswick (or beyond). Imports on the New Brunswick tie are purple. In the lower traces, we show both the available wind (solid green line) and the DAH forecast (dotted green line). When the dotted green line is higher than the solid one, the wind has been over-forecasted, and other resources will be required to make up the short-fall.

In this particular week of Case 7A there was relatively little wind on the peak hours of Monday, and the forecast was overly optimistic. The committed generation and NB tie imports helped to meet system load. No heroic measures, i.e., oil peaker operation or demand response, were needed. On Friday night, during a very low load (~800 MW) period, there was high wind and more of it than was forecast. During those hours, every committed unit was run down to minimum, and the maximum allowed export ([redacted]MW) was pushed out the NB tie line. Even with these measures, a significant amount of wind power was curtailed (>200MW) during the most limiting hour. As the results above show (Figure 75 and Figure 76), this happens relatively often. The total energy involved in these curtailments is valued at about $[redacted]M/year.

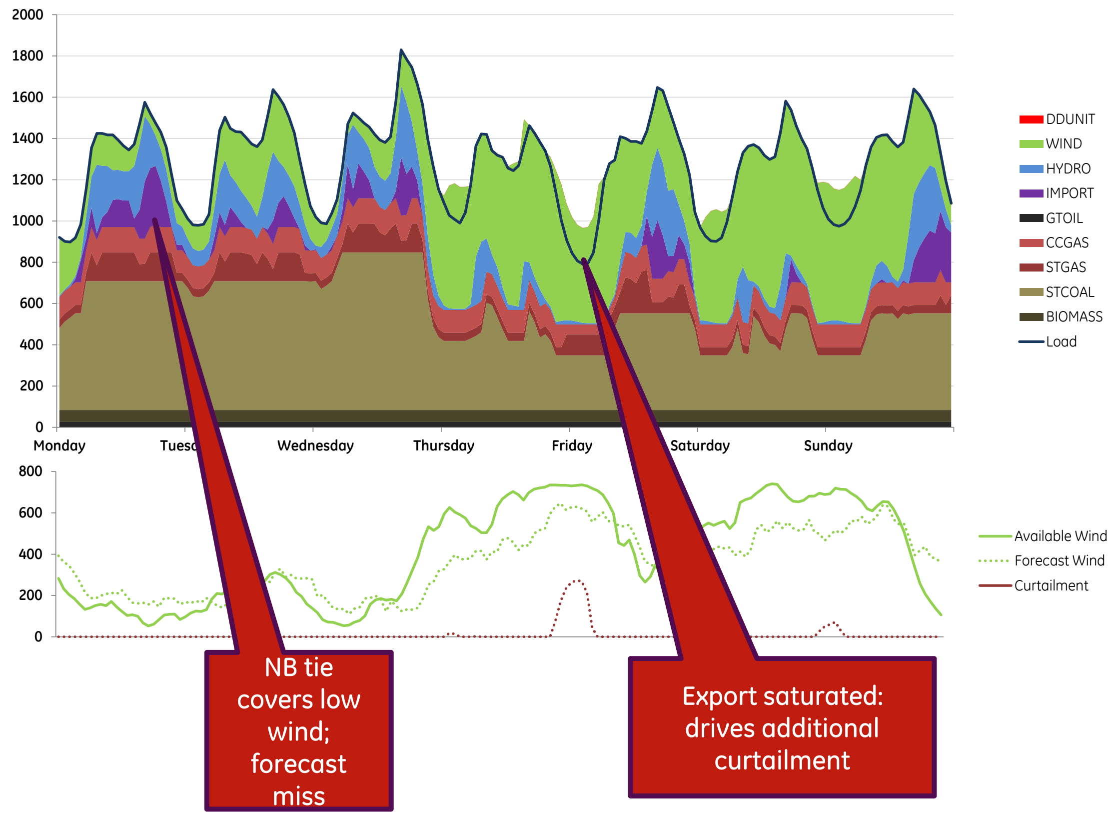



**Figure 100: Week 48 – 7A High Penetration Wind**

Figure 101 shows a rather challenging week in 2020 with the Maritime Link in service. In this particular week, the NB tie is under partial outage, and is only capable of allowing 45MW of import. This causes some operational discomfort on Wednesday. This is a day of peak load. To aggravate the situation, the wind forecast was significantly optimistic (over-forecast) during the peak load time. The Maritime Link 35-year block and supplemental 5-year block are at or near maximum import, so the system is highly stressed. The result is that expensive oil peakers are needed (black band), and demand response – the resource of last resort (DDunit - red band) is also needed. As noted earlier, demand response is invoked *before* the system violates spinning reserve requirements. More discussion of demand response is provided in Section 7.10. In subsequent sections, additional hourly results are included to help illustrate the impact of specific sensitivities.

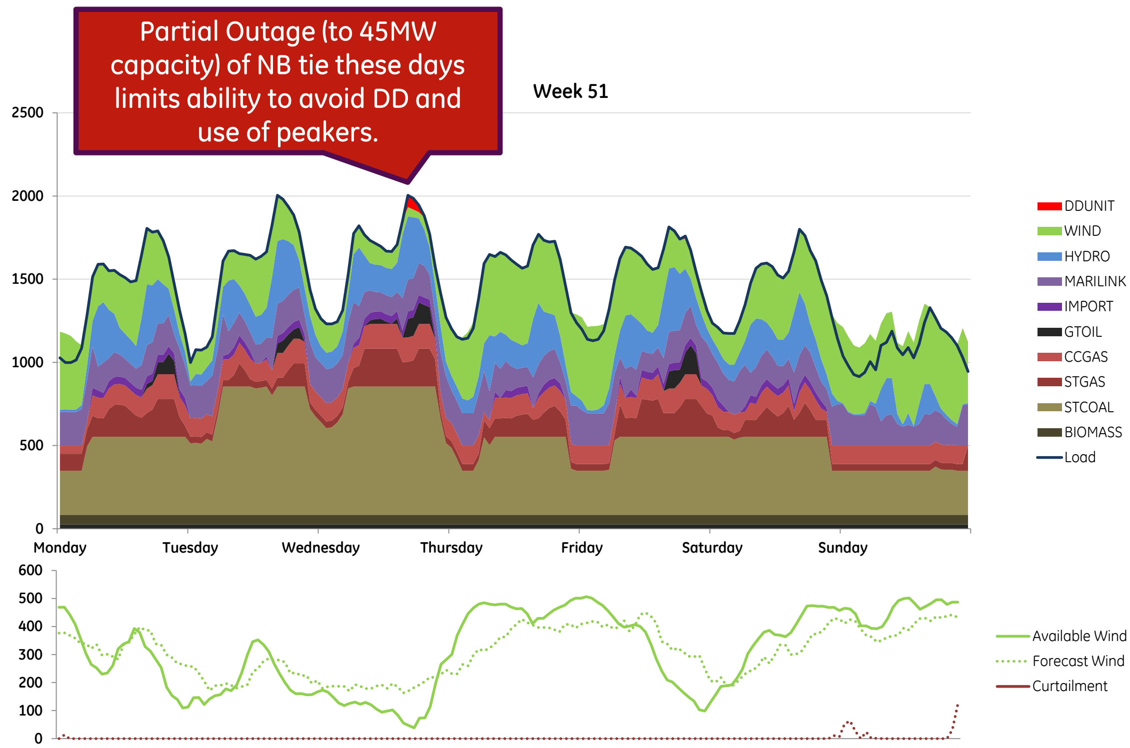



**Figure 101: Case 9A, Peak Load Week with Maritime Link**

### 7.2.8 Sub-hourly Performance

All of the results presented up to this point are for hourly simulations of the NSPI system for entire years of study. Successful operation across periods of high wind, substantial misses in wind forecast and other periods of stress have been demonstrated.

Data used in the hourly production simulations are hourly averages, and as such, sub-hourly variability of wind will, on average will net out. The power output of wind generation, just like the power consumption of system loads, varies from minute-to-minute. However, on a relative basis, wind variability is greater and less predictable. The necessity to have some operational agility to cover this variation is recognized, and has been reflected in the statistical work that leads to rules for carrying incremental reserves. Those rules are imposed on all the hourly simulations.

In this section we present simulations of selected days that capture much of this sub-hourly variation. The PLEXOS tool [described in appendix B] allows for simulations of shorter time step. In the following figures, results for steps of 10-minutes are shown. This resolution allows us to confirm that the reserve strategy works, and check for problems that might occur as the system follows these wind variations. Here we zoom in on some periods of high variability, and point out important operational considerations.

#### *7.2.8.1 PLEXOS Study Case 7A Results*

In the following sequence, we look more closely at the sub-hourly maneuvering of NSPI resources. Here we look at a few days of high wind, focusing on balancing the wind variability with thermal resources. In this analysis, we have forced the long term commitment determined by MAPS onto the daily runs. We have not allowed hydro resources to participate in sub-hourly balancing. This is a rather pessimistic assumption.

For NSPI hydro resources other than Wreck Cove, dispatch is established based on the DAH wind forecast and available monthly energy. In practice, NSPI's ability to manipulate hydro schedules during the day, and perhaps more importantly, in real time, will vary by plant and time of the year.

During periods when the conventional generation is hard against minimums, the total system will sometimes be short of downward maneuvering room. It is implicit in the hourly results that wind export and curtailments can be implemented in real time: that is, that a substantial fraction of the projects (those near the top of the curtailment priority list), have the capability to be exported and/or curtailed on very short intervals. Throughout the PLEXOS cases we have grouped export into curtailment – from a balancing perspective, this simplification is equivalent. But operationally, there is a big difference. The flexibility must come either from the NB tie or from the wind plants. When the NB tie is at export maximum - zero for these examples - then all of the operational flexibility must come from the wind plants.

In Figure 102, we look at the day of highest wind penetration, during which substantial curtailment occurs. During the periods highlighted with brackets, the other NSPI resources are hard against minimum. The red trace shows curtailment. (Even if exports were allowed to [redacted]MW, there would be curtailment here.) ALL of the sub-hourly variability is imposed against the wind plants.

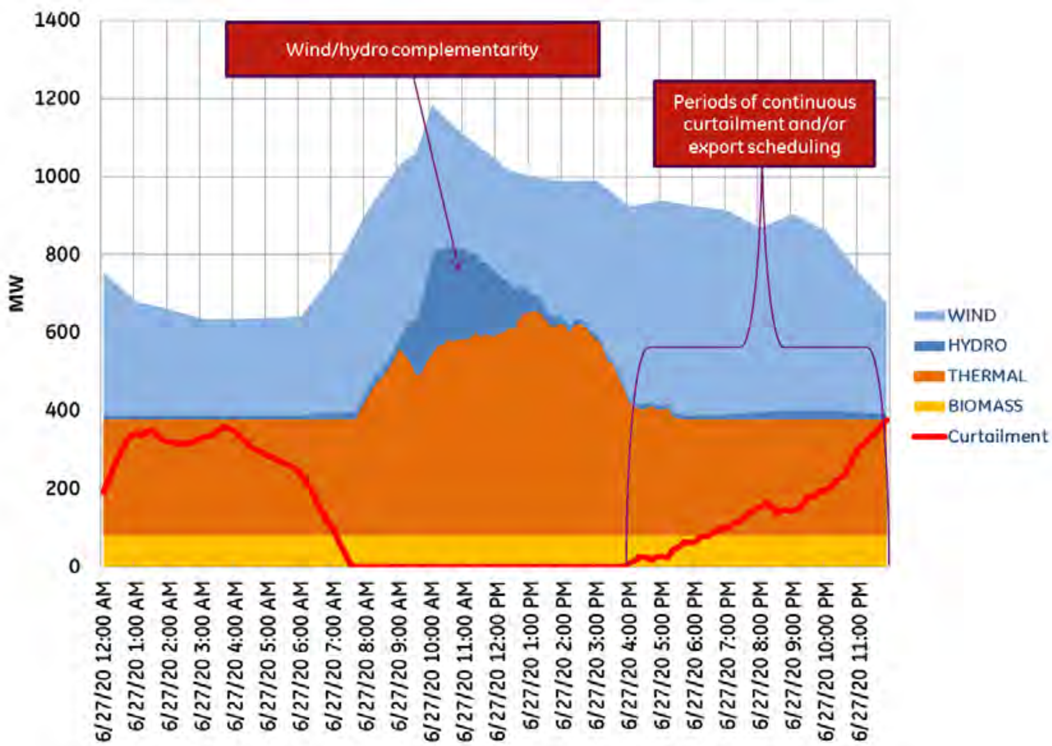



**Figure 102: Case 7A, 10-Minute Dispatch June 27 2020: Highest Wind Penetration Day - High curtailment**

This is relatively new ground for the industry: there is relatively little industry experience with "real-time" curtailment. Smaller systems, like NSPI, are more vulnerable to these requirements. The alternative is to pre-curtail wind generation, and increase dispatch of thermal generation in order to maintain down maneuvering room…in short, the wind is curtailed in anticipation of the possibility that it will increase. The system burns fossil fuel (or uses hydro) while wind is spilled.

Later in this report, we present a sensitivity sequence (group T) in Section 7.9.3, intended to show this operational approach. It shows an increase in operational cost, increased emissions and increased curtailment.

In situations where the host utility incurs significant costs (e.g. take-or-pay contracts on wind), the economic penalty for NOT having real-time scheduling/real-time curtailment of the wind plants is substantial.

The US utility, Xcel Energy, was in this situation. They have imposed a requirement since (~2010) that all new wind generation in their system accept AGC signals for sub-hourly re-dispatch. They have realized significant operational savings.

Figure 103 shows a detail of the preceding figure. In this two hour window, the total wind curtailment changes over each 10-minute period. Some of the changes in this period are non-trivial. Most modern wind plants can maneuver at this rate, but again, this is not common practice (yet) in the industry. Wind plant owners will, in general, not expect to have this requirement imposed upon them. The alternative, as noted, is more curtailment. The "who pays" question will be keenly scrutinized.

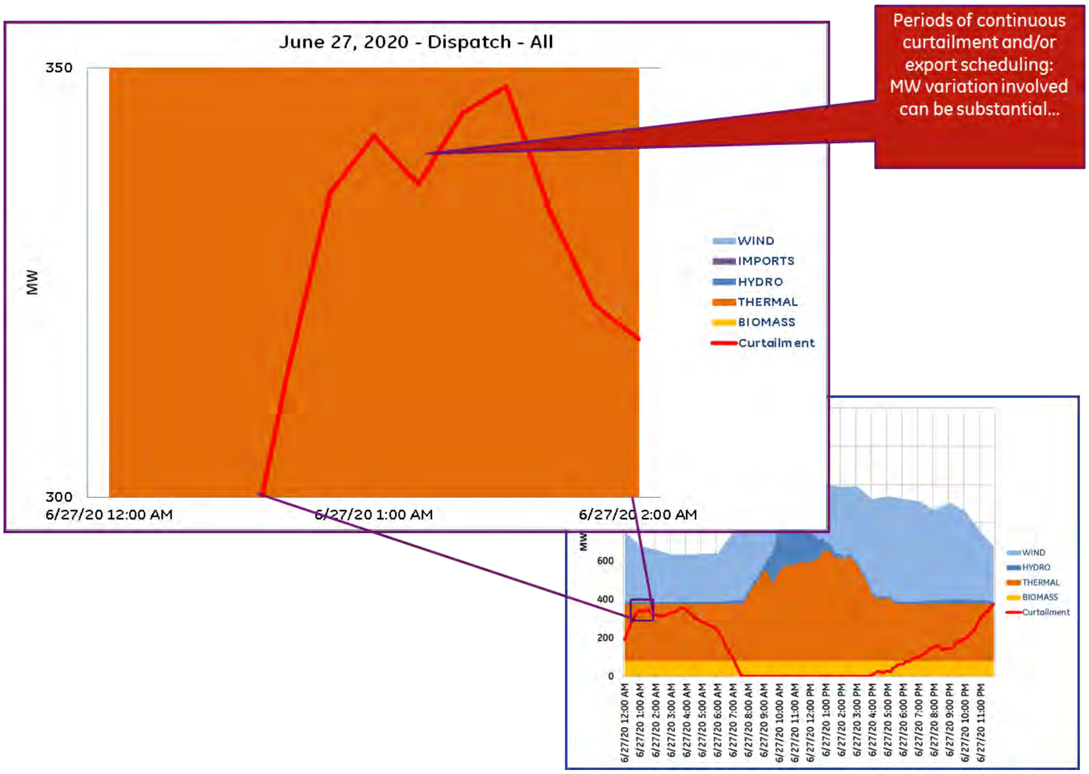



Figure 103: Case 7A, Detail of 10-Minute Dispatch of Thermal Plants, June 27, 2020

In Figure 104, the behavior of specific thermal plants on the same day is shown. Notice that in the periods when all the plants are not on their minima, there is intra-hour maneuvering of the plants. This is consistent with the hourly simulations, and gives some assurance that the reserves and amount of generation on line is able to cover total load and wind variability.

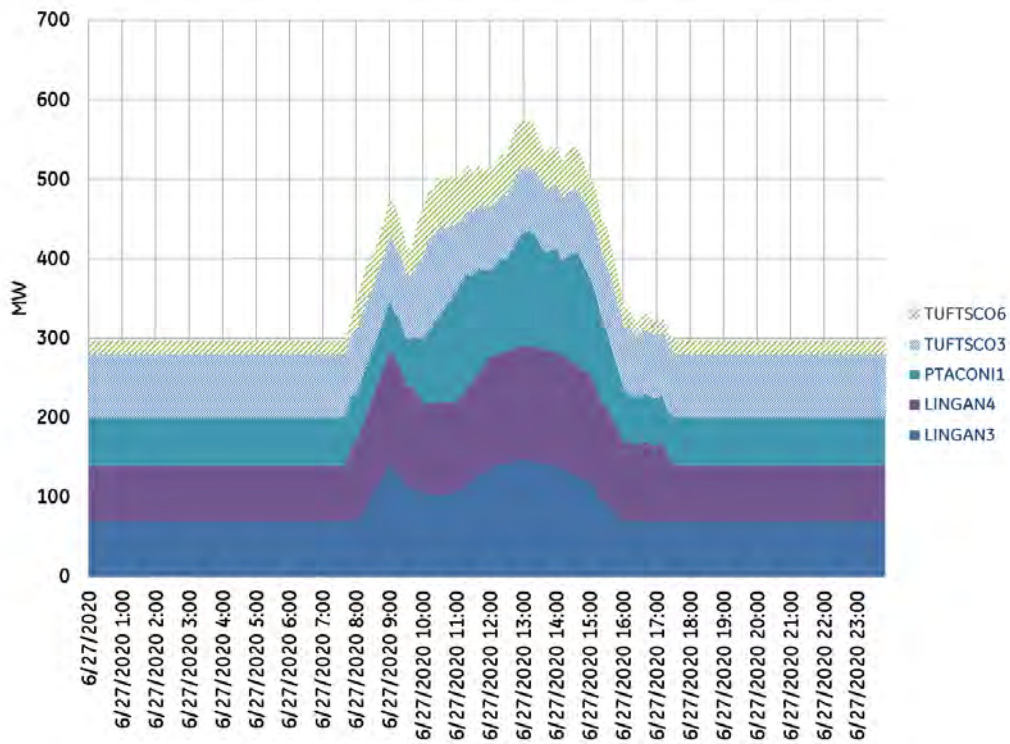



**Figure 104: Case 7A, 10-Minute Dispatch of Thermal Plants, June 27, 2020**

The period of highest curtailment (for the year) is shown in Figure 105. It is interesting to examine the behavior of the thermal plants on this day. In Figure 106, the thermal plants can be seen following load, during periods when they are not at minimum. Some significant maneuvering is observed. Looking more closely at a single unit, Figure 107 shows the behavior of Trenton 6. Broadly, the plant is either at maximum or minimum. The period around the early evening (~17:00), during which the plant periodically “bounces”. In practice, this type of maneuvering might be difficult for thermal plants. Since hydro resources are backed down to near their minimum during this time, it entirely possible that this type of maneuvering might be more reasonably imposed on hydro plants. These cases do not make allowance for that possibility. Wreck Cove is off line in these hours.

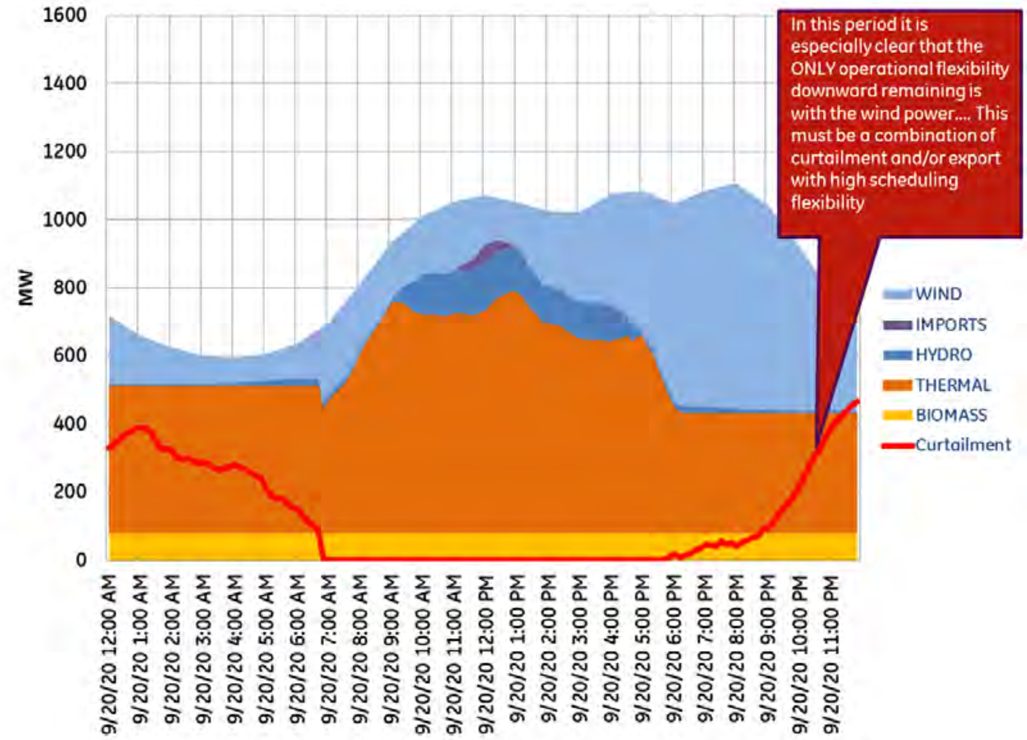



**Figure 105: Case 7A, Sunday, Sept 20, 2020 - Period of Highest Curtailment**

Our analysis doesn't include additional wear-and-tear costs on thermal plants. That cost will be very NPSI specific, but the best work in the industry suggests these costs are in the order of $0.06$/MWh to 2.0$/MWh of wind [20]. More discussion is provided in Section 7.9 on thermal flexibility.

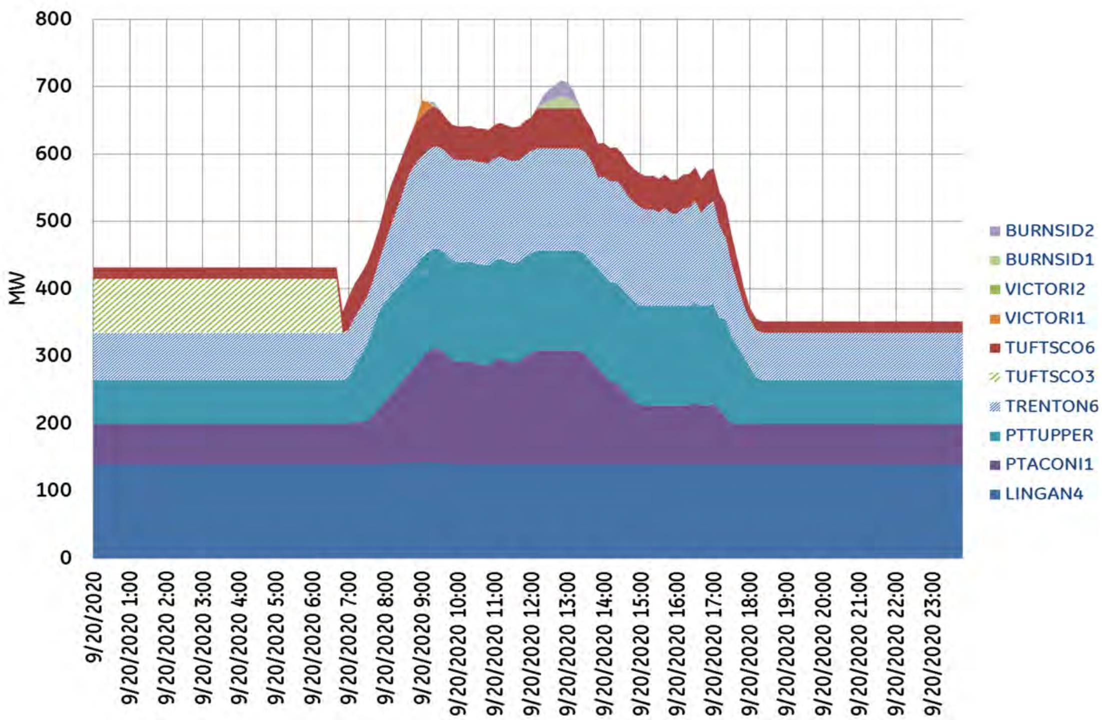



Figure 106: Case 7A, 10-Minute Dispatch of Thermal Plants, September 20, 2020

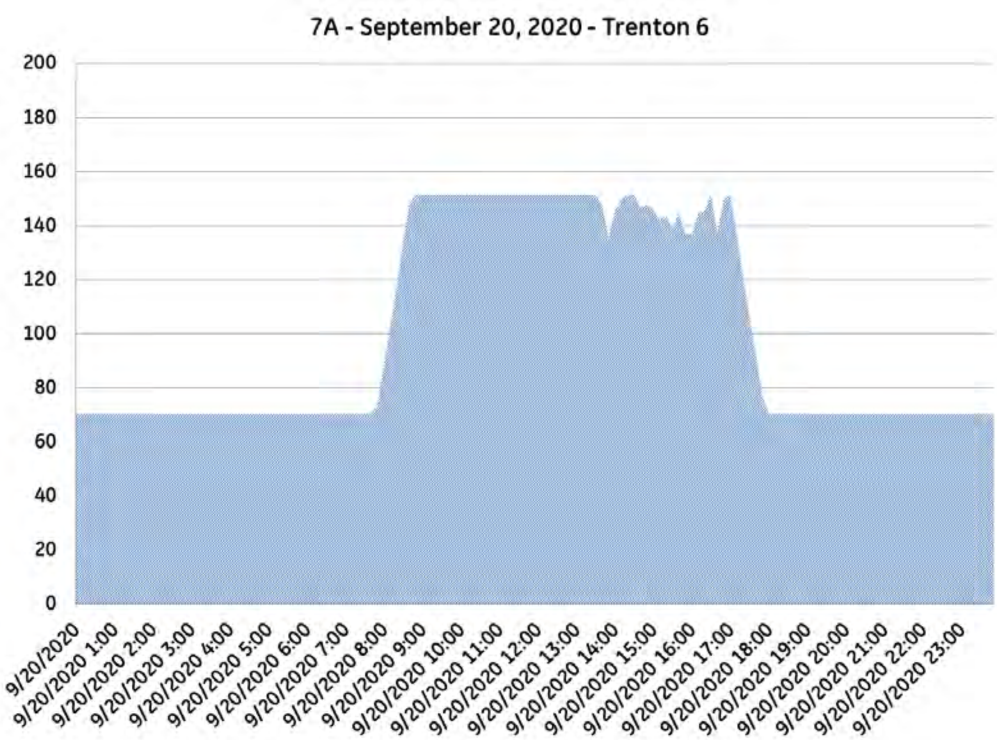



Figure 107: Case 7A, September 20, 2020 - Details of Single Plant (Trenton 6)

Figure 108 and Figure 109 show a day in which the morning net load rise is rapid. During that time, the wind export and/or curtailment can be reduced, making the wind resource a significant contributor to load following. Curtailed wind provides an operational option to help cover other system events. While out of the scope of this study, it should be noted that industry practice is moving towards expectation that curtailed wind will *always* provide primary frequency response (e.g. spinning reserve) and that it is a resource for load following as well [23]. NSPI operations should plan on taking advantage of this capability. Interconnect agreements should stipulate this functionality. More discussion is provided in section 7.11.4 on interconnection requirements.

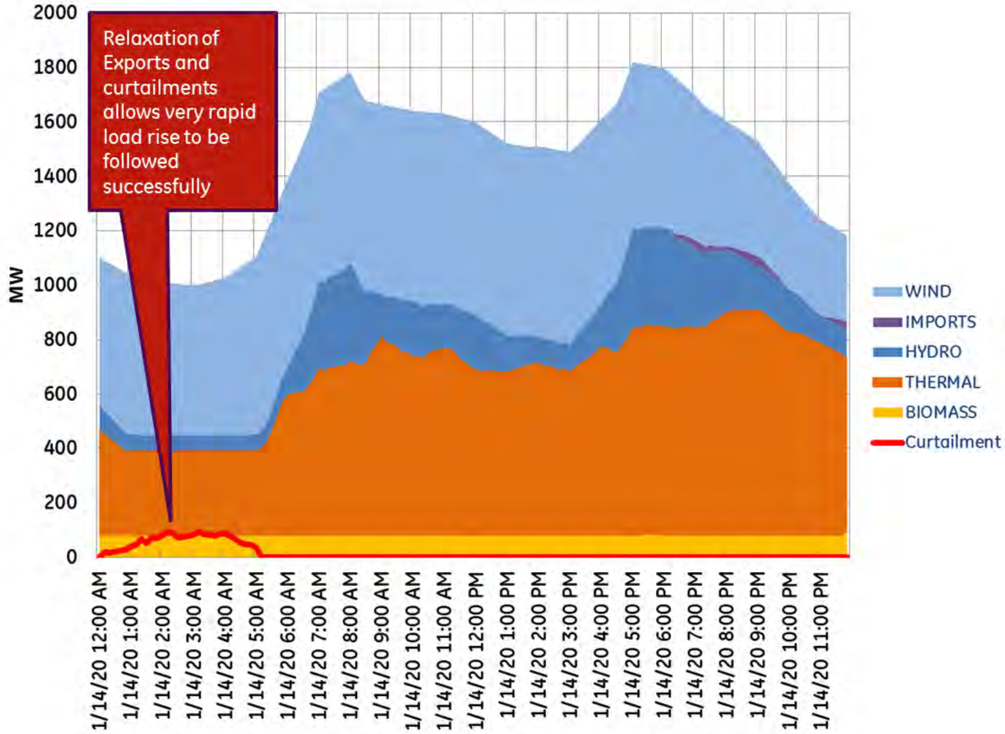



**Figure 108: Case 7A, 10-Minute Dispatch of Plant Types, January 14, 2020**

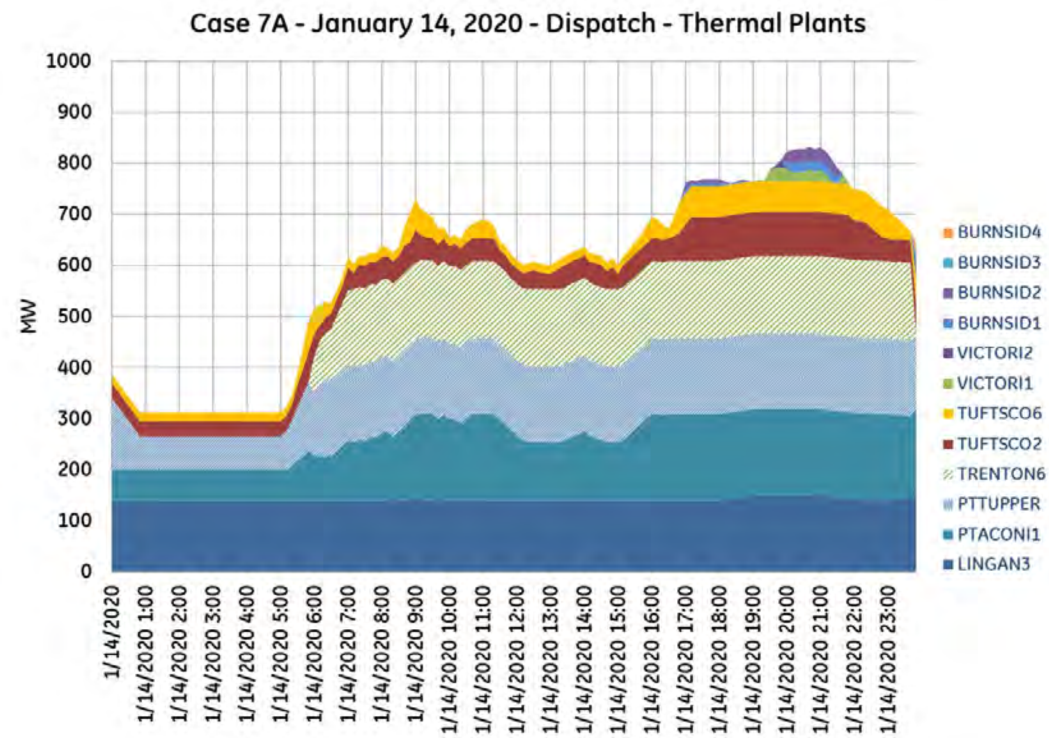



**Figure 109: Case 7A, 10-Minute Dispatch of Thermal Plants, January 14, 2020**

Figure 110 and Figure 111 show rapid and substantial change of NB tie imports, driven by both morning load rise and wind forecast error. This is explored further in the section on the NB tie operational flexibility.

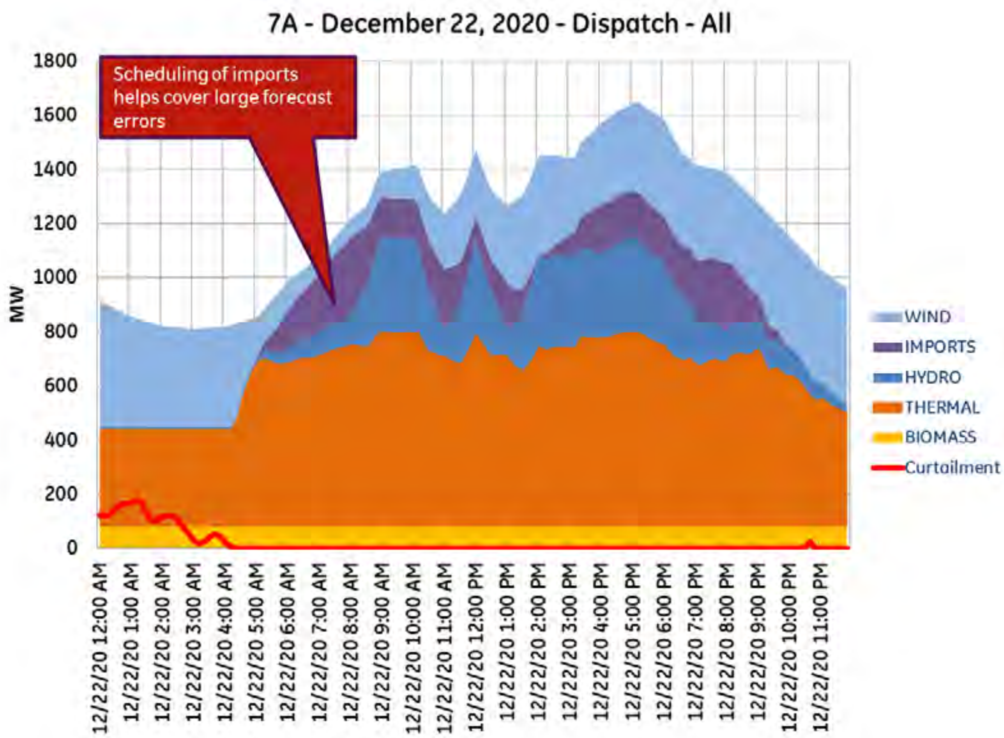



Figure 110: Case 7A, 10-Minute Dispatch of Plant Types, December 22, 2020

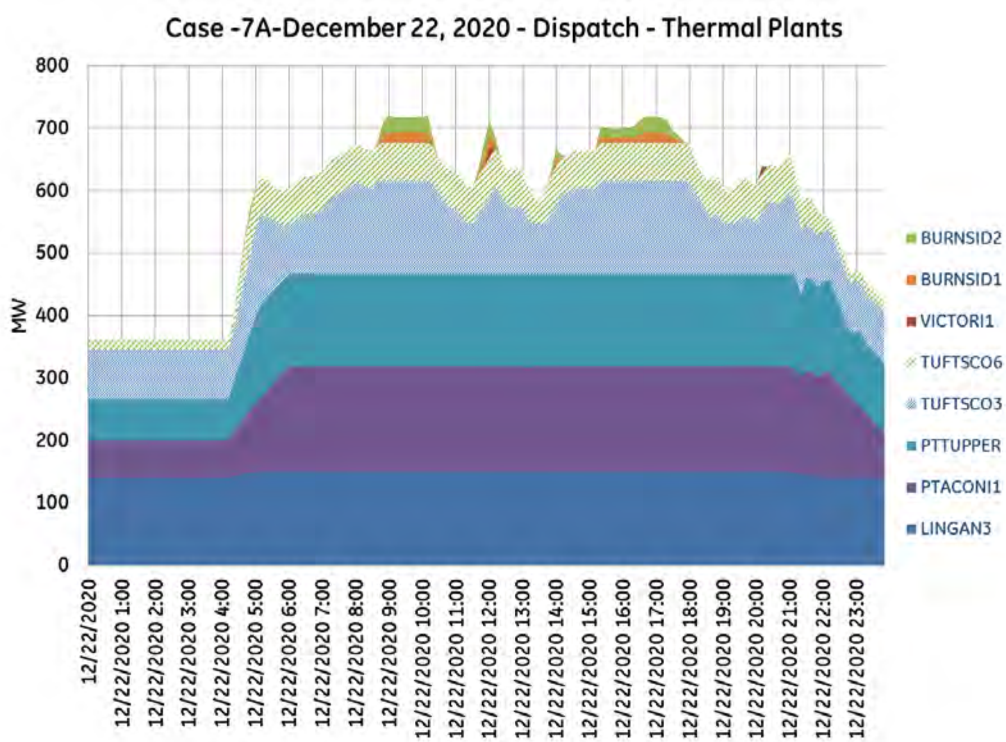



Figure 111: Case 7A, 10-Minute Dispatch of Thermal Plant, December 22, 2020

#### *7.2.8.2 PLEXOS Study Case 9A Results*

The days presented in this section highlight some of the sub-hourly impacts of the Maritime Link and interactions with the in-province wind. In Figure 112 and Figure 113, the operational constraints in the early morning hours are similar to those observed above for case 7. But, from hour 18:00 to 23:00, the Maritime Link is contributing to curtailment of the in-province wind plants. The tight energy and power constraints on the Maritime Link contract (35-year and supplemental 5-year blocks) make this a requirement. In this analysis, as discussed in Section 6, the conservative assumption is that the Maritime Link is scheduled by the hour in the day-ahead security constrained dispatch. However, it is possible that the contractual arrangement with the Maritime could be designed to allow frequent or even continuous refinement in schedule to provide some of the operational flexibility that is coming solely from the in-province wind plants. As with the NB tie, this strategy would effectively export some of the faster variability to the exporting system (Newfoundland and beyond).

Similarly, even during the day when there is no curtailment, the NSPI resources must maneuver within the hour. At least some of this maneuvering might be imposed on the Maritime Link. Again, the very tight daily energy constraints on the contract make this tricky: As each block runs out (e.g. as the 8 hour period of the main block nears the end of the 8 hour window), the operational flexibility decreases towards zero. This is because a fixed, exact amount of energy must be delivered in each and every contract block. Flexibility in this aspect of the Maritime Link contract might prove highly valuable to the system, but was not evaluated in this study.

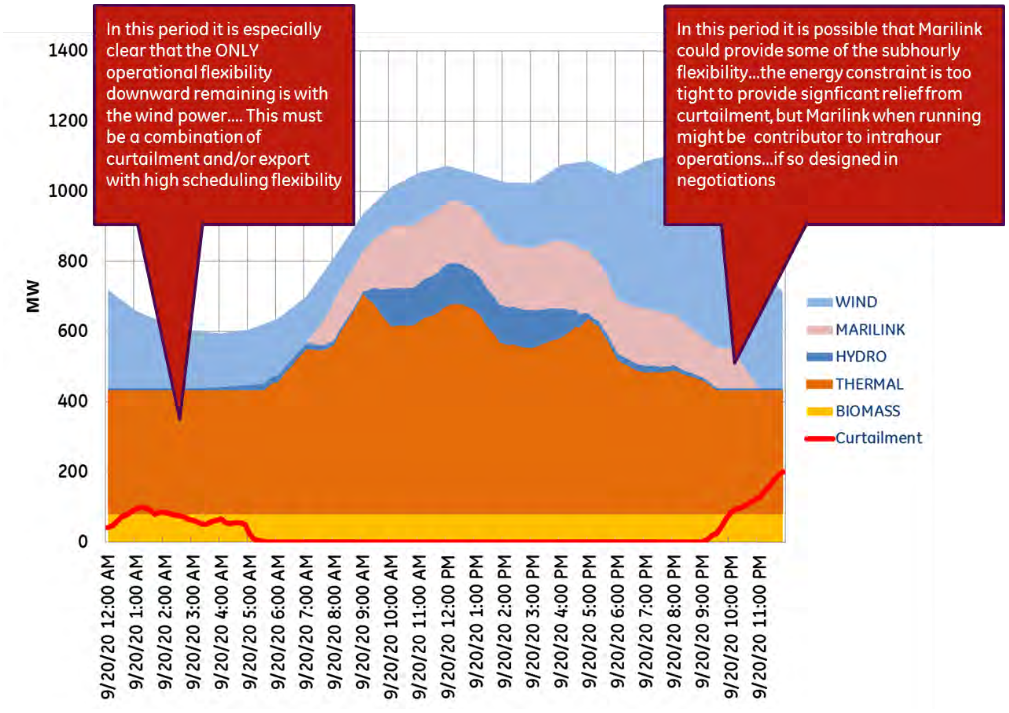



Figure 112: Case 9A, 10-Minute Dispatch of Plant Types, September 20, 2020

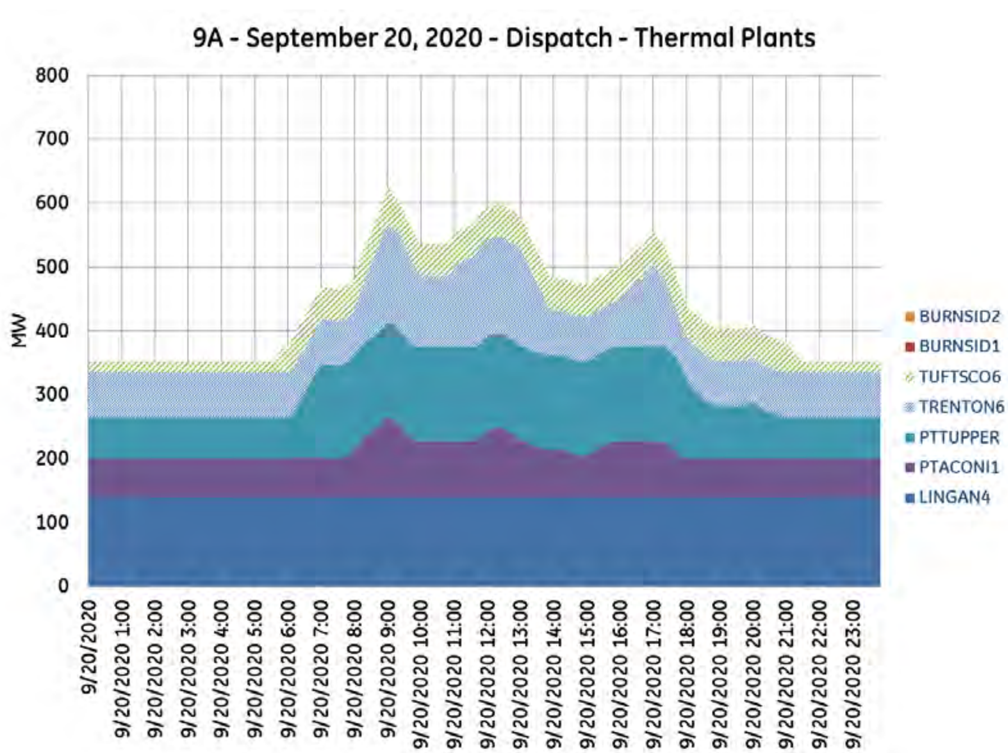



Figure 113: Case 9A, 10-Minute Dispatch of Thermal Plants, September 20, 2020

Figure 114 is similar to Figure 107, except during the evening "bounce", both NSPI hydro resource *and* the Maritime Link might be used to reduce the need to aggressively maneuver the thermal plant(s).

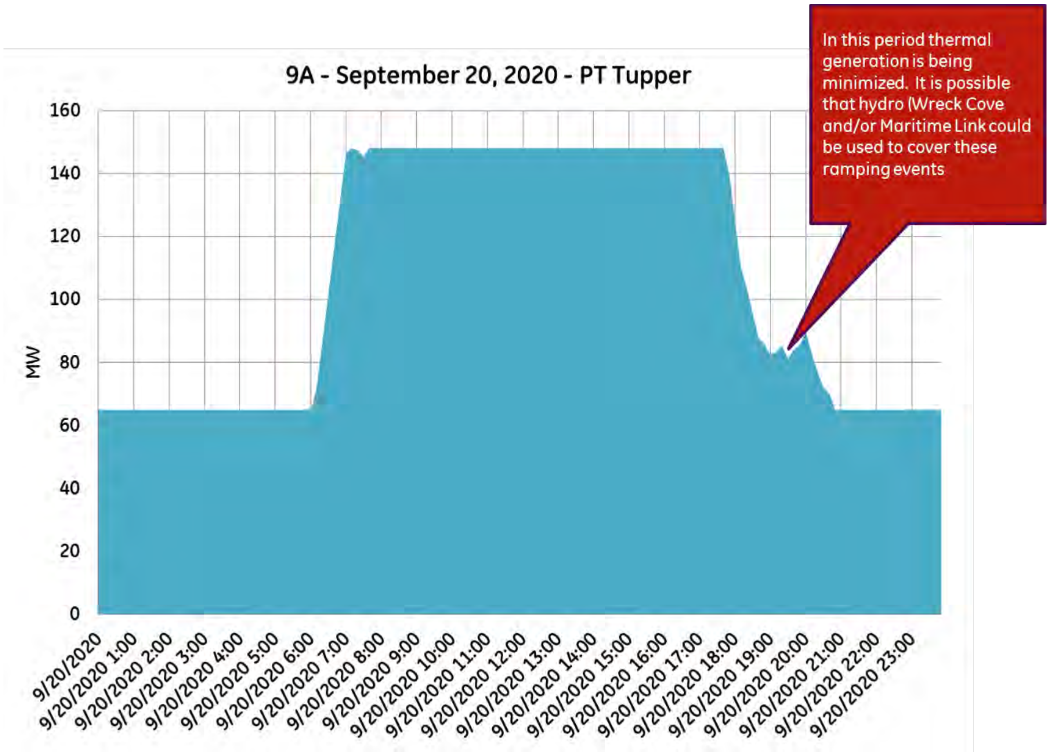



**Figure 114: Case 9A, September 20, Details of a Single Plant**

In Figure 115 the reflection of the wind variability on the thermal plants is clear at mid-day. The plot helps illustrate that, if the Maritime Link had additional operational flexibility, the frequent changes in dispatch on the NSPI thermal plants could, instead, be imposed on the Maritime Link. Figure 116 shows the 10-minute dispatch of the thermal plants.

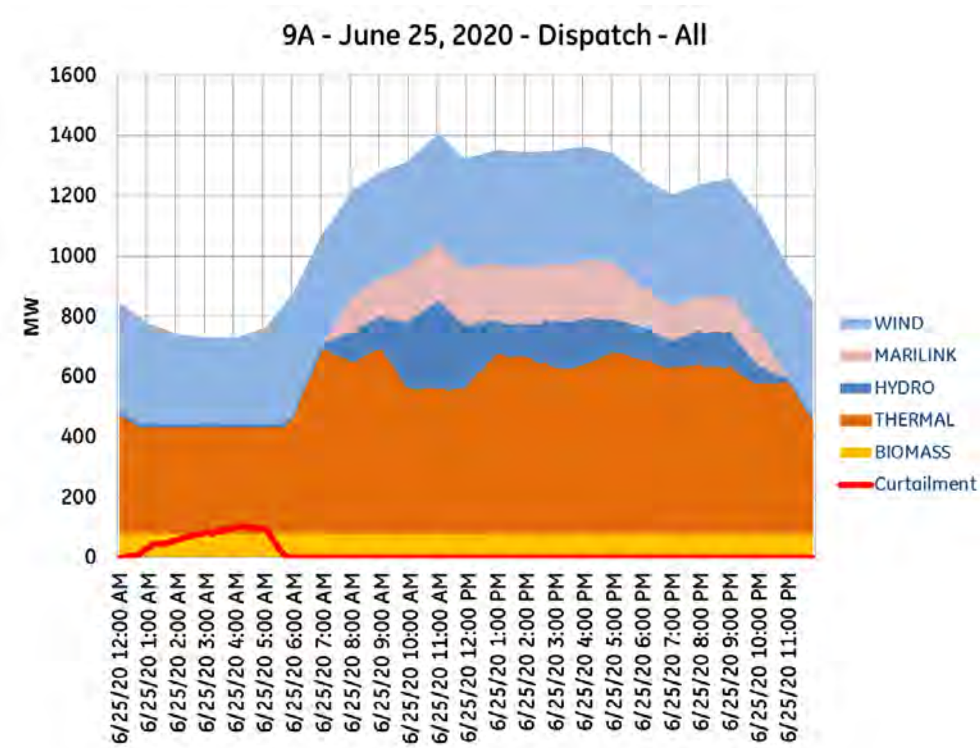



Figure 115: Case 9A, 10-Minute Dispatch of Plant Types, June 25, 2020

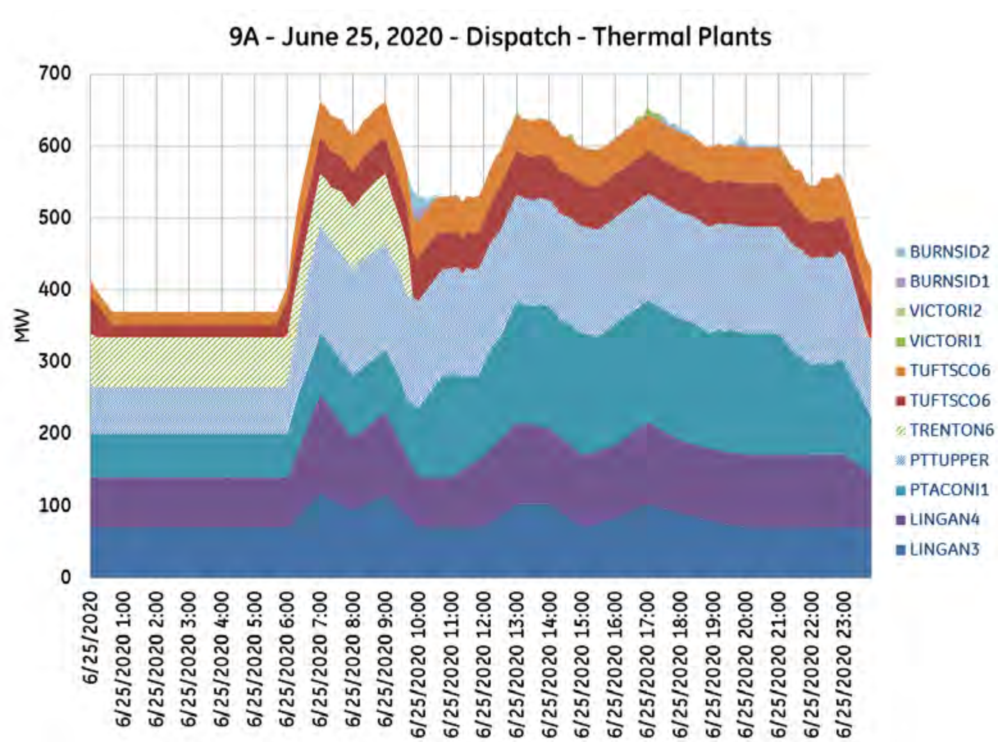



Figure 116: Case 9A, 10-Minute Dispatch of Thermal Plants, June 25, 2020

Figure 117 and Figure 118 reinforce the observation from the Case 7 simulations, that a high degree of curtailment flexibility is needed on the wind plants – the addition of the Maritime Link (at least as represented in this study) does not remove this need.

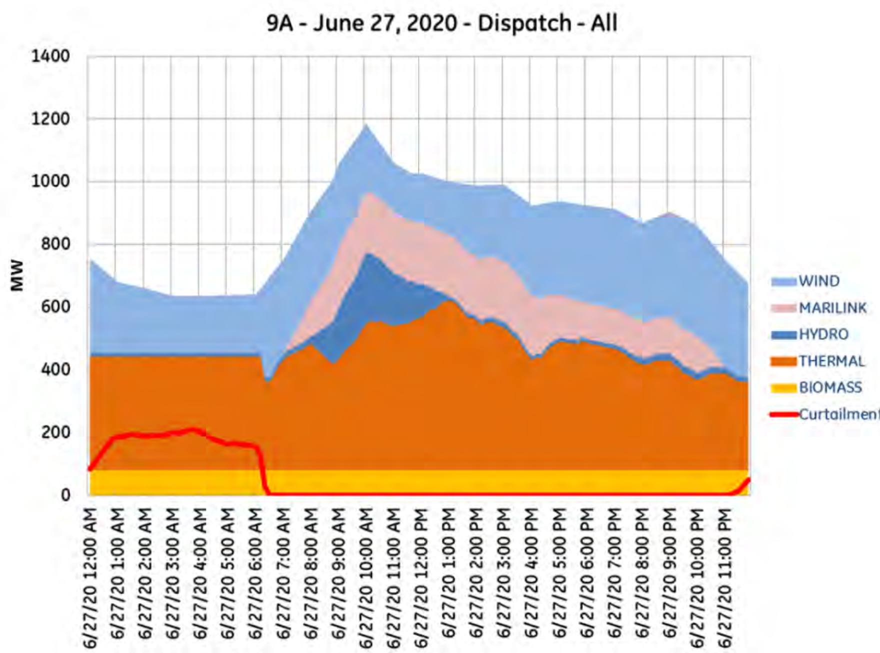



Figure 117: Case 9A, 10-Minute Dispatch of Plant Types, June 27, 2020

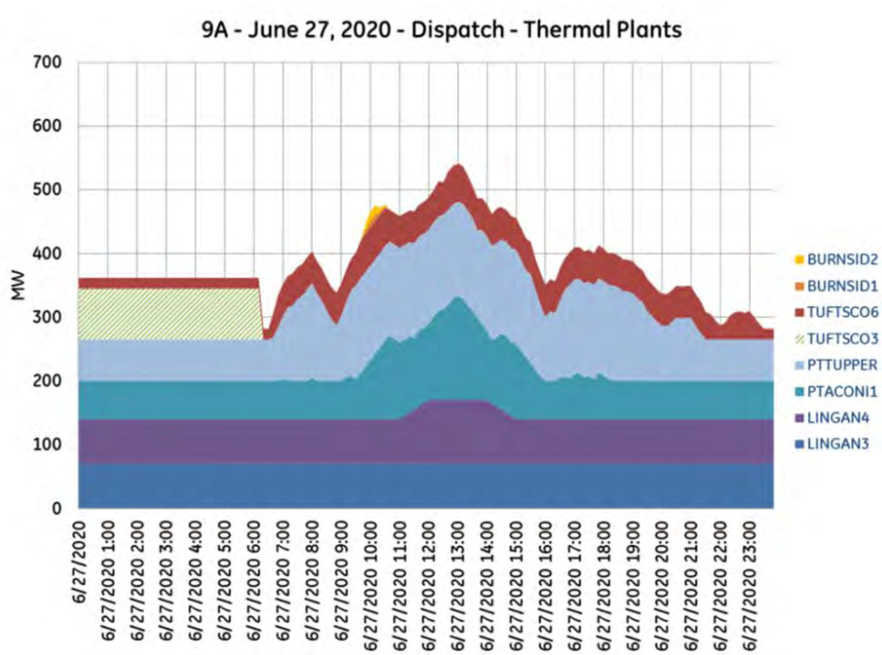



Figure 118: Case 9A, 10-Minute Dispatch of Thermal Plants, June 27, 2020

Figure 119 shows a situation where the short lead-time expensive oil peakers are needed to follow a rapid morning load rise that is exacerbated by declining wind power. They are only needed briefly, yet they are central to successful operation and contribute a non-trivial amount to system operating costs. (This is observable in Figure 79.) The other key point observable in Figure 119, is that the Maritime Link, especially in off peak hours, drives wind curtailment. In the early morning hours, the curtailment (or forced export) of wind approaches the power level of the Maritime Link.

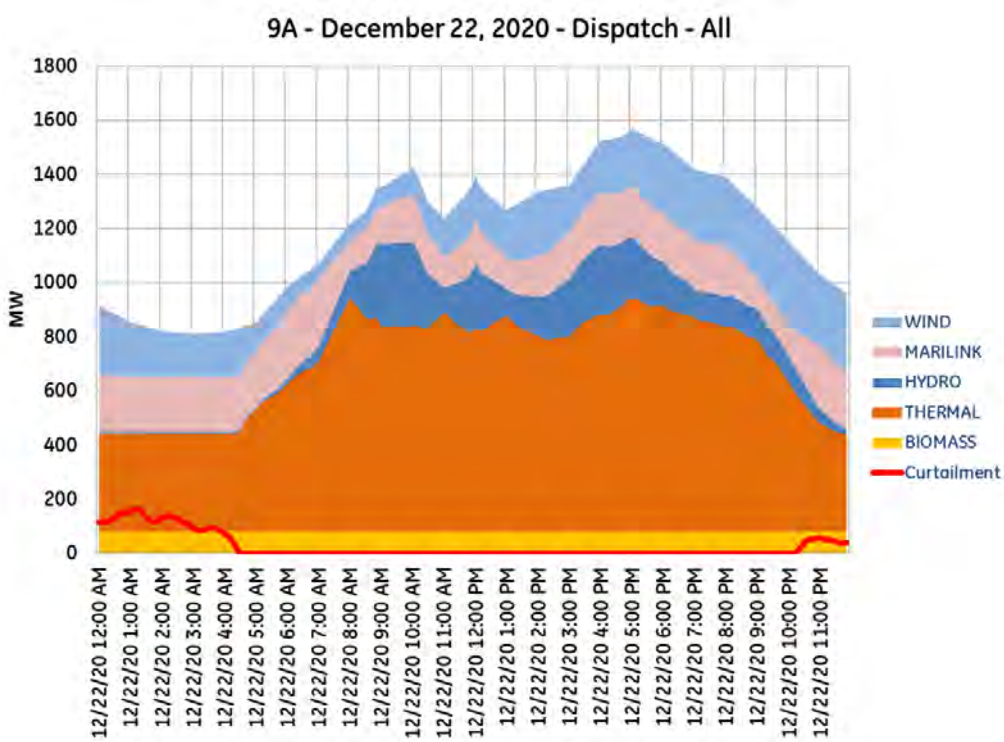



**Figure 119: Case 9A, 10-Minute Dispatch of Plant Types, December 22, 2020**

Figure 120 shows the 10-minute dispatch of the thermal plants. The maneuvering of the peakers during mid-day is striking in this figure.

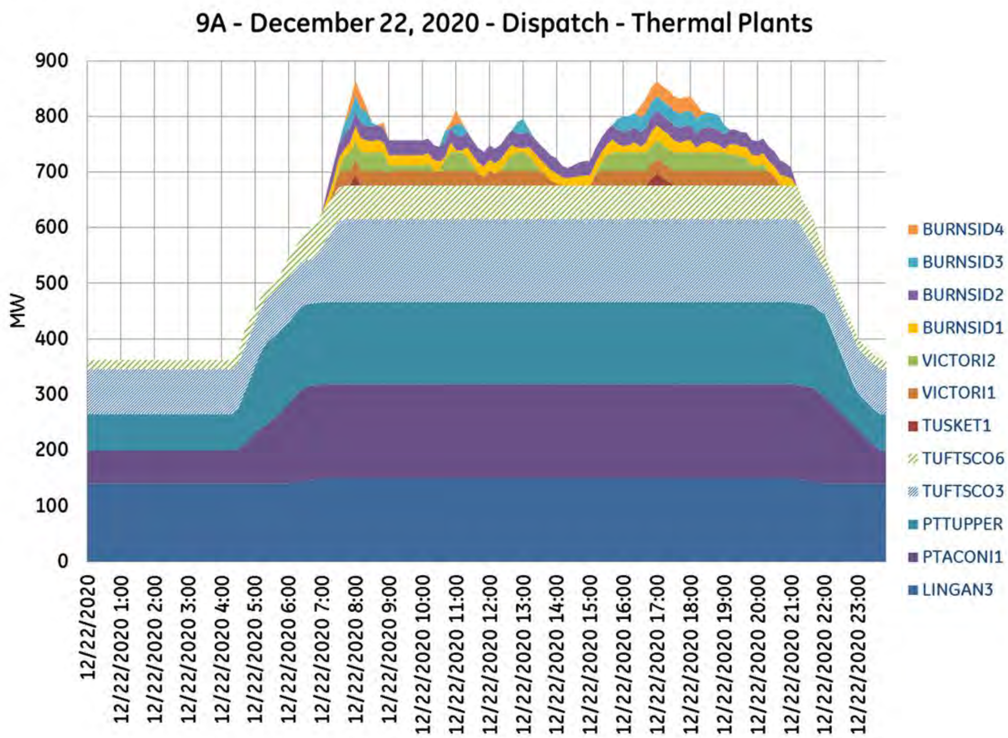



**Figure 120: Case 9A, 10-Minute Dispatch of Thermal Plants, December 22, 2020**

## 7.3 Sensitivities

This section introduces the sensitivity analyses. Each sensitivity analysis starts with a Base Case which reflects the main assumptions of the study that define the Nova Scotia power system and constitute the model inputs. The sensitivity analysis is performed by changing one variable at a time, and comparing results to the base case (or Sensitivity A below). The intent is to isolate, in so far as possible, specific factors that will influence operations or costs. The differential approach tends to filter out much of the impact of assumptions that are unimportant to the specific investigation, while providing insights for NSPI. Many of the sensitivities presented are aimed at providing guidance on the efficacy of various strategies or options aimed at improving performance. The choices of variables cover a wide range of drivers of interest that impact the robustness of the system to respond to renewable resource volatility.

The sensitivity cases include all of those identified by NSPI in discussions with GE, as well as many more that were developed to answer or provide insight into specific impacts and options for improvement of performance. The letter and "name" of sensitivity cases briefly are:

- Sensitivity A: Base Case with Flexible NB Imports

- Sensitivity B: Inflexible NB Imports
- Sensitivity C: 2hr Wind Forecast/1hr Persistence with Inflexible NB Imports
- Sensitivity D: No NB Imports
- Sensitivity E: 20% Discount on Wind Forecast
- Sensitivity F: Maritime Link Discretionary Block, Configuration A
- Sensitivity G: Minimum Steam Turbine Requirements of 3 instead of 4
- Sensitivity H: LMS100 Installed
- Sensitivity I: No NB Tie Line Outage
- Sensitivity J: Exports Priced at Market Levels
- Sensitivity K: Exports Priced at High Levels
- Sensitivity L: Expensive Gas Case
- Sensitivity M: Cheap/Dirty Coal Prices
- Sensitivity N: Maritime Discretionary Block, Configuration A, High Price
- Sensitivity O: Maritime Discretionary Block, Configuration A, Low Price
- Sensitivity P: Expensive Imports
- Sensitivity Q: Perfect Wind Forecast
- Sensitivity R: No Wind Forecast
- Sensitivity S: 10 MW Spin Reduction
- Sensitivity T: Increased Minimums on Steam Turbines
- Sensitivity U: Decreased Minimums on 2 Coal Units
- Sensitivity V: Marginal Value of Wind
- Sensitivity W: Marginal Value of Maritime Link
- Sensitivity X: Maritime Discretionary Block, Configuration B
- Sensitivity Y: Maritime Discretionary Block, Configuration B, High Price
- Sensitivity Z: Maritime Discretionary Block, Configuration B, Low Price

A more complete description of each sensitivity case is presented here:

A. Sensitivity A: "Base Case" with Flexible NB Imports - Base case includes imports that are committed and scheduled day-ahead, but can be adjusted real time to compensate for missed wind forecasts. All fuel, import price, and load assumptions were taken directly from NSPI. This was run for all 9 Cases defined by NSPI. Imports are on outage 15% of the time, and Exports are always available, but only at a price to avoid wind curtailment.

B. Sensitivity B: Inflexible NB Imports - All assumptions are the same as the base case, except all of the imports are inflexible. This means that each 25 MW block must be committed and scheduled DAH. Once committed at 25 NW, there can be no deviation in real time (they only have 1 power-point @ 25 MW). All flexibility for wind forecast error is carried by thermal units (diesels).

C. Sensitivity C: 2hr Wind Forecast/1hr Persistence with Inflexible NB Imports - This case takes Sensitivity B, and uses 1 hour persistence for wind - "this hours wind = next hours forecast." According to past experience this is a good proxy for a 2hr ahead forecast and a compromise between Sensitivity A and Sensitivity B.

D. Sensitivity D: No NB Imports - Takes the base case and applies a 100% outage rate on the Import Tieline from NB, and both the import and export units are uninstalled. Imports from the Maritime Link are unchanged.

E. Sensitivity E: 20% Discount on Wind Forecast - Taking the base case, the wind forecast unit generation is discounted by 20%. This makes the wind forecast more conservative and minimizes the times where expected wind generation is above actual wind generation.

F. Sensitivity F: ML Discretionary Block – This sensitivity builds upon Study Cases 8A & 9A, where a Discretionary Block of power from Maritime Link, constrained to 250 MW, is economically dispatched. Unlike the Maritime Link energy of cases 8 and 9, this energy need not be taken if it is uneconomic. The price for the discretionary energy is $60/MWh (2020 CND). Total generation is limited to 1.3 TWhs a year, and is dispatched only during on-peak hours.

G. Sensitivity G: Minimum Steam Turbine Requirements of [redacted] instead of [redacted] - The base case has a constraint that 4 out of 11 STs must be online and generating at any given time. This case reduces the number of required online STs to 3 at any given time.

H. Sensitivity H: LMS100 Installed - This sensitivity takes the base case and adds an additional 100 MW, flexible generator at the Onslow node. The unit has a HR ~8,300 Btu/kwh, 1hr minimum up and minimum down times, $4.50/MWh VOM and $0 start-up cost. The unit is added to provide "perfect capacity" and is used to mitigate wind forecast error and reduce calls on demand response.

I. Sensitivity I: No NB Tie Line Outage - 100% availability on the NB tieline imports (as opposed to 15% outage in the Base Case). This sensitivity was requested by NSPI.

J. Sensitivity J: Exports Priced at Market Levels - Instead of exporting energy only during hours of collapsed spot prices (wind curtailment), exports are now economically dispatched, based on prices provided by NSPI, which vary by year and on-peak/off-peak periods.

K. Sensitivity K: Exports Priced at High Levels - Same case as Sensitivity J, but exports are more expensive. Prices were provided by NSPI in their requested sensitivity table.

L. Sensitivity L: Expensive Gas Case - The base case plus high natural gas price scenario. Prices were provided by NSPI in their requested sensitivity table.

M. Sensitivity M: Cheap Coal Prices - The base case uses the clean/expensive fuel blend for the coal plant. This sensitivity uses the cheap coal blend to bookend the analysis.

N. Sensitivity N: Maritime Discretionary High Price - Building on Sensitivity F, applies a more expensive price ($65/MWh) for the discretionary economically dispatched Maritime Link energy.

O. Sensitivity O: Maritime Discretionary Low Price - Building on Sensitivity F, applies a less expensive price ($55/MWh) for the discretionary, economically dispatched Maritime Link energy.

P. Sensitivity P: Expensive NB Imports - Same as the Base Case, but Imports are more expensive. Prices were raised for both On-Peak and Off-Peak periods for all years. Prices were provided by NSPI in the requested sensitivity table.

Q. Sensitivity Q: Perfect Wind Forecast - MAPS Commitment uses the same wind shape as the dispatch. There is no forecast error. This includes Wreck Cove and Maritime Link modeling.

R. Sensitivity R: No Wind Forecast - No wind is accounted for in the dispatch process, all of the wind just shows up during the dispatch and the thermal fleet has to regulate accordingly.

S. Sensitivity S: 10 MW Spin Reduction - Hourly spin shape is reduced by 10MW all hours (does not go negative).

T. Sensitivity T: Increased Minimums on Steam Turbines - The minimum generating points for the 11 steam turbines on the system (Coal Plants + Tufts Cove 1, 2, and 3) is increased by 6 MW each. This change, in addition to the [redacted] operating nomogram, ensures that there is always, at a minimum, 24 MW of REG Down available from the ST units.

U. Sensitivity U: Decreased Minimums on 2 Coal Units - The two most utilized coal plants (with exception to must-run units PT Aconi and Lingan 3) are PT Tupper and Trenton 6. For this sensitivity, the generating minimums were reduced by 10 MW each to show the value of allowing STs to turn down to lower load levels.

V. Sensitivity V: Marginal Value of Wind – This sensitivity is intended to evaluate the marginal value of wind. To accomplish this, the latest Amherst wind plant was removed from each of the 9 Study Cases in order to identify the marginal impacts of the latest wind addition on the system. Amherst wind is a 30 MW plant with a capacity factor of 37% and about 96 GWh of delivered energy.

W. Sensitivity W: Marginal Value of Maritime Link – This sensitivity is intended to evaluate the marginal value of the Maritime Link. To accomplish this, Study Case 8 and Study Case 9 were run with 115.30 GWh less imports in order to identify the marginal impact of a GWh of Maritime Link.

X. Sensitivity X: Builds on Sensitivity F, but allows total Maritime Link flow to increase to 300 MW and is available during off-peak hours as well. Pricing is at $60/MWh on-peak and $50/MWh off-peak

Y. Sensitivity Y: Builds on Sensitivity X, and provides a higher price for the Maritime Link discretionary block. On-peak price is $65/MWh and off-peak price is $55/MWh.

Z. Sensitivity Z: Builds on Sensitivity X and provides a lower price for the Maritime Link discretionary block. On-peak price is $55/MWh and off-peak price is $45/MWh.

## 7.4 Fuel Price Sensitivities

### 7.4.1 Higher Natural Gas Prices

Sensitivity L is based on a higher natural gas price compared to the Base Case. Prices were provided by NSPI in their requested sensitivity table.

This sensitivity would be expected to make the gas-fueled units less competitive with the coal-based units, and at the same time, result in higher system variable costs, as confirmed in Figure 121 and Figure 122.

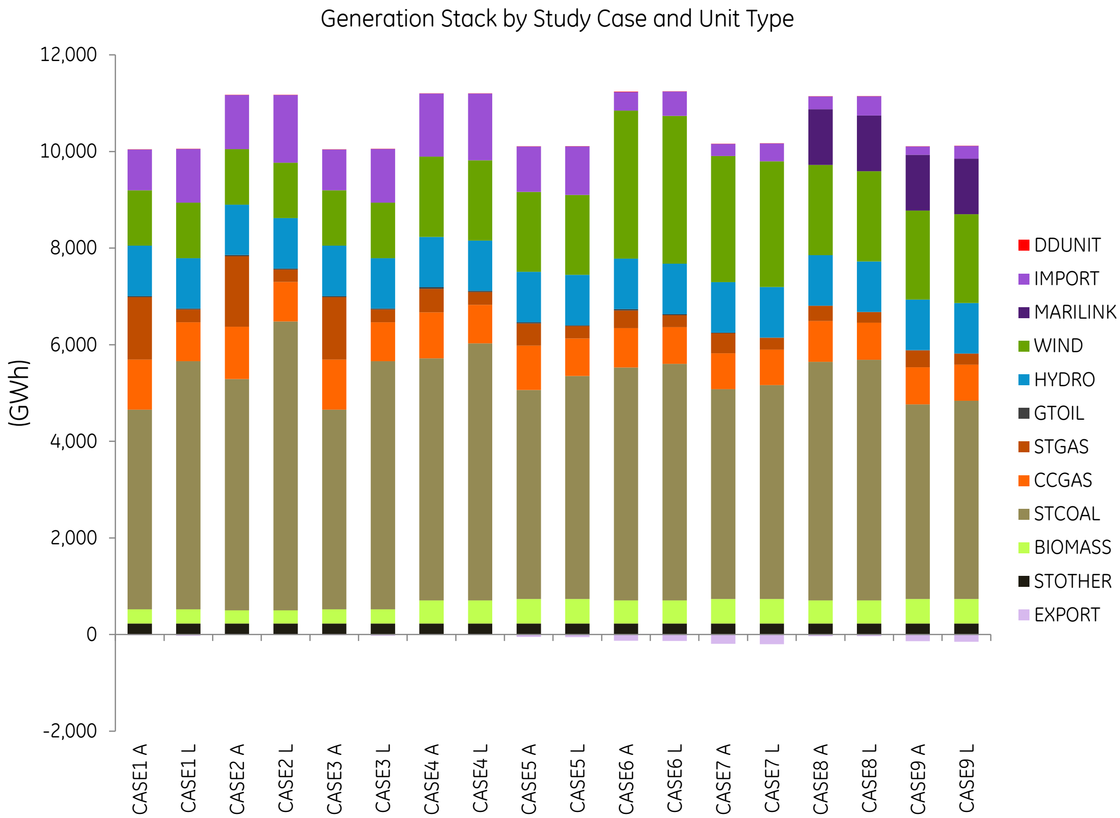



**Figure 121: Impact of Higher Gas Prices on Generation Stack**

It can be seen that the level of change in coal-fueled generation is lower in out years. This is as expected, since even in the base cases, the relative price of gas was high compared to coal. There is little room in 2020 to increase coal usage, even if the fuel is less expensive.

[redacted]

**Figure 122: Impact of Higher Gas Prices on Production Costs (Thousands $)**

**THIS FIGURE IS CONFIDENTIAL**

Higher gas prices, resulting in commitment of more coal-fueled units and less gas-fueled units, also results in availability of less flexible units in real time, causing slightly more curtailed energy, as shown in Figure 123.

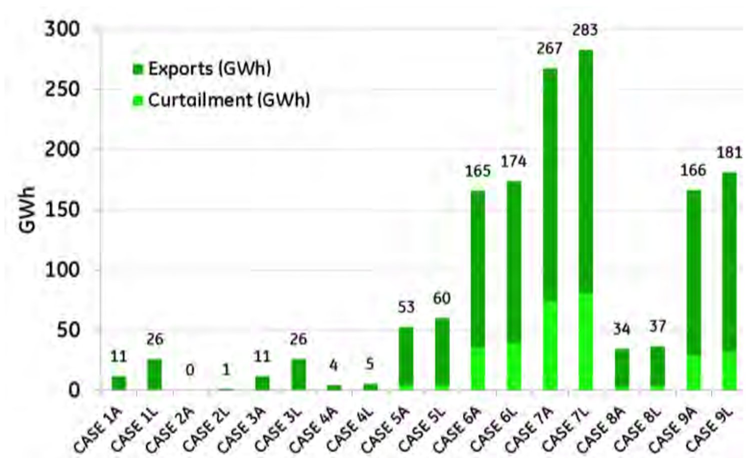



**Figure 123: Impact of Higher Gas Prices on Exports and Curtailed Energy**

Also as expected, a higher level of coal-fueled generation, replacing the more expensive gas-fueled generation, will also result in higher levels of $CO_2$ and SOx emissions, as shown in Figure 124 and Figure 125. The changes in emissions are consistent with the changes in generation mix shown in Figure 121.

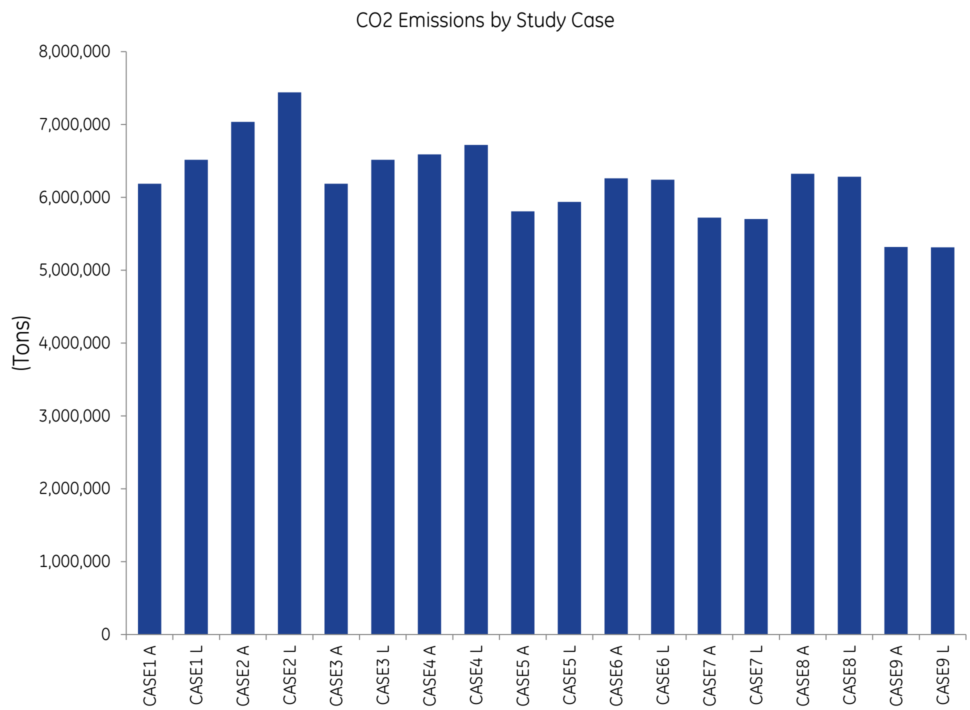



**Figure 124: Higher CO2 Emissions Resulting from Higher Gas Prices**

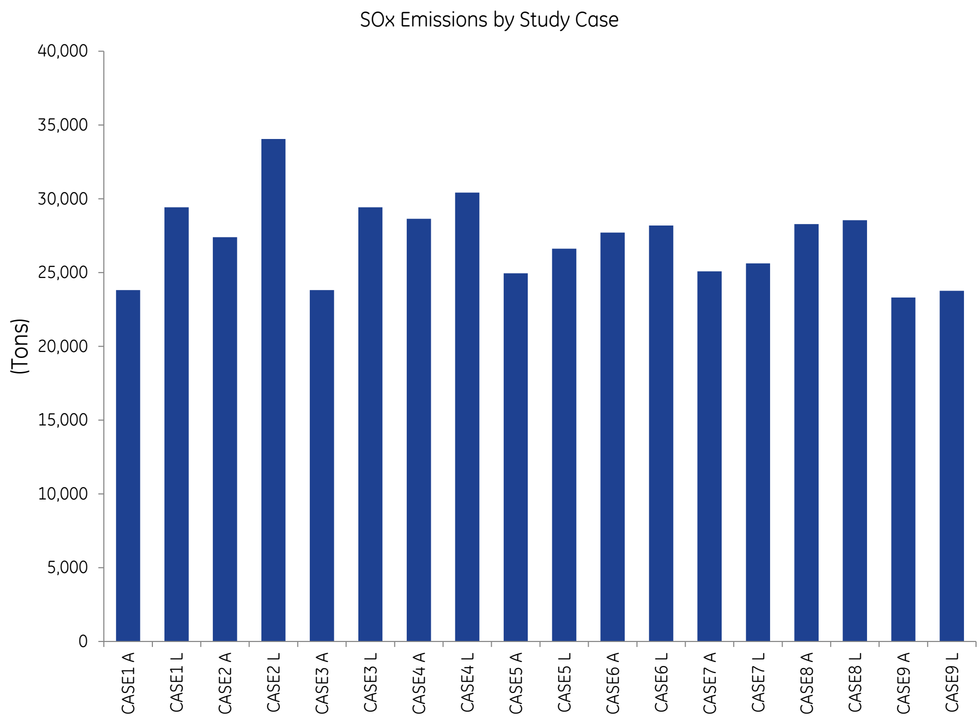



**Figure 125: Higher SOx Emissions Resulting from Higher Gas Prices**

### 7.4.2 Lower Coal Prices

NSPI has access to different kinds of coal fuels that range from clean and more expensive, and dirty and less expensive, as shown in Table 28. Since optimization of the fuel mix was not the primary focus of this project, the coal fuel mix that was initially used (in the first base case, Case 1A) to keep the emissions under the regulatory cap was used for all the base cases (i.e. all Sensitivity A cases). This was the more expensive and cleaner coal. The simulation results in all years confirmed that the emission caps were not being violated.

**Table 28: Clean and Dirty Coal Prices ($/MMBtu)**

| | | Clean | | | | Cheap | |
|---|---|---|---|---|---|---|---|
| | 2013 | 2015 | 2020 | | 2013 | 2015 | 2020 |
| | | | | | | | |
| **P. ACONI** | [redacted] | [redacted] | [redacted] | | [redacted] | [redacted] | [redacted] |
| **LINGAN** | [redacted] | [redacted] | [redacted] | | [redacted] | [redacted] | [redacted] |
| **TUPPER** | [redacted] | [redacted] | [redacted] | | [redacted] | [redacted] | [redacted] |
| **TRENTON 5** | [redacted] | [redacted] | [redacted] | | [redacted] | [redacted] | [redacted] |
| **TRENTON 6** | [redacted] | [redacted] | [redacted] | | [redacted] | [redacted] | [redacted] |

We investigated the impact of using the dirtier but cheaper coal in Sensitivity M. As shown in Figure 126, the coal-fueled generation - due to competitiveness of coal versus gas in the early years- is significantly higher compared to the base case. This causes lower utilization of gas-fueled generation and also results in lower NB imports. As shown in Figure 127, cheaper coal prices results in lowering of the total system costs.

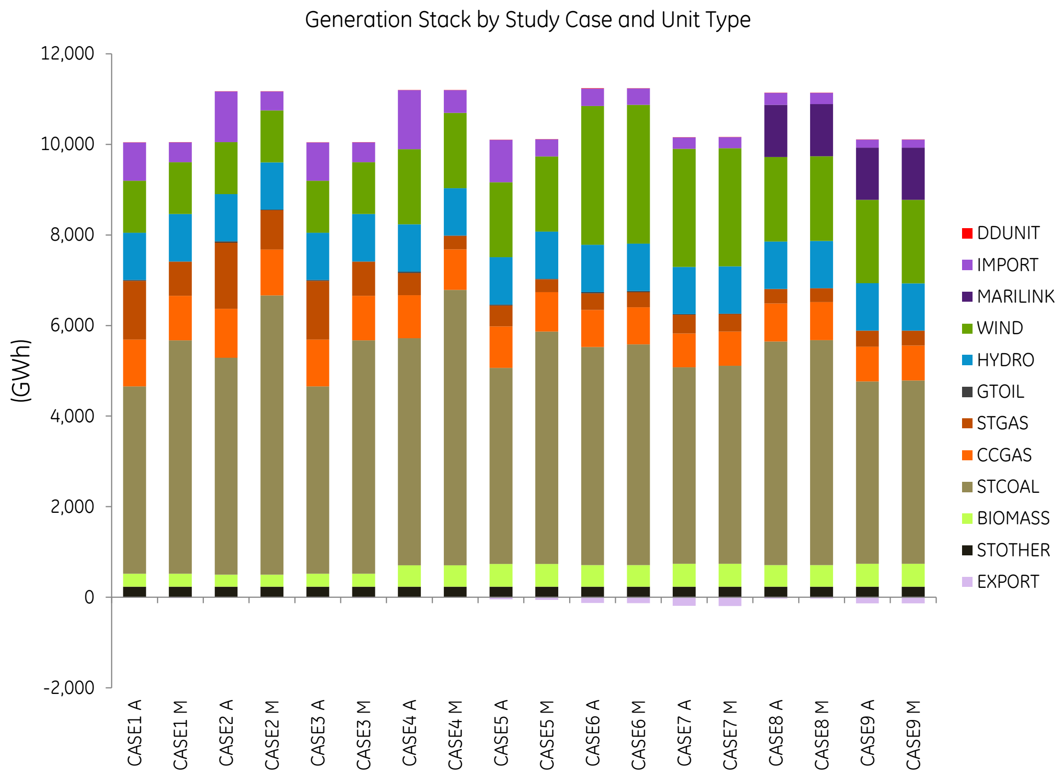



**Figure 126: Impact of Cheaper Coal on Generation Stack**

Again, as with the higher gas price case, in later years, even the more expensive coal is still relatively cheap. Therefore there is little latitude to increase coal generation, but the energy that is generated is significantly less expensive.

[redacted]

**Figure 127: Impact of Cheaper Coal on Production Costs**

**THIS FIGURE IS CONFIDENTIAL**

The results of Table 29 help illustrate why exact determination of fuel cost and coal mix is not critical to the important results of this study.

**Table 29: Impact of Cheaper Coal on Production Costs ($M)**

| | CASE | CASE | CASE | CASE | CASE | CASE | CASE | CASE | CASE |
|---|---|---|---|---|---|---|---|---|---|
| | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** |
| **Sensitivity A (Base Case)** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Sensitivity M (Inexpensive Coal)** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Savings ($M)** | 54.2 | 64.0 | 54.2 | 72.0 | 62.1 | 52.9 | 47.3 | 52.5 | 44.6 |

This analysis provides a broad range of production costs: $44.6M to $72.0M is a substantial fraction of these production costs. But, the single biggest question is whether to have all in-province wind – i.e. Case 6 and 7, or to add the Maritime Link and build less wind in-province.

NSPI has little control over whether the industrial load resumes operation or not, so the most meaningful comparisons are between Case 6 and Case 8, and between Case 7 and Case 9. Here the impact of coal price is minimal, $0.4M between cases 6 and 8, $2.7M between cases 7 and 9. This in no way says that coal prices and mix are broadly unimportant, but they are relatively unimportant to this decision.

Cheaper coal, resulting in commitment of more coal-fueled units and less gas-fueled units, also results in availability of less flexible units in real time, causing potentially more curtailed energy, as shown in the Figure 128.

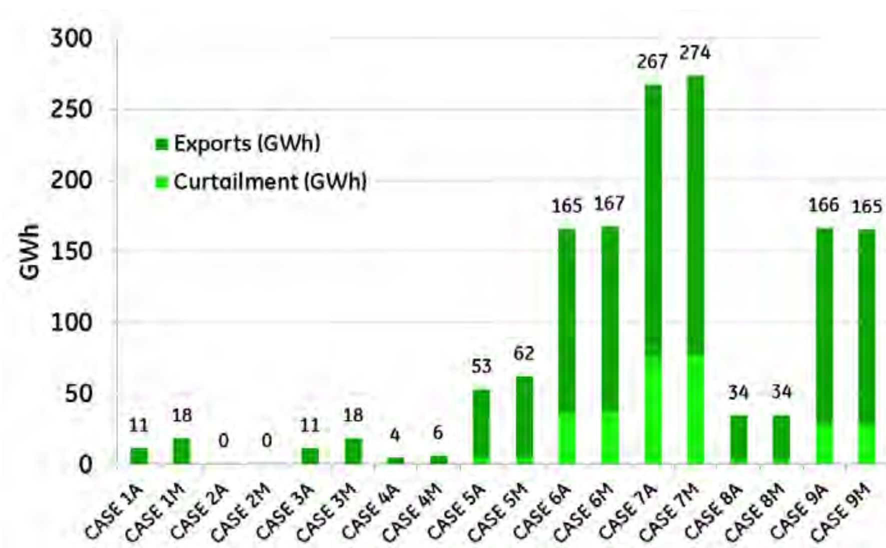



**Figure 128: Impact of Cheaper Coal on Exports and Curtailed Energy**

However, as shown in Figure 129 and Figure 130, cheaper coal result in higher utilization of coal-fueled units at the expense of gas-fueled units, causing higher emission of $CO2$ and SOx. In fact, results show a huge impact on SOx emissions, such that the SOx emission caps are violated. Air Emission caps were provided by NSPI, are shown in Table 30.

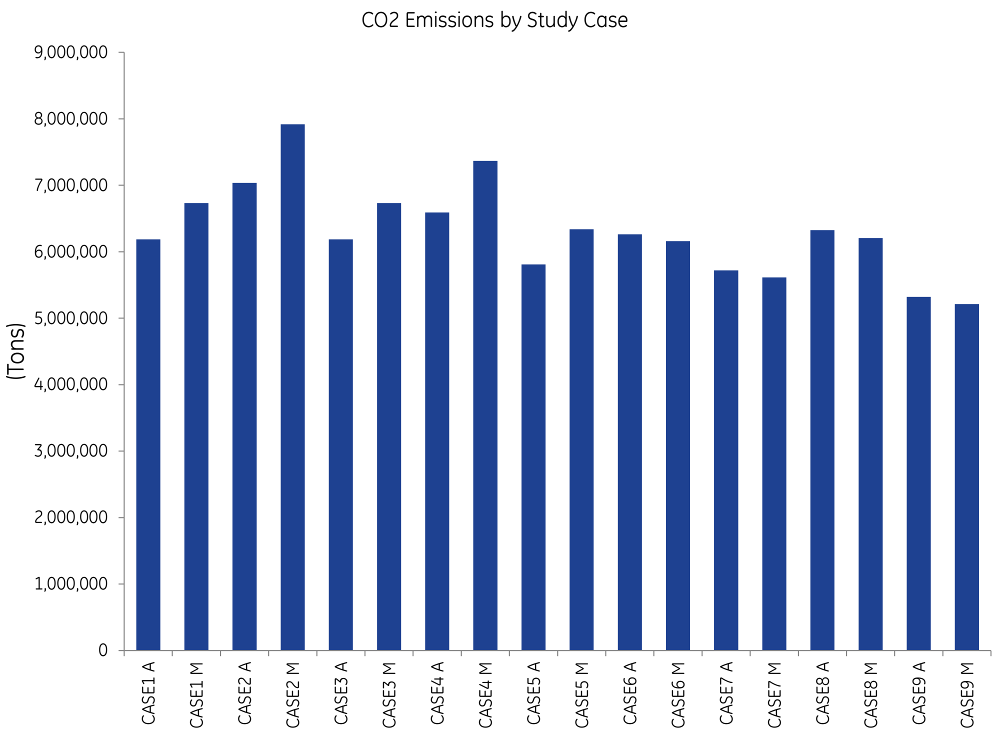



**Figure 129: Higher CO2 Emissions Resulting from Cheaper and Dirtier Coal**

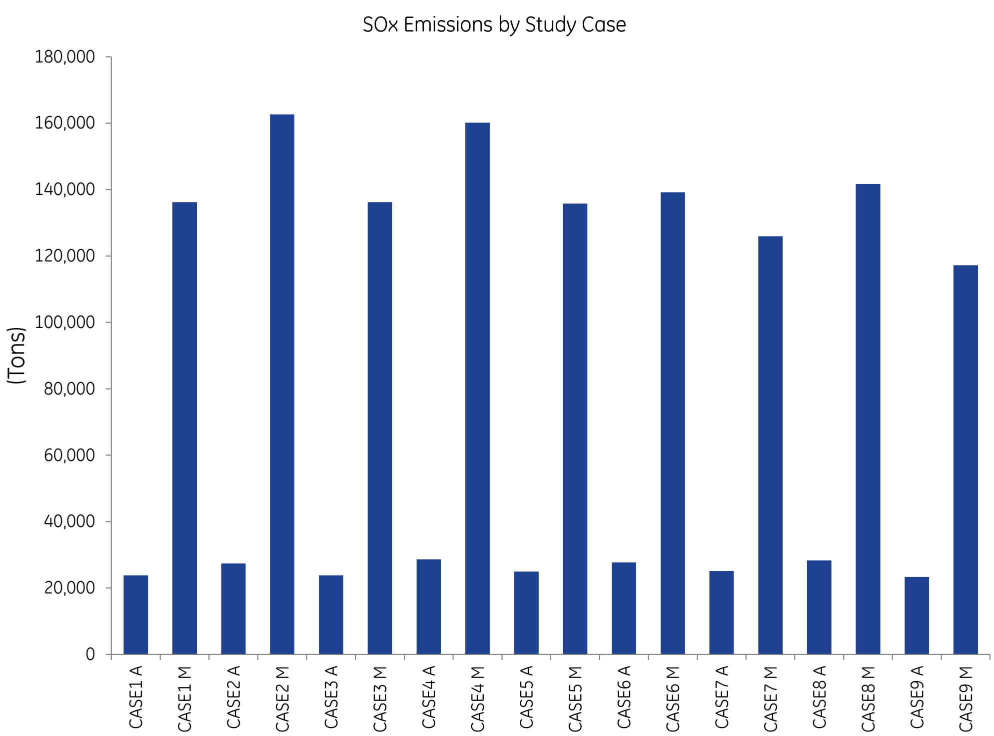



**Figure 130: Substantially Higher SOx Emissions Resulting from Cheaper and Dirtier Coal**

**Table 30: Air Emission Caps**

| Year | CO2 (kT) | SO2 (kT) | NOx (kT) | Hg (kg) |
|---|---|---|---|---|
| **2012** | 9,620 | 72.5 | 21.4 | 80 |
| **2013** | 9,435 | 72.5 | 21.4 | 70 |
| **2014** | 9,249 | 72.5 | 21.4 | 63 |
| **2015** | 9,064 | 60.9 | 19.2 | 60 |
| **2016** | 8,796 | 60.9 | 19.2 | 60 |
| **2017** | 8,528 | 60.9 | 19.2 | 60 |
| **2018** | 8,261 | 60.9 | 19.2 | 58 |
| **2019** | 7,993 | 60.9 | 19.2 | 52 |
| **2020** | 7,500 | 36.2 | 15.0 | 35 |

### 7.4.3 Gas versus Coal Prices

Relative gas and coal prices impact the relative competitiveness of gas and coal generation. In this section we compare the impact of relative price movements in Sensitivity L and Sensitivity M. Higher gas prices and lower coal prices would be expected to have relatively similar impact on the system operations if not costs, since both have the same impact on the relative competitiveness of coal versus gas units in the same direction. As can be seen in Figure 131, higher gas prices and lower coal prices result in more coal-fired generation and less gas-fired generation. The net change in coal and gas-fired generation is counterbalanced mostly by NB imports.

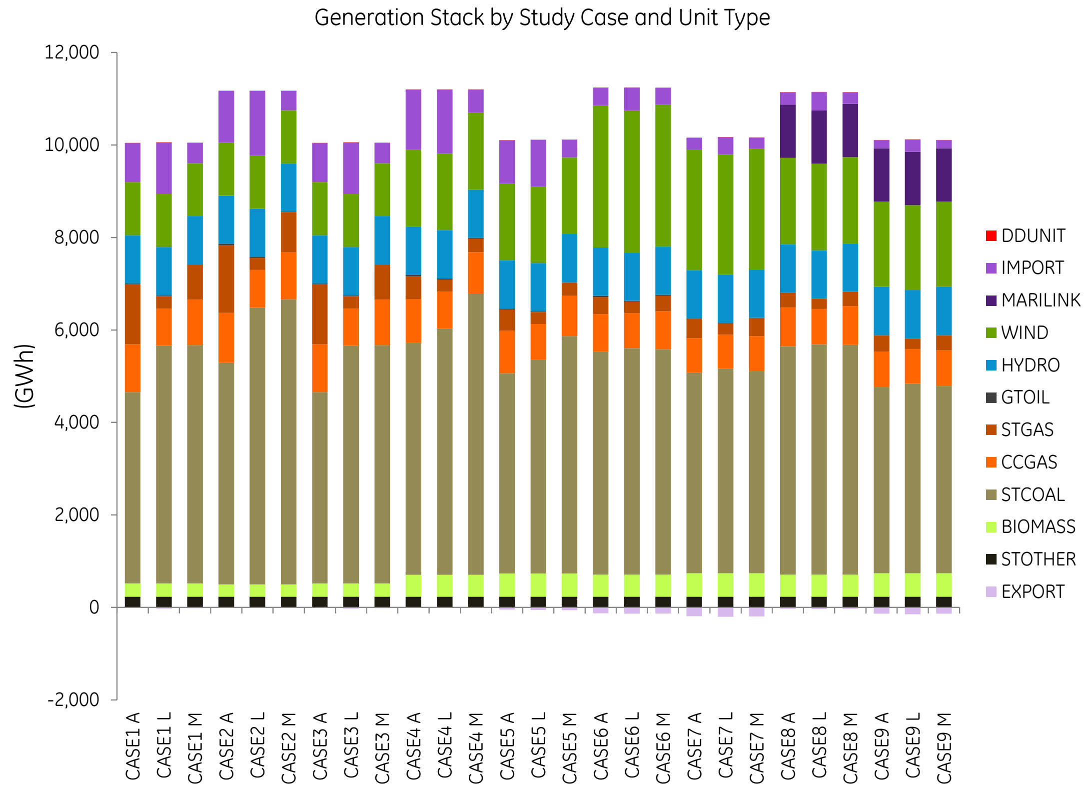



**Figure 131: Comparison of Generation Stack in Sensitivity A, L, and M**

However, cheaper coal and higher gas prices have a greater impact on the system production costs as shown in Figure 132 and Table 31. Sensitivity M results in lower production costs due to cheaper coal prices but roughly same amount of coal-fired generation as in Sensitivity L.

[redacted]

**Figure 132: Comparison of Production Costs in Sensitivity A, L, and M**

**THIS FIGURE IS CONFIDENTIAL**

**Table 31: Production Costs ($M) in Sensitivity A, L, and M**

| | CASE 1 | CASE 2 | CASE 3 | CASE 4 | CASE 5 | CASE 6 | CASE 7 | CASE 8 | CASE 9 |
|---|---|---|---|---|---|---|---|---|---|
| **Sensitivity A (Base Case)** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Sensitivity L (Expensive Gas)** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Sensitivity M (Inexpensive Coal)** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

Figure 116 and Figure 134 show the relative emissions of CO2 and SOx in cheap coal and expensive gas prices compared to the Base Case.

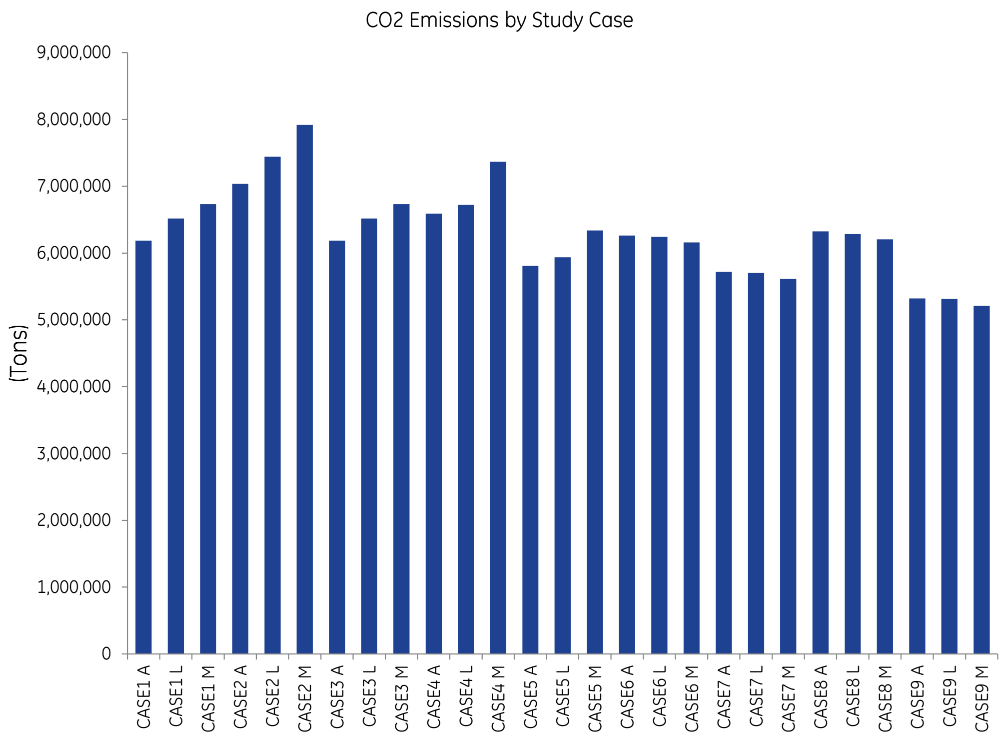



**Figure 133: Comparison of CO2 Emissions in Sensitivity A, L, and M**

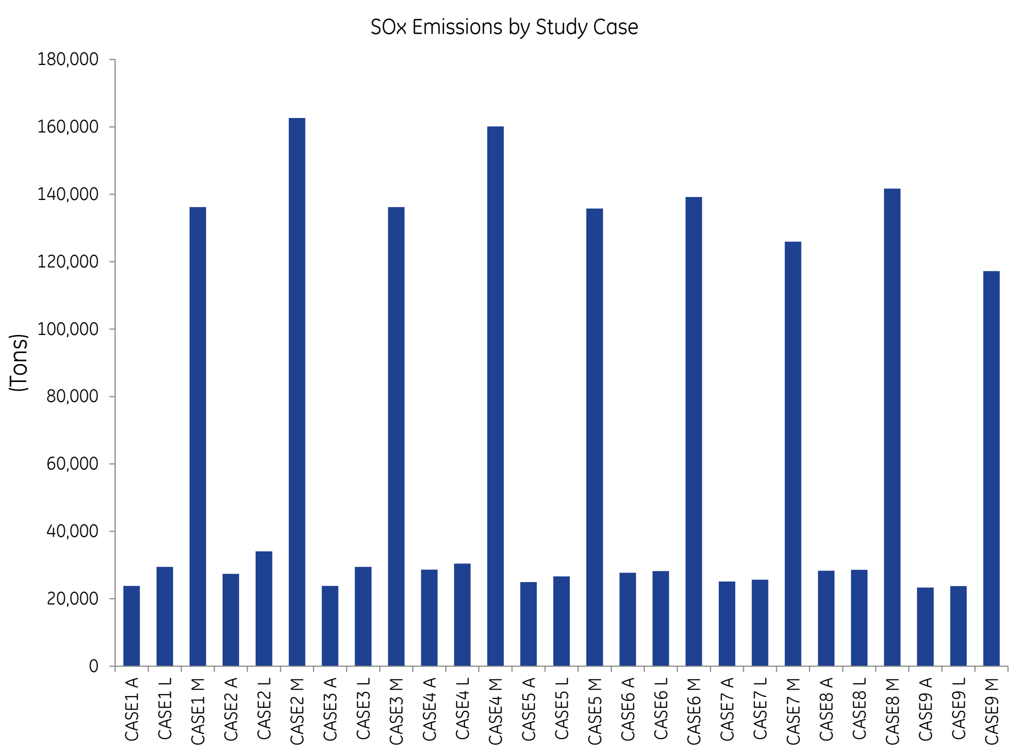



**Figure 134: Comparison of SOx Emissions in Sensitivity A, L, and M**

## 7.5 Wind Forecast

### 7.5.1 Forecast Error

With higher penetration of wind resources into the power grid, more accurate and timely forecasting of wind becomes important for reliable operation of the power system. Industry experience in large interconnected systems with high wind is that wind forecasting is absolutely indispensable [5], [6], [9], [13], and [21]. Large deviations between forecast and actual wind energy result in over- or under-commitment of dispatchable resources and continuous difficulty in maintaining adequate operating reserve and the minute by minute balancing of the supply and demand in the system. Figure 135 shows duration curves of the DAH wind forecast error used in this study. As discussed in Section 2this forecast data was synthesized by AWST to reflect the fidelity available today with state-of-the-art forecasting. As expected, at higher levels of wind power, the absolute value of the forecast error increases. (On a percentage basis, it gets a little better, owing to spatial and temporal diversity of a larger wind fleet). Notice that *most of the time*, the forecasts are pretty good: In the 916 MW case, it is relatively uncommon to have errors greater than 200 MW; in less than 5% of hours do the actual wind fall more than 200 MW short of the amount predicted for that hour a day in advance. Of course, the grid operator needs to successfully navigate those hours in which the forecast is badly wrong. The results presented in Section 7.2 include these effects, which include occasional use of expensive peaking units or demand response resources. The sensitivities presented in this section are intended to explore the effect of employing different operational strategies for the use of wind forecasting, and to quantify the potential benefits of improving the fidelity of forecasts.

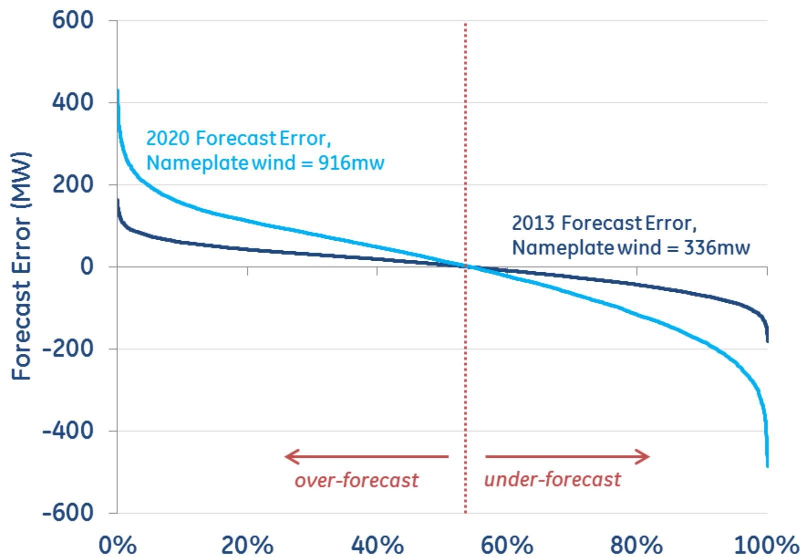



**Figure 135: Wind Forecast Error Duration Curves**

We investigated the impact of wind forecast and strategies that might be used by system operators by performing three sensitivities over the Base Case (Sensitivity A), namely:

- Sensitivity E - 20% Discount on Wind Forecast: Forecast wind is discounted by 20% which will result in over-commitment of thermal units as a defensive strategy to cover over-forecast (short falls), since actual wind energy will be greater in real time.
- Sensitivity Q - Perfect Wind Forecast: Forecast wind used for unit commitment is equal to actual wind used for economic dispatch. This case is quantify and bound the potential value of higher fidelity forecasts
- Sensitivity R: No Wind Forecast: Unit commitment assumes there will be no wind energy, but there is wind energy available in real time. This provides a reference point for quantifying the value of using imperfect, current state-of-the-art forecasting,

In GE MAPS, the day-head commitment of long lead generation is based on the expected load and wind. In these sensitivities, we have altered the forecast used, while retaining the same "actual" wind shape. In sensitivity E, we have reduced the forecast by 20% - the equivalent of system operators saying "we don't trust the forecast enough to count on it being right". Sensitivity Q assumes that there is perfect wind forecast, so the DAH commitment uses the same wind shape as the Economic Dispatch. This also applies to the building up of the Wreck Cove and Maritime Link schedules which are done in pre-processing prior to actually running of GE MAPS. In Sensitivity R, the unit commitment is based on the assumption that there will be zero wind power the following day.

Figure 136 presents the annual generation by unit type for Sensitivities A, E, Q, and R.

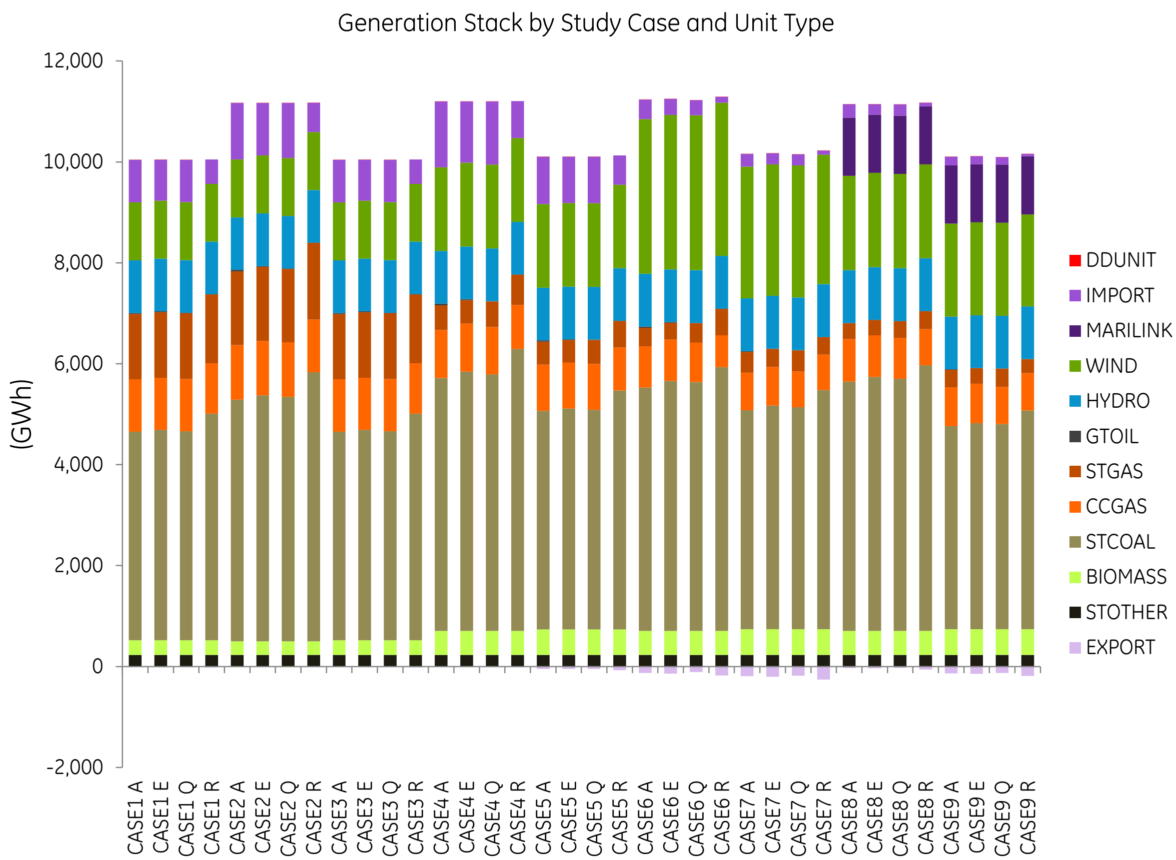



**Figure 136: Annual Generation by Unit Type under in Sensitivities A, E, Q, and R**

It can be seen that greatest impact of wind forecast error is the utilization of coal-fired plants and NB imports. The 20% Discount on Wind Forecast sensitivity and also the Perfect Wind Forecast sensitivity do not appear to show a big impact on the generation mix. However, the No Wind Forecast results in biggest impact due to over-commitment of the coal units, which in turn reduces the need for NB imports.

Figure 137 shows the annual generation by coal units and NB imports under in Sensitivities A, E, Q, and R.

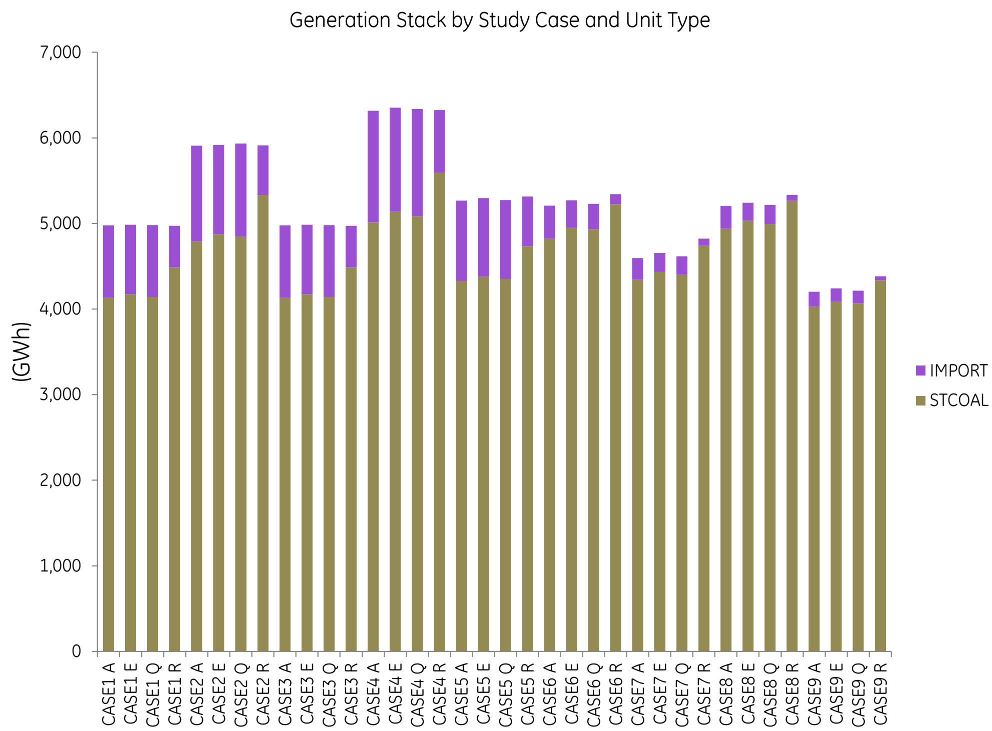



**Figure 137: Annual Generation by Coal Units and NB Imports under in Sensitivities A, E, Q, and R**

No Wind Forecast would be expected to result in surplus supply of wind due to over-commitment of thermal units, resulting in higher exports/curtailments but also lower demand response. Figure 138 and Figure 141 confirm these expectations.

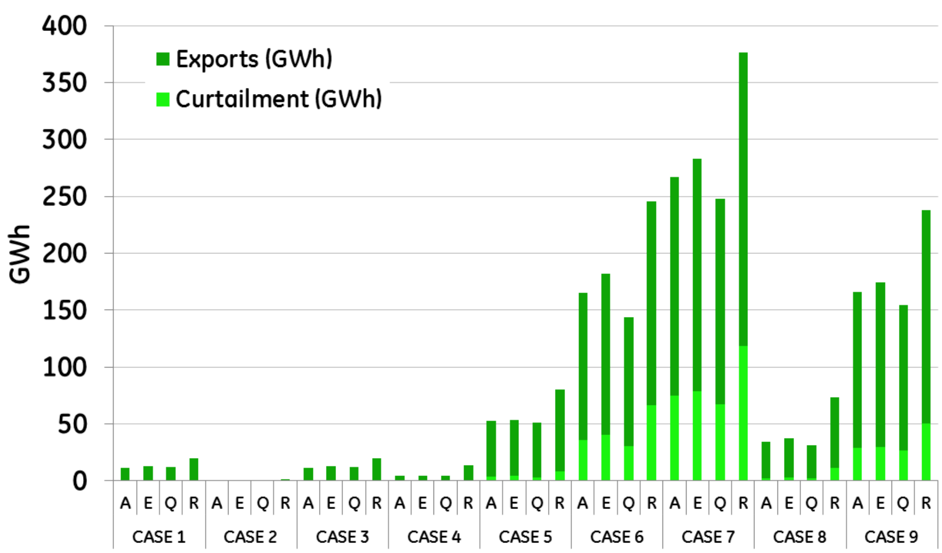



**Figure 138: Total Exports/Curtailments under in Sensitivities A, E, Q, and R**

The impact of having accurate wind forecast on production costs is complex. As can be seen in the following figure, the costs of coal-fired generation is increased, with a corresponding decrease in cost of NB Imports. Figure 139 and Table 32 show the annual production costs by selected unit types Sensitivities A, E, Q, and R.

[redacted]

**Figure 139: Annual Production Costs with Different Wind Forecasts**

**THIS FIGURE IS CONFIDENTIAL**

**Table 32: Annual Production Costs ($M) with Different Wind Forecasts**

| | CASE 1 | CASE 2 | CASE 3 | CASE 4 | CASE 5 | CASE 6 | CASE 7 | CASE 8 | CASE 9 |
|---|---|---|---|---|---|---|---|---|---|
| **Sensitivity A (Base Case)** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Sensitivity E (Discounted Forecast)** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Sensitivity Q (Perfect Forecast)** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Sensitivity R (No Forecast)** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

There is substantial amount of curtailment and exports when the system is committed without considering the wind. This is shown in Figure 140.

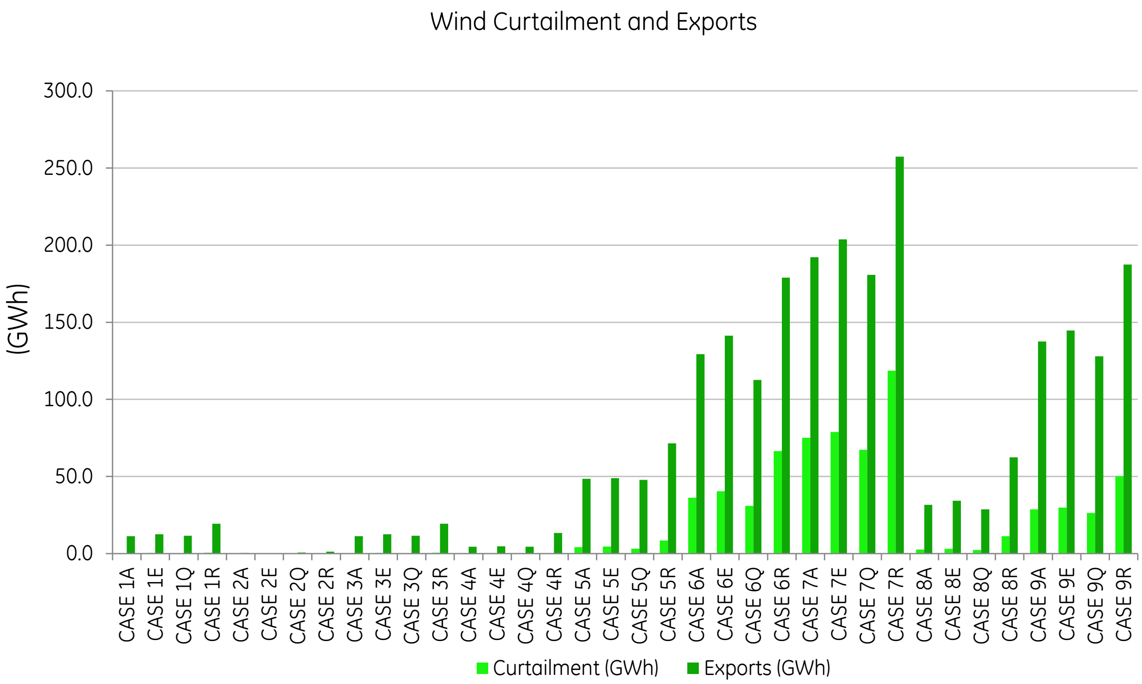



**Figure 140: Wind Curtailment and Exports under Different Wind Forecast Scenarios**

The use of demand response in these cases is a resource of last resort. The trends in Figure 141 are consistent with this approach. When the wind forecast is discounted (Sensitivity E) or completely disregarded (Sensitivity R), the system carries more generation. This higher level of generation means that the risk of being caught with inadequate fast start reserves is reduced, and therefore the amount of demand response is reduced. With the perfect foreknowledge of Sensitivity Q, the need for demand response is also reduced.

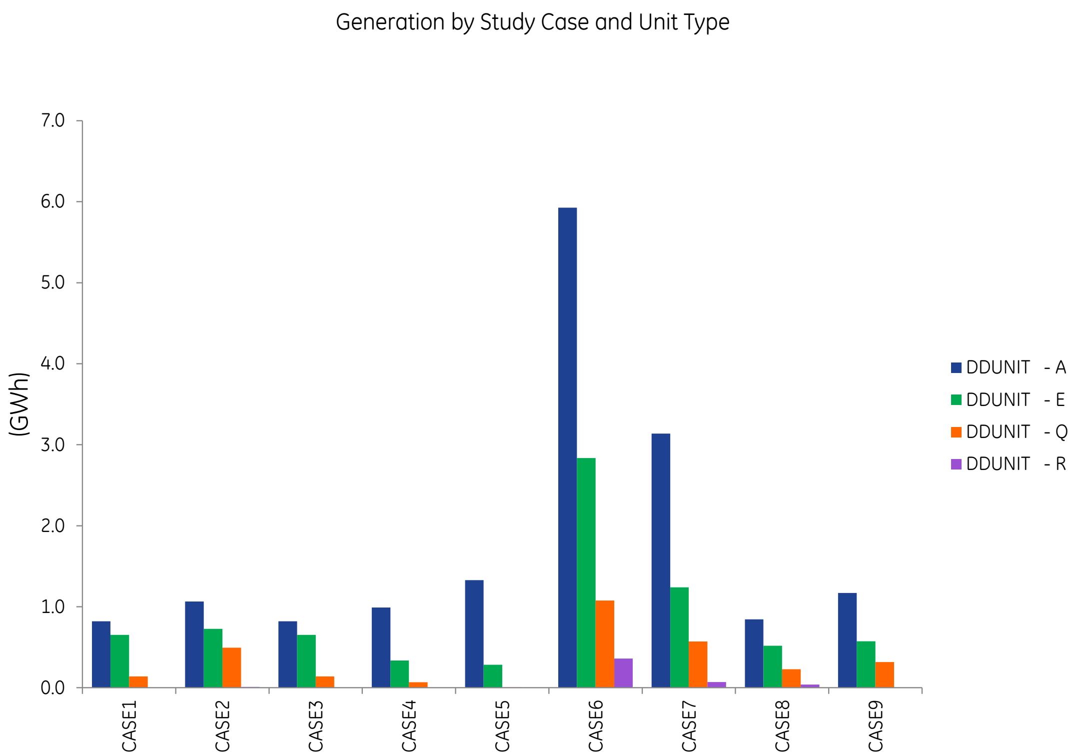



**Figure 141: Total Demand Response under in Sensitivities A, E, Q, and R**

Industry experience with wind forecasting is growing rapidly. Most system operators in North America that have substantial wind generation have invested heavily in forecasting. The development of forecasting methods and tools for system operators is growing. Some industry experiences of note are briefly discussed here.

- AESO. Alberta is host to a large and growing fleet of wind generation. With their single point of synchronous interconnect to British Columbia; there are some useful parallels to Nova Scotia. AESO has sponsored competitive development and investigation of new forecasting tools for system operation. [14]
- DTE (Detroit) depends on wind forecasting for economic integration to the MISO. DTE's experience is that DAH forecasting has accuracy of 10%-15% Mean-absolute-error (MAE: the metric used in the industry to measure accuracy. Lower is better). DTE also uses four HAH forecasting, which they report has accuracy on the order of 8%. They use this to adjust commitment and dispatch (more discussion in Section 7.11.2 below). DTE also uses persistence for very short term (5 minute) forecasting.
- Ability to track turbine availability, forced outages, and local wind behavior is important to the fidelity of forecasting. Development of protocols to collect and process this information will be important [3], and has a non-zero administrative cost

- New research on Doppler, LIDAR, etc. is improving short-term forecast technology, recently termed “now-casting”. This field is changing rapidly, and will be important to NSPI operations. NSPI needs to stay engaged with the industry.
- Xcel Energy has invested heavily in their forecasting. They consider forecasting to be a critical economic edge for them. It is worth noting that Xcel received cost recovery from their regulators for this investment. They have several people on staff that work full time on forecasting. NSPI should expect the same going forward and set expectations with its stakeholders and regulators for the required increase in administrative and operating costs.
- Capturing highly local wind behavior is difficult, for example predicting convention cells (thunder storms) is extremely difficult. The physical topology of Nova Scotia may make this difficult problem even tougher for NSPI.
- Overall, the findings of this study exhibit a level of asymmetry that we have not observed in other large system studies. The fact that low forecast errors is so much more expensive than high forecast errors, appears to be a function of the generation portfolio. Further investigation of forecasting strategies and possible changes to the NSPI portfolio are probably warranted.

### 7.5.2 Reserve (Up Range) Relationships

The economic operation of the system, through dispatch and commitment decisions has significant impacts on system reserves. Broadly, under any given operating condition, as wind power increases, other generation serving load is displaced. Two things happen: some generation is shutdown – de-committed, and some generation stays running, but is dispatched to a lower power level. The generation that is de-committed does not provide spinning or regulating reserves. Generation that stays running, but is backed down “naturally” contributes reserves – it is a relatively simple matter to increase output, should changes in wind power (or load) be necessary. The relationship between delivered wind energy, wind forecast error and system loads is not simple, but some overall trends can help understand system operations.

In this section we present three key relationships. In each of the following figures, we show points defined by hourly parings of up range and one independent system variable. The up-range is the difference between the dispatch and maximum power of all committed generation. In each of the three plots below, a minimum of around 60 MW can be observed: this is the minimum spinning reserve. On closer inspection, the minimum varies between 60 and about 85 MW – this is because we require additional reserves to cover wind variability.

In Figure 142 economic operation of the system for all the hours with zero or nearly zero wind (near the Y-axis), produce up range between a minimum of 60 MW and a maximum a bit less than 400MW. The trend-line in red shows a statistical expectation that about 180

MW of up range will be available. The slope of the red trace is 0.375. That means that each additional MW of wind production *tends* to "release" 0.375 MW of up reserve. In one sense, this extra reserve comes "for free" – that is, no additional constraints drive the system to a higher operating cost to provide those reserves. The only time there is cost associated with maintaining reserves is for the hours across the minimum – at the bottom of the distribution. Notice that at high wind (starting about 250MW, the system is very rarely against the minimum – at high wind, there is arguably no incremental cost to carry reserves. This obsevation is distinct from the reality that thermals that are backed down incur a heat rate penalty. This impact on variable production cost is reflected in the study results.

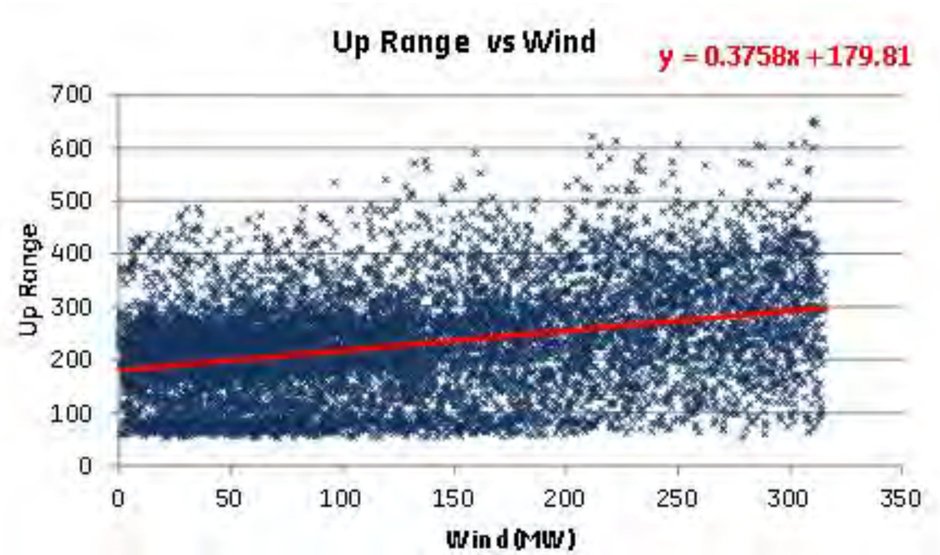



**Figure 142: Up Range vs. Wind Power (available)**

When more wind shows up than is forecasted, again some generation is de-committed and some is dispatched back. But the operational flexibility, and therefore the options for changing commitment in real-time – when the effect of the DAH forecast is felt – are less. In Figure 143, the slope of the trend line is 0.69. That for every MW of error in DAH wind forecast, 0.69 comes out of dispatch, with the balance coming from change in commitment.

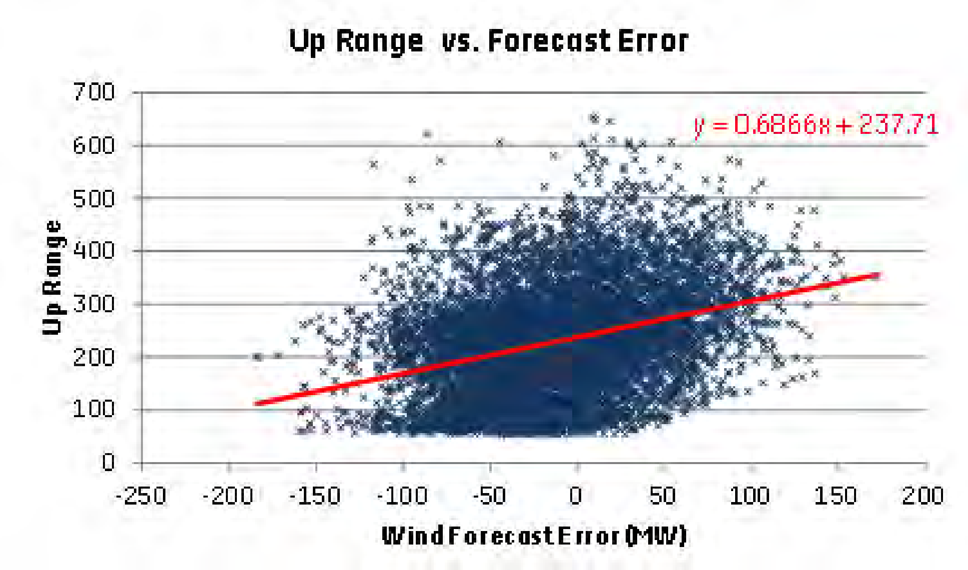



Figure 143: Up Range vs. Forecast Error

For comparison, an increase in load will tend to have a much closer correlation to commitment. The load and change in load is well known in advance, and so the system operator has the most options for serving load by changing commitment;generally thermal plants want to be run at their best heat rate, which economically discourages re-dispatch. In Figure 144, the slope is only 0.15, meaning that for a 1 MW increase in load, only 0.15 MW tends to come from re-dispatch.

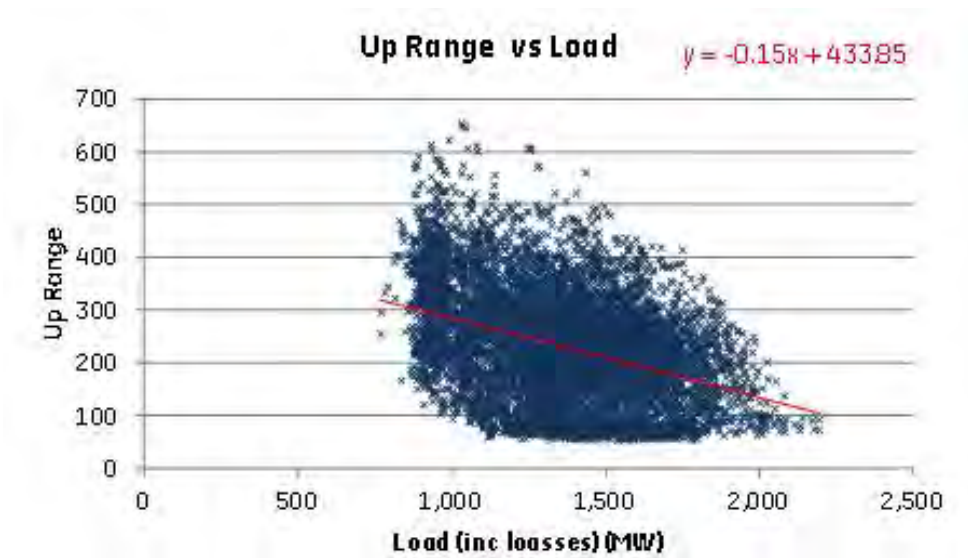



Figure 144: Up Range vs. Load

As in all systems we've studied, there is a wide range, which reinforces the reality that the relationships between natural operating reserve, wind, load and forecast error are not straightforward. But this also reinforces the reality that most of the time, addition of wind power *tends* to release committed up range naturally;that is with no additional economic penalty. Nevertheless, the condition under which the system must *deliberately* set aside reserves, the costs are non-trivial. This is reported later, in Section 7.10.2, where the cost of synchronized reserves is examined.

## 7.6 Flexibility and Availability of the New Brunswick Tie

As noted earlier, we represent the outside world through the NB tieline as an equivalent generator or combination of generators with given price curves that can operate in a manner consistent with the operational characteristics that govern the current operations of the intertie and NB electrical energy imports and exports.

Until 2020, the NB tieline with Nova Scotia is the only interconnection between Nova Scotia and the outside world. Nova Scotia relies on the NB imports to meet some of its electrical energy requirements throughout the year, and therefore, imports from NB play an important role in balancing the Nova Scotia power needs. However, there are a number of physical, economic, and contractual constraints on importing power from and exporting power to New Brunswick. Since variability of actual wind must be covered by flexible resources, any additional flexibility in NB import operations would be expected to help with mitigation of the impacts of greater penetration of wind resources in general, and in dealing with wind forecast errors in particular.

To evaluate the impact of the NB tie on the Nova Scotia grid, we performed a number of sensitivities, including investigation of the flexibility of import scheduling, NB time unavailability, and volatility of NB imports.

The main issues with wind power are its actual variability and also its forecast error. However, fidelity of wind forecasts in short-term are much higher than day-ahead.

In the Base Cases of the study we assume flexible imports in the sense of being able to do day-of operation scheduling. The ability to [redacted].

However, movement of the NB resource from hour-to-hour is a concern, since it implies a higher level of flexibility or accommodation by NB than might be practical (or palatable). Therefore, in Sensitivity B we consider inflexibility in imports, meaning that DAH import schedules are unchanged in real time.

Wind information available in short-term is rather good – much closer to "actual" than DAH. NSPI schedules NB imports shortly before "real-time" and locks them in. Therefore, in

Sensitivity C, we consider an "in-between" flexibility, in which the tie is firmly scheduled based on a two-hour look-ahead. We approximate a 2-hour ahead forecast (2HAH) based on the empirical fact that the statistical expectation of 2-hour-ahead forecast is approximately equal to 1 hour persistence.

In summary, NB tieline import sensitivities considered, include the following (Base Case Sensitivity A is included for comparison):

- Sensitivity A or Base Case assumes flexible Imports: They are always available and allowed to dispatch hourly in real-time.
- Sensitivity B assumes that NB imports are inflexible in real time after being scheduled in DAH. NB imports are modeled as a combination of multiple one-block units, with each unit having one power point at 25 MWs. This means that each 25 MW block is committed and scheduled DAH. But once committed, the real time dispatch cannot deviate from the DAH schedule. As a result, the NB imports in Sensitivity B have no role in responding wind forecast error. Hence, all flexibility for wind forecast error is covered by in-province resources: thermal units and Wreck Cove hydro.
- Sensitivity C uses one hour persistence for wind, with "persistence" meaning that "this hour's actual wind is taken as the next hours forecast." According to past experience this is a good proxy for a 2 HAD forecast and a compromise between Sensitivity A and Sensitivity B. The 2hr Wind Forecast was selected to simulate the more realistic same-day NB import scheduling, which according to NSPI staff is usually done 2 or a few hours ahead of real time. In this sensitivity, NB imports are committed and scheduled based on 2HAH forecast, and cannot deviate from the schedule. It is expected that [redacted] This sensitivity case also commits all long-lead time thermal and hydro generation based on the same 2HAH forecast; this is a modeling limitation that results in an optimistic assessment of the fidelity of information available for DAH scheduling of the other resources.
- Sensitivity D assumes a 100% outage rate on the NB tieline, or in other words, no imports from or exports to NB. Imports from the Maritime Link are unchanged.
- In Sensitivity I, 100% availability is assumed on the NB tieline imports (as opposed to 15% outage in the Base Case).

Figure 145, Figure 146, and Figure 147 compare the generation stack by unit types across these sensitivities. They show that full NB tie-line availability results in higher NB Imports and a commensurate decrease in the steam coal generation. Within the same study cases, the heights of the stacks may not be equal across the sensitivities considered, mostly due to exports (although small, are shown as negative below the x-axis).

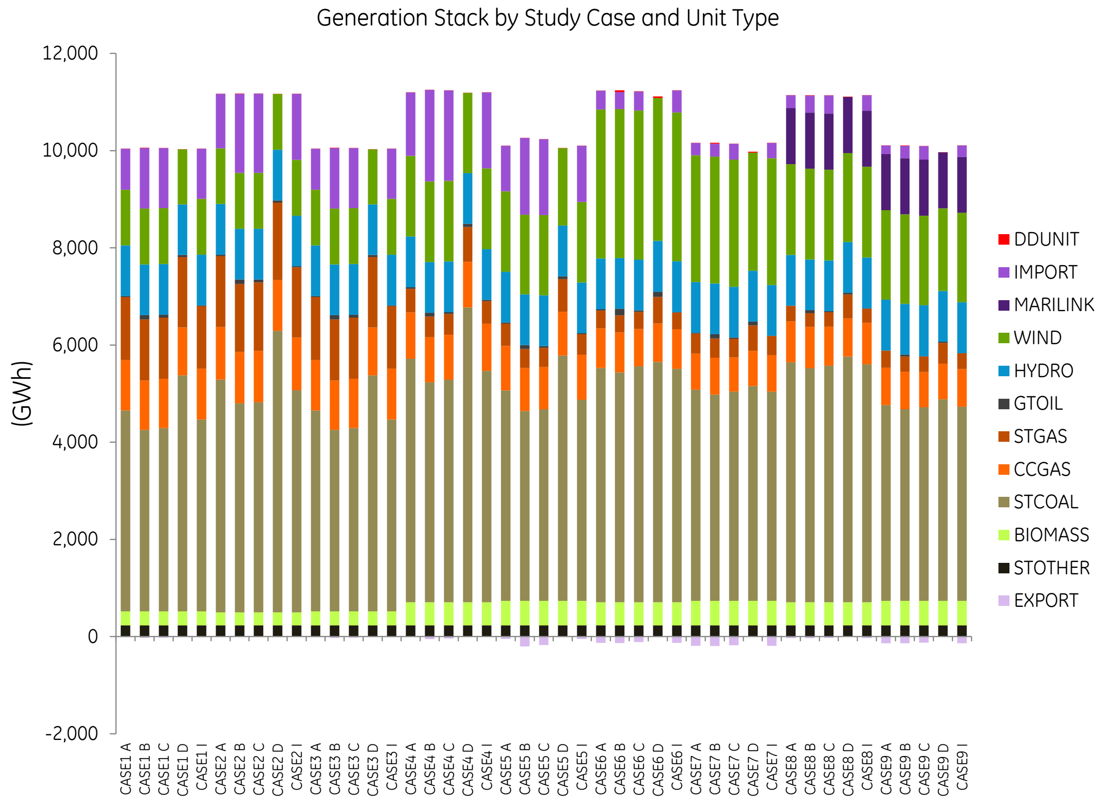



**Figure 145: Generation Stack in Sensitivities A, B, C, D, and I**

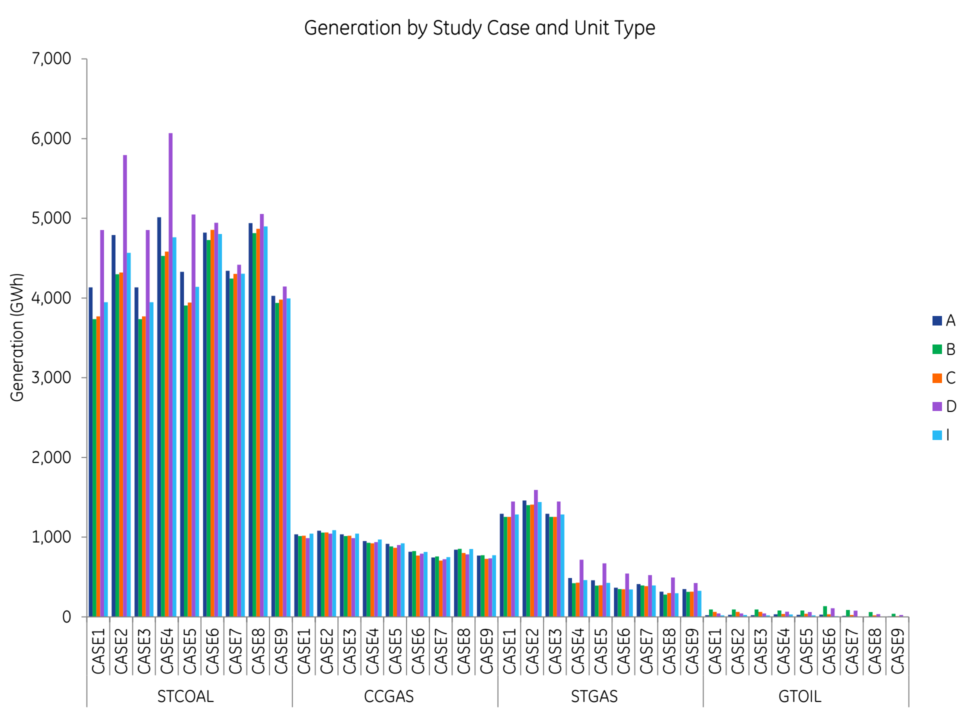



**Figure 146: Generation by unit types in Sensitivities A, B, C, D, and I**

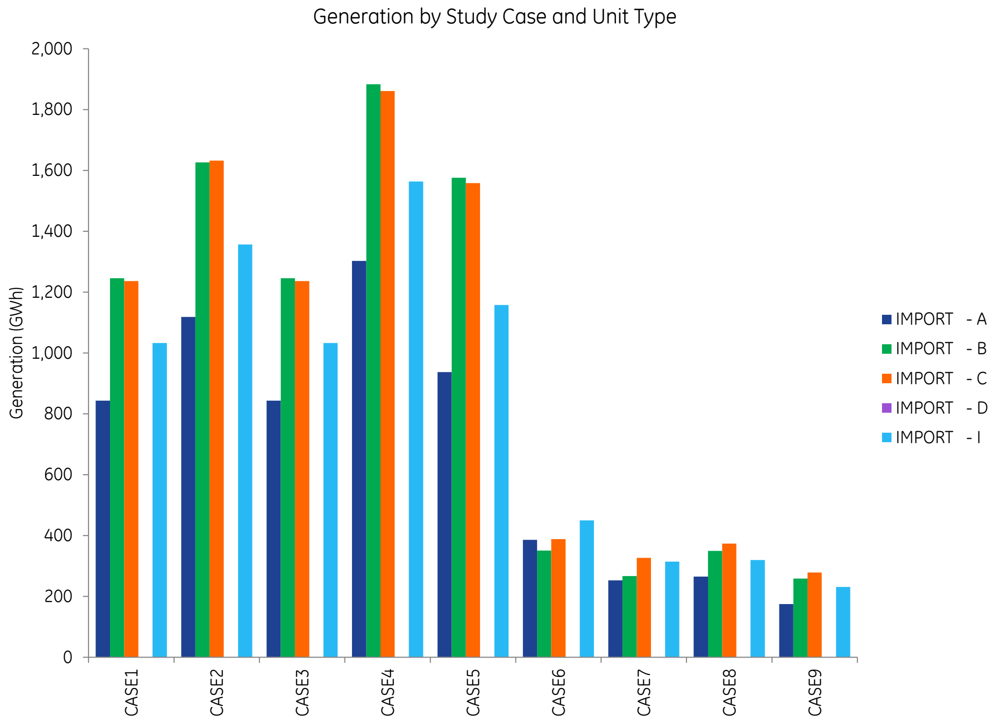



**Figure 147: NB Imports in Sensitivities A, B, C, D, and I**

As can be seen, one impact is increase in NB imports in Sensitivities B and C compared to Sensitivity A (Base Case), which implies that in the more flexible Sensitivity A, compared to inflexible Sensitivity B and C, less NB imports are called on in real time dispatch, than originally committed, resulting in more steam coal generation. Overall, there is less steam coal generation in Sensitivity B, but also a slight increase in GTOIL generation, since GT Oil units were called on to respond to wind forecast error. This is consistent with the expectation that lower flexibility in the tie will result in the expensive peakers being called upon more often. Conversely, the highest flexibility, i.e., Sensitivity A, results in the least use of the oil peakers.

It can be observed that the system behavior in 2hr Wind Forecast is similar to the Inflexible NB Import sensitivity. But compared to Sensitivity B, the additional flexibility (comprising shorter lead time for scheduling and better fidelity wind forecasts) in the same-day dispatch of NB Import results not only in somewhat lower level of imports, but also in a slightly higher thermal generation. This result is optimistic however, because the long lead thermal and hydro plants are scheduled based on better information than they actually would have.

Figure 148 illustrates the impact of the relative inflexibility of NB imports on the amount of potentially curtailed energy and exports. As can be observed, Sensitivity B, which represents the lowest level of NB Import flexibility, results in the highest level of potentially curtailed energy and exports. There are no exports in Sensitivity I. Somewhat surprisingly, improving the availability of the tie to perfect has relatively little impact on the curtailments.

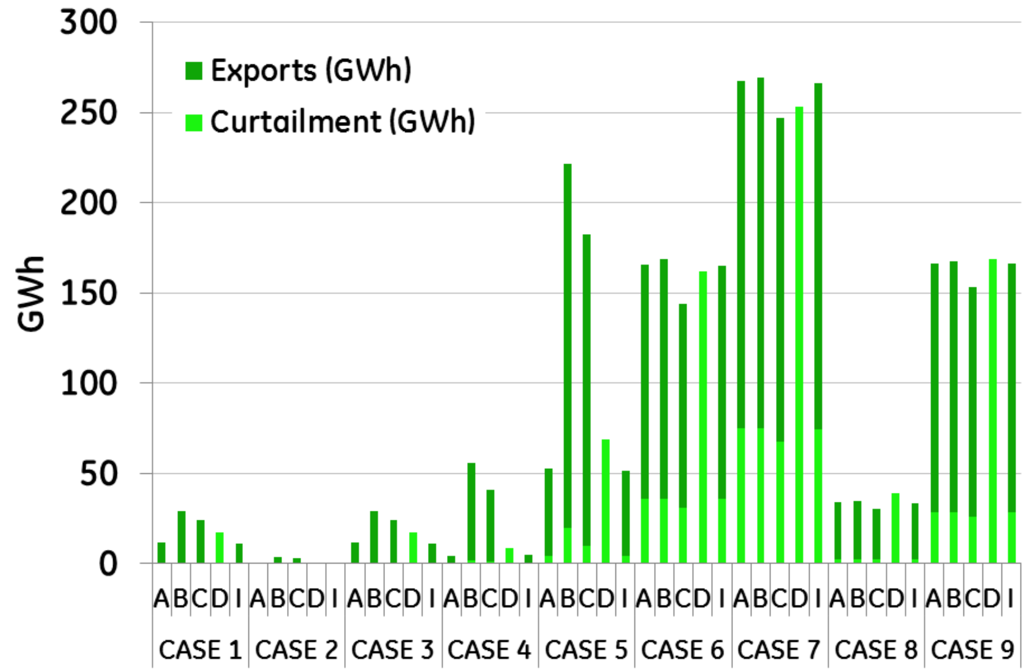



**Figure 148: Exports and Curtailment in Sensitivities A, B, C, D, and I**

Demand response is a proxy for a combination of actual demand response and real-time reserve violations. Hence, hours of demand response would be indicative of high stress/high risk. Under extremes, where voluntary/contractual demand response is exhausted, load interruptions are possible, although the study results do not show such hours.

As shown in Figure 149, the inflexibility of the NB Imports results in greater reliance on DR. or in the absence or DR type programs, resulting in more Unserved Energy. This figure includes some DR energy for events smaller that 10MW, which may be absorbed by other means. Thus, the total energies are probably slightly overstated.

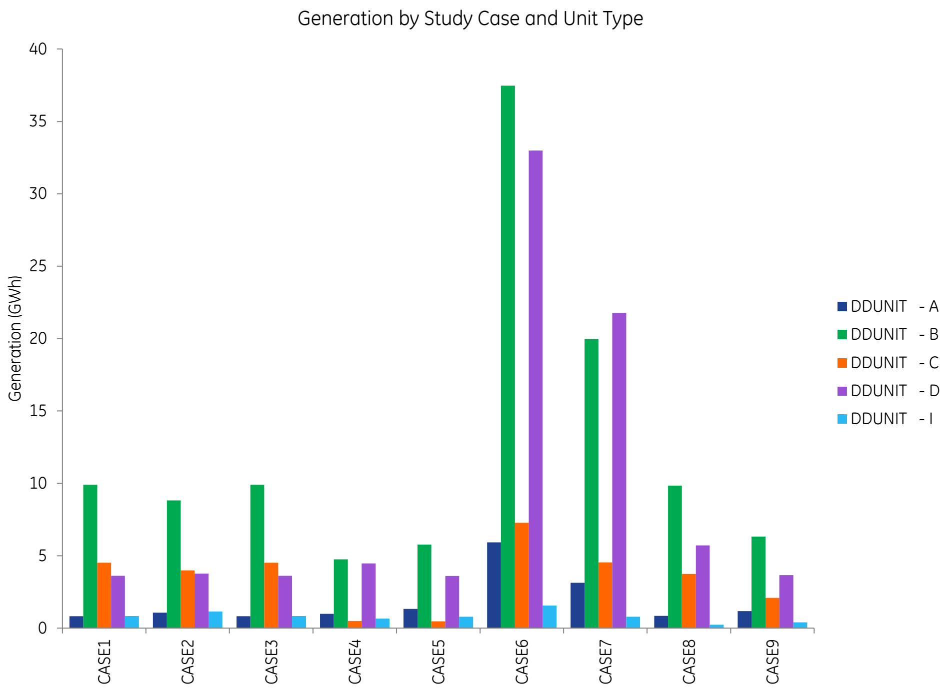



**Figure 149: DR in Sensitivities A, B, C, D, and I**

More detailed information on DR behavior under these sensitivities is provided in Figure 150, which gives duration curves of the DR for the four 2020 cases, for actions greater than 10MW.

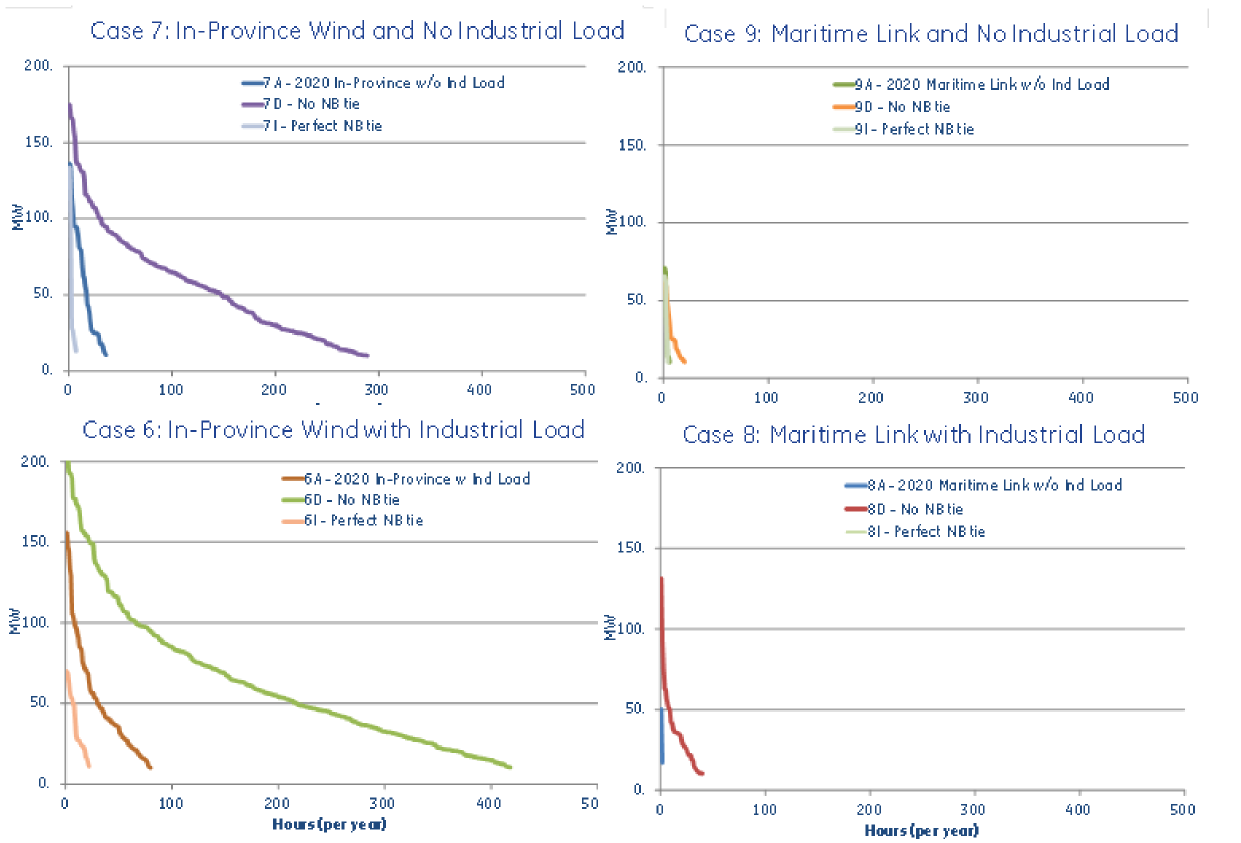



**Figure 150: DR Duration Curves in the Year under Sensitivities A, D, and I**

Higher degree of NB Import inflexibility implies need for more DR, which appears to hold across all Study Cases. These results suggest that if NB Imports cannot be made more flexible to deal with wind forecast errors, DR programs may provide an alternative option that will also reduce the amount of potentially curtailed wind energy.

The NB Import flexibility also impacts the system production costs as shown in the Figure 151. Production costs are provided in Table 33.

Forcing NB schedule to be less volatile (i.e., more inflexible), pushes volatility onto NSPI resources. Reducing NB schedule volatility would increase volatility of other resources.

However, economics appear to be relatively neutral, since this exercise was energy neutral, and therefore very close to revenue neutral.

The MAPS cases with high NB flexibility (Sensitivity A and I) are close to capturing this relationship, but

- Slightly overstate the benefit of NB imports
- Slightly understate the risk of wind curtailment
- Slightly understate the use of fossil peakers

[redacted]

Figure 151: Comparison of Production Costs with Different Import Schemes

THIS FIGURE IS CONFIDENTIAL

Table 33: Comparison of Production Costs ($M) with Different Import Schemes

| | CASE 1 | CASE 2 | CASE 3 | CASE 4 | CASE 5 | CASE 6 | CASE 7 | CASE 8 | CASE 9 |
|---|---|---|---|---|---|---|---|---|---|
| **Sensitivity A** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Sensitivity B** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Sensitivity C** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Sensitivity D** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Sensitivity I** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

### 7.6.1 Impact of NB Tie Unavailability

Complete unavailability of NB Tie has significant impact on operations. For instance, in 2020, without Maritime Link:

- Variable cost of operation increases by approximately [redacted]/year
- Curtailment of wind generation increases by about 7% of total wind generation

- Cost of curtailment increases by $18M in 2020 cases without the industrial load
- Use of demand response for operation under extreme stress increases by about 5-7x
- Use of peakers increases 3-7x, with up to 4x the number of starts

In 2020, with Maritime Link and unavailability of the NB Tie:

- Variable cost of operation increases by approximately [redacted]/year
- Curtailment of wind generation increases by about 8% of total wind generation
- Cost of curtailment increases by $18M in 2020 cases without the industrial load
- Use of demand response for operation under extreme stress increases by about 4-6x
- Use of peakers increases up to 7x, with up to 3x the number of starts
- Higher levels of real-time flexibility from the Maritime link would reduce, but are unlikely to eliminate, some of these penalties.

The following sequence of weekly traces present side-by-side (vertically) comparisons of interesting weeks with and without the NB tie. They illustrate a number of interesting points.

In Figure 152, the value of the NB tie is apparent in a few places. On Thursday, with substantial load and low wind power, the NB tie (upper traces) show the NB tie contributing, whereas without the tie there is heavy use of the oil peakers and demand response. This is evidence of high stress. Saturday is similar. Friday night, there is high export of excess wind power with the tie, and there is also curtailment. Without the tie, the curtailment increases. Figure 153, the amount and frequency of curtailment increases without the NB tie.

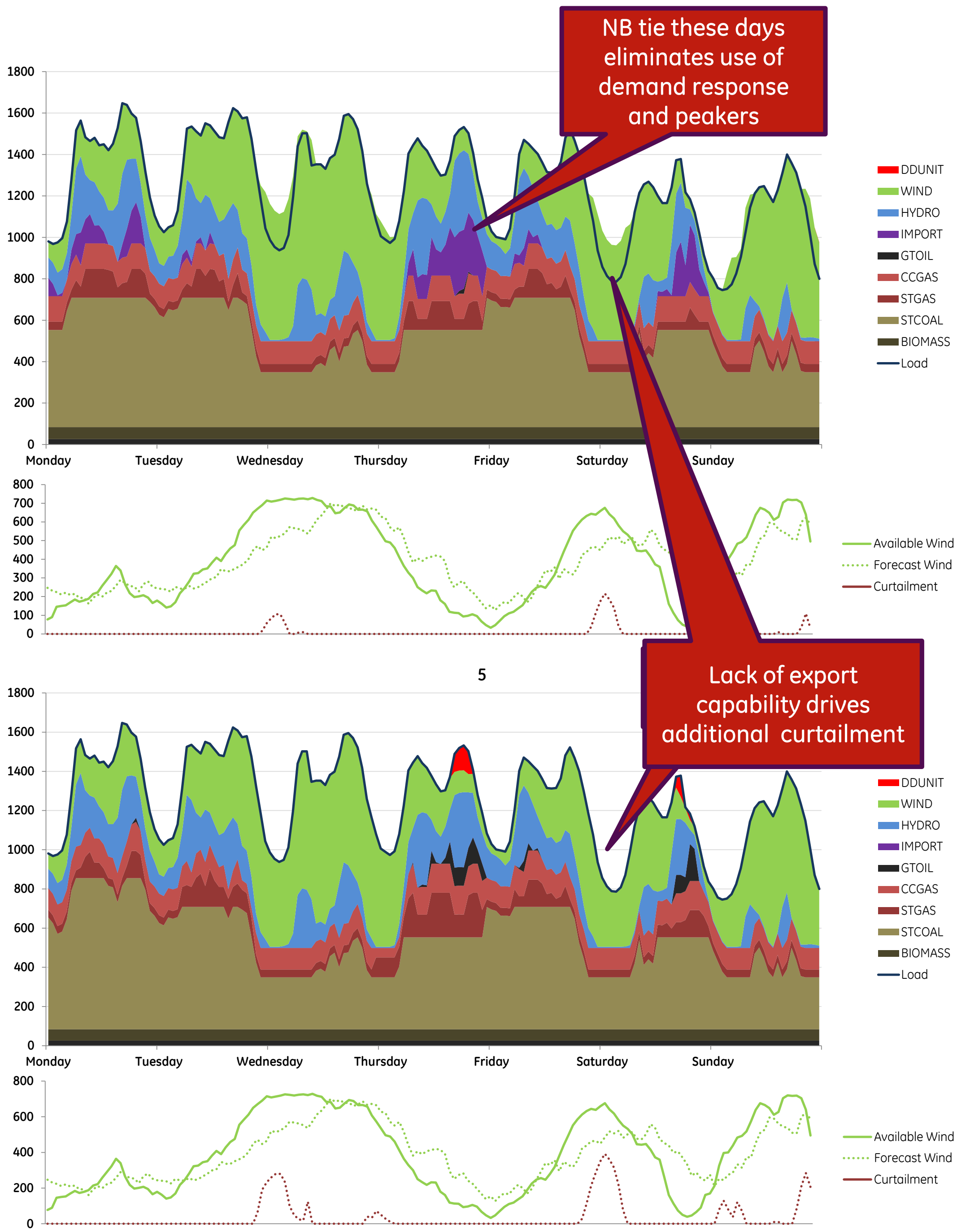



Figure 152: Case 7 - Week 5 - Comparison of NB Tie out to Baseline

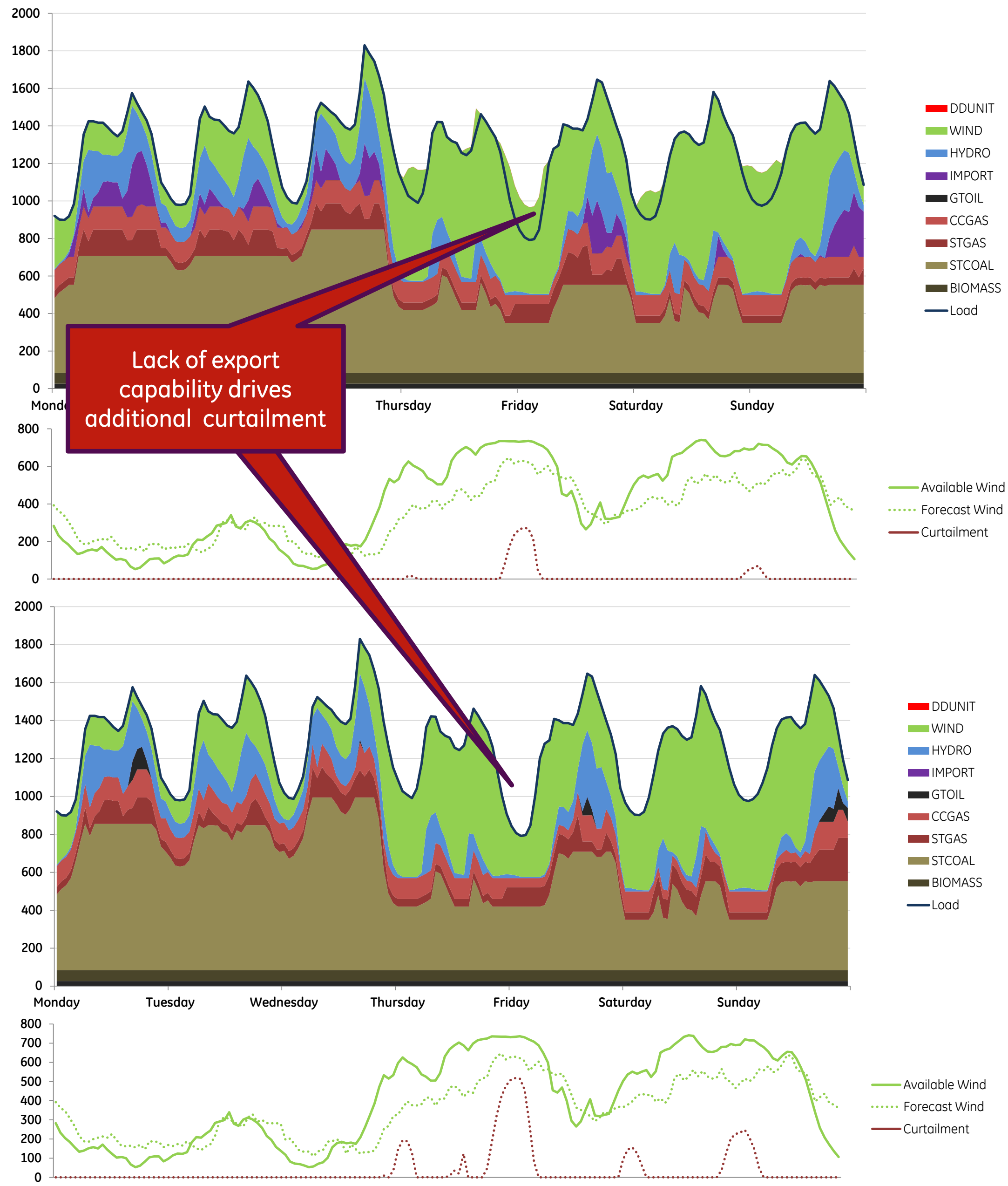



**Figure 153: Case 7 - Week 48 - Comparison of NB Tie out to Baseline**

The impact of the Maritime Link can be seen in Figure 154. As was shown earlier, the hard import schedule constraints on the Maritime Link drives in-province wind curtailment. With the NB tie unavailable, the curtailment can be seen to increase substantially. In Figure 155, a partial outage of the NB tie drives the two cases towards closer behavior.

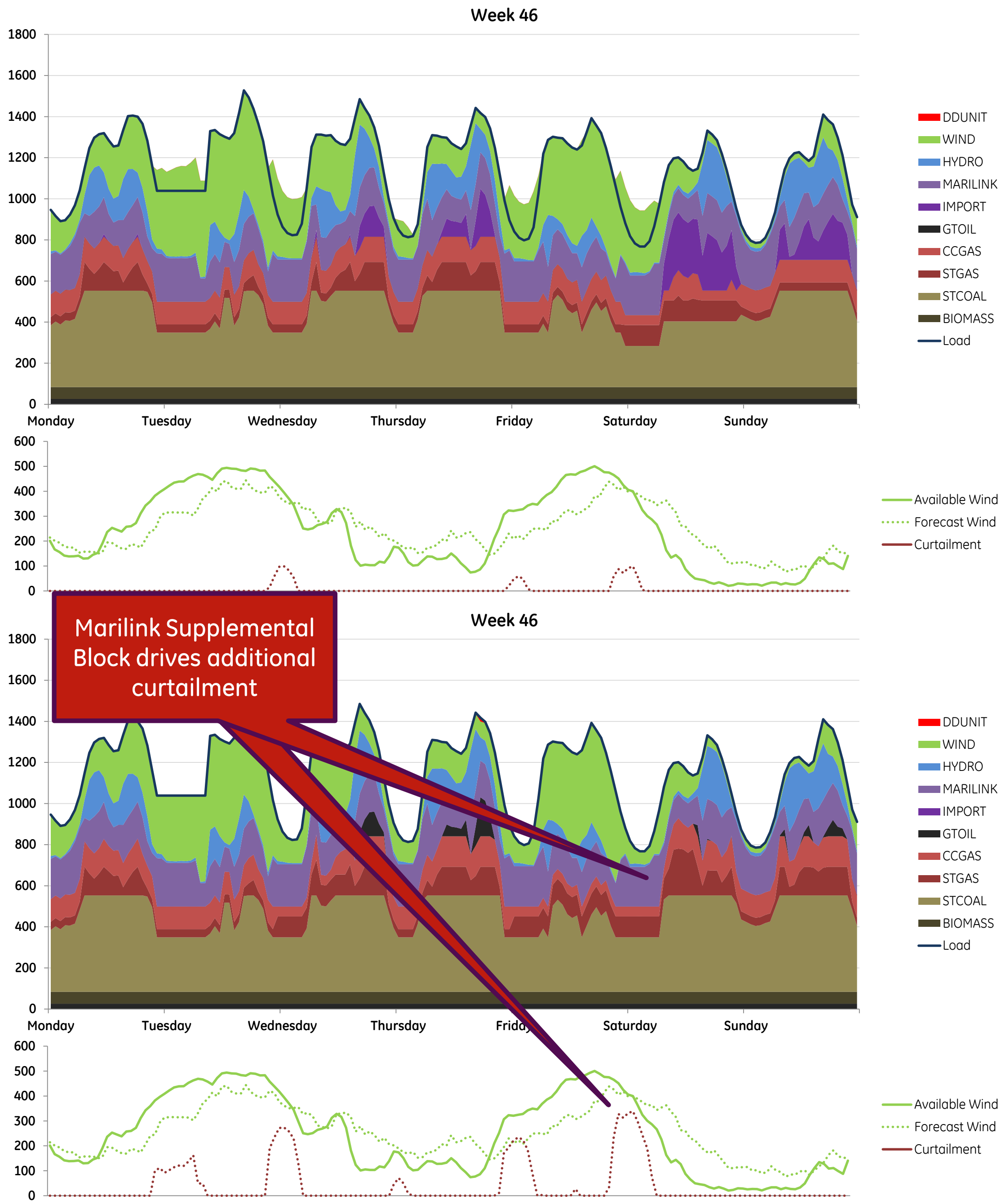



Figure 154: Case 9 - Higher Peaker Use with Maritime Link

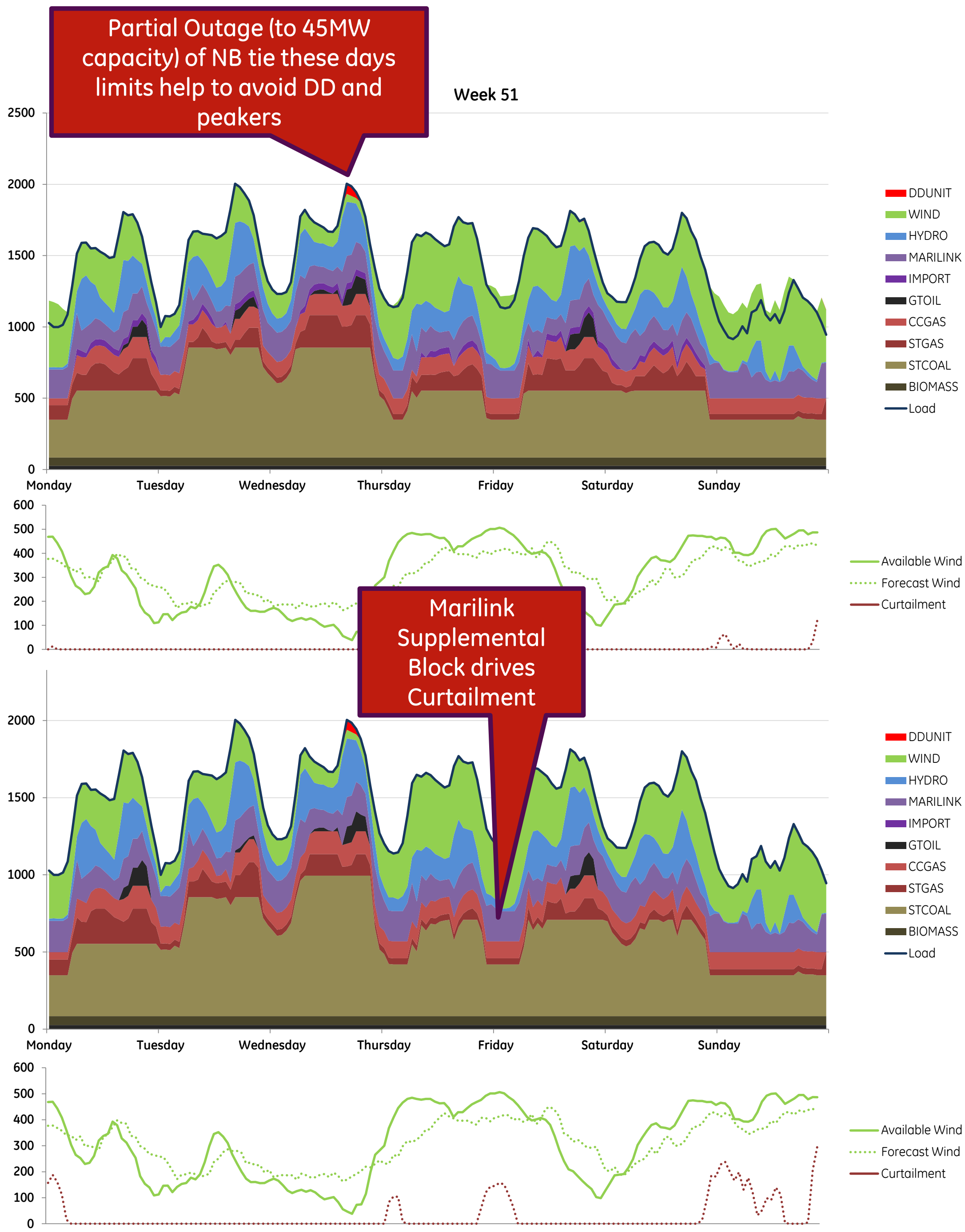



**Figure 155: Case 9 – Week 51 - Peak Load Week with Maritime Link**

The scheduling of hydro can play an important role in avoiding curtailment. In Figure 156 the upper trace shows how the hydro is scheduled. All hydro other than Wreck Cove, is scheduled DAH, based on the wind and load forecast. Wreck Cove (as discussed above) is further rescheduled in real-time to help counter wind forecast error. The lower traces in the figure compare the curtailment with and without the NB tie. This case illustrates that real-time shifting of hydro schedules might be a means to reduce curtailment. With no NB tie, the question will be more pressing, since more curtailment is at issue.

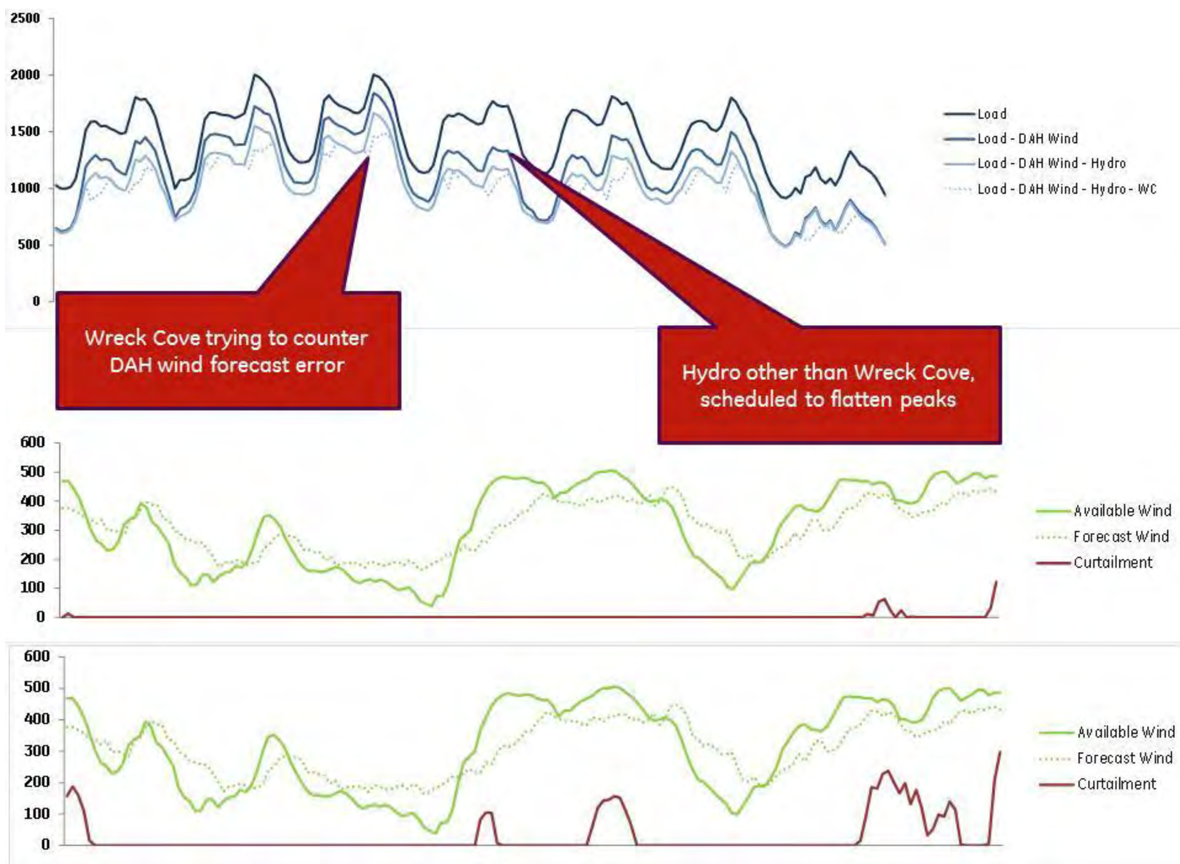



**Figure 156: Case 9 – Week 51 - Hydro Scheduling and Curtailment**

A final note, looking closer at the impact of a partial outage of the NB tie in Figure 157, shows how demand response might be a resource for covering occasional (or sustained) unavailability of the NB tie.

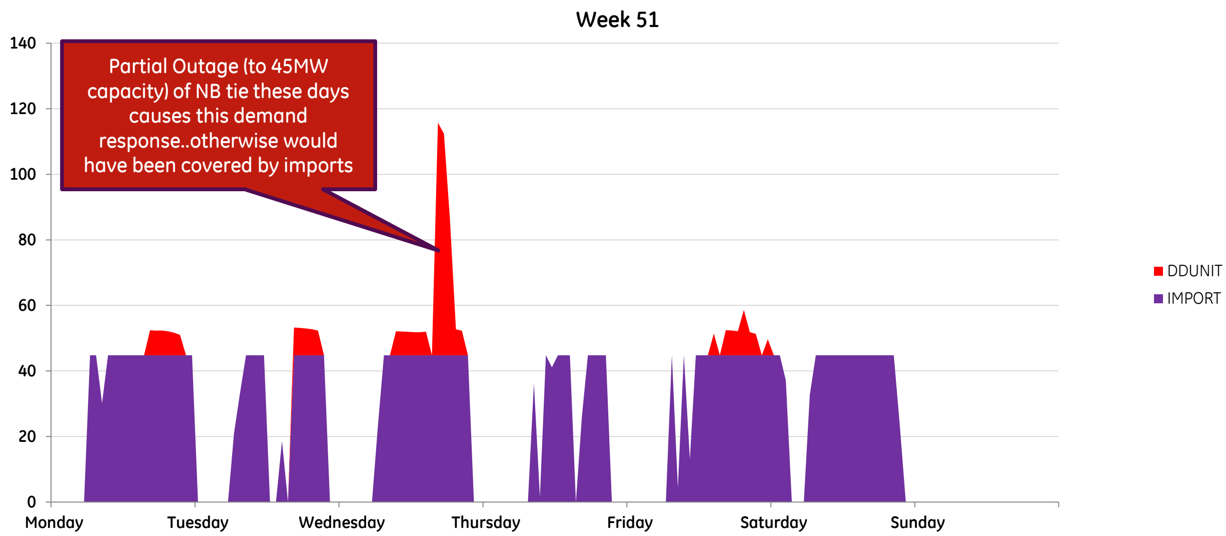



**Figure 157: Week 51 Detail: Impact of NB tie Partial Outage (Case 7A)**

### 7.6.2 Volatility of NB Imports

As noted above, the ability to [redacted], whereby NSPI would schedule NB imports shortly before "real-time", and lock them in, with short term wind forecast much closer to "actual" than DAH.

However, movement of the NB resource from hour-to-hour is a concern, implying a higher level of flexibility or accommodation by NB than the current norm and practice.

There is concern about the degree of stress imposed on both the NB tie and the systems behind it to follow constant movement of the wind power. There may be options for NSPI to reduce this volatility.

Production simulations do not penalize changes in schedule or other forms of mileage. If the system production (variable operating) cost is minimized by moving resources, including the NB tie, from hour-to-hour, there is no imputed cost associated with that motion. In practice, there is likely to be institutional "aversion" to constantly modifying NB imports, especially in the frequent case that they bounce up and down from hour to hour. In this section, we examine this motion of the NB tie line flows, and consider how modifications in operations might shift some of the variability that the production simulations impose on the tie line back to NSPI resources.

We focus on one week of operation with substantial variation in the tie flows. This and subsequent figures are based on Week 28 of Case 7A.

In Figure 158, the flow on the NB tie from the MAPS simulation of Case 7A is shown in blue. The variability from hour-to-hour on the tie is noticeable. The red trace shows a possible NB tie schedule that delivers the same energy over the period, but which is "averse" to hour-to-hour change. Notice that the red curve is considerably smoother, indicating substantially smaller changes from hour-to-hour on the tie schedule. We have used a simple smoothing algorithm as a proxy for the more sophisticated decision making that a human operator might impose. This exercise, at this point, assumes that the human operator has perfect knowledge of the recent past history of the tie flow, and high fidelity knowledge of the expected wind power production over the next few hours in the future.

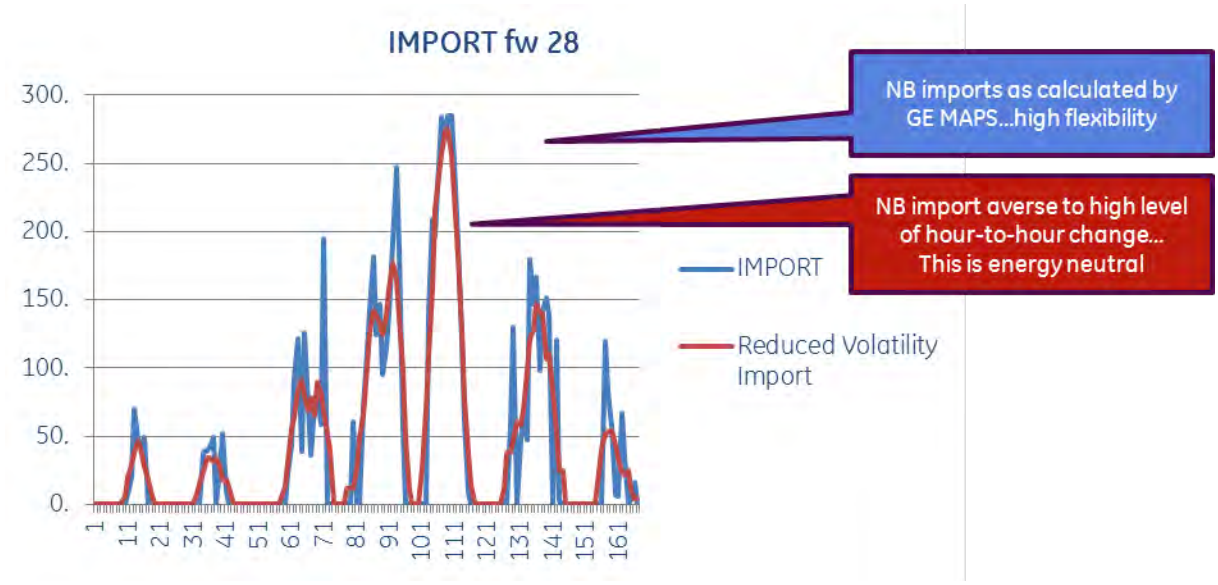



**Figure 158: Volatile NB Import versus Reduced Volatility Import**

The reduction in maneuvering of the NB tie must be covered by resources within Nova Scotia. Figure 159, shows the real time deviation from the more flexible MAPS model results. The question is whether this difference between the highly flexible import and a more practical less flexible import can be covered by other resources in NSPI.

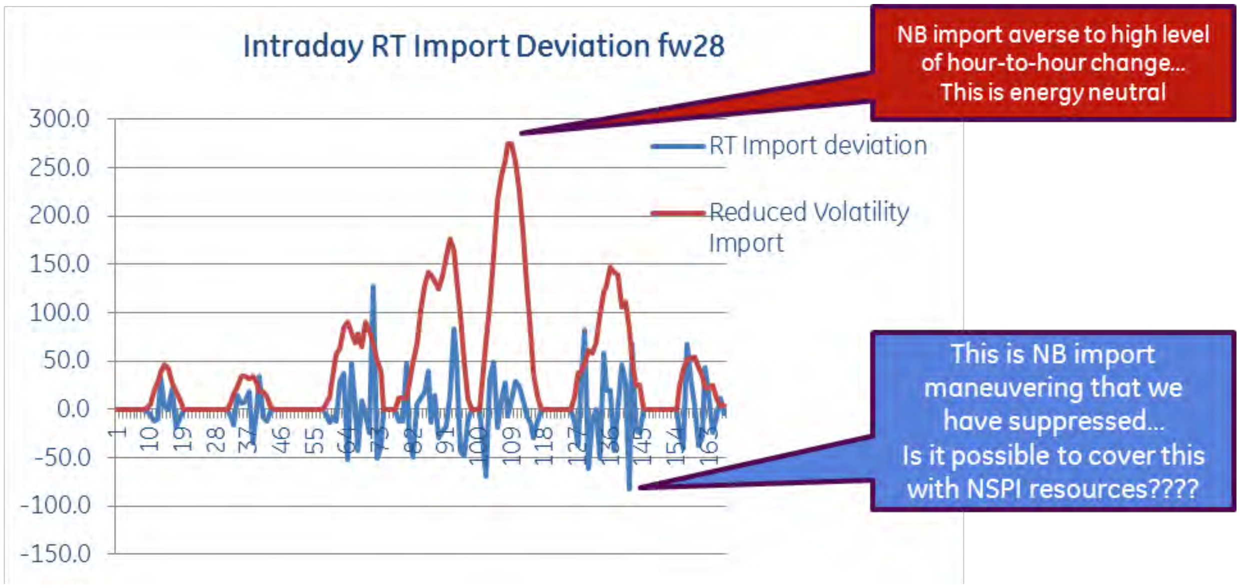



**Figure 159: Difference between Real Time Volatile NB Import and Reduced Volatility NB Import**

Part of the coverage of this real time deviation might be provided by NSPI hydro resources. In Figure 160, we show the total hydro up-range (blue trace) and down-range (green trace) during this week. The hydro is scheduled by MAPS in advance for real-time oepration with the primary objective of minimizing production cost. Reducing variation is not an objective. The incremental variation of the "averse" case of the previous figure is shown in red. Most hours, the red is between the blue and green traces, which is an idication that the hydro resources *should* have the ability to cover the incremental variability that has been pulled off the tie line. There are, however, some hours during which the hydro resources may fall short of covering parts of this deviation. Further, it is important to emphasis that this assumed range covers all of the hydro resources in NSPI, including but not limited to Wreck Cove. The ability of other hydro resources in NSPI can actually accommodate continuous rescheduling needs further investigation.

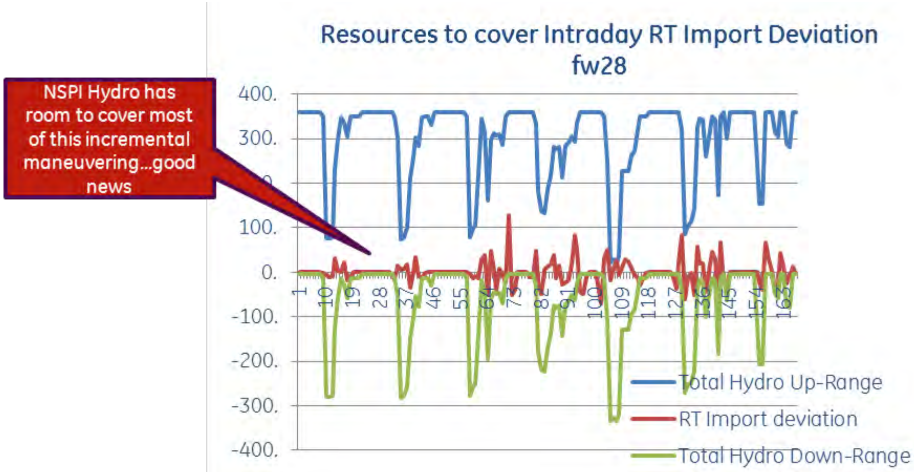



**Figure 160: NSPI Hydro Resources Coverage of Real Time NB Import Deviation**

Most of the real time import deviation that cannot be covered by NSPI hydro, which we refer to as either "Up or Down Residue after Hydro", can be covered by other flexible thermal resources. This is illustrated in Figure 161. However, there are hours during which even the flexible thermal down-range would not be sufficient to provide total coverage for the up or down residue after hydro. This is shown in the figure as the red curve following below the purple curve. In such hours, one would expect additional mitigation measures, which would most likely be curtailment of wind. During this week, the resources within NSPI are always able to increase output to cover limits on the hydro up range.

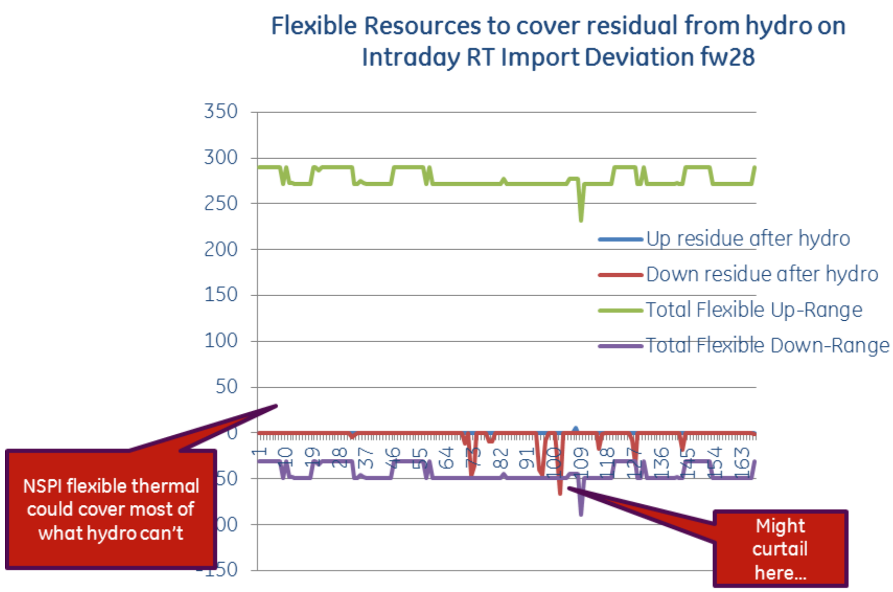



**Figure 161: Flexible Resource Coverage of Residual from Hydro Coverage of Intraday RLT Import Deviation**

The degree of annual movement in terms of annual mileage traveled by flexible import in comparison to the annual mileage of reduced volatility (maneuvering averse) import is shown in Figure 162. As indicated in the figure, reduced volatility import moves half as much as the flexible import during the year.

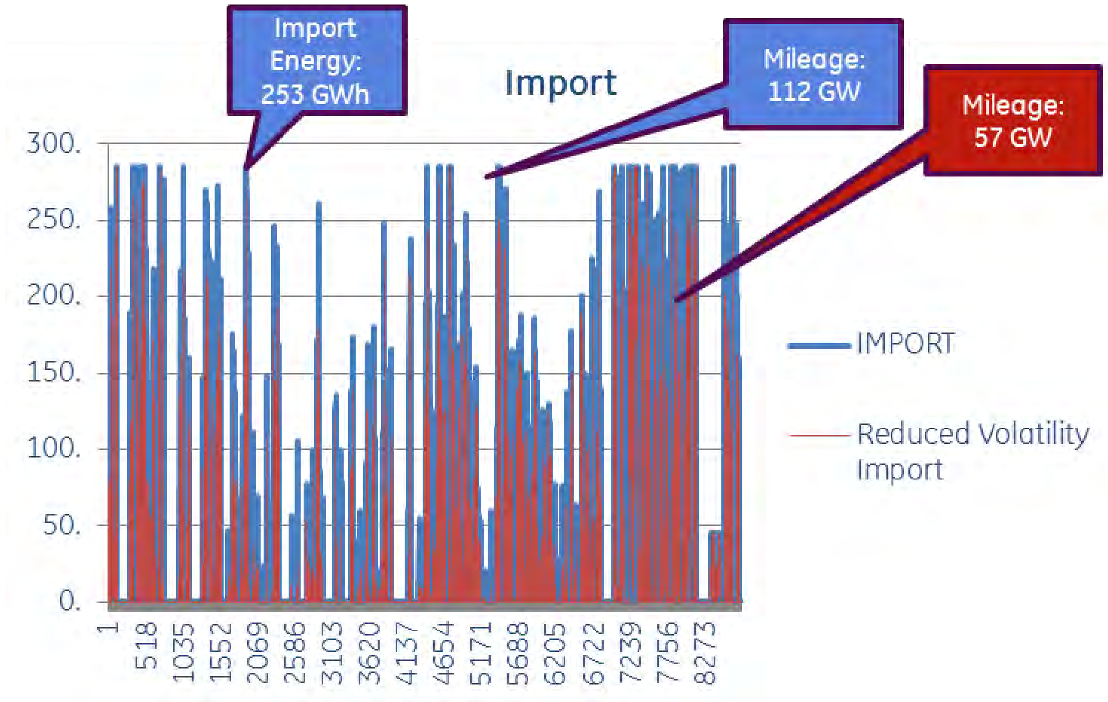



**Figure 162: Movement of Flexible Import with Reduced Volatility Import in Terms of Annual Mileage**

Figure 163 shows the total amount of energy shifted due to real time import deviation is about 80 GWh. This is a metric of the degree to which hydro energy production is moved as it participates more actively in the hourly balancing of the system. Further, the thermal plants must also be shifted. The amount of real time residue after hydro that is covered by flexible thermal is 2.6 GWh and 4.7 GWh, as indicated in Figure 164. In general, if the hydro resource proves to be less operationally flexible than this example supposes, then the impact on the thermal plants will increase.

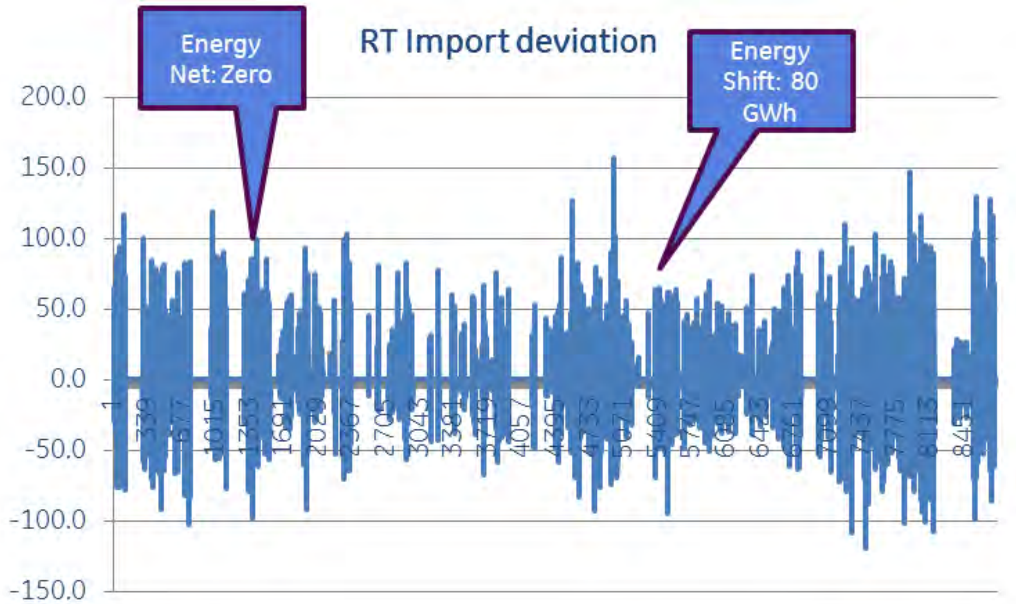



**Figure 163: Annual Energy Shift due to Real Time Import Deviation**

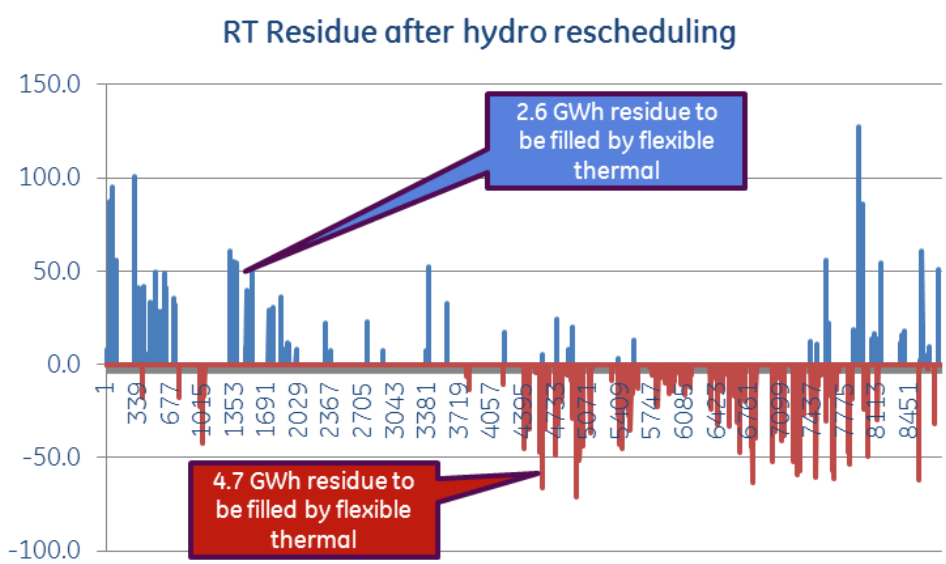



**Figure 164: Real Time Residue after Hydro Scheduling**

After accounting for all the hydro and flexible thermal coverage of the real time import deviation, there are still some hours in the year where there is some residue (after hydro and flexible thermal). For these few hours the remaining residue is shown in Figure 165, which will need to be covered either by elements such as energy storage or wind curtailment.

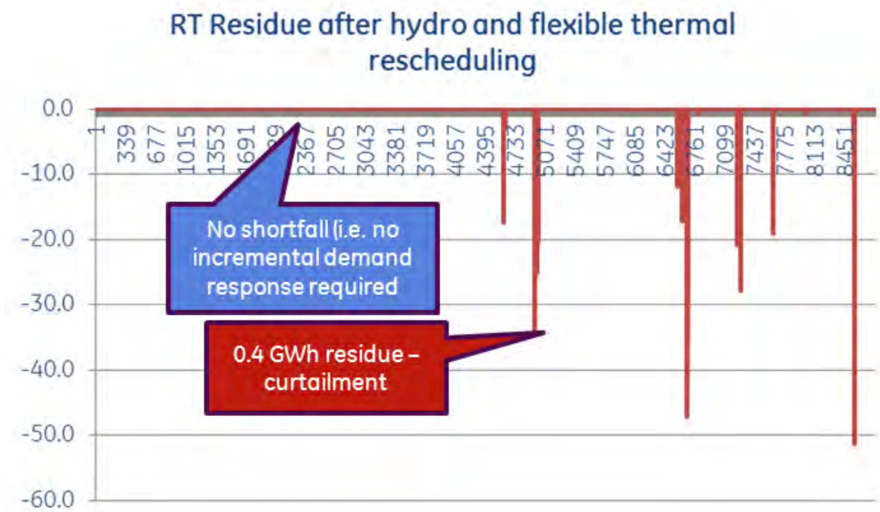



**Figure 165: Real Time Residue after Hydro and Flexible Thermal Rescheduling**

These examples strongly suggest that there is latitude within NSPI to reduce the volatility of schedule on the NB / BS tieline below the levels indicated by the production simulations. This comes, as it must, at the cost of increased maneuvering of NSPI resources. However, the impact is indeed not additives arithmetically. The annual hydro production for the two cases is shown in Figure 166. While the hourly traces are not too illuminating, notice that incremental hydro mileage is only about 14 GW – about 5%. This is an indication that a large benefit can be realized from shorter term scheduling of the hydro, that does not result in radically higher maneuvering of the hydro plants.

A closer inspection of the hydro schedule shows why this is the case. In Figure 167, original DAH schedule of the hydro (in total) is shown in blue. The hydro schedule as modified to reduce the NB tie volatility is shown in red. Notice that in some hours the hydro moves more, but in others it moves less. This is a consequence of the hydro being scheduled with better the knowledge associated with real-time or near real-time operations – some of the volatility imposed by DAH scheduling is "backed out".

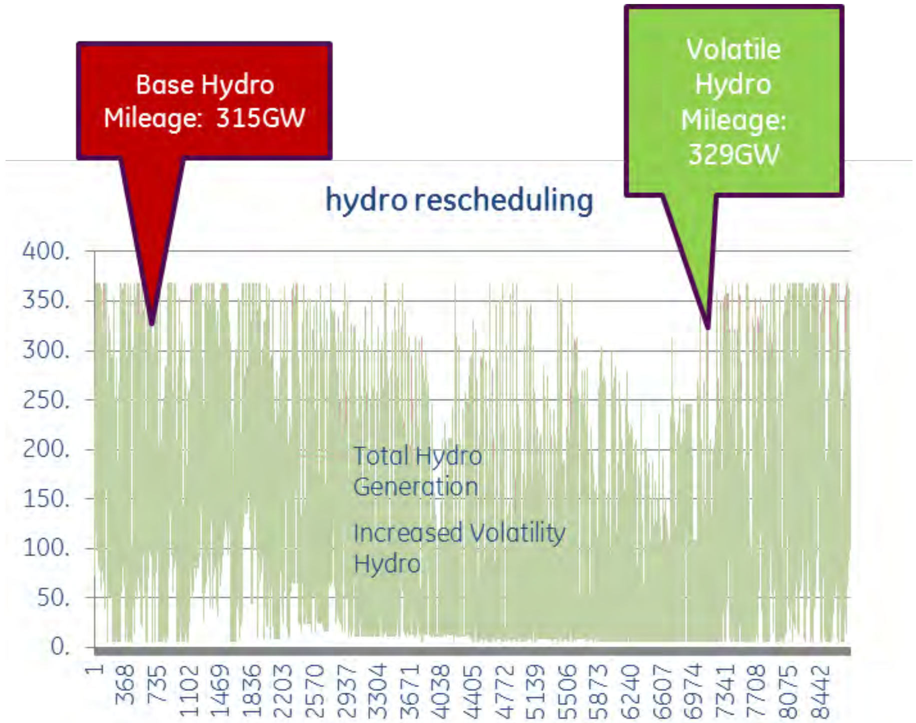



Figure 166: Hydro Rescheduling to Cover Real Time Import Deviation

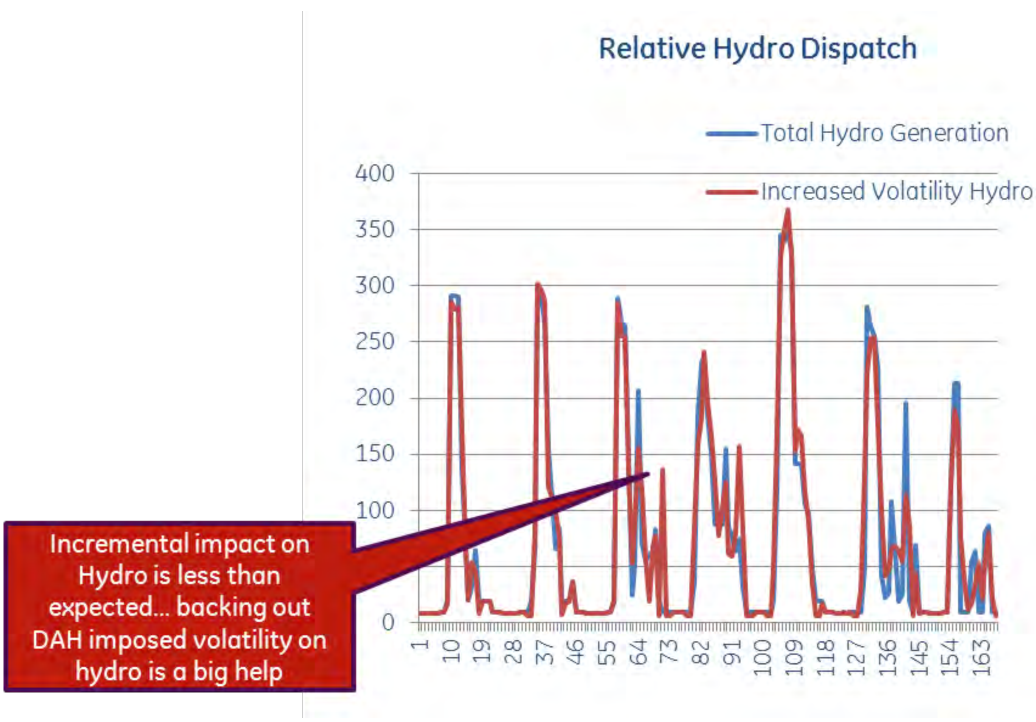



Figure 167: Relative Hydro Dispatch

The information necessary for NSPI to "smooth" the schedule of NB imports comes from a combination of:

- Short-term forecast information, i.e., where is the system (wind) likely to be over the next couple hours?
- Recent history, i.e., where have we been? – we are "reluctant" to move from that schedule

Consequently, there is effectively a lag in the response: The NB import schedule will not only be smoother, it will be a little "stale". The result is that NSPI resources will be required to maneuver more when:

- The forecast is poorer, including looking farther ahead
- (Re)scheduling of the NB tie is slower

The following sequence, illustrated in the next few figures and tables, is also based on Week 28 of Case 7A. It illustrates this shift to less responsive and less volatile NB scheduling, subject to slower changes in NB tie scheduling. In Figure 168, the same smoothing philosophy is imposed, but based on a slower response with poorer forecast of the wind power in the near future. For shorthand, we refer to this case as a one hour shift (back in time). The net result of this slower response is that more variability is imposed on the NSPI resources. In Figure 169, the residue that must be covered by NSPI resources is shown. At a glance, this figure looks the same as Figure 159, but the amount of power that must be covered by NSPI resources is greater. This is due to the slower decision making and poorer information likely for rescheduling the NB tie.

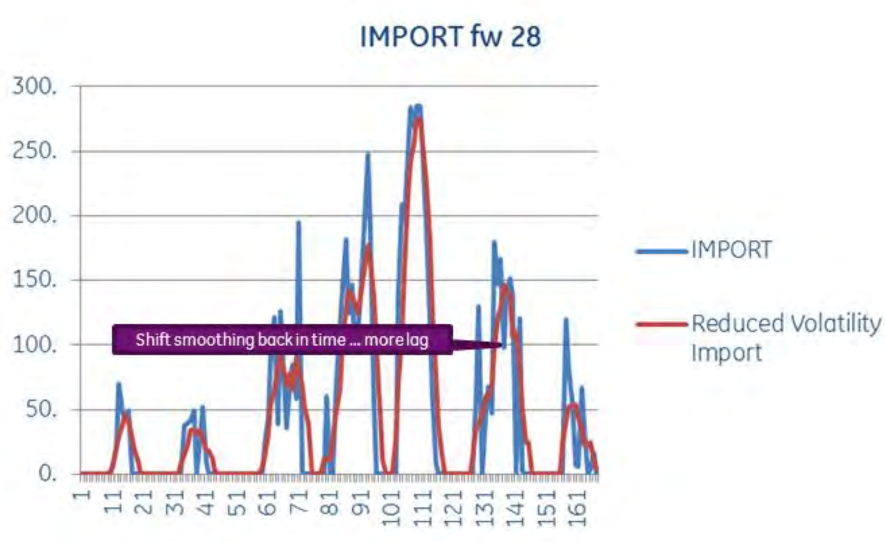



**Figure 168: 1 Hour Shift NB tie Smoothing**

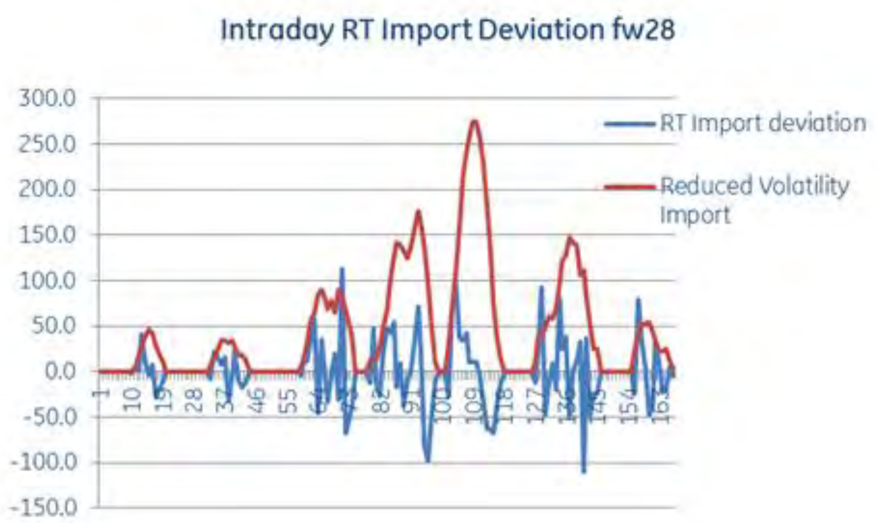



**Figure 169: Real Time Residue after NB tie schedule smoothing with 1hr shift**

This poorer information means that the hydro must move more, that there will be more energy and maneuvering imposed on the thermal plants when the hydro range is exhausted, and that there will be more wind curtailment. Table 34 summarizes the impact of lesser volatility in NB imports in terms of additional movement of hydro resources, additional flexible thermal energy, and additional curtailment. In this table we have also included a more pessimistic scenario, in which the NB tie rescheduling is shifted by 2 hours. As information exchange and rescheduling gets more stale, the impact on NSPI resources increases. It is, however, encouraging to note that incremental impacts are not great in absolute terms. For example, incremental wind curtailment of 2.9GWh represents only about 0.1% of total wind production in this case. The increase in hydro mileage is less than 10%

**Table 34: Summary of the Impact of Less Flexible NB Imports**

| | Base | Reduced Volatility | 1hr Lag | 2hr Lag |
|---|---|---|---|---|
| **Hydro Mileage** | 315 GW | 326 GW | 331 GW | 336 GW |
| **Thermal Addition (up/down)** | 0 | 2.6/4.7 GWh | 5.7/7.2 GWh | 10.5/15 GWh |
| **Additional Curtailment** | 0 | 0.4 GWh | 0.8 GWh | 2.9 GWh |

This exercise is intended to explore possible trade-offs and strategies for using NSPI resources to avoid possibly excessive changes in the NB tie line schedule. It is admittedly complicated, and it is only a proxy for what is likely to emerge as a relatively complicated process for scheduling the tie and NSPI hydro resources. A brief summary of the key points of this exercise is:

- [redacted]
- Forcing NB schedule to be less volatile pushes volatility onto NSPI resources
- However, it is not zero-sum:
    - NB schedule volatility can be reduced in about ½
    - While NSPI hydro volatility increases less than 10%
- Economics are expected to be roughly neutral:
    - This exercise was energy neutral, and therefore very close to revenue neutral. However, no production simulations were made to verify this, as the model cannot capture these nuances.
    - The MAPS cases with high NB flexibility are close to capturing this relationship, However, they:
        - Slightly overstate the benefit of NB imports
        - Slightly understate the risk of wind curtailment
        - Slightly understate the use of fossil peakers

## 7.7 Market Prices of Nova Scotia Imports and Exports

The ability to import power from New Brunswick and to export excess wind power is an important element in Nova Scotia system operation. In this section, we look at sensitivities to prices outside of Nova Scotia. It is important, when considering these cases, to remember that this study does not include detailed physical or economic modeling of New Brunswick or beyond. Consequently, the ability of these systems to actually provide or pay for power at these prices is not established by these cases. Rather, these are explorations of the possible operational impact *if these prices occur*.

### 7.7.1 Expensive Imports

Sensitivity P assumes more expensive NB imports. Prices are higher for both On-Peak and Off-Peak periods for all years. Prices, shown in Table 35, were provided by NSPI.

**Table 35: Import and Export Base and High Prices**

| Year | 2013 | 2015 | 2020 |
|---|---|---|---|
| | | | |
| **Base Price** | | | |
| | | | |
| NB to NS (NS Imports) | | | |
| On-Peak | [redacted] | [redacted] | [redacted] |
| Off-Peak | [redacted] | [redacted] | [redacted] |
| | | | |
| NS to NB (NS Exports) | | | |
| On-Peak | [redacted] | [redacted] | [redacted] |
| Off-Peak | [redacted] | [redacted] | [redacted] |
| | | | |
| | | | |
| **High Price** | | | |
| | | | |
| NB to NS (NS Imports) | | | |
| On-Peak | [redacted] | [redacted] | [redacted] |
| Off-Peak | [redacted] | [redacted] | [redacted] |
| | | | |
| NS to NB (NS Exports) | [redacted] | [redacted] | [redacted] |
| On-Peak | [redacted] | [redacted] | [redacted] |

The general trend shown in Figure 170, as expected, that higher prices for imports through New Brunswick will tend to result in lower import volumes. This mostly results in increased coal usage in early years, and in later years mostly gas. This is consistent with the changes in relative coal and gas prices observed elsewhere in the study. Also should be noted that the amount of wind and Maritime Link generation are essentially unchanged.

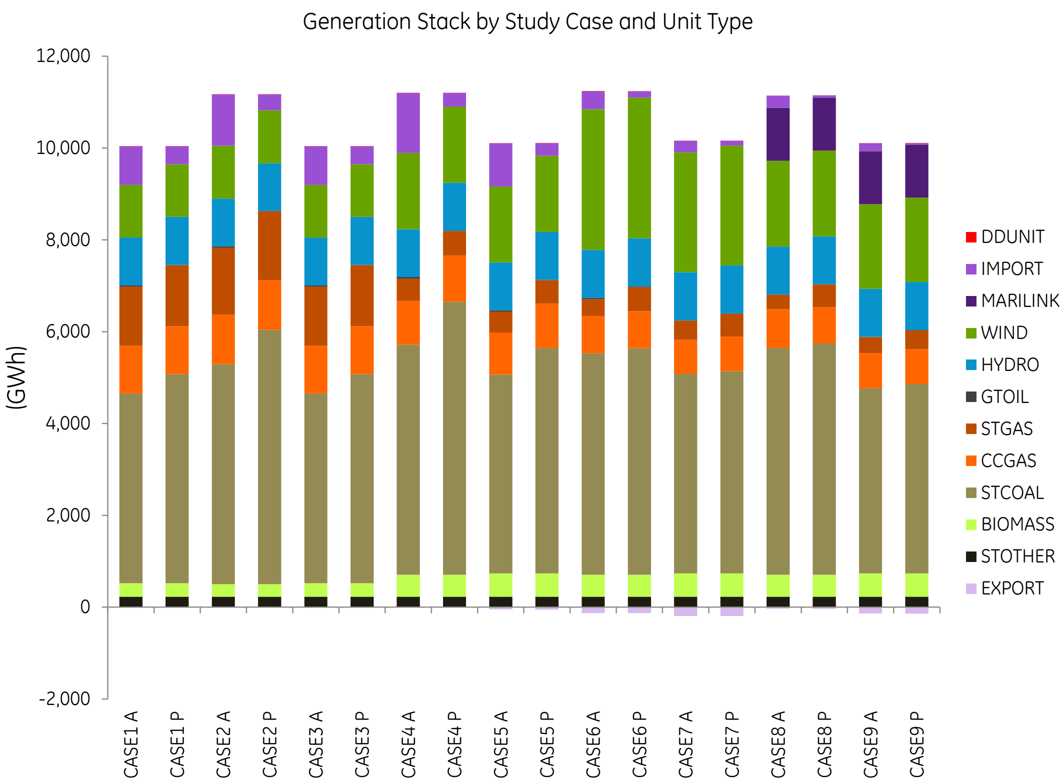



**Figure 170: Generation Stack with Expensive NB Imports versus the Base Case**

Figure 171 and Table 36 show the production costs for this sensitivity across all study cases.

[redacted]

**Figure 171: Production Costs under Expensive NB Imports versus the Base Case**

**THIS FIGURE IS CONFIDENTIAL**

**Table 36: Production Costs ($M) under Expensive NB Imports versus the Base Case**

| | CASE | CASE | CASE | CASE | CASE | CASE | CASE | CASE | CASE |
|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
| **Sensitivity A (Base Case)** | 359.8 | 417.2 | 359.8 | 446.8 | 384.1 | 457.4 | 409.2 | 436.6 | 373.2 |
| **Sensitivity P (Expensive Imports)** | 367.5 | 421.2 | 367.5 | 453.0 | 391.7 | 468.1 | 418.8 | 444.7 | 376.2 |
| **Costs ($M)** | 7.8 | 4.0 | 7.8 | 6.3 | 7.6 | 10.7 | 9.6 | 8.1 | 3.1 |

Higher prices for imports lead to higher variable operating costs. The production cost impact is lowest in Case 9, when imports are minimal. As shown in Figure 172, there is little impact on exports. It should be noted, however, that because exports are counted as sales, they are included in the total energy under the RES target. Therefore, every 100 GWh of exported energy would result in an additional 40GWh of renewable energy to achieve the 2020 RES target.

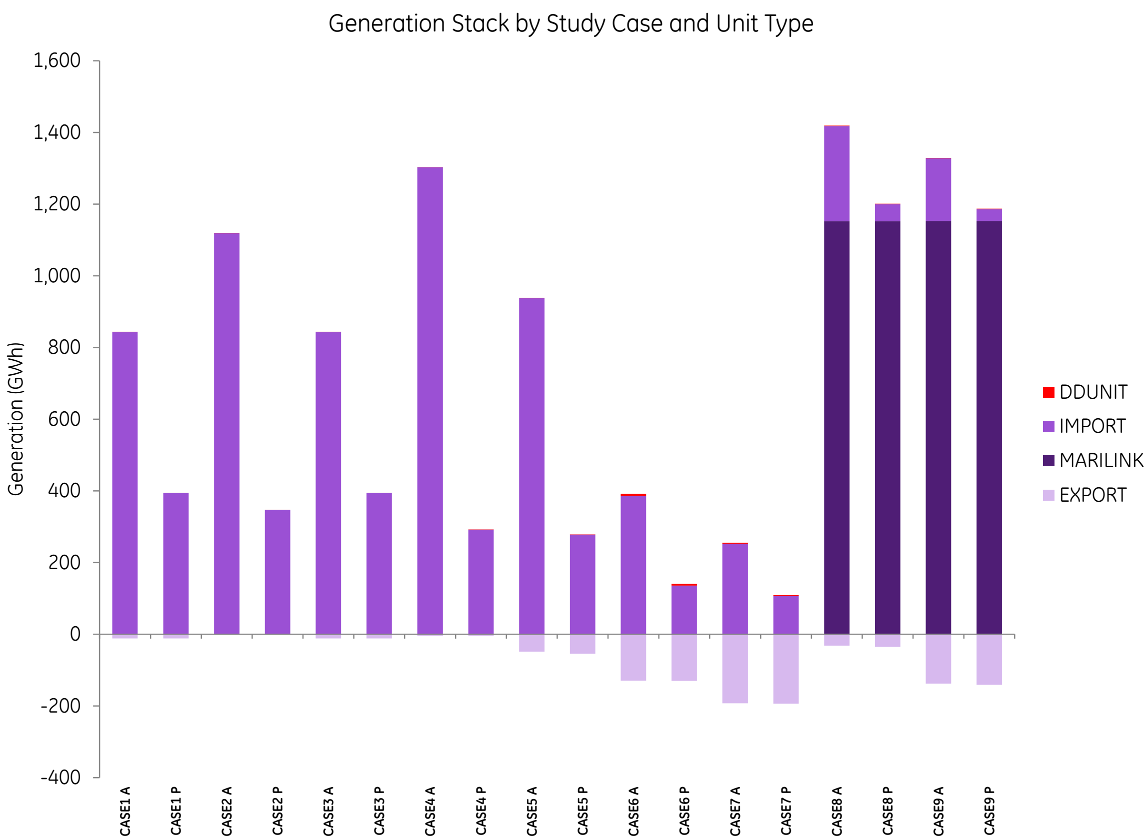



**Figure 172: Impact of Expensive NB Imports on DR, Maritime Link Imports, and Exports**

### 7.7.2 Pricing of Exports

In the cases presented so far, power exports out of Nova Scotia are assumed to not contribute any operational revenue. Or more precisely, the value of exports is always assumed to be lower than the marginal cost of production in Nova Scotia.

In the event that prices are anywhere between zero and this minimum, system operation will not change significantly. However it is possible that export prices may play a larger role if their relative values make them an attractive option for the province.

Initially, we look more at a range of possible revenue impacts if the export price stays below the marginal cost of production. This is a greatly simplified exercise, but makes a useful point:

There are two terms in the revenue associated with exports: (a) how much is exported and (b) price realized for exports.

The amount of excess is dependent on many factors, in particular the degree of conservativeness in use of wind forecasts for commitment, and the degree of flexibility assumed in the NB tie. Here, the "expected" value is for our base line model ("A"), with high and low bounds based on perfect and no wind forecast.

For sale price, most of our work is based on the premise that only the wind power that is "excess", i.e., which cannot be accepted by the NSPI grid, is exported, and that up to the limit of export capability.

We have not modeled the markets of NB and beyond, but as long as the sale price is below the marginal cost of production in NSPI (mainly the baseload generation), then this assumption is sound. For simplicity, we provide a range from low ($[redacted]/MWh) to high ($[redacted]/MWh).

The median value is purely speculative, but based on the notion that marginal costs of production in export markets (NB and beyond) are similar to NS. For reference, we have rather arbitrarily set the "median" value to $[redacted]/MWh. The range of possible revenues for this exercise is shown in Figure 173.

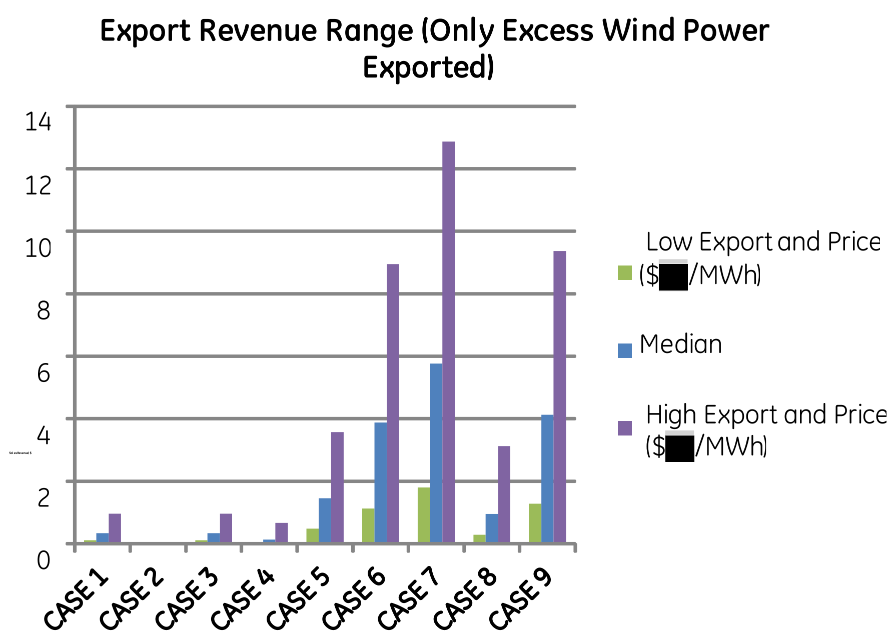



**Figure 173: Revenues from Export of Excess Wind Power**

In Sensitivity J, instead of exporting energy only during hours of collapsed spot prices (wind curtailment), exports are economically dispatched, based on prices provided by NSPI, which vary by year and on-peak/off-peak periods.

This sensitivity would be expected to result in significant increase in exports, which is confirmed by the results as depicted in the following figures.

Sensitivity K is similar to Sensitivity J, but export prices are set at a higher level. Prices, shown previously in Table 35, were provided by NSPI.

It would be expected that under with higher prices, exports will be even higher than those in Sensitivity J. Again, results as shown in Figure 174 to Figure 179 confirm this expectation. It is an interesting outcome that imports increase as well as a consequence of the affected unit commitments.

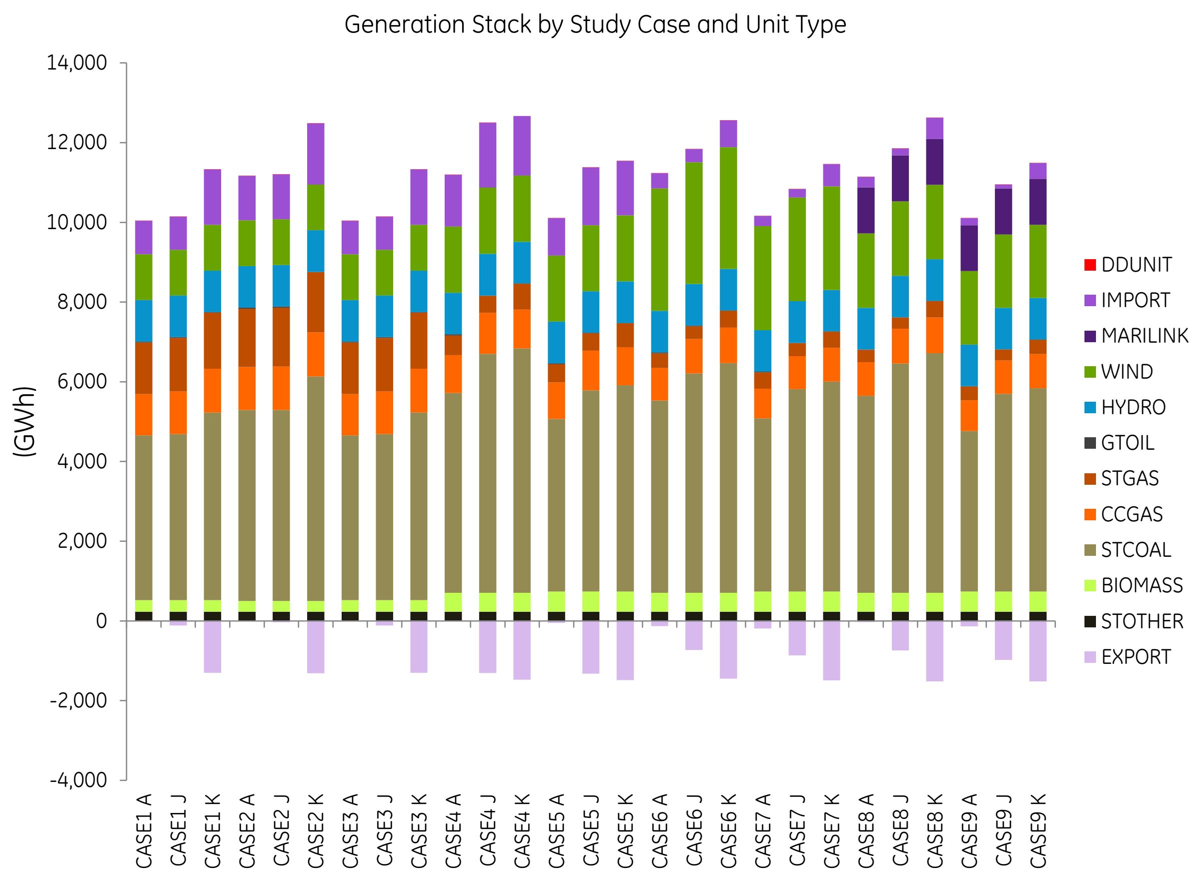



**Figure 174: Generation Stack under Different Export Pricing Schemes**

The cases show that higher coal usage, and more power is exported to New Brunswick results in more emissions, as expected.

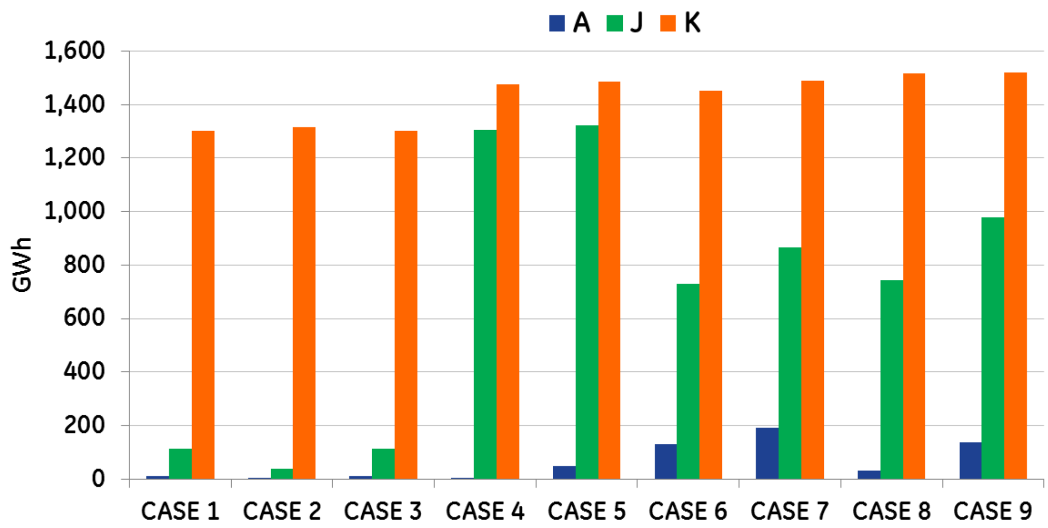



**Figure 175: Exports under different Export Pricing Schemes**

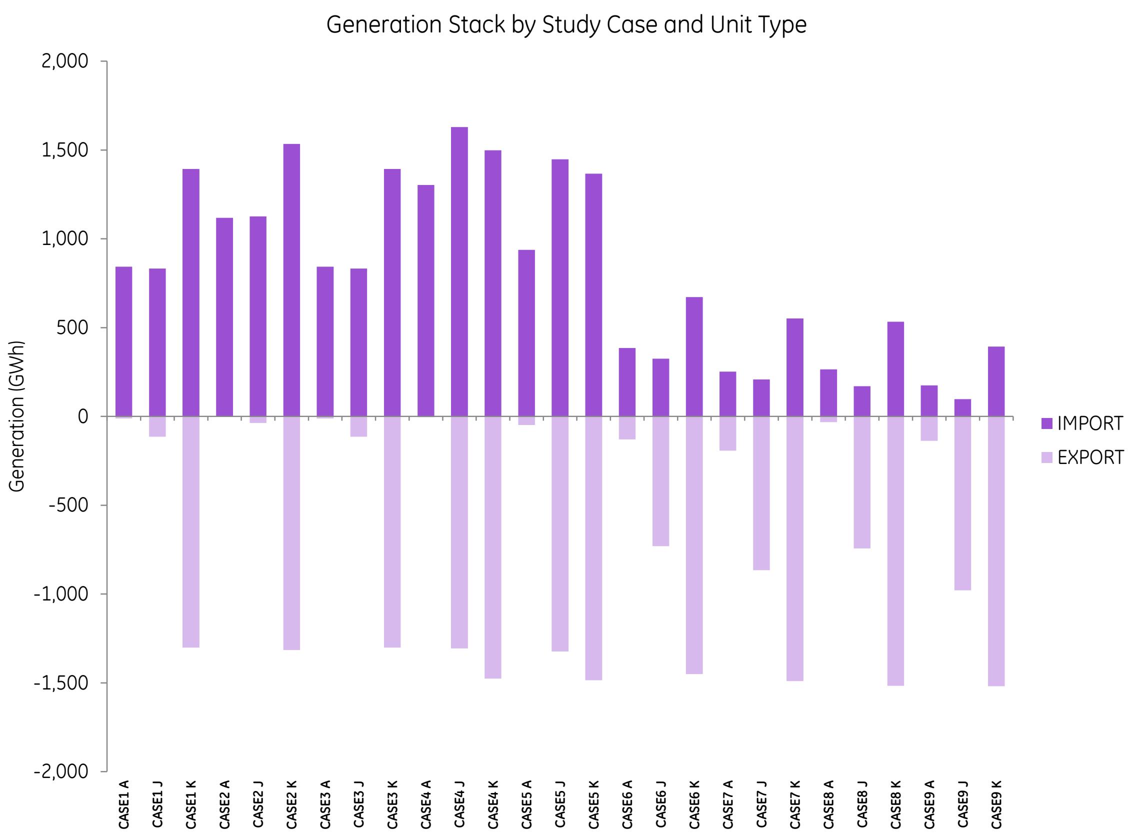



**Figure 176: Comparison NB Imports and Exports under Different Export Pricing Schemes**

[redacted]

**Figure 177: Production System Costs under Different Export Pricing Schemes**

**THIS FIGURE IS CONFIDENTIAL**

Table 37 shows the export revenues under pricing schemes of Sensitivity J and Sensitivity K.

**Table 37: Export Revenue under Different Export Pricing Schemes**

| | CASE | CASE | CASE | CASE | CASE | CASE | CASE | CASE | CASE |
|---|---|---|---|---|---|---|---|---|---|
| | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** |
| **Sensitivity J** | 8.2 | 5.1 | 8.2 | 61.4 | 62.0 | 56.7 | 66.1 | 57.7 | 74.4 |
| **Sensitivity K** | 95.2 | 96.3 | 95.2 | 130.4 | 131.2 | 236.4 | 242.6 | 247.1 | 247.6 |

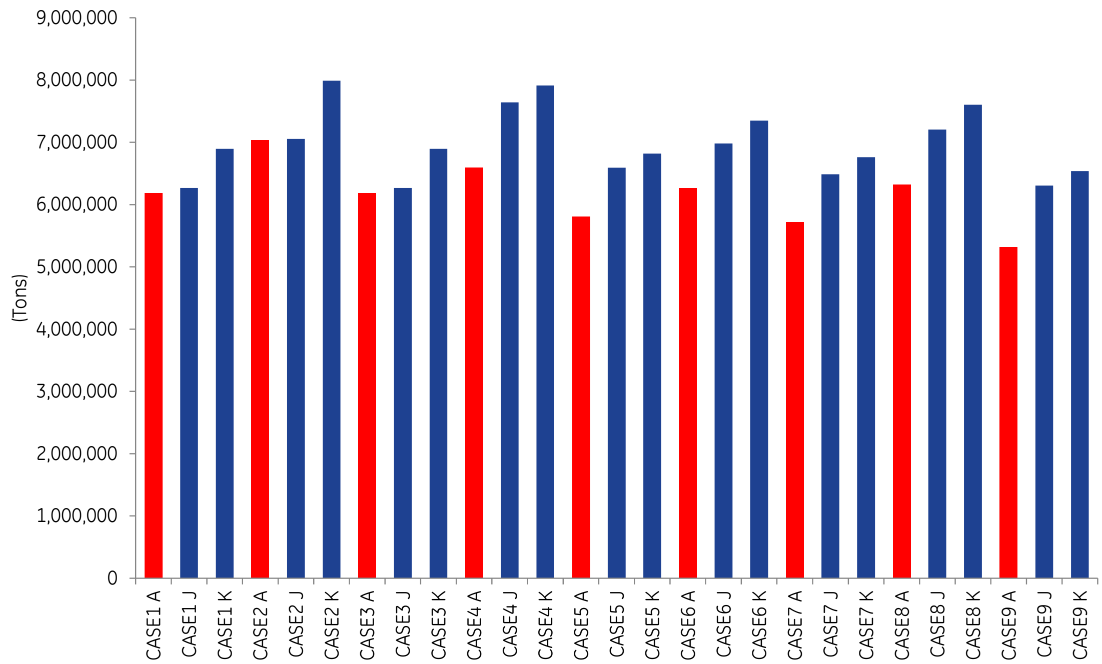



**Figure 178: CO2 Emissions under Different Export Pricing Schemes**

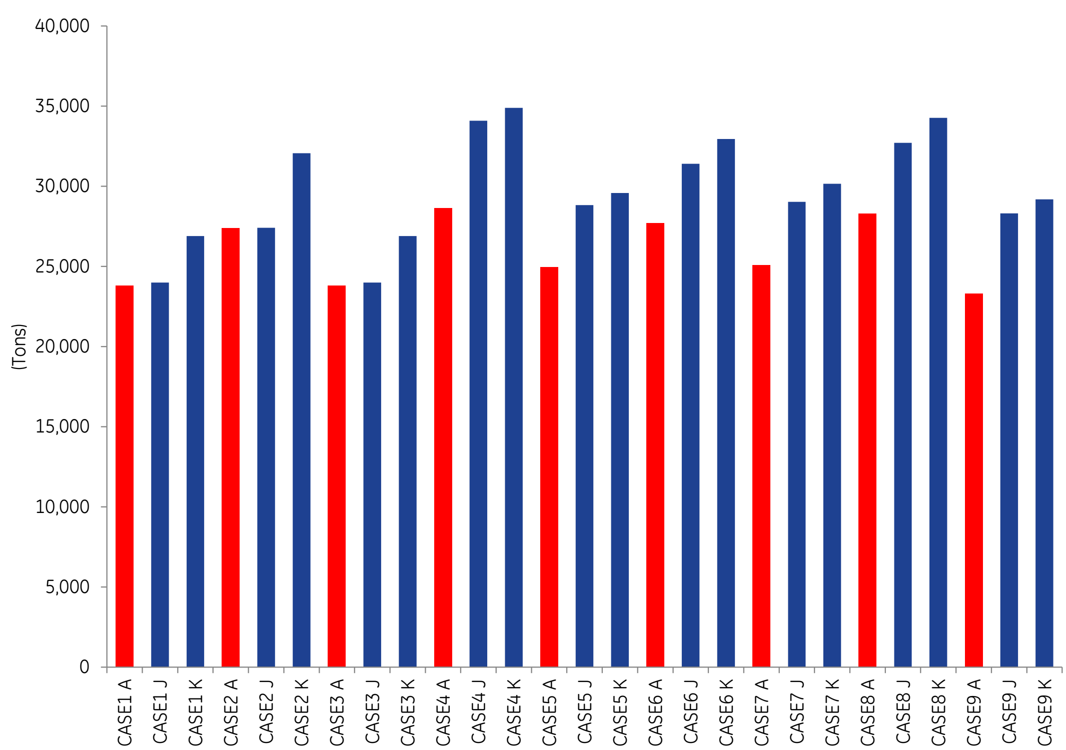



**Figure 179: SOx Emissions under Different Export Pricing Schemes**

## 7.8 Maritime Link Discretionary Block Operation

The discretionary block is handled very differently than the firm Maritime link 35-year and 5-year supplemental blocks. In these cases, the power from the discretionary block is only taken if it is economic. The implication is that the discretionary block is effectively dispatched in real time.

In total, six sensitivities on the Maritime Link were conducted in order to cover a broad range of potential operating constraints of the Maritime Link. In addition, each configuration was run under a range of potential economic pricing to better understand the economics of Maritime link operation. The two configurations are listed below:

Configuration A: an economic, Discretionary Block, of energy is constrained to 250 MW, less what is flowing on the Base and Supplementary blocks. The Discretionary Block energy is only available during On Peak hours and is dispatched according to the prices below:

- Sensitivity F: Maritime Discretionary Block, Configuration A @ $60/MWh
- Sensitivity N: Maritime Discretionary Block High Price, Configuration A @ $65/MWh
- Sensitivity O: Maritime Discretionary Block Low Price, Configuration A @ $55/MWh

Configuration B: an economic, Discretionary Block, of energy is constrained to 300 MW, less what is flowing on the Base and Supplementary blocks. The Discretionary Block energy is available during both On Peak and Off Peak hours and is dispatched according to the prices below:

- Sensitivity X: Maritime Discretionary Block, Configuration B @ $60/MWh
- Senstitivity Y: Maritime Discretionary Block, Configuration B @ $65/MWh
- Sensitivity Z: Maritime Discretionary Block, Configuration B @ $55/MWh

Table 38 provides an overview of the two different configurations and three different pricing scenarios of the Maritime Discretionary Block.

**Table 38: Overview of Discretionary Block Sensitivities F, N, O, X, Y, and Z**

| | Max On-Peak Limit (MW) | Max Off-Peak Limit (MW) | On-Peak Price ($/MWh) | Off-Peak Price ($/MWh) |
|---|---|---|---|---|
| Sensitivity F (Discretionary Block, Config A) | 250 | N/A | $60 | N/A |
| Sensitivity N (High Price Discretionary Block, Config A) | 250 | N/A | $65 | N/A |
| Sensitivity O (Low Price Discretionary Block, Config A) | 250 | N/A | $55 | N/A |
| Sensitivity X (Discretionary Block, Config B) | 300 | 300 | $60 | $50 |
| Sensitivity Y (High Price Discretionary Block, Config B) | 300 | 300 | $65 | $55 |
| Sensitivity Z (Low Price Discretionary Block, Config B) | 300 | 300 | $55 | $45 |

Table 38 shows the generation stack under each of the Maritime Link Discretionary Block sensitivities (F, N, O, X, Y, Z).

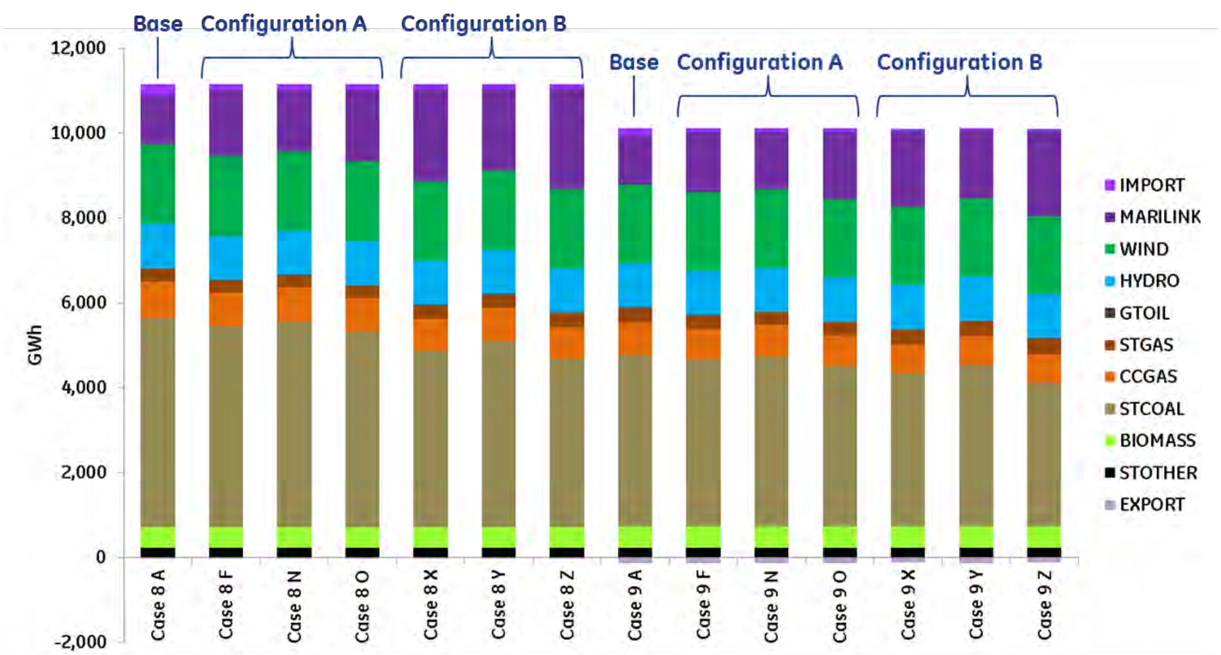



**Figure 180: Generation Stack under Maritime Link Discretionary Block Sensitivities A, F, N, O, X, Y, and Z**

Figure 180 shows fluctuations in the total imports from the Maritime link. The sensitivities with the Discretionary Block see an increase in the total amount of energy from the Maritime Link, while reducing overall generation from the rest of the thermal fleet (mostly coal). The relative price differences across the Discretionary Block sensitivities causes the total Maritime Link imports to fluctuate accordingly.

Figure 181, Table 39 and Table 40 show that the amount of Maritime Link energy imported is consistent with the direction of the price of the discretionary block and the availability on and off peak. The bottom (light purple) bar segments represent the Base 35-year and Supplemental 5-year Maritime blocks, which do not fluctuate across the sensitivities. The dark purple bar and light purple segments represent the discretionary block energy across each sensitivity, which vary due to the economic pricing and off-peak availability. The change in Maritime Link imports is counterbalanced mostly by change in the steam coal generation, and to a smaller extent, by NB imports and other thermal generation.

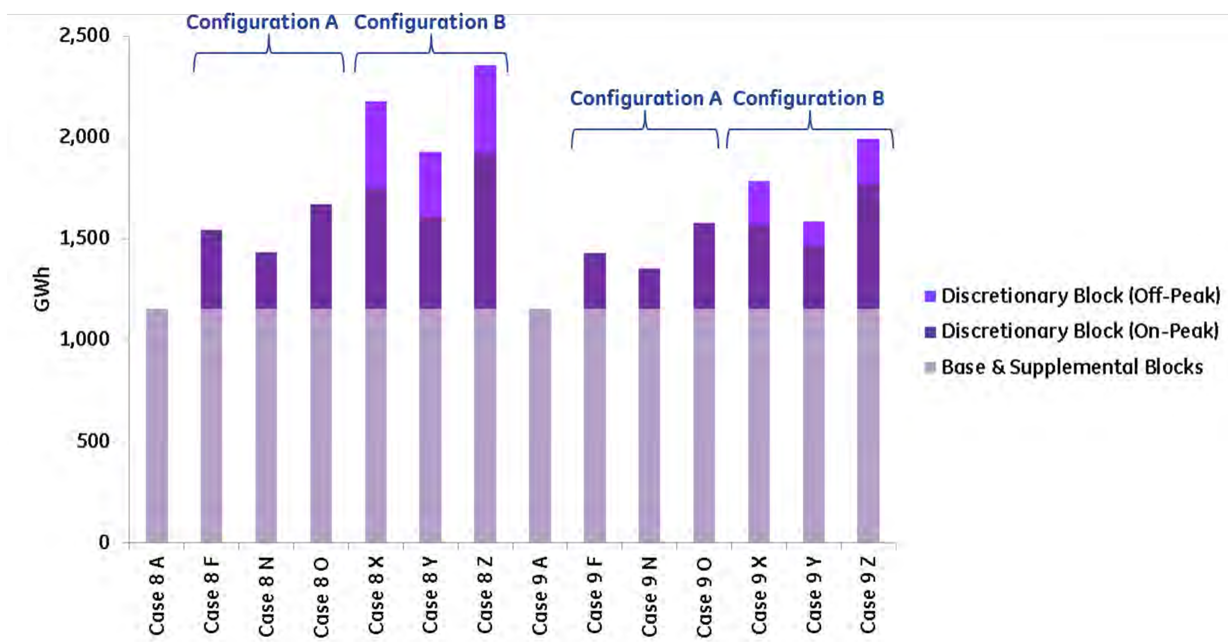



**Figure 181: Total Maritime Link Imports under Discretionary Block Sensitivities A, F, N, O, X, Y, and Z**

**Table 39: Maritime Link Imports (GWh) under Discretionary Block Sensitivities (Case 8)**

| | Maritime Link Base Blocks | Discretionary Block (On-Peak) | Discretionary Block (Off-Peak) | Maritime Link Total |
|---|---|---|---|---|
| Sensitivity A (Base Case) | 1153.0 | N/A | N/A | 1153.0 |
| Sensitivity F (Discretionary Block, Config A) | 1153.0 | 389.6 | N/A | 1542.7 |
| Sensitivity N (High Price Discretionary Block, Config A) | 1153.0 | 279.2 | N/A | 1432.2 |
| Sensitivity O (Low Price Discretionary Block, Config A) | 1153.0 | 516.9 | N/A | 1669.9 |
| Sensitivity X (Discretionary Block, Config B) | 1153.0 | 592.8 | 432.6 | 2178.5 |
| Sensitivity Y (High Price Discretionary Block, Config B) | 1153.0 | 457.7 | 319.0 | 1929.7 |
| Sensitivity Z (Low Price Discretionary Block, Config B) | 1153.0 | 765.9 | 439.3 | 2358.2 |

**Table 40: Maritime Link Imports (GWh) under Discretionary Block Sensitivities (Case 9)**

| | Maritime Link Base Blocks | Discretionary Block (On-Peak) | Discretionary Block (Off-Peak) | Maritime Link Total |
|---|---|---|---|---|
| Sensitivity A (Base Case) | 1153.3 | N/A | N/A | 1153.3 |
| Sensitivity F (Discretionary Block, Config A) | 1153.3 | 276.1 | N/A | 1429.5 |
| Sensitivity N (High Price Discretionary Block, Config A) | 1153.3 | 199.7 | N/A | 1353.0 |
| Sensitivity O (Low Price Discretionary Block, Config A) | 1153.3 | 426.4 | N/A | 1579.7 |
| Sensitivity X (Discretionary Block, Config B) | 1153.3 | 415.3 | 215.9 | 1784.5 |
| Sensitivity Y (High Price Discretionary Block, Config B) | 1153.3 | 309.1 | 124.6 | 1587.1 |
| Sensitivity Z (Low Price Discretionary Block, Config B) | 1153.3 | 616.0 | 224.1 | 1993.4 |

Table 41 shows the annual production cost and production cost savings for Case 8 and 9 under each of the Discretionary Block sensitivities. The inclusion of the Maritime Link Discretionary Block reduces production cost of the thermal operating fleet between $17.4 and $77.2 million depending on the case and sensitivity selected.

**Table 41: Production Costs ($M) under Different Maritime Discretionary Block Schemes**

| | Case 8 (M$) | Case 9 (M$) | Case 8 Savings (M$) | Case 9 Savings (M$) |
|---|---|---|---|---|
| Sensitivity A (Base Case) | 481.4 | 415.6 | - | - |
| Sensitivity F (Discretionary Block, Config A) | 452.8 | 393.8 | 28.6 | 21.9 |
| Sensitivity N (High Price Discretionary Block, Config A) | 459.2 | 398.2 | 22.2 | 17.4 |
| Sensitivity O (Low Price Discretionary Block, Config A) | 445.4 | 385.3 | 36.0 | 30.3 |
| Sensitivity X (Discretionary Block, Config B) | 414.5 | 372.1 | 66.9 | 43.5 |
| Sensitivity Y (High Price Discretionary Block, Config B) | 429.1 | 383.5 | 52.3 | 32.1 |
| Sensitivity Z (Low Price Discretionary Block, Config B) | 404.3 | 360.9 | 77.2 | 54.8 |

As noted in Section 6 and in Section 7.2.7.2, the Maritime Link presents the possibility of providing a valuable flexible resource for NSPI. For the 35-year and 5-year supplemental power blocks, tight power and energy constraints were given. These blocks were dispatched conservatively using DAH information. The tight energy constraints (as noted elsewhere) are very constraining. Nevertheless, using this ML discretionary block (or the main blocks differently) might produce some benefits. For example the main block could be dispatched in the peak 16 hours at 154 MW, retaining full +/- 40MW for operational agility. The discretionary block, being largely free of daily energy constraints, but subject to maximum power constraints, presents a further opportunity for NSPI to procure valuable flexibility.

## 7.9 Thermal Plant Flexibility and Cycling

### 7.9.1 Minimum Steam Turbine requirements of [redacted] instead of [redacted] (Sensitivity G)

The Base Case (aka, Sensitivity A), has a constraint that [redacted] out of 11 steam units (ST) must be online and generating at any given time. This constraint, which was provided by NSPI, is driven by system stability considerations. Sensitivity G considers a scenario where the number of required online STs is reduced to [redacted] at any given time. This case does not demonstrate that relief of that constraint (from [redacted] to [redacted] is possible; rather it is intended to quantify any possible operational benefits that could result. Relieving a system constraint would be expected to provide more operational flexibility and result in lowering of the system costs. Results are shown in the following Figure 182, Figure 183, and Table 42.

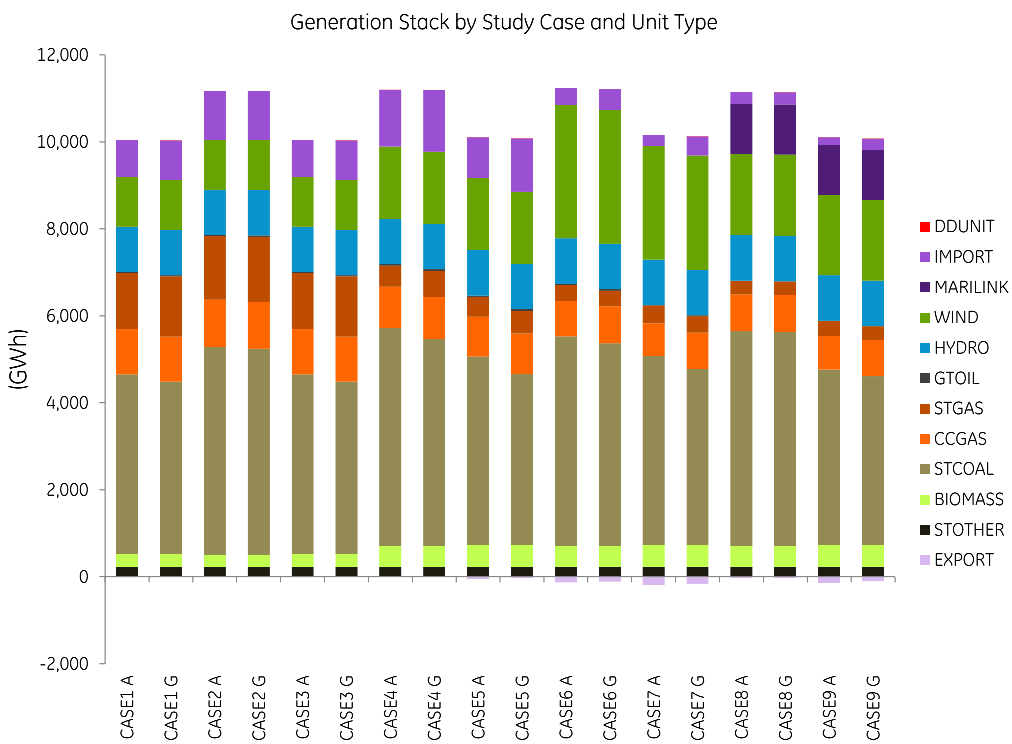



**Figure 182: Comparison of Generation Stack in Sensitivity G with the Base Case**

[redacted]

**Figure 183: Comparison of Production Costs between Sensitivity G and the Base Case**

**THIS FIGURE IS CONFIDENTIAL**

**Table 42: Comparison of Production Costs ($M) between Sensitivity G and the Base Case**

| | CASE | CASE | CASE | CASE | CASE | CASE | CASE | CASE | CASE |
|---|---|---|---|---|---|---|---|---|---|
| | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** |
| **Sensitivity A** | 359.8 | 417.2 | 359.8 | 446.8 | 384.1 | 457.4 | 409.2 | 436.6 | 373.2 |
| **Sensitivity G** | 360.8 | 417.4 | 360.8 | 451.3 | 388.6 | 461.5 | 410.7 | 436.7 | 371.3 |

Figure 184 depicts the amount of wind curtailment and exports in the Base Case and Sensitivity G.

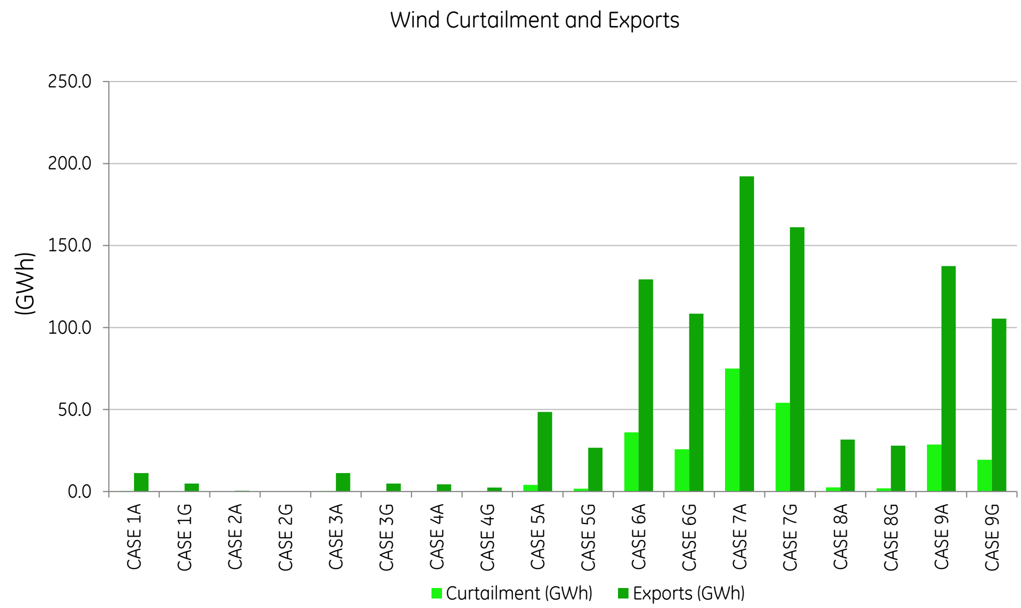



**Figure 184: Wind Curtailment and Exports in Scenarios A and G**

In the preceding figures we observe relatively small differences in production costs between Sensitivity G and the Base Case. The least impact is observed in Study Case 8. Contrary to (our) expectations, reducing the must-run constraint slightly increases the overall operating cost, rather than reducing it in every case except Study Case 9. We also observe that exports and curtailments drop. These results suggest that there is little incentive for NSPI to try to relieve this particular operational constraint. There is a shift of generation from STCOAL units to Imports and also to STGAS and GTOIL units. Figure 185, Figure 186, and Figure 187 show the annual total generation, average number of starts, and average online hours of the coal plants.

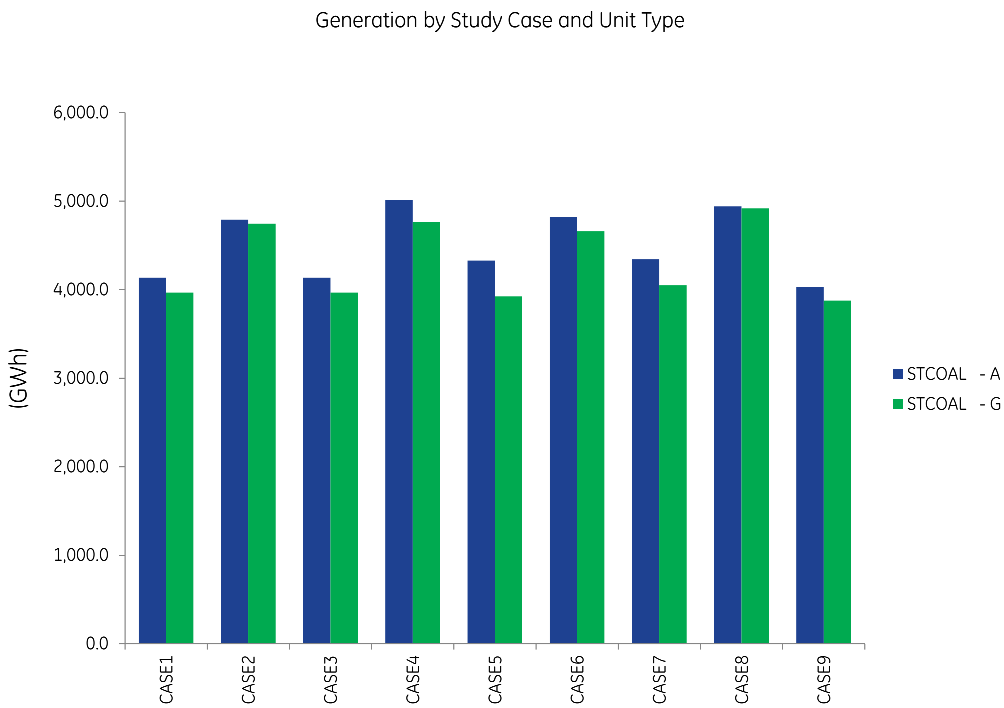



**Figure 185: Annual Generation by Coal Plants in Sensitivities A and G**

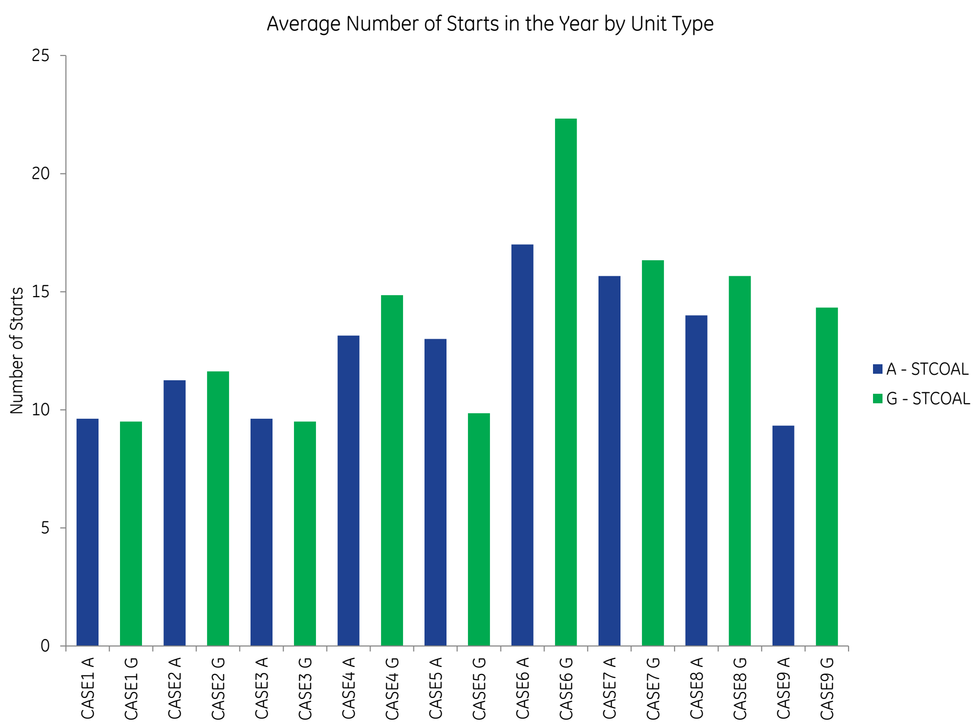



**Figure 186: Average Number of Starts by Coal Plants in Sensitivities A and G**

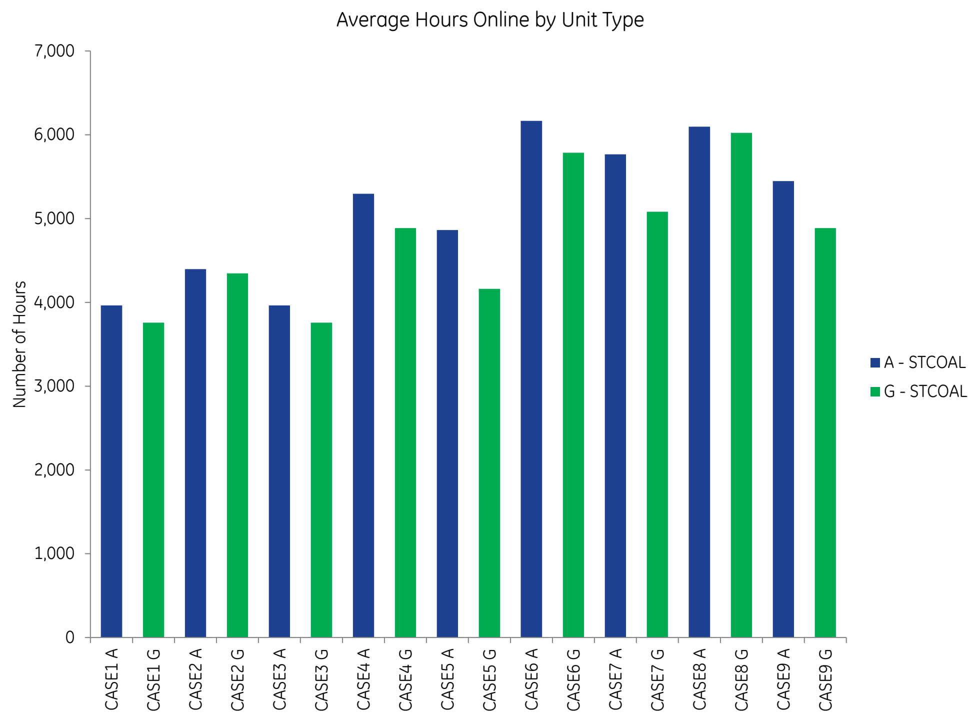



**Figure 187: Average Number of hours by Coal Plants in Sensitivities A and G**

In Sensitivity G, compared to Sensitivity A, a lower coal based generation is expected due to relaxing of the constraint. Another impact is higher average number of starts, since coal unit operations become more flexible. At the same time, average hours of operations drops. These results are consistent with the fact that fewer coal units will be running at times, but the total energy from coal only declines slightly. This means some runs will be rather short.

Figure 188 compares the production cost of steam coal plants across study cases under the same sensitivities. As expected, production costs drop due to the relaxing of the constraint.

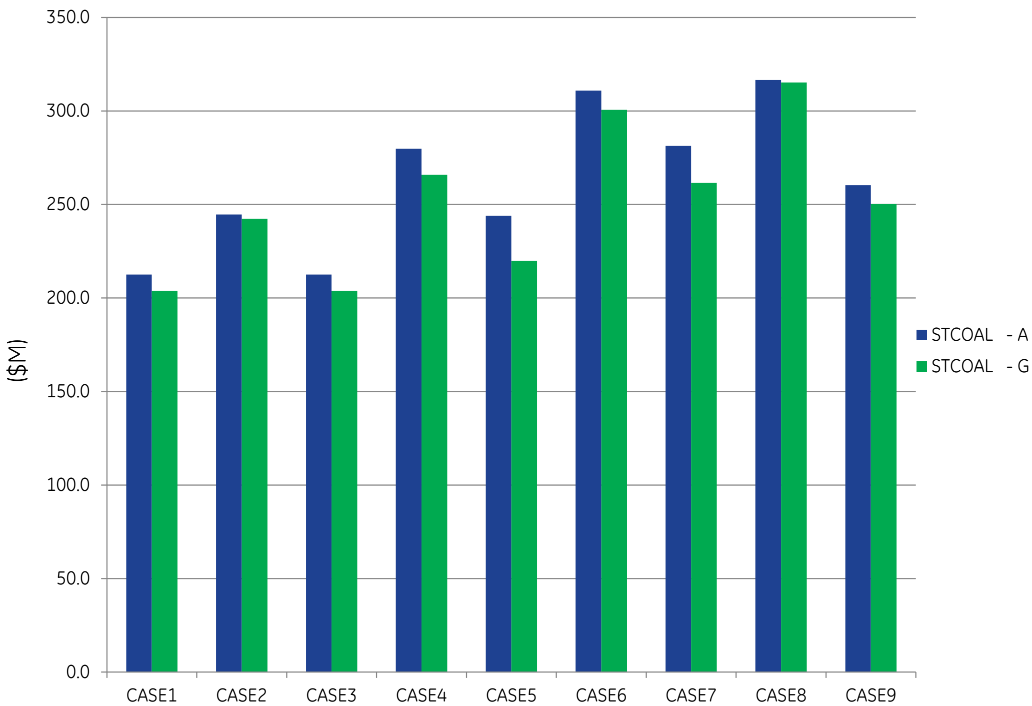



**Figure 188: Comparison of Production Costs of Steam Coal Units between Sensitivity G and the Base Case**

### 7.9.2 New Flexible Gas Generation Added (LMS100) (Sensitivity H)

Sensitivity H adds an additional 100 MW flexible generator at the Onslow node over the Base Case installed generation. The unit has a HR of about 8,300 Btu/kWh, a one hour minimum up and minimum down times, a $4.50/MWh VOM and a $0 start-up cost. The unit is added to provide capacity and is used to mitigate wind forecast error. As shown later in Section 8, our reliability analysis and wind capacity evaluation section, the study case 7 is about 100-150 MW short of capacity, and hence, an efficient flexible unit might be a welcome addition.

As depicted in Figure 189 and Figure 190, the main impact in early years is the GTGAS (i.e. the new unit) tends to displace coal (STCOAL), and in later years it tends to displace STGAS generation. The new unit also tends to displace NB Imports. The change in generation of these unit types are also reflected in their costs, and the shift in relative costs over the period of the study. This has been evident in several of the sensitivities. Overall, in each case, the production costs are lower in the Sensitivity H compared to the Base Case, by virtue of having an additional flexible and economic resource.

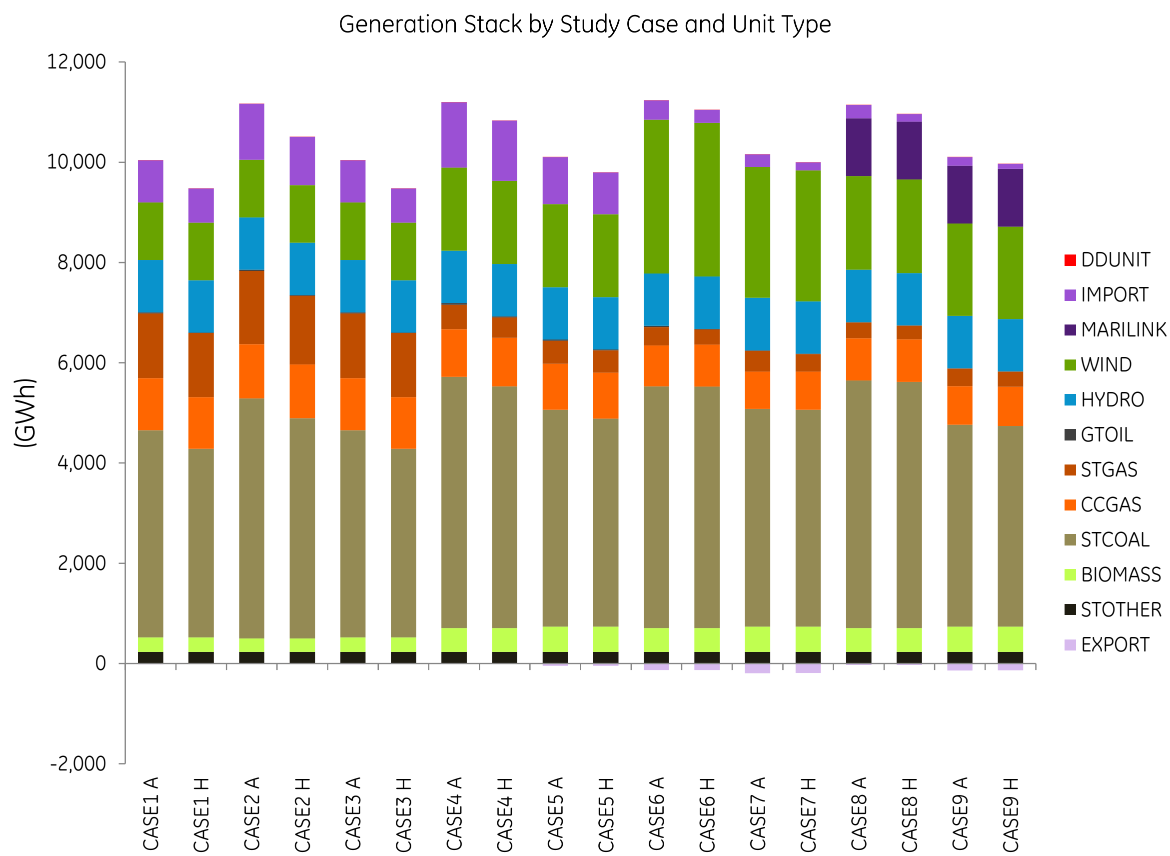



**Figure 189: Comparison of Generation Stack in Sensitivity H with Base Case**

[redacted]

**Figure 190: Comparison of Production Costs between Sensitivity H and the Base Case**

**THIS FIGURE IS CONFIDENTIAL**

Table 43 provides a comparison of production costs between Sensitivity H and the Base Case.

**Table 43: Comparison of Production Costs between Sensitivity H and the Base Case ($M)**

| | CASE 1 | CASE 2 | CASE 3 | CASE 4 | CASE 5 | CASE 6 | CASE 7 | CASE 8 | CASE 9 |
|---|---|---|---|---|---|---|---|---|---|
| **Sensitivity A (Base Case)** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Sensitivity H (Flexible Gas)** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| **Savings ($M)** | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

Another impact of an additional flexible resource, as shown in Figure 191, is a significant decrease in NB Imports. Interestingly, as indicated in Table 44, there is only a slight reduction in exports and curtailed energy.

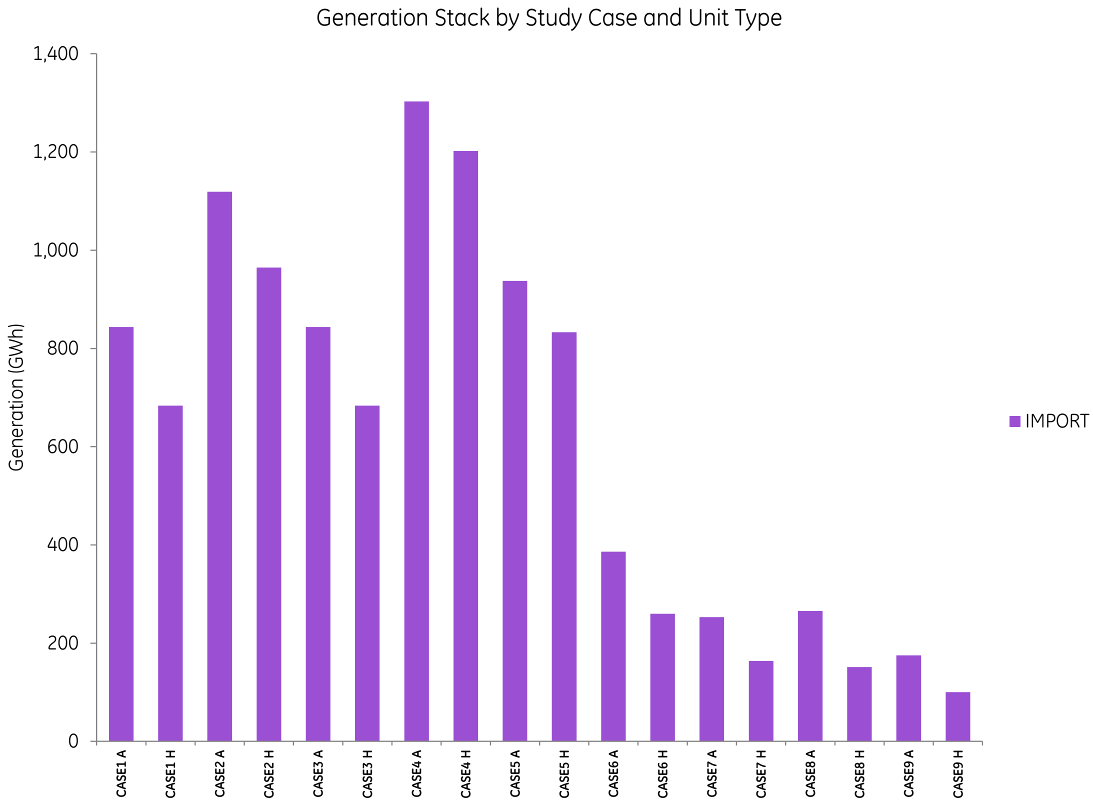



**Figure 191: NB Import Levels With and Without the LMS100**

**Table 44: Annual Exports and Curtailment (GWh) in Sensitivities A&H**

| | CASE | CASE | CASE | CASE | CASE | CASE | CASE | CASE | CASE |
|---|---|---|---|---|---|---|---|---|---|
| | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** |
| **Sensitivity A Exports** | 11.2 | 0.4 | 11.2 | 4.4 | 48.5 | 129.3 | 192.2 | 31.7 | 137.5 |
| **Sensitivity H Exports** | 9.9 | 0.4 | 9.9 | 4.6 | 47.1 | 129.0 | 191.4 | 31.1 | 136.7 |
| | | | | | | | | | |
| **Sensitivity A Curtailment** | 0.3 | 0.0 | 0.3 | 0.0 | 4.1 | 36.1 | 75.0 | 2.6 | 28.6 |
| **Sensitivity H Curtailment** | 0.3 | 0.0 | 0.3 | 0.0 | 4.1 | 36.1 | 74.7 | 2.5 | 28.2 |

The total annual cost savings, as summarized in Table 43, vary between $[redacted]M and $[redacted]M. There would also be a small savings from the reduction in curtailment. In addition to these savings, there are some possible savings due to reduction in variable cost for maneuvering the coal and combined cycle plants. This aspect is discussed further in Section 7.9.5 below, but additional savings from this variable cost reduction could possibly be as high as $[redacted]M per year.

NSPI has a variety options for flexible gas fired generation additions. The LMS100 used for this illustration has very good heat rates over a wide operating range. It is clean and it has and good starting characteristics. At 100MW, as noted, the capacity may be welcome. However, we have not attempted to identify or quantify the "best" option. Other, small aero-derivative gas turbines are available in smaller MW ratings, and also have high flexibility and low costs for maneuvering. Further, there a variety of generation options that are driven by gas reciprocating engines. These units which range in rating from a few MW up to close to 20MW are small, clean, efficient, quickly installed and very fast starting. *Very roughly*, the capital cost of these technologies is in the neighborhood of $800/kW. The results presented in Section 8, suggest that NSPI may need to add capacity (beyond the wind and ML additions). In which case, it is very important the operational flexibility of new resources be a major consideration in the procurement of those new resources.

Figure 192 shows that the extra capacity and flexibility of the new gas unit tends to reduce the need to call on demand response.

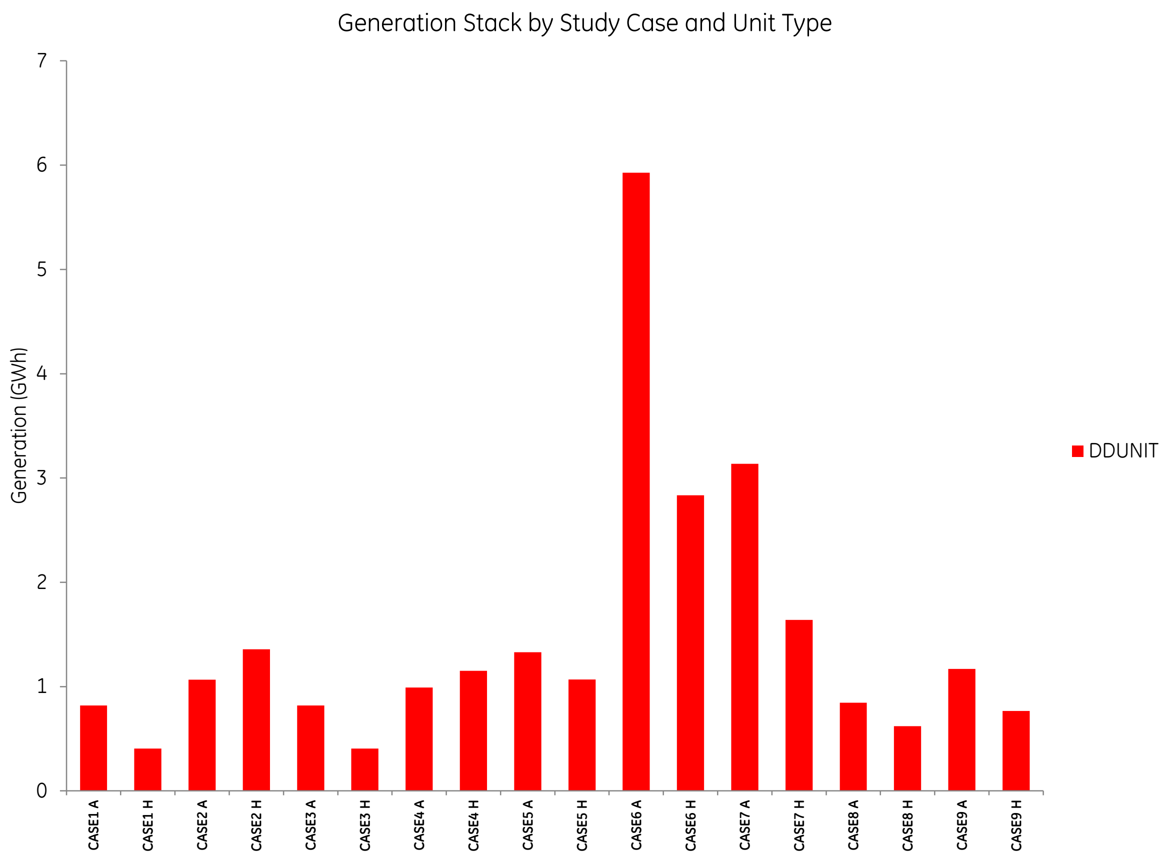



**Figure 192: DR Levels With and Without the LMS100**

### 7.9.3 Increased Minimums on Steam Turbines (Sensitivity T)

In the event that wind plants cannot be dispatched on a sub-hourly basis (as discussed in Section 7.2.7), they will need to be curtailed in order to provide down maneuvering room on thermal plants. This will occur primarily under low load conditions, and so typically the only economic units that will be available to provide this function are the coal plants. The operational implication is that online steam coal units will need to be dispatched (on an hourly average basis) at a higher point that would be possible if down maneuvering room was provided by the wind plants (or some other resource). This sensitivity is intended to examine the impact of procuring down reserve from these plants rather than from the wind plants. To model this in Sensitivity T, the minimum loads of the 11 steam turbines on the system (Coal Plants and Tufts Cove 1, 2, and 3) are increased by 6 MW each. This change, in addition to the [redacted] operating nomogram, ensures that there is always, at a minimum, 24 MW of REG Down available from the ST units. This 24 MW of down regulation is based on the average incremental variability imposed by the wind, as discussed in the statistical analysis of Section 3.

Figure 193 presents a comparison of the generation by type for each study case in Sensitivities A and T.

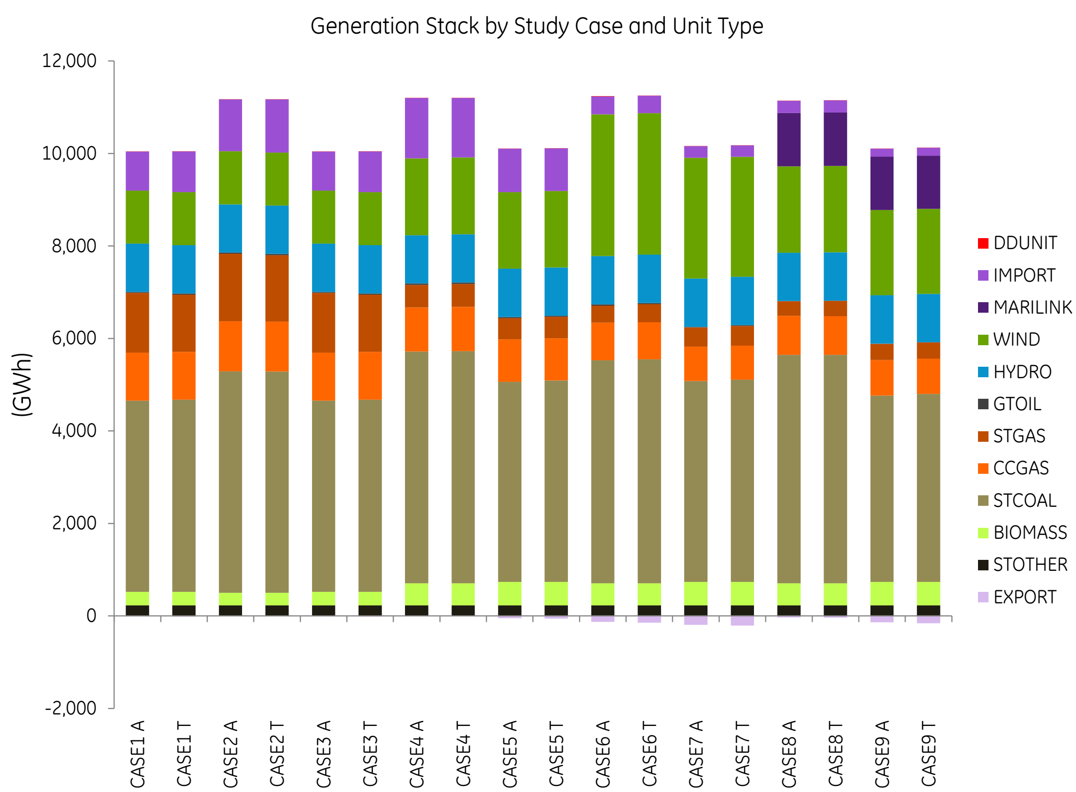


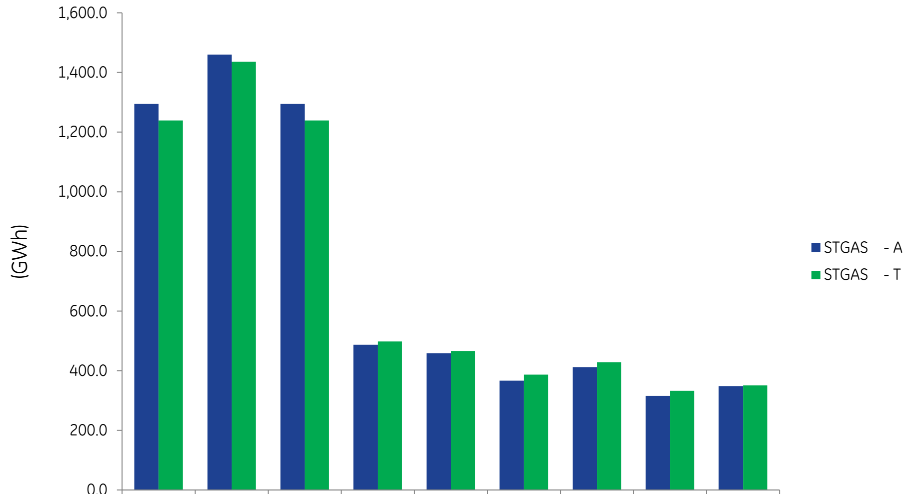

**Figure 193: Impact of Increasing Steam Unit Minimum Loads on Generation Stack**

Since the generation differences between the two sensitivities are not clearly discernible from the above figure, we also provide generation data by individual unit types. Figure 194 presents the steam coal generation. As can be observed in Figure 194, the impact on coal based generation is minimal.


| | CASE1 | CASE2 | CASE3 | CASE4 | CASE5 | CASE6 | CASE7 | CASE8 | CASE9 |
|---|---|---|---|---|---|---|---|---|---|
| STCOAL - A | 4,134.6 | 4,790.6 | 4,134.6 | 5,014.0 | 4,328.9 | 4,821.0 | 4,342.7 | 4,939.4 | 4,027.5 |
| STCOAL - T | 4,156.6 | 4,786.4 | 4,156.6 | 5,023.7 | 4,358.8 | 4,845.1 | 4,374.2 | 4,941.5 | 4,065.9 |

**Figure 194: Impact of Increasing Steam Unit Minimum Loads on Steam Coal Generation**

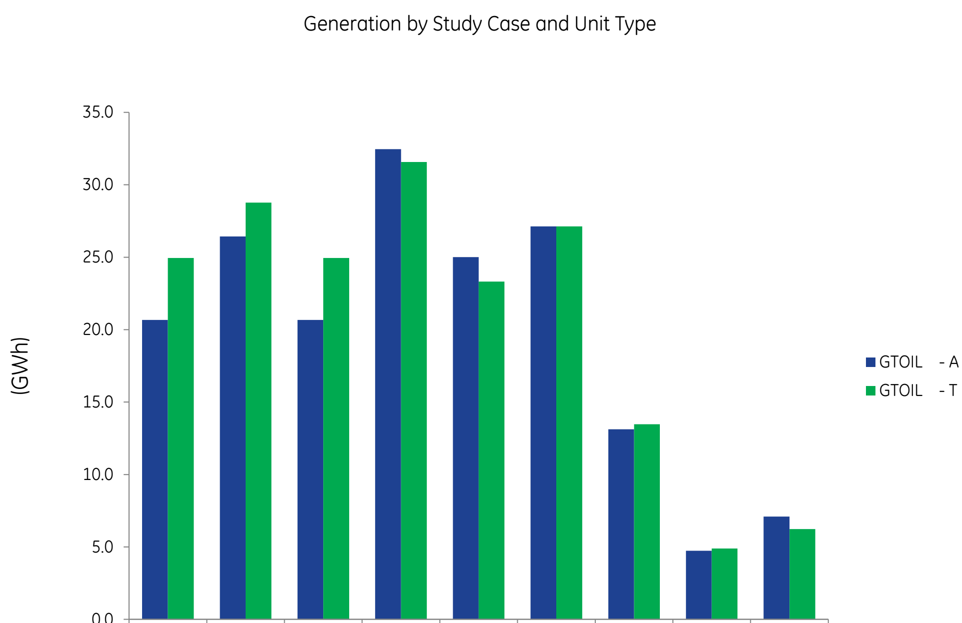
Figure 195 presents the steam gas generation. Although the differences appear to be greater than those of the steam coal units, the appearances are misleading, since the scale of the y-axis is greater by almost a factor of 4.




| | CASE1 | CASE2 | CASE3 | CASE4 | CASE5 | CASE6 | CASE7 | CASE8 | CASE9 |
|---|---|---|---|---|---|---|---|---|---|
| STGAS - A | 1,294.5 | 1,459.9 | 1,294.5 | 487.0 | 458.4 | 366.9 | 412.2 | 315.7 | 348.7 |
| STGAS - T | 1,239.1 | 1,435.8 | 1,239.1 | 497.9 | 466.2 | 386.9 | 428.2 | 332.7 | 350.5 |

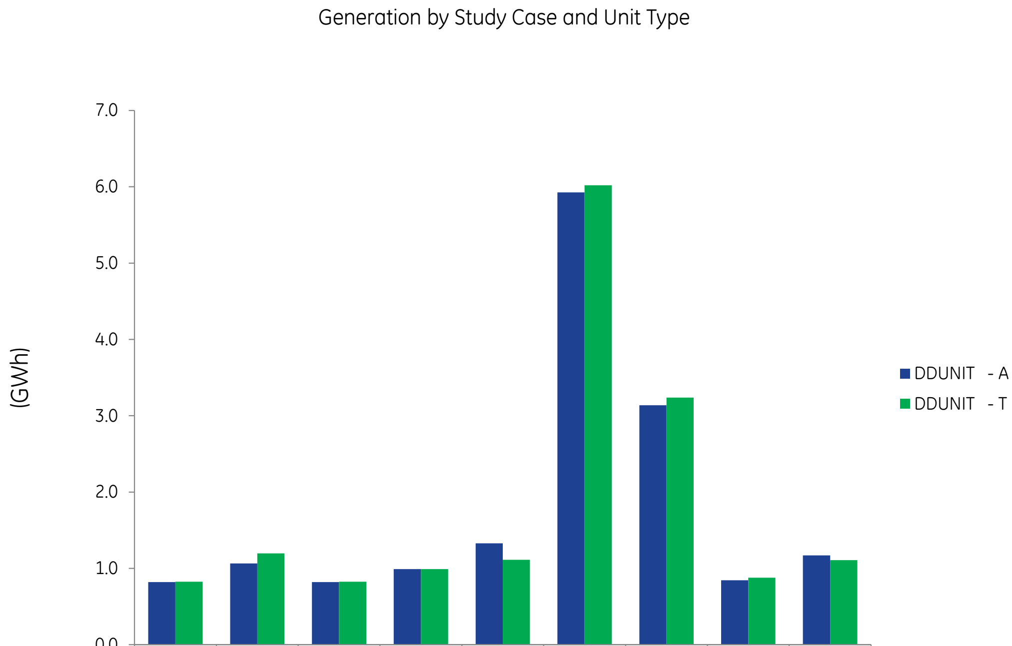
**Figure 195: Impact of Increasing Steam Unit Minimum Loads on Steam Gas Generation**

Figure 196, Figure 197, and Figure 198 show the impact on generation of oil based generation, demand response, and NB and ML imports, respectively. In all of these cases, the impacts, on absolute terms, are minimal.



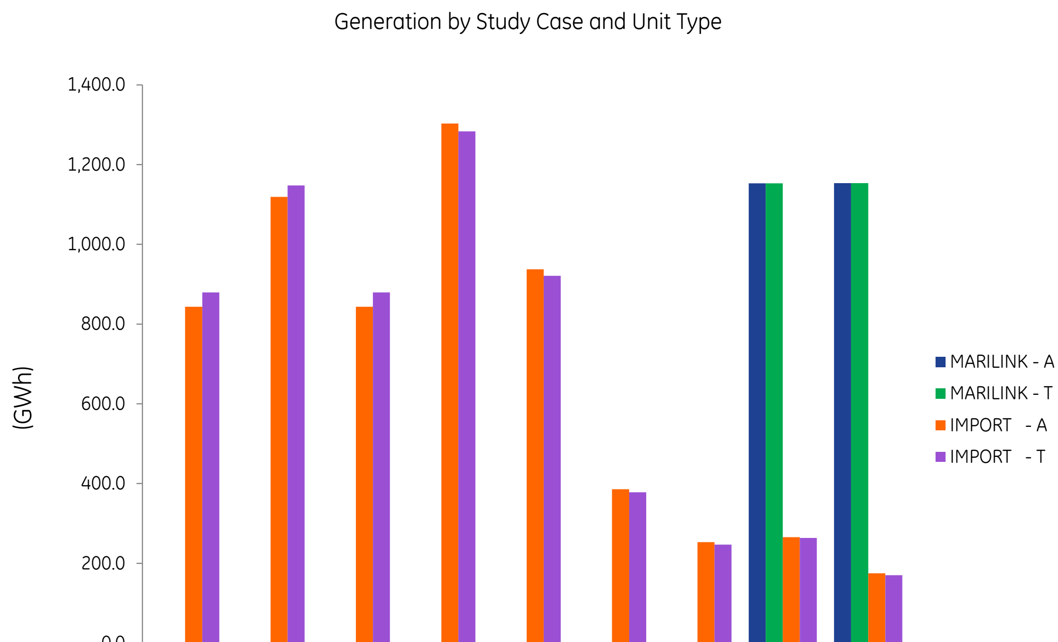

| | CASE1 | CASE2 | CASE3 | CASE4 | CASE5 | CASE6 | CASE7 | CASE8 | CASE9 |
|---|---|---|---|---|---|---|---|---|---|
| GTOIL - A | 20.7 | 26.4 | 20.7 | 32.5 | 25.0 | 27.1 | 13.1 | 4.7 | 7.1 |
| GTOIL - T | 24.9 | 28.8 | 24.9 | 31.6 | 23.3 | 27.1 | 13.5 | 4.9 | 6.2 |

**Figure 196: Impact of Increasing Steam Unit Minimum Loads on Oil-Fired Generation**




| | CASE1 | CASE2 | CASE3 | CASE4 | CASE5 | CASE6 | CASE7 | CASE8 | CASE9 |
|---|---|---|---|---|---|---|---|---|---|
| DDUNIT - A | 0.8 | 1.1 | 0.8 | 1.0 | 1.3 | 5.9 | 3.1 | 0.8 | 1.2 |
| DDUNIT - T | 0.8 | 1.2 | 0.8 | 1.0 | 1.1 | 6.0 | 3.2 | 0.9 | 1.1 |

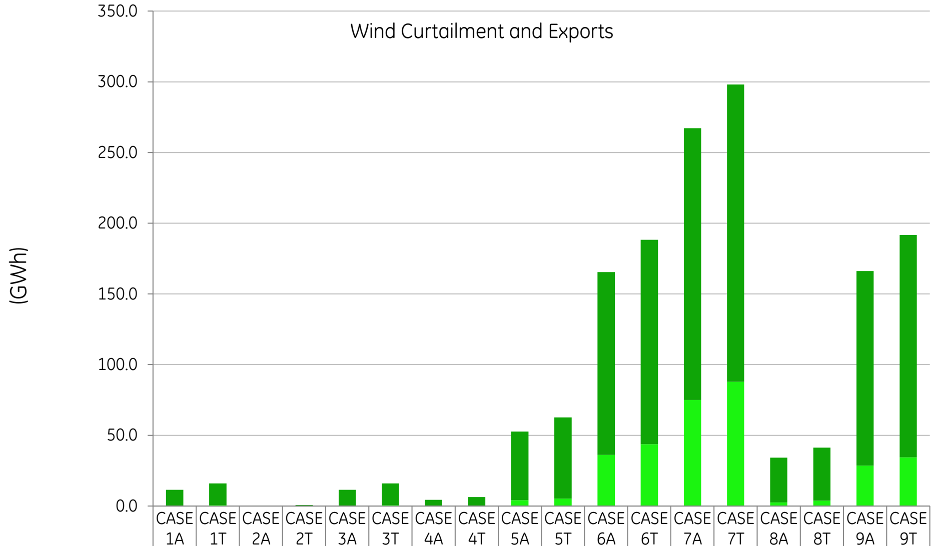
**Figure 197: Impact of Increasing Steam Unit Minimum Loads on Demand Response**




| | CASE1 | CASE2 | CASE3 | CASE4 | CASE5 | CASE6 | CASE7 | CASE8 | CASE9 |
|---|---|---|---|---|---|---|---|---|---|
| MARILINK - A | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,153.0 | 1,153.3 |
| MARILINK - T | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,153.0 | 1,153.3 |
| IMPORT - A | 843.5 | 1,118.9 | 843.5 | 1,302.9 | 937.6 | 386.0 | 252.9 | 265.4 | 174.9 |
| IMPORT - T | 879.6 | 1,148.0 | 879.6 | 1,283.4 | 920.9 | 378.2 | 246.6 | 263.5 | 170.3 |

**Figure 198: Impact of Increasing Steam Unit Minimum Loads on NB and Maritime Link Imports**

Figure 199 compares the impact of increasing steam unit minimum load on exports and wind curtailments. The greater impacts are in the out years, with significantly more exports and also wind curtailments. Higher wind curtailments are the result of higher minimum dispatch requirements on steam units. The coal plants can not back down as far, increasing the frequency and amount of wind that must be either exported or curtailed. The trend across all of the cases is for a roughly 10% increase in the combination of exports and curtailments.




| | CASE 1A | CASE 1T | CASE 2A | CASE 2T | CASE 3A | CASE 3T | CASE 4A | CASE 4T | CASE 5A | CASE 5T | CASE 6A | CASE 6T | CASE 7A | CASE 7T | CASE 8A | CASE 8T | CASE 9A | CASE 9T |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Exports (GWh) | 11.2 | 15.3 | 0.4 | 0.7 | 11.2 | 15.3 | 4.4 | 6.3 | 48.5 | 57.4 | 129.3 | 144.6 | 192.2 | 210.3 | 31.7 | 37.6 | 137.5 | 157.3 |
| Curtailment (GWh) | 0.3 | 0.7 | 0.0 | 0.0 | 0.3 | 0.7 | 0.0 | 0.0 | 4.1 | 5.3 | 36.1 | 43.7 | 75.0 | 87.8 | 2.6 | 3.8 | 28.6 | 34.4 |

**Figure 199: Impact of Increasing Steam Unit Minimum Loads on Exports and Curtailment**

Cost impacts are shown in Figure 200, and Table 45. The largest cost impacts are in the early years. In general, requiring a higher minimum load on steam units increases the operational costs, particularly when the units are idling at their minimum load.

[redacted]

**Figure 200: Impact of Increasing Steam Unit Minimum Loads on Production Costs**

**THIS FIGURE IS CONFIDENTIAL**

**Table 45: Impact of Higher Steam Unit Minimum Load on Production Costs ($M)**

| | CASE | CASE | CASE | CASE | CASE | CASE | CASE | CASE | CASE |
|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
| Sensitivity A (Base Case) | 359.8 | 417.2 | 359.8 | 446.8 | 384.1 | 457.4 | 409.2 | 436.6 | 373.2 |
| Sensitivity T (Higher ST Minimum) | 363.1 | 419.7 | 363.1 | 446.9 | 384.4 | 459.1 | 411.6 | 437.8 | 374.4 |
| Delta ($M) | 3.3 | 2.6 | 3.3 | 0.2 | 0.3 | 1.8 | 2.4 | 1.1 | 1.2 |

The net result of this investigation is that cost implications of pre-curtailing wind and using the coal steam plants for down reserves is not great, but that the combined export and curtailment of wind power increases about 10%.

Table 46 and Table 47 present the impact of higher steam unit minimum load on CO2 and SOx emissions. Again, on this scale, the impacts are minimal.

**Table 46: Impact of Increasing Steam Unit Minimum Loads on CO2 Emissions**

| | CASE | CASE | CASE | CASE | CASE | CASE | CASE | CASE | CASE |
|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
| Sensitivity A | 6,187 | 7,037 | 6,187 | 6,591 | 5,809 | 6,262 | 5,721 | 6,325 | 5,320 |
| Sensitivity T | 6,193 | 7,039 | 6,193 | 6,612 | 5,843 | 6,296 | 5,765 | 6,335 | 5,360 |
| Change (%) | 0.1% | 0.0% | 0.1% | 0.3% | 0.6% | 0.5% | 0.8% | 0.2% | 0.8% |

**Table 47: Impact of Increasing Steam Unit Minimum Loads on SOX Emissions**

| | CASE | CASE | CASE | CASE | CASE | CASE | CASE | CASE | CASE |
|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
| Sensitivity A | 23.81 | 27.40 | 23.81 | 28.65 | 24.96 | 27.72 | 25.09 | 28.29 | 23.31 |
| Sensitivity T | 23.92 | 27.37 | 23.92 | 28.71 | 25.11 | 27.84 | 25.26 | 28.30 | 23.52 |
| Change (%) | 0.5% | -.01% | 0.5% | 0.2% | 0.6% | 0.5% | 0.7% | 0.0% | 0.9% |

### 7.9.4 Decreased Minimums on 2 Coal Units (Sensitivity U)

The two most utilized coal plants (with exception of must-run units PT Aconi and Lingan 3) are PT Tupper and Trenton 6. For Sensitivity U, the minimum loads of these units were reduced by 10 MW each to show the value of allowing steam turbines to turn down to lower load levels.

Figure 201, Figure 202, and Figure 203 show the impact of lower minimum loads on these two units on total generation by type, and also separately for steam coal, and the imports. Results show not a large absolute change.

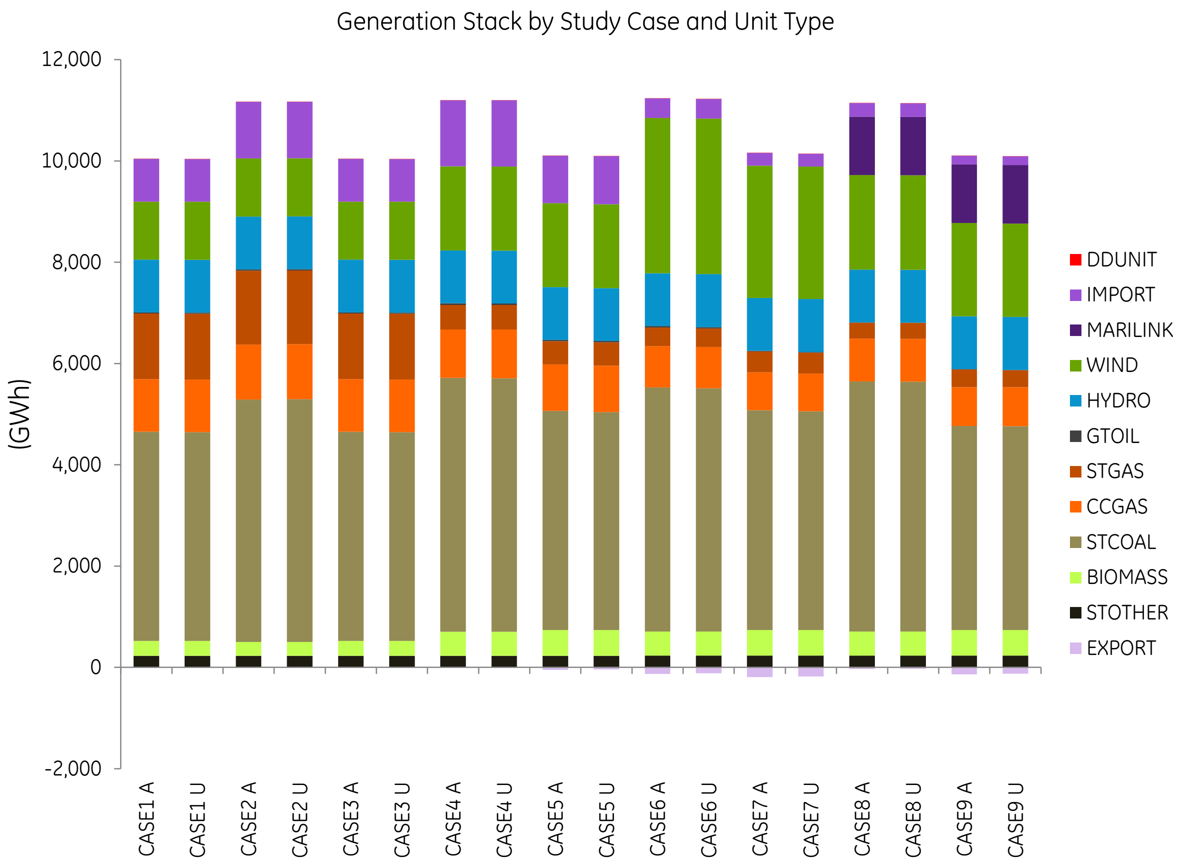
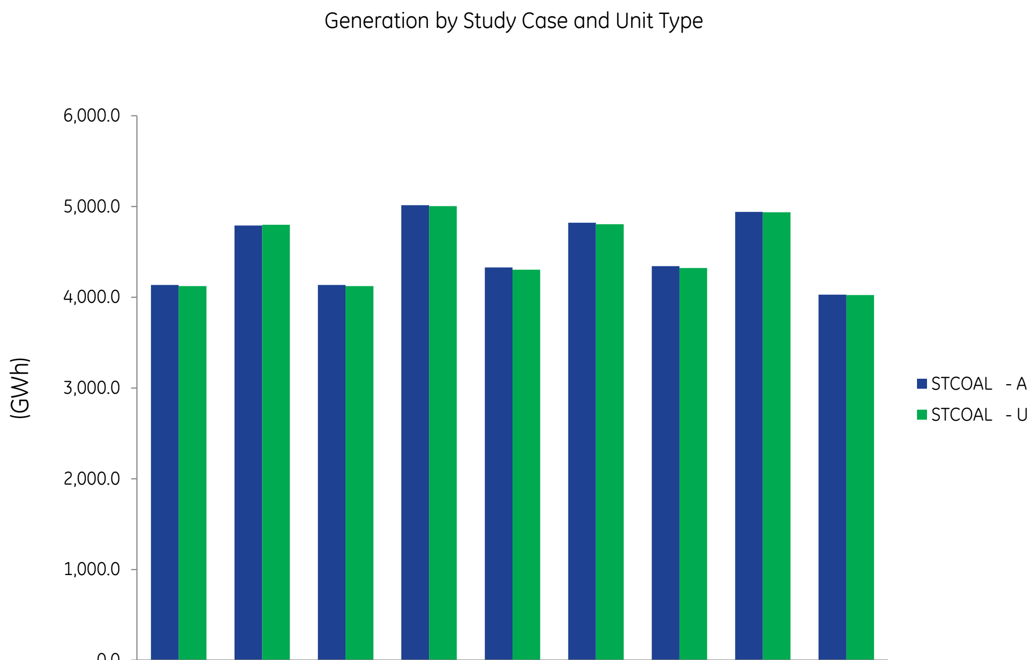



**Figure 201: Generation Stack under Sensitivity U**




| | CASE1 | CASE2 | CASE3 | CASE4 | CASE5 | CASE6 | CASE7 | CASE8 | CASE9 |
|---|---|---|---|---|---|---|---|---|---|
| STCOAL - A | 4,134.6 | 4,790.6 | 4,134.6 | 5,014.0 | 4,328.9 | 4,821.0 | 4,342.7 | 4,939.4 | 4,027.5 |
| STCOAL - U | 4,123.1 | 4,799.3 | 4,123.1 | 5,004.3 | 4,303.2 | 4,803.8 | 4,321.4 | 4,936.4 | 4,024.7 |

**Figure 202: Steam Coal Generation Stack under Sensitivity U**

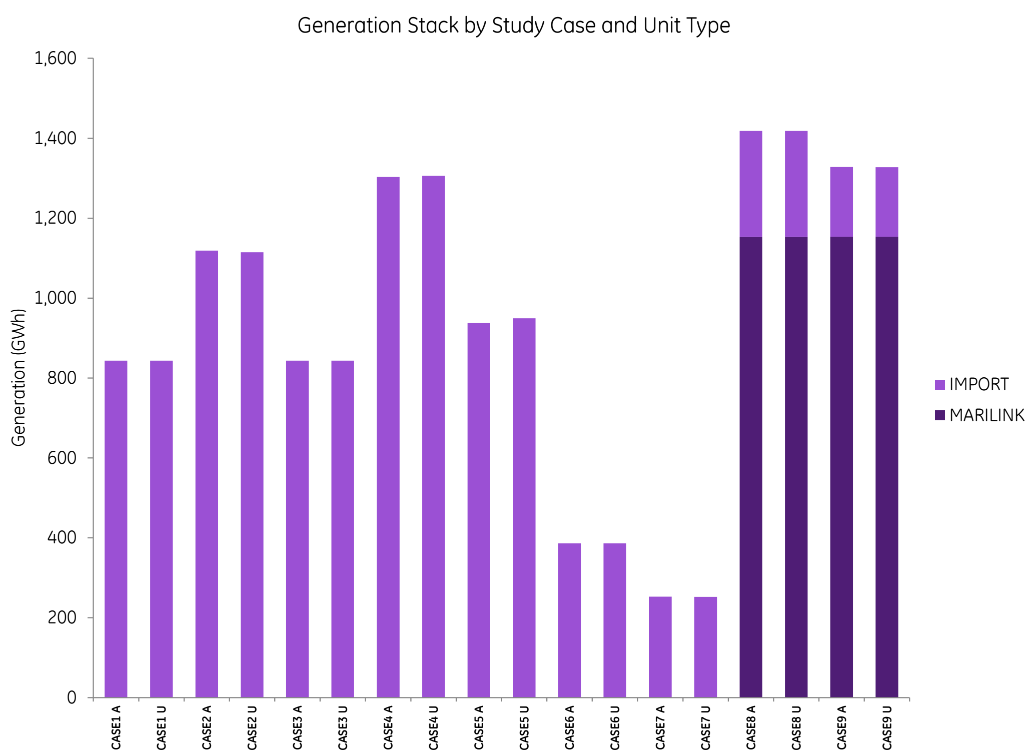



**Figure 203: NB and ML Imports under Sensitivity U**

Figure 204 and Table 48 present the cost impacts of reducing coal unit minimums. Again the results indicate minimal impact on costs.

[redacted]

**Figure 204: Production Costs Impact of Reducing Coal Minimums**

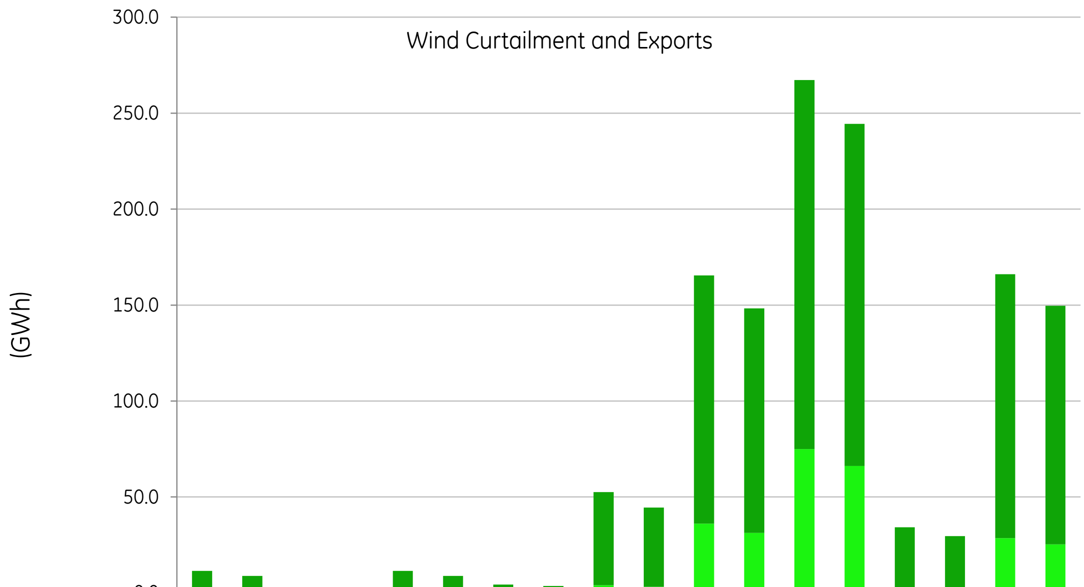
**THIS FIGURE IS CONFIDENTIAL**

**Table 48: Production Cost Impact of Reducing ST Coal Minimums ($M)**

| | CASE 1 | CASE 2 | CASE 3 | CASE 4 | CASE 5 | CASE 6 | CASE 7 | CASE 8 | CASE 9 |
|---|---|---|---|---|---|---|---|---|---|
| **Sensitivity A (Base Case)** | 359.8 | 417.2 | 359.8 | 446.8 | 384.1 | 457.4 | 409.2 | 436.6 | 373.2 |
| **Sensitivity U (Lower COAL Minimum)** | 359.6 | 416.9 | 359.6 | 446.4 | 383.7 | 456.4 | 407.9 | 436.3 | 371.0 |
| **Delta ($M)** | 0.2 | 0.3 | 0.2 | 0.4 | 0.3 | 1.0 | 1.3 | 0.3 | 2.1 |

The counter-intuitive increase in production costs could be a consequence of the asymmetry of the fleet. Day-ahead schedule, i.e., unit commitment, takes into account a wider range of available capacity, and hence it results in fewer units committed that sometimes increase the cost of occasional bad forecasts. This result is somewhat at odds with results seen in other studies. Closer inspection of heat-rates and other operational factors at deep turn-back may be useful.

Figure 205 compares the impact of reducing steam unit minimum load on experts and wind curtailments. The greater impacts are in the out years, with significantly lower exports and also wind curtailments. As might be expected, the relative impacts of lower coal unit minimums are the opposite of the impact of higher steam coal minimums.




| | CASE 1A | CASE 1U | CASE 2A | CASE 2U | CASE 3A | CASE 3U | CASE 4A | CASE 4U | CASE 5A | CASE 5U | CASE 6A | CASE 6U | CASE 7A | CASE 7U | CASE 8A | CASE 8U | CASE 9A | CASE 9U |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Exports (GWh) | 11.2 | 8.8 | 0.4 | 0.2 | 11.2 | 8.8 | 4.4 | 3.7 | 48.5 | 41.2 | 129.3 | 117.0 | 192.2 | 178.2 | 31.7 | 27.5 | 137.5 | 124.3 |
| Curtailment (GWh) | 0.3 | 0.1 | 0.0 | 0.0 | 0.3 | 0.1 | 0.0 | 0.0 | 4.1 | 3.3 | 36.1 | 31.3 | 75.0 | 66.2 | 2.6 | 2.1 | 28.6 | 25.3 |

**Figure 205: Exports and Curtailment in Sensitivity U**

### 7.9.5 Cycling Mileage

Increased coal plant cycling has a cost in terms of wear-and-tear. This is the subject of fierce debate and investigation in the industry today. Estimates of these costs vary wildly. Recent work sponsored by NREL [20], that includes current state-of-the-art estimates for these costs, showed that they would be expected to reduce the variable cost savings from wind energy between \$0.06 and \$2.0 per MWh of wind energy. Based on the amount of wind energy that could be operating on the Nova Scotia power system in the high wind penetration cases in 2020, the cycling costs could possibly be as high as \$6 million annually over and above the estimated production costs. Those costs are not reflected in our analysis here.

One measure of operational maneuvering is "mileage" – the sum of the absolute value of the total hourly MW changes in dispatch. It is calculated by summing up the absolute value of hourly MW change of each unit over the year. It is a measure of a unit's movement up and down on its loading range.

Figure 206 illustrates the average daily cycling mileage of all the coal plants in selected Study Cases in Sensitivity D (No NB Imports). The highest mileage is achieved by the PT Aconi unit. The lowest mileage is achieved by Lingan units.

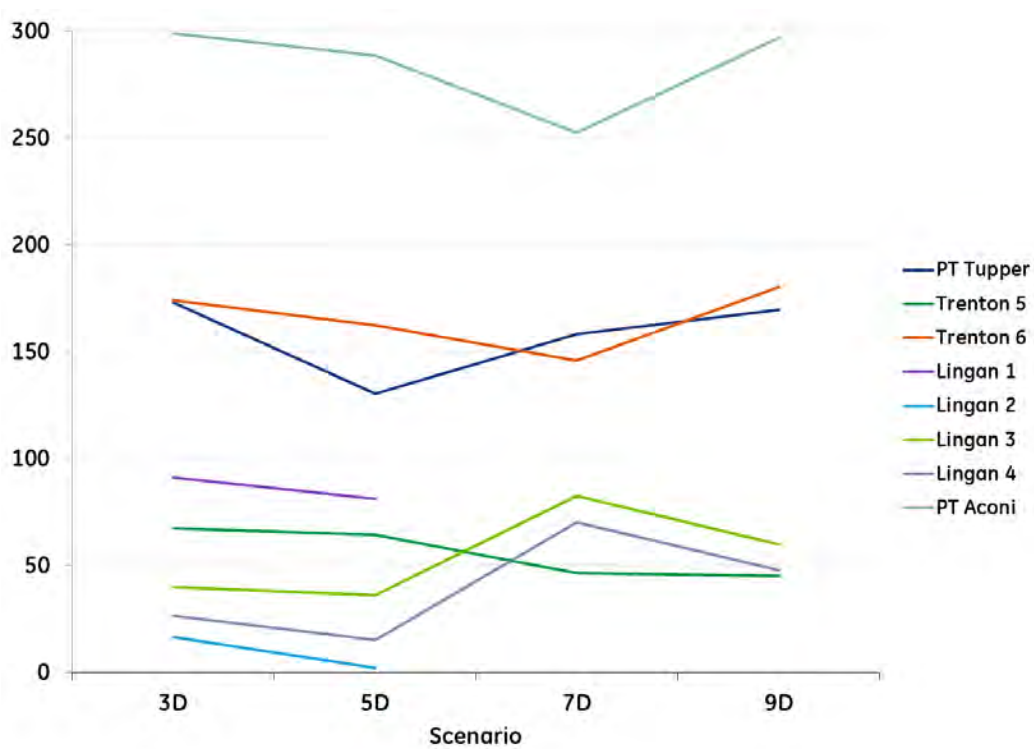



**Figure 206: Average Daily "Cycling Mileage" of Coal Units across Selected Study Cases in Sensitivity D**

Another perspective on cycling mileage is provided in Figure 207 which compares the mileage of the D Sensitivity (no imports) to the Base Case A. The annual totals for all the coal plants are summarized in Table 49. The mileage on the coal plants increases about 20% to Case 7 and about 30% to Case 9. The Maritime Link base being higher than case 7 is a little counter intuitive, but probably reflects the fact that other more expensive maneuvering plants are pushed out of the stack more often. This is a different facet of the fact that energy from the Maritime Link has a higher marginal value than the wind power (as discussed in Section 7.2)

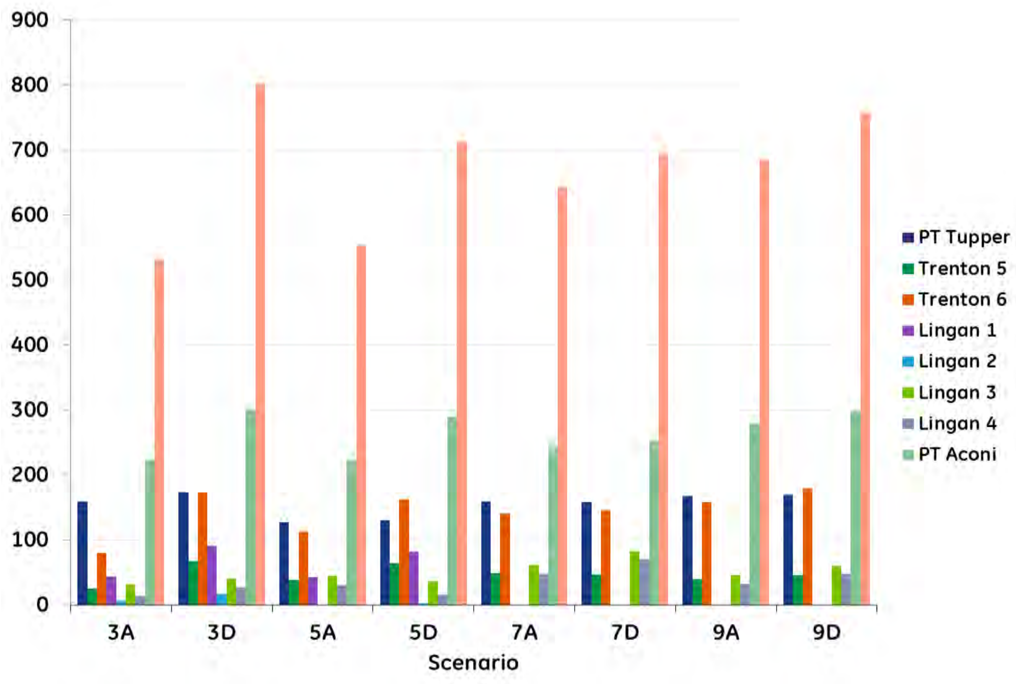



**Figure 207: Average Daily "Cycling Mileage" of Coal Units across Selected Study Cases in Sensitivities A & D**

**Table 49: Total Annual Coal Fleet "Cycling Mileage" by Sensitivity**

| | CASE 3 | CASE 5 | CASE 7 | CASE 9 |
|---|---|---|---|---|
| **Sensitivity A** | 194,041 | 202,190 | 234,772 | 250,271 |
| **Sensitivity B** | 238,278 | 242,098 | 256,399 | 276,732 |
| **Sensitivity C** | 234,129 | 235,736 | 264,576 | 277,414 |
| **Sensitivity D** | 292,765 | 259,932 | 253,044 | 276,554 |

The total wind energy varies by Case, and was summarized above in Table 16. The totals are roughly in the range of 2000 to 3,000 GWh of wind energy. If the NREL analysis of an incremental cost of $0.06/MWh to $2.0/MWh of wind applies to NSPI plants – a speculation that is not substantiated here – then the total incremental costs to NSPI of integrating this level of wind energy will be on the order of $0.12M/year to $6.0M/year. Quantifying this cost more precisely requires extensive study and testing that is out of the scope of this study. However, these possible costs do provide some useful context. Capital intensive measures to reduce the cycling of the coal plants, which could include addition of other resources, including generation, demand control, and energy storage, would be unlikely to be justified solely on this savings. Improved operational strategies, perhaps based on better information (e.g. better wind forecasting) or enhanced control schemes (e.g. better use of Wreck cove or other hydro resources, or the Maritime Link) might be well justified to realize these savings.

## 7.10 Demand Response

### 7.10.1 Role of Demand Response

Demand Response (DR) covers the whole range of demand side resources from direct load control (operators disconnect load on demand) to responsive demand based on dynamic pricing and other control signals (price schedules or signals are passed to customers to incent load reduction). The advent of new technology is enabling more sophisticated and engaging demand response options that, coupled with dynamic pricing, are making possible more flexible and robust customer response behavior. Smart Grid innovations in advanced metering infrastructure (AMI), wide area network (WAN) and home area network (HAN) communications, energy management systems (EMS), and smart appliances are making DR both technologically feasible and economically viable and are enabling wider deployment.

Despite the relatively slow economy, utility and retail DR programs are being driven by state regulatory commissions and by utilities' need of managing their peak demand and reducing long-term capacity costs. In U.S., FERC orders #719 and #745 are expected to open up opportunities for participation of demand resources in the wholesale market, with DR to be paid ISO locational marginal prices and to be treated similar to supply side resources in energy, capacity, and ancillary services markets.

DR benefits utilities, customers, and the power system in a number of ways, including:

- Direct and indirect benefits to customers in addition to opportunities for customer choice, control and contribution to their energy equation;
- Reduced need for future investments in generation and transmission;
- Increased economic efficiency by price responsive (and price-elastic) demand; and
- Increased system reliability due to peak load curtailment or as an ancillary services provider.

Indeed, we foresee a greater need for DR as an ancillary service in a world with more wind and solar power, where DR can act as reserve to cover the forecast errors and provide a very low cost approach for providing reserves. This becomes particularly important for the inevitable worst-case wind or solar forecast error scenario that leaves an operator short many GW of generation without much time to deploy reserves.

FERC estimates that, if the current level of demand response is preserved through the next decade, DR would shave 38 GW off U.S. peak demand in the year 2019 and, with dynamic pricing, the total potential could range between 14% and 20% of peak demand or 138 to 188 GW depending on whether dynamic pricing is deployed on an opt-in basis or opt-out basis[2]. The Brattle Group estimates $65B in costs avoidance in US through 2030 from DR[3]. Hence, under the proper alignment of technology, pricing, and incentives, DR is expected to play a key role in the value proposition for smart grid and a key part of the grid of the future. DR has been a largely untapped resource with significant potential. The idea of addressing a grid challenge by deploying software and minimal hardware—without building large power plants or new T&D equipment—is simply too valuable to overlook NARC has recognized demand response as a critical element [15].

The GE MAPS unit designated as DDUNIT is a stand-in for all types of Demand Response (DR) type action or resources that would constitute the resources of last resort after all other less expensive resources in the system have been utilized. Hence, the Base Case DDUNIT is modeled similar to a thermal plant with very high operating costs that is kicked in when all other resources have been exhausted.

DR may or may not include Unserved Energy, since Unserved Energy (i.e., not serving the customers) can be considered to be simply a DR of the most expensive kind. An actual DR resource under a typical utility DR program, such as residential A/C unit or water heater under Direct Load Control (DLC) or a commercial or industrial load under Critical Peak Pricing (CPP) is not necessarily more expensive that a supply side generation resources. In fact, such resources have already proven to be a lower cost options in some of the capacity markets in the U.S. ISO markets.

The implications are that as the cost of DR drops (as expected with further experience and improvements in system architecture for monitoring, communication, and control, and other smart grid related technological enablers), such demand side resources may become more competitive with supply side resources, not only offering energy and capacity products, but also offering ancillary services of the types more appropriate for enabling further integration of renewable energy resources in the NSPI power grid.

### 7.10.2 Impact of Sensitivities on Demand Response

Figure 208, Figure 209, and Figure 210 present the level of DR utilization in sensitivities that resulted in the highest level of call on DR resources, i.e., Sensitivity A, B, C, and D. Note that

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[2] FERC, "National Action Plan on Demand Response", June 17, 2010

[3] The Brattle Group, "Demand Response & Energy Efficiency, The Long View", August 12, 2010

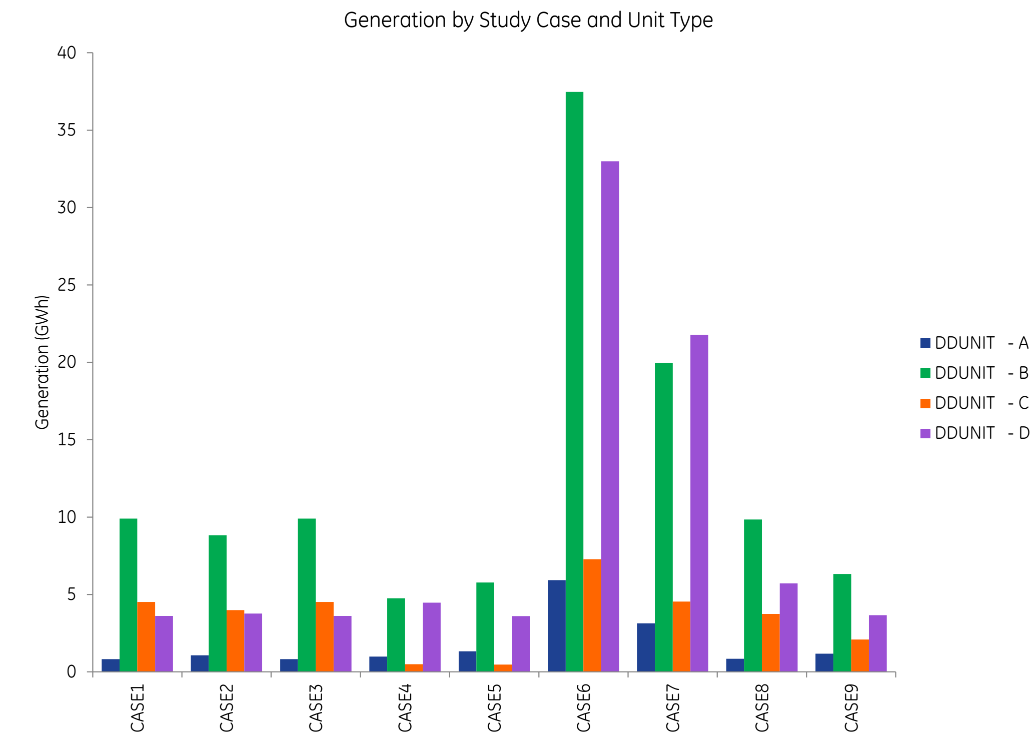


**Figure 208: Level of DR Resource Utilization in Sensitivities A, B, C, and D**

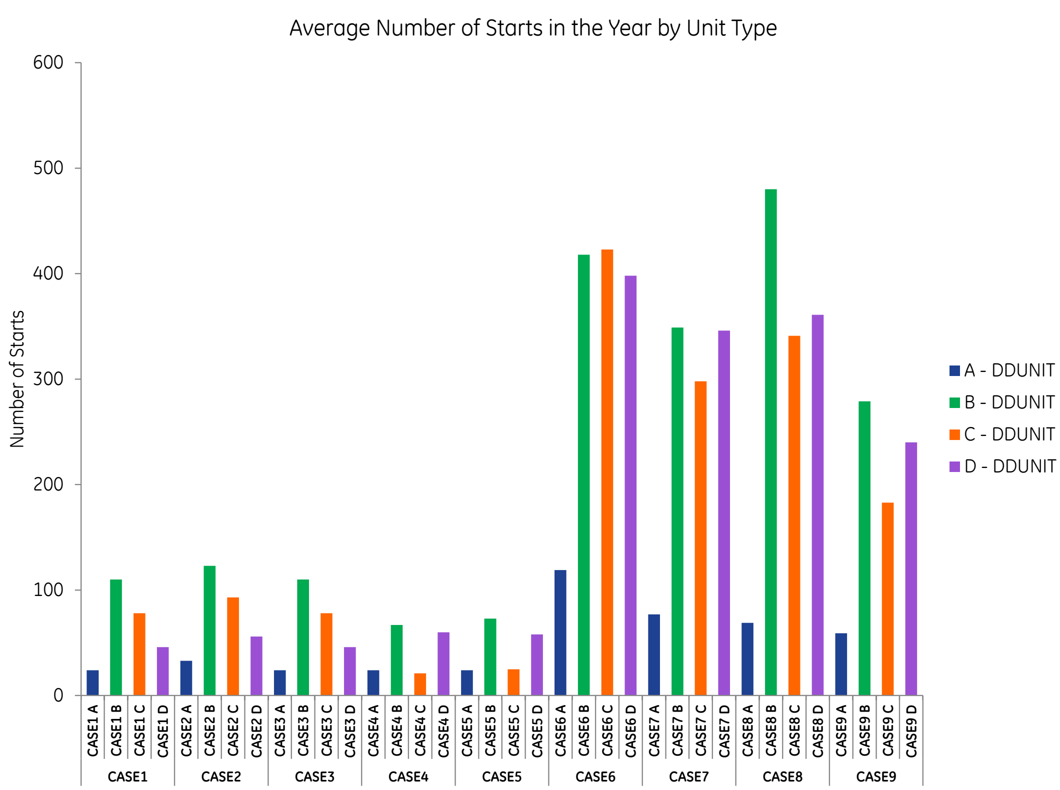


**Figure 209: Average Number of DR Resource Starts in Sensitivities A, B, C, and D**

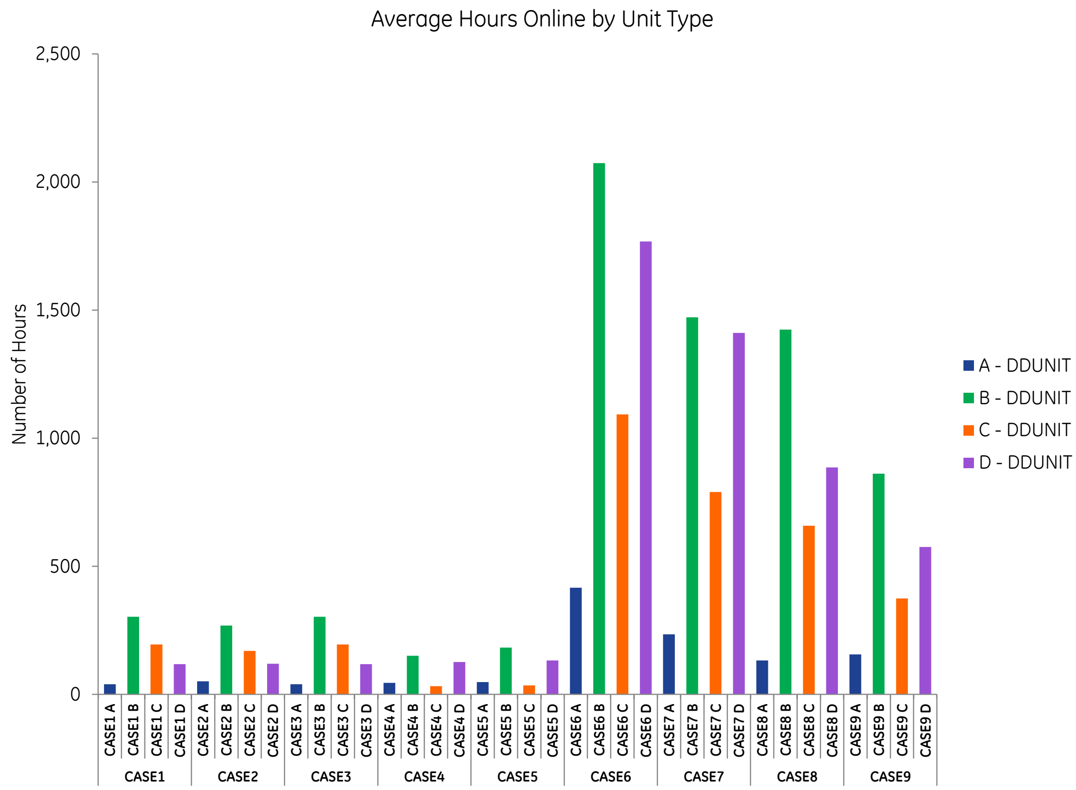


**Figure 210: Average Hours DR Resource Are Online in Sensitivities A, B, C, and D**

These results demonstrate that greater inflexibility in NB imports results in higher dependence on DR resources. It is interesting to note that in the case of No Imports (Sensitivity D) results in less need for DR, compared to the sensitivities with relative inflexibility of NB imports. Less need for DR appears to be the result of commitment of more thermal capacity in the absence of NB imports. However, DR utilization in all Year 2020 cases increase significantly, particularly in the absence of ML imports.

These results also reflect the fact that we have assigned a high price to DR. As noted earlier, advent of new enabling and automated technology and further DR aggregation and integration into the power grid would be expected to lower the price of DR participation in the market, and most likely transform DR resources into less expensive flexible resources that may be dispatched ahead of supply-side resources, as well as play a more significant role in providing load following operating reserve to mitigate the volatility and intermittency of renewable resources.

### 7.10.3 10-MW Spin Reduction (Sensitivity S)

In Sensitivity S, the hourly spin requirement is reduced by 10 MW all hours, but it is not allowed to go negative. The intent is to see how the relaxing of the spin requirements impacts the system wide generation and costs. This is a proxy for the addition of any technology that might be able to provide the equivalent functionality to spinning and regulating reserves. This could include technologies like battery energy storage, highly agile demand response (e.g. of the type that an industrial load might be able to provide). Table 50 shows the marginal cost of these reserves from the perspective of cost to carry these reserves.

**Table 50: Production Cost Savings with a 10 MW Reduction in Hourly Spin Requirement ($M)**

| | CASE 1 | CASE 2 | CASE 3 | CASE 4 | CASE 5 | CASE 6 | CASE 7 | CASE 8 | CASE 9 |
|---|---|---|---|---|---|---|---|---|---|
| **Sensitivity A (Base Case)** | 359.8 | 417.2 | 359.8 | 446.8 | 384.1 | 457.4 | 409.2 | 436.6 | 373.2 |
| **Sensitivity S (-10 MW Spin)** | 359.1 | 416.5 | 359.1 | 446.4 | 383.5 | 456.1 | 408.8 | 438.2 | 372.8 |
| **Savings ($M)** | 0.6 | 0.7 | 0.6 | 0.3 | 0.6 | 1.2 | 0.4 | -1.5 | 0.4 |

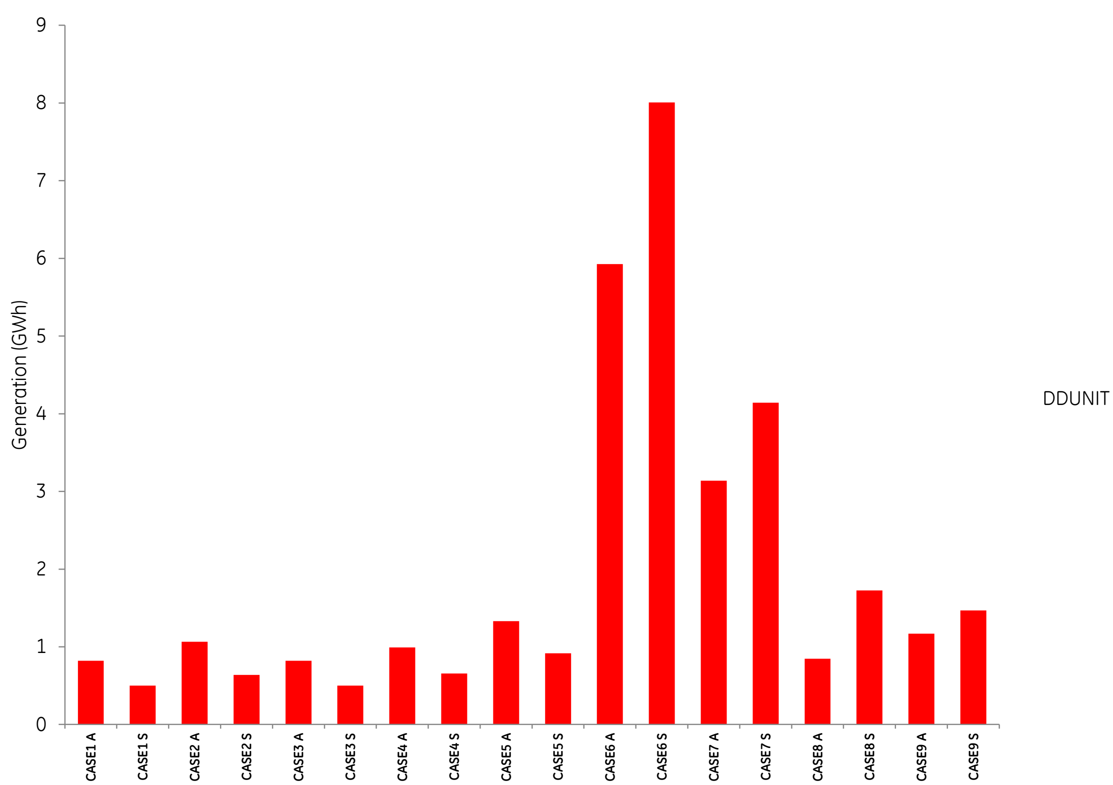


**Figure 211: Impact of 10-MW Spin Reduction on Demand Response**

Spin requirements are always satisfied, but if supply-side resources are not sufficient to meet the requirements, demand response (DR) is invoked as a last resort, due to the higher than supply-side resource cost assigned to DR.

As an example, in one of the runs, the model results show that DR was called for 80 hours or about 1% of the hours during the year. As long as DR can be called for, there is no non-responsive unserved energy, and the system has adequate resources to meet during those hours.

Alternatively, reserve requirements could have been violated, without invoking DR. This happens when cost of violating reserve requirement is set at a level lower than cost of invoking DR. Figure 212 shows the demand response in the 2020 cases. The model will tend to invoke DR in very small blocks. In these figures, unlike the results presented above in Figure 208, Figure 209 and Figure 210, any DR less than 10MW is suppressed as it represents a condition where NSPI would be more likely to use some of the synchronized spinning reserves instead. The economic incentive to secure demand response than can provide the same functionality as synchronized spinning reserve is reflected in the NPV discussion above.

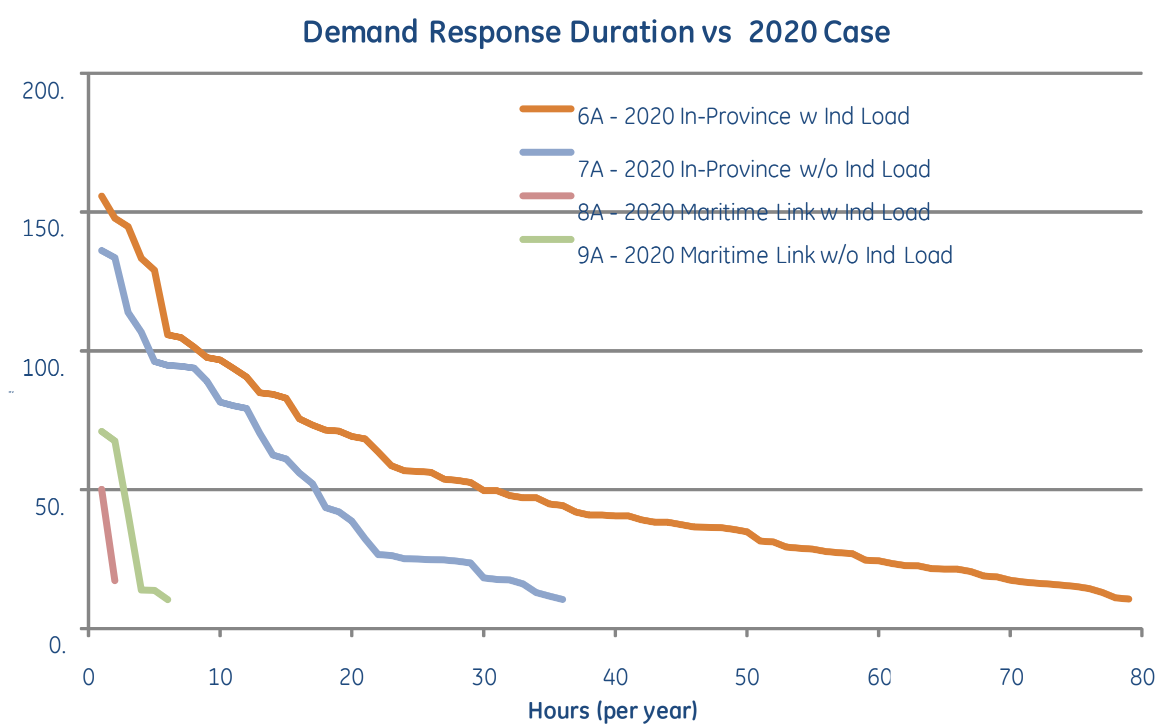


**Figure 212: DD Unit Duration Curves for Cases 6 – 9**

### 7.10.4 Impact of NB Tie Availability on the Need for Demand Response

When load, conventional generation outages and unanticipated changes or shortfalls in predicted wind occur, the system can find itself with insufficient conventional generation and import capability to meet load and satisfy reserve requirements. For this study, demand response is used as a resource of last resort, which is consistent with NPSI's operating practices.

This study found that the number of hours that NSPI's Large Industrial Interruptible customers could be interrupted increases significantly in the 2020 cases. As illustrated in the demand response duration curves of Figure 213, there were approximately 30 hours (blue arrow) in 2012 where NSPI's Large Industrial Interruptible customers were interrupted (again, the minimum interruption reported here is 10MW) when a forced outage rate of 15% was used for the NB / NS tie line (Case 1A). If the NB tie is assumed to be completely unavailable (Case 1D), that could increase to nearly 90 hours (purple arrow). Having the NB tie perfectly available (Case 1I) would have essentially no impact on demand response.

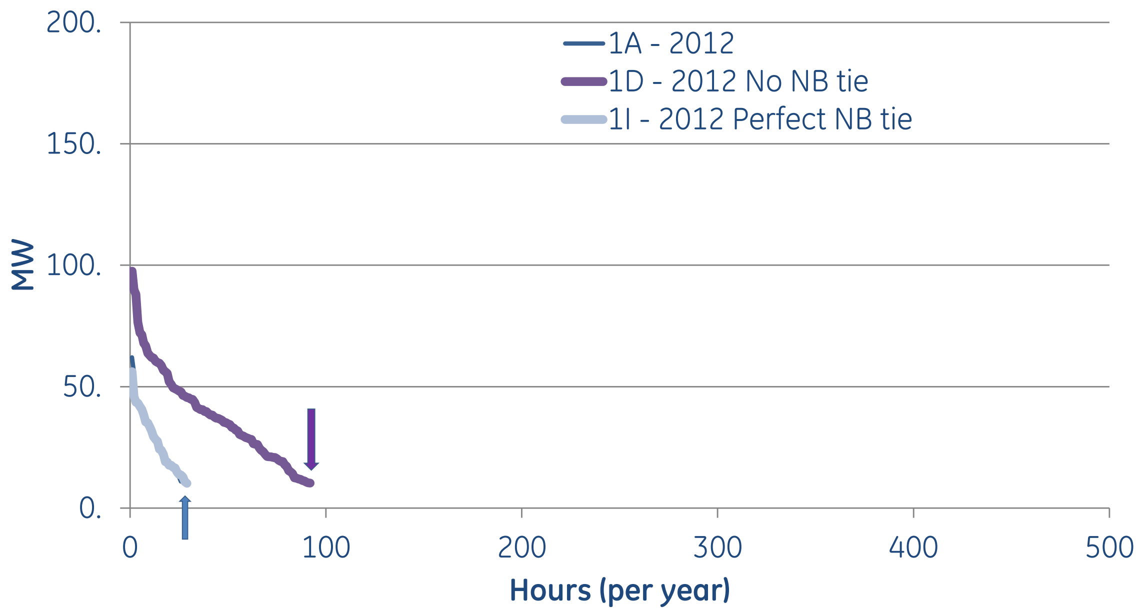


**Figure 213: Demand Response Duration vs. Availability of NB Tie - 2012**

Figure 214 shows the same information for the four possible 2020 cases. In the high-wind penetration case that includes large industrial load and 915 MW of installed wind capacity (Case 6), the impact on Large Industrial Interruptible customer interruptions increases substantially relative to the 2012 base case (from 30 to 90 hours now, increasing to 80 to 420 hours). NSPI's Large Industrial Interruptible customers would be interrupted three to four times as many hours as they are in the 2012 base case. In both cases (6 and 7) that rely only on in-province wind additions (without the Maritime Link), the availability of the NB tie has a large impact on frequency and amount of demand response required.

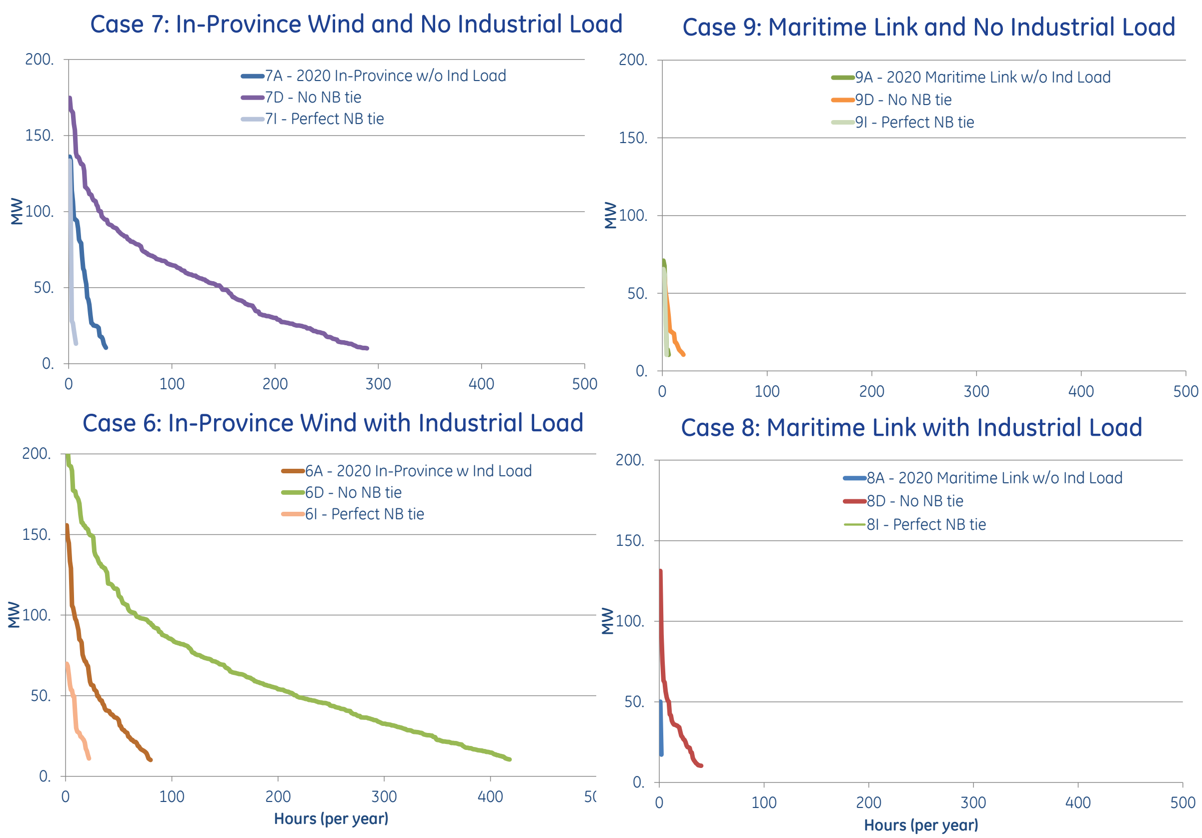


**Figure 214: Demand Response Duration vs. Availability of NB Tie - 2020**

In Case 8, which includes the Maritime Link, large industrial load, and 550 MW of installed wind capacity, the number of hours that NSPI's Large Industrial Interruptible customers would be interrupted is reduced to nearly zero in the case where the NB / NS tie line is modeled at a 15% forced outage rate (Case 8A in Figure S 4). In the absence of the NB / NS tie line (Case 8D) the number of hours that NSPI's Large Industrial Interruptible customers would be interrupted would be approximately 60% less than the 2012 base case without the NB / NS tie line (Case 1D).

In the absence of large industrial load in 2020 (cases 7 and 9), the impact is somewhat similar. As illustrated in Figure S 4, the number of hours that Large Industrial Interruptible customers would be interrupted in Case 7 would increase by at least 30% relative to the 2012 base case, whereas the number of hours Large Industrial Interruptible customers would be interrupted in case 9 is nearly 80% less than the 2012 base case.

Demand response is a valuable resource, especially in high wind systems. Other studies have shown demand response to be highly economical for helping systems handle occasional extremes caused by wind power. Nova Scotia should pursue development of more and more agile, demand response resources. If this proves to be challenging for NSPI and its customers and it is found that there is not enough new interruptible customer base in Nova Scotia to address the increase in calls on demand response in the high wind penetration cases, there are a number of options available to mitigate the risk of increased levels of customer interruptions. The Maritime Link, investments in new generation capacity (in-province) and improving the ability for Nova Scotia to import through the NB / NS tie line are all options that NSPI should consider in parallel with pursuing development of more and more agile demand response.

## 7.11 Operational and Performance Considerations

This section covers several topics of interest which cut across cases and sensitivities, and which NSPI should consider in the planning and policy making. Some of these discussion items are slightly out of scope, but are mentioned here for continuity.

### 7.11.1 Reserves Deliverability, Interface Loading and Congestion

In order to meet reserve requirements in high demand areas, resources offering reserve capacity should have access to the areas that need reserve. A reserve resource in an export constrained region is of no use in meeting the all-province reserve requirements, since it cannot deliver the needed reserve capacity. To investigate the reserve deliverability within Nova Scotia, we investigated flows across three interfaces that had been identified as potentially constraining reserve deliverability from [redacted] across the province. The interfaces of interest are:

- [redacted]
- [redacted]
- [redacted]

Each of these interfaces is subject to some form of thermal, stability, or voltage constraints and the concern is that at high actual power flows across these interfaces, these interfaces may not have sufficient unused capacity to enable delivery of reserves when they are called for.

Although our security constrained economic dispatch models do not explicitly model (or co-optimize) the reserve deliverability together with economic dispatch subject to transmission constraints, they can monitor the flows across each interface (or even line), and hence, can provide some view of the available transfer capacity during different hours of the year.

Figure 215, Figure 216, and Figure 217 show the annual flow duration curves for those three interfaces. All three interfaces [redacted]. It should be noted that the analysis was done only for the flexible imports case.

[redacted]

**Figure 215: Flow Duration Curves across ONS Interface**

**THIS FIGURE IS CONFIDENTIAL**

[redacted]

**Figure 216: Flow Duration Curves across ONI Interface**

**THIS FIGURE IS CONFIDENTIAL**

[redacted]

Figure 217: Flow Duration Curves across CBX Interface

THIS FIGURE IS CONFIDENTIAL

The Interface [redacted] appears to have the most variation among cases because the Industrial Load and Maritime Link are both sited on the limited side of the interface.

Results show that these interfaces are [redacted] and there are also [redacted] Although these results do not guarantee [redacted] less than a couple of hundred hours in the year. Levels of power flows appear to increase in the later years, with highest levels of flows occur in 2020 with the Maritime Link in operation. Hence the reserve deliverability will become more challenging with passage of time. Reinforcements to the grid may be necessary, especially with the addition of the Maritime Link.

### 7.11.2 Dispatch Interval

Over the past several years, major investigations of wind integration [20],[5],[1] in North America have shown that frequency with which economic generation is re-dispatched, and the frequency with which intertie schedules are updated are key elements in secure and economic operation of systems with high levels of wind generation. In systems with in-frequent re-dispatch and schedule up-dates (e.g. hourly), all sub-hourly wind variability must be covered by dedicated reserve resources within the balancing authority bounds. This tends to drive systems to carry and use more regulation – typically the most expensive ancillary service. In short, long intervals drive up "integration costs" unnecessarily. Several systems have made aggressive moves towards shortening the re-dispatch/re-schedule interval, to improve the economy of operation; to name just one: New York has recently moved to 5 minute rescheduling with neighbors.

The sub-hourly results presented in Section 7.2.7 of this report highlight the relatively high level of inter-hour variability. We have already observed that it will be desirable to have the ability to do frequent, near real-time curtailment of the wind plants under low/minimum load conditions. Institutionally, it is not clear what the implications are for NSPI. It is possible that the tools, people, and processes to maintain a high pace of nearly constant adjustment will be needed.

### 7.11.3 Dynamic Constraints

The provincial transmission system is represented in the production simulations presented in this report. Thermal limits and interface constraints are imposed in the model. Interface limits and operational constraints based on stability and voltage limitations were provided by NSPI. Production simulation uses these limits as model boundary conditions, but does not confirm or invalidate these limits. The addition of large amounts of wind generation has the potential to impact these limit is, which must be established using load flow and stability analysis. Similarly, the addition of the Maritime link will have a major impact on the grid. As planning for integration of new wind generation progresses, these limits will need to be re-evaluated. Ideally, analysis that provides some linkage between stability and production work could be used to evaluate the operational costs imposed by these constraints, providing guidance on the value of relieving them. Stability analysis could be used to test (and cost) options to do so. Stability analysis should also consider how the latest functionality available from wind plants could be used to the advantage of the NSPI system. Another constraint that should be considered is system short-circuit strength. Modern wind turbines can only operate in systems that are anchored by synchronous generation. They cannot be operated in systems that are too weak. In this context, "weak" can be defined by low short circuit levels. The industry measures this relative strength by effective "short circuit ratio" (SCR). This is usually defined as the system SC MVA at the point of interconnection divided by the MW rating of the connected wind plant. SCR levels below about 5 are indicative that some extra care is needed; levels below about 3 are cause for concern. The must-run requirements on NSPI coal plants may make this issue less of a concern, but due diligence requires this be considered. Maintaining minimum short circuit levels can be difficult or expensive in some circumstances. Benefits, in terms of reliability and improved economy, are likely from frequent re-evaluation of these constraints. This may present a human resource challenge for NSPI.

### 7.11.4 Wind Plant Controls and Requirements for Interconnection

As was shown in Figure 71, NSPI faces operation with significant periods of time during which wind power is the *majority* of power supply. In case 7, this is the case for more than 1000 hours each year. The notion, still held by some, that wind plants can function as passive elements in the grid, simply pushing MW out, and leaving the host system to address any operational challenges is an anachronism that Nova Scotia would find expensive and operationally challenging to entertain. Over the past decade, wind technology has advanced considerably. There are a wide range of functions and performance characteristics commercially available that make wind plants better mannered, easier to live with, and in many regards, resources that have characteristics that are superior to the conventional synchronous thermal generation they tend to displace. Recently, "Frequency Response" has become an especially important issue, with NERC driving industry discussion and proposed new standards for frequency response obligation. Wind power can impact frequency response positively or negatively. A recent work [8] in the western U.S. has started to address this issue. New standards have been imposed in Texas for active power controls on wind plants [25]. Hawaii will require these functions [7].

Much of this advanced functionality is optional, and wind plant developers tend (naturally) to avoid adding cost or complexity to their projects without definable benefits to themselves. This reality drives the need for "interconnection requirements" (aka "grid codes") that impose minimum functionality on new plants as pre-requisite for connecting to the grid. This is critically important and has been the subject of intense effort around the world. NSPI needs to adopt industry best practice on wind plants, and benefit from the experience (good and bad) of other systems that have grappled with these issues.

Recently GE produced a recommendations document for ISO-NE [3] which provides a good overview of the current state of the art in plant controls and gives ISO-NE specific recommendations. Most of those recommendations are applicable to Nova Scotia as well. The latest NERC Integrating Variable Generation Task Force (IVGTF) report [4] [12] on the subject, includes much of that work, as well as updates and inputs from a wide range of industry experts. Successful integration of large amounts of wind power in Nova Scotia will require that wind plants be held to a high level of functional requirements.

### 7.11.5 Automatic Generation Control

The analysis presented in this report includes insight into the expected incremental variability due to wind power (Section 3), and the need to carry synchronized reserves that can maneuver and cover system disturbances. To some extent, this work has not explored the nuances between ancillary services of spinning reserve, regulation/AGC and short-term dispatch. Broad discussion of industry best practices can be found in the NERC IVGTF reports [10].

One newly emerging trend in the industry is dispatch of wind generation during periods of high stress – i.e., minimum load and possible wind curtailment – is the placement of wind on AGC. This practice appears to be rapidly evolving towards industry standard in places with high wind penetration. The experience of Xcel Energy was briefly mentioned in Section 7.2. The potential for this is discussed in [3] and [4]. NSPI and the wind plant owners may benefit substantially from incorporating this function, as it has the potential to reduce wind curtailment and to mitigate some scheduling, dispatch and reserve challenges.

# 8 Reliability and Wind Capacity Evaluation

## 8.1 Reliability Evaluation

A Loss of Load Expectation (LOLE) reliability evaluation was performed for each of the cases. We used GE Concorda Suite's Multi-Area Reliability Simulation (GE MARS) software to calculate the daily LOLE, in days per year, for each Case. In addition to the daily LOLE, GE MARS also calculated hourly LOLE, in hours per year, and Expected Unserved Energy (EUE), in MWh per year.

The LOLE analysis determines the Effective Load Carrying Capability (ELCC) of the incremental wind generation additions. This was done including internal NSPI transmission constraints. For year 2020 cases, the Maritime Link was loaded according to the daily energy and power constrained dispatch used in the production simulations.

The daily LOLE determined the number of days in which an outage was expected to occur. Since typical generation outages are equally likely at any time of the day this index is historically calculated at the time of the system daily peak load. However, wind generation varies throughout the day. In recent work with the California ISO (CAISO) [17], [18], GE Energy Consulting has expanded the GE MARS program to determine the daily LOLE while looking at every hour of the day. In this way any off-peak outages caused by significant drops in the wind generation will be fully accounted for.

## 8.2 System Modeling Assumptions

The approach is based on a sequential Monte Carlo simulation which provides for a detailed representation of the hourly loads, generating units, and interfaces between the interconnected areas. In the sequential Monte Carlo simulation, chronological system histories are developed by combining randomly-generated operating histories of the generating units with the inter-area transfer limits and the hourly chronological loads. Consequently, the system can be modeled in great detail with accurate recognition of random events, such as equipment failures, as well as deterministic rules and policies which govern system operation, without the simplifying or idealizing assumptions often required in analytical methods. Because GE MARS is based on a sequential Monte Carlo simulation, it uses state transition rates, rather than state probabilities, to describe the random forced outages of the thermal units. State probabilities give the probability of a unit being in a given capacity state at any particular time, and can be used if one assumes that the unit's capacity state for a given hour is independent of its state at any other hour. Sequential Monte Carlo simulation recognizes the fact that a unit's capacity state in a given hour is dependent on its state in previous hours and influences its state in future hours. It thus requires the additional information that is contained in the transition rate data.

The transmission system between interconnected areas is modeled through transfer limits on the interfaces between pairs of areas. Simultaneous transfer limits can also be modeled in which the total flow on user-defined groups of interfaces is limited. Random forced outages on the interfaces are modeled in the same manner as the outages on thermal units, through the use of state transition rates.

Figure 218 shows the system configuration that was used by GE MARS. Limits on the interfaces were modeled, and all other ties were unrestricted. During the course of the study, the interfaces were not found to be operating at their limits, allowing capacity to be shared among all of the areas.

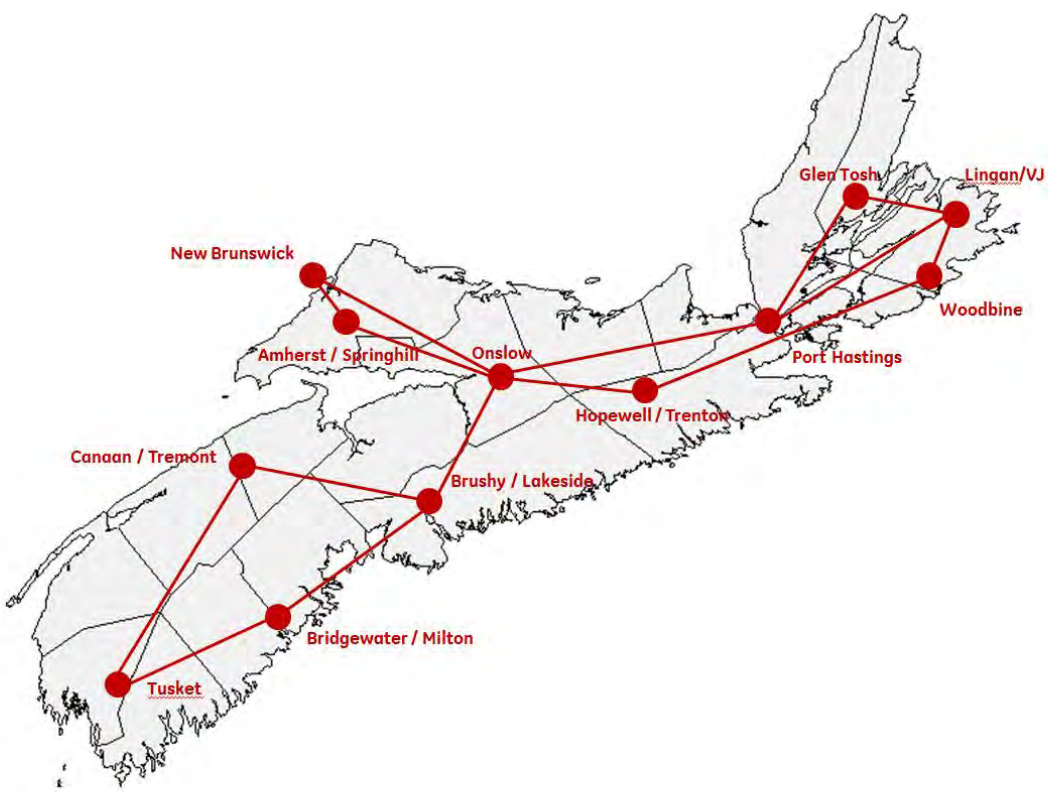


Figure 218: GE MARS System Model

The New Brunswick tie was modeled as providing capacity equal to the minimum of 25% of the Nova Scotia system load, or 285 MW. Additionally, a 15% forced outage rate was applied to this resource.

The system load was modeled based on the 2020 load profiles.

Unit characteristics and maintenance schedules were copied from the GE MAPS input assumptions. Units were modeled as two state units, either fully available or unavailable, based on their state transition rates. Since state transition rates cannot be calculated from forced outage rates alone, the number of transitions between the two states was taken from the 2007-2011 class averages in the NERC Generating Availability Report, issued on September 2012.

The wind expansions were modeled in blocks, as shown in Table 51, which were based on grouping of wind generation plants:

- Block 1: Base case wind (335.8 MW)
- Block 2: 2015 COMFIT (36 MW) [The underlying hourly wind generation pattern results in 120 GWh of COMFIT energy]
- Block 3: 2020 COMFIT (89.1 MW) [The underlying hourly wind generation pattern results in 300 GWh of COMFIT energy]
- Block 4: REA Wind Additions (CASE6) (116 MW)
- Block 5: Generic wind additions to reach 40% RES requirement (365 MW)

**Table 51: Wind Blocks for Capacity Valuation**

| Wind Block | Capacity (MW) |
|---|---|
| Block 1 | 335.8 |
| Block 2 | 36.0 |
| Block 3 | 89.1 |
| Block 4 | 116.0 |
| Block 5 | 365.0 |

(Block 0 is the system before the base case wind is installed)

These blocks together make up:

2013: Block 1

2015: Block 1 and Block 2

2020 (CASE8 and CASE9): Block 1, Block 3, and Block 4

2020 (CASE6): Blocks 1, and 3 through 5

Three sensitivities were modeled on the cases:

- Industrial Load: The large industrial load was taken out of the system ("IL in" vs. "IL out")
- Lingan 1: The retirement of Lingan 1 was postponed and was available ("L in" vs. "L out") (Lingan 2 is retired in all cases reported here.)
- Maritime Link: In the case with the large industrial load out and Lingan 1 unavailable, the maritime link was available. ("ML in" vs. "ML out")

The Maritime Link was modeled using the hourly profile. The tight power and daily energy constraints of the 35-year and 5-year supplemental blocks of the Maritime Link create some ambiguity about its contribution from a capacity perspective. During peak load periods, the Maritime Link is power constrained to 194 MW. However, depending on the operating history for that day, energy constraints may be more limiting. By using the scheduled dispatch, we are being conservative in the assessment of the capacity contribution, since under some conditions, DAH schedule could *presumably* be overridden to avoid loss-of-load. On the other hand, we have not explicitly included forced outage of the line. The industry experience with modern subsea HVDC is that they generally have high availability. The availability of most systems commissioned in the past decade is usually, but not always, in the neighborhood of 99% [16]. Hence, disregarding the forced outage rate of the HVDC only slightly, overstates its capacity value. Overall, we expect our results to be slightly pessimistic.

## 8.3 Capacity Value Calculations

Each of the GE MARS cases quantified the incremental capacity value for each block of wind generation.

Based on the ratios of capacity among the areas in the target block, perfect capacity was added to the system to develop a capacity value curve. Perfect capacity is an ideal unit that has a fixed output for all hours of the year, with no outages. An advantage of perfect capacity over other methodologies is that it is independent of forced outage rate, unit size and load profiles which affect other measures. Perfect capacity can be converted into the capacity of a conventional thermal unit based on the forced outage rate of that unit.

Each block was modeled to determine the reliability of the system with that block installed. The equivalent perfect capacity was then determined by finding the amount of added capacity brought the system to the same level of reliability. This is demonstrated in Figure 219, where the new resource (red box: +335.8 MW of Wind) increases the system reliability to approximately 0.32 days/year. To achieve this same level of reliability in the base system (blue line) required 104.5 MW of perfect capacity.

The equivalent perfect capacity value can also be expressed as a % Capacity Value using the following equation:

$$Capacity\ Value\ (\%) = \frac{Perfect\ Capacity\ Added\ (MW)}{Original\ Capacity\ (MW)}$$

The capacity value of this 335.8 MW block of new wind power is 104.5 MW, or 31%. The capacity value of any resource does not exist in a vacuum, but rather is a function of the resources already in a system. This concept is important and highly relevant to capacity valuation for wind power. To put these results in context, this means that NSPI has a 31% chance that wind from this block of resources will be there when it is really needed. This compares to about 90% chance that thermal resource with a 10% forced outage rate will be available when it is really needed. But timing matters: if another wind plant of *identical* wind profile is added to the system, it will be less valuable from a reliability perspective, compared to a new plant that produces power at somewhat different times were added. This is true, even if the annual energy production were identical. Therefore, in this analysis, we have built-out the proposed additions of wind power in blocks. The temporal diversity of the resources is reflected in the results.

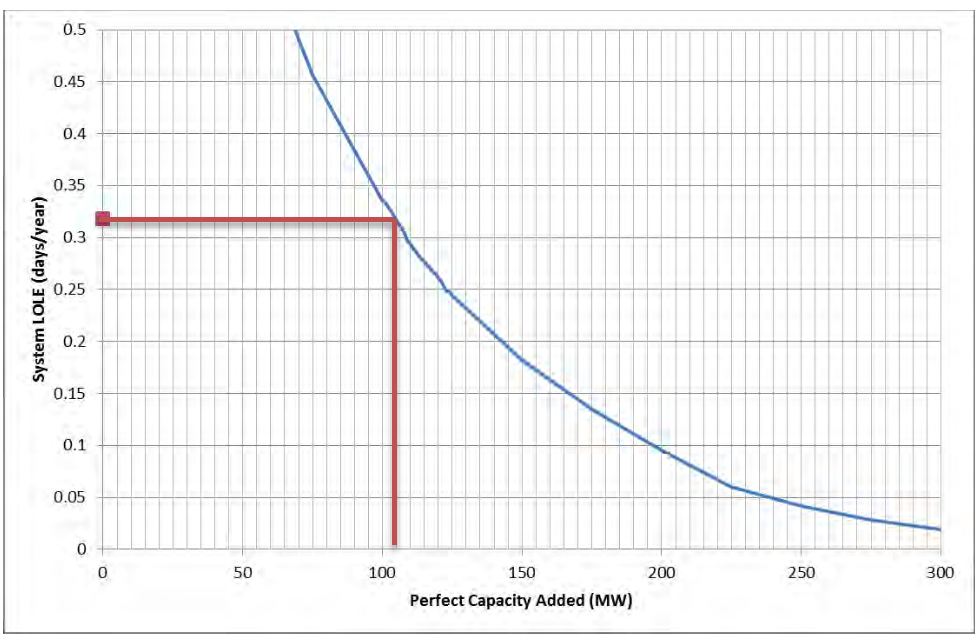


**Figure 219: Example Capacity Value Calculation**

## 8.4 Capacity Values of Wind Plants

The capacity values of the blocks, shown in Figure 220, although they vary slightly with sensitivity case, are rather similar. The capacity value of the first block (the base wind) is in the low 30% range. This is an indication that wind regime in Nova Scotia is well suited to the provincial power needs. Values in the range of 5-20% are more common in the northeast US. The larger variation appears when the incremental blocks have high coincidence with the preceding blocks. Block 3 had a very small incremental improvement over block 2 (average of 12.4 MW) for its rating of 89.1 MW. This is due to the saturation effects encountered when simply increasing the penetration of a variable resource without adding diversity, which occurred when the COMFIT resources in block 2 were scaled up to the values used in block 3.

As can be observed, block 5 added around 12%. These are not bad by industry experience, but certainly not as good as the base blocks. The diminishing return on added wind is expected and consistent with the physics as well as industry experience.

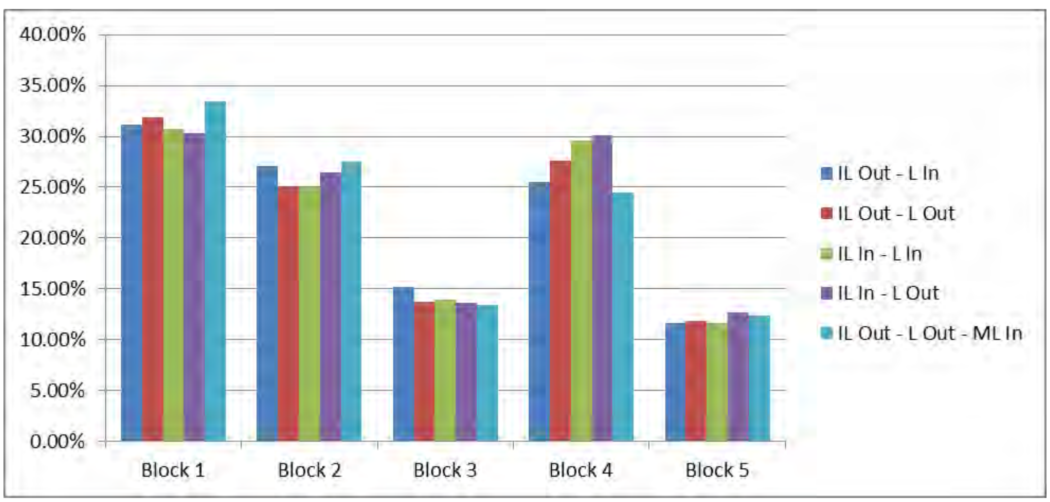


**Figure 220: Incremental Capacity Value (%) for all blocks**

Figure 221 shows the incremental capacity value (%) for the five blocks studied, for each of the five sensitivities modeled.

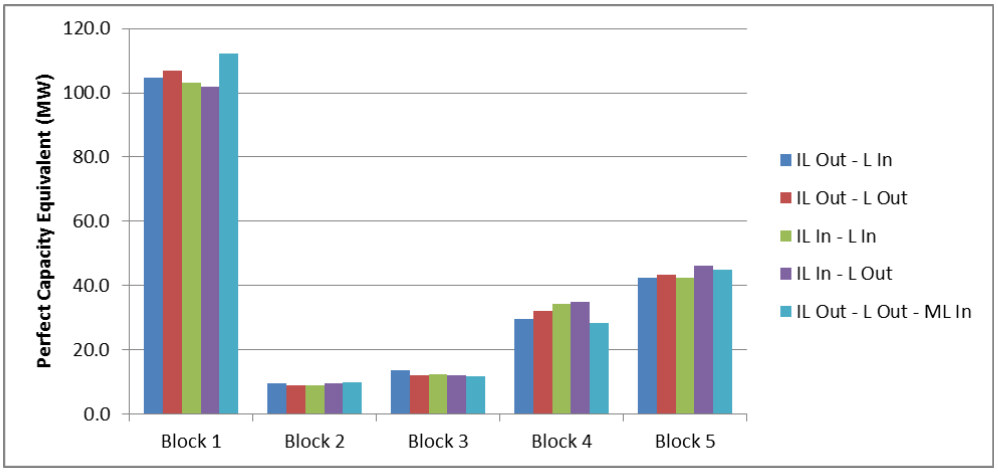


**Figure 221: Incremental Perfect Capacity Equivalent**

## 8.5 Loss-of-Load Expectation Results

The results presented in this section were used to produce the capacity values presented above. However, with further careful examination, these results give useful insight in the broader context of NSPI resource adequacy.

Figure 222 shows the same, but in terms of megawatts of perfect capacity added. For each of the sensitivities, the perfect capacity curves were run for blocks 0 through 4. These curves were used as the basis for evaluating the perfect capacity needed for blocks 1 through 5, respectively. These curves are shown below, and can be read using the guidance provided above in Figure 219. It is important to note again that this analysis does not give any capacity credit to existing interruptible loads. In so far as those loads could be considered equivalent capacity, the implied capacity requirements are reduced by the amount of firmly interruptible load.

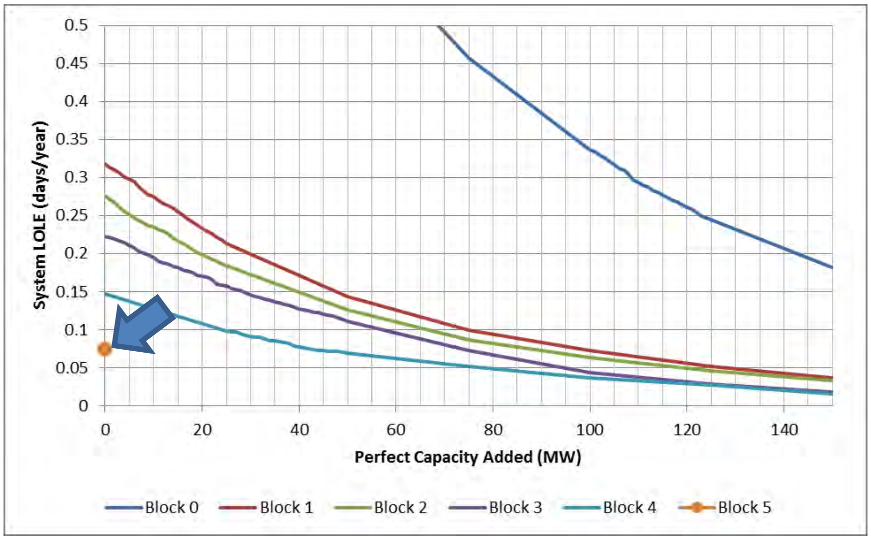


**Figure 222: Perfect Capacity Curve - No Industrial Load, Lingan 1 available**

The system LOLE steadily improves with the addition of each block of wind power. Intersection of the "block" trace with the Y-axis gives the LOLE for that portfolio of wind generation. Hence, as was shown in Figure 219, the LOLE for this case - 2020 load, no large industrial load, Lingan 1 available (not retired) – and the current wind (block 1), is 0.32 - i.e., 3.2 events per 10 years. By the time that Block 4 is added (as expected in the plan), the LOLE has dropped to 0.15 – close to the industry standard of 1 event per 10 years. If all of Block 5 is added, the LOLE drops below the maximum, to about 0.07 (blue arrow). For this portfolio and set of assumption, the system meets the LOLE objective with some margin.

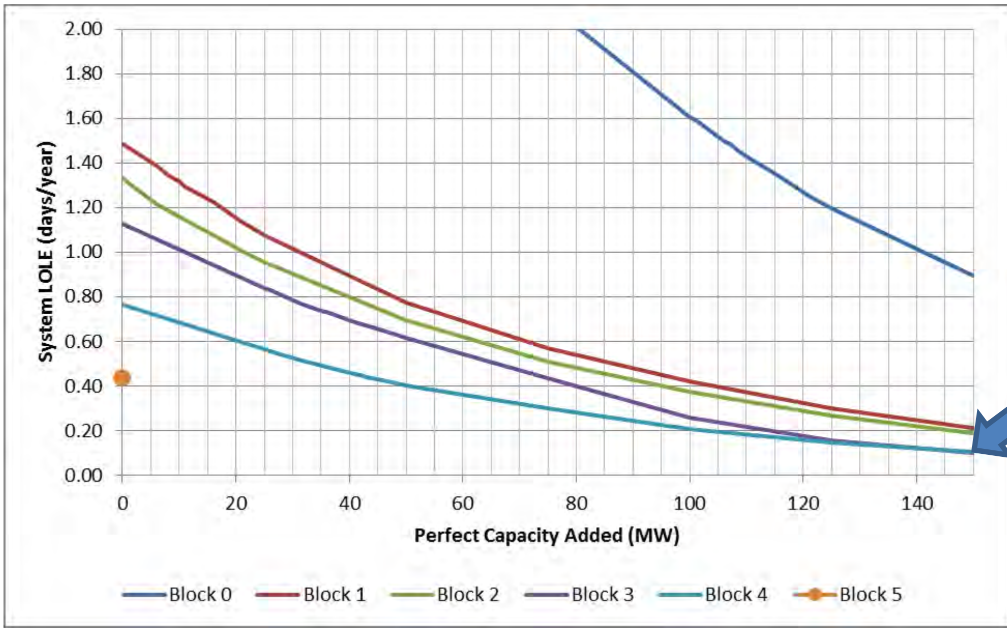


**Figure 223: Perfect Capacity Curve - No Large Industrial Load, Lingan 1 retired**

In Figure 223, the retirement of Lingan 1, adversely affects the LOLE, as must be the case. LOLE with the existing wind exceeds one per year (about1.5). With the addition of wind up to Block 4, the LOLE is improved to 0.80. In order to meet a target of 0.1 LOLE, another approximately 150 MW of new "perfect" generation is needed – as indicated by the arrow.

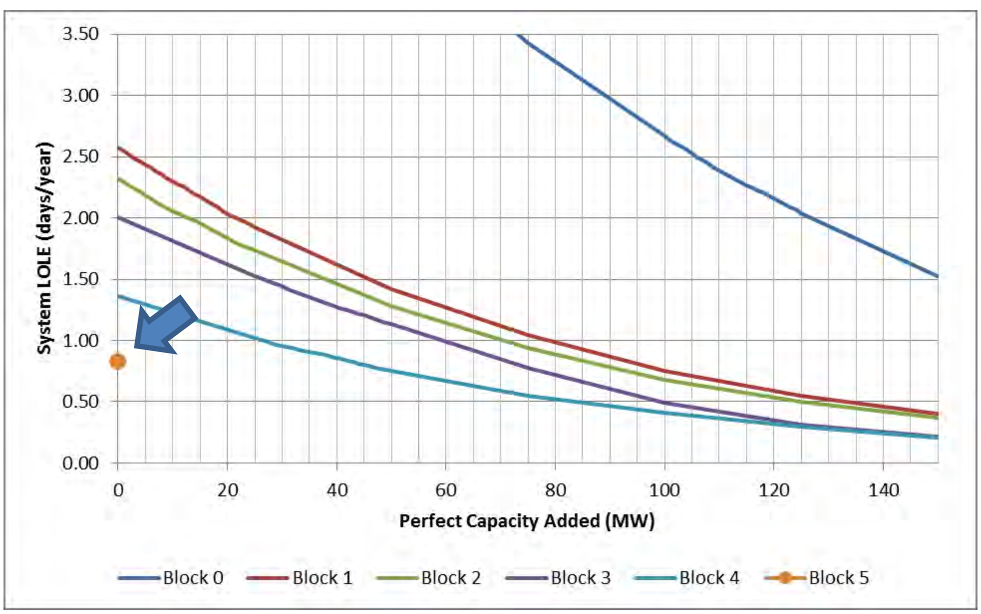


**Figure 224: Perfect Capacity Curve - With Large Industrial Load, Lingan 1 available**

In the event that the PH PM2 industrial load resumes, the system will be more stressed under high load conditions, and the LOLE will get worse, as must be the case. In Figure 224, the higher LOLE are apparent. With the addition of all 5 blocks of wind (as in the analysis throughout this report), the LOLE is about 0.80.

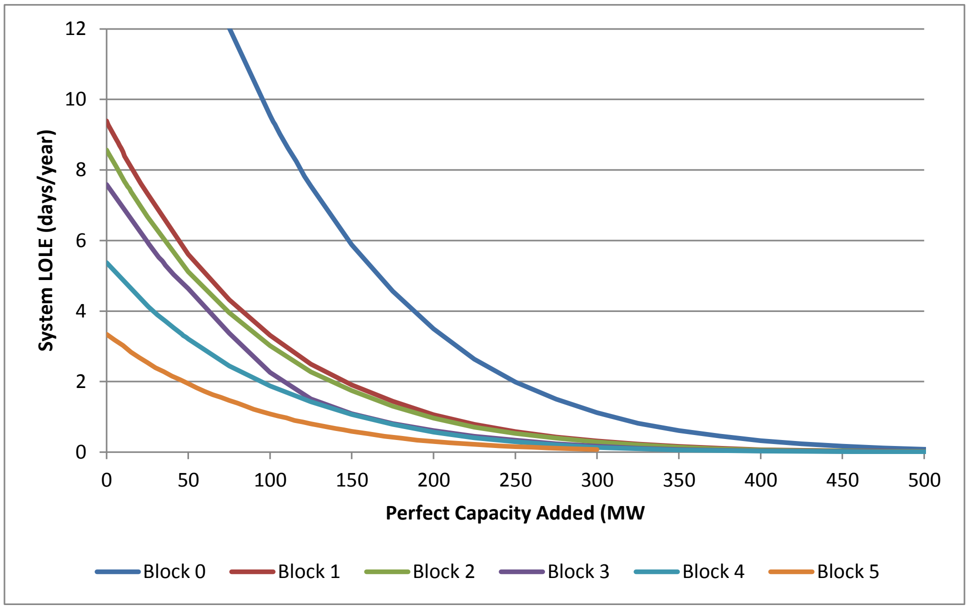


**Figure 225: Perfect Capacity Curve - With Industrial Load, Lingan 1 retired**

As expected, the most stressful condition is with the PH PM2 industrial load included and retirement of Lingan 1 plant. Figure 225 shows, that even with the addition of all the proposed wind plants, the LOLE is on the order of 3. It is difficult to read that figure for smaller LOLE, so zoomed version of the same data is shown in Figure 226. In this case, we ran Block 5 out with added perfect resource, until an LOLE of 0.1 was reached. This analysis shows that the system needs about 290 MW of perfect capacity.

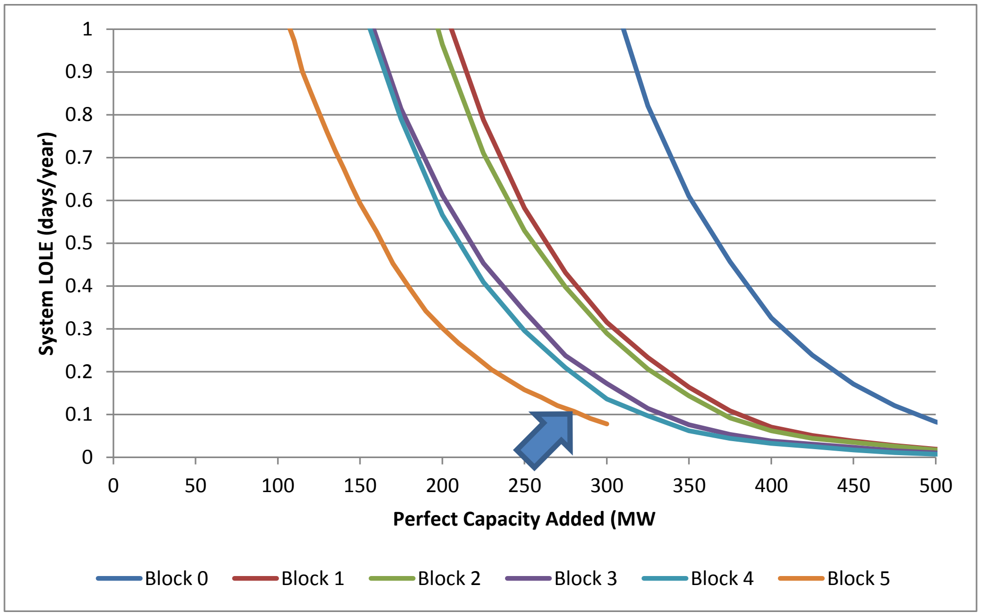


**Figure 226: Perfect Capacity Curve - With large Industrial Load, Lingan 1 retired – Detail**

The addition of the Maritime Link provides significant reliability benefits. As noted above, even though the 35-year and 5-year supplemental blocks are power and energy constrained, it delivers power generally when the system is stressed. Figure 227 shows the 5 blocks, all with the addition of the Maritime Link. The plan is for Block 3 to be in place for the scenario with the Maritime Link. The system is only short about 8 MW of perfect resource in this case. A comparison with Figure 223 shows the relative impact of the Link. For example, the LOLE for Block 3 without the Link is about 1.1, so the Maritime Link improves the LOLE by about 1.0, which is the equivalent of about 150 MW of perfect resource (blue arrow in Figure 223). Since the Maritime Link *must* average 154 MW during peak load hours, this result is as expected.

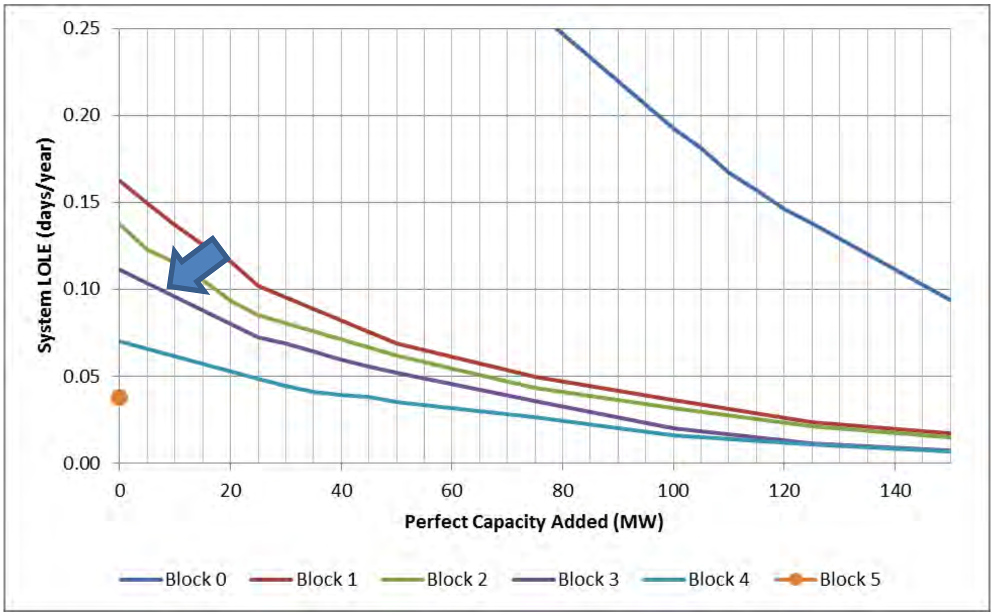


**Figure 227: Perfect Capacity Curve – No Large Industrial Load, Lingan 1 retired, Maritime Link Available**

As noted earlier, the primary intent of the analysis presented here was to quantify the capacity value of the wind additions. As Figure 220 showed, this value is relatively insensitive to exact assumptions about the balance of the system. In comparison, the figures presented in this section demonstrate the high level of sensitivity of *absolute LOLE* figures to assumptions about load level and availability of other resources, including the NB tie line. This study is *not* an overall resource planning study for NSPI. While the LOLE figures presented here are meaningful, they are not intended to be a substitute for the exhaustive analysis needed for complete system-wide capacity adequacy studies.

# 9 Model Benchmarking

## 9.1 Benchmarking of Model results with 2011 Actual Data

In order to validate the results of the dispatch modeling conducted in this study, a historical back-cast was run to compare modeled results to actual historical data. This is an important step in the modeling process and necessary to validate future scenarios and forecasted results. The GE MAPS model was benchmarked to the year 2011. Unit characteristics, the underlying transmission model and overall model configuration was unchanged, but macro-level inputs and assumptions were aligned to real, historical, 2011 data where available. This allows for direct comparison between simulated results and historical operation. The following macro level inputs were changed using 2011 actual data rather than the input assumptions highlighted in Section 5;

- 2011 Actual Load Shapes
- 2011 Annual Peak Demand (MW) and Energy (GWh)
- 2011 Thermal Maintenance Schedule
- 2011 Monthly Hydro Generation by Plant
- 2011 Fuel Prices (approximate)
- 2011 Hourly Net Imports
- 2011 Hourly Wreck Cove Dispatch
- Tufts Cove CC Removed (TUFTSCO6 & TUFTSCDF)

Although a completely faithful hour by hour replication of an actual power system is practically impossible, the following charts indicate a high degree of reasonableness of our modeling assumptions and the modeling results by demonstrating a rather close fidelity of model results to actual data.

## 9.2 Comparison of Annual Results

The first step of validating the 2011 benchmark run was to compare annual generation by type between the simulation results and the 2011 actuals. It is not surprising that annual generation by type (thermal, hydro, wind and imports), shown in Figure 228, is nearly identical between the modeled results and historical data. This is because hydro generation, imports and load data were fixed inputs into the model. However, it is important to show the overall energy breakdown over the past few years because the total share of in-province thermal generation is dramatically reduced throughout the scenarios and cases analyzed in this study. Note that the thermal and wind generation includes only NSPI owned assets and does not include the generation from IPP units due to historical data availability.

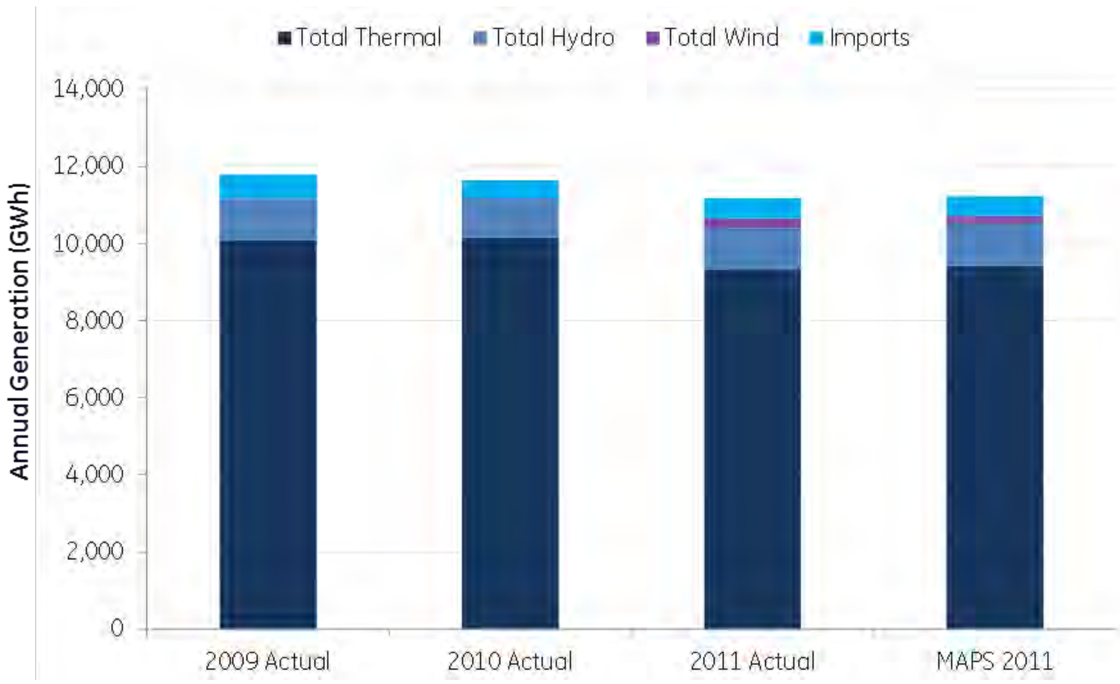


**Figure 228: 2011 Model Benchmark, Annual Generation by Type**

A more important comparison between the benchmark simulation and actual results is the annual generation by plant and individual unit. Although the hydro and wind generation is a fixed input throughout the study period, thermal generation can come from several generating units, the extent of which is determined by the model's security constrained economic dispatch. The generation from individual thermal resources is highly dependent on input characteristics such as heat rate, fuel price, operating costs and transmission. Figure 229 shows the annual historical generation by thermal plant (GWh) in 2009, 2010, and 2011 along with the modeled results from the 2011 benchmark. The modeled results are intended to be closely aligned with the 2011 results, due to consistency in load, hydro generation, and maintenance outages, however 2009 and 2010 historical were also provided to demonstrate a likely range of potential annual generation. The figure demonstrates robust modeling and close alignment between modeled results and actual grid operation.

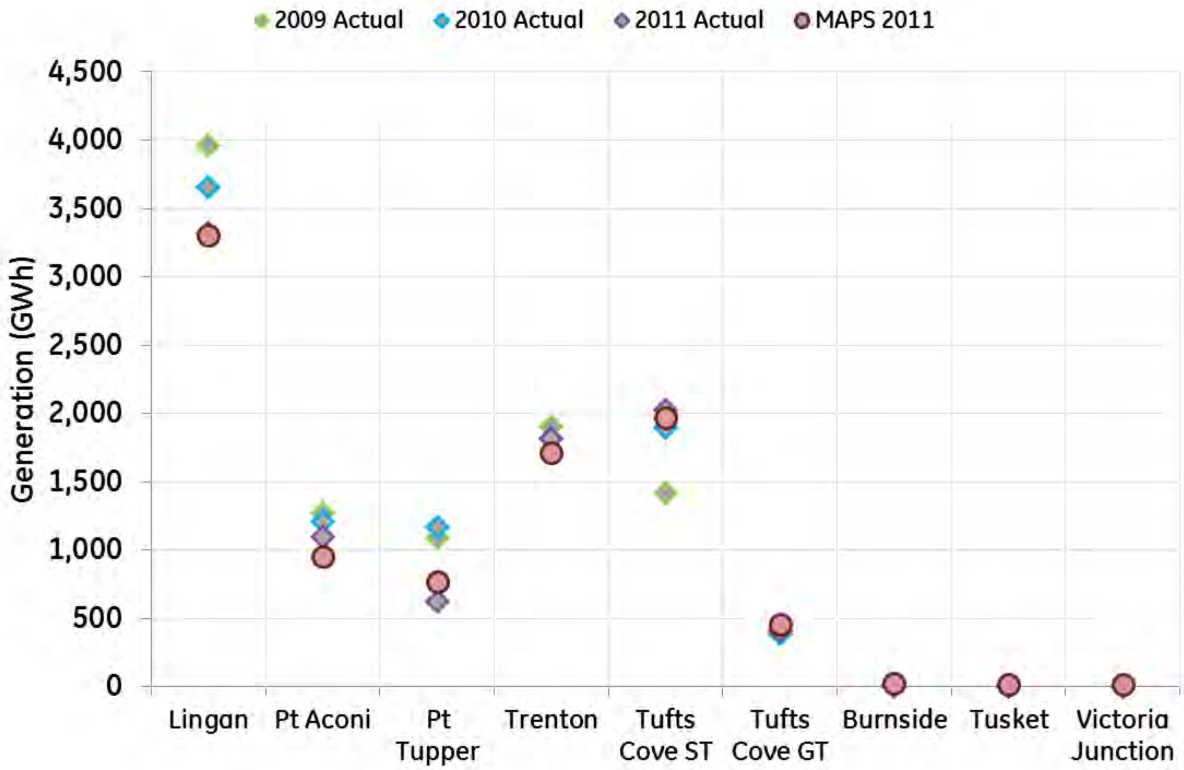


**Figure 229: 2011 Model Benchmark, Annual Generation (GWh) by Plant**

The modeled results were also compared on a unit-level basis to historical results in Figure 230. Oftentimes simulation on a unit level basis is somewhat less accurate because the model does not capture operating preferences that are not based on economic decisions. This is especially true where there are multiple units at the same plant with similar or identical characteristics (i.e. Lingan). For example, a plant operator may shift utilization to different turbines in order to spread operating hours across all units to balance overall maintenance and degradation of parts. On the other hand, the model tends to favor individual units at the same plant that have a relatively minor heat rate advantage, everything else being equal. Of particular importance in the 2011 modeled benchmark is the [redacted]. This causes the unit to over-generate relative to the 2011 actuals while [redacted] under-generates. Despite these shortfalls, Figure 230 demonstrates accurate modeling results, even on an individual thermal unit basis.

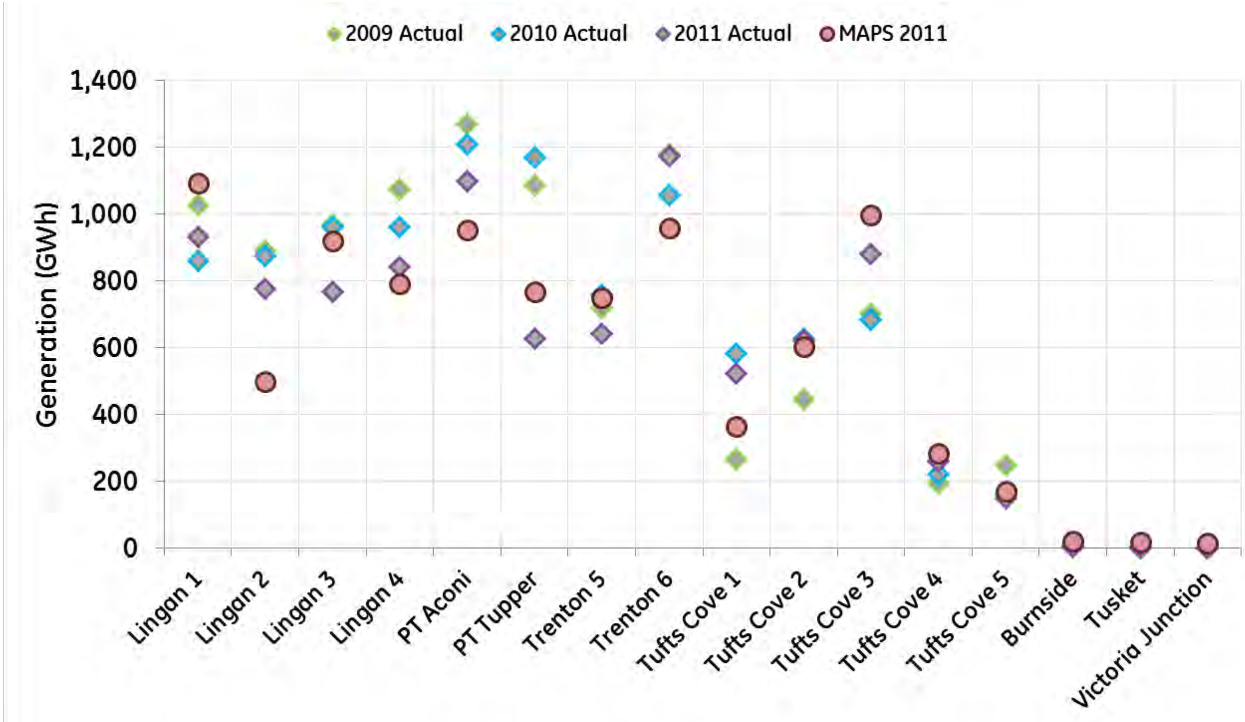


**Figure 230: 2011 Model Benchmark, Annual Generation (GWh) by Unit**

Also included in the 2011 benchmark is the modeled average heat rate by unit. The annual average heat rate is calculated by dividing the total annual fuel consumption (Btu) by the total annual energy generation (kWh). Although each unit's full-load heat rate and heat rate curve is an input into the model, the average annual heat rate is dependent on the overall utilization of the plant, and the relative amount of time the unit is operating at part-load. Figure 231 compares the 2011 benchmark modeled results to the 2009, 2010 and 2011 actual average heat rate and shows similar operations between the simulation and actual operation.

[redacted]

Figure 231: 2011 Model Benchmark, Average Heat Rate (Btu/kwh) by Unit

THIS FIGURE IS CONFIDENTIAL

## 9.3 Comparison of Monthly Generation of Coal Plants

Also included in the 2011 benchmark is a comparison of monthly thermal generation between the modeled results and 2011 historical operation. The monthly generation is highly dependent on the annual load profile, hydro availability and maintenance schedules, all of which were aligned to 2011 historical data. The next several figures show plant level operation in 2011 historically and from the MAPS modeled results. Again the benchmarked results validate the overall results from the simulation, given proper inputs.

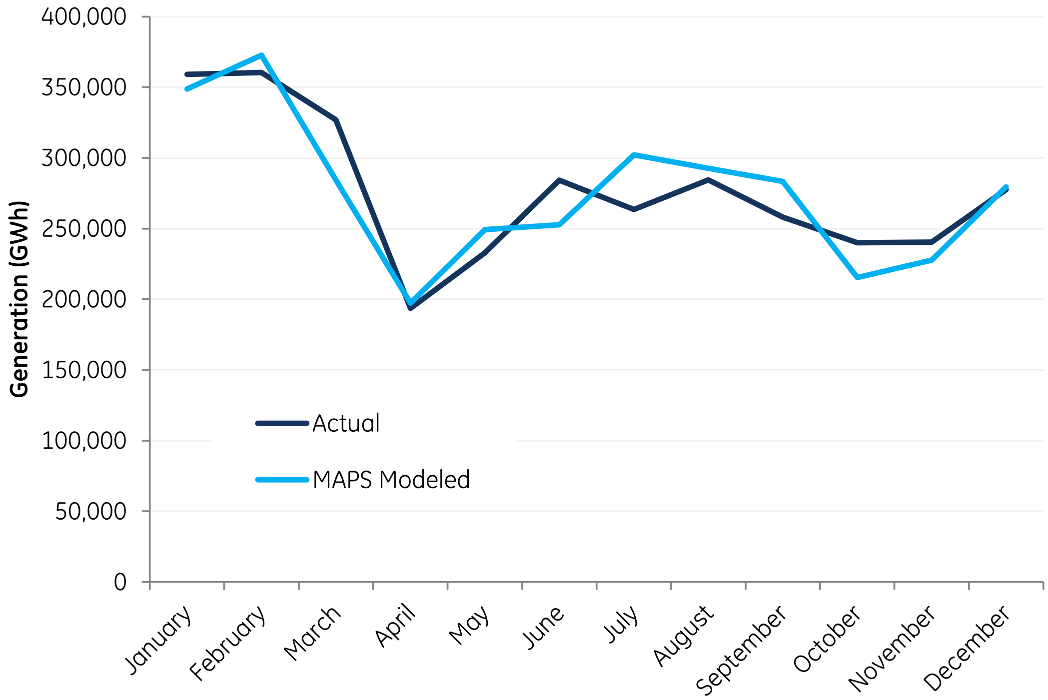


**Figure 232: 2011 Model Benchmark - Lingan Monthly Generation**

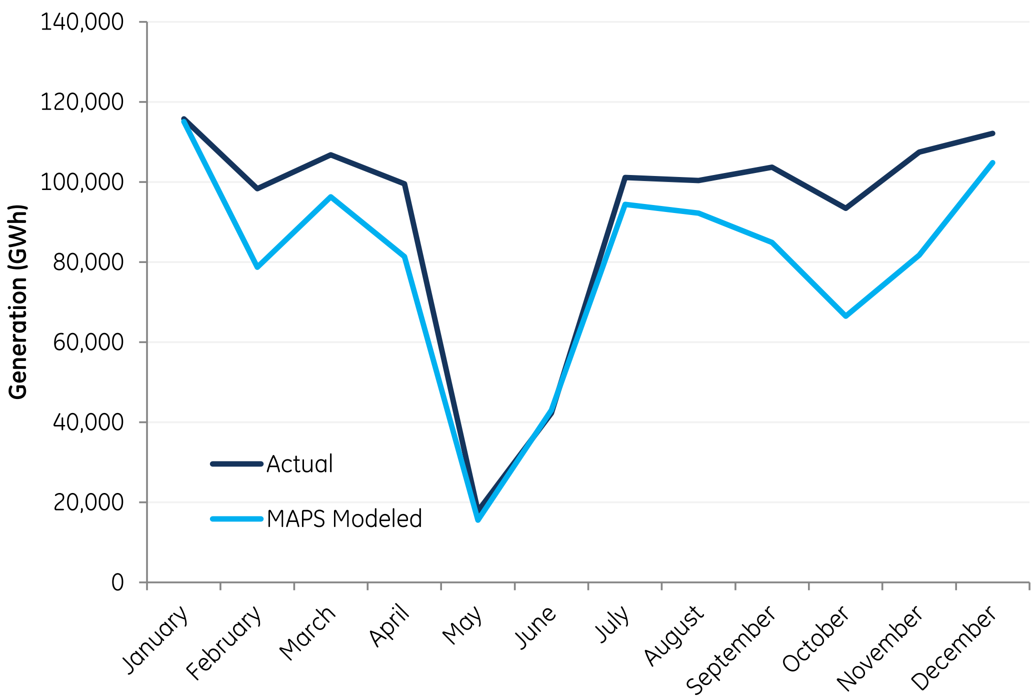


**Figure 233: 2011 Model Benchmark - PT Aconi Monthly Generation**

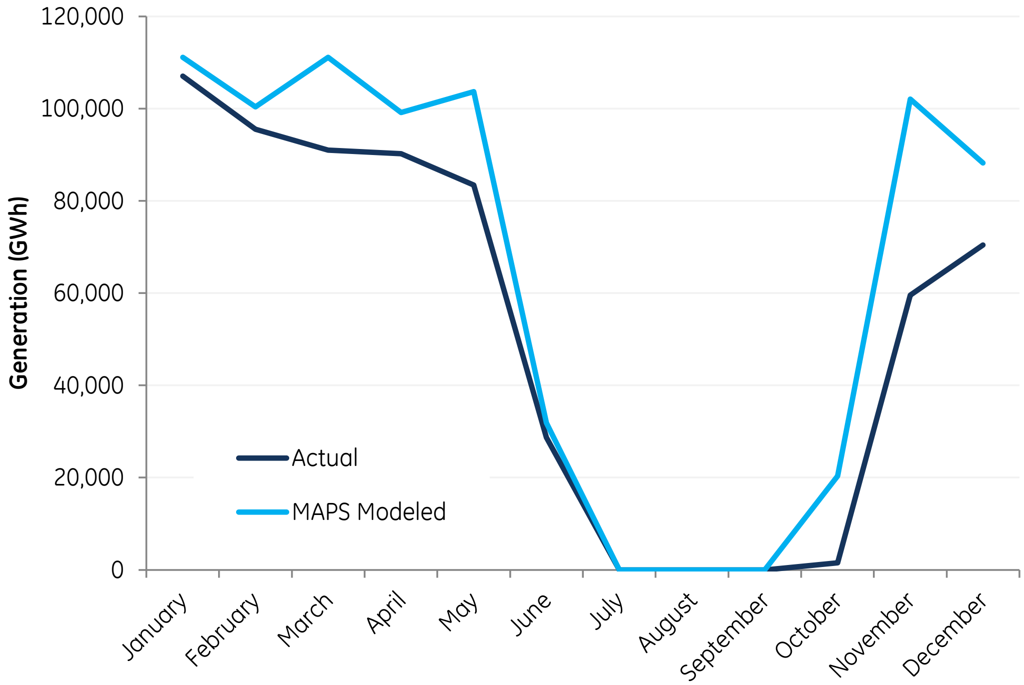


**Figure 234: 2011 Model Benchmark - PT Tupper Monthly Generation**

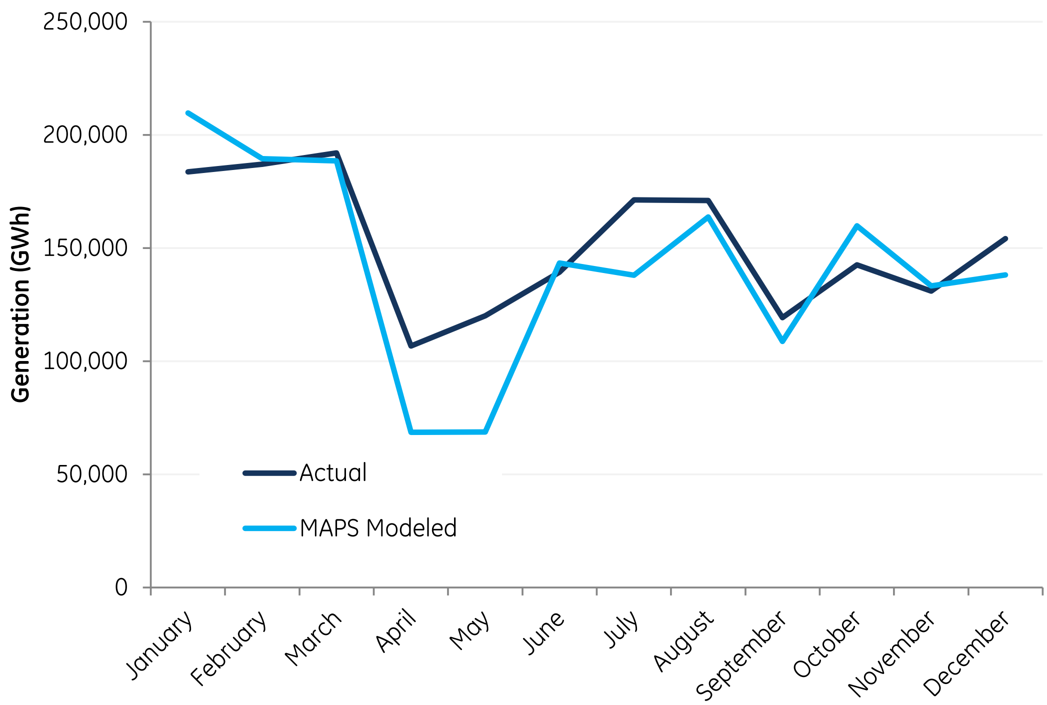


**Figure 235: 2011 Model Benchmark - Trenton Monthly Generation**

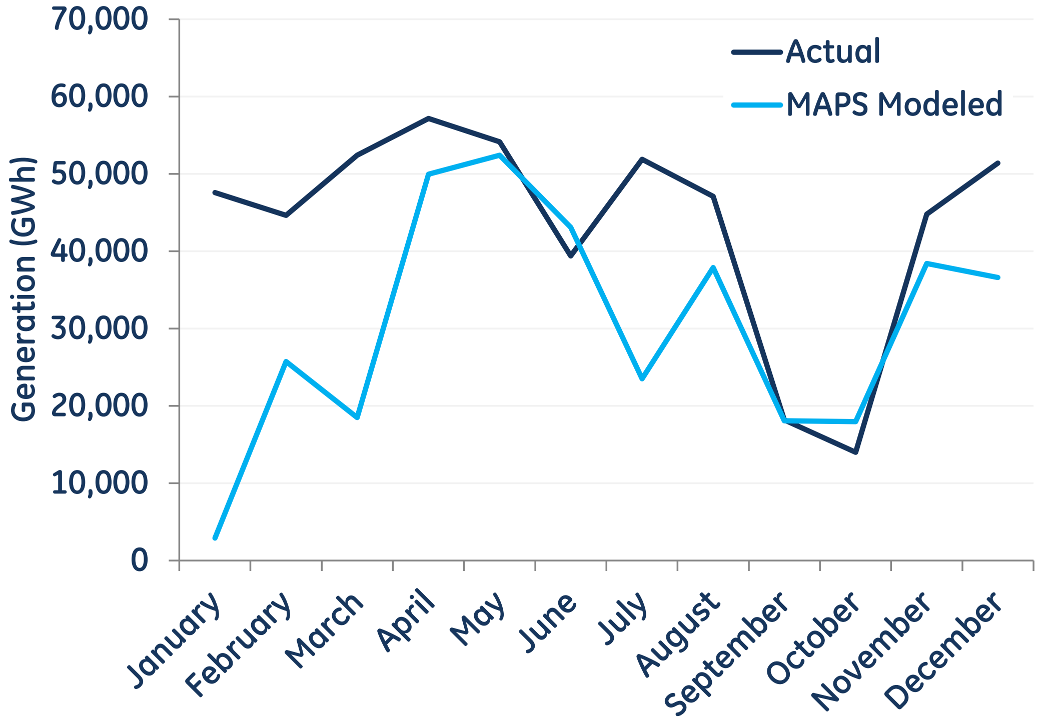


Figure 236: 2011 Model Benchmark - Tufts Cove 1 Monthly Generation

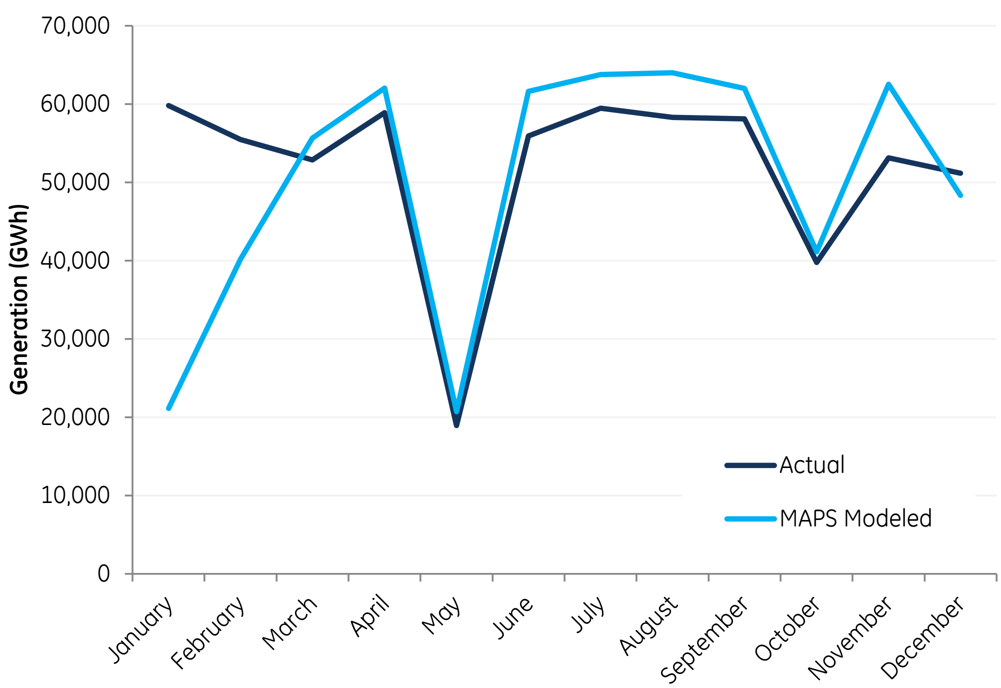


Figure 237: 2011 Model Benchmark - Tuft Cove 2 Monthly Generation

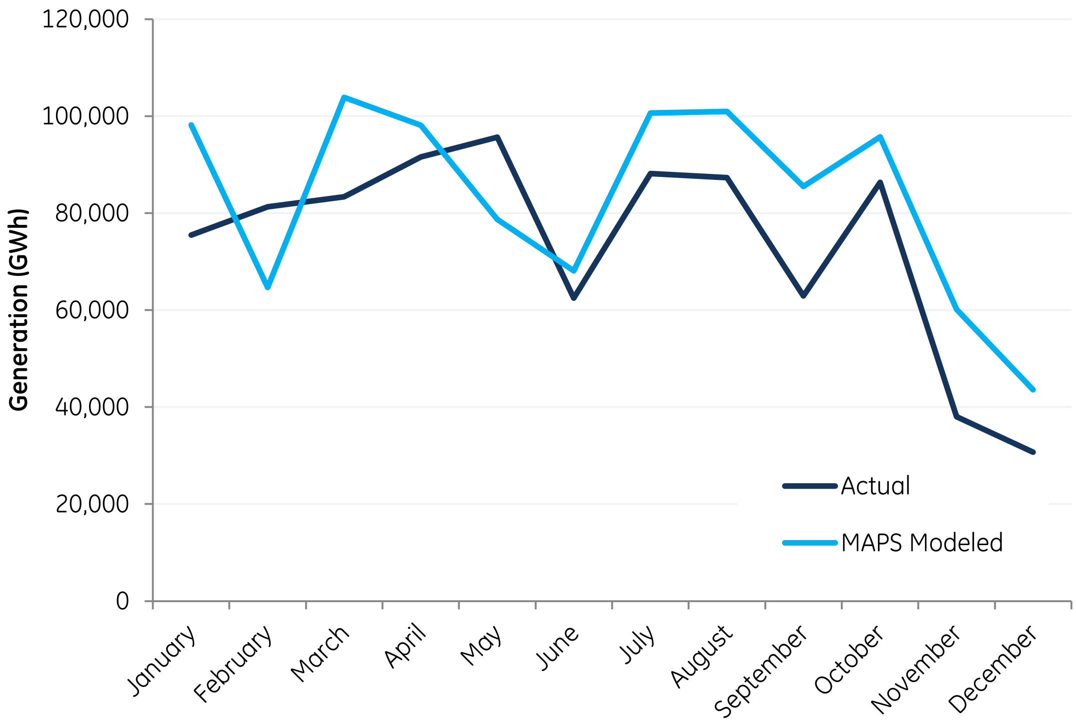


Figure 238: 2011 Model Benchmark - Tufts Cove 3 Monthly Generation

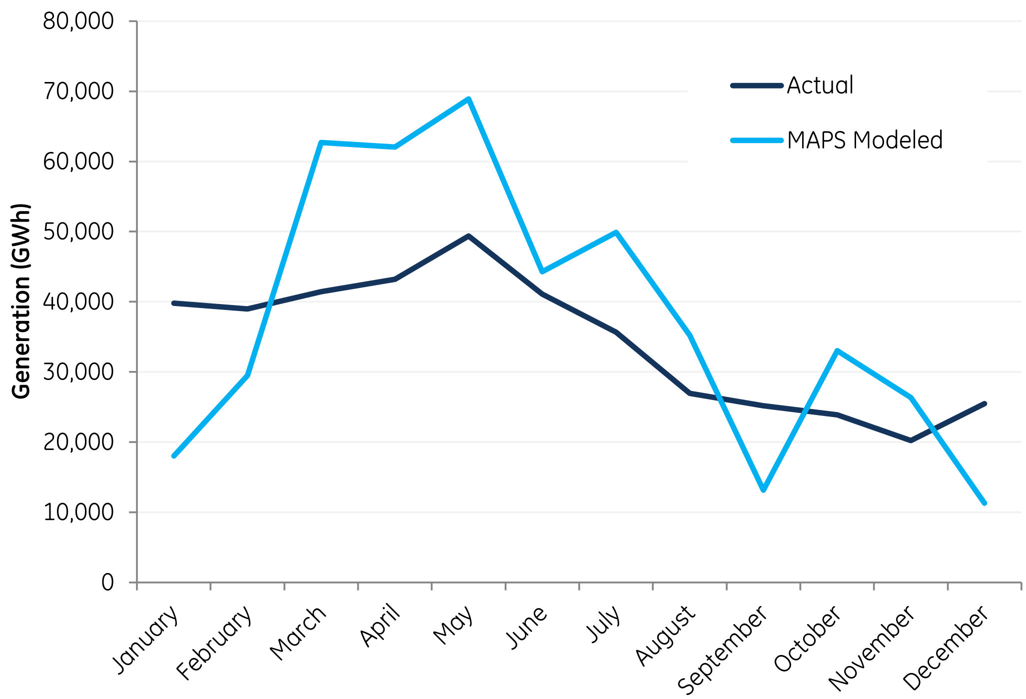


Figure 239: 2011 Model Benchmark - Tufts Cove 4 & 5 Monthly Generation

# 10 Conclusions and Recommendations

## 10.1 Conclusions

- NSPI could successfully operate the Nova Scotia bulk power system while meeting the Provincial renewable energy requirements. The requirement of 40% renewable energy by 2020 that includes integrating up to 25% wind power is possible, but not without supporting capital investments to mitigate the risks associated with integrating this level of wind generation.
- While this study concludes that it may be technically feasible to integrate large amounts of wind power in Nova Scotia, it would not be without significant impact to Nova Scotia Power's customers and the utility.
- The modeling results of the high-wind penetration base cases (prior to performing sensitivity analysis and evaluating potential mitigating options) point to a number of risks and potential outcomes that require careful consideration. Some of these include:
    - The number of hours that NSPI's Large Industrial Interruptible customers would be interrupted would increase by approximately 50 to 330 hours (about 150 to 400 percent) relative to 2012, depending on the case. The cases including the Maritime Link would see the level of potential Large Industrial Interruptible customer interruptions reduced by 60 to nearly 100 percent of the levels experienced in 2012.
    - NSPI must export and curtail wind power that cannot be accepted by the grid. In the 2020 time frame, under some cases, this would approach 10% of the total available wind energy in high wind penetration cases.
    - In high wind penetration cases, curtailment of wind energy would increase by 40 to 75 times the level experienced in 2012. Wind generators could see reduced revenues due to increased curtailments (assuming they are not paid for curtailments).
    - In high wind penetration cases, export of excess wind energy would increase by 10 to 16 times relative to 2012. The modeling completed in this study assumes that there would be a market outside of Nova Scotia to export this excess wind energy to, but NSPI would need to further evaluate this potential. Inability to export excess wind energy would result in higher levels of curtailment than those found in this study.

  - Total forced curtailment and export of wind energy can approach 10% of total wind energy, depending on the case.
  - NSPI's existing thermal generating plants would experience much higher levels of cycling than they do today. The number of starts and stops would increase by as much as 200% on some units and the mileage (the sum of the absolute value of the total hourly MW changes in dispatch) on coal generating units would increase by 20% to 30%. Forced outage rates may increase as well. Further study to evaluate impact on existing thermal generating fleet of the increases in cycling and operational maneuvering should be considered.
  - Variable maintenance costs for thermal plants would increase. Although it was not in the scope of this study to quantify this cost, some of the best work done to date has been by NREL, where it was concluded that the additional cost of unit cycling reduces the value of the renewable energy to the system by about $0.06/MWh to almost $2.00/MWh, depending on the renewable penetration and on whether the lower or upper bounds for thermal plant cycling costs are selected.
- Although not included in the scope of this study, NSPI and its customers will need to consider the additional capital costs associated with mitigating some of the these risks and potential outcomes.
- The marginal value of wind energy, as measured by variable operating (production) cost savings, ranges from $50/MWh to $68/MWh.
- The marginal value of Maritime Link energy, as measured by variable operating (production) cost savings, ranges from $58/MWh to $72/MWh.
- Variable operating cost savings, mostly reduced fuel consumption, range from $24M to $131M per year. These savings do not include the cost of purchased power from Independent Power Producers (IPPs) and the capital recovery costs for new NS Power-owned wind plants and capital investment required to support the high wind penetration options.
- Carbon emissions are reduced ½ to ¾ ton/MWh of wind power. SOx emissions drop 1½ to 3 kg/MWh.
- The tie to New Brunswick is important to operations. Reduced availability of that tie can cost up to $[redacted]/year. It is important for export of excess wind power.

## 10.2 Recommendations

Achieving 2020 renewable electricity requirements in the high wind energy cases (Cases 6 and 7) would require much more than increasing the installed wind capacity to the levels shown in Table S1, which in some cases are nearly three times present-day capacity. In order to integrate high levels of wind energy and continue to operate and manage the power system in a reliable, economical and effective manner, a number of additional capital investments and changes to existing operating practices and procedures are recommended.

- Look for operational flexibility [9, 11]: it is the single most critical factor for successful integration of wind power. All possible sources of flexibility should be considered:
  - Further develop and consider incentivizing responsive, agile demand side resources as one of the options to address the significant increases in Large Industrial Interruptible customer interruptions that are expected.
  - Investigate the physical limits on the operational flexibility of existing hydro and thermal resources and develop strategies and make investments to maximize the operational flexibility of these generating resources. Prioritize and invest in cost-effective improvements to existing plants.
  - Look to further increase the flexibility of the imported energy through the Maritime Link beyond the levels currently negotiated. Wider MW range (e.g. > ±40MW on peak), and more frequent real-time schedule adjustment (e.g. 5 minute intervals).
  - Require wind plants have the capability to participate in real-time balancing by having the capability to accept and impose curtailments immediately and at frequent (sub-hourly) intervals.
  - Require wind plants to have the capability to provide primary frequency response, especially when curtailed.
  - Recognize and develop a grid code that will require that wind plants be held to a high level of functional requirements, staying engaged and coordinated with the members of the utility industry that are leading in this regard.
  - Invest in maximizing the flexibility of the interconnection with New Brunswick to improve the availability of this tie and also increase the capacity for both import and export. Also work with New Brunswick to address any constraints on the NB system that currently limit the capability to import firm energy into Nova Scotia.
  - Consider shortening dispatch and scheduling intervals, including on the interconnection to New Brunswick to 5 minutes.

  - Develop capability: tools, people, and processes to maintain a high pace of nearly constant adjustment.
  - Investigate the ability of New Brunswick and markets further afield to accept (and pay for) excess wind power from Nova Scotia.
  - Addition of high-efficiency, fast-acting flexible generation for capacity reasons and operational flexibility. Operational flexibility must be a primary consideration during specification and procurement.
  - Consider adding other technologies, such as short-term energy storage.

- Carefully consider reserves and refine the existing reserve strategy. Consider all of the resources that can provide reserve as part of a refined strategy to ensure the higher reserve requirements are met in the most reliable and economic manner. Further investigate deliverability of reserves.
- Invest in wind forecasting capability and tools for operation. All systems with high wind power world-wide have reached this conclusion. Investment in physical and personnel expansions in both operations and planning will be required.
- Re-examine system stability and other dynamic constraints impacted by high wind and the Maritime Link and make the investments required in the transmission system to mitigate any system stability risks.

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# 12 Appendix: GE MAPS Description

## 12.1 Application of GE MAPS to the NSPI Study

Production cost modeling of the NSPI system was performed with the GE's Multi Area Production Simulation (GE MAPS) software program. This commercially available modeling tool has a long history of governmental, regulatory, independent system operator and investor-owned utility applications. The production cost model provides the unit-by-unit production output (MW) on an hourly basis for an entire year of production (GWh of electricity production by each unit). The results also provide information about the variable cost of electricity production, emissions, fuel consumption, etc.

The overall simulation algorithm is based on standard least marginal cost operating practice. That is, generating units that can supply power at lower marginal cost of production are committed and dispatched before units with higher marginal cost of generation. Commitment and dispatch are constrained by physical limitations of the system, such as transmission thermal limits, minimum spinning reserve, as well as the physical limitations and characteristics of the power plants.

The primary source of model uncertainty and error for production cost simulations, based on the model, consist of:

- Some of the constraints in the model may be somewhat simpler than the precise situation dependent rules used by NSPI.
- Marginal production-cost models consider heat rate and a variable O&M cost. However, the models do not include an explicit heat-rate penalty or an O&M penalty for increased maneuvering that may be a result of incremental system variability due to as-available renewable resources (in future scenarios).
- The production cost model requires input assumptions like forecasted fuel price, forecasted system load, estimated unit heat rates, maintenance and forced outage rates, etc. Variations from these assumptions could significantly alter the results of the study.
- Prices that NSPI pays to IPPs for energy are not, in general, equal to the variable cost of production for the individual unit, nor are they equal to the systemic marginal cost of production. Rather, they are governed by PPAs. The price that NSPI pays to third parties is reflected in the simulation results insofar as the conditions can be reproduced.

The simulation results provide insight into hour-to-hour operations, and how the commitment and dispatch may change subject to various changes, including equipment or operating practices. Since the production cost model depends on fuel price as an input, relative costs and change in costs between alternative scenarios tend to produce better and more useful information than absolute costs. The results from the model approximate system dispatch and production, but do not necessarily identically match system behavior. The results do not necessarily reproduce accurate production costs on a unit-by-unit basis and do not accurately reproduce every aspect of system operation. However, the model reasonably quantifies the incremental changes in marginal cost, emissions, fossil fuel consumption, and other operations metrics due to changes, such as higher levels of wind power.

## 12.2 Unique Features of GE MAPS

GE MAPS is a highly detailed model that calculates hour-by-hour production costs while recognizing the constraints on the dispatch of generation imposed by the transmission system. When the program was initially developed over twenty years ago, its primary use was as a generation and transmission planning tool to evaluate the impacts of transmission system constraints on the system production cost. In the current deregulated utility environment, the acronym GE MAPS may more also stand for Market Assessment & Portfolio Strategies because of the model's usefulness in studying issues such as market power and the valuation of generating assets operating in a competitive environment.

The unique modeling capabilities of GE MAPS use a detailed electrical model of the entire transmission network, along with generation shift factors determined from a solved ac load flow, to calculate the real power flows for each generation dispatch. This enables the user to capture the economic penalties of re-dispatching the generation to satisfy transmission line flow limits and security constraints.

Separate dispatches of the interconnected system and the individual companies' own load and generation are performed to determine the economic interchange of energy between companies. Several methods of cost reconstruction are available to compute the individual company costs in the total system environment. The chronological nature of the hourly loads is modeled for all hours in the year. In the electrical representation, the loads are modeled by individual bus.

In addition to the traditional production costing results, MAPS can provide information on the hourly spot prices at individual buses and on the flows on selected transmission lines for all hours in the year, as well as identifying the companies responsible for the flows on a given line.

Because of its detailed representation of the transmission system, GE MAPS can be used to study issues that often cannot be adequately modeled with conventional production costing software. These issues include:

Market Structures – GE MAPS is being used extensively to model emerging market structures in different regions of the United States. It has been used to model the New York, New England, PJM and California ISOs for market power studies, stranded cost estimates, and project evaluations.

Transmission Access – GE MAPS calculates the hour spot price ($/MWh) at each bus modeled, thereby defining a key component of the total avoided cost that is used in formulating contracts for transmission access by non-utility generators and independent power producers.

Loop Flow or Uncompensated Wheeling – The detailed transmission modeling and cost reconstruction algorithms in MAPS combine to identify the companies contributing to the flow on a given transmission line and to define the production cost impact of that loading.

Transmission Bottlenecks – GE MAPS can determine which transmission lines and interfaces in the system are bottlenecks and how many hours during the year these lines are limiting. Next, the program can be used to assess, from an economic point of view, the feasibility of various methods, such as transmission line upgrades or the installation of phase-angle regulators for alleviating bottlenecks.

Evaluation of New Generation, Transmission, or Demand-Side Facilities – GE MAPS can evaluate which of the available alternatives under consideration has the most favorable impact on system operation in terms of production costs and transmission system loading.

Power Pooling – The cost reconstruction algorithms in GE MAPS allow individual company performance to be evaluated with and without pooling arrangements, so that the benefits associated with pool operations can be defined.

## 12.3 Modeling Capabilities of GE MAPS

GE MAPS has evolved to study the management of a power system's generation and transmission resources to minimize generation production costs while considering transmission security. The modeling capabilities of MAPS are summarized below:

Time Frame – One year to several years with ability to skip years.

**Company Models –** Up to 175 companies.

**Load Models –** Up to 175 load forecasts. The load shapes can include all 365 days or automatically compress to a typical week (seven different day shapes) per month. The day shapes can be further compressed from 24 to 12 hours, with bi-hourly loads.

**Generation –** Up to 7,500 thermal units, 500 pondage plants, 300 run-of-river plants, 50 energy-storage plants, 15 external contracts, 300 units jointly owned, and 2,000 fuel types. Thermal units have full and partial outages, daily planned maintenance, fixed and variable operating and maintenance costs, minimum down-time, must-run capability, and up to four fuels at a unit.

**Network Model –**Includes 50,000 buses, 100,000 lines, 145 phase-angle regulators, and 100 multi-terminal High-Voltage Direct Current lines. Line or interface transmission limits may be set using operating nomograms as well as thermal, voltage and stability limits. Line or interface limits may be varied by generation availability.

**Losses -** Transmission losses may vary as generation and loads vary, approximating the ac power flow behavior, or held constant, which is the usual production simulation assumption. The incremental loss factors are recalculated each hour to reflect their dependence on the generation dispatch.

**Marginal Costs –** Marginal costs for an increment such as 100 MW can be identified by running two cases, one 100 MW higher, with or without the same commitment and pumped-storage hydro schedule. A separate routine prepares the cost difference summaries. Hourly bus spot prices are also computed.

**Operating Reserves –** Modeled on an area, company, pool and system basis.

**Secure Dispatch –** Up to 5,000 lines and interfaces and nomograms may be monitored. Each study hour considers the effect of hundreds of different network outages.

Report Analyzer – MAPS allows the simulation results to be analyzed through a powerful report analyzer program, which incorporates full screen displays, customizable output reports, graphical displays and databases. The built-in programming language allows the user to rapidly create custom reports.

**Accounting –** Separate commitment and dispatches are done for the system and for the company own-load assumptions, allowing cost reconstruction and cost splitting on a licensee-agreed basis. External economy contracts are studied separately after the base dispatch each hour.

**Bottom Line –** Annual fuel plus O&M costs for each company, fuel consumption, and generator capacity factors.

# 13 Appendix: PLEXOS Descriptions

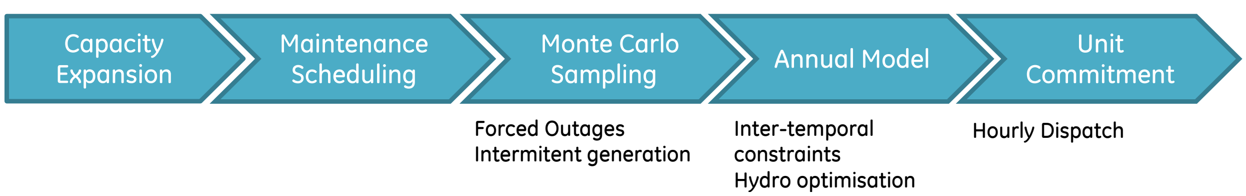
## 1.1 Introduction to PLEXOS

PLEXOS is a mathematical programming tool developed by Energy Exemplar[4]. The purpose of the program is to use sophisticated mathematical and optimization techniques to simulate the operation of electricity markets and systems capturing all technical and financial drivers on system operation. The model has a very broad application:

- Dispatch and portfolio analysis;
- Strategic planning; and
- Long-term investment analysis.

PLEXOS is used by utilities, regulators, and consultants around the world to model electricity markets and is the software of choice for modeling some of the American and European markets. For this reason GE Energy Consulting selected PLEXOS as a mathematical simulation tool for all its European modeling work, as well as for modeling the a number of American and Australian electricity markets.

A key factor distinguishing PLEXOS from other market simulation tools is that the model can be used for long-term investment planning through to short-term unit commitment. The model achieves this by running the model through a number of phases, whereby the solution from one phase is passed as input to the next phase.




PLEXOS can handle all the inputs and drivers shown in Figure 240.

4 www.energyexemplar.com

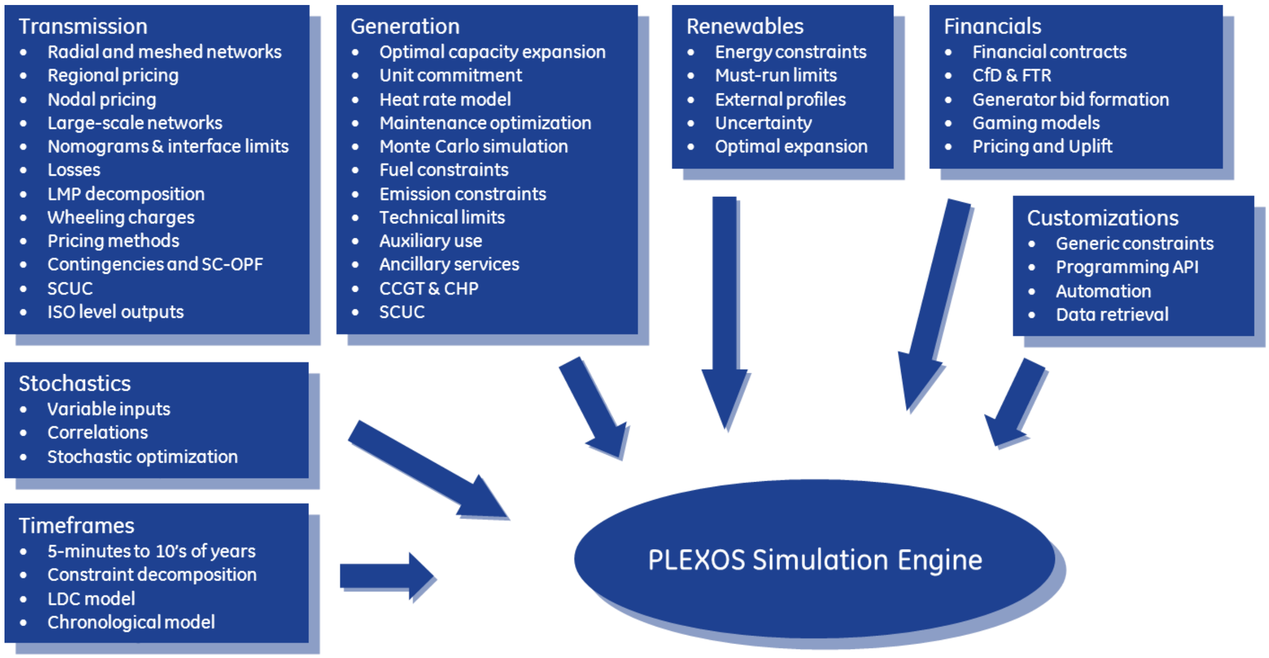



**Figure 240: PLEXOS Modeling Capability**

Source: Energy Exemplar

## 13.1 Main Features of PLEXOS

Note: the description below was taken from the Energy Exemplar website.

PLEXOS model:

- Seamlessly integrates generation dispatch, unit commitment, optimal power flow and pricing simulations with stochastic modeling, renewables, emissions and ancillary services.
- Scales easily from single plant or portfolio optimization to simulation of large-scale systems with thousands of generating units and transmission nodes.
- Optimizes from single interval as short as 1-minute to daily, weekly, annual and multi-annual timeframes.
- A flexible object-oriented design tightly integrated with state of the art optimization tools allows PLEXOS to provide unsurpassed functionality across these application areas:

- Market Analysis:
  - price forecasting
  - generation forecasting
  - budgeting analyses
- Operational Modeling:
  - short-term unit commitment
  - fuel budgeting
  - trading and risk management
- Transmission Studies:
  - transmission investment economic analysis
  - congestion management
  - nodal pricing
  - outage planning
- Resource Planning:
  - capacity expansion planning
  - hydrological modeling
  - contract optimization
- Renewable Generation Integration:
  - detailed (5-minute) production and transmission studies
  - generation flexibility and ancillary services modeling
- Distribution and Smart Grid:
  - smart load modeling
  - investment analysis

### *Features of the simulator*

Generation: Detailed renewable and fossil generation technical-economical characteristics. deterministic and stochastic unit commitment on/off decisions, random outages, temperature dependency and various autoregressive models for wind speed, solar radiation and natural inflows, multiple fuels and Combined Cycle modeling details featuring non-convex heat rates, start-up/shutdown profiles, complex fuel transitions and operational modes.

Transmission: Optimal power flow with losses fully integrated with dispatch and unit commitment. Security and n-x contingency constraints (SCUC), DC lines and phase shifters. Generic constraints and interface limits, transmission aggregation, Monte Carlo simulation, multiple AC networks, 10,000's buses and lines, nodal pricing and price decomposition.

Capacity Expansion: Planning optimal generation and transmission expansion planning over 30+ year timeframe. Optimal NPV of investment and production costs, chronological expansion for detailed ramping, fast frequency control and replacement reserves investment opportunities, stochastic 2-stage optimization support, LRMC, optimal emission target decommissioning, capacity payments and reliability indices.

Hydro Modeling: Highly detailed cascading hydro networks featuring GIS visualization from Google Earth. Efficiency curves, head storage dependency, waterway flow delay times, spillways, evaporation, deterministic and stochastic solutions over any horizon. Seamless integration with detailed short-term unit commitment via target volumes or future opportunity cost decomposition. Pump storage energy and ancillary market co-optimization.

Ancillary Services: Ancillary service provision co-optimized with generation dispatch and unit commitment. Detailed treatment of start-up and shutdown combined with ramping and reserve interaction minute-by-minute. Multiple reserve classes including spinning, regulation, up and down and replacement services.

Emissions: Generation dispatch constrained by emission limits and/or reflective of emissions price and number of emission types. Flexible grouping for emission constraint sets over any timeframe including multi-annual.

Financial: Comprehensive financial reporting to Generator, Region and Company level. Dynamic bidding of generation resources reflective of contract position and/or medium term revenue requirements based on recovery of build costs from capacity expansion planning, Bertrand and Cournot games, flexible user-defined mark-up definitions and automated schemes such as RSI.

Scope and Compatibility: Highly configurable timeframe and simulation interval as short as 1-minute, choose between regional, zonal and full-nodal network detail, multiple pricing, uplift and capacity payment options to support various market rules, choice of commercial mathematical programming engines (CPLEX, Gurobi, MOSEK, Xpress-MP).

## 13.2 Use of PLEXOS in this Study

For the sub-hourly analyses in this study, a detailed generation/transmission PLEXOS model was built, using the short-term mode. A 10-min model was configured to assess the sub-hourly economic dispatch in order to understand impact of wind variability and uncertainty and the sub-hourly response of flexible resources. The model combined NSPI inputs (thermal plant characteristics such as minimum up and down and ramp rate constraints), hourly outputs from GE MAPS model (i.e., commitment and hydro-plants outputs), and AWST 10-min wind data.

# 14 Appendix: GE MARS Description

The Multi-Area Reliability Simulation software program (GE MARS) enables the electric utility planner to quickly and accurately assess the reliability of a generation system comprised of any number of interconnected areas.

## 14.1 Mars Modeling Technique

A sequential Monte Carlo simulation forms the basis for MARS. The Monte Carlo method provides a fast, versatile, and easily-expandable program that can be used to fully model many different types of generation and demand-side options.

In the sequential Monte Carlo simulation, chronological system histories are developed by combining randomly-generated operating histories of the generating units with the inter-area transfer limits and the hourly chronological loads. Consequently, the system can be modeled in great detail with accurate recognition of random events, such as equipment failures, as well as deterministic rules and policies which govern system operation, without the simplifying or idealizing assumptions often required in analytical methods.

## 14.2 Reliability Indices Available From Mars

The following reliability indices are available on both an isolated (zero ties between areas) and interconnected (using the input tie ratings between areas) basis:

- Daily LOLE (days/year)
- Hourly LOLE (hours/year)
- LOEE (MWh/year)
- Frequency of outage (outages/year)
- Duration of outage (hours/outage)
- Need for initiating emergency operating procedures (days/year)

The use of Monte Carlo simulation allows for the calculation of probability distributions, in addition to expected values, for all of the reliability indices. These values can be calculated both with and without load forecast uncertainty.

## 14.3 Description of Program Models

**Loads:** The loads in MARS are modeled on an hourly, chronological basis for each area being studied. The program has the option to modify the input hourly loads through time to meet specified annual or monthly peaks and energies. Uncertainty on the annual peak load forecast can also be modeled, and can vary by area on a monthly basis.

MARS has the capability to model the following different types of resources:

- Thermal
- Energy-limited
- Cogeneration
- Energy-storage
- Demand-side management

An energy-limited unit can be modeled stochastically as a thermal unit with an energy probability distribution (Type 1 energy-limited unit), or deterministically as a load modifier (Type 2 energy-limited unit). Cogeneration units are modeled as thermal units with an associated hourly load demand. Energy-storage and demand-side management are modeled as load modifiers.

For each unit modeled, the user specifies the installation and retirement dates and planned maintenance requirements. Other data such as maximum rating, available capacity states, state transition rates, and net modification of the hourly loads are input depending on the unit type.

The planned outages for all types of units in MARS can be specified by the user or automatically scheduled by the program on a weekly basis. The program schedules planned maintenance to levelize reserves on an area, pool, or system basis. MARS also has the option of reading a maintenance schedule developed by a previous run and modifying it as specified by the user through any of the maintenance input data. This schedule can then be saved for use by subsequent runs.

**Thermal Units:** In addition to the data described previously, thermal units (including Type 1 energy-limited units and cogeneration) require data describing the available capacity states in which the unit can operate. This is input by specifying the maximum rating of each unit and the rating of each capacity state as a per-unit of the unit's maximum rating. A maximum of eleven capacity states are allowed for each unit, representing decreasing amounts of available capacity as a result of the outages of various unit components.

Because MARS is based on a sequential Monte Carlo simulation, it uses state transition rates, rather than state probabilities, to describe the random forced outages of the thermal units. State probabilities give the probability of a unit being in a given capacity state at any particular time, and can be used if you assume that the unit's capacity state for a given hour is independent of its state at any other hour. Sequential Monte Carlo simulation recognizes the fact that a unit's capacity state in a given hour is dependent on its state in previous hours and influences its state in future hours. It thus requires the additional information that is contained in the transition rate data.

For each unit, a transition rate matrix is input that shows the transition rates to go from each capacity state to each other capacity state. The transition rate from state A to state B is defined as the number of transitions from A to B per unit of time in state A:

$$TR\ (A\ to\ B) = \frac{\textit{Number of Transitions from A to B}}{\textit{Total Time in State A}}$$

If detailed transition rate data for the units is not available, MARS can approximate the transitions rates from the partial forced outage rates and an assumed number of transitions between pairs of capacity states. Transition rates calculated in this manner will give accurate results for LOLE and LOEE, but it is important to remember that the assumed number of transitions between states will have an impact on the time-correlated indices such as frequency and duration.

**Energy-Limited Units:** Type 1 energy-limited units are modeled as thermal units whose capacity is limited on a random basis for reasons other than the forced outages on the unit. This unit type can be used to model a thermal unit whose operation may be restricted due to the unavailability of fuel, or a hydro unit with limited water availability. It can also be used to model technologies such as wind or solar; the capacity may be available but the energy output is limited by weather conditions.

Type 2 energy-limited units are modeled as deterministic load modifiers. They are typically used to model conventional hydro units for which the available water is assumed to be known with little or no uncertainty. This type can also be used to model certain types of contracts. A Type 2 energy-limited unit is described by specifying a maximum rating, a minimum rating, and a monthly available energy. This data can be changed on a monthly basis. The unit is scheduled on a monthly basis with the unit's minimum rating dispatched for all of the hours in the month. The remaining capacity and energy can be scheduled in one of two ways. In the first method, it is scheduled deterministically so as to reduce the peak loads as much as possible. In the second approach, the peak-shaving portion of the unit is scheduled only in those hours in which the available thermal capacity is not sufficient to meet the load; if there is sufficient thermal capacity, the energy of the Type 2 energy-limited units will be saved for use in some future hour when it is needed.

**Cogeneration:** MARS models cogeneration as a thermal unit with an associated load demand. The difference between the unit's available capacity and its load requirements represents the amount of capacity that the unit can contribute to the system. The load demand is input by specifying the hourly loads for a typical week (168 hourly loads for Monday through Sunday). This load profile can be changed on a monthly basis. Two types of cogeneration are modeled in the program, the difference being whether or not the system provides back-up generation when the unit is unable to meet its native load demand.

**Energy-Storage and DSM:** Energy-storage units and demand-side management are both modeled as deterministic load modifiers. For each such unit, the user specifies a net hourly load modification for a typical week which is subtracted from the hourly loads for the unit's area.

## 14.4 Transmission System

The transmission system between interconnected areas is modeled through transfer limits on the interfaces between pairs of areas. Simultaneous transfer limits can also be modeled in which the total flow on user-defined groups of interfaces is limited. Random forced outages on the interfaces are modeled in the same manner as the outages on thermal units, through the use of state transition rates.

The transfer limits are specified for each direction of the interface or interface group and can be input on a monthly basis. The transfer limits can also vary hourly according to the availability of specified units and the value of area loads.

## 14.5 Contracts

Contracts are used to model scheduled interchanges of capacity between areas in the system. These interchanges are separate from those that are scheduled by the program as one area with excess capacity in a given hour provides emergency assistance to a deficient area.

Each contract can be identified as either firm or curtailable. Firm contracts will be scheduled regardless of whether or not the sending area has sufficient resources on an isolated basis, but they can be curtailed because of interface transfer limits. Curtailable contracts will be scheduled only to the extent that the sending area has the necessary resources on its own or can obtain them as emergency assistance from other areas.

## 14.6 Emergency Operating Procedures

Emergency operating procedures are steps undertaken by a utility system as the reserve conditions on the system approach critical levels. They consist of load control and generation supplements which can be implemented before load has to be actually disconnected. Load control measures could include disconnecting interruptible loads, public appeals to reduce demand, and voltage reductions. Generation supplements could include overloading units, emergency purchases, and reduced operating reserves.

The need for a utility to begin emergency operating procedures is modeled in MARS by evaluating the daily LOLE at specified margin states. The user specifies these margin states for each area in terms of the benefits realized from each emergency measure, which can be expressed in MW, as a per unit of the original or modified load, and as a per unit of the available capacity for the hour.

The user can also specify monthly limits on the number of times that each emergency procedure is initiated, and whether each EOP benefits only the area itself, other areas in the same pool, or areas throughout the system. Staggered implementation of EOPs, in which the deficient area must initiate a specified number of EOPs before non-deficient areas begin implementation, can also be modeled.

## 14.7 Resource Allocation among Areas

The first step in calculating the reliability indices is to compute the area margins on an isolated basis, for each hour. This is done by subtracting from the total available capacity in the area for the hour the load demand for the hour. If an area has a positive or zero margins, then it has sufficient capacity to meet its load. If the area margin is negative, the load exceeds the capacity available to serve it, and the area is in a loss-of-load situation.

If there are any areas that have a negative margin after the isolated area margins have been adjusted for curtailable contracts, the program will attempt to satisfy those deficiencies with capacity from areas that have positive margins. Two methods are available for determining how the reserves from areas with excess capacity are allocated among the areas that are deficient. In the first approach, the user specifies the order in which an area with excess resources provides assistance to areas that are deficient. The second method shares the available excess reserves among the deficient areas in proportion to the size of their shortfalls.

The user can also specify that areas within a pool will have priority over outside areas. In this case, an area must assist all deficient areas within the same pool, regardless of the order of areas in the priority list, before assisting areas outside of the pool. Pool-sharing agreements can also be modeled in which pools provide assistance to other pools according to a specified order.

## 14.8 Output Reports

The following output reports are available from MARS. Most of the summaries of calculated quantities are available for each load forecast uncertainty load level and as a weighted-average based on the input probabilities.

- Summary of the thermal unit data.
- Summary of installed capacity by month by user-defined unit type.
- Summary of load data, showing monthly peaks, energies, and load factors.
- Unit outage summary showing the weeks during the year that each unit was on planned outage.
- Summary of weekly reserves by area, pool, and system.
- Annual, monthly, and weekly reliability indices - by area and pool, isolated and interconnected.
- Expected number of days per year at specified margin states on an annual, monthly, and weekly basis.
- Annual and monthly summaries of the flows, showing for each interface the maximum and average flow for the year, the number of hours at the tieline limit, and the number of hours of flow during the year.
- Annual summary of energy and hours of curtailment for each contract.
- Annual summary of energy usage for the peaking portion of Type 2 energy-limited units.
- Replication year output, by area and pool, isolated and interconnected, showing the daily and hourly LOLE and LOEE for each time that the study year was simulated. This information can be used to plot distributions of the indices, which show the year-to-year variation that actually occurs.
- Annual summary of the minimum and maximum values of the replication year indices.

- Detailed hourly output showing, for each hour that any of the areas has a negative margin on an isolated basis, the margin for each area on an isolated and interconnected basis.
- Detailed hourly output showing the flows on each interface.

## 14.9 Program Dimensions

All of the program dimensions in MARS can be changed at the time of installation to size the program to the system being studied. Among the key parameters that can be changed are the number of units, areas, pool, and interfaces.

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