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to the Electricity Industry

Nova Scotia Power Stability Study for Renewable Integration

Report

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ABBREVIATIONS

AC	Alternating Current
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BESS	Battery Energy Storage Systems
DC	Direct Current
EMT	Electromagnetic Transient
EPRI	Electric Power Research Institute
FCAS	Frequency Control Ancillary Service
FFR	Fast Frequency Response
HVDC	High Voltage Direct Current
IE	Republic of Ireland
kV	kilo Volt
LSI	Largest Single Infeed
MW	Megawatt
MVA	Mega volt ampere
NB	New Brunswick
NI	Northern Ireland
NS	Nova Scotia
NSPI	Nova Scotia Power Inc.
NS-UARB	Nova Scotia Utility and Review Board
POI	Point of Interconnection
RMS	Root Mean Square
RoCoF	Rate of Change of Frequency
SA	South Australia
SC	Synchronous Condenser
SCRIF	Short Circuit Ratio with Interaction Factor
STATCOM	Static Synchronous Compensator
UFLS	Under Frequency Load Shedding
UK	United Kingdom

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Background Scene

Policies related to sustainable energy sources are driving the decarbonization of the energy mix. The technologies available for harnessing energy from sustainable sources and integrating these sources into existing power grids rely heavily on the use of power electronics. Wind and solar generation have proven to be the most cost-effective choices so far and have been deployed in many geographic regions, depending on the availability of local natural sources of energy. This move is observed as a clear shift from conventional synchronous generation (steam, hydro, combustion turbine) to power electronic device driven generation (wind, solar, battery energy storage) dominating the scene. The design and development concept of the power grid is based on conventional generating units providing inertia with rotating mass and system technical performance in terms of voltage and frequency stability was based on that concept. Therefore, the move toward a power electronic dominated power grid is expected to change the dynamic behavior of the power system [1].

System stability is a loosely used collective terminology that defines the overall level of system behavior within the context of integration of power electronic based generation. In terms of sustainable energy sources, the question then is the limit of power electronic based generation that can be accommodated in the system with impacting various system technical performance parameters. These cover transient voltage stability, frequency stability, short-circuit current levels, voltage waveform quality, voltage fluctuation and so on. Addressing system stability issues often results in Ancillary or Grid Services to be required. Depending on system characteristics, some systems experience part of the issues in a more prominent way than others and some can be resolved by relatively simple means under specific conditions. However, in general, with increased penetration of power electronic interfaced energy sources, all power systems will experience some form of change in their dynamic behavior with reduced system inertia, reduced system strength and possible interaction between the remaining synchronous machines on synchronizing and damping torque components [1]. Power quality is also a system characteristic that is influenced by this shift.

Study Objective

The objective of this study is to assess the integration of increased levels of renewable generation in Nova Scotia and to form recommendations for reinforcement and/or for further investigations required to enable this integration.

The Nova Scotia power system like any other power system is limited in its ability to accommodate an increasing number of power electronic interfaced generation. The specific limitations are due to its size, level of demand and limited interconnection with neighboring systems. The most challenging issues are its ability to export excess power to neighboring systems via the existing ties and to survive in an islanded mode following the loss of the AC ties.

This study looks into the possibility of increasing the levels of generation from renewables but more specifically from wind sources in Nova Scotia from the current installed capacity of 600 MW. Different renewable sources of energy have different intermittency characteristics. However, regardless of the primary source of energy (wind, solar, tidal, etc.), inverter-based generation has similar dynamic characteristics as viewed from the electrical grid, and this dynamic characteristic is different from that of a synchronous generator. Increasing intermittent inverter-based generation beyond this point in Nova Scotia while removing thermal units from system dispatch represents a challenge which needs to be addressed by careful consideration of many different aspects. These include system transient stability, regulation reserve to compensate for wind and load fluctuations, frequency control of Nova Scotia in islanded operation, keeping the short circuit levels sufficiently high, and preferably expanding the export market. It is noted that the trend observed in the Nova Scotia system - that inverter-based generation displaces conventional forms of generation - is seen in other jurisdictions around the world as well. Two examples, one from Australia (South Australia power system) and one from Europe (Irish power system) are given as comparative background information due to their similarities to the Nova Scotia system as well as PSC's system knowledge and involvement in those jurisdictions.

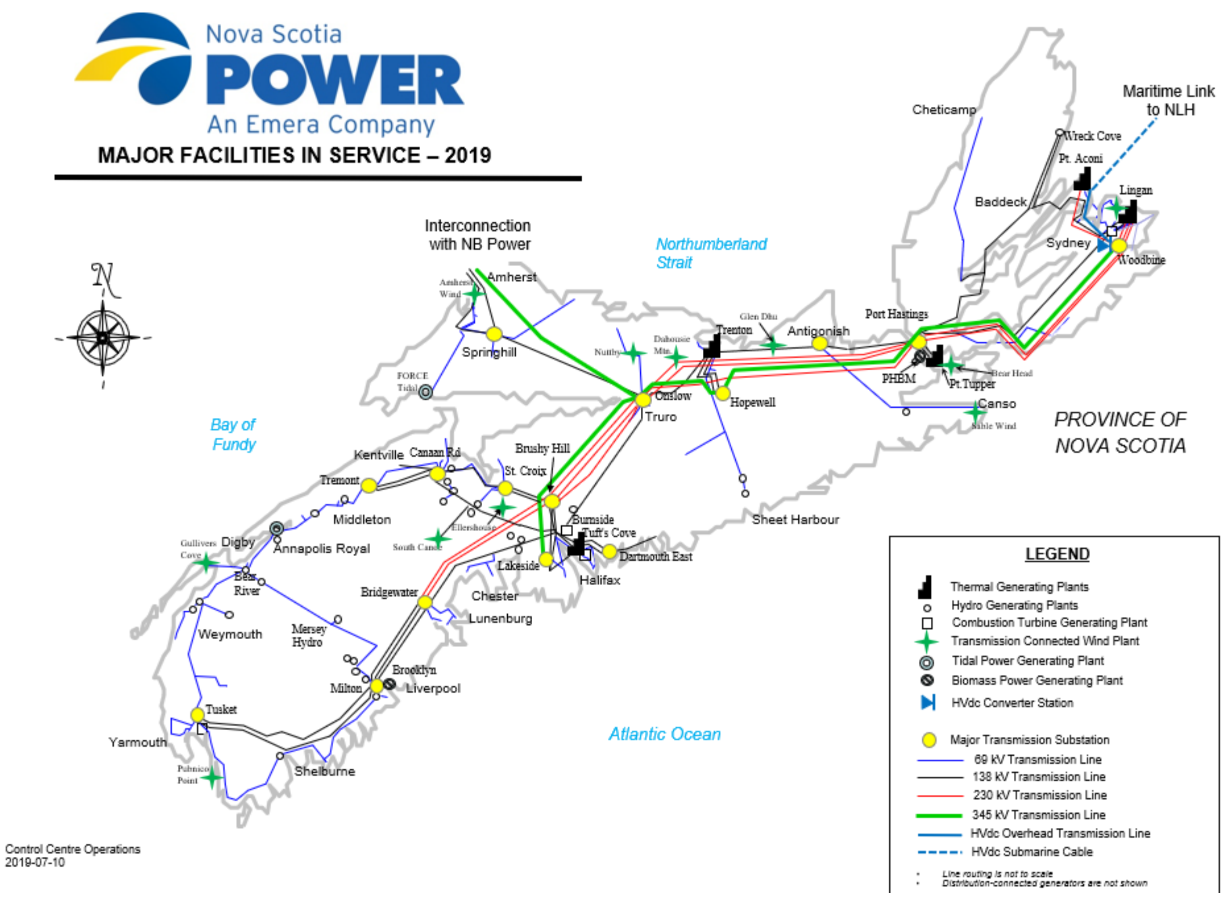
The main driver behind this study has been the directive issued by the Nova Scotia Utility and Review Board (NS-UARB) regarding the need for such a study:

> *"Establish requirements to allow increased levels of wind on the NSPI system. Two threshold criteria to allow increased levels of cost-effective wind resources are completion of a second 345 kV intertie to New Brunswick, and assessment of NSPI's Provincial transmission system and related support services (to maintain stability and voltage criteria). NSPI should determine, with specificity, the set of technical improvements required to allow different increments of additional wind on their system. This should include the effect of additional transmission capacity to New Brunswick, the presence of the Maritime Link, and the ability to further increase wind penetration through transmission grid reinforcement. This should also recognize that the introduction of bulk scale battery storage as a possible capacity resource that can provide co-benefits associated with stability and voltage support."*

Study Approach and Methodology

There are two main components to this study: the first is an initial glimpse into the aforementioned international experience from Australia and Ireland in order to draw comparisons to the Nova Scotia system. This identifies the challenges other systems have, the metrics used to measure the adequacy of the system to support increasing levels of variable renewable generation, and the solutions that have been suggested or tried. The second component of the study mainly comprises transient stability simulations, but also other means of analysis performed on the Nova Scotia system model to establish an understanding of the particular technical issues that Nova Scotia has to deal with. The analysis allows for recommendations for system reinforcements and for further investigations in order to integrate an increased level of renewable generation in Nova Scotia.

The following map shows the major generation and transmission facilities in Nova Scotia. An HVDC link connects Nova Scotia to Newfoundland. Nova Scotia is also connected through two AC links (345-kV and 138-kV) to New Brunswick. The energy import and export happen through these two links. In addition to scheduled flow, these links provide for emergency supply. The reserve capacity allocated to the links is an important part of secure operation of the interconnected grid. As the renewable generation capacity increases at a faster pace than the demand in Nova Scotia, excess generation above what the system requires or is able to accommodate, will become a more frequent occurrence. This excess generated power must be exported or curtailed[1]. This economical tradeoff is studied in resource planning exercises such as an Integrated Resource Plan.



[1] Curtailment could be an economic option if the cost of upgrades to permit low or no curtailment operation exceed the benefits of the curtailment reduction.

As the map shows, the transmission connected wind farms are spread throughout the province. This study has found that for some of the wind farms the short circuit levels are marginally low. For the wind farms that are close to online thermal generating plants the short circuit level at the point of interconnection to the grid is generally higher than for those which are remote from online large synchronous machines. However, if the thermal units are retired or dispatched off this advantage fades away. The inverter-based generators typically use the voltage at the Point of Interconnection (POI) to synchronize with the grid. When the short circuit ratio at the POI is very low, during faults in the system the voltage measurement will become erroneous, and it can cause the wind farm to become unstable resulting in the tripping of the farm or control system oscillations. This is especially a problem in the South Australia system due to a large geographic area and long transmission lines with wind farms clustered together remote from synchronous machines. One way to remedy this situation is to install synchronous condensers in close proximity to the wind farms.

Increasing the transfer levels on the ties and retiring of synchronous generators in correlation to bringing on more renewable generation in Nova Scotia poses another challenge; the frequency stability of the grid. The major event of interest in this regard is tripping of the AC ties to New Brunswick and islanding of Nova Scotia which causes large frequency excursion (over-frequency or under-frequency) in Nova Scotia. At present under-frequency load-shedding is relied upon for mitigation, but this creates its own problems as the shed load needs to be restored and raises reliability and reputational concerns. This challenge is more pronounced in Nova Scotia in comparison to the other two systems referenced in this report, i.e. South Australia and Ireland (due to the relatively smaller size, and hence lower online inertia, of the NS system as compared to SA or Ireland but with comparable largest single contingency on a percentage basis).

Study Criteria

Historically, generation in power systems consisted mainly of synchronous machines with high inertia, such as thermal units. As a result, most disturbances in the system were not able to cause large frequency excursions. However, as more conventional generators are being retired and replaced by inverter-based generators, the frequency excursions in the system have become more extreme.

Conventional power systems operate around a narrow frequency band (60 Hz in North America). When the frequency deviates from the nominal frequency, several unwanted effects happen and the automatic controllers in the system act to bring it back to the nominal value. There are both fast and slow controllers in the system that are sensitive to frequency changes. Under frequency load shedding is a fast remedial action which sheds some load if the frequency dips and stays below a certain threshold. In Nova Scotia one scenario that causes this to happen is when the AC ties are tripped while importing power from New Brunswick. The higher is the import prior to tripping, the bigger the frequency dip will be.

The main question that was answered by the simulations in this study was if the Nova Scotia system, upon disconnecting from the AC interconnection or losing one DC pole, will be able to survive the transients and remain stable. In addition, several other contingencies internal to Nova Scotia were simulated.

The criteria checked for each simulation were:

- No cascade generator or transmission line tripping
- No loss of synchronism
- Frequency maintained with the frequency fault ride-through envelope
- Voltage at generator connection points maintained within the voltage fault ride-through envelope
- No thermal overloads on lines
- Fault current levels sufficient to operate transmission and distribution protection
- Short circuit ratio maintained for wind farm points of interconnection

It should be noted that transient stability simulation looks into the behavior of the system a few seconds immediately after a disturbance in the system. Wind variations in longer time frames of minutes or hours are known to also have an impact on the stability of the system and need to be properly considered. However, this study did look into the regulation reserves needed to accommodate increased levels of wind generation.

Another impact of inverter-based generation is that it reduces the short circuit level in the system. This has a negative impact on transmission system protection[2] as the relays do not see the same level of currents flowing during short circuit events and might not isolate the affected part of the system in time to protect the equipment. From the viewpoint of the inverter-based generator, very low short-circuit levels might cause its controllers to mal-function. Therefore, it is important to maintain a minimum level of short circuit ratio at wind farm locations.

Study Results

This study showed that 600 MW of wind generation can be handled by the existing system under a variety of system load and conditions studied. This conclusion was arrived at by considering different metrics such as the short circuit ratios at wind farm points of interconnection to the grid, regulation

[2] More of an issue for distance protection. Differential protection is less susceptible to maloperation due to low fault levels.

reserve needed to compensate for wind fluctuations, and mainly by performing transient stability simulations. In these simulations the Nova Scotia system was stressed by maximizing wind MW output and reducing the number of synchronous generators online.

Next, simulations were performed with different system reinforcements and increased wind levels. It was found that a second 345-kV AC transmission line to New Brunswick will allow wind generation to be increased close to 1000 MW. The loss of the existing 345 kV tie is a major contingency for the Nova Scotia system and inclusion of this second tie brings system security and flexibility in terms of operating the system.

In the third batch of studies, synchronous condensers and battery storage systems were added into the Nova Scotia power system as an alternative to adding the second 345-kV AC tie to New Brunswick. This study found that at 1000 MW wind level, a 200-MVA synchronous condenser and a 200-MW battery storage with fast ramping capability will be enough to reduce the under-frequency load shedding to two stages (out of six) in case of losing the AC tie to New Brunswick. It is important to note that the investigation looked only at the addition of these two technologies without the second New Brunswick tie. Both these options require further study.

Interpretation of Results

To be able to rely on the protection systems that have been successfully operating in the system for decades it is important to keep a certain amount of rotating inertia online. The study concluded that for the existing system, Nova Scotia should have at least three thermal units online so that in case of islanding it can come back to a new stable steady state operating condition. Translating this into an online minimum system inertia value is possible and a figure is provided, however, to refine this figure, further studies covering a variety of dispatch scenarios is required. Minimum thermal limits were set based on the loss of a single tie to New Brunswick, with limited support from Maritime Link and no support from wind generation. Therefore, the second tie eliminates the primary rationale behind the minimum online thermal units. However, other services are required for the system which are provided by the thermal units regardless of the second tie option. Those services include:

- Balancing services (tie-line control) to manage fluctuations in load and renewable generation (wind, solar).
- Load following, a longer-term generation control service to manage load pickup from overnight to daytime loads
- Short circuit current and voltage control at a local level (perhaps provided with a combination of synchronous condensers and the second tie).

The addition of a second tie will push the possible level of wind generation to 1000 MW and will also bring about enhanced system security and stability as it avoids islanding of Nova Scotia in the event of losing a single AC tie. A similar increase in wind capacity can be achieved with the introduction of synchronous condensers and battery storage; however, with this option islanding of Nova Scotia, and subsequent load or generator shedding and challenges with frequency control in islanded operation will not be addressed.

Adding synchronous condensers has three major benefits. First, they stay online during short circuit events and contribute to the short circuit current therefore improving the short circuit ratio. Second, they add to the online inertia in the system, so the frequency excursion magnitudes and rates of change reduce. Third, synchronous condensers have a fast voltage controller that can regulate the voltages in the system.

Batteries also bring several advantages in general. Like synchronous condensers they help with regulating the voltage. However, being inverter-based they do not contribute to the short circuit ratio. Batteries can compensate for the power imbalance caused by a transmission tie trip or a generator or load trip event rapidly, up to their power capability. Simulations done with both batteries and synchronous condensers in this study show that the load shedding can be effectively reduced. The batteries also help with the more long-term task of regulation with intermittent wind power.

The study results indicate that for the scenarios studied, the contribution of the synchronous condenser to the online inertia in Nova Scotia in islanded operation cannot reduce the load shedding amount by a significant amount. Hence, a combination of batteries and synchronous condensers seem to provide a better technical solution (however, still not better than a second tie to avoid islanding for the same contingencies). Introduction of synchronous condensers by retro fitting existing synchronous generators that are planned to be decommissioned has been considered as a possible option in some systems. The choice between such conversion as opposed to a new standalone procurement and installation needs to be made based on project delivery, technical requirements and limitations, and cost-benefit analysis.

Observations from the Study

The current study has utilized only a limited but representative number of system scenarios. The analysis shows the possibility of an increased wind capacity especially with the inclusion of the second tie to New Brunswick. However, more dispatch scenarios will need to be studied or at least checked in order to establish a more robust level of renewable penetration.

Time domain simulations using RMS quantities, such as done in this study, have known limitations. By expanding the studies into electromagnetic time domain, it is possible to establish a more technically robust behavior from the power electronic device controls, which in turn may increase the level of renewables that can be accommodated.

The study has not specifically looked into the provisions of grid code requirements. This is an area other jurisdictions have taken forward especially with regard to the expectations for renewable sources, provisions like synthetic inertia to name one.

Implications on power quality requirements have also not formed part of the analysis conducted. Introducing larger volumes of power electronic devices into the system has known adverse effects with regards to, for example, harmonic distortion levels on the system.

Conclusions and Recommendations

The study results suggest that the existing Nova Scotia power system can support the existing 600 MW of wind generation. In the current state, in order to stay secure for the loss of the New Brunswick tie, at least 3 thermal units are required to be online. Even with this measure, when the tie is importing, a large amount of customer load needs to be shed to recover the system frequency during such an event.

The development of the second 345 kV tie to New Brunswick (Onslow to Salisbury) allows the integration of a further 400MW of wind generation (system installed total of 1000 MW inverter-based generation). Furthermore, it provides an enhanced level of system reliability and security for the Nova Scotia system across a range of operating conditions including storm events.

The same level of wind generation can be reached with the deployment of synchronous condensers and BESS. However, to avoid all stages of load shedding to be activated following trip of the existing tie to New Brunswick when importing, the synchronous condenser and BESS need to be large (judged by comparison to such installations in other jurisdictions). A 200 MVA synchronus condenser fitted with flywheel and a 200 MW BESS reduce the load shedding to 2 stages out of 6. This option also lacks the ancillary reliability benefits afforded by the second 345kV tie line.

Study results indicate that the tie to New Brunswick is of the highest significance to the stability of the NS Power system as the loss of the tie dictates most of the planning and/or operational actions. Strenthening of this tie with a second 345 kV line becomes crucial and should be considered as the first alternative to explore before the introduction of other technological solutions or in tandem with them. Application of synchronous condenser and BESS in addition to the second tie line, would result in more benefits such as an increase in renewable generation and enhanced system security and flexibility.

In concluding, within the scope of the studies performed in preparing this report, it is recommended that the existing study should be expanded to establish a system security level commensurate with increased wind generation. The defined topology should include the second tie as a starting position so that intuitive studies to establish maximum renewable generation penetration with minimum system reinforcement can be established.

Further recommendations beyond the introduction of the second tie include:

- Expand the existing study to check wider system dispatch scenarios and establish requirements in terms of support.
- Perform enhanced studies in EMT area to support technical requirement.
- Establish how the requirements can be met, such as service provision via specific investments or via grid code changes.
- Commission parallel studies to check other areas of possible technical limitations such as power quality.

1. Introduction

As part of the move to more sustainable electrical energy sources, there is a growing trend in shifting the production of electrical energy to more carbon free sources. Harnessing sustainable and renewable energy sources and then integrating these into power networks is mainly achieved through the use of power electronic devices with different electrical performance characteristics when compared to synchronous machines.

A key aspect of this shift from synchronous generation to power electronic device driven generation, is the expected change in the dynamic behavior of the power system that will have an impact on the various stability characteristics that define technical limits of operation. Many factors are expected to affect the way this proliferation influences the operability of the system, for example smaller systems may require more stringent performance requirements, introduction of new technology or services while others can accommodate this change to a level with no substantial change.

The main technical aspects associated with the integration of power electronic converter-based generation concentrate around voltage and frequency stability issues, reduced system strength, effect of loads and potential interaction issues. Issues associated with voltage stability are due to lack of reactive power provision or demand (demand issue due to the loads being fed by distributed sources). On the frequency stability side, the lack of inertia is earmarked to be the major issue as it has been observed to increase the rate of change of frequency following system disturbances. Furthermore, in systems where priority is given to reactive power rather than active power in terms of control, frequency issues due to lack of active power injection have been observed following voltage dips on the systems. Reduced system strength is expected to bring several new issues such as the lack of enough short circuit current to trigger protection systems, mis-operation of phase-locked-loop controllers and commutation failures of line commutated converters due to increased chance of voltage depression. Loads with constant power characteristics drawing an increased current under reduced system strength with the voltage depressed will also add to the ongoing technical issues. Finally, oscillation due to resonances and especially at sub-synchronous frequencies is being envisaged as a further limitation to be caused by the introduction of control interactions.

The Nova Scotia power system has experienced a steady growth of wind generation through the years with the total installed wind capacity in 2018, reaching just over 600 MW. This steady growth, relative to the size of the system, is partly due to the requirements introduced for Nova Scotia to have a more diverse energy mix, reaching 40% renewable energy by 2020 and partly due to the take up of community owned wind generation projects as part of Community Feed-in Tariff introduced back in 2011. The 600 MW level was thought to be at or near the limit of economic wind integration into the Nova Scotia Power system without any system upgrades. Therefore, the need arose to revisit the situation and to study and investigate if 600 MW can indeed be supported by the current system conditions, and in addition to look into the possibilities of increasing the wind penetration level in Nova Scotia beyond the potential limit.

The current work was therefore commissioned and executed as a result of the directive issued by the Nova Scotia Utility and Review Board (NS-UARB) which states that the study should:

> *"Establish requirements to allow increased levels of wind on the NSPI system. Two threshold criteria to allow increased levels of cost-effective wind resources are completion of a second 345 kV intertie to New Brunswick, and assessment of NSPI's Provincial transmission system and related support services (to maintain stability and voltage criteria). NSPI should determine, with specificity, the set of technical improvements required to allow different increments of additional wind on their system. This should include the effect of additional transmission capacity to New Brunswick, the presence of the Maritime Link, and the ability to further increase wind penetration through transmission grid reinforcement. This should also recognize that the introduction of bulk scale battery storage as a possible capacity resource that can provide co-benefits associated with stability and voltage support."*

This report sets out to explain the studies performed in order to establish the level of power electronic converter-based generation that can be accommodated on the Nova Scotia power system as is and by considering the developments suggested in the above directive.

It is worth noting that the upward trend of conventional generation being displaced with inverter-based generation is not unique to Nova Scotia and other electric power systems are facing similar challenges. High level comparative information for two such systems are provided in the report due to PSC having specific knowledge about these two systems and their similarities to the Nova Scotia electric power system.

The following sections describe the methodology used in this study along with the assumptions made. Information for the Nova Scotia power system is provided in more detail including power flow, dynamics, and contingency models.

Observations from the transient stability simulations and an overview of studies and issues from two other jurisdictions (South Australia and Ireland) are discussed in order to draw parallels and/or jurisdictional best practices.

It is important to note that the term "wind" or "wind generation" is used interchangeably with renewable energy sources and the generic conclusions would also apply to other power electronic interfaced generation (solar, BESS) that have similar control characteristics.

2. Wind Integration Experience in Other Jurisdictions

This section discusses the experiences of two jurisdictions, i.e. South Australia and Ireland, in integrating large amounts of inverter-based generation into their systems. While every jurisdiction has its own unique characteristics, learnings can be drawn related to technical challenges and how these have been addressed and overcome or mitigated.

2.1. South Australia

South Australia has experienced rapid growth in renewable generation, reaching very high levels of penetration by global standards. These changes have been driven by various government-led renewable energy policies aimed at reducing carbon emissions as well as rapid changes in the economics of power generation, generally favoring renewable generation. During the 2017-18 financial year, renewable generation in South Australia exceeded demand for 366 hours, with the excess energy exported to Victoria via the existing AC and/or DC interconnector.

The South Australian transmission network covers a geographically large area (over 200,000 square kilometers) with approximately 5,600 kilometers of transmission lines, operating at 132 kV and 275 kV. The maximum demand is 3,005 MW. The load and conventional generation are largely concentrated in the Adelaide metropolitan area, however the bulk of the utility scale renewable generation (1,809 MW of wind generation and 135 MW of solar PV generation) is connected to remote parts of the network, with a large cluster of wind generation approximately 200 km north of Adelaide. The utility scale renewable generation is complemented by a significant and rapidly growing amount of rooftop solar PV generation (currently 930 MW of installed capacity). South Australia is interconnected with Victoria via a 275 kV double circuit AC interconnector (650 MW transfer capability) and a voltage source converter HVDC link (200 MW transfer capability). A map of the South Australian transmission system is shown in Figure 2-1.

The nominal frequency of the South Australia power system is 50 Hz.

On 28 September 2016, South Australia suffered a statewide blackout, causing loss of supply to 850,000 customers. While 80% - 90% of load was restored within 8 hours, supply was only restored to all customers by 11 October 2016. The subsequent investigation by the Australian Energy Market Operator (AEMO) found that while extreme weather triggered the sequence of events that led to the blackout, the loss of the AC interconnector that precipitated the complete loss of supply was largely due to the unforeseen sustained reduction in output from a number of wind generators in the state.

Following the blackout and the findings of this investigation, AEMO focused its attention on determining measures to be taken to ensure that the South Australian system continues to operate in a secure state, while accommodating a large and growing amount of renewable generation.

Figure 2-1 South Australian Transmission System Map

In the South Australian context, the following critical issues associated with high renewable penetration have been identified by AEMO:

Low system strength

Low system strength is generally characterized by low fault levels due to high system impedances and low levels of synchronous generation. Given the long transmission distances and sparse, radial network topology, fault levels in the South Australian system are particularly low. This is further exacerbated by the fact that the synchronous generation in service is located relatively far from the major wind generation clusters. Further, as more inverter-based generation is connected in close proximity to other inverter-based systems, the system strength as measured by the short circuit ratio, is eroded even further.

The types of inverters typically used in utility scale renewable facilities require a minimum system strength (often specified as a minimum short circuit ratio) in order to maintain stable operation. This could result in the generator tripping due to contingencies under low system strength conditions that it would otherwise remain connected for. Power electronic devices such as STATCOM are similarly susceptible to low system strength.

Low system strength also results in larger magnitude voltage disturbances, affecting the network in a wider area, than would be the case for a higher strength system.

Low system strength may also cause potential mal-operation of protection systems, with distance protection relays considered particularly susceptible. For example, protection may fail to operate for a fault with possible cascaded tripping due to fault clearance by out-of-zone protection. Protection system adequacy is considered a less critical issue within South Australia as the transmission system protection generally consists of duplicate distance and differential protection, with differential protection able to operate reliably at low system strength.

Frequency control

AEMO manages power system frequency control through the Frequency Control Ancillary Services (FCAS) market. There are eight FCAS markets, consisting of Regulation Raise, Regulation Lower, Fast Raise (within 6 seconds), Fast Lower (within 6 seconds), Slow Raise (within 60 seconds), Slow Lower (within 60 seconds), Delayed Raise (within 5 minutes) and Delayed Lower (within 5 minutes). While the FCAS market is technology neutral, these services have predominantly been provided by synchronous generators. There is some concern that increasing renewable penetration could potentially result in less FCAS capability being available in the market. However, most modern utility scale renewable generators are capable of offering all eight FCAS services with economic tradeoff effects.

Higher penetration of inverter-based renewable generators also reduces the total system inertia. Lower system inertia tends to increase the rate of change of frequency (RoCoF). AEMO found that the reduction in inertia could be mitigated to a certain extent, but not entirely, by increasing the amount of Fast FCAS provided (raise or lower within 6 seconds). In the South Australian context, a certain minimum amount of inertia therefore needs to be online in order to ensure that the rate of change of frequency is limited to less than 3 Hz/s to provide sufficient time for FCAS resources to act and as a last resort, for reliable operation of the UFLS scheme.

AEMO also investigated the possibility of using fast frequency response (FFR) provided by inverter-based systems to compensate for the reduction in inertia. However, it was found that the time delays required for accurate frequency measurement would still make it necessary to have sufficient inertia online. The minimum inertia requirement is simultaneously met when dealing with the system strength issue.

Reactive support shortfalls

The withdrawal of synchronous generation may result in reactive support gaps at key network locations. Northern Power Station, with a capacity of 520 MW was retired in May 2016. This led to a sudden loss of a significant amount of reactive support. ElectraNet is currently considering installing a Synchronous condenser at Davenport (near the network location where Northern Power Station was connected). The synchronous condenser is primarily installed to address the system strength shortfall, however it will also add inertia as well as providing reactive support.

In order to address these issues, the following actions have been taken by AEMO:

1. **Model requirements**

   Inverter-based generation requires a minimum system strength (specified as a minimum short circuit ratio) in order to maintain stable operation. The key component is the phase-locked-loop (PLL), which tracks the phase angle of the grid voltage in order to synchronize the inverter to the grid. As the PLL is either simplified or completely ignored in RMS models, accurate assessment of system performance under very low system strength conditions requires the use of detailed EMT models. Accurate, site-specific and plant-specific RMS models (in PSS®E format) as well EMT models (in PSCAD™ format) must be provided by all generators with capacity above 5 MW seeking to connect to the grid. The PSS®E and PSCAD™ models have to be benchmarked against each other and against site-measured responses obtained during commissioning tests in order to demonstrate that the models accurately represent the plant. Accurate, high fidelity models are of critical importance to AEMO in order to correctly determine the technical envelope of the system, particularly in determining minimum system strength and minimum inertia requirements.

2. **Minimum number of online synchronous machines**

   AEMO developed a detailed PSCAD™ model of the South Australian system, including detailed models of all generators and relevant protection to determine the minimum number of synchronous machines required to be online to provide sufficient system strength at different levels of renewable generation. A complex picture has emerged from this South Australian study, with approximately 65 different combinations of online synchronous machines determined for a range in non-synchronous generation levels. At present, AEMO directs these synchronous generators to run once non-synchronous generation reaches 1,295 MW and a system strength shortfall is predicted.

3. **Renewable FCAS trial and subsequent enforcement**

Until relatively recently, many inverter-based generators were connected to the network without frequency control capability specified in their performance standard or enabled in the physical plant. Recognizing that these devices are capable of providing frequency control services, AEMO requested that the ability to provide all 8 FCAS market services be tested at Hornsdale Wind Farm in South Australia to demonstrate the feasibility of these services being offered by inverter-based generation. The trial was a success and AEMO has subsequently insisted that all inverter-based generators seeking to connect to the network incorporate frequency control capability into their technical performance standards and demonstrate their capability to provide these services when commissioning the new generator.

4. Grid code changes

In 2018, a number of changes were introduced to the grid code, specifically imposing more onerous technical performance requirements on generators connecting to the grid. A number of these changes have been made in response to the lessons learnt from the South Australian blackout and with a view to increasing system resilience under low system strength. The key new requirements are:

a. More onerous voltage disturbance withstand requirements
b. Increased RoCoF withstand capability, requiring generators to remain connected for rates of change of frequency of +/-3 Hz/s for 1 second and +/-4 Hz/s for 0.25 seconds.
c. Multiple fault ride through withstand capability, requiring generators to remain connected for up to 15 faults occurring within a 5-minute period.

5. System strength rule change

In 2018, following the introduction of the “Managing power system fault levels” rule change, new measures were introduced to address system strength issues within the Australian interconnected system. This rule change had two key components:

a. AEMO determined minimum fault levels at a number of designated fault level nodes, effectively introducing a lower limit to system fault levels that should not be breached in order to maintain reliable system operation. In South Australia, the fault level nodes and associated minimum fault levels were: Davenport 275 kV bus - 1,150 MVA, Robertstown 275 kV bus - 1,400 MVA and Para 275 kV bus – 2,200 MVA). AEMO found that a system strength shortfall currently exists in South Australia. ElectraNet, the transmission system owner and system planner in South Australia has proposed mitigating this system strength shortfall by installing a number of synchronous condensers by 2020. ElectraNet further proposed specifying these synchronous condensers to have higher inertias (by fitting flywheels to the synchronous condensers) to assist in limiting the rate of change of frequency in South Australia. This has been proposed on the basis that the additional capital cost is relatively low, while the benefits are significant.

b. All new generator connections are assessed at an early stage of the connection evaluation process to establish whether they would have an adverse impact on system strength to mitigate adverse system strength impacts. The network service provider performs a preliminary system strength impact assessment (PIA) using steady state analysis tools and if necessary, a full impact assessment (FIA) using electromagnetic transient (EMT) models at the connection inquiry stage. Should this assessment indicate an adverse system strength impact, then approval of the connection application would be subject to the generator agreeing to take action to restore system strength to acceptable levels. This requirement has resulted in synchronous condensers being required for a number of inverter-based renewable projects. Renewable generators are particularly likely to be affected as they tend to connect to relatively weak grid locations and reduce system strength by reducing the effective short circuit ratio. This rule change has unfortunately had some potentially negative consequences, with generators attempting to use system strength to disadvantage competitors and inefficient network investment due to synchronous condensers being installed on a per-project basis instead of optimizing system wide benefits.

6. Minimum inertia requirement

AEMO performed detailed studies to determine the minimum inertia requirements for each state in the interconnected system. In the South Australian context, the minimum inertia requirements are easily met when the minimum number of synchronous machines are online to ensure that the system strength requirements are met. For this reason, system strength is more critical than frequency control at this point in time. Given that ElectraNet are proposing installing synchronous condensers with higher inertias to mitigate the system strength issue, the minimum inertia requirement is likely to be met without significant market intervention as is currently the case, with AEMO directing certain synchronous generators to run during periods of high wind generation.

In addition to these measures, final approval from the Australia Energy Regulator (AER) is currently being sought for the construction of a second AC interconnector, a 330 kV double circuit line from the mid north region of South Australia (where a large amount of wind generation is currently connected) to Wagga in the neighboring state of New South Wales (also a region where large amounts of wind and solar PV generation is connected). The second AC connector will be designed to provide a nominal transfer capacity of 800 MW. The benefits of this interconnector are increased system security in South Australia, considered essential given the increasingly credible loss of both circuits of the existing AC interconnector, as well as facilitating increased penetration of renewables.

South Australian System Characteristics relevant to renewable penetration:

- **Total installed wind capacity**: 1,809 MW (29.2% of total installed generating capacity, including rooftop PV))

- **Total installed solar capacity**: 135 MW utility scale (2.2% of total installed generating capacity, including rooftop PV) and 930 MW rooftop PV (15% of total installed capacity)
- **Total installed synchronous condenser**: None at present, however ElectraNet plans to install synchronous condensers by 2020 to address the system strength and inertia shortfall. This shortfall is currently managed by AEMO directing synchronous machines to run, however ElectraNet's analysis indicates a net market benefit for synchronous condensers to be used instead.
- **Total installed battery**: 130 MW, consisting of Hornsdale: 100 MW / 129 MWh and Dalrymple: 30 MW / 8 MWh.
- **Minimum required total online inertia**: At present, the minimum online inertia required is 6,000 MW.s. This figure is based on SA operating as an island, taking into account the potential loss of the largest synchronous generator in the state, the Pelican Point gas turbine, which withdraws 1620 MW.s of inertia. The minimum threshold inertia after losing the Pelican Point gas turbine is 4,400 MW.s
- **AC or DC ties to other systems: AC interconnector**: a double circuit 275 kV line to Victoria with bi-directional transfer capacity of 650 MW. DC interconnector: a DC link with Victoria with transfer capacity of 200 MW (import to SA) and 220 MW (export from SA). The transfer capacity of the DC link is often limited by constraints within the Victorian system.
- **Largest single contingency in the system**: Loss of the largest generating unit, the 750 MW generator at Kogan Creek in Queensland for the interconnected system or the loss of the largest generator in SA if islanded. This is the 160 MW Pelican Point gas turbine (which has high inertia) or to a lesser extent the loss of a Torrens Island Power Station as turbine (200 MW), depending on unit commitment. The loss of both circuits of the double circuit AC interconnector (up to 650 MW) may be reclassified by AEMO as a credible contingency should there be an increased risk to extreme weather or bushfires.
- **What is the highest recorded inverter-based generation in the system**: Renewable penetration can be measured in a number of different ways. Table 2-1 lists renewable penetration in 2017-18 by installed capacity, energy consumption and as a percentage of state-based demand. At periods of 100% penetration, the minimum number of synchronous machines remain online as described above and South Australia is exporting to Victoria.
- **Peak summer load**: SA Summer 2018 operational maximum demand was 3,005 MW, occurring at 7:30 pm. The time at which maximum demand occurs has in recent years shifted later in the evening by increasing rooftop PV penetration.
- **Peak winter load**: Winter peak operational demand is approximately 2400 MW.
- **Minimum load**: A major consideration is the minimum demand, presently about 646 MW (2017-18 actual, recorded at 1:30 pm), occurring in the early afternoon due to high rooftop PV generation (approximately 930 MW installed capacity in 2017-18, with approximately 820 MW

output at minimum demand). The minimum demand is forecast to become negative by 2024 (90% POE) and continue to fall thereafter.

Table 2-1: Renewable Generation in 2017-18 by Installed Capacity, South Australia

Description	Wind value for South Australia	Rooftop PV value for South Australia
Capacity penetration: installed capacity as a percentage of total installed generation*	40%	16%
Energy penetration: ratio of annual energy to annual total energy consumption**	43%	9%
Maximum instantaneous penetration (excluding exports): maximum observed ratio of energy to demand at any instant in time during the year**	138%	33%
Periods of 100% (or greater) instantaneous penetration	366 hours	0 hours

* Wind calculations are based on AEMO registered capacity for all South Australian generating systems at the end of the financial year. However, excluded are generating units that are effectively mothballed for more than six months of the financial year, and wind farms whose output did not yet reach 90% of registered capacity by end of the financial year. Rooftop PV capacity penetration is calculated by adding estimated rooftop PV capacity at end of the financial year to registered capacity.

** Wind generation analysis is based on operational demand as generated, whilst rooftop PV is based on underlying demand.

- **Lowest frequency dip experienced in the system**: 47 Hz, just prior to frequency collapsing completely during the SA system blackout event on 28 September 2016.
- **Load shedding considered for low frequency events?** Yes. However, UFLS is considered an operational measure and is not taken into account when planning the system.
- **Rate-of-Change-of-Frequency (RoCoF) relays in the system**: Yes, on generators. RoCoF in the system must be limited to 3 Hz/s for the UFLS scheme to operate reliably.

2.2. Ireland

The Irish transmission system comprises two distinct areas; the transmission system of Ireland (IE) operated by EirGrid at 400 kV, 220 kV and 110 kV and the transmission system of Northern Ireland (NI) operated by SONI at 275 and 110 kV. The two systems are electrically connected by means of one 275 kV double circuit from Louth in IE to Tandragee in NI. There are also two 110kV connections: Letterkenny in IE to Strabane in NI and Corraclassy in IE to Enniskillen in NI. The 400 kV, 275 kV and 220 kV networks form the backbone of the transmission system and the whole system is operated as an All-Island system. System peak is experienced in winter months due to greater heating and lighting requirements and peak is around 6500 MW. The minimum demand on the system is in summer months, termed “minimum summer night valley” and is around 2500 MW. The Irish transmission system map is shown in Figure 2-2.

The nominal frequency of the Irish power system in 50 Hz.

As part of European Union’s binding national targets, Ireland is committed to 16% of the country’s total energy consumption to come from renewable energy sources by 2020. The total energy consumption includes heating, transport and electricity. In the electricity sector this target necessitates a significant increase in the amount of renewable generation on the Irish power system and an All-Island Grid study (published in 2008) concluded that up to 42% of renewable generation could be accommodated on the whole Irish system (Ireland and Northern Ireland). In 2010, EirGrid and SONI published the study results on the Facilitation of Renewables (FoR) [5] summarizing the operational implication of managing such high levels of variable renewable generation on the system. In 2011, EirGrid in Ireland and SONI in Northern Ireland embarked upon a multi-year project referred to as DS3 (**D**elivering a **S**ecure, **S**ustainable electricity **S**ystem) to meet the 40% renewable electricity target by 2020. This is expected/planned to be delivered largely by wind (around 37%) and is the highest for any synchronous system in Europe.

As part of the FoR studies, a number of possible system issues has been identified and these have been categorized according to severity as those that impose fundamental operational limits, those that may impose fundamental operational limits, those that impose operational limits but can be mitigated and those that seem not to impose operational limits. Among those the most important technical issue encountered is frequency stability and its emergence cannot be mitigated via current technology. An overview of the issues identified is given in Figure 2-3.

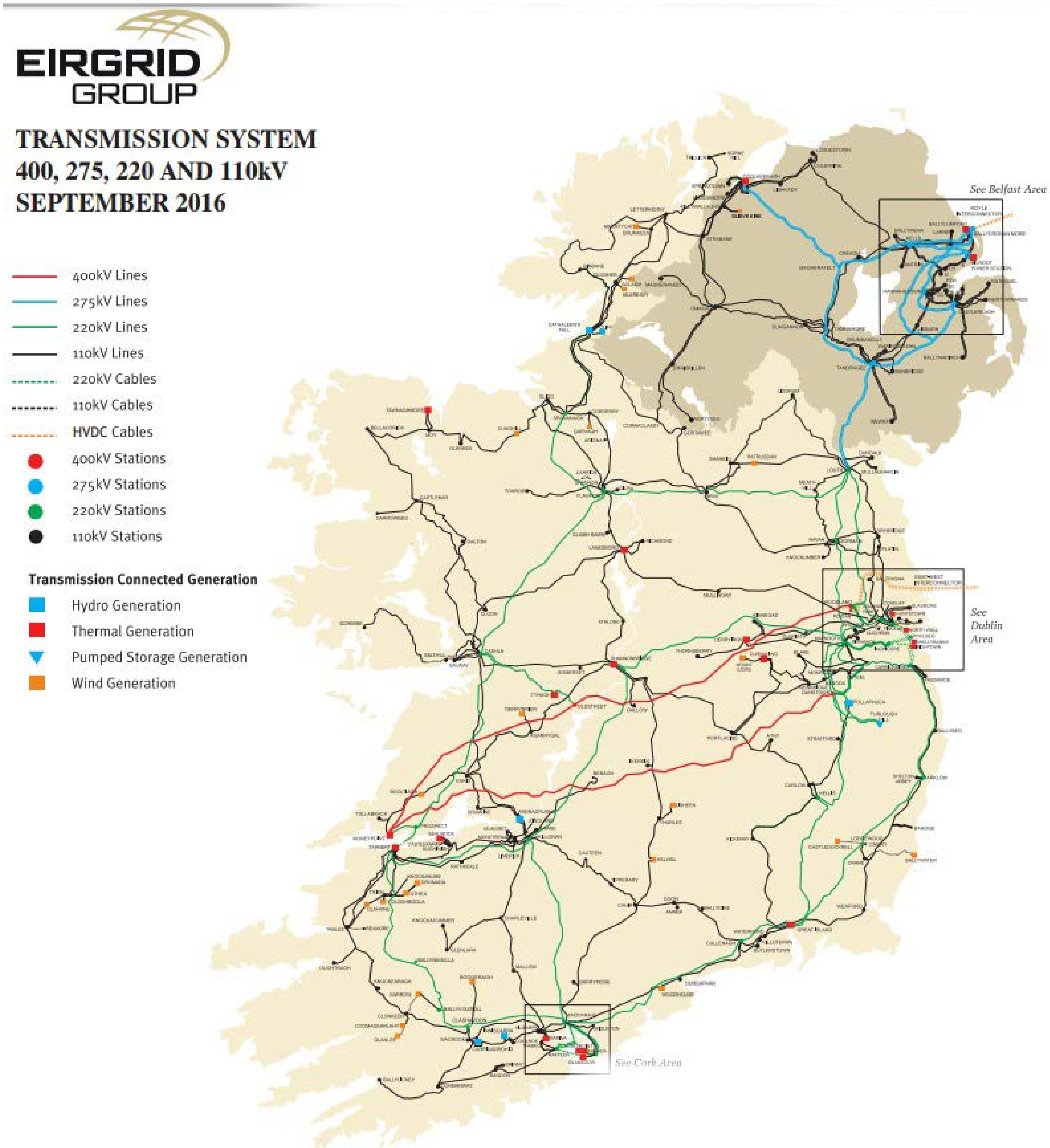


Figure 2-2 Irish Transmission System Map

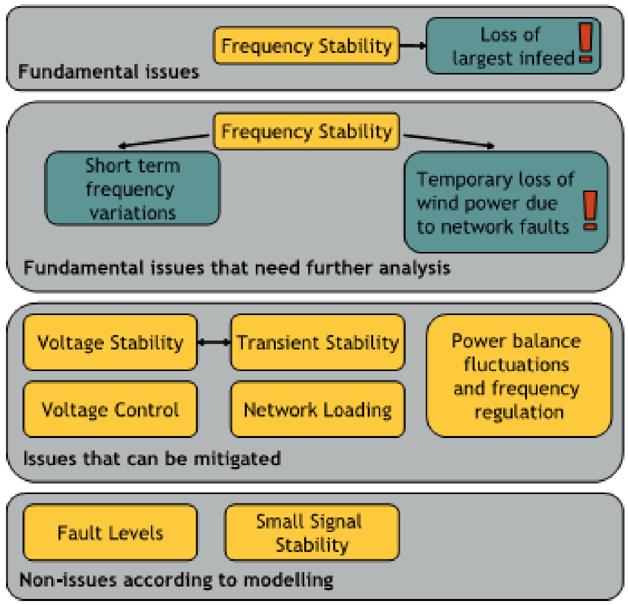


Figure 2-3: Classification of Issues in the Irish Power Grid

As part of the studies, a metric that captures range of issues with a single constraint was developed termed as System Non-Synchronous Penetration (SNSP). This provides a measure of the non-synchronous generation on the system instantaneously and is defined as the ratio of the real-time MW contribution from non-synchronous generation and the net HVDC imports to demand plus net HVDC exports. Increasing this operational metric, results in a decrease in system inertia as more and more conventional power plants are replaced with inverter-based generation. The exact change will depend on the dispatch scenarios and the individual inertia constants of each dispatch unit, however in general the level will decrease. Therefore, a second operational metric that considers instantaneous system inertia is considered. This is a ratio based on the stored kinetic energy in conventional generator plants and loads to the dispatched power of the largest infeed (MW.s/MW) considering that the generators and loads (rotating) will have a strong impact on the frequency response to system disturbance such as the loss of generation. Further operational metrics have been considered, the most prominent one being the minimum number of conventional units being online. This was checked against a minimum level of 100 MW units with no clear correlation between online units and the SNSP operational metric. Decreasing the minimum level of generators considered to 50 MW has not revealed any correlation and hence the metric is not considered to provide a global picture.

Wider study results suggested that keeping frequency within the acceptable boundaries following loss of largest infeed with some operational maneuvering (such as de-sensitizing RoCoF relays and implementing restriction on imports) is possible and that operational levels of 70 to 80% on the SNSP metric and 20 to 30 MW.s/MW on the second metric can be reached. Similar frequency stability studies following system faults suggested an operational limit of 60 to 70% on the SNSP metric and 20 to 30 MW.s/MW.

On the voltage stability and control side, analysis indicated that there will be increased demand for reactive power support and that these can be mitigated by reinforcing the grid code compliance requirements of wind generation on provision of reactive power capability, installation of reactive power sources such as static var compensators at strategic locations and identification and definition of conventional "must run units". On the interrelated transient stability side, study results identified that beyond 70 to 80% SNSP, is likely to experience issues.

On power balance regulation, ramping up and down of conventional generation was investigated and result indicated that introducing some form of curtailment in extreme positive ramp situation would help reduce power gradients. The study also concluded that reinforcing the 110kV network especially at remote areas for loading purposes would greatly facilitate the implementation of the 2020 scenario.

Small signal stability identified as a non-issue as the increased wind generation improved the damping of oscillation in the system. Few inter-area and local modes were identified as less damped, but these did not pose a threat to the stability of the system. On fault level side, the study checked whether the lowest fault level during increased wind generation will be equal or higher than the minimum fault level experienced with no wind power in the system. The analysis concluded this not to be an issue.

Following identification of technical issues and constraints, the project moved onto developing the required technical and commercial mechanism to facilitate, incentivize and hence improve system performance and capability. The DS3 project included multiple workstreams all neatly combined under three categories: system performance, system policies and system tools. Each of these areas were deemed as fundamental to the success of delivering 40% renewable electricity target and hence each were set with their own objectives. In system performance objectives were concentrated on providing current and future plant performance capability, enhancing existing monitoring processes with grid code compliance, ensuring the development of a portfolio of plant aligned with the long term needs of the system and review of RoCoF requirements. Adapting and updating system operational policies to align with managing the voltage and frequency securely on an All-Island basis was set as part of the system policy objectives along with availability of renewable generation data for analytical purposes. And lastly, objectives were set to develop and implement enhanced tools to manage increased system complexity and provide support in decision making in the control centers.

A comprehensive review of System Services [6] was carried out in order to identify the needs, effectiveness of the existing services at the time and payment structures and more importantly develop new services with new and/or revised payment structures that foster focus on performance and investment. As a result of the review by the Single Electricity Market (SEM) Committee, 14 System

Services aiming to support frequency and voltage control were designed to be provided by the existing and new entrants (such as battery storage). The identified and implemented services are:

- Synchronous Inertial Response (SIR)
- Fast Frequency Response (FFR)
- Dynamic Reactive Response (DRR)
- Ramping Margin 1 Hour (RM1)
- Ramping Margin 3 Hour (RM3)
- Ramping Margin 8 Hour (RM8)
- Fast Post-Fault Active Power Recovery (FPFAPR)
- Steady-state reactive power (SRP)
- Primary Operating Reserve (POR)
- Secondary Operating Reserve (SOR)
- Tertiary Operating Reserve 1 (TOR1)
- Tertiary Operating Reserve 2 (TOR2)
- Replacement Reserve (De-Synchronised) (RRD)
- Replacement Reserve (Synchronised) (RRS)

Out of the 14 services, SIR, FFR, DRR, RM1, RM3, RM8 and FPFAPR were new services. Procurement of these services were done on an interim basis until 2018 and since then moved to a regulated contract tariff. As a result of this initiative, 11 conventional units have revised their technical offer data improving load up rates, synchronization notice time etc., 8 conventional (synchronous) units have reduced minimum load for provision of SIR with a net benefit of 330 MW and 12 conventional units are providing FFR (around 210 MW) all indicating a positive operational impact. In addition, a number of wind units are contracted to provide a number of services such as POR, SOR, TOR1, FFR and SSRP as well emulated (synthetic) inertia. Similar impact has been observed on demand side also with 20+ units providing various services.

To date the highest wind generation occurred last December (2018-12-12) with a peak of 3939 MW. At the time of this generation the load was recorded as 5588 MW equating to 70.5% of demand being supplied by wind. This should not be confused with the operational metric SNSP for which the latest winter peak period figure was around 62.8%. Higher SNSP numbers on the system have been reached especially during periods of lower demand and currently there is an operational limit of 65% SNSP. There are plans to increase the level of SNSP from the current limits of 65% to 70% initially and then to 75% within the next year if Ireland is to meet the 40% target. Currently, the biggest issue with the increase of SNSP is due to RoCoF relay settings. The requirement is to increase the settings to 1Hz/s making sure that the generation portfolio can meet this (or that the volume of non-compliance is manageable). The second hurdle is the introduction of decision-making support tools in control center environment.

The following bullet pointed list contains few background information about the Irish system for the reader to have a feel and draw their own conclusions in terms of comparison with other systems.

- Total installed wind capacity: All Island about 5 GW, approximately 3.7 GW in Ireland and 1.3 GW in Northern Ireland.
- Total installed solar capacity: Approximately 100 MW in Northern Ireland and none in Ireland.
- Total installed synchronous condenser: None dedicated, one of the units in Northern Ireland can be operated as synchronous condenser.
- Total installed battery: Only one battery in Northern Ireland – Kilroot 10MW. A lot of batteries are being installed as a result of the new DS3 system services. As service procurement is in the execution stage, information is very scarce.
- Minimum required total online inertia: Currently there is a floor of 23,000 MW.s on an All Island basis. They have plans to drop it to 20,000 MW.s and then subsequently to 17,500MW.s before the end of 2020. This change is linked to increased SNSP and RoCoF changes.
- AC or DC ties to other systems: Two DC ties Moyle 500MW LCC to Scotland and EWIC 500 MW VSC to England considering that the system is operated as an All-Island system. Between Ireland (EirGrid) and Northern Ireland (SONI) there is one 275kV double-circuit line and two 110kV single-circuits.
- Largest single contingency in the system: Changes depending on the interconnector flows and the generation dispatch. In general, it is either the trip of one HVDC interconnector or the trip of a large synchronous unit. Normally during the load peak, the LSI is between 400 MW and 500 MW.
- Amount of reserve provided through the tie lines: The HVDC's can give up to 75 MW each as static reserve.
- Highest recorded inverter-based generation in the system: The highest wind generation was recorded in December 2018 with a peak of 3939 MW when the load was 5588 MW at the time, so the wind supplied 70.5% of the demand.
- Peak summer load: About 2.5 GW on an All-Island basis.
- Peak winter load: About 6.5 GW on an All-Island basis.
- Lowest frequency dip experienced in the system: 49.249 Hz from 2017 published results.
- Load shedding for low frequency events: Yes, they have interruptible loads as part of an ancillary service referred to as Demand Side Units (DSU), which are contracted to provide static POR (primary operational reserve) and it triggers at 49.8 Hz. Under-Frequency Load Shedding is the very last resort to secure the system in case of a severe frequency event – it operates in stages starting at 48.85 Hz.
- Rate-of-Change-of-Frequency (RoCoF) relays in the system: Transmission level is set at 0.5 Hz/s and is being increased to 1 Hz/s. At distribution level it is used as Loss of Mains protection.

3. Study Methodology

This section describes the general methodology followed in this study to determine acceptable levels of wind generation that can be integrated for existing and future system conditions without introducing major system technical challanges. For this particular study, the technical performance criterion for acceptability is the transient stability of the system. Furthermore, fault level recovery criteria were also checked and these are described later in this section.

Therefore the core of the analysis is transient stability simulations which were performed in PSS®E version 33. At a high level, the study mainly looks into the system response a few seconds after a system disturbance.

Transient stability simulation is a well-established method used to study the rotor angle stability in power systems. The differential and algebraic equations describing the system are solved successively at discrete time steps in RMS time domain (effectively an electromechanical time domain study). The typical time step used to advance the state of the system is quarter of a cycle. The power electronic devices such as HVDC controls or inverter-based generation controls are represented by their average behavior.

The simplifications that are applied to component models in transient stability simulation allow the response of very large interconnected systems within a time window of 10 to 20 seconds to be investigated. On the other hand, the simplified models might mask some potential issues. This is the case, for example, for phase-locked loop components used to synchronize inverter-based generation to the grid. The phase-locked loop relies on the measurement of voltage at the point of interconnection to provide a reference for synchronization. In weak systems, characterized by low short circuit ratios, this measurement is challenged, potentially causing instability. To capture this behavior, a finer time domain study (in electromagnetic study time scales) is required.

The initial starting point of the study was to look into the existing system. After assessing the current situation, the analysis was continued by adding a second 345-kV tie to New Brunswick. This is a major system reinforcement measure which eliminates islanding of Nova Scotia in the event of tripping the exising 345-kV tie (assuming N-1 criteria, and limiting transfers with transmission planned or unplanned outages). The main reason to repeat the studies with this system development is that it is expected that this measure will allow the wind levels to be increased beyond the exising level if other criteria are also met[3].

[3] It should be recognized that other islanded scenarios which are not included in this study, such as the Maritimes Area islanded from New England, Cape Breton islanded from mainland Nova Scotia, must be properly analyzed before any findings could be operationalized.

The study next looked into how much wind can be added without a second tie but rather with increasing the effective online inertia on the Nova Scotia system in islanded operation by utilizing fast-acting energy storage technology and voltage regulators.

Although the use of a more comprehensive (and hence more costly) hybrid solution consisting of both a second tie system reinforcement measure and the introduction of synchronous condenser and/or battery storage can be considered, this option has been left out of the analysis for the time being due to increased complexity and likely costs.

Renewable generation is intermittent in nature and hence in the case of wind generation, sufficient regulation reserve is needed to accommodate wind fluctuations in longer time frames. Using recorded data from the Nova Scotia SCADA system and through a simplified analysis introduced in Section 3.2, *Estimation of Regulation Reserve*, thresholds are established for regulation reserve in order to be able to accommodate wind fluctuations. The purpose of this part is to evaluate, before stepping into transient stability simulations, whether there is enough regulation reserve in the system to accommodate fluctuations in time frames of tens of minutes which are known to cause system stability issues.

The base cases used for transient stability simulation will have generation dispatched to meet the following requirements:

- MW output is set so that tie line flows match the case summary.
- Contingency spinning reserve is not dispatched, as it is assumed that under-frequency load shedding is used to handle the frequency fall from a tie line trip. (Note that Tasmania relies on load shedding for a HVDC tie trip, however this is a direct inter-trip and not based on frequency measurement).
- Regulation reserve is dispatched to handle fluctuations in wind generation and demand and keep the AC tie flow constant. The Maritime Link HVDC tie can be used to provide ± 60 MW of regulation reserve using its frequency dependent power modulation. If this is insufficient then regulation reserve can be provided by battery storage or by conventional generators. (Battery storage is already used in other jurisdictions to smooth the output from windfarms, for example the 315 MW Hornsdale windfarm in South Australia has an adjacent 100 MW 129 MWh battery).

3.1. Overview of Transient Stability Simulation

Figure 3-1 shows in a flowchart style how the study is performed. Note however that:

- For the existing wind analysis, mitigation only consists of existing system manipulation such as bringing more thermal units online or switching shunts on or off. These changes will be applied to the original base cases and will be kept in the models for the simulations to follow.

- For the second tie analysis, the main mitigation measure is effectively added prior to adding more wind.
- For analysis without a second tie and with synchronous condenser and battery options, wind is increased in steps of 100 MW. The final stop point is somewhat subjective and dependent on the results observed in the previous steps.

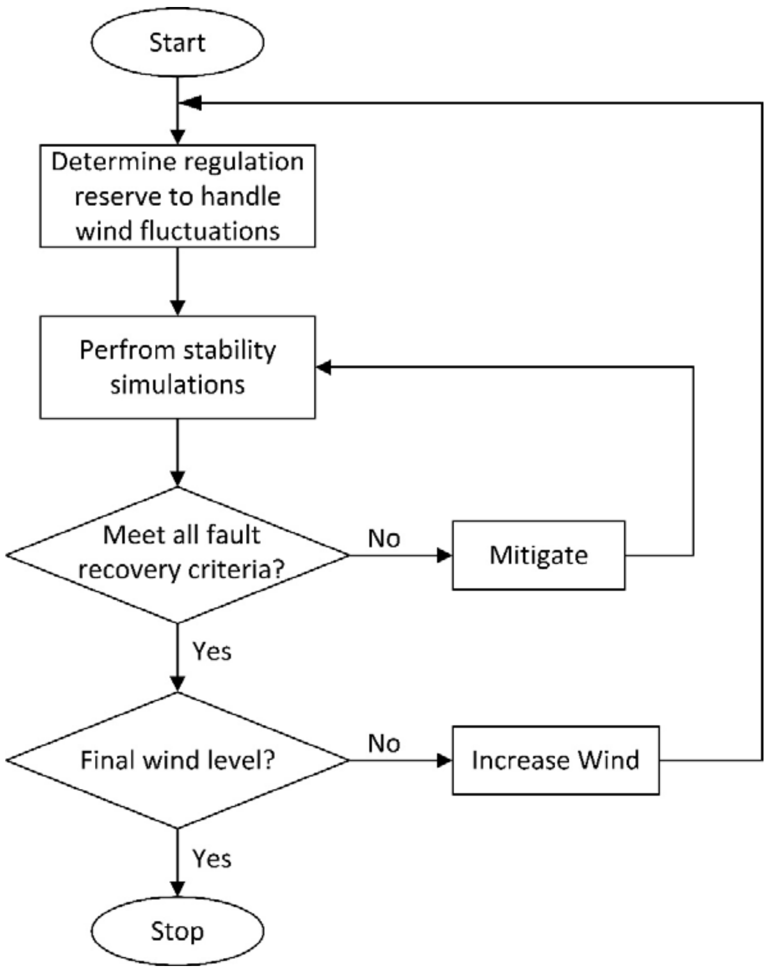


Figure 3-1: General Flow of Simulation

The criteria checked for each simulation are:

- No cascade generator or transmission line tripping
- No loss of synchronism
- Frequency maintained with the frequency fault ride-through envelope
- Voltage at generator connection points maintained within the voltage fault ride-through envelope

- No thermal overloads on lines
- Fault current levels sufficient to operate transmission and distribution protection
- Short Circuit Ratio with Interaction Factors (SCRIF) maintained for wind generation (to ensure that the PSS®E model is valid). The SCRIFs will be calculated with the additional new wind farms.

As a measure for validity of transient stability simulations, and as an additional check, short circuit ratios at nodes with wind generation are calculated. The methodology used for this calculation is explained in Section 3.3, *Calculation of Short Circuit Ratio*.

3.2. Estimation of Regulation Reserve

In any given electric power system there is a need to balance generation and demand so that a stable operating equilibrium with constant frequency can be maintained. Reference to system frequency is due to the fact that it is representative of the rotational speed of the synchronized generators connected and also that it is a shared parameter by all participants within the power system. Disturbance in the balance between generation and demand causes a deviation in the frequency and needs to be offset quickly. As there is limited ability to store kinetic energy, the energy is usually stored in other forms (water in reservoir for example). System operators keep a finite amount of generating capacity as reserve (usually termed as operating reserve) in order to meet demand in case a generator is no longer capable of generating or there is another level of disturbance to the generation. In most electric systems the level of the reserve is at least equal to the amount of the largest generator plus a finite amount of peak load. There are other types of reserve such as frequency-response reserve and replacement reserve but the explanation of these are beyond the scope of this report. Inclusion of renewable generation introduces a form of intermittent power where some of this power maybe lost due to lack of original energy source(s). Therefore, an increased amount of reserve, here termed regulating reserve may be required to cover the intermittency and associated shortages of power. Before any studies can be conducted the level of regulating reserve was calculated to check whether this will have a major impact on the level of renewable generation integration. The methodology of how this level was established is described next.

The simplified methodology used to estimate the regulation reserves required to handle wind fluctuation is described below:

1) From the 5-min controllable infeed (Conventional Generation + Tie Import), at the beginning of every half hour, interpolate the straight-line controllable infeed for every 5 minutes within the half hour. This is assumed to be the system operator’s forecastable 5-min controllable dispatch used

for controllable ramping. Note that the controllable infeed equals the Uncontrollable Demand + Losses – Wind Generation[4].

2) For every 5-min value, find the deviation between the 5-min controllable infeed and the straight line controllable infeed. This deviation is assumed to be provided by regulation reserve.
3) Plot a bar graph of positive and negative deviations in 5-MW bins.
4) Find the 3-sigma value for positive and negative deviations. This gives the required positive and negative regulation reserve from controllable sources.
5) Observe whether the 3-sigma values change as more wind generation comes online.
6) Develop a simple equation relating wind generation to regulation.

The linear relationships between the installed capacity of wind and the regulation reserves calculated based on the above methodology are shown in Figure 3-2 and Figure 3-3 along with the developed equations for positive and negative regulation respectively. The summarized results of the regulation reserve calculated using this methodology is shown in Table 3-1.

Table 3-1: Regulation Reserve

Year	Installed Capacity (MW)	Non telemetered Capacity (Year End) (MW)	Telemetered Capacity (MW)	Estimated Telemetered (Ratio Method) (MW)	Regulation Reserve - Installed Capacity (MW)	Regulation Reserve (3-Sigma)	
						Negative [MW]	Positive [MW]
2015	549	96	453	0.0	453.0	-26.3	25.4
2016	580	110	470	0.0	470.0	-28.3	27.3
2017	595	122	473	122.0	595.0	-32.3	30.4
2018	595	113	482	113.0	595.0	-30.8	29.5
Projected values based on linear approximation					700.0	-35.2	33.1
					800.0	-38.5	35.9
					900.0	-41.8	38.7
					1000.0	-45.1	41.5

[4] For 137MW of unmetered COMFIT wind sites, the 5-min generation values were estimated based on a ratio of actual wind data.

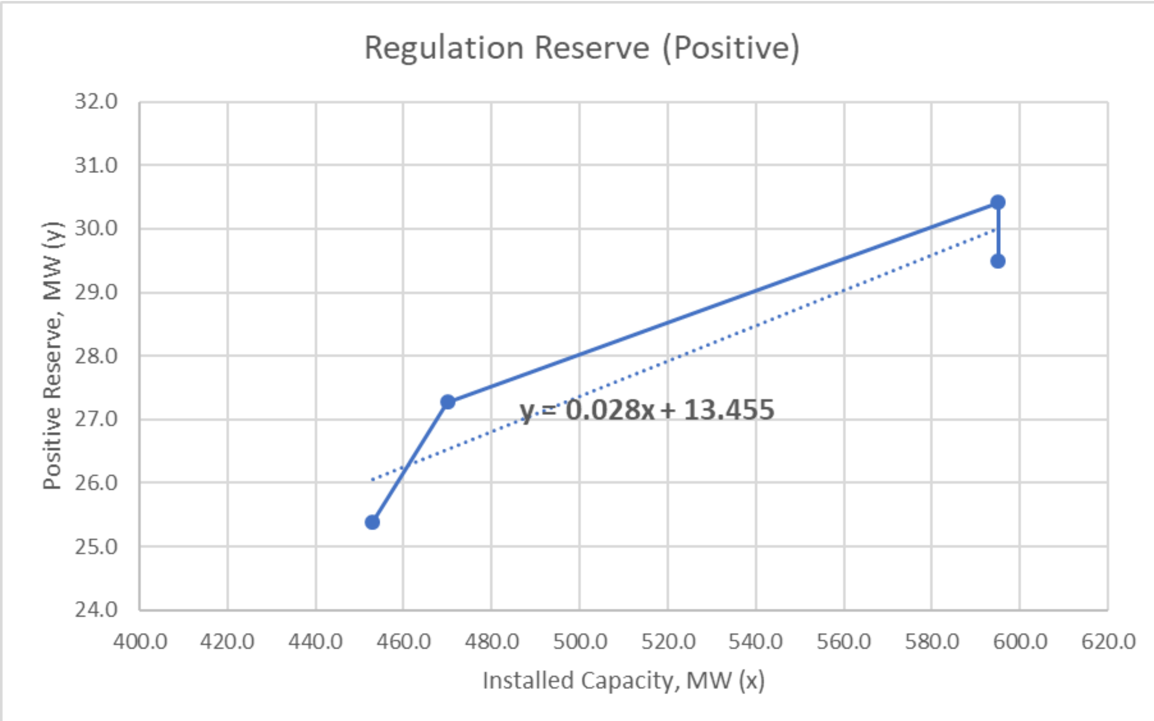


Figure 3-2: Linear Approximation for Positive Regulation Reserve Estimation

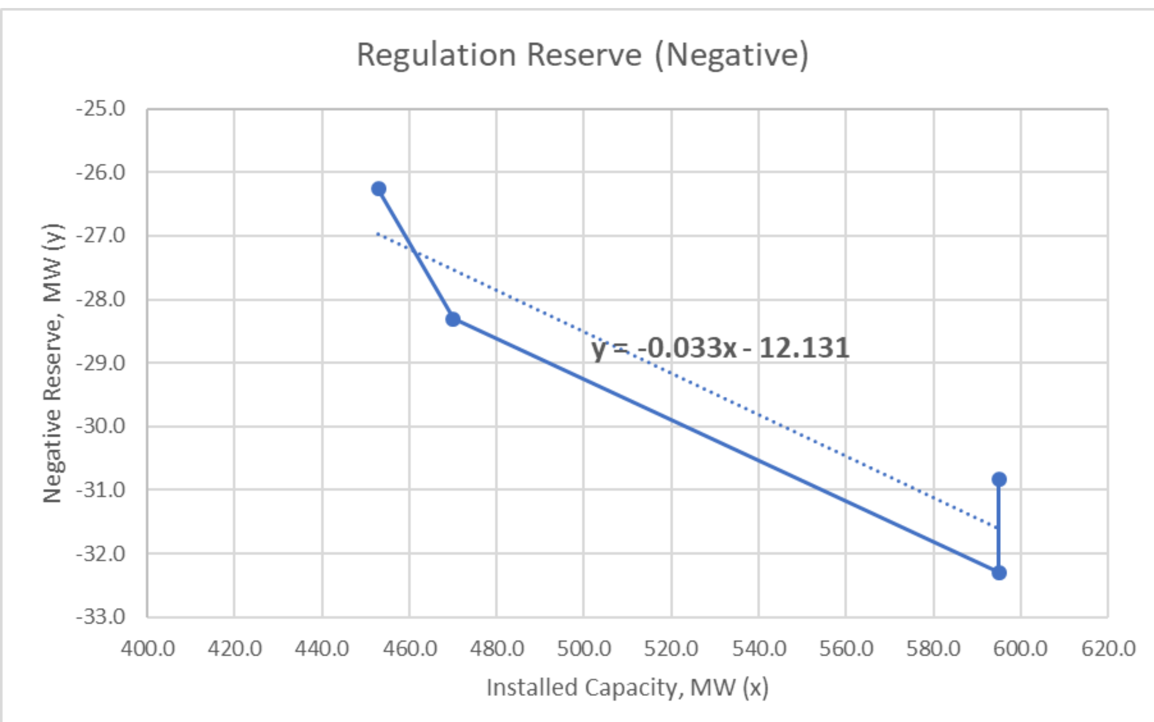


Figure 3-3: Linear Approximation for Negative Regulation Reserve Estimation

3.3. Calculation of Short Circuit Ratio

Grid strength in many jurisdictions is one of the challenges of connecting inverter-based renewable resources to the integrated Bulk Electric System (BES). Strong grids can provide stable reference source for the renewable resources at the point of interconnection (POI). Short Circuit Ratio (SCR) is commonly used to measure the relative grid strength. The short circuit ratio at the POI is defined as follows [3].

$$SCR_{POI} = \frac{SCMVA_{POI}}{MW_{POI}}$$

Where

$SCMVA_{POI}$ = Short circuit MVA level at POI (without wind generator)

MW_{POI} = Nominal power rating of the inverter-based wind generator being connected at POI

In case of multiple inverter-based generators connected in an electrically close region, SCR calculated using the above formula cannot be applied to represent grid strength accurately. Short Circuit Ratio with Interaction Factor (SCRIF) is the more rigorous method that considers the impact of all other generators in the vicinity of POI considering electrical closeness. *SCRIF* at POI of wind generator i is defined as:

$$SCRIF_i = \frac{S_i}{P_i + \sum_j \left(IF_{ji} \times P_j\right)}$$

Where

S_i = Short circuit MVA level at POI of wind generator i

P_i = Nominal power rating (MW) of wind generator i being connected at POI

P_j = Nominal power rating (MW) of wind generator j

IF_{ji} = $\Delta V_i / \Delta V_j$ (change in bus i voltage for a change in bus j voltage)

For Nova Scotia system, the SCRIF was calculated for different cases to evaluate the grid strength at point of interconnection of wind generators.

There is no universally accepted level of SCR or SCRIF value that is deemed to be safe for modelling and/or operational purposes. However there is a generally accepted view that a value of 3 or higher provides a somehow acceptable level. With this in mind and based on wind turbine manufacturer advice [7], the SCR threshold is set to 3 for PSS®E Vestas Wind Turbine Generator (WTG) model. It is mentioned that at very low SCR values, EMT models (i.e. PSCAD™) provide a more accurate representation of the interaction of the power plant equipment, which in turn results in improved accuracy of the studies. Since, there is no absolute defined minimum SCR, the above is used to provide direction for further validation of the results. It must be noted that at some wind farm locations in the Nova Scotia system, the short circuit level is low providing SCRIF values below 3.

4. System Description and Modeling

This section aims at providing a better understanding of the conditions under which the system has been analyzed, models used in the analysis and the contingencies applied.

4.1. Overview of Nova Scotia Electrical System

Figure 4-1 shows Nova Scotia's simplified bulk power system. It is connected to New Brunswick through one 345-kV (L-8001) and two 138-kV (L-6535, L-6536) AC transmission lines, which join to a single circuit at Springhill (effectively the interconnection is a single 345-kV line in parallel with a single 138-kV line). It is also connected to Newfoundland through Maritime Link which is a Voltage Source Converter (VSC) HVDC transmission with two poles.

There are fifteen major transmission substations in Nova Scotia, and the transmission voltages consist of 345 kV, 230 kV, 138 kV, and 69 kV. Major thermal generating plants are Lingan, Tufts Cove, Trenton, Point Aconi, and Point Tupper. Transmission-connected wind generation facilities are spread throughout the province. In addition, there are distribution connected wind generating facilities, some of which are not metered. The total installed wind capacity is approximately 600 MW.

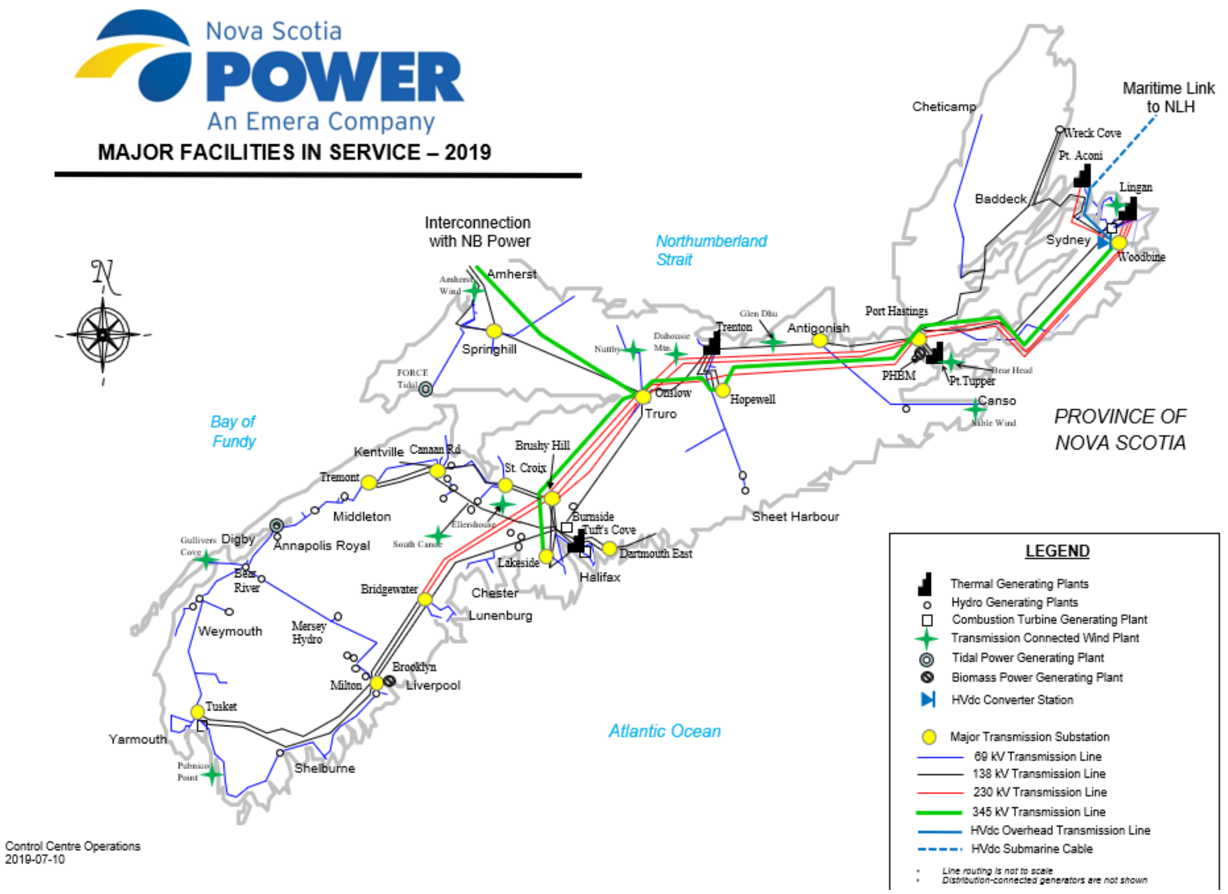


Figure 4-1: NSPI Major Facilities Map

4.2. Power Flow Models

The overall studies are based on a very limited number of cases. These cases have been provided by Nova Scotia Power and are believed to represent indicative system conditions where system issues may be encountered. The four base cases provided for this study are listed in Table 4-1 and some further explanation per case follows the table.

Table 4-1: Summary of Original Base Cases

Base Cases	Case 01	Case 02	Case 03	Case 04
NS* Basic Load [MW]	678	1214	1675	1604
NS Total Generation [MW]	670	793	1815	787
NS Conventional Generation [MW]	85	208	1230	202
NS Wind Generation [MW]	585	585	585	585
NS Thermal Units Online	0	2	8	1
NS to NB† (+: export) [MW]	-250	0	500	-410
NS to NL‡ (+: export) [MW]	200	-475	-475	-475
Nova Scotia Online Inertia [MW.s]	387	1788	6666	1347
Total Online Inertia [MW.s] Pre-contingency	501853	1788	505558	506711

* NS: Nova Scotia

† NB: New Brunswick

‡ NL: Newfoundland

Case 01 is a light load case with high import from New Brunswick. There are no thermal units online. Under this case Nova Scotia will experience under-frequency if islanded from New Brunswick with the loss of the tie.

In Case 02 Nova Scotia is already islanded from New Brunswick. Two thermal units are online for frequency (wind/load) regulation and there is high import from Newfoundland. The contingencies within the Nova Scotia system have pronounced impact on voltage and frequency.

Case 03 is a shoulder load case with high internal Nova Scotia flows. For the purposes of this case, new wind would replace Cape Breton generation. Nova Scotia delivers reserve to New Brunswick in addition to flow-through service from Newfoundland to New Brunswick. If the 345-kV intertie from NS to NB is lost, a Special Protection System will run-back import from Newfoundland to prevent Nova Scotia from islanding.

Case 04 is the high summer peak load case with one thermal unit online. New Brunswick delivers reserve to Nova Scotia with high import from Newfoundland.

Note that these base cases were altered as a result of applying mitigation measures and increasing wind in the system as the analysis proceeded. Whenever a change is applied to a base case, it is stated in the relevant section and the scope to which the change applies is made clear.

It is important to note that the above four cases are representative cases of important system scenarios. Needless to say that in a given electric power system, there could be a high number of system scenarios that take into account the various demand levels, dispatch scenarios, merit order scenarios, studied contingencies, seasonal variations etc. and in most analytical cases it is almost impossible to replicate and simulate all. Instead, a reduced number of representative cases are formulated, modelled, studied and analysed to draw generalized conclusions. The above four base cases are believed to be representative cases for the Nova Scotia power system in stressing the system in terms of technical limitations with the introduction of increased wind generation.

4.3. Dynamic Models

This section discusses the dynamic models of Nova Scotia system components.

4.3.1. Load

Active power loads in Nova Scotia are 50% constant current and 50% constant impedance. Reactive power loads are 100% constant impedance. As such, the reactive loads are frequency-dependent (since NETFRQ is turned on[5]).

4.3.2. Synchronous Generator

Nova Scotia system has both thermal and hydro generating units. The MVA ratings of thermal units are generally much larger than those of hydro units. The thermal units are modeled using round rotor generator models (GENROE and GENROU) with controls. The hydro units are modeled using salient pole generator model (GENSAL) with controls.

4.3.3. Wind Generation

There are three different types of wind turbines connected to the Nova Scotia power system. These are induction generators (type-2), doubly-fed induction generators (DFIG, type-3) and full converter type generators (type-4). Table 4-2 summarizes the number of wind turbines according to their type and provides the total installed capacity in terms of MVA.

Table 4-2: Existing Wind Dynamic Types in Nova Scotia System

[5] Checking NETFRQ flag in PSS®E results in network parameters, machine flux models and reactive loads modeled on constant impedance to be adjusted based on local frequency. Frequency dependent load models such as IEELBL or LDFRBL are not used in the NSPI system.

Type	Description	Total MVA
2	Induction Generator	34
3	DFIG (manufacturer A)	122
3	DFIG (manufacturer B)	177
4	Full Converter	268

In the course of this analysis new wind generation is added to the base cases. The dynamic model used for these new wind generation is type-4. Figure 4-2 shows the buses chosen by NSPI to connect the new wind farms and their maximum MW output.

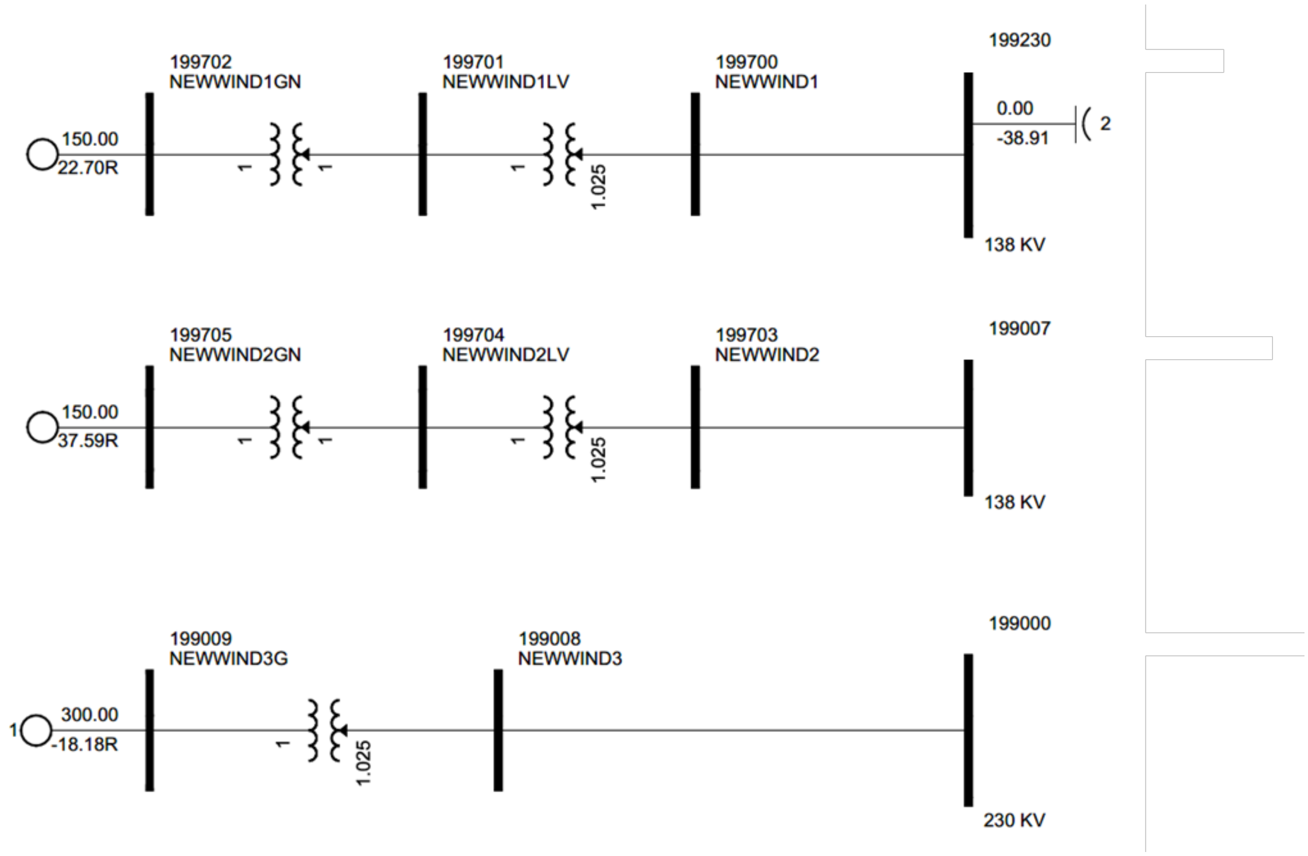


Figure 4-2: Locations for Adding New Wind Generation

4.3.4. Maritime HVDC Link

The Maritime HVDC link has two poles each of which is modeled as two coupled generators as shown in Figure 4-3. The user-defined model that is used to control current injection through these generator pairs is C_ABBL_2OT_MTM [8]. Note that voltage source converter HVDC models the HVDC link as independent generator components in the power flow. These generator components get internally connected through C_ABBL_2OT_MTM dynamic model. The event of tripping a pole is modelled by putting the corresponding generator pairs out of service.

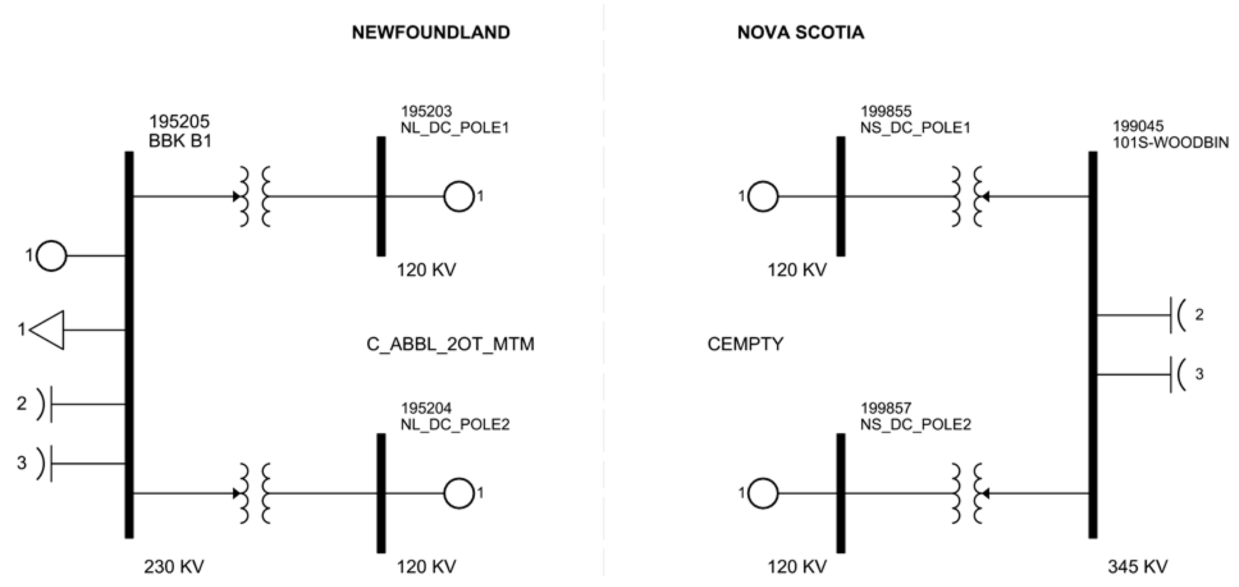


Figure 4-3: Maritime HVDC Link Between Nova Scotia and Newfoundland

4.3.5. Synchronous Condenser (SC)

Synchronous condenser is a synchronous machine without a turbine or load. During normal operation, it can exchange reactive power with the network thereby regulating the voltage at the expense of a small amount of active power consumption to compensate for losses. The voltage control loop of the synchronous condenser provides fast voltage regulation at the connection point. During frequency disturbances, the synchronous condenser exchanges active power with the grid as well by slowing down or speeding up. The energy that is injected into or absorbed from the electrical grid is due to the inertia of the synchronous condenser.

Synchronous condensers are added to the Nova Scotia system as part of this study. Each synchronous condenser is rated at 100 MVA. The dynamic models used for synchronous condenser are salient pole machine (GENSAL) and simplified excitation system (SEXS) with inertia set to 5 s (500 MW.s). This represents a synchronous condenser fitted with flywheel to increase its inertia. Although Nova Scotia has seven combustion turbines, each rated 30 MVA, equipped with a clutch allowing them to operate in synchronous condenser mode, they are not considered to be suitable for this purpose due to their low inertia and high losses.

4.3.6. Battery Energy Storage System (BESS)

Battery Energy Storage Systems bring several advantages such as dispatchability and predictability of renewables. Like synchronous condensers they help with regulating the voltage. However, being inverter-based they do not contribute to the short circuit ratio. Batteries can compensate for the power imbalance caused by a transmission tie trip or a generator or load trip event rapidly, up to their power capability. The batteries also help with the more long-term task of regulation with intermittent wind power.

Batteries are added to the Nova Scotia system as part of this study. Each battery is rated at 100 MW and the dynamic model used for it is EPRI Battery Energy Storage (CBEST) [4]. This model represents a battery which has a large enough storage capacity to be able to deliver its full output of 100 MW for the entire simulation time (typically 20 s). The auxiliary supply signal, PAUX [MW], is either simply a ramp command to inject or absorb power in the shortest possible time or a combination of ramp and PID controller.

4.3.7. Protection

The protection in the Nova Scotia model consists of distance protection (DISTR1) relays, low-voltage load shedding (LVS3BL, LVSHBL) relays, and low-frequency load shedding (LDSHBL) relays. Generator shedding if needed is implemented in the contingency (see Section 4.4). It is noted that there are 5 stages of fast load shedding followed by a final load shedding that is activated after 10 seconds. If all stages are activated, as much as 35% of load will be shed.

4.4. Contingencies

The contingencies applied to each case are design contingencies that put the already stressed system under even more stress. If the transient simulation shows that the system survives the initial shock after applying these contingencies, there is a good indication that it can survive other less severe disturbances.

5. Transient Stability Simulations and Results

This section presents the results of transient simulation studies performed as part of this project. The results are discussed under three subsections: Existing System, System with Additional 345-kV Tie, and System with Synchronous Condenser and BESS.

5.1. Existing System

The base cases in Table 4-1 are studied under existing system conditions to see if 600 MW of wind can be supported. This part of analysis is used to quantify a minimum required number of online thermal units.

Case 01, 600 MW Wind, Light Load, High Import from NB with no Thermal Units Online

Nova Scotia system does not survive the event of tripping the AC ties and becoming islanded from the interconnection. The only online synchronous machines in the island are small hydro units. The total aggregate online inertia in Nova Scotia is 387 MW.s. These generators oscillate relative to each other, resulting in the frequency measured at different buses to change rapidly below and above the nominal value. Since the frequency does not consistently stay below the thresholds set for load shedding, effective load shedding does not happen in this case. The dynamic simulation stops short of reaching the final time indicating numerical problems in the software.

The mitigation for the above situation was obtained by bringing more thermal units online as shown in Table 5-1.

Table 5-1: Thermal Units Added to Case 01

Thermal Unit	Bus Number	MW output
Tufts Cove Unit 3	199169	50
Lingan Unit 1	199001	105
Lingan Unit 3	199003	160

The load in Nova Scotia was scaled up to 893 MW, and the Maritime HVDC link was adjusted to export an additional 100 MW (300 MW total) power to Newfoundland. Following the introduction of the above additional units, the total online inertia in Nova Scotia rose to 2766 MW.s. The system in this case stays transiently stable following the tripping of the AC tie lines. Three stages of load shedding are activated resulting in 150 MW of load being disconnected. The frequency settles at around 59.8 Hz. For comparative purposes utilizing two thermal units, all stages of load shedding get activated, disconnecting about 180 MW of load in order to keep the system transiently stable.

Figure 5-1 shows the frequency at Woodbine 345 kV bus when contingency 1 is applied to the original Case01 and to the revised Case01 with the three thermal units running.

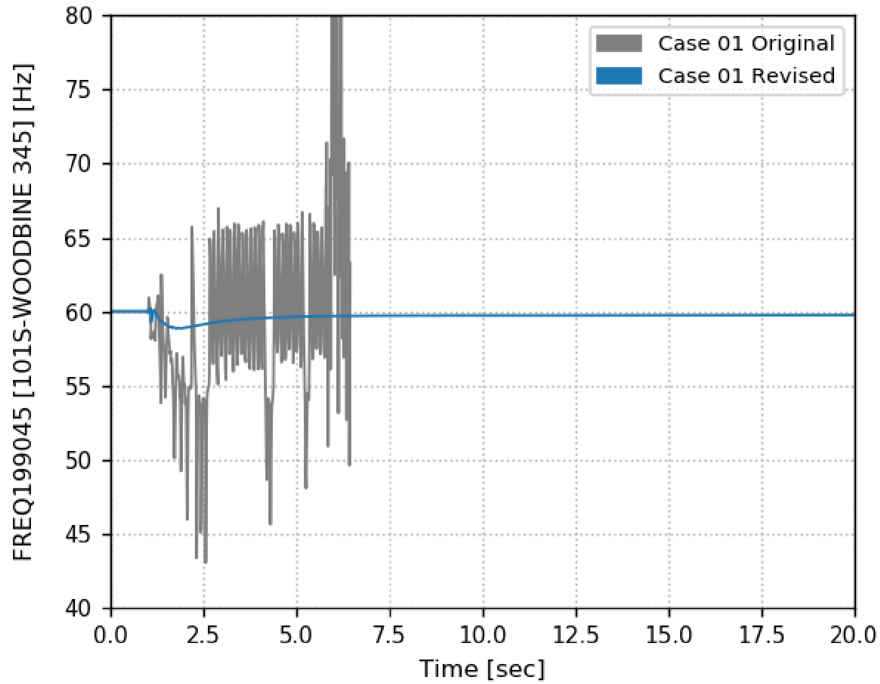


Figure 5-1: Frequency Variations, Case 01, Contingency01_L8001_fault_67N_SPS

A summary of the analysis with Case 01 is presented in Table 5-2.

Table 5-2 Case 01 Adjustment Summary

	Case 01 Original	Case 01 Revised
NS Basic Load [MW]	678	893
NS Total Generation [MW]	670	980
NS Conventional Generation [MW]	85	395
NS Wind Generation [MW]	585	585
NS Thermal Units Online	0	3
NS to NB (+: export) [MW]	-250	-250
NS to NL (+: export) [MW]	200	300
Nova Scotia Online Inertia [MW.s]	387	2766

Case 02, 600 MW Wind, NS Islanded from NB, Two Thermal Units Online

In this case it is assumed that Nova Scotia has successfully separated from the interconnection and is running in an islanded mode. Therefore, the contingencies applied to this case are contingencies within the Nova Scotia system. It was found that none of the applied contingencies cause the system to become unstable. The voltage levels are acceptable and line loadings remain within the thermal limits. Therefore, it seems that once Nova Scotia is operating in an islanded mode, two thermal units can provide enough inertia for it to survive the transients caused by the studied internal contingencies. However, it should be noted that as in all the other cases, the long-term wind fluctuations are not studied here. Sufficient regulating reserve with fast enough ramping capability must be available to be able to control the frequency of the islanded system. Although NPCC requires the system to survive the loss of both poles of the Maritime Link (475 MW or 39% of total load), this study included loss of one pole only.

Case 03, 600 MW Wind, High NS flows, Wind Replacing CB Generation, NS Delivers Reserve to NB

Nova Scotia under system conditions represented in Case 03 is able to support 600 MW of wind. It was found that none of the applied contingencies cause the system to become unstable. The voltage levels are acceptable and line loadings remain within the limits.

It is noted that tripping of the 345 kV tie (L8001) does not cause islanding of Nova Scotia due to a Remedial Action Scheme (RAS) that will prevent the 138 kV circuit from tripping during periods of heavy export to NB. The tripping of L8001 will activate this RAS which will run-back the Maritime Link by 330 MW, or trip two thermal units each operating at or above 150 MW.

Case 04, 600 MW Wind, Summer Peak with One Thermal Unit Online, NB Delivers Reserve to NS

The original base Case 04 under the event of tripping the AC tie causes the system to become unstable. The frequency dips below 58 Hz and all the stages of under frequency load shedding are activated. The load shedding helps recover the frequency, but due to the loss of large amounts of load, system voltages rise too high. This in turn causes the effective load to be increased resulting subsequently in the fall of the frequency. Some further studies were then conducted to check whether the frequency fall can be reduced. In order to achieve, the thermal unit 102S-ACONI (bus 199043) was brought online and this case is designated as Case 04a for comparative purposes. This on its own is not enough and therefore further additional mitigation approaches were checked. The switching-off of some shunt elements are thought to help reduce voltage rise (and hence load increase) and therefore control frequency reduction. With this in mind, the shunts in Table 5-3 were switched off prior to applying the contingency. This scenario is designated as Case 04a Caps Off for comparative purposes.

Table 5-3: Shunts Switched Off to Remedy the Voltage Rise Issue

Bus number	Bus Name	kV	MVAR
199110	1N-ONSLOW	138	50.0
199135	74N-SPRNGHIL	138	36.0
199178	90H-SACKVILL	69	24.0
199340	43V-CANAANRD	138	28.8

Figure 5-2 shows the frequency variation at Woodbine Substation and Figure 5-3 shows the voltage variation at Onslow substation before and after the adjustments to the original base case model.

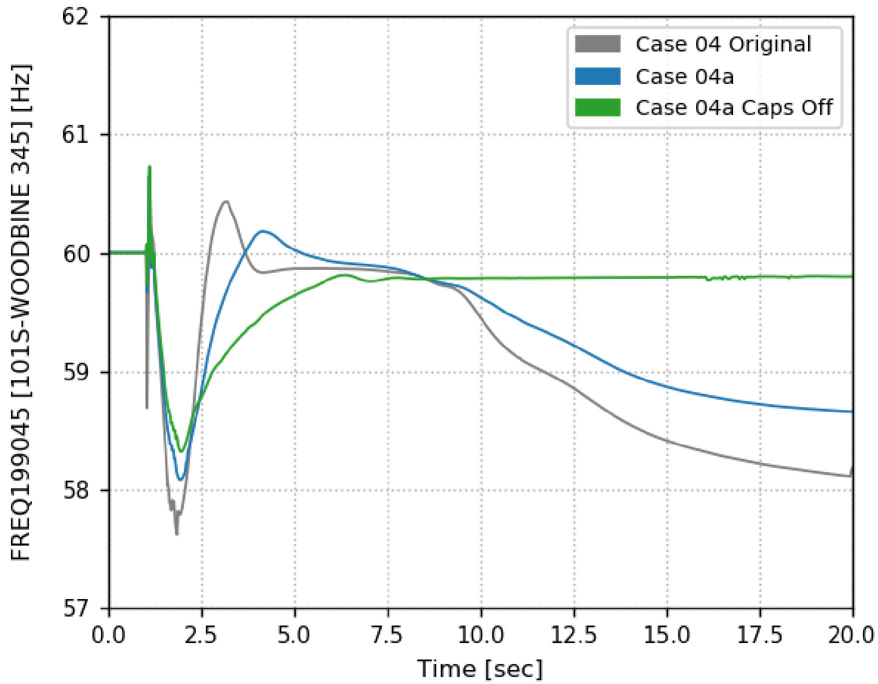


Figure 5-2: Frequency Variations, Case 04, Contingency03_Fault_on_L8001_67N_GP6_SPS

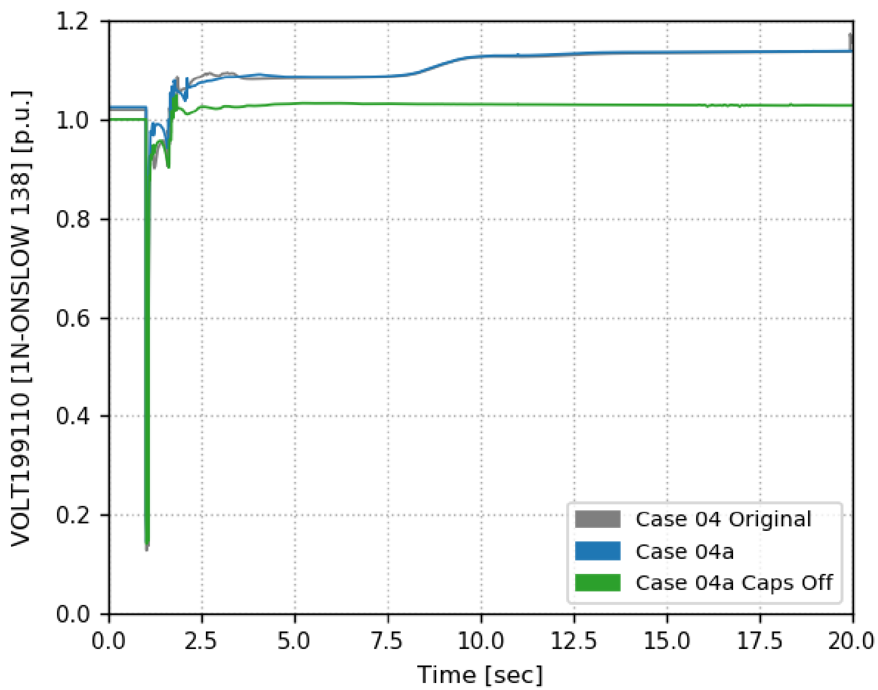


Figure 5-3: Voltage Rise at ONSLOW, Case 04, Contingency03_Fault_on_L8001_67N_GP6_SPS

Table 5-4 shows the adjustments made to Case 04.

Table 5-4 Case 04 Adjustment Summary

	Case 04 Original	Case 04 Revised
NS Basic Load [MW]	1604	1619
NS Total Generation [MW]	787	972
NS Conventional Generation [MW]	202	331
NS Wind Generation [MW]	585	585
NS Thermal Units Online	1	2
NS to NB (+: export) [MW]	-410	-417
NS to NL (+: export) [MW]	-475	-300
Nova Scotia Online Inertia [MW.s]	1347	2280

In summarizing the studies with the system as is and the four base cases, both Case 02 and 03 result in the system being stable following the introduction of 600 MW wind, whereas Case 01 and 04 result in unstable condition following a designated system contingency. However, in both of these unstable cases, existing facility manipulations were able to make the system stable.

Summarizing the case studies, with the changes made in the original cases, and with allowing load shedding to happen it is concluded that the existing system can survive the transients and remain stable while hosting 600 MW of wind generation. Table 5-5 summarizes the observations from transient stability simulations performed on the original base cases.

Table 5-5: Summary of Transient Stability Simulation Results, Original Base Cases

Simulation Case	**Transient Stability Result**	**Mitigation applied**
Case 01	Unstable system, mitigation needed	3 thermal units added
Case 02	System stable	
Case 03	System stable	
Case 04	Unstable system, mitigation needed	1 thermal unit added, 4 shunts switched off.

In order to investigate whether wind capacity can be increased in the existing system Cases 03 and 04 were further examined. Cases 01 and 02 were dismissed because the system conditions represented by them imply that wind will need to be curtailed even if more capacity is added. For the additional studies in Cases 03 and 04, wind was added in proposed locations 1 and 2.

For Case 03 in which Nova Scotia has high inertia and high load, adding wind was achieved by reducing the internal conventional generation. At 700 MW of total wind generation, simulation of the contingencies showed stable operation. At 800 MW of wind one thermal unit was switched off. In this case Contingency01_L8004_fault_101S_NOSPS stops at about 4 seconds indicating transient stability issues.

For Case 04 in which Nova Scotia has high load and high import, adding wind was achieved by reducing the import through the Maritime HVDC link. The severity of tripping one or two DC poles is therefore less pronounced as more wind is added. The tripping of AC tie causes the same amount of MW to be lost and Nova Scotia to become islanded as in lower levels of wind. All stages of load shedding get activated in simulations with 700 MW and 800 MW of total wind generation resulting in 360 MW of load to be shed. It is noted that the control of frequency in Nova Scotia in islanded operation is the main issue. This major issue requires additional system reinforcements to accommodate increase of wind beyond present levels.

5.2. System with Additional 345-kV Tie

For the second phase of the studies, an additional 345kV line between the Nova Scotia and New Brunswick systems were added. The presence of this second tie, reinforces the Nova Scotia system especially under the N-1 contingency of one of the tie lines and hence the system no longer becomes islanded. It is also envisaged that this second tie line can increased the level of wind generation that can be accommodated in the Nova Scotia system. This additional 345-kV tie between Nova Scotia and New Brunswick is shown in Figure 5-4.

Under the base cases of Case 01 and 02, adding wind to Nova Scotia is not feasible assuming the wind needs to be curtailed due to lack of enough load or export limit. Therefore, no studies were performed under cases 01 and 02 and only cases 03 and 04 are used for adding extra wind.

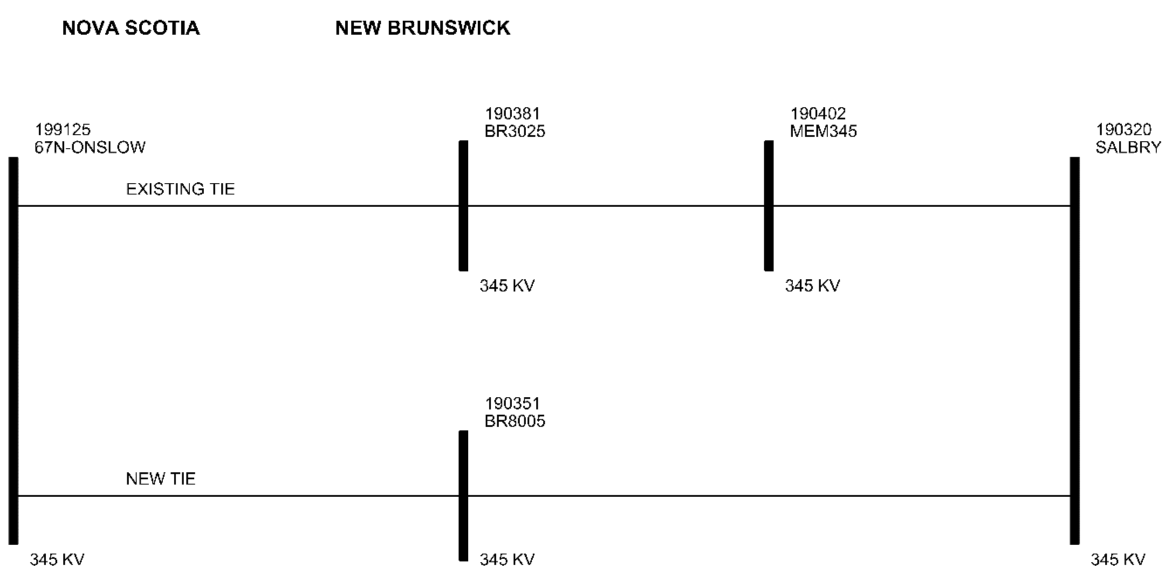


Figure 5-4: Existing and New 345 kV AC Tie Between Nova Scotia and New Brunswick

Case 03, 900 MW Wind

300 MW of additional wind generation was added in proposed wind locations 1 and 2 bringing the total wind generation to 900 MW. A corresponding amount of reduction was initiated from conventional thermal generation to compensate for the additional generation from the wind. As a result the online inertia in the Nova Scotia system reduced from 6666 MW.s to 5869 MW.s. None of the studied contingencies resulted in transient instability. The voltage levels remained within acceptable boundaries and line loadings were all within the thermal ratings.

Case 04, 900 MW Wind

Similar to Case 03, an additional 300 MW of wind generation was added in proposed wind locations 1 and 2 bringing the total wind generation to 900 MW. Thermal generation and Maritime HVDC link power exchange were adjusted to compensate for this additional generation from the wind. No studied contingency caused any transient instability with voltage levels all within acceptable boundaries and line loadings remain within their thermal limits.

Case 03, 1000 MW Wind

Following the successful introduction of 300 MW of wind at proposed wind locations 1 and 2, a further additional 100 MW of wind was added in proposed location 3 (radial with Lingan). Thermal generation was reduced to compensate for the additional generation from the wind. None of the checked contingency cases caused any transient instability. The voltage levels were within acceptable boundaries and line loadings remained within their thermal limits.

As a sensitivity check, wind generation in location 3 was further increased by about 50 MW. With this dispatch and under the contingency of tripping a DC pole, Nova Scotia system loses its synchronism. Tripping of a DC pole causes 240 MW of import to be lost which causes the power export on the AC ties to reduce by about the same amount. Figure 5-5 shows the angle of ACONI G1 (Bus 199043) for three different wind levels. The reference is the angle of machine 126652, 1 (RAV 3) in area 102.

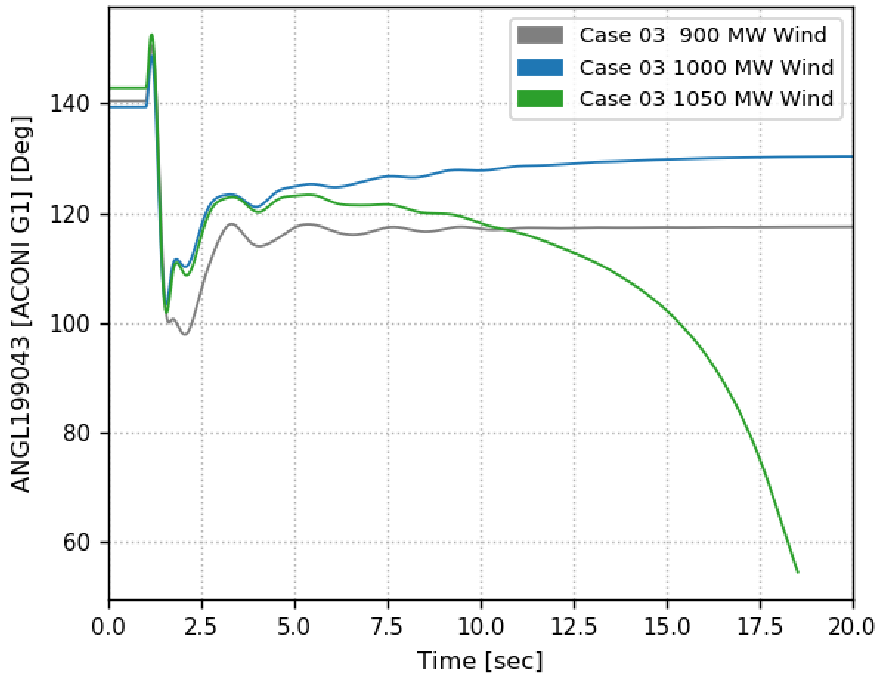


Figure 5-5: Angle Instability, Case 03, Contingency04_Fault_on_ML_Pole2

Figure 5-6 is the plot of several machines in 4 different areas. The reference is the angle of machine 126652, 1 (RAV 3) in area 102. Note that the generators in Nova Scotia (Area 106) and New Brunswick (Area 105) stay in synchronism and drift as a whole with respect to generators in IESO (Area 103).

Therefore, it is safe to conclude that the amount wind generation that can be accommodated within the Nova Scotia system with the introduction of a second 345kV tie-line cannot exceed 1000 MW.

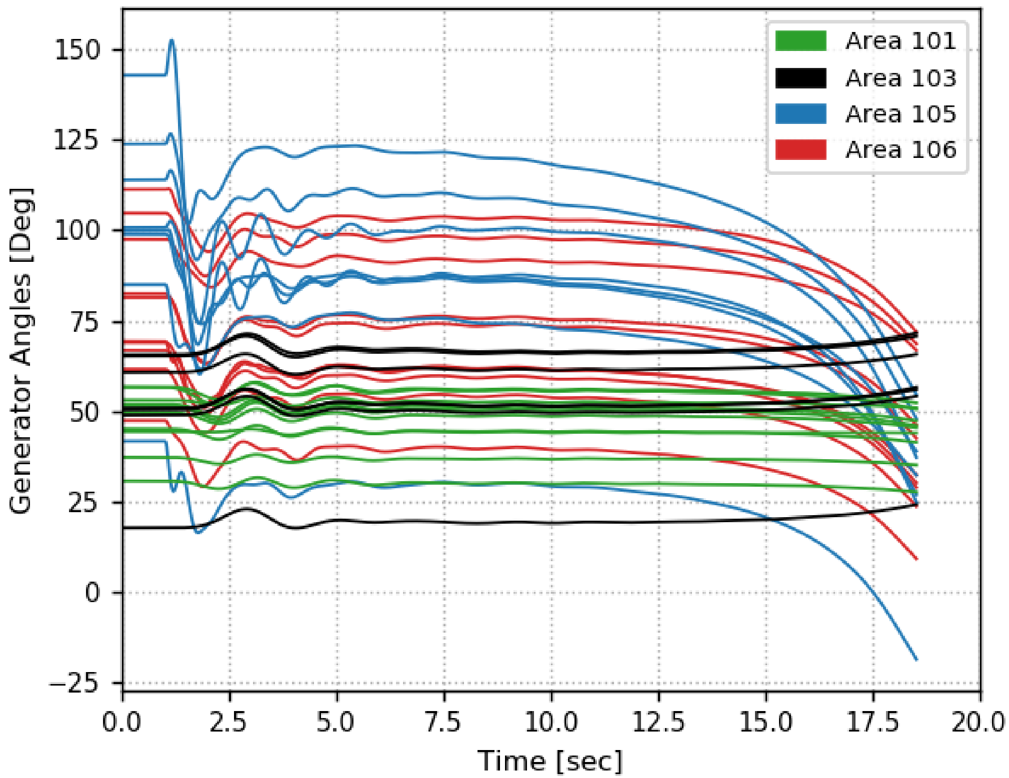


Figure 5-6: Angles is 4 Areas, Case 03, Contingency04_Fault_on_ML_Pole2, 1050 MW Wind

Case04, 1000 MW Wind

A similar approach was taken in Case 04 also with the addition of another 100 MW wind in proposed location 3 (radial with Lingan) in addition to the 300 MW of wind in proposed wind locations 1 and 2 bringing the total wind to 1000 MW. Thermal generation and Maritime HVDC link power transfer were adjusted accordingly to compensate for generation from the wind. None of the studied contingencies caused any transient instability with the voltage levels staying within acceptable boundaries and line loadings remaining within their thermal limits. It should be noted that for Case 04 it was decided not to perform a sensitivity check at 1050 MW wind as Case 03 provided a negative result.

A full summary of the study results with the inclusion of the second 345 kV tie line to New Brunswick is given in Table 5-6. As can be seen, with the inclusion of the second 345 kV tie line, the wind generation that can be accommodated reaches around about 1000 MW with any further increase causing system instability issues and requiring further mitigation measures.

Table 5-6: Summary of Transient Stability Simulation Results, Base Cases with Second 345 kV Tie

Simulation Case	Transient Stability Result with 300 MW additional wind (overall wind is at 900 MW)	Transient Stability Result with 400 MW additional wind (overall wind is at 1000 MW)	Transient Stability Result with 450 MW additional wind (overall wind is at 1050 MW)
Case 01	Not relevant	No study performed	No study performed
Case 02	No study performed	No study performed	No study performed
Case 03	System stable	System stable	System unstable
Case 04	System stable	System stable	No study performed

5.3. System with Synchronous Condenser and BESS

This section summarizes the observations made following the addition of synchronous condenser and BESS to the Nova Scotia system under base case conditions 03 and 04. During the studies wind is increased in steps of 100 MW using the three locations introduced in Section 4.3.3, *Wind Generation*. Synchronous condenser and BESS are added to the ONSLOW substation where the 345 kV AC tie to New Brunswick is connected. The idea behind this choice of location is that the major event of interest which causes under-frequency or over-frequency in Nova Scotia is the tripping of the AC tie, and the system strengthening components are deemed most effective when they provide their contribution (active and reactive power injection or absorption) where the imbalance occurs. It should be noted that for the studies in this section there is only the existing 345 kV tie line to New Brunswick. Figure 5-7 shows the components that are added to the base cases. There are also dynamic models added to the dynamic file as explained in Sections 4.3.5 and 4.3.6.

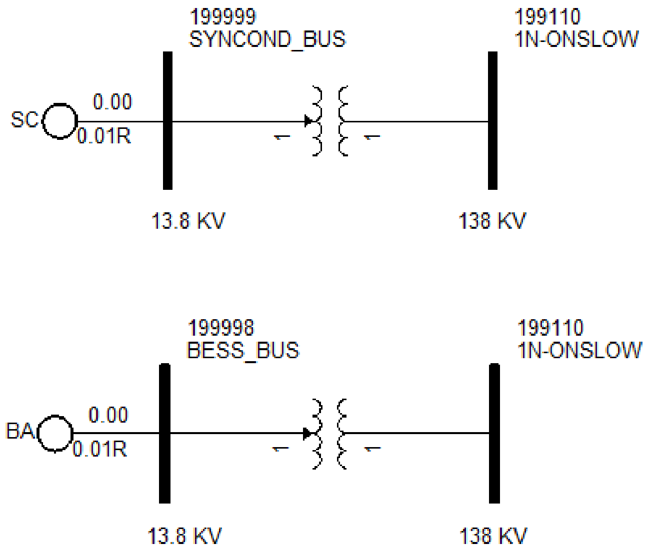


Figure 5-7: Location of Synchronous Condenser and BESS

In order to provide a comparative perspective on the active power output behavior of a SC with that of a BESS a sample study was run. Figure 5-8 shows the active power outputs from the SC and BESS following the tripping of the AC tie into New Brunswick. It is seen that initially the synchronous condenser and BESS both inject active power with the former's response being faster as BESS has delayed response due to the reaction of the controls. However, the output of the synchronous condenser changes with the frequency and becomes negative. For example, with the stator at system synchronous frequency and the rotor at a slower speed, the SC will generate active power and in the opposite case with faster rotor it will absorb active power). In comparison, the BESS is able to maintain the maximum output. It should be noted that in this sample case a ramp controller was used to increase the output of the BESS from 0 MW to 100 MW.

The very fast active power injection from a synchronous condenser which is due to its inertia helps reduce the frequency drop initially. However, by itself the SC does not provide any active power support once the transients have died down. Therefore, if no BESS is used, the gap between generation and load cannot be recovered in the few seconds following the event. The role of BESS in this time frame then becomes essential to reduce the deficit until the slower controllers can respond by adjusting the output of other generators. Or alternatively a more effective reduction in load shedding can be achieved by proper combination of synchronous condenser and BESS.

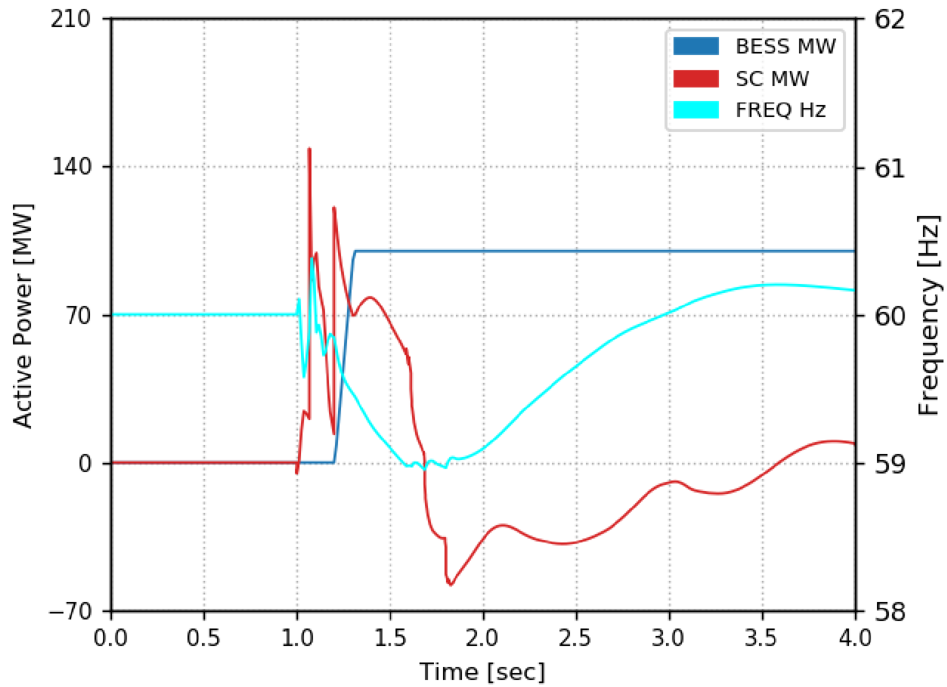


Figure 5-8: SC/BESS MW Output, Case 04a, Contingency03a_Fault_on_L8001_67N_IPM_SPS

The studies with the introduction of synchronous condenser and BESS were performed for each technology being introduced on its own and as a combination. These were introduced at ONSLOW 138 kV and their level was chosen as 100 MVA or 100 MW each. The wind level in both Case 03 and Case 04 was increased up to 1000 MW in steps of 100 MW. It was found that the system remains transiently stable after applying the studied contingencies.

Figure 5-9, Figure 5-10, and Figure 5-11 show the simulation results of tripping the AC tie to New Brunswick with Case 04 at 100 MVA and 100 MW levels of SC and BESS, respectively, either considered alone or together. When both SC and BESS are added, load shedding reaches 306 MW to survive the tripping of the tie.

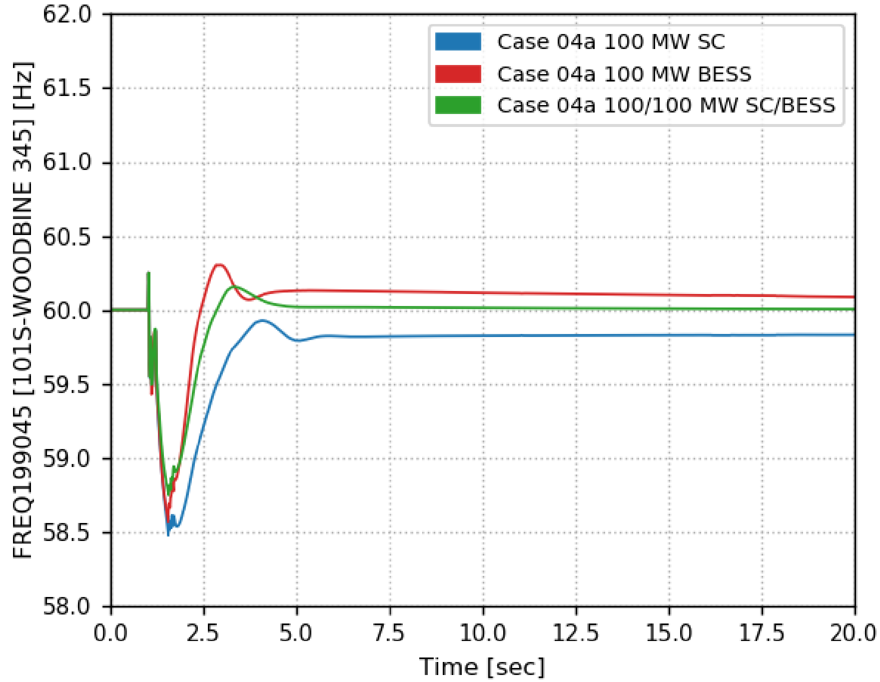


Figure 5-9: Frequency Variations, Case04a, Loss of AC Tie, 100 MVA SC, 100 MW BESS

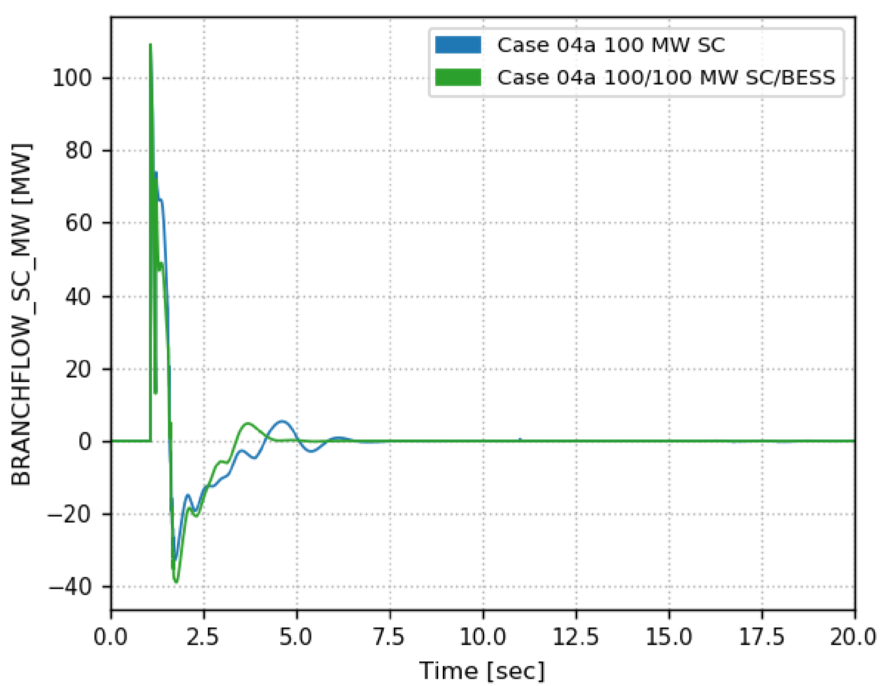


Figure 5-10: SC MW Output, Case04a, Loss of AC Tie, 100 MVA SC, 100 MW BESS

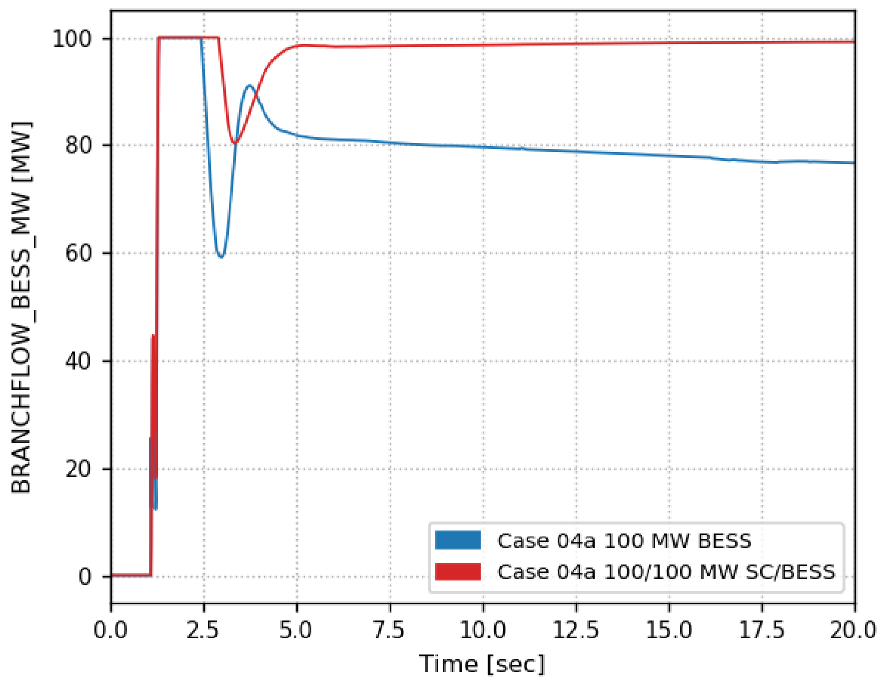


Figure 5-11: BESS MW Output, Case04a, Loss of AC Tie, 100 MVA SC, 100 MW BESS

Increasing BESS rating to 200 MW and the SC to 200 MVA in Case 04, only two stages of under-frequency load shedding become activated when the AC tie is tripped resulting in about 210 MW of load being shed. Figure 5-12 shows the frequency variations at Woodbine substation with three different technology combinations when wind generation is at 1000 MW. The best result is achieved with both the synchronous condenser and BESS in service. Figure 5-13 shows the MW output from the synchronous condenser. Note that the output goes to zero when the transients have died out. Figure 5-14 shows the MW output of the BESS. The controller used for BESS consists of a ramp controller and a PID controller. That is why the BESS output initially goes up to 200 MW, but then reduces to damp frequency oscillations.

Clearly the higher the rating of the SC and BESS, the better the response and less load is shed. Figure 5-15 compares the frequency in Nova Scotia Woodbine substation with 100 and 200 levels of SC/BESS and the level of support obtained with higher rating is evident.

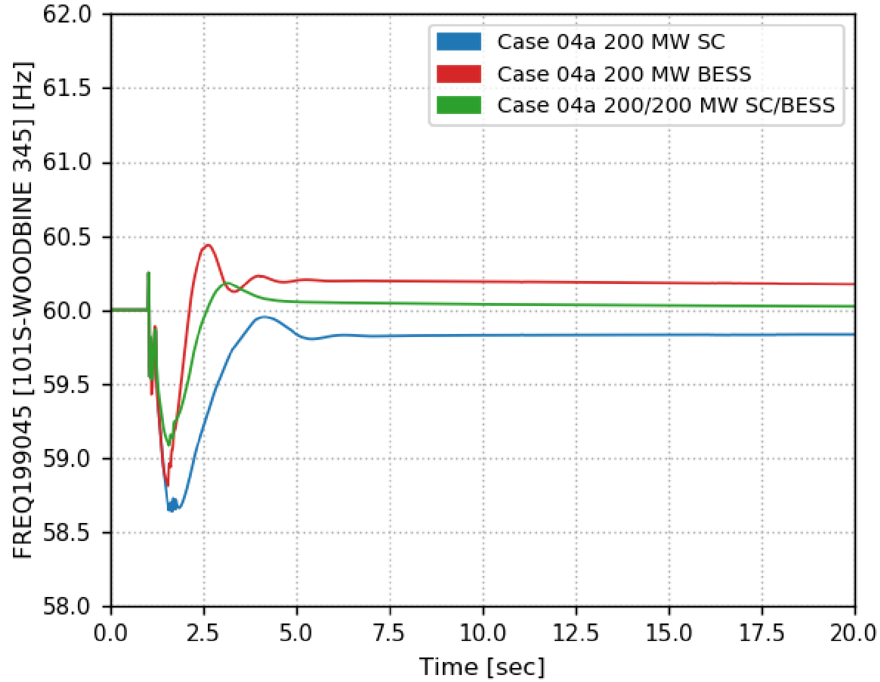


Figure 5-12: Frequency Variations, Case04a, Loss of AC Tie, 200 MVA SC, 200 MW BESS

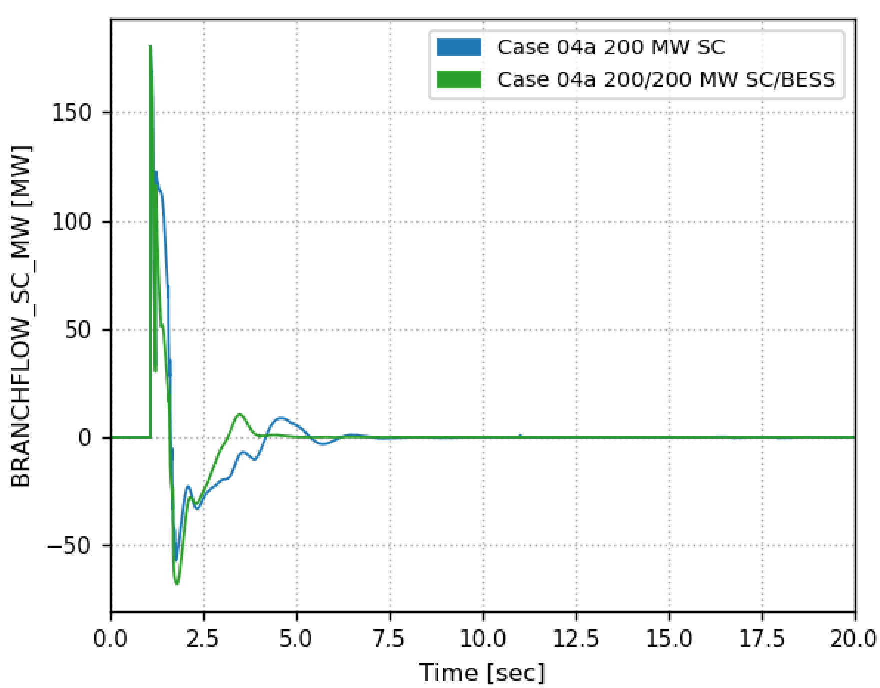


Figure 5-13: SC MW Output, Case04a, Loss of AC Tie, 200 MVA SC, 200 MW BESS

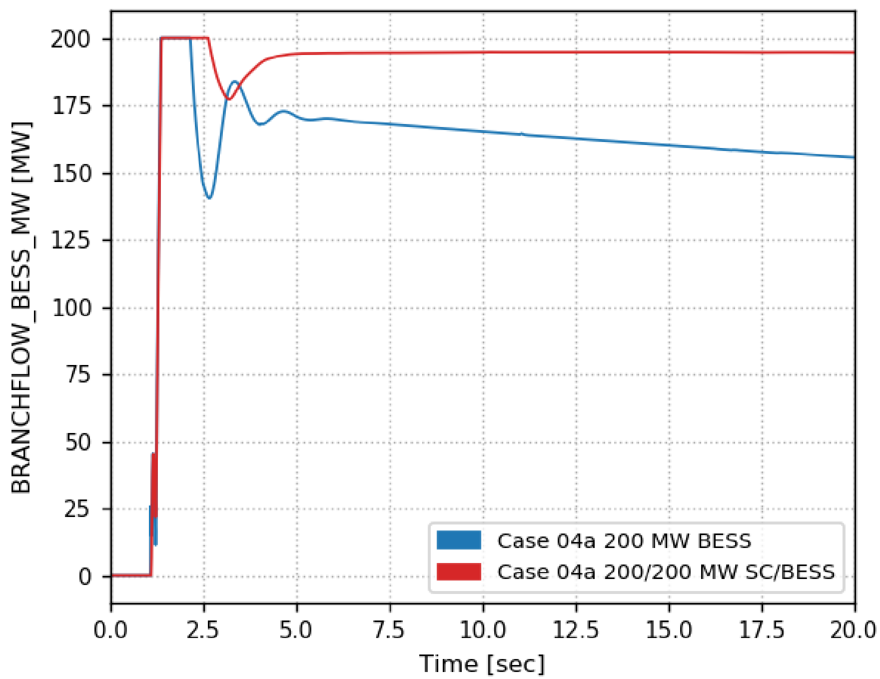


Figure 5-14: BESS MW Output, Case04a, Loss of AC Tie, 200 MVA SC, 200 MW BESS

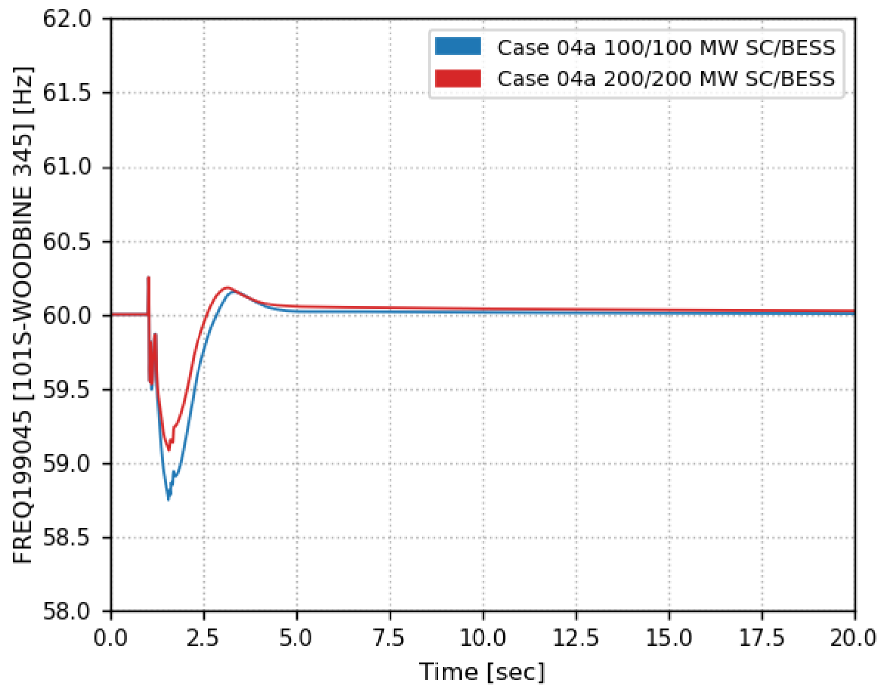


Figure 5-15: Comparison of Frequency with SC/BESS of 100 MVA/MW versus 200 MVA/MW

This analysis added synchronous condensers and batteries at steps of 100 MVA and 100MW, respectively. Although the system is transiently stable in both 100 and 200 levels, a more effective reduction in load shedding was obtained at the 200 level and it was achieved when both synchronous condensers and BESS were considered. The synchronous condenser fast inertial response provides enough time for battery output to ramp up and stay up for the duration of transient study. This has been used as a criterion to choose 200 as the preferred level. Theoretically, it is possible to increase the size of the SC and BESS combination to even higher levels and perhaps eliminate the operation of the load shedding scheme or utilize the load shedding scheme but increase the level of wind generation. However, it is of importance to note that the largest battery installed in South Australia is rated at 100 MW/129 MWh. There are applications in other places to install batteries as large as 150 MW. Given that this technology is new and rapidly changing and, given the large size of both battery and synchronous condenser required to observe the effect in Nova Scotia, it is better to consider this technological solution as a supporting option to reinforcing the system with the addition of a second AC tie. The latter not also provides a proven method of strengthening the system, but it eliminates the most important and critical contingency Nova Scotia system faces.

6. Observations from the Analysis

Table 6-1 shows a summary of all the transient stability studies performed indicating that the limit of wind integration based on the investigated options is estimated to be approximately 1000 MW. This calculated level is based on two distinct system scenarios that represent stressed system conditions but nevertheless the representative number of system dispatch and loading cases could be expanded to check as many operational scenarios as practical. Furthermore, while stability is a critically important parameter for technology considerations going forward, other operating factors may enter into criteria for project selection.

The system as it stands is capable of operating with 600 MW wind with the inclusion of some adjustments, such as maintaining a minimum level of thermal generation under certain conditions and by switching off some shunts to control excess voltage. The analysis indicates that these mitigations are relatively straightforward to implement. Simulations with 700 MW of wind during high load and high internal thermal generation or high import from Newfoundland (cases 03 and 04) show stable transient operation; however, this only suggests that the existing system can accommodate this wind under certain conditions. This result must be interpreted with great care as establishing a precise limit is not possible, and experience has shown that once the AC tie to New Brunswick is lost even with the existing wind levels, controlling of the Nova Scotia frequency in islanded operation is very challenging.

The level of renewable generation could be increased to 1000MW with the inclusion of a second tie to New Brunswick. To refine this limit more dispatch scenarios, more wind locations, and more contingencies might need to be considered. The inclusion of this second tie will significantly reduce the probability of islanding of Nova Scotia. In addition to providing system security against an N-1 criterion to the Nova Scotia system, the inclusion of the second tie could facilitate the export of the excess generation from renewable energy, negating the need to curtail it.

Another observation is that the 1000 MW renewable level that can be integrated with the introduction of the second tie, could also be achieved with the use of other technologies, namely synchronous condensers and battery storage system. However, the results of this study indicate that utilizing these solutions on their own as primary facilitator of renewable energy does not solve system issues and vulnerability of the system to frequency stability issues under the critical New Brunswick tie contingency.

Most controllers of power electronic converter-based generation utilize phase-locked-loop and with reduced short-circuit level their operation becomes more difficult. The study did touch upon the likely effect this may have but did not go into a detailed electromagnetic time domain simulation to establish the full picture with respect to the installed wind generation in Nova Scotia system.

Revision of grid codes is heavily relied on in increasing the penetration of renewables in other jurisdictions. For example, in the case of South Australia more stringent frequency response requirements from wind generation may initially be deemed as limiting these resources, but in the wider view this requirement facilitates connection of more renewables with the system being able to ride through more stressing contingencies. Grid codes are also used to create a wider ancillary market where part of the required services can be procured in a regulated environment, ultimately the market dictating the price of the service. Ireland has extensive work in this area with successful outcomes. Introducing new or amended requirements in grid code is usually followed with strict compliance checks and in both South Australia and Ireland these checks now form part of a structured compliance process for the system users. Checks usually are repeated following changes in generator control settings or following maintenance outages in order to prove capability for operational purposes.

A qualitative analysis of power quality issues that may be affected by (or affect the operation of) large scale inverter-based generation should normally form part of a wider study. A typical issue that is encountered is control of harmonics on the system, among others. In most cases this is done with planning stage analysis and emission limit specification leading to installation of shunt passive filters which shift the issue from one harmonic to another. An increased number of such installations is typically masking wider issues and at worst impacting transient stability. Decreasing short-circuit levels adversely impact system harmonic impedances up until the first system resonance point. It is therefore recommended that issues associated with power quality are also looked into as part of a wider system impact study.

Table 6-1 Overall Transient Stability Study Summary

System scenario	Cases	600 MW Wind	700 MW Wind	800 MW Wind	900 MW Wind	1000 MW Wind	1050 MW Wind
System as is, no topological changes or additional devices	Case 01	Unstable, addition of 3 thermal units makes system stable	No study performed	No study performed			
	Case 02	Stable	No study performed	No study performed			
	Case 03	Stable	Stable	Unstable			
	Case 04	Unstable, addition of one thermal unit and switching off four shunts make system stable	Stable, Caution: Islanded operation at this wind level can be problematic.	Stable, Caution: Islanded operation at this wind level can be problematic.			
Introduce a second 345 kV line to New Brunswick	Case 01		No study performed	No study performed	No study performed	No study performed	
	Case 02		No study performed	No study performed	No study performed	No study performed	
	Case 03		Stable	Stable	Stable	Stable	Unstable
	Case 04		Stable	Stable	Stable	Stable	
Introduce SC and/or BESS	Case 01		No study performed	No study performed	No study performed	No study performed	
	Case 02		No study performed	No study performed	No study performed	No study performed	
	Case 03		Stable	Stable	Stable	Stable	
	Case 04		Stable	Stable	Stable	Stable	

7. Conclusions and Recommendations

Phase 1 of the study looked at the capability of the existing Nova Scotia power system to reliably support the existing 600 MW of installed wind that has been integrated to date. Knowing that the tie to the New Brunswick system is of critical importance in terms of system stability and security, the second phase of the studies looked into the level of wind generation that can be accomodated with the inclusion of a new additional 345-kV tie to the New Brunswick system. The third phase of studies were then performed to establish whether the level of increased wind penetration with the second tie can be achieved by the introduction of other technologies without requiring additional interconnection.

Through simulations of 4 different cases that represent stressed conditions in the Nova Scotia power system and applying several severe contingencies, it was concluded that the existing Nova Scotia power system can support 600 MW of wind generation. The study estabished that while Nova Scotia is connected to New Brunswick, there needs to be at least 3 thermal units online so that in the event of separation from the interconnection, the Nova Scotia islanded system can survive the disturbance. Minimum thermal limits were set based on the loss of a single tie to New Brunswick, with limited support from Maritime Link and no support from wind generation. Therefore, the second tie eliminates the primary rationale behind the minimum online thermal units. However, other services are required for the system which are provided by the thermal units regardless of the second tie option. Those services include:

- Balancing services (tie-line control) to manage fluctuations in load and renewable generation (wind, solar).
- Load following, a longer-term generation control service to manage load pickup from overnight to daytime loads
- Short circuit current and voltage control at a local level (perhaps provided with a combination of synchronous condensers and the second tie).

Even with the introduction of thermal units, a large amount of load needs to be shed to recover the frequency and, in one case, due to light load conditions, the voltages in Nova Scotia rise beyond the statutory boundaries. This, in turn, will have the effect of increasing the load that is voltage sensitive. Hence, in addition to running thermal units, reactive power resources should have sufficient dynamic range in order to control high voltages.

A more general way of quantifying thermal unit requirements is by using the total aggregate online inertia as a measure. The case which established three thermal units as the limit has a total online inertia of 2766 MW.s. It is not possible to define this number as the absolute minimum due to the representative but limited number of dispatch case studies conducted for this report. Therefore, it is recommended that other dispatch scenarios consisting of different combinations of synchronous generators and possibly other technologies be studied to refine this number, which could be used as an equivalent alternative to the minimum number of thermal units.

Noting that the loss of the New Brunswick tie is a major event for the Nova Scotia system the second set of studies considered whether the wind generation can be increased with the introduction of a second tie circuit between New Brunswick and Nova Scotia and if so by how much. These studies indicated that an increase in wind capacity will be possible with the introduction of the second 345-kV tie between Nova Scotia and New Brunswick, and that the system is able to accomodate close to 1000 MW of wind generation. The limiting factor is established as system stability and the final refined figure will depend on the specific location of any new wind generation. Three different locations were examined to add the additional wind. It was observed that if the wind generation goes above 1000 MW, the event of tripping a DC pole which causes a rush of power through the AC tie, might cause the Nova Scotia system to go out of synchronism with respect to another part of the interconnection. Under such a scenario, system separation will take place. Going a step further and tripping both DC poles, system separation takes place at reduced wind generation levels. More detailed investigation is needed to establish specific reason for this behaviour.

The last part of the transient stability study looked at the possibility of accomodating a similar amount of wind (up to 1000 MW) as in the case of the second tie but without the introduction of the second tie. In doing this, two different technologies were investigated; synchronous condensors and BESS. Introduction of 200 MVA synchronus condenser and 200 MW BESS at Onslow Substation, resulted in acceptable levels of load shedding (2 out 6 stages get activated) following trip of the existing tie - significantly less than when the levels were set at 100 MVA and 100 MW of SC and BESS, respectively.

The cases where the only synchronous tie from Nova Scotia to the outside world is lost while importing results in loss of up to 40% of Nova Scotia load through underfrequency load shedding, remaining with a high percentage of wind generation which does not have primary frequency control. Restoring load in such a situation will require additional generation reserve. Therefore, this report recommends that determining reserve capacity to be able to restore load requires further investigation. Considering that the tie to New Brunswick is of the highest significance in terms of system stability, and the loss of the tie dictates most of the planning and/or operational actions, strenthening of this tie with a second 345 kV line becomes crucial and should be considered as the first alternative to explore before the introduction of any other technology. Introduction of technology in addition to the second tie line would bring additional benefits such as accomodating more wind but more importantly system security and flexibility in the changing face of generation mix. The study did not specifically establish the increased amount of wind that can be accomodated with the use of synchronous condenser and battery storage technology in combination with the introduction of the second tie line; this is likely an important area for further investigation.

Some background information on two other systems have been provided in the report in order to draw some similarities with the Nova Scotia power system. Table 7-1 shows the comparison between Nova Scotia system and the South Australian and Irish systems.

Table 7-1: Comparison Between Nova Scotia and Other Jurisdictions

Property	Nova Scotia	South Australia	Ireland
Area [km^2]	52,942	200,000*	84,421
Total Installed Wind Capacity [MW]	600	1809	5000
Total Installed Solar Capacity [MW]	Negligible	1065	Negligible
Total Installed Synchronous Condenser [MW]	0†	0	0
Total Installed Battery Storage [MW]	0	130	10
Peak Demand [MW]	2180	3005	6500
Minimum Demand [MW]	650	1000	2500
Percentage of Minimum to Peak Demand [%]	30	33	38
AC Ties to Neighbors	2 circuit 300 MW import 330 MW Firm/500 MW non-firm export	2 circuits 650 MW import 650 MW export	None
DC Ties to Neighbors	2 poles 250 MW import / pole 250 MW export / pole	1 pole 220 MW import 220 MW export	2 poles 500 MW import / pole 500 MW export / pole
UFLoad Shedding	Used	Used	Used
RoCoF	Not used	Used (3 Hz/s)	Used (0.5 Hz/s)
Minimum Required Total Online Inertia [MW.s]	2766	6000	23000
Ratio of Minimum Required Total Online Inertia to Peak Demand [s]	1.3	2.0	3.5

* Area covered by transmission network

† Nova Scotia has 6-7 combustion turbines (30 MVA each) which can function as synchronous condensers. They were not dispatched in the base cases as they are generally used for dynamic reactive power reserve and quick-start operating reserve. They are also low inertia devices in synchronous condenser mode of operation

It is noted that the online inertia in Nova Scotia is based on the number calculated for the existing system capabilities with limited scenarios and is well below those for the other two systems. This implies that the frequency excursions will be larger for events that cause imbalance between load and generation and is a generic indication of increased vulnerability to lose synchronism under the tie line outage with increased power electronic converter based generation. It is therefore strongly recommended to perform further system studies with wider dispatch scenarios and a defined system development plan to establish a more robust online inertia level.

Load shedding is used in all three systems, however, in South Australia and Ireland load shedding is not relied upon for mitigating the effects of planning contingencies. It is an operational tool and in the case of Ireland demand side units are proven to provide not just load sheding but some other system services.

Rate-of-Change-of-Frequency (RoCoF) monitoring and protection relays are being increasingly used to deal with system frequency issues and in turn facilitate a more planned integration of power electronic converter based generators. The settings of RoCoF relays in South Australia and Ireland need to be adjusted to allow for faster rate of change without tripping in order to accommodate lower online inertia that is a consequence of retiring conventional generators in favor of inverter-based generators. These relays are not used in the Nova Scotia system, therefore the complication that may arise out of their use is not a concern. RoCoF relays cause tripping of equipment (generation, load, etc.) on a predictive basis. Their use can be advantageous in the absense of fast frequency controllers. However, they increase the time and effort for system restoration. Use of fast controllers such as batteries to control the frequency can introduce flexibility to the use of RoCoF relays in relation to frequency stability. In Ireland, the use of RoCoF relay setting is being inceared to 1 Hz/s in addition to fast frequency response requirements that are being sourced from the market as an ancillary service.

South Australia is seeking to construct a second 330 kV AC double circuit tie line from the mid north region of South Australia to Wagga in the neighboring state of New South Wales. The benefits of this interconnector are increased system security in South Australia, considered essential given the increasingly credible loss of both circuits of the existing AC interconnector, as well as facilitating increased penetration of renewables. It is of interest to note that in terms of interconnection with neighboring grids, South Australia is similar to Nova Scotia and the second AC circuit as planned is comparable to the second New Brunswick tie line. However, there is difference between the two systems in terms of reliance on the interconnection to neighboring grids. Loss of the single tie between the Nova Scotia and New Brunswick power systems has a pronounced effect on the technical performance of the Nova Scotia system and without resolving this contingency, the options to increase the level of renewable integration in Nova Scotia are limited. The loss of the AC tie in the South Australia case does not have similar pronounced consequences in terms of system technical performance.

Given that a minimum number of synchronous machines need to be online for frequency control and assuming Nova Scotia load remains practically unchanged, if the size of the export market cannot be increased as more variable renewable energy is installed, the renewable generation would have to be curtailed. This economic tradeoff can be examined in an exercise such as an Integrated Resource Plan.

The following are the recommendations for system reinforcement based on this study:

1) The existing system renewable integration level is close to 600 MW. While simulations with 700 MW of wind show stable transient behavior in the event of tripping the New Brunswick tie under certain system conditions, it is not recommended to assume this as a firm limit. The reality is that establishing a firm limit by looking into a limited number of system conditions and scenarios is not possible, and there are already indications from the past events that frequency control of Nova Scotia in islanded operation is very difficult.
2) In terms of benefits derived from adding a second tie versus adding synchronous condenser and battery energy storage, the former reinforcement measure is superior, because it eliminates the islanding of Nova Scotia in the event of losing a single AC tie.
3) With either a second tie or combination of synchronous condenser and battery energy storage the renewable integration can be close to 1000 MW. This result was obtained base on the transient stability simulations of the representative system conditions and representative contingencies.
4) Exploiting both a second tie and technologies such as synchronous condenser and battery energy storage will increase system security and reliability in different operating scenarios including in islanded mode.

In general, following the limited studies performed, this report recommends that this study be expanded in order to establish a system security level commensurate with increased wind generation. This should be based on well-defined system topologies which include the second tie as a starting position. Most studies of this nature are based on the criterion of establishing maximum renewable generation penetration with minimum system reinforcement. This can be seen as a balanced approach in terms of system development. However, it is noteworthy that the Nova Scotia system is rather unique in its behavior to the existing New Brunswick tie contingency and hence any study without the second tie appears to be counter intuitive. Therefore, in continuation to the work done here, PSC would recommend to:

1) Expand the existing study: The study should be expanded initially to capture wider dispatch and loading scenarios. The expanded study should then look at the possibility of introducing specific technology measures to understand the effect these might have especially with regards to the time frame (fast frequency response vs primary or secondary frequency response), location and level.

2) Provision of enhanced studies: The above expanded studies should be enhanced further with time domain simulations in order to establish fast frequency response requirements as well as other areas such as response and ride-through under depleted short-circuit ratios.

3) Expand the set of contingencies studied: Only a select set of contingencies were included for expediency for this study. Planning studies are normally conducted with a full set of steady-state and stability contingencies. Of particular note is the requirement to survive both poles of the Maritime Link (net 475 MW).

4) Establish best route for services: Combining the two studies above, determine what level of ancillary services can be obtained via grid code enhancements from contracted Power Producers.

5) Impact on power quality study: Increased level of power electronic converter based generation is known to bring other issues into the system, one of the most prominent one being power quality. This area usually has two aspects; the effect power electronic based generation has on the level of power quality expected at system level and the probability of power electronic converter based generation operating reliably in such an environment. A parallel study to the above should look at the impact of increased renewable generation on the power quality at Nova Scotia system. An emerging area of concern relates to control interactions among power electronic devices as well as between power elecrtonic devices and other system devices (series capacitors and generator turbines) especially at sub-synchronous frequencies. The interaction covers possibilities between HVDC and FACTS devices and wind turbine generators. The possibility of such interactions should be investigated as system characteristics come into effect.

8. References

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