Report on
2015 NPCC OVERALL TRANSMISSION RELIABILITY ASSESSMENT of the
2020 PLANNED BULK POWER SYSTEM

Approved by the RCC
on
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Working Group on Inter-Area Dynamic Analysis (SS-38)
Task Force on System Studies

This report was prepared by the NPCC Working Group on Inter-Area Dynamic Analysis, SS-38. SS-38 reports to the NPCC Task Force on System Studies.
SS-38 WORKING GROUP ON INTER-AREA DYNAMIC ANALYSIS

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EXECUTIVE SUMMARY

OBJECTIVE

In accordance with the NPCC Reliability Assessment Program, the SS-38 Working Group on Inter Area Dynamics has conducted an Overall Transmission Assessment for the year 2020 NPCC system. The overall study builds upon and supplements the Transmission Reviews conducted annually by each of the NPCC Areas by examining the system from a broader regional and inter-regional perspective. The last Overall Transmission Assessment was conducted in 2009.

The objectives of this (2015) assessment were to:

1. Assess the dynamic performance of the year 2020 NPCC system from a standpoint of system robustness, by simulating various extreme and beyond criteria contingencies.
2. Evaluate the impact of any developments in the adjacent PJM region and simulate the effect of extreme contingencies originating in the PJM region.
3. Evaluate, from a dynamic perspective, the most severe gas pipeline contingencies identified in the EIPC Gas-Electric System Interface analysis. Also, evaluate beyond criteria contingencies associated with gas pipelines by simulating overlapping electrical faults.
4. Evaluate the impact of distributed generation on the dynamic performance of the NPCC system.

This report focuses on the results from the analysis conducted to meet the first three objectives. Regarding the forth objective, the original plan was to conduct the DG sensitivity utilizing the composite load model that will include PV generation. However, this model is presently not expected to be available for the foreseeable future. As an alternative, SS-38 has modeled DG sensitivity using the PV generator model in PSSE Rev 33, which is based on the type 4 wind model, WT4. However, the software limitation on the number of wind generators that can be included for study prevented SS-38 from completing this analysis in time for the December 2015 RCC meeting. This limitation was communicated with the software vendor who stated that that number of allowable wind generators will be increased for the next Rev 33 release which is scheduled in November 2015. With this software update available soon, SS-38 is expected to complete the DG sensitivity by January 2016 and will provide an addendum to the OTA report for a presentation at the March 2, 2016 RCC meeting.

RESULTS AND CONCLUSIONS

The results from the extreme contingency testing demonstrate the overall strength and robustness of the NPCC system projected for 2020 as all but three of the extreme contingencies tested in this study resulted in a stable and damped response with no adverse inter-Area or inter-regional impact:
1. In New England, loss of the Surowiec substation without a fault resulted in the loss of synchronism between New England and New Brunswick. However, after separation, both systems returned to the stable state.

2. In New York a 3-phase fault followed by a breaker failure at Marcy 345 kV resulted in system separation in New York State. This was seen in previous assessments as well as during recent underfrequency load shedding studies.

3. In Ontario, a 3-phase fault followed by breaker failure at Claireville 500 kV resulted in Ontario becoming dynamically unstable.

All gas pipeline contingencies simulated in this assessment exhibited a stable and well damped system response.

With regard to beyond criteria contingency testing, results also demonstrate the overall strength and robustness of the NPCC system. All the beyond criteria contingencies tested in this study resulted in a stable and damped response with no adverse inter-Area or inter-regional impact:

1. Responses to All Gas Pipeline contingencies with overlapping electrical faults were stable and well damped.

2. Response to Loss of major Ties between Areas (e.g. all Hydro Quebec HVDC Exports) were stable and well damped.

Further, extreme contingencies in adjacent RFC region did not negatively impact the dynamic performance of the NPCC system projected for 2020.
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1 INTRODUCTION

In accordance with the NPCC Reliability Assessment Program, the Task Force on System Studies (TFSS) is mandated to conduct an Overall Transmission Assessment. The overall study builds upon and supplements the Transmission Reviews conducted annually by each of the NPCC Areas by examining the system from a broader regional and inter-regional perspective. The last Overall Transmission Assessment was conducted in 2009.

2 BASE CASES DEVELOPMENT

The following four base cases were developed by the SS-38 working group for study in this assessment:

- One light load case based on the 2020 Light Load case prepared by MMWG during 2014/2015. PSSE Rev 33 was used to run simulations on this case.

- Two summer peak load cases based on the 2020 Summer Peak Load case prepared by MMWG during 2014/2015. PSSE Rev 33 was used to run simulations on these cases.

- One winter peak load case was developed for testing on the Hydro-Quebec system. This case was based on the winter peak case used for the HQT CATR 2014 (2019 system conditions). Projects were added to the case to represent the 2020 system conditions. PSSE Rev 32 was used to run simulations on this case.

The light load case stressed NPCC transfers in the East to West direction. For the summer peak load cases, the first case stressed the system in the E-W direction and the second case stressed the system in the W-E direction.

Transfer levels in the Winter Peak load case were chosen to stress the Hydro-Quebec interconnection.
### Table 2.1: Base case interface flows (in MW)

<table>
<thead>
<tr>
<th>Interface</th>
<th>Light Load (E-W)</th>
<th>Summer Peak (E-W)</th>
<th>Summer Peak (W-E)</th>
<th>Winter Peak (HQ)</th>
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<tr>
<td>NS-NB</td>
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<td>350</td>
<td>0</td>
<td>200</td>
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<td>NB-NE</td>
<td>1000</td>
<td>1000</td>
<td>0</td>
<td>800</td>
</tr>
<tr>
<td>Madawaska HDVC HQ-NB</td>
<td>0</td>
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<td>0</td>
<td>0</td>
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<td>Eel River HVDC HQ-NB</td>
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<td>1650</td>
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<td>Outaouais HVDC (HQ-Ont)</td>
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<td>1800</td>
<td>1800</td>
<td>-1800</td>
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</tr>
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</table>
3 Contingencies Tested

Since the objective of this study was to assess system robustness, only extreme and beyond extreme contingencies were tested. Further, only transient stability simulations were run as no steady state simulations were deemed necessary for this assessment.

Each of the contingencies listed below were tested on both summer peak load cases, as well as the light load case, with the exception of the HQ contingencies, which were only tested on the winter peak load case.

Extreme Contingencies:

The following extreme contingency types, as defined in NPCC Directory 1, were selected for this assessment:

1. Three-phase fault on a transmission line with failure of a circuit breaker to operate and correct operation of a breaker failure protection system and its associated breakers (with due regard to successful and unsuccessful reclosing):

   New England: 3-phase fault w/ Breaker Failure at West Medway 345 kV
   3-phase fault w/ Breaker Failure at Millbury 345 kV
   3-phase fault w/ Breaker Failure at Wachusett 115 kV

   New York: 3-phase fault w/ Breaker Failure at Marcy 345 kV (EC 12)
   3-phase fault w/ Breaker Failure at Moses 230 kV (EC 30)

   Ontario: 3-phase fault w/ Breaker Failure at Claireville 500 kV
   3-phase fault w/ Breaker Failure at Hawthorne 500 kV

   Maritimes: 3-phase fault w/ Breaker Failure at Onslow 345 kV

   HQ: 3-phase fault on Manicouagan to Levis 735 kV Line w/ delayed clearing at Manicouagan

   PJM: 3-phase fault w/ Breaker Failure at Branchburg 500 kV

2. Loss of all transmission circuits emanating from a generating station, switching station, substation or dc terminal without a fault:

   New England: 1. Loss of Northfield 345 kV substation
   2. Loss of Mystic 345/115 kV substation
   3. Loss of Millbury 345 kV substation
   4. Loss of Surowiec 345 kV substation

   New York: 1. Loss of Niagara 345/230/115 kV substation

   Ontario: 1. Loss of Claireville 500 kV substation
   2. Loss of Longwood 500 kV substation

   Maritimes: 1. Loss of Keswick 345 kV substation
   2. Loss of Woodbine 345/230 kV substation
2015 NPCC Overall Transmission Assessment

PJM:  
1. Loss of Susquehanna 500 kV substation

3. Loss of all transmission circuits on a common right-of-way, without a fault:
   
   New England: Loss of Dunbarton- South ROW
   
   New York: Loss of Niagara-Ontario Ties
   
   Ontario: Loss of Bruce ROW
   
   Maritimes: Onslow-Halifax ROW
   
   HQ: 
   1. Loss of three 735 kV lines south of Albanel substation
   2. Loss of three 735 kV lines south of Abitibi substation

4. Sudden loss of fuel delivery system to multiple plants (i.e., gas pipeline contingencies, including both gas transmission lines and gas mains) within a region without a fault:
   
   New England: Loss of Chaplin Gas Line (Results in loss of several Generators in Southeastern New England)
   
   New York: Loss of Gas Supply Resulting in Loss of Several Generators in New York Area 6 (Capital District = 1620 MW)
   
   Ontario: Loss of Gas Supply to Lennox Generation (2200 MW)
   
   Maritimes: No gas pipelines to test
   
   HQ: No gas pipelines to test

5. Failure of a Special Protection System, to operate when required following the normal contingencies listed in Table 1 of NPCC Directory 1, Category I, Single Event.
   
   New York: Loss of Ladentown 345 kV Ties and Failure of SPS (SPS39F)
**Beyond Criteria Contingencies:**

The following beyond criteria contingency types were examined for this assessment:

1. Loss of major ties with an Area:
   
   - Loss of all HQ HVDC exports
   - Loss of all New York – New England Ties
   - Loss of all Ontario-New York and Ontario - Michigan ties

2. Overlapping gas and electric contingencies:
   
   New England: Chaplin Gas Line + Normally Cleared 3 phase fault at W Medway 345 kV
   
   New York: Tennessee Gas line + Normally Cleared 3 phase fault @ Edic 345 kV
   
   Ontario: Loss of Gas pipeline supplying Lennox (2200 MW) + Normally Cleared 3 phase fault at Hawthorn 500 kV

3. Two simultaneous 3-phase faults on separate transmission lines:
   
   New York: Normally Cleared 3-phase fault on Edic-New Scotland and Marcy - Coopers Corners and Edic-Fraser (CE01 & CE07)

4. Simultaneous loss of two substations:
   
   HQ: Loss of two 735 kV substations in the Montreal region (Grand-Brûlé and Boucherville).
4 STUDY RESULTS

4.1 NEW YORK

The Assessment was performed with a summer 2020 peak load and winter 2020 light load base cases. The summer 2020 case has a New York Area total load of 33,207 MW, about 950 MW less than the total load in the previous study case, and a total generation of 35,378 MW, about 2,998 MW more than the total generation in the previous study case. The study cases (summer peak load) were dispatched East-to-West and West-to-East across the NPCC Areas, while the light load case was dispatched East-to-West. The transfer schedules for the NPCC Areas are shown in Table 2.1.

Some of the major changes in system model between the previous assessment and this year’s assessment include: the addition of Hudson Transmission Project (HTP), a new HVDC tie line between PJM and New York and the Mainsburgh 345 kV substation between Watercure and Homer City. Other changes include the addition of the Hopatcong 500 kV tie to Ramapo. Stability analysis was conducted to evaluate the performance of the bulk power system for beyond criteria and extreme contingencies as defined in the NPCC Directory #1, Design and Operation of the Bulk Power System. A total of seven (7) contingencies (one beyond criteria contingency, five extreme contingencies and one loss of gas contingency) were simulated to test the performance and robustness of the bulk power system.

The contingencies and results are described in detail below. The stability analysis results indicate that the interconnected power systems would be stable for the beyond criteria contingencies tested and for the system conditions tested. Some of the extreme contingencies tested may result in a loss of local load or generation within an area due to low voltage or first-swing instability of isolated generators. In most of these cases the affected area would be confined to the NYISO system. Overall, the results are consistent with the previous overall transmission assessment.

4.1.1 EXTREME CONTINGENCY ASSESSMENT

New York: Loss of New York-Ontario Ties at Niagara (EC01)

This extreme contingency consists of the loss of two 230 kV and two 345 kV circuits across the Niagara River which link New York and Ontario. The loss of these circuits isolates all of the power from the Niagara station onto transmission east and south of the Niagara/Buffalo area, resulting in low-frequency oscillations.

This contingency consists of the no-fault loss of the two Beck-Niagara 345 kV (PA301 and PA302) ties, the Beck-Niagara 230 kV (PA27) tie, and the Beck-Packard 230 kV (BP76) tie. All four ties are assumed to open simultaneously. This contingency was simulated on all the transfer test cases.

The simulation plots for this contingency shows that the system response is very well damped even with a high Western NY Export of 1900 MW. There has been a significant improvement in system damping compared to the system response for the same contingency in the previous assessment. Previous studies have shown sustained oscillation for this contingency. This is largely because of the installation of Power
System Stabilizers (PSS) at the Niagara units and the system upgrades/reinforcements in the Rochester network

Ordinarily, just opening the Niagara ties with high Western NY export can cause system oscillations. This condition is usually mitigated by rejecting three or four Niagara units to reduce the Western NY export to below 1100 MW.

**New York: Loss of Niagara Station (EC02)**

This extreme contingency consists of the loss of the entire Niagara station. This contingency has been shown to cause widespread severe voltage drops across western New York and adjoining areas of PJM in previous area transmission reviews which would result in expected loss of load in these areas.

This contingency is the no-fault loss of the entire Niagara Station, which includes approximately 2660 MW of generation. The contingency consists of the simultaneous loss of one 345 kV bus, two 230 kV buses, two 115 kV buses, thirteen Niagara generators of approximately 187 MW each, and twelve Lewiston generators of approximately 20 MW each. Four 345 kV circuits, four 230 kV circuits, and thirteen 115 kV circuits are lost as a result. This contingency was simulated on all three transfer test cases.

The dynamic simulations of this contingency showed a stable and well damped system response. This underscores the benefit of the reactive support/system upgrades along the Western New York transmission corridor.

**New York: Three-Phase Fault on Moses-Massena 230 kV with Backup Clearing (EC30)**

This extreme contingency consists of a three-phase fault and stuck breaker at the Moses Station in Northern New York. The resulting delay in clearing causes the Moses units at St. Lawrence, along with a few other generators in Northern New York, to lose synchronism.

This contingency consists of a three-phase fault at the Moses end of one of the two Moses-Massena 230 kV circuits (MMS-2). The Massena end of the line is cleared normally after 5.5 cycles, but a stuck breaker develops at Moses. Backup clearing disconnects the AT4 230-115 kV transformer at Moses and removes the fault from the system at 12.5 cycles after the fault is initiated. This contingency was simulated on all three transfer cases.

This contingency (EC30) resulted in sustained oscillations. There were no first-swing instability or loss of Moses-St Lawrence generation as was the case in the previous assessment. There is a significant improvement in the system response compared to the previous assessment and this is largely because of the Power System Stabilizers (PSS) recently installed on some of the Moses generation units. The sustained oscillations were observed on the E-W/W-E summer peak transfer cases; however, the light load case was very stable.
New York: Three-Phase Fault on Marcy-Volney 345 kV with Backup Clearing at Marcy (EC12)

This extreme contingency consists of a three-phase fault and stuck breaker at the Marcy Station in Central-East New York. In some cases, the delay in clearing can cause all of the Oswego Complex units to lose synchronism, resulting in widespread power system instability.

This contingency begins with a three-phase fault at the Marcy end of the Marcy-Volney 345 kV (VU-19) line. The Volney end of the line is cleared normally in 4.5 cycles, but a stuck breaker develops at Marcy. Backup clearing opens the Marcy end of the Marcy-Edic 345 kV (UE 1-7) tie 10 cycles after the fault is applied, and the Edic end of this tie opens 1 cycle later, removing the fault from the system. The net effect of the contingency is to place a three-phase fault at Edic for 11 cycles.

This contingency resulted in widespread oscillations in all three transfer cases simulated due to first-swing instability of all Oswego units. It should be noted that this contingency dynamically broke up New York system into islands using the Out-of-Step trip function in PSS/E, in the 2013-2014 NPCC Under Frequency Load Shedding (UFLS) assessment.

New York: Loss of Ladentown 345 kV Ties and Failure of SPS (SPS39F).

This extreme contingency consists of the loss of two 345 kV circuits at the Ladentown station in southeastern New York, resulting in the isolation of Bowline 1 generation at the nearby Bowline station on to the 345-138 kV transformer at West Haverstraw and Bowline 2 is isolated on to the second 345-138 kV transformer at Bowline (upgrade). Due to this recent system upgrade, this contingency is no longer as severe.

Type III SPS #39 trips Bowline unit #2 (maximum output 600 MW) if this contingency occurs. Prior to the system upgrade, this contingency can cause thermal overloads; a failure of the SPS to operate can result in un-damped oscillations.

This contingency consists of the simultaneous no-fault loss of the Ladentown-Ramapo 345kV (W72) and Ladentown-Buchanan 345 kV (Y88) circuits. SPS #39 disconnects Bowline unit #2 8 cycles after the loss of the two lines.

The system response showed a stable and well damped oscillation in the W-E transfer case but showed sustained/un-damped oscillations for the E-W transfer case.

New York: Loss of Tennessee Gas Pipeline (EC51)

See details of this contingency in the EIPC Target 3 report (confidential), dated April 3, 2015.
For this extreme contingency, it is assumed that the units don’t have access to backup fuel; hence the contingency is modeled as a simultaneous loss of all the generating units fed by the pipeline.

The system response to this contingency showed a stable and well damped oscillation for all three transfer test cases.

4.1.2 BEYOND CRITERIA CONTINGENCY ASSESSMENT

New York: Loss of Edic-New Scotland and Loss of Marcy-Coopers Corners and Edic-Fraser (CE01 & CE07)

This beyond criteria contingency was modeled to further test the resiliency of the New York system. Contingency NY09, consists of two design contingencies, NY01: a three-phase fault on the Edic-New Scotland 345 kV line cleared in 5.0 cycles, followed by NY02: a double line to ground fault on the double circuit common tower on the Marcy-Coopers Corners and Edic-Fraser 345 kV lines.

The system response is stable and well damped in all three transfer test cases.

New York: Loss of Tennessee Gas Pipeline and Loss of Edic-New Scotland (EC51+CE01)

This beyond contingency consists of loss of the Tennessee pipeline and an overlapping three-phase fault at the Edic end of the Edic-New Scotland 345 kV line (#14). The Edic end of the line is cleared in 3.5 cycles and the New Scotland end is cleared in 5.5 cycles after the fault is applied. An auto-reclosing attempt is made at New Scotland 45.5 cycles after the initial fault application; the breaker reopens 4.5 cycles later.

As with the previous gas pipeline contingency (EC51) all units are assumed not to have access to backup fuel, hence the contingency is modeled as a simultaneous loss of all the generating units fed by the pipeline and an overlapping three-phase fault at Edic.

The system response to this contingency showed a stable and well damped oscillation for all three transfer test cases.

4.2 NEW ENGLAND

4.2.1 EXTREME CONTINGENCY ASSESSMENT

New England: Three-phase fault at West Medway 345 kV station on 357 line, single phase stuck breaker (IPT) 105 at W Medway

In this contingency, a three-phase fault at West Medway 345 kV on the 357 line to Millbury and breaker 105 (IPT) fails to open results in loss of the 344 345 kV line to Bridgewater substation. The fault is cleared from Millbury in 4.5 cycles, from West
Medway in 9.5 cycles, and from Bridgewater in 10.25 cycles.

The system response was stable and well damped in all cases.

**New England: Three-phase fault at Millbury 345 kV station on the 308 line, single phase stuck breaker (IPT) 0802 at Millbury 345 kV**

In this contingency, a three-phase fault at Millbury 345 kV on the 308 line to Wachusett and breaker 0802 (IPT) fails to open, results in the loss of 301/302 345 kV line to Carpenter Hill and Ludlow. The fault is cleared from Wachusett in 4.5 cycles, from Millbury in 9.5 cycles, and from Carpenter Hill and Ludlow in 10.5 cycles.

The system response was stable and well damped in all cases.

**New England: Three-phase fault at Wachusett 115 kV station on 115-69kV transformer bank #1, three phase stuck breaker 13T at Wachusett 115 kV**

In this contingency, a three phase-fault at Wachusett 115 kV on the 115-69 kV transformer bank #1 and breaker 13T (non-IPT) fails to open results in loss of 345-115 kV transformer #5 at Wachusett. Fault is cleared from Wachusett in 12 cycles.

The system response was stable and well damped in all cases.

**New England: Loss of Millbury 345 kV station without a Fault**

This contingency involves the simultaneous loss of six 345 kV circuits without a fault: Millbury – Wachusett 345 kV lines (314, 343), Millbury - Carpenter Hill - Ludlow line (301/302) Millbury – West Medway line (323, 357), and Millbury – West Farnum.

The system response was stable and well damped in all cases.

**New England: Loss of Northfield 345 kV station without a Fault**

This contingency involves the simultaneous loss of three 345 kV circuits without a fault, and over 1000 MW of generation/load: Northfield – Vernon (381), Northfield – Ludlow (354), and Northfield – Berkshire – Alps (312/393), and all pumped storage generation/pumps at Northfield.

The system response was stable and well damped in all cases.

**New England: Loss of Mystic 345/115 kV station without a Fault**

This contingency involves the simultaneous loss of five 345 kV circuits, one 345-115 kV autotransformer, six 115 kV circuits, and over 2000 MW of generation without a fault.

The system response was stable and well damped in all cases.
**New England: Loss of Surowiec 345/115 kV Substation without a fault**

This contingency involves the simultaneous loss of six 345 kV circuits, 345/115 kV autotransformer and 115 kV circuits without a fault: Surowiec - Elm Street 345 kV line (3020), Surowiec - Maine Yankee 345 kV lines (375, 377), Surowiec - Buxton 345 kV lines (374, 3038), Surowiec - Merrill Road 345 kV line (3026), 345/115 kV autotransformer at Surowiec, Surowiec – Raymond – Kimball Road 115 kV line (208), Surowiec – Maine Yankee 115 kV line (81), Surowiec – Crowley 115 kV line (62), Surowiec – Merrill Road 115 kV line (64), Surowiec – Topsham – Bath 115 kV line (69), Surowiec – Topsham – Mason 115 kV line (81), Surowiec – Prides Corner - Moshers 115 kV line (167) and Surowiec – Spring Street 115 kV line (166).

This contingency resulted in a system separation (out of step conditions) between New Brunswick and New England. After the system separation, the system response in both Areas (New Brunswick and New England) was stable and well damped.

**New England: Loss of Dunbarton South R.O.W (EC 204)**

This contingency involves the simultaneous loss of two 345 kV circuits, two 230 kV circuits, a 345/34.5 kV transformer, Phase II HVDC bipolar line and generation without a fault: Scobie – Lawrence – Sandy Pond 345 kV line (326), Scobie – Amherst 345 kV line (380), North Litchfield – Tewksbury 230 kV lines (A201 & B202), 345/34.5 kV transformer at Lawrence, Phase II HVDC bipolar line, tripping of Granite Ridge CT2 generation with Granite Ridge steam runback to half output due to SPS operation.

The system response was stable and well damped in all cases.

**New England: Loss of Chaplin Gas Pipeline**

See details of this contingency in the EIPC Target 3 report (confidential), dated April 3, 2015.

The loss of the Chaplin gas line results in the tripping of several generators, at intervals of about 1 hour. To simulate this contingency, the time between tripping of individual generator supplied by this pipeline was compressed to 1 second intervals. This was done so that transient stability simulations could be completed in a timely manner. Assuming a 1 second interval between generator trips is conservative from a transient stability standpoint, and if the simulation results are acceptable for this interval, they will also be acceptable for 1 hour intervals (since, with a 1 hour interval, the system can be re-dispatched between loss generators).

The system response was stable and well damped in all cases.

**4.2.2 BEYOND CRITERIA CONTINGENCY ASSESSMENT**

**New England: Loss of all Hydro-Quebec HVDC Exports**

All HVDC Ties between Hydro-Quebec and the Eastern Interconnection portion of NPCC were tripped in 1 second intervals, without a fault.

The system response was stable and well damped in all cases.
New England: Loss of all Tie Lines to New York

All AC and DC tie lines between New York and New England were tripped simultaneously, without a fault.

The system response was stable and well damped in all cases.

New England: Loss of Chaplin Gas Pipeline + 3-phase fault at West Medway.

See New England: Loss of Chaplin Gas Pipeline contingency above.

The overlapping electrical contingency consists of a normally cleared (5 cycles) 3-phase fault at West Medway 345 kV substation on the 323 345 kV line to Millbury.

The system response was stable and well damped in all cases.

4.3 Ontario

The Assessment was performed with a summer 2020 peak load and 2020 light load base cases. The summer 2020 case has Ontario Area total load of 23,504 MW, and a total generation of 22,919 MW. The study cases (summer peak load) were dispatched East-to-West and West-to-East across the NPCC Areas, while the light load case was dispatched East-to-West.

Some of the major changes in system model between the previous assessment and this year’s assessment are:

- East-West Tie: New 230 kV line from Lakehead TS to Wawa TS
- Clarington TS (Formerly Oshawa Area TS)
- Pickering retirement - 3,094 MW
- Napanee GS (Formerly Oakville GS) - 900 MW
- Green Electron Power Plant (Formerly Greenfield South) – 289 MW

A total of 7 contingencies were simulated for Ontario; 5 extreme contingencies, one beyond criteria contingency, and one overlapping gas and electric contingency. These contingencies were chosen as they are fairly stringent contingencies from different areas within Ontario. All of these contingencies were simulated on the 2020 Summer East-to-West, Summer West-to-East and light load cases.

4.3.1 Extreme Contingency Assessment

4.3.1.1 ON-EC1: Three-phase fault at Claireville 500 kV station on Claireville-Milton circuit (V586M) with stuck breaker L522L586 at Claireville
This extreme contingency simulates a three-phase fault at Claireville 500 kV on the V586M line at Claireville side and breaker L522L586 fails to open. Results in loss of C522V line to Cherrywood 500 kV. The fault is cleared from Milton in 5.25 cycles, from Claireville in 10.25 cycles, and from Cherrywood in 13.25 cycles. Claireville TS is located in Central Ontario, and is a key junction point where the 500 kV transmissions from the North and West meet.

The system remained stable and well damped for summer peak East-to-West case and light load case. However, for summer peak West-to-East case generators in Ontario started to slip poles and Ontario area became dynamically unstable. This response has been seen in past studies. For the East-West case, a large amount of generation from the Bruce complex power flows to Michigan which relieves flow on the 500 kV corridor from Bruce to Claireville. For the West-East case, the 500 kV corridor from Bruce to Claireville is highly stressed, and a 3-phase fault with delayed clearing at Clairville can result in dynamic instability of Ontario.

4.3.1.2 ON-EC2: Three-phase fault at Hawthorne 500 kV station on Hawthorne-Lennox circuit (X522A) with stuck breaker T1L522 at Hawthorne

This extreme contingency simulates a three-phase fault at Hawthorne 500 kV on the X522A line at Hawthorne side and breaker T1L522 fails to open. Results in loss of T1 autotransformer 500/230 kV to Hawthorne 230 kV. The fault is cleared from Lennox 500 kV in 5.25 cycles, from Hawthorne 500 kV in 10.25 cycles.

The system response was stable and well damped in all cases.

4.3.1.3 ON-EC3: Loss of the Claireville 500 kV Station

This extreme contingency simulates the loss of the entire 500 kV Claireville station without a fault. Claireville TS is located in Central Ontario, and is a key junction point where the 500 kV transmissions from the North and West meet.

The system response was stable and well damped in all cases.

4.3.1.4 ON-EC3: Loss of the Longwood 500 kV Station

This extreme contingency simulates the loss of the entire 500 kV Longwood station without a fault. Longwood TS is located in Western Ontario, and is a key junction point between Western and Central Ontario.

The system response was stable and well damped in all cases.

4.3.1.5 ON-EC4: Loss of the Bruce Complex Right of Way

This extreme contingency simulates the loss of the entire right of way coming out of the Bruce complex towards the Milton and Claireville stations. This includes four 500 kV circuits from Bruce to Milton and Claireville, as well as four 230 kV circuits out of the
Bruce complex.

Bruce SPS operated, and the system response was stable and well damped in all cases.

4.3.2 Beyond Criteria Contingency Assessment

4.3.2.1 ON-BC1: Sudden loss of ON-NY and ON-MICH ties

This beyond extreme contingency simulates the loss of the all ties between Ontario and New York as well as Ontario and Michigan simultaneously.

For the summer peak cases, un-damped oscillations were observed in New York and Michigan. For the light load case, most of Ontario’s generators started to slip poles and the Ontario Area became unstable.

4.3.3 Overlapping gas and electric contingencies

See details of the gas contingency in the EIPC Target 3 report (confidential), dated April 3, 2015.

The overlapping electrical contingency consists of a normally cleared (5.25 cycles) three-phase fault at Hawthorne 500 kV substation on the X522A line to Lennox.

The system response was stable and well damped in all cases.
4.4 Québec

The Assessment was performed with a winter 2020 peak load case.

Three extreme contingencies and one beyond extreme contingency were simulated.

The extreme and beyond extreme contingencies were performed using dispatch patterns considered highly probable for the year and load level being studied. This has led TransÉnergie to define scenarios with transfers and load corresponding to 90% of peak load to test extreme contingencies.

The system remained stable and well damped with no adverse inter-Area impact for all simulated contingencies.

4.4.1 Extreme Contingency Assessment

4.4.1.1 HQ: 3-phase fault on Manicouagan to Levis 735 kV line, delayed clearing

This extreme contingency is initiated by the application of a permanent three-phase fault at Manicouagan substation on a 735 kV line to Levis. The line is opened normally in 5 cycles at the remote end. At Manicouagan the fault is transformed into a line-to-ground fault when a single phase circuit breaker fails to open. The fault is finally cleared within 15 cycles.

The system remained stable and well damped for this contingency. No voltage or thermal violations were observed.

4.4.1.2 HQ: Loss of Three 735 kV Lines South of Albanel Substation

This extreme contingency involves the loss of a three line right-of-way south of Albanel substation. It requires a generation rejection of 2700 MW at LG-4 and LA-1 generating stations and a remote load shedding of 2500 MW.

The system remained stable and well damped for this contingency. No voltage or thermal violations were observed.

4.4.1.3 HQ: Loss of Three 735 kV Lines South of Abitibi Substation

This extreme contingency involves the loss of a three line right-of-way south of Abitibi substation. It requires a generation rejection of 3125 MW at LG-2 generating station and a remote load shedding of 2825 MW.

The system remained stable and well damped for this contingency. No voltage or thermal violations were observed.
4.4.2 Beyond Criteria Contingency Assessment

4.4.2.1 HQ: Simultaneous loss of two 735 kV substations in the Montréal region (substations Grand-Brûlé and Boucherville)

This beyond criteria contingency involves the simultaneous loss of two 735 kV substations in the Montréal region. Using the winter peak case, this contingency resulted in the loss of approximately 2500 MW of load.

The system remained stable and well damped for this contingency. No voltage or thermal violations were observed.

4.5 Maritimes

New Brunswick’s and Nova Scotia’s combined load representation is 3247 MW for the Summer Peak base cases and 1944 MW for the Light Load base case.

Four extreme contingency cases simulating disturbances having the greatest impact on the neighboring system south of the Maritimes were studied.

The results showed a stable and damped response for all contingencies studied and in general are consistent with past assessments.

4.5.1 Extreme Contingency Assessment

New Brunswick: Loss of Keswick 345 kV Station without a Fault

This contingency involves the simultaneous loss of four 345 kV circuits, one 345/230 kV transformer and one 345/138 kV transformer without a fault: Keswick – Keene Road 345 kV line 3001, Keswick – Coleson Cove 345 kV line 3002, Keswick – Point Lepreau 345 kV line 3003 and Keswick – St. Andre 345 kV line 3011, as well as Keswick T3 and T4. The loss of these lines breaks the 345 kV ring around NB and results in the blocking of the Madawaska HVDC by SPS action.

The system response was stable and well damped in all cases.

Nova Scotia: Three-phase fault at Onslow 345 kV station on line L-8002, single phase stuck breaker (IPT) 67N-812 at Onslow

A fault on line L-8002 with a failure of breaker 67N-812, results in the loss of line L-8002 and transformer 67N-T81. To model this contingency a three-phase fault was applied at the Onslow end of line 8002 for four cycles. The attempt to clear the fault by tripping line 8002 resulted in the failure of breaker 67N-812 (IPT) at Onslow and the evolution of the fault into a single line-to-ground fault. Breaker failure protection resulted in clearing the single line-to-ground fault in 9 cycles by tripping the transformer 67N-T81.

The system response was stable and well damped in all cases.
Nova Scotia: Loss of Woodbine 345/230 kV station without a Fault

This contingency involves the simultaneous loss of one 345 kV circuit, five 230 kV circuits and one bipolar DC link without a fault: Woodbine – Hopewell 345 kV line (8004), Woodbine – Lingan 230 kV lines (7014, 7021 & 7022), Woodbine – Port Hastings 230 kV lines (7011 & 7012), and one bipolar HVDC line (Maritime Link).

The system response was stable and well damped in all cases.

Nova Scotia: Loss of Onslow South R.O.W

This contingency involves the simultaneous loss of one 345 kV circuit and three 230 kV circuits without a fault: Onslow – Lakeside 345 kV line (8002), Onslow – Brushy Hill 230 kV lines (7001, 7001 & 7018)

The system response was stable and well damped in all cases.

4.6 Reliability First Corporation

4.6.1 Extreme Contingency Assessment

RFC: Three-phase fault at Branchburg on Branchburg – Jefferson 500 kV line, three-phase stuck breaker at Branchburg

Jefferson is a planned new substation as a part of the Susquehanna – Roseland 500 KV project. The existing Branchburg – Ramapo 500 kV line will be looped into this new substation. Branchburg – Jefferson will be a critical 500 KV transmission line in the Northeastern portion of PJM, just one bus away from Ramapo Substation.

In this contingency a three-phase fault at Branchburg, on the Branchburg - Jefferson 500 KV line was studied. The far end terminal of the line at Jefferson was opened in normal clearing time of 4 cycles, whereas the Branchburg terminal breaker was simulated to have failed on all three phases. The fault was cleared by the breaker failure scheme in an additional 8 cycles resulting in the loss of the Branchburg - Elroy 500 KV line.

All generating units were found to be stable and all oscillations very well damped.

RFC: Loss of the Susquehanna 500kV station without a fault

This extreme contingency simulates the loss of the Susquehanna 500 kV station without a fault.

The system response was stable and well damped in all cases.

RFC: 3-phase fault at Homer City 345 kV followed by stuck breaker at Homer City 345 kV

The system response was stable and well damped in all cases.