

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation)
and Northeast Power Coordinating Council, Inc.)

Docket No. RC09-3-000

COMPLIANCE FILING AND ASSESSMENT OF BULK ELECTRIC SYSTEM
DEFINITION REPORT
OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION AND NORTHEAST
POWER COORDINATING COUNCIL, INC.
IN RESPONSE TO THE DECEMBER 18, 2008 COMMISSION ORDER

In compliance with the Federal Energy Regulatory Commission's ("FERC" or the "Commission") December 18, 2008, order in the above-captioned proceeding ("December 18 Order"),¹ and pursuant to the stated intent of the North American Electric Reliability Corporation ("NERC") and the Northeast Power Coordinating Council, Inc. ("NPCC") (collectively "Joint Filing Parties") in their February 20, 2009 filing, the Joint Filing Parties respectfully submit the report entitled "NPCC Assessment of Bulk Electric System Definition" ("NPCC BES Definition Report"). The Joint Filing Parties also submit associated Bulk Electric System ("BES") element lists consistent with the developed Bulk Electric System ("BES") definition, and the list of newly registered Generator Owners ("GO") and Generator Operators ("GOP") pursuant to NPCC's May 4, 2009 Compliance Guidance Statement on GO and/or GOP registration.

¹ *North American Electric Reliability Corporation and Northeast Power Coordinating Council, Inc.*, 125 FERC ¶ 61,295 (2008); see also *North American Electric Reliability Corporation and Northeast Power Coordinating Council, Inc.*, Notice of Extension of Time (Jan. 15, 2009).

I. Documents Submitted With This Filing

1. The report entitled “NPCC Assessment of Bulk Electric System Definition,” Attachment A;
2. New York and New England lists of NPCC BES elements consistent with developed BES definition, Attachment B1 and B2, respectively²; and
3. List of newly registered GO/GOP Entities, Attachment C.

Attachments B1, B2 and C to the instant filing contain confidential and privileged information as defined by the Commission’s regulations at 18 C.F.R. Part 388 and Commission orders, as well as NERC Rules of Procedure, including the NERC CMEP, Appendix 4C to the Rules of Procedure. Specifically, the information pertains to proprietary or business design information, including design information related to vulnerabilities of critical energy infrastructure information that is not publicly available. Accordingly, the information set forth in the Attachments B1, B2 and C has been redacted from the public filing. In accordance with the Commission’s Rules of Practice and Procedure, 18 C.F.R. §388.112, a non-public version of the information redacted from the public filing is being provided under separate cover. Joint Filing Parties request that the confidential, non-public information be provided special treatment in accordance with the above regulation.

² References to Canadian entity facilities have been excluded.

II. Correspondence and Communications

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III. Background

In its December 18, 2008 Order directing the Submission of Data (Docket No. RC09-3-000), the Commission,³ among other things, directed the Joint Filing Parties to submit a comprehensive list of BES facilities within the United States portion of the NPCC Region.⁴ The December 18 Order also sought additional information so that the Commission could better understand the scope and comprehensiveness of the definition of BES used in the NPCC Region.⁵

³ *North American Electric Reliability Corporation and Northeast Power Coordinating Council, Inc.*, 125 FERC ¶ 61,295 at PP 1 and 12-13 (2008) (“December 18 Order”).

⁴ *Id.* at P 1.

⁵ *Id.* at P 13.

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On February 20, 2009, the Joint Filing Parties submitted a comprehensive list of facilities 100 kV and above within the United States portion of the NPCC Region along with responses to the Commission's set of questions and data requests.⁶ The materials provided in that filing also identified those facilities that are not captured in the current NPCC Approved BES List.

The February 20 Compliance Filing stated that NPCC was undertaking a detailed review of the implementation of a 100 kV bright-line test within the United States portion of NPCC. This review would: (1) identify and evaluate the issues associated with utilizing, for applicability of NERC Reliability Standards within the United States portion of NPCC, the interpretation of the NERC definition of "bulk electric system," which includes facilities generally operated at voltages of 100 kV or higher and excludes radial transmission facilities; and (2) assess the possible incremental reliability benefits and potential impacts related to the adoption of such a bright-line definition within NPCC (U.S.), including the international impact, if there were to be different BES definitions across the U.S. and Canadian portions of the NPCC Region. NPCC stated that NPCC's committees and task forces would complete this assessment and NPCC would submit its findings to the Commission by September 20, 2009.

On April 21, 2009, Joint Filing Parties supplemented their initial compliance filing⁷ with 125 revisions to the attachments identifying which generator stations are subject to NERC Reliability Standards by indicating which generators are currently registered as a Generator Owner ("GO") and/or as a Generator Operator ("GOP") and are therefore responsible for meeting the applicable FERC-approved NERC Reliability Standards. The April 21

⁶ See *North American Electric Reliability Corporation and Northeast Power Coordinating Council, Inc.*, "Compliance Filing of the North American Electric Reliability Corporation and the Northeast Power Coordinating Council, Inc. in Response to the December 18, 2008 Commission Order," Docket No. RC09-3-000, February 20, 2009 ("February 20 Compliance Filing").

⁷ See *North American Electric Reliability Corporation and Northeast Power Coordinating Council, Inc.*, "Supplemental Compliance Filing of the North American Electric Reliability Corporation and Northeast Power Coordinating Council, Inc. In Response to the December 18, 2008 Commission Order," Docket No. RC09-3-000, April 21, 2009 ("April 21 Supplemental Filing").

Supplemental Filing also described NPCC's ongoing efforts to review and modify the NPCC Compliance Registry for GOs and GOPs.

In their June 5, 2009 informational status report,⁸ the Joint Filing Parties stated that, since the April 21 Supplemental Filing, NPCC developed a new Compliance Guidance Statement, *NPCC-CGS-002 Rev. 0, "Defining Generator Materiality for Registration* ("CGS"), to provide additional insights regarding NPCC's application of the phrase "generator materiality," which is included in the NERC *Statement of Compliance Registry Criteria – Revision 5.0*. NPCC also reported that it conducted a re-verification of the NPCC Compliance Registry during the first half of 2009 and is continuing its efforts to investigate the need for new additional entities to register.

IV. Bulk Electric System Definition Assessment Report

A. NPCC Bulk Electric System Review Process

At its February 3, 2009 meeting, the NPCC Board of Directors ("NPCC Board") assigned the NPCC Reliability Coordinating Committee ("RCC"), through NPCC's Task Force structure, the assessment of the utilization of a 100kV "bright line" definition for the NPCC Bulk Electric System for application of NERC Reliability Standards in the U.S. The NPCC Board directed that the assessment be completed in time to allow for an NPCC FERC filing by September 20, 2009.

Subsequent to this assignment, the Joint Task Force Chairs Steering Committee ("JTFC Steering Committee") conducted numerous teleconferences during the course of the assessment devoted to the coordination of the BES assessment efforts of the Task Forces, NPCC Members

⁸ See *North American Electric Reliability Corporation and Northeast Power Coordinating Council, Inc.*, "Informational Status Report of the North American Electric Reliability Corporation and Northeast Power Coordinating Council, Inc. In Response to the December 18, 2008 Commission Order," Docket No. RC09-3-000, June 5, 2009 ("June 5 Informational Status Report").

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and registered entities. In addition, the individual Task Forces also met in special session meetings in support of the effort.

Furthermore, NPCC held a special breakout session at its compliance workshop from May 19, 2009 through May 21, 2009 in Boston, to allow potentially affected parties in attendance an opportunity to discuss the BES Impact Assessment and provide feedback on the NPCC effort. The compliance workshop was attended by over 255 participants.

As a first step in the BES cost/reliability benefit assessment, NPCC established a working definition of the BES in NPCC that was consistent with NERC's definition of the BES, one that included a 100 kV bright-line approach to defining the BES within the U.S. portion of NPCC. The working BES definition was only intended as a starting point for use in this impact assessment. It did not represent an early endorsement of an official NPCC proposal to define the BES in the NPCC Region.

Further refinements and clarification of the characteristics of radial facilities were considered by the NPCC Task Forces to eliminate subjectivity from this classification and to adapt the application to the system conditions in the Northeast for purposes of NPCC's evaluation. These refinements also included sensitivity evaluations of the characteristics of radial facilities, using accepted and replicable methodologies, to identify facilities that have minimal participation in bulk transfers and negligible impact to the reliability of the international, interconnected power system.

The working definition was modified through Task Force discussions and resulted in the developed definition presented in this filing that was used in the BES cost/reliability benefit assessment.

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To facilitate reporting, an assessment spreadsheet⁹ was developed to be used by the registered entities and Task Forces to summarize the cost/reliability benefit assessment results, and the NPCC Task Forces were charged with specific responsibilities to ensure that reviews were completed to meet the September 20, 2009 Commission filing deadline. An assessment project schedule¹⁰ was also developed to ensure that efforts remained on track.

All registered NPCC Transmission Owners, Transmission Operators, GOs, GOPs, Distribution Providers and Load Serving Entities (approximately 400 registered functional entities in total), were informed of the BES cost/reliability benefit assessment. These registered entities utilized the NPCC-developed definition of the BES to evaluate the impact that each NERC standard and associated requirements applicable to their functional areas would have on reliability, reporting requirements, operation and maintenance and capital costs, resources, scheduling, and other financial considerations.

Throughout the development of the NPCC BES Definition Report, the NPCC Task Forces and affected NPCC registered entities had the opportunity to provide the JTFC Steering Committee with identified issues for resolution through the NPCC “Open Process” website.

NPCC continues to believe that its impact-based approach documented in the A-10 Criteria document provides an adequate level of reliability assurance on those elements that affect the reliability of the international, interconnected system in the Northeast by identifying those elements that could cause widespread outages. This approach also enables NPCC to focus its reliability assurance efforts on these elements. Therefore, NPCC intends to continue its utilization of the A-10 Criteria in identifying those key facilities in both the U.S and Canadian

⁹ See: <http://www.npcc.org/viewDoc.aspx?name=Final+BES+Spreadsheet.pdf&cat=commRelCoord>

¹⁰ See: <http://www.npcc.org/viewDoc.aspx?name=BES+Schedule.pdf&cat=commRelCoord>

portions of NPCC to which the more stringent NPCC Criteria will apply and for identifying BES elements in the Canadian portion of NPCC.

B. BES Assessment Findings

In general, NPCC concluded that application of the developed BES bright-line definition within NPCC would increase the number of facilities for which NERC compliance would be required, resulting in economic and resource impacts without identified increases in the overall reliability of the NPCC international, interconnected power system. Such an application could:

- Expand NERC Standard compliance monitoring activities;
- Enhance power system awareness; and,
- Provide additional coordination.¹¹

NPCC's registered entities estimate that application of the developed BES definition, reflecting the defined radial "exclusions," would represent the addition of approximately 1270 lines in the U.S. over the current BPS definition, and that the additional compliance that would be required is estimated to cost approximately \$280M (2009 \$U.S.).¹²

The registered entities indicated that there is the potential for significant capital expenditure. For instance, bringing newly defined BES elements into compliance with the TPL standards is estimated to comprise approximately \$234 million of the total estimated cost.¹³ Of the TPL standards, the most significant cost and related added complexity is associated with compliance to the NERC TPL-003-0a Standard.¹⁴ Beyond the capital expenditures identified in the BES Report, there will be significant additional resources (time and personnel) needed to

¹¹ See "NPCC Assessment of the Bulk Electric System Definition" report at 2 and 24, September 14, 2009 ("BES Definition Report").

¹² *Id.*

¹³ *Id.* at 16.

¹⁴ *Id.* at 21-22.

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meet the rigor of the NERC standards for this expanded list of facilities.¹⁵ These additional experienced resources are engaged in on-going current power system improvement projects and would have to be diverted from these efforts to meet this need; alternatively, additional resources would need to be hired and trained.

Importantly, the costs identified in the NPCC BES Definition Report are illustrative and could be orders of magnitude greater. When evaluating the impact of adopting the developed BES definition, only those currently approved NERC Standards were evaluated. NERC standards presently under development and/or revision may require additional levels of element design redundancy for all facilities identified under a bright-line test similar to those more stringent requirements that presently apply to selected facilities within NPCC that are identified under NPCC's A-10 impact-based Criteria. Extension of such additional requirements to the broad range of elements captured under a bright-line test will certainly result in greater cost impacts.

NERC has not separately evaluated the conclusions reached in the NPCC BES Definition Report.

C. Bulk Electric System Definition

1. Developed BES Definition

Upon careful consideration of the identified costs, reliability impacts and jurisdictional concerns associated with the adoption of a voltage-based approach for defining the BES for the U.S. portion of NPCC, NPCC has developed a definition for U.S. registered entities within the NPCC footprint to be consistent with other regions that have adopted a voltage-based BES

¹⁵ Conclusions of the Task Force on coordination of Operation, Task Force on System Protection, and Task Force on System Studies, *Id.* at 18, 19-20, and 20-22.

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definition. The definition of BES¹⁶ for the U.S. registered entities within the NPCC footprint is as follows:

Inclusions:

1. Transmission elements operated at voltages of 100 kV or higher;
2. Transformers, including phase angle regulators, with both primary and secondary windings of 100 kV or higher;
3. Individual generation resources greater than 20 MVA (gross nameplate rating) and are directly connected via a step-up transformer(s) to designated BES Transmission facilities by a designated BES transmission path;
4. Generation plant with aggregate capacity greater than 75 MVA (gross nameplate rating) and are directly connected via a step-up transformer(s) to designated BES Transmission facilities by a designated BES transmission path;
5. Generator step-up transformers and the generator interconnecting line lead associated with BES generators.

Exclusions:

Radial portions of the transmission system as follows:

1. An area serving load that is connected to the rest of the network at a single transmission substation at a single transmission voltage by one or more transmission circuits,
2. Tap lines and associated facilities which are required to serve local load only,
3. Transmission lines that are operated open for normal operation, or
4. Additionally as an option, those portions of the NPCC transmission system operated at 100 kV or higher not explicitly designated as a BES path for generation which have a one percent or less participation in area, regional or inter regional power transfers (“Transfer Distribution Factor Methodology”).¹⁷

The lists of facilities that would be identified under this BES definition are included in Attachments B1 and B2. These lists show a comparison between the BES listing that was furnished to the Commission in the February 20 Compliance Filing and a BES list based on the developed BES definition.

The list of elements under this BES definition include approximately 78% of all New York transmission facilities and 87% of all New England transmission facilities. In both

¹⁶ There are situations where specific NERC Standards apply to non-BES equipment.

¹⁷ NPCC assessments of any such Balancing Authority Area-wide determinations are conducted during the course of NPCC Transmission Reliability Studies.

instances this represents a significant increase in the number of included elements over the elements identified in the NPCC Approved BES List provided to the Commission in the February 20 Compliance Filing.

NPCC will continue to utilize the methodology established under the A-10 criteria for application of NERC Reliability Standards in the Canadian portion of NPCC.

2. Announcement of Commission Public Meeting

On September 10, 2009, the Commission Staff announced a public meeting to present research conducted by the faculty of the University of Wisconsin-Madison, sponsored by the Commission, on Topological and Impedance Element Ranking (“TIER”) of the Bulk-Power System.¹⁸ This project is intended to develop a methodology to aid in identifying and ranking the elements of the Bulk-Power System in the United States which could be utilized in future proceedings to aid in refining the scope of what constitutes the Bulk-Power System. NPCC observes that the outcome of this effort could have a direct bearing on the substance of this proceeding.

3. Transfer Distribution Factor Method for Defining Radial Elements

The developed BES definition includes an additional optional methodology for classifying radial elements that would be excluded from the list of BES elements. This methodology utilizes a transfer distribution factor (“TDF”) approach which is a proven, technically sound, replicable and accepted methodology for determining the participation of transmission elements in power transfers. In fact, FERC has accepted a TDF methodology very similar to that described here with the objective of identifying transmission facilities, or “Highways,” associated with major inter-zonal interfaces for the purpose of cost allocation in the

¹⁸ *Mandatory Reliability Standards for the Bulk Power System*, Notice of Public Meeting, Docket No. RM06-16-000 (Sept. 10, 2009).

context of New York ISO's Capacity Resource Interconnection Service ("CRIS").¹⁹ In order to determine what in-series facilities participate significantly in cross-state transfers across the interfaces, all generation upstream of the interface is uniformly shifted to all generation downstream of the interface; any circuit that carries the specified percentage or more of the transfer is considered "in-series" with the interface.²⁰ Because the TDF approach will identify those in-series elements participating in power transfers along the various NYCA transmission paths, it will include all series elements along an identified transmission path which participate in bulk power transfers.

Moreover, to ensure all portions of the transmission system are covered in identifying the Bulk Electric System elements, three types of transfers are used Intra-Area, Area Interface, and Cross-Area. Every transfer is done under an "all lines in" condition while monitoring every element greater than 100 kV within the Area. For every transfer performed, the TDF for every element is recorded. After all transfers have been performed, the TDFs recorded for each element and for each transfer, are compared to find the highest TDF. If the highest TDF recorded for a given element is less than the defined 1% BES cutoff, the element would not be classified as BES.²¹

It is estimated that under this approach approximately 20% of lines above 100 kV within the NYCA are excluded from the BES list.²² The facilities excluded are those elements that were determined to have less than a 1% participation in NYCA power transfers under all three

¹⁹ *Guidance Order on Conceptual Proposal*, 122 FERC ¶ 61,267 (2008) (*Guidance Order*) at P49 (approving the method for determining in-series highway elements but seeking additional description); Joint Compliance Filing of the New York Independent System Operator, Inc. and the New York Transmission Owners on Consensus Deliverability Plan, Docket No. ER04-449 (Aug. 5, 2008) at 10 (providing additional clarification of the transfer distribution factor approach to determine in-series highway elements); *New York Independent System Operator Inc.*, 126 FERC ¶ 61,046 (2009)(order conditionally accepting filed tariff revisions).

²⁰ *BES Definition Report* at 12.

²¹ *Id.* at 12-13.

²² *Id.* at 13-14.

transfer types examined. Furthermore, of the 20% that is excluded by the TDF approach, a significant portion of these radial elements would have already been excluded under the other radial criteria outlined in the developed definition.

D. BES Definition Among the Canadian Members

The Canadian members of NPCC believe that enforcing mandatory reliability standards is essential for designing, maintaining and operating a reliable and secure interconnected electricity grid. However, the application of NERC reliability standards should be limited to wide-area reliability without expanding its scope to cover local area reliability.

The Canadian members further believe a bright line, voltage-based definition of BES, such as that being reviewed for the U.S. members of NPCC, would result in NERC reliability standards being applied to facilities, 100 kV and above, which will only impact local areas. These facilities do not have a wide-area impact and would not result in cascading outages.

The Canadian members of NPCC remain resolute in their belief that the impact-based approach currently used by NPCC to determine the applicability of NERC standards is the most efficient manner in which to maintain reliability of the Bulk Electric System. The Canadian members of NPCC strongly believe that significant additional costs will be incurred without identified reliability benefits if a bright line voltage-based definition were adopted across Canadian NPCC. Moreover, this exercise would result in diverting funds and key expert resources from other higher value reliability projects and activities. The Canadian members do not expect Canadian provincial regulators to support expenditures by their regulated entities to expand the applicability of the NERC reliability standards if they are unable to demonstrate benefits to reliability.

NPCC's Canadian entities further believe that there is no identified reliability concern associated with maintaining a separate definition of BES elements for Canadian and U.S. NPCC

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systems because the transmission facilities participating in international power transfers that would be identified under the developed NPCC BES bright line definition are already identified as BES elements under the NPCC A-10 Criteria.

E. Implementation Schedule

Time would be needed to implement changes to bring the additional BES elements identified under the developed BES definition into compliance with the various NERC Standards. In most cases, a two-year implementation plan appears achievable. This would permit hiring of additional personnel, training of such personnel, development of enhanced documentation, and other necessary changes to be made. It is anticipated that approximately 75% of applicable PRC standards could be implemented to become compliant within two years. Likewise, it is anticipated that compliance could be achieved for a majority of the operations-related reliability standards within a two-year period. However, the acquisition, installation and training associated with new tools may require up to five years, and major capital projects, such as the construction of new transmission could require up to ten years.

If directed by the Commission to adopt the developed BES definition for U.S. registered entities within the NPCC footprint, NPCC would need additional time to carefully consider and develop a more extensive and detailed implementation plan. Accordingly, if the Commission orders NPCC to adopt the developed BES definition for its U.S. registered entities, NPCC requests that the Commission grant NPCC three months time to review and coordinate the detailed implementation plans that would need to be developed by the registered entities and make a subsequent compliance filing for Commission approval.

V. Generation Registration

Since the second half of 2008, NPCC has been engaged in ongoing efforts to review and modify the NPCC Compliance Registry for GOs and GOPs. Generators registered as a GO

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and/or a GOP are responsible for meeting applicable FERC approved NERC Reliability Standards for a GO and/or a GOP.

The most recent task in this effort was the development of a new Compliance Guidance Statement, *NPCC-CGS-002 Rev. 0, "Defining Generator Materiality for Registration*, ("CGS"), further clarifying NPCC's application of the phrase "generator materiality," which is included in the *NERC Statement of Compliance Registry Criteria – Revision 5.0*. On May 4, 2009, NPCC distributed the CGS to all NPCC registered entities and, recognizing that this CGS would impact new entities that are not registered, NPCC staff worked with Balancing Authorities within the United States portion of NPCC to collect the market participant contact names of additional entities that could be required to register under this CGS. Throughout May 2009, NPCC contacted these new entities to discuss the CGS and the process NPCC would use to register newly identified entities in accordance with NPCC's CGS.

Following the completion of its initial generator verification efforts on June 4, 2009, NPCC registered a number of additional GOs and GOPs. NPCC has revised the list of GOs and GOPs and all of their generator assets that meet the definition of generation materiality on the Attachment C. These GOs and GOPs are now required to be in full compliance with the applicable FERC approved NERC Standards. NPCC is continuing its generator outreach efforts through the dissemination of supporting materials to the newly indentified GOs and GOPs, as well as sessions at NPCC Compliance Workshops held twice a year.

The revised list of registered GOs (31) and GOPs (30) was transmitted to NERC on August 10, 2009. Of the 31 new GOs and 30 GOPs added to the NERC and NPCC registry, only six mitigation plans were submitted by three (3) of the newly registered GOs. It is estimated that the three (3) GOs for which mitigation plans have been submitted will achieve full compliance

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by February 2010 for FAC-008-1, “Facility Rating Methodology” and FAC-009-1, “Establish and Communicate Facility Ratings.” All of the newly identified GOs and GOPs performed a complete gap analysis/review of all the applicable FERC- approved NERC Standards and have started the self-certification process according to NPCC’s 2009 compliance self-certification schedule. Seven (7) generator assets were removed from the prior NPCC supplemental file dated April 21, 2009 because they did not meet the criteria of the NERC and NPCC generation materiality after further discussions with the GOs and the applicable Balancing Authority.

NPCC staff will continue to work closely with these new entities to ensure that they are developing a strong compliance program and culture, performing the proper self-certifications, and preparing for spot-checks and audits.

VI. Conclusion

The Joint Filing Parties respectfully request that the Commission accept this filing, the NPCC BES Definition Report, and Attachments as compliant with its December 18 Order.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 21st day of September, 2009.

/s/ Holly A. Hawkins
Attorney for the North American Electric
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ATTACHMENT A

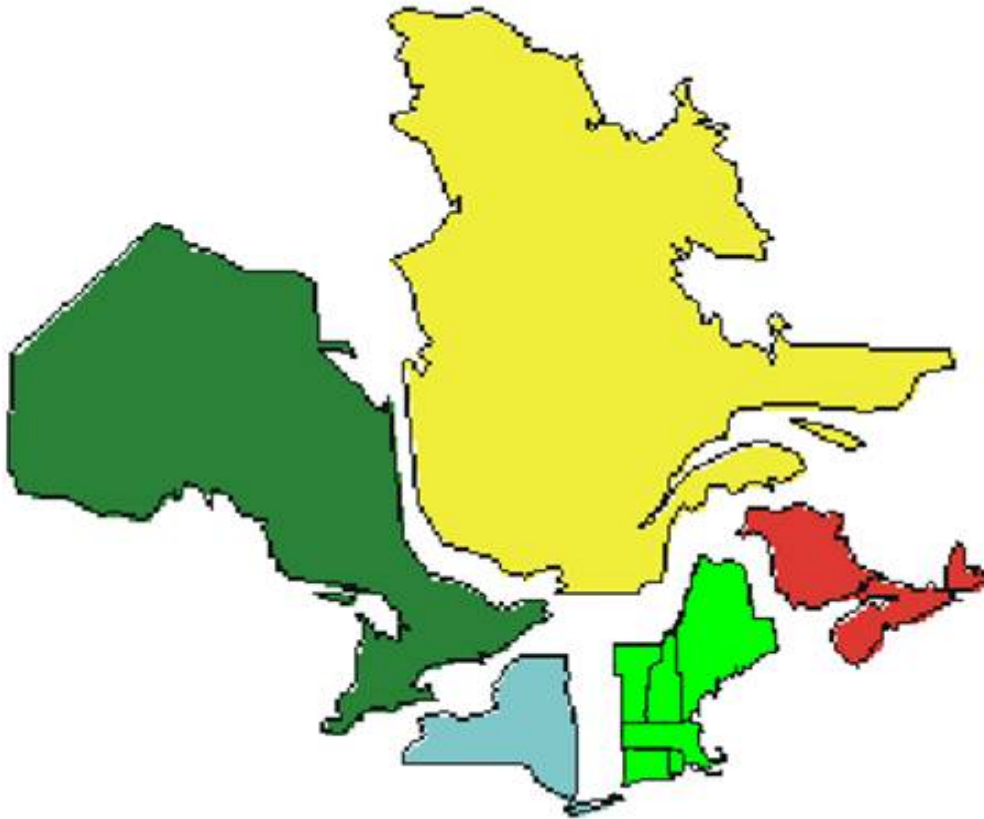
The report entitled “NPCC Assessment of Bulk Electric System Definition”

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NPCC Assessment of Bulk Electric System Definition



**Approved by the NPCC Board
September 14, 2009**



Executive Summary

NPCC Board Assignment

At its February 3, 2009 meeting, the NPCC Board of Directors (“Board”) assigned the NPCC Reliability Coordinating Committee, through NPCC’s Task Force structure, the assessment of the utilization of a 100kV “bright line” definition for the NPCC Bulk Electric System for application of NERC Reliability Standards in the U.S. The Board directed that the assessment be completed in time to allow for an NPCC FERC filing by September 20, 2009.

Conclusions

Application of the BES definition included in this report, with the defined radial “exclusions” would represent the addition of approximately 1,270 lines (U.S.) over the current BPS definition and is estimated to cost in excess of approximately \$280M (2009 \$U.S.) based on application of the current NERC Standards. This cost estimate could be order of magnitudes larger if the analysis were extended to consideration of pending and/or proposed NERC Standards. The assessment identified that the most significant cost and related added complexity would be associated with compliance with NERC TPL-003-0a Standard, depending on its implementation. In addition, experienced protection and control personnel will be needed to address applicability of the new requirements to additional facilities. Additional experienced expertise is presently scarce; available personnel would have to be diverted from on-going current power system improvement projects to meet this need.

In general, based on the entity survey responses and Task Force reviews, application of the BES definition developed in this report would increase the number of facilities for which NERC compliance will be required, resulting in economic and resource impacts without identified increases in the overall reliability of the NPCC interconnected power system.

Such an application could:

- ✓ Expand NERC Standard compliance monitoring activities,
- ✓ Enhance power system awareness; and,
- ✓ Provide additional coordination.

Members of NPCC believe that enforcing mandatory reliability standards is essential for designing, maintaining and operating a reliable and secure interconnected electricity grid. However, many members believe that the application of NERC reliability standards should be limited to wide area reliability based on utilization of the reliability impact based methodology included in the NPCC A-10 criteria, without expanding its scope to cover local area reliability.

Canadian members of NPCC also strongly believe that applicability of NERC Reliability Standards should be defined through the use of the NPCC A-10 Criteria, and that significant

additional costs will be incurred without identified reliability benefits if a bright line definition were adopted across Canadian NPCC. The need and justification for standards that impact reliability of a local area, within individual provinces, should be determined by applicable Canadian provincial regulators. Canadian members do not expect provincial regulators to support expenditures, by their regulated entities, to expand the applicability of the NERC reliability standards if they are unable to demonstrate increased benefits to local consumers. Lastly, extending the applicability of NERC Standards would divert funds and key expert resources from other higher value reliability projects and activities.

Developed NPCC “Bulk Electric System” (BES) Definition

Responsive to the Board’s assignment, the NPCC Reliability Coordinating Committee (“RCC”) reviewed the identified costs, reliability impacts and jurisdictional concerns in considering a voltage-based approach for defining the BES. The following definition has been developed to be consistent with other Regions that have adopted a voltage-based BES definition, and is respectfully submitted to the NPCC Board for its review and consideration.

The following Bulk Electric System¹ (“BES”) definition utilizes the methodology established under the A-10 criteria for application of NERC Reliability Standards in the Canadian portion of NPCC, while defining a voltage-based BES definition for U.S. Entities within the NPCC footprint with certain exclusions:

1. Transmission elements operated at voltages of 100 kV or higher;
2. Transformers, including Phase Angle Regulators, with both primary and secondary windings of 100 kV or higher;
3. Individual generation resources greater than 20 MVA (gross nameplate rating) and are directly connected via a step-up transformer(s) to designated BES Transmission facilities by a designated BES transmission path;
4. Generation plant with aggregate capacity greater than 75 MVA (gross nameplate rating) and are directly connected via a step-up transformer(s) to designated BES Transmission facilities by a designated BES transmission path;
5. Generator step-up transformers and the generator interconnecting line lead associated with BES generators.

Radial Exclusions

Radial portions of the transmission system excluded from the NPCC BES transmission system include:

1. An area serving load that is connected to the rest of the network at a single transmission substation at a single transmission voltage by one or more transmission circuits,
2. Tap lines and associated facilities which are required to serve local load only,
3. Transmission lines that are operated open for normal operation, or

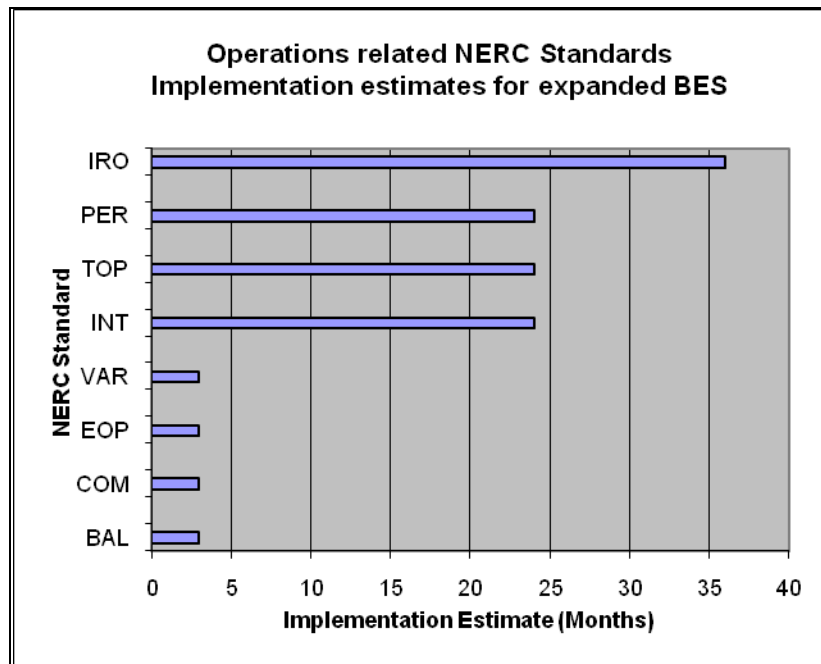
¹ There are situations where specific NERC Standards apply to non-BES equipment.

4. Optionally, those portions of the NPCC transmission system operated at 100 kV or higher not explicitly designated as a BES path for generation which have a one percent or less participation in area, regional or inter regional power transfers.²

BES Implementation Estimate

If FERC orders this change in definition for BES then registered entities within the U.S. portion of NPCC would need time to implement the change. In most cases, a two-year implementation plan appears feasible and reasonable. This permits hiring of additional personnel, training of such personnel, enhanced documentation, etc. The acquisition, installation and training associated with new tools may require up to five years, and major capital projects, such as the construction of new transmission could require up to ten years.

The RCC recommends, should FERC order NPCC to adopt the developed NPCC BES definition for utilization by U.S. registered entities, that the respective NPCC Task Forces develop a GANTT chart outlining the specific implementation program for the associated NERC Standards. As an example, a summary of the implementation estimates for the operational related standards is shown below.



² Power Transfer Distribution Factor analysis is an analysis that is performed to identify portions of the NPCC transmission system that have minimal impact on transfers across the power system and perform similarly to radial systems. NPCC assessments of any such Balancing Authority Area-wide determinations are conducted during the course of NPCC Transmission Reliability Studies.

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Introduction

On December 18, 2008 FERC directed³ the North American Electric Reliability Corporation (“NERC”) and the Northeast Power Coordinating Council, Inc. (“NPCC”) to submit a comprehensive list of bulk electric system facilities within the U.S. portion of the NPCC region. The response to the Order, for U.S. registered entities only, included, in part:

- ✓ the existing NPCC approved list of bulk power system facilities (the “Informational List” of July 2007), currently being used for the application of NERC Reliability Standards;
- ✓ the December, 2007 NPCC Bulk Power List (based on application of the NPCC A-10 Criteria);
- ✓ a list of all New York and New England transmission facilities (lines and transformers) greater than 100kV;
- ✓ a comparison between the list of all transmission facilities greater than 100kV and both the Informational List and the NPCC BPS List; and,
- ✓ a list of generation (greater than 20 MVA) directly connected to a bus that is greater than 100kV.

The NPCC Board of Directors (“Board”) submitted a companion letter to FERC staff (see Appendix A), explaining the reliability merits of the current NPCC impact based Bulk Power System definition committing to:

- ✓ identifying and evaluating the issues associated with utilizing, for applicability of NERC Reliability Standards within the United States portion of NPCC, the NERC definition of “bulk electric system” which includes facilities generally operated at voltages of 100 kV or higher and excludes radial transmission facilities
- ✓ assessing the impacts related to the adoption of such a bright line definition within NPCC (U.S.), including the international impact of having different definitions across the U.S. and Canadian portions of the NPCC Region; and
- ✓ filing the results of that assessment with FERC on September 20, 2009.

NERC and NPCC also submitted an Informational Status Report on June 5th to FERC describing the progress made to date on NPCC’s application of the definition of the BES in NPCC and its continuing generator registration efforts, in the above-captioned proceeding.

NPCC Board Assignment

The Board assigned the NPCC Reliability Coordinating Committee (“RCC”), through NPCC’s Task Force structure, the assessment of the utilization of a 100kV “bright line” definition for the NPCC Bulk Electric System (“BES”) for application of NERC Reliability Standards in the U.S. portion of NPCC. The assessment requested each NPCC U.S. Transmission Owner, Transmission Operator, Generator Owner, and Generator Operator to identify the implications of adopting such a bright line definition, including, but not limited to, the effects, including both impacts and benefits, on system reliability, necessary resources, investment requirements and costs to consumers. The Board directed that the assessment be completed in time to allow for a joint NPCC/NERC FERC filing by September 20, 2009.

³ See: <http://www.npcc.org/relServices/Filings.aspx>

Impact Assessment Process

Reliability Coordinating Committee

The NPCC Reliability Coordinated Committee (RCC) agreed that the RCC Chair and Vice Chairs and the NPCC Joint Task Force Chairs (“JTFC”) act as a Steering Committee for the individual NPCC Task Forces and registered entities activities to guide the timely completion of the above mentioned assessment. The RCC agreed that each NPCC Task Force would identify and evaluate issues within their areas of responsibility associated with utilizing the NERC definition of “bulk electric system”⁴ for applicability of NERC Reliability Standards within the U.S. portion of NPCC.

Joint Task Force Chairs Steering Committee

The Joint Task Force Chairs Steering Committee conducted numerous teleconferences during the course of the assessment devoted to the coordination of the BES assessment efforts of the Task Forces and NPCC Members. In addition, the individual Task Forces also met in special sessions meetings in support of the effort.

The first step of the BES Impact Assessment sought to establish a working definition of the BES in NPCC that was consistent with NERC’s definition of the BES, one that included a 100 kV bright line approach to defining the BES within the U.S. portion of NPCC. To facilitate this, the RCC directed the Task Force on Coordination of Planning (“TFCP”) to clarify potentially subjective terms in the NERC definition and to adapt the application of “radial transmission facilities” to the system conditions in the Northeast for purposes of NPCC’s evaluation.

The JTFC Steering Committee and the Task Forces developed an NPCC working definition of BES facilities for the purposes of evaluating the impact of applying NERC Reliability Standards within the U.S. portion of the NPCC Cross-Border Regional Entity.

This working BES definition was only intended for use in this Impact Assessment; it did not represent an early endorsement of an official NPCC BES proposal to define the BES in the NPCC Region. Further refinements and clarification of the characteristics of radial facilities, including sensitivity evaluations, using accepted and replicable methodologies were considered in the assessment to identify facilities that have minimal participation in bulk transfers and negligible impact to the reliability of the international, interconnected power system.

⁴ The NERC definition of bulk electric system includes facilities generally operated at voltages of 100 kV or higher and excludes radial transmission facilities. Bulk electric system is defined by NERC as “the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.” *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 51 (2007).

Impact Assessment Spreadsheet & Schedule

To facilitate reporting, an impact assessment spreadsheet ⁵ was developed to be used by the registered entities and Task Forces to summarize the reliability impact assessment results; the NPCC Task Forces were charged with specific responsibilities to ensure that reviews were completed to meet the September 20, 2009 Commission filing deadline.

The key major assumptions agreed upon were:

- ✓ Only FERC approved Reliability Standards were addressed.
- ✓ Applicability to other (higher) kV thresholds in certain individual standards remain unchanged.
- ✓ Applicability of CIP Standards remains unchanged.
- ✓ Regionally-specific NPCC Criteria were not applied to the expanded listing of BES elements. (NPCC Criteria is applicable to Bulk Power System elements as identified by the NPCC A-10 process.)

The impact assessment contained in spreadsheet (sheet 1) identified the applicable NERC Standards. The highlighted Standards in the spreadsheet indicated those not yet approved by FERC, provided for information only.

The impact assessment spreadsheet (sheet 2) identified the:

- ✓ NERC BOT Approval Date: the date on which the NERC Board of Trustees adopted the standards;
- ✓ Regulatory Approval Date: the date the applicable regulatory authority approved the standard to be implemented in the jurisdiction; and,
- ✓ Mandatory Implementation Date: the date on which the standard becomes mandatory and enforceable in accordance with the existing laws of the jurisdiction and the approval granted by the regulatory authority

A BES Impact Assessment project schedule ⁶ was also developed. The BES impact assessment spreadsheet and schedule were available during the course of the assessment on the NPCC Open Process section of the NPCC public website.

Registered Entity Notifications

All registered NPCC Transmission Owners, Transmission Operators, Generator Owners, Generator Operators, Distribution Providers and Load Serving Entities (approximately 400 registered functional entities in total), were informed of the BES Impact Assessment. These registered entities utilized the NPCC working definition of the BES to evaluate the impact that each NERC standard and associated requirements applicable to their functional areas would have on reliability, reporting requirements, operation and maintenance and capital costs, resources, scheduling, and other financial considerations.

⁵ See: <http://www.npcc.org/viewDoc.aspx?name=Final+BES+Spreadsheet.pdf&cat=commRelCoord>

⁶ See: <http://www.npcc.org/viewDoc.aspx?name=BES+Schedule.pdf&cat=commRelCoord>

Reliability Coordinating Committee Review

Throughout the development of the BES Impact Assessment, the NPCC Task Forces and effected NPCC registered entities had the opportunity to provide the JTFC Steering Committee with identified issues for resolution through the NPCC “Open Process” website. The RCC reviewed the comments received and provided guidance regarding issues and assumptions needed for further assessment of the economic and reliability impacts. The identified issues and corresponding resolutions were posted on the Open Process website during the assessment.

NPCC held a compliance workshop from May 19, 2009 through May 21, 2009 in Boston, Massachusetts for all registered entities in Northeastern North America, which was attended by over 255 participants. The opening presentation of the workshop covered the status of activities related to the BES Impact Assessment and the reliability impacts of adopting an NPCC BES definition. In addition, a separate, stakeholder-led breakout session was conducted, following the first day of the workshop, to allow affected parties in attendance an opportunity to discuss the BES Impact Assessment and provide feedback to NPCC Staff.

The NPCC Balancing Authorities, transmission and generation asset owners provided their identification of their facilities that would fall under the working definition of the NPCC BES.

Assumptions

Working BES Definition

The working BES definition included all transmission elements operated at voltages of 100 kV or higher, but excludes radial portions of the transmission system.

This working definition of the NPCC BES was reviewed by the NPCC Board at its April 28, 2009 meeting. During the course of the assessment, several aspects of the BES working definition were clarified through the NPCC Open Process and are summarized below:

- ✓ Only existing approved NERC standards should be used for this impact assessment.
- ✓ Most wind farms have medium voltage collector systems between the 600 v generator terminals and the transmission system (the collector might be 25kV or 34.5 kV). The generator should be included as BES based on its size and the collector system is considered internal plant equipment. However, if the collector system is actually a local distribution network, the generation may be considered "distributed generation" and not included. There is work underway at NERC to clarify this situation, but for this evaluation wind farms over 75 MVA with medium voltage collector systems should be included. The standards that apply to generators would apply, since the collector system would be considered plant equipment.
- ✓ The radial exclusions apply to transmission feeding load. A generator is BES if it meets the size requirements and is also directly connected to 100kV and above. Therefore the radial line connecting the generator is also BES.
- ✓ It is assumed that NPCC BPS criteria apply only to Bulk Power System Elements as identified using the NPCC A-10 Methodology. NERC standards will apply to all 100 kV and above BES facilities, not otherwise excluded based on radial or other considerations, including those facilities identified by the A-10 Methodology.
- ✓ The following should be considered in the assessment (The NPCC Board BES assignment has been sent to all affected U.S. registered entities, including the LSEs and DPs, in order to capture these impacts):
 - Benefit/Cost realizations attributed to TOs being required to register as TOPs.
 - Benefit/Cost realizations attributed to a GO/GOP being required to register as a TO and/or a TO/TOP.
 - Benefit/Cost realizations attributed to a GO/GOP being required to register for the first time.
 - Benefit/Cost realizations attributed to LSEs/DPs being required to register for the first time or as a TO and/ or a TO/TOP.
- ✓ The BES is determined at the Planning Coordinator Area level of NPCC.
- ✓ Estimates of the "required implementation timeframes" should be included in the registered entities spreadsheet responses.
- ✓ Capacitors and other facilities connected to BES buses should be accounted for in the impact assessment, based on the applicable NERC Standards.
- ✓ All inter-company, inter-area, inter-regional and international transmission lines are not BES, unless 100 kV and above and non-radial. For this assessment, the working definition of BES applies, regardless of inter area and interregional boundaries.

- ✓ All identified critical [cyber] assets are not BES (e.g. a control center is not BES). NERC has published Draft Guidance on identifying critical assets at: <http://www.nerc.com/filez/sgwg.html> ; NPCC has published Guidance on identifying critical assets at: <http://www.npcc.org/documents/regStandards/Guide.aspx> (see NPCC B-27 Document) According to the guidelines, engineering studies are used to identify critical assets.
- ✓ T-tapped transformers with high-side voltage at 100kV and above are BES if both transformer windings are greater than 100kV
- ✓ Type 1 Special Protection Systems (SPS) are not part of the BES, only the transmission assets associated with the Type 1 SPS.
- ✓ All transmission facilities in a defined operational interface are not BES, unless 100 kV and above and non-radial.
- ✓ Currently there is no NERC Standard for the frequency of relay maintenance; although this particular requirement is being considered. For NPCC, NERC Standards now apply to the BPS; NPCC's relay maintenance criteria address all those requirements.
- ✓ The NPCC BES assignment, working BES definition, and assessment spreadsheet were additionally sent to all NPCC LSEs and DPs for information, in an effort to reach the widest audience of registered entities that the BES definition may impact. To the extent the LSEs and DPs believe they may be affected by a change to the BES definition, they were encouraged to return the assessment spreadsheet.
- ✓ The change in the BES definition may expand the list of assets for which the Planning Authority is responsible. The responding registered entities need to coordinate their responses with their Planning Authorities.
- ✓ To the extent possible, the registered entities should provide an estimate of the time they believe it would take them to get into compliance due to the adaptation of the working BES definition.
- ✓ For NERC Standards that have higher kV thresholds (e.g., FAC-003-1 has a 200 kV threshold) for applicability, it should be assumed that such NERC Standards will keep the higher voltage qualifier. If registered entities are already following them (as should be the case for FAC-003 Vegetation Management), then there will be no incremental impact. If registered entities are not already following them, they should evaluate the impact as the NERC Standard is currently written.

Transfer Distribution Factor Methodology

It was noted that additional sensitivity evaluations, using proven, technically sound, replicable and accepted methodologies are also underway in order to identify those facilities that have minimal impact on bulk transfers that would also be considered to be excluded from the BES definition. One such methodology involves the use of the Transfer Distribution Factor (TDF) test. The purpose of the TDF methodology is to identify Area transmission facilities 100 kV and higher that do not play a significant role in system transfers. Facilities that meet these requirements would be classified as non-BES facilities. The methodology is transparent, repeatable and non-complex.

Background

The transfer distribution factor (TDF) is a percentage change (response) in loading on a line due to a power transfer from one point to another. When implemented using a linearized power flow solution, the TDF is a function of transmission network impedances and topology, along with the locations of the source and sink of the given transfer. The TDF is not affected by pre-transfer loading on circuits, nor by the amount or direction of power transferred so long as the participation of individual source and sink elements (i.e. generators) is kept constant.

FERC has accepted a TDF methodology very similar to that described here with the objective of identifying transmission facilities, or “Highways”, associated with major inter-zonal interfaces for the purpose of cost allocation in the context of New York ISO’s Capacity Resource Interconnection Service (CRIS). In the CRIS process, “Highways” are defined as transmission facilities that comprise significant New York interfaces, and their immediately connected, in-series facilities. In order to determine what in-series facilities participate significantly in cross-state transfers across the interfaces, all generation upstream of the interface is uniformly shifted to all generation downstream of the interface; any circuit that carries the specified percentage or more of the transfer is considered “in-series” with the interface.

Methodology

A key requirement to make the methodology repeatable and non-complex is for the source and sink of any transfer to participate in a constant, uniform way. In this methodology, generation is used for both the source and sink, and the participation of each generator included in a source or sink is directly proportional to its size (e.g. a 100 MW generator will participate twice as much as a 50 MW generator). To accomplish this, all generation within the Area is turned on and dispatched at the same percentage of their maximum output. That dispatch percentage is based on generation meeting load plus losses plus interchange, and in the New York example equals 77.5%. So for example, any generator that has a maximum output of 100 MW would be dispatched at 77.5 MW in the base case; any 50 MW generator would be dispatched at 38.75 MW. By removing any judgment-based selection of source or sink, the transmission line TDFs are only affected by generation location and size, thus making the methodology easily repeatable and transparent.

To cover all portions of the transmission system in identifying what are Bulk Electric System elements, three types of transfers are used: Intra-Area, Area Interface, and Cross-Area. Every transfer is done under an “all lines in” condition while monitoring every element greater than 100 kV within the Area. For every transfer performed, the TDF for every element is recorded.

The objective of Intra-Area transfers is to identify transmission elements which participate in transfers between neighboring zones. The aggregate of generation in one zone is shifted to the aggregate of generation in an adjacent zone. For this type of transfer, lower voltage transmission elements tend to participate more than in longer distance transfers.

The objective of Area Interface transfers is to identify transmission elements associated with predefined interfaces in the Area, in a manner virtually identical to the NYISO CRIS Highways test. A generation transfer is performed for each interface, shifting the aggregate of generation

upstream of the interface to the aggregate of generation downstream of the interface. In the New York example (see Figure 1) of the Volney-East interface, all generation in New York zones A, B, and C is increased and all generation in zones E, F, G, H, I, J, and K is decreased an equal amount. All power from the transfer flows across the Volney-East interface, defined by the boundary of zones C and E, as well as across any elements “in series” with the interface.

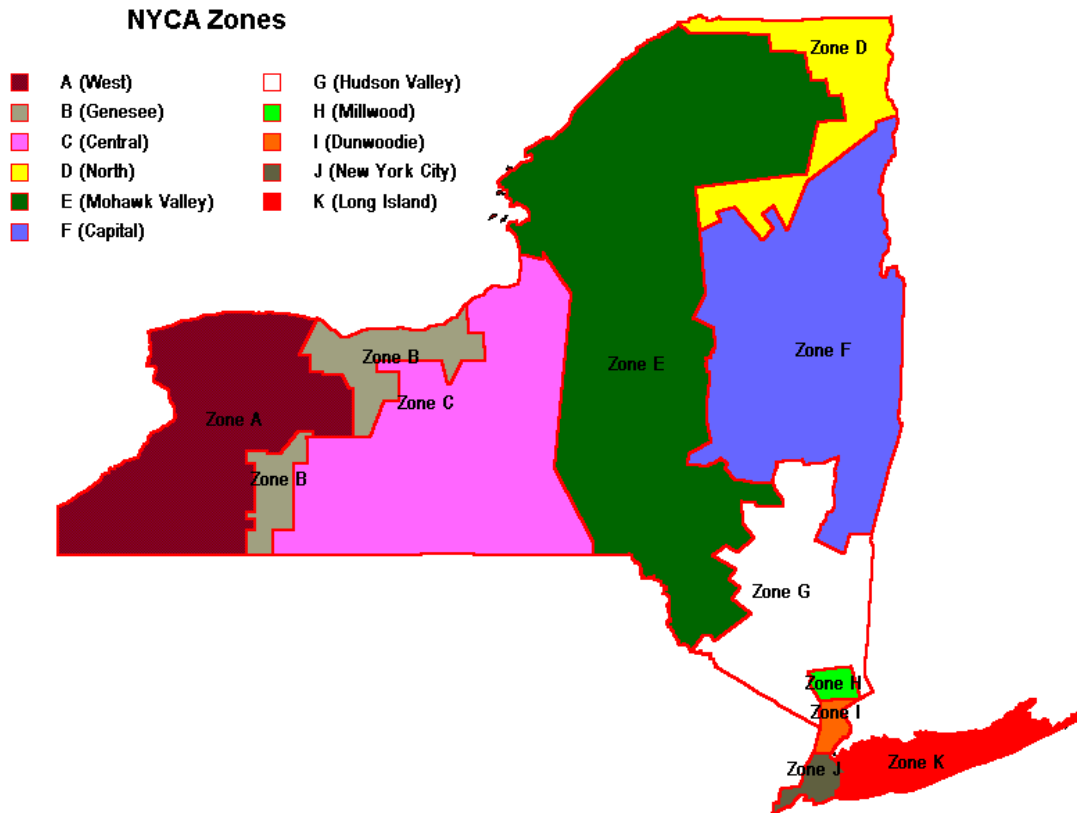


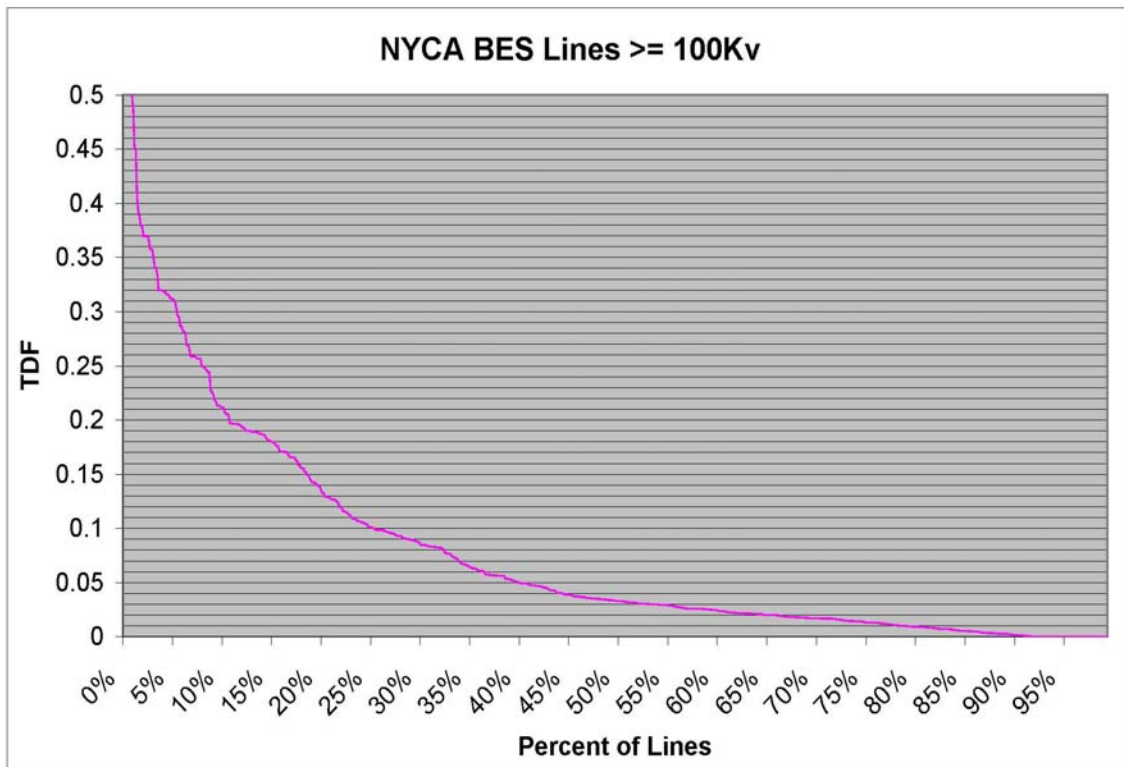
Figure 1 - New York Control Area Zones

The objective of Cross-Area transfers is to identify major transmission paths which participate in transfers of power across the entire Area under study. Proxy generation is selected in each neighboring Area and each possible transfer pair is evaluated. For New York ISO for example, the following transfers are performed: Ontario – New England, Ontario – PJM, PJM – New England, Québec – PJM. For such long distance transfers, only extra high voltage (EHV) facilities tend to participate.

After all transfers have been performed, the TDFs recorded for each element, for each transfer, are compared to find the highest TDF. If the highest TDF recorded for a given element is less than the defined BES cutoff, the element would not be classified as BES. As shown in Table 1, using New York as an example, approximately 20% of lines above 100 kV would not be classified as BES using a TDF cutoff of 1%. The 1% TDF cutoff, which is well below the TLR or other transfer participation factor cutoffs, was utilized as a clarification of the characteristics

of radial facilities which have minimal participation in bulk transfers and negligible impact on the reliability of the international interconnected power system.

Table 1 – New York Control Area BES Facilities



Cost/Reliability Benefit Analysis

Estimated Economic Impacts

The approximate economic costs estimated by the U.S. registered entities regarding adoption of the developed BES definition are summarized below in Table 2 based on application of the current NERC Standards. It is acknowledged that this cost estimate could be order of magnitudes larger if the analysis were extended to consideration of pending and/or proposed NERC Standards.

**Table 2 – Approximate U.S. Registered Entities Estimated Economic Impacts
(2009 \$U.S. x 1,000)**

O/M & Additional Costs	Capital Costs	TOTAL	Applicable NERC Standard(s) ⁷
8	-	8	BAL-001-0.1a BAL-002-0 BAL-003-0.1b BAL-005-0.1b
158	160	318	CIP-001-1
467	165	632	COM-001-1.1 COM-002-2
426	25,800	26,246	EOP-002-2.1 EOP-003-1 EOP-004-1 EOP-005-1 EOP-006-1 EOP-007-0 EOP-008-0 EOP-009-0
966	100	1,066	FAC-001-0 FAC-002-0 FAC-003-1 FAC-008-1 FAC-009-1 FAC-012-1 FAC-013-1
-	-	-	INT-003-2 INT-007-1 INT-009-1 INT-010-1.1

⁷ See: <http://www.nerc.com/page.php?cid=2|20> for a description of the NERC Standards.

O/M & Additional Costs	Capital Costs	TOTAL	Applicable NERC Standard(s)⁷
230	-	230	IRO-001-1.1 IRO-003-2 IRO-014-1 to IRO-016-1
15	-	15	MOD-002-0 to MOD-007-0 MOD-009-0 to MOD-012-0 MOD-013-1 MOD-014-0 MOD-016-1.1 MOD-017-0.1 MOD-018-0 MOD-019-0.1 MOD-020-0 MOD-024-1 MOD-025-1
10	-	10	NUC-001-1
1,302	600	1,902	PER-002-0 PER-003-0
3,595	12,854	16,449	PRC-002-1 to PRC-005-1 PRC-006-0 to PRC-015-0 PRC-016-0.1 PRC-017-0 PRC-018-1 PRC-020-1 to PRC-022-1
367	100	467	TOP-001-1 TOP-007-0 TOP-008-0
1,340	232,797	234,137	TPL-001-0.1 TPL-002-0a TPL-003-0a TPL-004-0 TPL-005-0 TPL-006-0.1
18	100	118	VAR-001-1a VAR-002-1.1a
8,902	272,670	281,578	

Summary of Task Force Assessment Results

Task Force on Coordination of Planning

The primary mission of the Northeast Power Coordinating Council, Inc. (NPCC) Task Force on Coordination of Planning (TFCP) is to promote reliability through the coordination of NPCC Area and NERC planning processes and activities.

Planning Review

With regard to the development of the NPCC developed “Bright Line” BES definition, the TFCP was charged with developing the first draft of the BES definition that was to be used by the Task Forces and registered entities in their assessment of the impact of such a definition. This assignment was completed on March 31, 2009. A significant work effort was required in order to formulate a definition that met the general guidelines, was measurable and easy to understand. As the individual members of TFCP had diverse and sometimes conflicting opinions about what should and should not be included, extensive discussion was required in order to meet the required schedule and to develop a definition that all could support.

This assignment was discussed extensively at the TFCP teleconference meetings held on March 23, 30 and 31, 2009. Subsequent to the development of the definition, the TFCP discussed and provided comments on progress with the *NPCC Assessment of the Bulk Electric System Report* to the Joint Task Force Chairs at all of their meetings held subsequent to the development of the definition. These teleconference and face-to-face meetings were held on April 24, May 11, July 15, July 17 and August 18, 2009. The TFCP also provided suggestions for the estimated implementation plan and timelines. In addition, individual TFCP members have provided comments on this work to the Joint Task Force Chairs through the Chair of TFCP on numerous occasions throughout the April to August 2009 time period. These comments mainly dealt with changes to the definition that were made during the deliberations on the report. The TFCP comments have been addressed.

Conclusion

The TFCP is satisfied that the process followed during the development of this report allowed that any concerns that TFCP or individual TFCP members had could be adequately addressed. The TFCP applauds the efforts and contributions of the various Task Forces and individuals that went into this report and supports its conclusions.

Task Force on Coordination of Operation

The NPCC Task Force on Coordination of Operation (TFCO) is charged to promote, and provide a forum for, the active coordination of reliability and operation among the NPCC Areas and NERC Regions to enhance the reliability of the interconnected bulk power system. TFCO operates under the direction of the Reliability Coordinating Committee.

Two TFCO voting representatives are selected by each of the five NPCC Reliability Coordinator Areas, defined as Ontario, the New York ISO, the ISO New England Inc., the Maritimes Area and Québec, one of whom must be a representative of the Area’s Reliability Coordinator. The second voting representative for the Area should be a representative of a Transmission Operator from that Area.

TFCO participation is open to all NPCC Members, and they shall have a reasonable opportunity to express views on any matter to be acted upon at the meeting. Any NPCC Member may request membership to the NPCC Task Force on Coordination of Operation. All guests attending a meeting of the NPCC Task Force on Coordination of Operation shall be identified at the meeting to the members and alternates present.

Operational Review

The NPCC Task Force on Coordination of Operation assessed the following NERC Standards applicable to system operations:

- Resource and Demand Balancing (BAL-001 through BAL-006);
- Communications (COM-001 through COM-003);
- Emergency Preparedness and Operations (EOP-0;01 through EOP-009);
- Interchange Scheduling and Coordination (INT-001 through INT-010);
- Interconnection Reliability Operations and Coordination (IRO-001 through IRO-016);
- Transmission Operations (TOP-001 through TOP-008); and
- Voltage and Reactive (VAR-001 and VAR-002).

Three additional meetings, together with conference calls, were dedicated to the completion of this work.

Conclusion

The major conclusion of the NPCC Task Force on Coordination of Operation is that the impact of the application of these standards with an expanded BES definition is largely that some registered entities will need to expand personnel and training to accommodate additional procedural and reporting requirements.

The addition of control room operators is a lengthy process that requires the following tasks:

- ✓ Budgeting and reallocation of limited resources
- ✓ Hiring Process (Candidate Solicitation: Interviewing, Testing, Evaluation)
- ✓ Training and NERC Certification
- ✓ Assumption of Responsibilities

Task Force on System Protection

The purpose of the NPCC Task Force on System Protection (TFSP) is to promote the reliable and efficient operation of the interconnected bulk power systems in Northeastern North America through the establishment of Directories, Criteria, Guidelines, and Procedures and coordination of design, relative to the relay protection associated with the bulk power system.

There are currently 14 TFSP members, who are selected by registered entities in each of the five NPCC Areas, defined as Ontario, New York, New England, the Maritimes, and Québec, including an NPCC staff member. In addition to the 14 members, there are also currently 4 alternate members.

TFSP participation is open to all NPCC Members, and members have a reasonable opportunity to express views on any matter to be acted upon at the meeting. The Agenda for each meeting is posted on the public portion of the NPCC website.

System Protection Review

The NPCC Task Force on System Protection assessed the following NERC Reliability Standards:

- PRC-001-1
- PRC-003-1
- PRC-004-1
- PRC-005-1
- PRC-007-0
- PRC-012-0
- PRC-013-0
- PRC-014-0
- PRC-015-0
- PRC-016-0.1
- PRC-017-0
- PRC-018-1

The above standards were assessed at two regularly scheduled Task Force meetings and one extended conference call.

Conclusion

The major conclusion of the NPCC Task Force on System Protection is that the impact of the application of these standards with an expanded BES definition is largely that some registered entities will need to expand engineering and maintenance personnel, increased documentation and reporting, and some additional Disturbance Monitoring Equipment.

As an example, as the applicability of PRC-005 (Transmission and Generation Protection System Maintenance and Testing), expands to facilities that are not currently BES, the following impacts are incurred;

- ✓ Extend Maintenance Contracts for Newer Generator Facilities approaching their first schedule relay maintenance period.
- ✓ In order to guarantee 'auditable' compliance, engineering and testing firms would have to be hired to validate and enhance the current program. Estimated to be a one-time cost.
- ✓ Additional Maintenance staff required due to increased Regulatory program and documentation needs
- ✓ Update BES Testing & Maintenance Procedure to ensure applicability for all protection systems 100kV and above. Additional Tech Man-hours to ensure no testing backlog exists
- ✓ Internal Resources, testing, consulting, and other Costs.

- ✓ All non-BPS TPS elements to would become brightline will be rolled into one program requiring more frequent maintenance and testing. This will result in the hiring of more technicians

Task Force on System Studies

The general scope of the TFSS is to provide for active overall coordination of system studies of the reliability of the interconnected bulk power system and for the review of certain NPCC documents, in accordance with the schedule set forth in the Reliability Assessment Program.

The TFSS includes representation from all five Areas of NPCC, including Reliability Coordinators, Planning Coordinators, Transmission Owners, Load-Serving Entities, and Transmission Operators.

TFSS normally meets six times per year. Since the directive from the NPCC Board to review the impact of adopting a 100kV Bright Line definition of the BES, the topic has been discussed at three of the regularly scheduled meetings, (March, May, and July). In addition, four special conference calls on this effort were held (February, two in April, and July).

System Studies Review

TFSS reviewed all currently approved NERC standards for applicability to the expertise of TFSS. Some standards were deemed to have direct interest to more than one Task Force, and TFSS reviewed such standards from its point of view.

Before the Impact Assessment was conducted by registered entities, members of TFSS reviewed each relevant NERC standard in detail, commenting on the potential for significant impact due to the application of the standard consistent with the developed BES definition.

The standards reviewed by TFSS included:

1. Facility Requirements (FAC-001, FAC-002, FAC-008, FAC-009, FAC-010, and FAC-013)
2. System Data Requirements (MOD-010 and MOD-012)
3. Protection and Control (PRC-002, PRC-009, PRC-010, and PRC-018)
4. Transmission Planning (TPL-001 through TPL-004).

Conclusion

The Task Force on System Studies concluded that the working definition of the BES had the potential to unintentionally exclude significant generation resources that were interconnected via radial transmission. TFSS recommended that the final definition of BES be clarified accordingly.

The review of the standards by TFSS, and the subsequent review of responses by registered entities, concluded that there is a significant burden of documentation and study to meet NERC standards applied to expanded parts of local systems. Members of NPCC conduct and document studies of the Bulk Power System to meet the requirements of NPCC criteria and thus NERC standards. Presently, Area and/or local criteria and procedures are applied to the design and study of the non-BPS system. Application of the NERC Standards is that the impact will be a significant expansion the resources (time and personnel) needed to meet the rigor of the NERC

standards, specifically the four TPL standards, on the larger BES system. This resource requirement has been identified in the need to recruit experienced study personnel, develop documentation, and conduct the additional studies on an ongoing basis.

Beyond the need for increased documentation and studies, TFSS identified the potential for significant capital expenditure as parts of the BES that currently meet local design criteria must be upgraded to meet NERC standards. Of particular concern is the implementation of TPL-003:

1. Category C events permit "Planned/Controlled loss of demand or curtailed firm transfers" which is further explained in Note C. It is unclear why Note C starts with "Depending on system design and expected system impacts..." This seems to be a way to incorporate undervoltage load-shedding or load-shedding Special Protection Systems for this type of fault, or it could be simply referring to network topology.
2. There is a potential for diverse implementation of the C3 contingencies (N-1-1). An example is the implementation of TPL-003 for a load center fed via two lines. Loss of the first line does not overload the second line. Loss of the second line results in loss of consequential load, which is permitted. Now let's say that there are three lines in service. One line is lost and the other two lines are not overloaded, however if the second line is lost, then the last line will be overloaded. C3 permits "manual system adjustment" to prepare for the second contingency, but what happens if the only adjustment that can be made is the curtailment of firm load (as would be the case if there was no dispatchable generation in the load pocket)? This standard may require you to cross-trip the third line to prevent it from overloading, which would interrupt all customers in the load pocket, or trip some firm load via an SPS to prevent overload of the third circuit, or build a fourth circuit.
3. Requirement 1.3.12 has recently been interpreted by NERC for Ameren in TPL-003a to require studies to be conducted: Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed. This can be particularly onerous with respect to C3 contingencies (N-1-1). This could be interpreted as a requirement for studies to be performed with a protection system (or component) out of service for maintenance, followed by a category C 6,7,8,9 event, which calls for a SLG fault on a generator, line, transformer or bus section with the second protection system out of service. If this means that all BES requires three protection systems, then that exceeds NPCC already stringent criteria for its own BPS.

There are two factors that affect the impact of adopting a NERC standard for newly defined Bulk Electric facilities, the implementation of the requirements, and the local criteria to which the facilities were designed before they received BES classification. For example, the implementation of TPL-003 by some registered entities has resulted in the expectation that significant system reinforcement of the newly designated BES may be required. This requirement is subject to the implementation of the footnotes "b" and "c" in the Table 1 of TPL-003. The current version of the standards allows "planned or controlled interruption of electric supply... without impacting the overall reliability of the interconnected power system", or may require the "controlled electric supply to customers (load shedding) ... to maintain the overall reliability of the interconnected transmission systems". It is unclear how these footnotes would be interpreted for BES, particularly in remote parts of the system away from the BPS.

Regardless of the implementation of the footnotes with respect to loss of load, TPL-003 does not allow thermal or voltage violations in excess of applicable limits or cascading element tripping, and therefore the following assumptions were used by one entity to assess the need for system reinforcements:

- a. All 3(or more)-line-terminal 115 kV substations need to be modified/rebuilt to a breaker-and-a-half design to avoid a complete outage of all facilities connected to the substation, to avoid criteria violations following N-1-1 events. Although detailed system studies have not yet been performed, it is estimated that the nature of their looped 115kV system, which was designed to a local criteria that does not consider bus faults following a N-1 event, could experience voltage or thermal violations at the remote end of the 115kV loop.
- b. All load areas with more than 300 MW of load (depending on the emergency rating of the lines serving the load post-contingency) may need more than three 115 kV lines serving that area, to avoid criteria violations following N-1-1 events. Although an alternative may be the installation of load-shedding SPS's, there is a risk that those SPS's may not be approved.

Although the impact assessment was conducted with the currently approved version of NERC standards, it was recognized by TFSS and member systems that the ongoing development of a more stringent version of the TPL criteria could significantly expand the need for capital expenditure for parts of the system now considered "local."

TFSS notes that footnotes (b) and (c) of Table 1 of TPL-001 acknowledge the distinction between reliability to local load and "overall reliability of the interconnected power system" and concludes that the addition of transmission facilities to meet the requirements of N-1-1 may improve the reliability of service to those customers in the load pocket, it does nothing to improve the "overall reliability of the interconnected power system."

Task Force on Infrastructure Security & Technology

The foundation of Version 1 of the Cyber Security Standards (CIP-002-1 – CIP-009-1) is CIP-002-1 R1 which allows each Entity to choose its Critical Asset identification methodology. During the creation of NPCC's Regional Critical Asset Identification Guideline (B-27), TFIST determined that most NPCC members use a reliability impact based methodology as a cornerstone of that Entity's methodology. A reliability impact based methodology is a central part of that Guideline.

TFIST expects little to no impact in moving to the developed BES definition since the CIP002 - CIP009 Standards (both versions 1 and 2) allow the registered entity to choose its methodology in determining their Critical Assets. Note that the existing CIP Standards are version 1 since the NERC BOT has approved version 2 but the regulators have not.

Canadian Review

Canadian members of NPCC believe that enforcing mandatory reliability standards is essential for designing, maintaining and operating a reliable and secure interconnected electricity grid. However, the application of NERC reliability standards should be limited to wide area reliability

without expanding its scope to cover local area reliability. NPCC's defined bright line approach would result in NERC reliability standards being applied to additional facilities, 100 kV and above, which could be deemed only local area impactful. These facilities do not have a wide area impact and would not result in cascading outages. In all Canadian provinces within the NPCC footprint, there are adequate local area reliability standards and criteria in place and which are under the purview of the provincial regulators.

Canadian members of NPCC are committed to designing, building and operating their electric power systems so that their respective operations do not adversely impact their inter-connections within Canada or with the U.S. At the same time, Canadian members are committed, through their provincial regulatory requirements, to ensure that their customers are provided with safe, secure, reliable power in a cost effective manner, as mandated by provincial regulators. Canadian members of NPCC strongly feel that the balance between these interests is best achieved through the impact based approach currently used by NPCC to determine the applicability of NERC standards. This impact based approach has been in existence for many years and has not resulted in technical seams issues with neighboring Regional Entities.

Canadian members of NPCC strongly believe that significant additional costs will be incurred without identified reliability benefits if a bright line definition were adopted across Canadian NPCC. Moreover, this exercise would result in diverting funds and key expert resources from other higher value reliability projects and activities. Canadian members do not expect Canadian provincial regulators to support expenditures by their regulated entities to expand the applicability of the NERC reliability standards if they are unable to demonstrate benefits to reliability.

Canadian NPCC members strongly urge NPCC to retain its impact based methodology for determining facilities which are critical to the international, interconnected bulk electric system.

Conclusions

Application of the BES definition included in this report, with the defined radial “exclusions” would represent 1,270 lines and 31 generating facilities (U.S.) over the current BPS definition and is estimated to cost in excess of approximately \$280M (2009 \$U.S.) based on application of the current NERC Standards. It is acknowledged that this cost estimate could be order of magnitudes larger if the analysis were extended to consideration of pending and/or proposed NERC Standards. The assessment identified that the most significant cost and related added complexity would be associated with compliance with NERC TPL-003-0a Standard, depending on its implementation. In addition, experienced protection and control personnel will be needed to address applicability of the new requirements to additional facilities. Additional experienced expertise is presently scarce; available personnel would have to be diverted from on-going current power system improvement projects to meet this need.

In general, based on the entity survey responses and Task Force reviews, application of the BES definition developed in this report would increase the number of facilities for which NERC compliance will be required, resulting in significant economic and resource impact with questionable, if any identified increase in the overall reliability of the NPCC interconnected power system.

Such an application could:

- ✓ Expand NERC Standard compliance monitoring activities,
- ✓ Enhance power system awareness for the Reliability Coordinators; and,
- ✓ Provide additional coordination.

Members of NPCC believe that enforcing mandatory reliability standards is essential for designing, maintaining and operating a reliable and secure interconnected electricity grid. However, many members believe that the application of NERC reliability standards should be limited to wide area reliability based on utilization of the reliability impact based methodology included in the NPCC A-10 criteria, without expanding its scope to cover local area reliability.

Canadian members of NPCC also strongly believe that applicability of NERC Reliability Standards should be defined through the use of the NPCC A-10 Criteria, and that significant additional costs will be incurred without commensurate reliability benefits if a bright line definition were adopted across Canadian NPCC. More importantly, regardless of the financial impact, this exercise would result in diverting funds and key expert resources from other higher value reliability projects and activities.

Developed NPCC “Bulk Electric System” (BES) Definition

Responsive to the Board’s assignment, the NPCC Reliability Coordinating Committee (“RCC”) reviewed the identified costs, reliability impacts and jurisdictional concerns in considering a voltage-based approach for defining the BES. The following definition has been developed to be consistent with other Regions that have adopted a voltage-based BES definition, and is respectfully submitted to the NPCC Board for its review and consideration.

The following Bulk Electric System⁸ (“BES”) definition utilizes the methodology established under the A-10 criteria for application of NERC Reliability Standards in the Canadian portion of NPCC, while defining a voltage-based BES definition for U.S. Entities within the NPCC footprint with certain exclusions:

1. Transmission elements operated at voltages of 100 kV or higher;
2. Transformers, including Phase Angle Regulators, with both primary and secondary windings connected to 100 kV or higher;
3. Individual generation resources greater than 20 MVA (gross nameplate rating) and are directly connected via a step-up transformer(s) to designated BES Transmission facilities by a designated BES transmission path;
4. Generation plant with aggregate capacity greater than 75 MVA (gross nameplate rating) and are directly connected via a step-up transformer(s) to designated BES Transmission facilities by a designated BES transmission path;
5. Generator step-up transformers and the generator interconnecting line lead associated with BES generators.

Radial Exclusions

Radial portions of the transmission system excluded from the NPCC BES transmission system include:

1. An area serving load that is connected to the rest of the network at a single transmission substation at a single transmission voltage by one or more transmission circuits,
2. Tap lines and associated facilities which are required to serve local load only,
3. Transmission lines that are operated open for normal operation, or
4. Optionally, those portions of the NPCC transmission system operated at 100 kV or higher not explicitly designated as a BES path for generation which have a one percent or less participation in area, regional or inter regional power transfers.⁹

BES Implementation Estimate

System Protection Standards

Based on TFSP review, the following is a high level estimate of % implementation following adoption of the developed BES definition:

- ✓ 75% of applicable PRC standards can be implemented to become compliant within two years (medium term)
- ✓ 25% of applicable PRC standards can be implemented to become compliant beyond two years (long term)

⁸ There are situations where specific NERC Standards apply to non-BES equipment.

⁹ Power Transfer Distribution Factor analysis is an analysis that is performed to identify portions of the NPCC transmission system that have minimal impact on transfers across the power system and perform similarly to radial systems. NPCC assessments of any such Balancing Authority Area-wide determinations are conducted during the course of NPCC Transmission Reliability Studies.

System Studies Standards

Based on TFSS review and survey respondents comments of respondents:

- ✓ Near term (requires modification or creating of procedural documents, or is something that is currently underway).

- FAC-001
- FAC-002
- FAC-008
- FAC-010
- FAC-012
- MOD-010
- MOD-011
- MOD-012
- MOD-013
- MOD-014
- MOD-015
- PRC-006
- PRC-010
- PRC-013
- PRC-015

- ✓ Medium term (within two years - requires studies or changes to NPCC documentation)

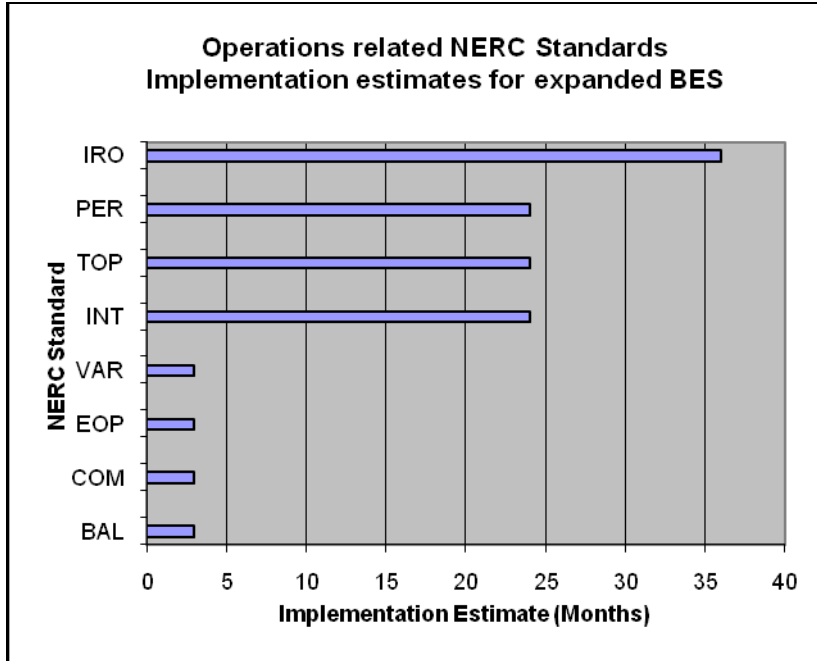
- FAC-009
- PRC-002
- PRC-012
- PRC-014
- PRC-018
- PRC-023
- TPL-001
- TPL-004

- ✓ Long-term (beyond two years)

- TPL-002
- TPL-003

Operational Standards

Based on TFCO review, the following is an estimate of implementation following adoption of the developed BES definition:



Summary

If FERC orders this change in definition for BES then registered entities within the U.S. portion of NPCC would need time to implement the change. In most cases, a two-year implementation plan appears feasible and reasonable. This permits hiring of additional personnel, training of such personnel, enhanced documentation, etc. The acquisition, installation and training associated with new tools may require up to five years, and major capital projects, such as the construction of new transmission could require up to ten years.

The RCC recommends, should FERC direct NPCC to adopt the developed NPCC BES definition for utilization by U.S. registered entities, that the respective NPCC Task Forces develop a GANTT chart outlining the specific implementation program for the associated NERC Standards.

Appendix A

NPCC Board Assignment Companion Letter

Mr. Joseph H. McClelland
Director, Office of Electric Reliability
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

February 20, 2009

Re: Docket No. RC09-3-000

Dear Mr. McClelland:

On February 20, 2009 the North American Electric Reliability Corporation (“NERC”) and the Northeast Power Coordinating Council, Inc. (“NPCC”) submitted, in response to the Federal Energy Regulatory Commission (“FERC” or “Commission”) Order Directing the Submission of Data (Docket No. RC09-3-000) issued by the Commission on December 18, 2008, a comprehensive list of bulk electric system facilities within the U.S. portion of the NPCC region. That response includes the existing NPCC approved list currently being used for application of NERC Reliability Standards, (the “Approved BES List” of June 2007), as well as a listing of all transmission elements (lines and transformers) operated at voltages 100kV and above, and generators, 20 MVA or greater, that were connected to busses operated at 100kV and above within the U.S. portion of NPCC.

The NPCC Board of Directors, at its February 3, 2009 meeting, discussed the NPCC response to the December 18, 2008 FERC Order. Paramount among their concerns was the application of a criterion that differed from NPCC’s impact-based approach without an in-depth evaluation of the effects and any unintended potential consequences it could have on the reliability of the NPCC region. After thorough consideration, the NPCC Board directed that NPCC, in addition to furnishing the requested information, should submit this companion letter to the FERC Staff explaining the reasoning behind NPCC’s development of an impact-based approach to Bulk Power System definition, and commit to:

- (1) identifying and evaluating the issues associated with utilizing, for applicability of NERC Reliability Standards within the United States portion of NPCC, the implementation of the NERC definition of “bulk electric system” used by all other Regional Entities, which includes facilities generally operated at voltages of 100 kV or higher and excludes radial transmission facilities;
- (2) assessing the possible incremental reliability benefits and potential negative impacts related to the adoption of such a bright line definition within NPCC (U.S.), including the international impact if there were to be different BES definitions across the U.S. and Canadian portions of the NPCC Region; and,
- (3) submitting the results of that assessment to FERC on September 20, 2009.

NPCC, a cross-border regional entity and international reliability organization, has a longstanding commitment to maintaining the reliability of the bulk power system within its

Region. NPCC was formed over forty-three years ago in 1966 as a direct result of the Northeast blackout in November 1965. After reviewing the circumstances of that blackout it was recognized that increased coordination between neighboring utilities needed to occur. It was also recognized there was a need to establish design and operation rules or criteria that addressed the unique characteristics of the international, interconnected NPCC system. NPCC created a set of criteria that covered many aspects of the electrical system in the Region including: the basic design and operation of the bulk power system, emergency operations, design and maintenance of bulk power system protection and emergency reserve operation. During the course of the years that followed, the original criteria were reviewed on a regular basis and revised along with supporting guidelines and procedures to assure that, as the bulk power system evolved the criteria was kept current. In addition new criteria was introduced as needed to address additional changes to the power system or to address lessons learned from other major system events such as the blackouts of 1977 and 2003. Well in advance of the U.S. reliability legislation, NPCC member systems voluntarily adhered to the reliability criteria established by NPCC, and through NPCC's *Membership Agreement* and subsequent *Bylaws* made compliance with these criteria mandatory on NPCC's members.

This has led to a sustained culture of compliance within NPCC centered on the functional evaluation of system elements and their relationship to maintaining reliability. In addition to this history of maintaining reliability from a functional perspective, the electrical system in the NPCC Region exhibits several characteristics that better lends itself to an impact-based approach to defining the BES elements. The electrical system in the NPCC Region is characterized by 1) large concentrated load pockets; 2) both synchronous and asynchronous electrical ties; and 3) a significant number of multiple circuit transmission corridors.

The NPCC criteria that evolved to meet these characteristics were necessarily more stringent or more specific than the NERC Reliability Standards. Some examples of these more specific or more stringent criteria are:

- 1) the use of a single phase to ground ("s-l-g") fault with delayed clearing, such as a stuck breaker fault as a standard design criteria contingency;
- 2) the inclusion of a two phase to ground ("l-l-g") fault on adjacent circuits, such as a double circuit tower contingency in the design criteria;
- 3) the inclusion of the simultaneous permanent loss of both poles of HVDC bipolar facility;
- 4) more stringent and more specific requirements regarding bulk power system relay maintenance;
- 5) more stringent requirements regarding system protection coordination; and,
- 6) more stringent requirements related to special protection systems.

Recognizing that reliability of the bulk power system relied on the implementation of the NPCC Criteria and that not all facilities on the system responded to electrical disturbances in the same manner, NPCC adopted a performance based methodology for determining the elements that constituted the bulk power system and were required to meet the NPCC Criteria. The rationale for this methodology was to identify system performance that caused or had the potential to cause cascading type or large scale outages without reference to voltage class or configuration. Clearly there could be facilities lower than 100kV which could have a widespread impact on reliability, likewise, there may be facilities larger than 100 kV within NPCC which would not have a widespread impact on the overall system. Identifying those elements that could cause

widespread outages enables NPCC to better focus its reliability assurance efforts on those elements that affect the reliability of the international, interconnected system in the Northeast.

The NPCC impact-based approach is tailored to meet the needs of NPCC by defining a power system element as being part of the bulk power system based on the effect it has on system performance. The methodology utilizes both transient stability analysis and steady-state power flow analysis to determine the impact on system performance resulting from power system faults. The transient stability test, based on application of a bus fault at a single voltage level that is un-cleared locally is used first to identify Bulk Power System buses. Tripping of un-faulted elements as a consequence of the fault is part of the test. Operation of Special Protection Systems, including undervoltage load shedding, is taken into account in these tests. In addition, power flow tests are used to identify Bulk Power System buses based on steady-state parameters such as postcontingency thermal loading and voltage. The results of either the transient stability test or the power flow test are evaluated and then the Bulk Power System determination is made by the Balancing Authority, and affirmed by NPCC.

Before deviating from this approach that has evolved out of the characteristics and history of the NPCC region, NPCC, through its Committee and Task Force structure, commits to undertake an in depth evaluation of the possible incremental reliability benefits and potential negative impacts of the utilization, in the U.S., of a 100kV “bright line” definition for the bulk electric system for application of NERC Reliability Standards. The initial step of such an assessment will be identifying and evaluating the issues associated with utilizing, for applicability of NERC Reliability Standards within the United States portion of NPCC, the NERC definition of “bulk electric system” which includes facilities generally operated at voltages of 100 kV or higher and excludes radial transmission facilities. Among, the issues to be addressed are:

- a) possibly inconsistent definition among the U.S. and Canadian members of NPCC;
- b) clear definition of the term radial transmission facilities;
- c) the need to develop methodologies for documenting compliance with NERC Standards at the 100 kV level which had formerly relied on application of NPCC’s BPS focused criteria;
- d) maintenance and capital investment impacts of a change in definition;
- e) required implementation timeframes; and,
- f) confirming that the costs to consumers provide incremental reliability benefits.

NPCC envisions that this assessment will require its U.S. registered entities (transmission owners, transmission operators, generator owners, generator operators and distribution providers) to identify the implications of adopting a bright line definition. Lastly, the Board directed that the NPCC Reliability Coordinating Committee, NPCC’s senior technical committee, coordinate the assessments through the Task Force structure. Once this evaluation has been completed and reviewed by NPCC, NPCC will submit its findings to FERC on September 20, 2009.

Sincerely,

Edward A. Schwerdt

Edward A. Schwerdt
President and CEO

cc: NPCC Board of Directors

ATTACHMENT B1

New York List of NPCC BES Elements Consistent with Developed BES Definition

**Privileged and Confidential Information Has Been Removed
From This Public Version**

ATTACHMENT B2

New England List of NPCC BES Elements Consistent with Developed BES Definition

**Privileged and Confidential Information Has Been Removed
From This Public Version**

ATTACHMENT C

List of Newly Registered GO/GOP Entities

**Privileged and Confidential Information Has Been Removed
From This Public**