UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

INTERPRETATION OF TRANSMISSION PLANNING RELIABILITY STANDARD	**)** **)**	**Docket No. RM10-6-000**

INFORMATIONAL FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN RESPONSE TO ORDER NO. 754

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March 15, 2012

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I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC") hereby submits to the Federal Energy Regulatory Commission ("FERC" or "Commission") for informational purposes in compliance with Paragraph 20 of Order No. 754,[1] a report on the reliability issues concerning system protection associated with the Commission-approved interpretation of Requirement R1.3.10 of Reliability Standard TPL-002-0. In Order No. 754, the Commission approved an interpretation to R1.3.10 of TPL-002-0, and directed NERC to file, within six months of the date of the Final Rule, an informational filing explaining "whether there is a further system protection issue that needs to be addressed and, if so, what forum and process should be used to address that issue and what priority it should be accorded relative to other reliability initiatives planned by NERC."[2] By this filing, NERC submits an informational report in response to Order No. 754.

[1] *Interpretation of Transmission Planning Reliability Standard*, 136 FERC ¶ 61,186 (September 15, 2011) (Order No. 754)
[2] Order No. 754 at P 20.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[3]

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III. DISCUSSION

In a November 17, 2009 filing, NERC submitted to the Commission a proposed interpretation to Requirement R1.3.10 in Reliability Standard TPL-002-0 – System Performance Following Loss of a Single Bulk Electric System Element.[4] In a subsequent Notice of Proposed Rulemaking ("NOPR") issued on March 18, 2010, the Commission proposed to remand NERC's interpretation. As a result of the comments filed in response to the NOPR, FERC issued Order No. 754 in which it reversed the original NOPR proposal and approved NERC's proposed interpretation of Requirement R1.3.10 of TPL-002-0. In Order No. 754, FERC directed NERC to submit an informational filing, within six months from the date of the Final Rule, explaining "whether there is a further system protection issue that needs to be addressed and, if so, what

[3] Persons to be included on FERC's service list are indicated with an asterisk. NERC requests waiver of 18 C.F.R. § 385.203(b) to permit the inclusion of more than two people on the service list.

[4] *Petition of the North American Electric Reliability Corporation for Approval of Interpretation to Reliability Standard TPL-002-0 — System Performance Following Loss of a Single Bulk Electric System Element (Category B)*, Docket No. RM10-6-000 (November 17, 2009).

forum and process should be used to address that issue and what priority it should be accorded relative to other reliability initiatives planned by NERC."[5]

A technical conference, titled Staff Meeting on Single Point of Failure on Protection Systems ("Technical Conference"), concerning the Commission's Order No. 754 was held on October 24-25, 2011 at FERC in Washington, DC. The Technical Conference was attended by representatives of FERC technical staff, NERC staff, and industry stakeholders with subject matter expertise in system protection and planning. The attendees focused on the Commission's concern regarding assessment of protection system failures.

Presentations given at the Technical Conference addressed: the voluntary transmission planning standards from 1997 (pre-version 0 NERC standards), the 2009 NERC Advisory to Industry ("NERC Advisory"),[6] current mandatory Reliability Standards, an account of the June 14, 2004 Westwing outage event,[7] and practices applied by entities in the Reliability*First* Corporation ("RFC"), Midwest Reliability Organization ("MRO"), Southwest Power Pool, Inc. ("SPP"), Northeast Power Coordinating Council ("NPCC") and Western Electricity Coordinating Council ("WECC") Regions. The Westwing outage, in particular, was discussed at length, and is one of three significant events referenced in the NERC Advisory that concerns protection system single points of failure. Altogether, NERC identified five events between 2004 and 2010 in which a single point of failure on a protection system caused, in whole or in part, an event on the Bulk-Power System ("BPS").

Initially, the issue of protection system failure revolved around the transmission planning standards (*i.e.*, TPL-001 through TPL-004), which specify BPS performance for certain

[5] Order No. 754 at P 20.
[6] Industry Advisory, *Protection System Single Point of Failure*, (March 30, 2009). Available at http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf.
[7] The Westwing disturbance resulted in the loss of approximately 5,000 MW of generation and the potential for collapse of the Western Interconnection.

contingencies and include protection system failure criteria. In that discussion, concerns were raised about how a transmission planner is made aware of a protection system component, which may impact the clearing of a fault and BPS performance in the case of protection system failure. After further discussion, a consensus was reached that system performance requirements in the transmission planning standards are achieved jointly through collaboration between transmission planning and protection system engineers.

At the Technical Conference, the attendees narrowed their concerns into four (4) consensus points: (1) the concern with assessment of single point of failure is a performance-based issue, not a full redundancy issue; (2) the existing approved standards address assessments of single points of failure; (3) assessments of single point of failure of non-redundant primary protection (including backup) systems need to be sufficiently comprehensive; and (4) lack of sufficiently comprehensive assessments of non-redundant primary protection systems is a reliability concern.[8]

From the four consensus points, the Technical Conference attendees developed a problem statement to be used to address the Commission's concern about "… whether there is a further system protection issue that needs to be addressed…"[9] The problem statement is "the group perceives a reliability concern regarding the comprehensive assessment of potential protection system failures by registered entities. The group agrees on the need to study if a [reliability] gap exists regarding the study and resolution of a single point of failure on protection systems."[10] Further discussion during the Technical Conference determined the next steps needed for NERC

[8] Consensus points developed at the Technical Conference.
[9] Order No. 754 at P 20.
[10] Problem statement developed by consensus at the Technical Conference.

to be responsive to the Commission's directive, "… and, if so, what forum and process should be used to address that issue…."[11]

Three individual processes were identified to address the Commission's concern.

(1) A Request for Interpretation ("RFI") of the applicable and currently enforceable transmission planning standard(s) potentially including Reliability Standards TPL-001, TPL-002, TPL-003, and TPL-004.

(2) A Request for Data or Information (*i.e.*, Data Request), as allowed by the NERC Rules of Procedure, Section 1600, that could be used to determine the potential exposure to and reliability risk associated with the single point of failure concern.

(3) NERC's Project 2009-07, Reliability of Protection Systems, could be utilized, as necessary, to develop an appropriate new reliability standard that addresses the single point of failure concern.

Each of the three processes is addressed below.

i. Request for Interpretation

An RFI is currently proceeding in accordance with NERC's Standard Processes Manual.[12] RFIs allow any entity directly and materially affected by the reliability of the North American BPS to request additional clarity about one or more Requirements in a Reliability Standard.

In this case, the RFI (attached as **Exhibit A**), prepared with input from Commission staff and industry stakeholders, identified the specific standards and requirements that address single points of failure on protection systems. This group identified TPL-003-0a — System Performance Following Loss of Two or More Bulk Electric System Elements (Category C) and

[11] Order No. 754 at P 20.
[12] *Standard Processes Manual*, Appendix 3A to the NERC Rules of Procedure at pp. 27-28. The Rules of Procedure are available at: http://www.nerc.com/page.php?cid=1|8|169.

TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D) [13] as the standards that address potential single points of failure issues. In TPL-003-0a, requirements R1.3.7, R1.3.10 and R1.5; in TPL-004-0, requirements R1.3.7 and R1.4 were identified as the specific requirements that pertain to the issue of protection system failure.

The RFI was brought before the NERC System Protection and Control Subcommittee ("SPCS") and the Transmission Issues Subcommittee[14] ("TIS") (collectively the "Joint Team") at their joint meeting on December 6-8, 2011 ("Joint Meeting"). The Joint Meeting participants reviewed the work of the interpretation team and recommended several modifications to improve clarity of the draft request. At the Joint Meeting, the SPCS agreed to sponsor the RFI[15] in accordance with the NERC Standards Process Manual. The finalized RFI was submitted to NERC on January 27, 2012, and subsequently accepted on February 3, 2012, by the NERC Standards Committee Executive Committee ("SCEC"). The SCEC directed NERC staff to assemble an interpretation drafting team and designate the RFI a high priority to address the need for clarification raised in the RFI. By directing NERC staff to address the RFI as a high priority, the SCEC also addressed the Commission's directives that NERC determine the appropriate priority for responding to the single point of failure concern.[16]

The RFI seeks to address the second and fourth consensus points from the Technical Conference that (2) existing approved standards address requirements to assess single point of

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[13] This would apply both to TPL-003-0a and NERC Board of Trustees approved TPL-003-1a and TPL-004-0 and the TPL-004-1 that was submitted to the Commission on February 17, 2011. *Petition of the North American Electric Reliability Corporation for Approval of Four Transmission Planning System Performance Reliability Standards and Retirement of Four Existing Reliability Standards,* Docket No. RM11-18-000 (March 31, 2011).

[14] In December 2011, the NERC Planning Committee formed the System Analysis and Modeling Subcommittee ("SAMS"), which assumed responsibilities assigned to the TIS.

[15] This RFI project is identified as Project 2012-INT-02 TPL-003-0a and TPL-004-0a for SPCS and may be accessed via NERC's website at http://www.nerc.com/docs/standards/dt/Order_754_Interpretation_Request_Form_2011_12_23_DRAFT.pdf.

[16] Order No. 754 at P 20.

failure; and (4) lack of sufficiently comprehensive assessments of non-redundant primary protection systems is a reliability concern. The RFI also addresses the first sentence of the problem statement "reliability concern regarding the comprehensive assessment of potential protection system failures by registered entities."[17]

ii. Data Request

NERC has initiated a Request for Data or Information ("Data Request"),[18] to determine the potential exposure to and reliability risk associated with the single point of failure concern. The current version of the Data Request[19] is based on an approach that utilizes TPL-004-0 Table I Category D contingencies with a three-phase (3Ø) fault and assesses simulated system performance against performance measures based on system performance attributes that could be similar to the Westwing event, or other events upon which the NERC Advisory was based. The system protection components to be addressed in the Data Request include: (1) protective relays, (2) communication systems, (3) AC current and voltage inputs, (4) DC control circuitry, and (5) station DC supply. A draft of the Data Request was presented at the Joint Meeting and was revised based on input from the SPCS and TIS.

NERC provided FERC with notice consistent with the NERC Rules of Procedure, Section 1602, on December 14, 2011. NERC then posted the Data Request on December 22, 2011 for a forty-five (45) day comment period for industry stakeholders' review and opportunity to submit comments. During the comment period, NERC staff conducted two web-based (*i.e.*, webinar) informational presentations that included a live question and answer session that allowed participants to ask questions about the Data Request. Responses during the webinars

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[17] Problem statement developed at the Technical Conference.
[18] Data Requests are allowed under the NERC Rules of Procedure, Section 1600 – Requests for Data or Information. NERC's Rules of Procedures are available at: http://www.nerc.com/page.php?cid=1|8|169.
[19] The Data Request has not been finalized at the time of this filing. A draft version of the Data Request (current as of March 14, 2012) is attached as **Exhibit B**.

were verbal; however, chat questions were recorded and detailed written responses were prepared. More than eighty (80) different questions were submitted and responded to by NERC staff and posted to the NERC website and the respective audience was notified the responses were available for review.

The Data Request 45-day comment period ended on February 6, 2012 with fifty-six (56) individual entities providing comments. Comments were fully considered and summary responses developed by the SPCS and System Analysis and Modeling Subcommittee ("SAMS") on February 14-15, 2012 at their joint meeting held at the NERC headquarters in Atlanta, Georgia. The SPCS and SAMS, modified the Data Request based on comments received from industry to correct inconsistencies and to provide better clarity about the required entity's performance. The revised Data Request will be posted for comment by April 25, 2012. NERC intends to bring the Data Request to the NERC Board of Trustees for approval on August 16, 2012.

During the Joint Meeting and subsequent February 2012 meeting of SAMS and SPCS, several topics were discussed in detail. These discussions are summarized in the following sections of this filing.

a. Reporting Entities

Significant discussions were held regarding which registered entities should be required to report the data to NERC. Some participants proposed that Generator Owners and Transmission Owners should supply the data as the protection system asset owners, but this method would create issues regarding which assets to evaluate and how to link the request to transmission performance. Additional issues identified include how to manage the number of reporting entities and duplication of effort for jointly-owned facilities.

To resolve these issues, reduce the resource burden on asset owners, and minimize the number of reporting entities, the Joint Team agreed that the Transmission Planners are the appropriate entities to respond to the Data Request. Each Transmission Planner has established relationships with Generator Owners and Transmission Owners within its planning area. Utilizing these established relationships, rather than requiring reporting by Generator Owners and Transmission Owners, reduces the number of reporting entities to a manageable number while harnessing the coordination provided by the Transmission Planners to eliminate gaps in the analysis and duplication in the data reporting.

b. Voltage Thresholds and Facility Selection Criteria

The Joint Team carefully considered the voltage thresholds to be included in the Data Request. The Joint Team discussed the advantages of limiting the Data Request to facilities operated at voltages 200 kV and above versus including facilities operated at 100 kV and above. Limiting the Data Request to voltages at 200 kV and above mitigates the burden on entities while targeting the voltage levels associated with events discussed in the NERC Advisory and focuses on voltages levels at which a single point of failure is more likely to impact system performance. However, confining the Data Request to only those facilities operated at 200 kV and above may limit understanding of the exposure and potential risk associated with the single point of failure concern. Protection systems on facilities operated at voltages below 200 kV are more likely to have single points of failure. While the reliability risk to system performance typically is less at lower voltage levels, events that originated at voltages below 200 kV have had a significant impact on bulk electric system performance.

To balance the desire for a broader understanding of the single point of failure concern with the additional burden on entities that would result by including all facilities operated at 100 kV and above, the Data Request employs a sampling method that requires the Transmission Planner to qualify certain transmission facilities in its planning area. That method establishes that buses meeting the following criteria will be included in the assessment of potential single points of failure: (1) buses operated at 200 kV or higher with 4 or more circuits; (2) buses operated at 100 kV to 200 kV with 6 or more circuits; (3) buses directly supplying off-site power to a nuclear generating station; and (4) any additional buses the Transmission Planner believes are necessary for the reliable operation of the BPS. NERC believes this proposed sampling method will provide sufficient data to assess the Commission's concern.

c. Fault Types

The Joint Team also considered what type of faults should be included in the Data Request: single-line-to-ground ("SLG") or three-phase (3Ø) faults, as it is not uncommon for a SLG fault to evolve to a multi-phase fault. The Joint Team agreed to use a 3Ø fault because a 3Ø fault represents a credible worst-case system condition that may result from a single point of failure, thereby bounding the potential reliability risk to system performance. Basing the Transmission Planners' studies solely on SLG faults may understate the reliability risk. Additionally, under the NERC Rules of Procedure, NERC is not to collect data or information for requirements of any reliability standard or compliance or enforcement information through a Data Request.[20] Because the Reliability Standards do not specify specific performance criteria for 3Ø faults, this Data Request avoids the collection of data that could be used to assess performance with Reliability Standards. The Joint Team discussed that Transmission Planners already have simulations of Category D contingencies available; and may utilize simulations

[20] Rules of Procedure, Section 1601- Scope of a NERC or Regional Entity Request for Data or Information.

from previous studies to the extent they exist to lessen the burden in their evaluation and collection of the requested data.

d. Performance Measures

The Joint Team specified criteria that avoid collection of compliance information pertaining to existing Reliability Standards. The conditions that require further evaluation include: (1) the loss of synchronism of 2,000 MW or more of generation in the Eastern Interconnection or Western Interconnection, or 1,000 MW or more of generation in the ERCOT or Québec Interconnections, (2) loss of synchronism between two portions of the system, and (3) negatively-damped oscillations.

Tripping generation due to unit instability (loss of synchronism) in excess of the thresholds stated for each interconnection, system separation (loss of synchronism) that results in isolation of a portion of an interconnection, or system oscillations that increase in magnitude (negatively-damped) are indicators of adverse impact to the reliability of an interconnection. These criteria will enable the Transmission Planner to identify system performance indicative of the potential for instability, uncontrolled separation, or cascading outages, without requesting detailed analyses to confirm the extent to which instability, uncontrolled separation, or cascading outages may occur. These indicators are adequate to assess the reliability risk associated with the Commission's concern regarding single points of failure.

e. Protection System Components and Attributes

Extensive Joint Team discussions were held regarding the level of detail to be reported regarding protection systems. Discussion focused on whether to report single points of failure on a composite protection system basis (*i.e.*, only report whether a protection system contains a single point of failure), or whether information should be reported to identify the protection system components on which single points of failure exist. Joint Team members expressed concerns about the reporting burden imposed if the Data Request were to require the identification of every single point of failure on a protection system. The Joint Team then weighed this burden against the need to collect sufficient data to assess whether a further system protection reliability gap exists and needs to be addressed and, if so, to provide information with sufficient detail to develop appropriate and focused measures to address the concern.

To ensure sufficient detail is captured, the Joint Team decided to focus on the five component groups specified in the NERC Glossary of Terms[21] definition of protection system: (1) protective relays, (2) communication systems, (3) AC current and voltage inputs, (4) DC control circuitry, and (5) station DC supplies. Additional guidance for these component groups was added to the Data Request from the NERC SPCS technical report, "Protection System Reliability: Redundancy of Protection System Elements."[22] This additional guidance identifies the attributes that a protection system must contain for each component category to be considered as not having a potential single point of failure. To reduce the burden on respondents, the Joint Team agreed that the purpose of the Data Request is to capture whether a potential single point of failure exists for a given component group; therefore, the joint team specified that the asset owner conducting an assessment of a protection system would only be required to identify the first potential single point of failure discovered for each component group of a protection system.

Additional discussion focused on the station DC supply and whether it is informative to require data for the station DC supply. While the station DC supply is a potential single point of

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[21] Glossary of Terms Used in NERC Reliability Standards. Available at: http://www.nerc.com/files/Glossary_of_Terms.pdf.

[22] *Protection System Redundancy: Redundancy of Protection System Elements*, NERC System Protection and Control Task Force, (November 2008). Available at: http://www.nerc.com/docs/pc/spctf/Redundancy_Tech_Ref_1-14-09.pdf.

failure for many protection systems, the Joint Team discussed that requiring the Transmission Planner to simulate the 3Ø fault test at every bus where redundant station DC supplies are not installed would undermine the other efforts to minimize burden on the entities. Further, the exposure to a single point of failure on the station DC supply is sufficiently mitigated by measures industry already performs including periodic testing and remote monitoring. After further discussion, the Joint Team agreed it would be more informative to report attributes of station DC supplies separately from the other protection system components rather than only reporting whether a potential single point of failure exists. Entities will report for each bus evaluated whether (1) the protection systems include two independent station DC supplies, (2) the protection systems include one station DC supply that is centrally monitored, including alarming for a battery open condition if the station DC supply is a battery, (3) the protection system includes one station DC supply that is centrally monitored, but does not include alarming for a battery open condition if the station DC supply is a battery, or (4) the protection system includes one DC supply that is not centrally monitored.

f. Method

The Joint Team discussed the method by which Transmission Planners would identify the buses at which a single point of failure in a protection system could result in a reliability risk. An iterative process was developed within the Data Request that requires the Transmission Planner to communicate with the Generator Owners and Transmission Owners in its planning area. This process illustrates the statement made during the Technical Conference that transmission planning and protection system engineers currently collaborate regarding protections system characteristics.

A number of commenters expressed concern that inclusion of a prescriptive method in the Data Request unnecessarily increases the burden on entities by precluding alternate methods or the use of existing studies or protection system assessments. Based on a review of industry comments, the Data Request makes clear that entities may use an alternate method or use information from existing studies and assessments of protection systems in developing responses to the Data Request, provided the data is consistent with the intent of the Data Request and consistent with the data that would be developed by using the method in the Data Request. The method and instructions for the reporting template provide clarity to facilitate consistent reporting of data.

g. Schedule and Reporting

The proposed data request requires a high degree of attention and engagement by transmission planners. Considering Transmission Planners' regular duties, the effort required by the Transmission Planners to perform simulations, and to coordinate the necessary evaluations with its Generator Owners and Transmission Owners, the Joint Team established a twenty-four month timeline to complete the Data Request. The Joint Team developed a tiered approach for studies and reporting: (i) entities report receipt of the Data Request within 30 days; (ii) entities submit an interim status report within six months; (iii) entities submit results for facilities operated at 300 kV and above within 12 months; (iv) entities submit results for facilities operated at 200 kV and above and below 300 kV within 18 months; and (v) entities report results for facilities operated at 100 kV and above and below 200 kV within 24 months. This timeline will provide adequate time for the responding entities to complete the required data collection and analysis.

The Joint Team developed a template for each entity to use to assist the Transmission Planner with the Data Request collection structure. The template includes instructions to assist the Transmission Planner in summing and reporting the data provided by each Generator Owner and Transmission Owner in its area. The collected data will be reported by equipment type, voltage class, and protection system component to allow NERC to conduct a more detailed and specific analysis. Protection system data will be categorized for the following equipment types: (1) buses, (2) transmission lines, (3) transmission transformers, (4) generator step-up transformers ("GSUs"), (5) step-down transformers, and (6) shunt devices. Additionally, each category is expanded further to categorize the data by voltage class: (1) ≥100 kV to 200 kV, (2) ≥200 kV to 300 kV, (3) ≥300 kV to 400 kV, (4) ≥400 kV to 600 kV, and (5) ≥600 kV. Data for each applicable protection system will identify the protection system components for which a potential single point of failure exists: (1) protective relays, (2) communication systems, (3) AC current and voltage inputs, and (4) DC control circuitry. As noted above, data will also be reported for the attributes of the station DC supply at each bus evaluated. The template is only a guide; however, each planner is required to electronically submit its data to NERC in a consistent format that ensures NERC is able analyze the data if the planner chooses not to use the template.

iii. Reliability Standard Project 2009-07 Reliability of Protection System

The third process discussed at the Technical Conference to address the directives in Order No. 754 was NERC's Project 2009-07 — Reliability of Protection Systems. This process was proposed as part of a tiered approach to be considered further after review of the RFI and Data Request. Information from the RFI and Data Request may be used to support Project 2009-07, should the Data Request confirm there is a further system protection issue that needs to be addressed through the standard development process. Based on the NERC Standards Committee prioritization process, Project 2009-07 has not yet attained a priority level sufficient to assign industry resources for development. The assignment of priority for Project 2009-07 will be reevaluated following analysis of the responses to the Data Request and the progress of the RFI.

IV. CONCLUSION

NERC respectfully requests submits this informational filing in compliance with Paragraph 20 of Order No. 754.

Respectfully submitted,

/s/ Andrew M. Dressel

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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 15th day of March, 2012.

/s/ Andrew M. Dressel
Andrew M. Dressel

Attorney for the North American Electric Reliability Corporation

EXHIBIT A

Interpretation Request Form 2012-INT-02 TPL-003-0a and TPL-004-0

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Interpretation Request Form

2012-INT-02 TPL-003-0a and TPL-004-0

When completed, email this form to:
laura.hussey@nerc.net

For questions about this form or for assistance in completing the form, call Laura Hussey at 404-446-2579.

Note: A valid interpretation request is one that requests additional clarity about one or more requirements in approved NERC reliability standards, but does not request approval as to how to comply with one or more requirements.

Request for an Interpretation of a Reliability Standard			
Date submitted:	December 12, 2011		
Contact information for person requesting the interpretation.			
Name:	Jonathan Sykes (PG&E), Chairman SPCS		
Organization:	NERC System Protection & Control Subcommittee		
Telephone:	(510) 874-2691	**E-mail:**	jfst@pge.com
Identify the Standard (include version number, e.g., PRC-001-1) that needs clarification and its associated title.			
Standard	**Title**		
TPL-003-0a	System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)		
TPL-004-0	System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)		
Identify specifically what Requirement needs clarification.			
Standard	**Requirement (and text)**		
TPL-003-0a	**R1.3.1** Be performed and evaluated only for those Category C contingencies that		

	would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-003-0a	**R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-003-0a	**R1.5.** Consider all contingencies applicable to Category C.
TPL-004-0	**R1.3.1.** Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-004-0	**R1.3.7.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-004-0	**R1.4.** Consider all contingencies applicable to Category D.

Identify the nature of clarification that is requested (Check as many as applicable).

- ☒ Clarify the required performance
- ☐ Clarify the conditions under which the performance is required
- ☐ Clarify which functional entity is responsible for performing an action in a requirement
- ☐ Clarify the reliability outcome the requirement is intended to produce

Please explain the clarification needed.

This interpretation request has been developed to address Commission concerns related to the term "Single Point of Failure" and how it relates to system performance and contingency planning clarification regarding the following questions about the listed standards, requirements and terms. More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an Industry Advisory — Protection System Single Point of Failure[1] (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

Question 1: For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects[2] of either "stuck breaker" or "protection system failure" contingency[3], or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1[4] requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system response.

Question 2: For the phrase "Delayed Clearing[5]" used in Category C[6] contingencies 6-9 and Category D[7] contingencies 1-4, to what extent does the description in Table 1, footnote (e)[8] require an entity to

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[1] NERC Website: (http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf)

[2] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

[3] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

[4] "*Be performed and evaluated only for those Category (TPL-003-0a Category C and TPL-004-0 Category D) contingencies that would produce the more severe system results or impacts*."

[5] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

[6] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

[7] As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system? There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap. Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design. The lack of clarity is compounded by the similarity between the phrase "Delayed Clearing" used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term "Delayed Fault Clearing." While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to "stuck breaker" or "protection system failure" contingency assessments.
Identify the material impact to your organization or others, if known, caused by the lack of clarity or an incorrect interpretation of this standard.
There is a material impact to the entities required to perform transmission planning assessments and to the entities that may rely on these assessments. The lack of clarity in defining the required studies impacts entities by: • Potential non-compliance if the correct contingencies are not studied • Inefficient use of resources if contingencies are studied that are not required and mitigation plans are implemented that are not required • Potential negative impact to grid reliability if the correct contingencies are not assessed

[8] Footnote (e) Delayed Clearing: "failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,"

EXHIBIT B

Draft Request for Data or Information: Order No. 754 Single Point of Failure on Protection Systems

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Request for Data or Information [DRAFT 2]

Order No. 754 Single Point of Failure on Protection Systems

RELIABILITY | ACCOUNTABILITY



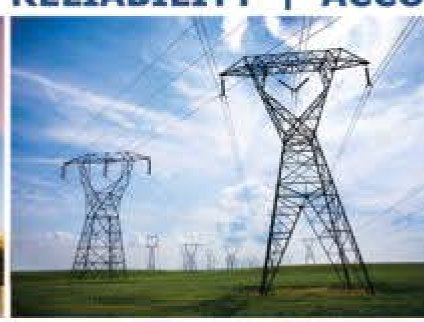


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Table of Contents

Introduction and Survey Scope

In accordance with Section 1600 of the NERC Rules of Procedure,[1] NERC may request data or information that is necessary to meet its obligations under Section 215 of the Federal Power Act, as authorized by Section 39.2(d) of the Federal Energy Regulatory Commission's ("FERC") regulations ("data request"). This is a proposal for such a request.

On September 15, 2011, FERC issued Order No. 754[2] *Interpretation of Transmission Planning Reliability Standard* in which FERC stated that "there is an issue concerning the study of the non-operation of non-redundant primary protection systems e.g., the study of a single point of failure on protection systems."[3] FERC also directed NERC to initiate a process "to explore this reliability concern, including where it can best be addressed, and identify any additional actions necessary to address the matter."[4]

On October 24 and 25, 2011, a Technical Conference on "Single Point of Failure on Protection Systems" was held by FERC that was attended by FERC staff, NERC staff, and several industry subject matter experts from the United States and Canada. At the Technical Conference, three single point of failure events[5] were discussed including an extended discussion of the so-called "Westwing Outage" that occurred in 2004 on the Western Interconnection. NERC staff believes that the prudent approach to address this issue is to first discover the extent and risk involved with single point of failure events. Therefore, NERC staff seeks approval of this Section 1600 data request as the proper approach to determine the risks to the Bulk Electric System ("BES") posed by potential single point of failure events, so that NERC can then develop an appropriate response to address the issue. Accordingly, NERC is issuing this data request in accordance with the requirements of Section 1602.1 of the NERC Rules of Procedure. NERC initially provided this proposed data request to FERC for information on December 14, 2011. NERC previously posted this proposed data request for public comment for a forty-five (45) day comment period. Based on consideration of comments received during the posting NERC has decided to post this proposed data request a second time and provided the revised proposed data request to FERC on ___________. NERC is hereby posting this revised proposed data request for public comment for a second forty-five (45) day comment period. After consideration of comments received, NERC will present this proposed data request to the NERC Board of Trustees for approval, as required by Section 1602 of the NERC Rules of Procedure. Upon NERC Board of Trustees approval, this data request will be issued and become mandatory.

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1 NERC's Rules of Procedure are available at: http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20111117.pdf.

2 *Interpretation of Transmission Planning Reliability Standard*, 136 FERC ¶ 61,186 (http://www.nerc.com/filez/standards/order_754.html)

3 *Ibid*, at P 19 (2011). ("Order No. 754")

4 *Ibid.at P 20 (2011). ("Order No. 754")*

5 In general terms a single point of failure exists when failure of a single component can affect the operation of all protection systems applied on an Element(s). For the purposes of this Request for Data or Information, single point of failure would be reported whenever a protection system component does not meet one of the attributes defined in Table B.

The purpose of this survey is to solicit data and information from each Transmission Planner in the United States, in coordination with Generator Owners, Transmission Owners, and Distribution Providers in its transmission planning area, to identify specific information regarding potential single points of failure on their protection systems in order to determine whether there is a risk to BES reliability.

NERC Contact Information

The survey must be completed in electronic format. Should the submitting entity experience any issues with submitting its data, contact Scott Barfield-McGinnis, Order No. 754 Project Manager via email at Scott.Barfield@nerc.net or by telephone at (404) 446-9689. If any of your entity's responses to this survey are deemed confidential/safeguards, contact the project manager directly for further instructions.

Official correspondence may be mailed to:

NERC – Order No. 754
C/O Scott Barfield-McGinnis, Standards Development Advisor
3353 Peachtree Road, Suite 600, North Tower
Atlanta, GA 08540

Alternate NERC Points of Contact:

Herb Schrayshuen: Herb.Schrayshuen@nerc.net
Phone: (404) 446-2563

Phil Tatro: Phil.Tatro@nerc.net
Phone: (508) 612-1158

Authority

Under Section 215 of the Federal Power Act (16 U.S.C. § 824o), Congress entrusted FERC with the duties of approving and enforcing rules to ensure the reliability of the Nation's bulk power system, and with the duties of certifying an Electric Reliability Organization ("ERO") that would be charged with developing and enforcing mandatory Reliability Standards, subject to FERC approval. NERC was certified as the ERO on July 20, 2006. NERC's authority for issuing this survey is derived from Section 215 of the Federal Power Act, and from the following sources:

NERC is requesting this information in accordance with its authority provided in 18 C.F.R. §39.2(d), which provides:

Each user, owner or operator of the Bulk-Power System within the United States (other than Alaska and Hawaii) shall provide the Commission, the Electric Reliability Organization and the applicable Regional Entity such information as is necessary to implement section 215 of the Federal Power Act as determined by the Commission and set out in the Rules of the Electric Reliability Organization and each applicable Regional Entity. The Electric Reliability Organization and each Regional Entity shall provide the Commission such information as is necessary to implement section 215 of the Federal Power Act.

NERC Rules of Procedure Section 1600 provides:

> ***1601. Scope of a NERC or Regional Entity Request for Data or Information***
> *Within the United States, NERC and regional entities may request data or information that is necessary to meet their obligations under Section 215 of the Federal Power Act, as authorized by Section 39.2(d) of the Commission's regulations, 18 C.F.R. § 39.2(d). In other jurisdictions NERC and regional entities may request comparable data or information, using such authority as may exist pursuant to these rules and as may be granted by ERO governmental authorities in those other jurisdictions. The provisions of Section 1600 shall not apply to requirements contained in any Reliability Standard to provide data or information; the requirements in the Reliability Standards govern. The provisions of Section 1600 shall also not apply to data or information requested in connection with a compliance or enforcement action under Section 215 of the Federal Power Act, Section 400 of these Rules of Procedure, or any procedures adopted pursuant to those authorities, in which case the Rules of Procedure applicable to the production of data or information for compliance and enforcement actions shall apply.*
>
> ***1602. Procedure for Authorizing a NERC Request for Data or Information***
> 1. *NERC shall provide a proposed request for data or information or a proposed modification to a previously-authorized request, including the information specified*

in paragraph 1602.2.1 or 1602.2.2 as applicable, to the Commission's Office of Electric Reliability at least twenty-one (21) days prior to initially posting the request or modification for public comment. Submission of the proposed request or modification to the Office of Electric Reliability is for the information of the Commission. NERC is not required to receive any approval from the Commission prior to posting the proposed request or modification for public comment in accordance with paragraph 1602.2 or issuing the request or modification to reporting entities following approval by the Board of Trustees.

2. *NERC shall post a proposed request for data or information or a proposed modification to a previously authorized request for data or information for a forty-five (45) day public comment period.*
    - 2.1. *A proposed request for data or information shall contain, at a minimum, the following information: (i) a description of the data or information to be requested, how the data or information will be used, and how the availability of the data or information is necessary for NERC to meet its obligations under applicable laws and agreements; (ii) a description of how the data or information will be collected and validated; (iii) a description of the entities (by functional class and jurisdiction) that will be required to provide the data or information ("reporting entities"); (iv) the schedule or due date for the data or information; (v) a description of any restrictions on disseminating the data or information (e.g., "confidential," "critical energy infrastructure information," "aggregating" or "identity masking"); and (vi) an estimate of the relative burden imposed on the reporting entities to accommodate the data or information request.*
    - 2.2. *A proposed modification to a previously authorized request for data or information shall explain (i) the nature of the modifications; (ii) an estimate of the burden imposed on the reporting entities to accommodate the modified data or information request, and (iii) any other items from paragraph 1.1 that require updating as a result of the modifications.*
3. *After the close of the comment period, NERC shall make such revisions to the proposed request for data or information as are appropriate in light of the comments. NERC shall submit the proposed request for data or information, as revised, along with the comments received, NERC's evaluation of the comments and recommendations, to the Board of Trustees.*
4. *In acting on the proposed request for data or information, the Board of Trustees may authorize NERC to issue it, modify it, or remand it for further consideration.*
5. *NERC may make minor changes to an authorized request for data or information without board approval. However, if a reporting entity objects to NERC in writing to*

such changes within 21 days of issuance of the modified request, such changes shall require board approval before they are implemented.

6. *Authorization of a request for data or information shall be final unless, within thirty (30) days of the decision by the Board of Trustees, an affected party appeals the authorization under this Section 1600 to the ERO governmental authority.*

1603. Owners, Operators, and Users to Comply

Owners, operators, and users of the bulk power system registered on the NERC Compliance Registry shall comply with authorized requests for data and information. In the event a reporting entity within the United States fails to comply with an authorized request for data or information under Section 1600, NERC may request the Commission to exercise its enforcement authority to require the reporting entity to comply with the request for data or information and for other appropriate enforcement action by the Commission. NERC will make any request for the Commission to enforce a request for data or information through a non-public submission to the Commission's enforcement staff.

Survey

Description

The survey seeks to identify Elements[6] within each transmission planning area on which a three-phase fault accompanied by a protection system failure could result in a potential reliability risk. The following items will be reported in accordance with the data reporting template:[7]

- Statistics concerning the buses evaluated
- Statistics concerning the attributes of the protection system(s) associated with each identified Element
- Statistics concerning the attributes of the station DC supply at selected buses in each transmission planning area

Method

The Transmission Planner and the Generator Owners, Transmission Owners, and Distribution Providers within the Transmission Planner's planning area may follow the specific steps below as their method for creating the statistics associated with this data request. Entities may use an alternate method, including combining steps, skipping steps, or reordering steps, to minimize burden based on their particular circumstances, and may use information from existing studies (e.g., Category D simulations from transmission planning assessments) and existing assessments of protection systems in developing responses to the data request.

The method will produce two lists of buses. The first list ("List of Buses to be Tested") will be the complete set of buses which meet the Criteria in Table A, "Criteria for Buses to be Tested." The second list ("List of Buses to be Evaluated") will be a subset of the first, and will contain all of the buses from the first set, which have both of the following characteristics.

- The bus has at least one Element for which the protection system does not fully meet the redundancy attributes for all component categories of Table B, "Protection System Attributes to be Evaluated."

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6 Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.

7 The data request reporting template is provided with the data request as a tool to assist the Transmission Planner and will not be used to submit actual data. NERC will issue further guidance on the method of reporting.

- Planning studies simulating a three phase fault, show that clearing times resulting from a single point failure of a least one protection system on an Element connected to that bus will result in system performance exhibiting one of the adverse impacts identified in Table C, "Performance Measures."

The Protection Systems for all circuits on the second bus set will be analyzed per step 9 of the method.

Entities that follow an alternate method or utilize existing studies and existing assessments of protection systems in developing responses must assure that the data provided is consistent with the data (in form and substance) that would be developed by using the following method.

1. Each Transmission Planner will develop a "List of Buses to be Tested," including each bus[8] in its transmission planning area that meets the criteria in Table A, "Criteria for Buses to be Tested."
2. Each Transmission Planner will coordinate with Generator Owners, Transmission Owners, and Distribution Providers in its transmission planning area to identify the following:
   - Transformers with through-fault protection[9] that have at least one winding connected at a bus to be tested.
   - Any bus from the list developed in step 1, that can be excluded from testing on the basis that the protection system(s) for all Elements connected to the bus and for the physical bus(es),[10] if any, meet the attributes for all categories of components in Table B, "Protection System Attributes to be Evaluated," based on the Generator Owner's, Transmission Owner's or Distribution Provider's knowledge of the protection system(s). Each Transmission Planner will create an initial "List of Buses to be Evaluated" by removing from the ""List of Buses to be Tested," any buses identified in step 2.
3. Each Transmission Planner will simulate a three-phase fault on each bus in its transmission planning area on the "List of Buses to be Tested" as revised in step 2. The three-phase fault is simulated based on the following parameters:

[8] For the purposes of this testing, all bus configurations will be treated as a straight bus (single-breaker) configuration. For example, a fault simulated on a ring bus configuration is modeled as though the fault is on a straight bus, and not on the terminals of any of the elements connected in the ring bus configuration. A fault simulated on a breaker-and-a-half configuration is modeled as though the two buses are a single straight bus.

[9] Through-fault protection is applied to protect a transformer from the effects of through-fault current for a fault external to the transformer. In the context of this data request, a transformer differential protection zone that overlaps the bus on which the fault is simulated is considered to not provide through-fault protection. Through-fault protection must also be capable of detecting faults on adjacent elements outside the transformer differential zone.

[10] To be excluded from testing, the protection systems must be evaluated for all Elements connected to the "bus" as defined in step 1, as well as the protection systems for the physical bus(es), if any (e.g., the physical buses in a breaker-and-a-half configuration).

- Simulations will be based on case(s) used to perform the most recent annual transmission assessment representing stressed system conditions (e.g., load level and transfer levels) that will likely produce the most conservative results based on past studies or engineering judgment.
- Trip the remote terminals of all transmission lines connected to the faulted bus based on the maximum expected remote clearing time provided by the Generator Owner, Transmission Owner, or Distribution Provider.
- For each transformer connected to the faulted bus that is protected by through-fault protection, the Transmission Planner will trip the transformer based on the maximum expected clearing time provided by the Generator Owner, Transmission Owner, or Distribution Provider.
- For each transformer connected to the faulted bus that is not protected by through-fault protection, the Transmission Planner will not trip the transformer or any Element connected to the other terminal(s) of the transformer not connected to the faulted bus.
- Simulation durations will be long enough to confirm whether system performance exhibits one or more of the adverse impacts identified in Table C, "Performance Measures."
- Evaluate the system response for each simulated fault against the criteria in Table C, "Performance Measures."

4. Each Transmission Planner will revise its initial "List of Buses to be Evaluated" developed in step 2, by removing any buses at which the simulated performance in step 3 does not exhibit any of the adverse impacts identified in Table C, "Performance Measures," and inform each Generator Owner, Transmission Owner, and Distribution Provider of each of its buses on this initial "List of Buses to be Evaluated."
5. The Generator Owner, Transmission Owner, and Distribution Provider will evaluate its protection system(s) at each bus on the "List of Buses to be Evaluated," developed by the Transmission Planner in step 4. The Generator Owner, Transmission Owner, and Distribution Provider will identify and inform the Transmission Planner of any bus at which the protection system(s) for all Elements connected to the bus and for the physical bus(es), if any, meet the attributes for all categories in Table B, "Protection System Attributes to be Evaluated."
6. The Transmission Planner will revise the "List of Buses to be Evaluated" by removing the buses identified in step 4 at which the protection system(s) for all Elements connected to the bus and for the physical bus(es), if any, meet the attributes for all categories in Table B, "Protection System Attributes to be Evaluated."

7. The Transmission Planner will consult with the Generator Owner, Transmission Owner, and Distribution Provider regarding actual clearing times[11] for all Elements that will trip for a fault on each bus identified on the "List of Buses to be Evaluated" as revised in step 6.
8. The Transmission Planner will simulate a three-phase fault, on each bus identified on the "List of Buses to be Evaluated" as revised in step 6, using the actual clearing times provided by the Generator Owner, Transmission Owner, and Distribution Provider[12] in accordance with the method described in step 4, except that actual clearing times will be used in place of tripping Elements based on the maximum expected clearing time.
9. The Transmission Planner will update the "List of Buses to be Evaluated" that was revised in step 6, by removing from the list each bus at which the simulated system performance in step 8 does not exhibit any of the adverse impacts identified in Table C, "Performance Measures," and provide this final "List of Buses to be Evaluated" to each respective Generator Owner, Transmission Owner, and Distribution Provider.
10. The Generator Owner, Transmission Owner, and Distribution Provider will review documentation for its protection system(s) for each Element connected to each bus on the final "List of Buses to be Evaluated" and the physical bus(es), if any, and provide information to the Transmission Planner necessary for the Transmission Planner to complete the data request reporting template. This data includes:
    - For each bus evaluated in step 9, whether the protection systems meet each of the attributes listed in Table B, "Protection System Attributes to be Evaluated," for each protection system component category.
    - The attributes of the station DC supply listed in Table D, "Station DC Supply Attributes to be Reported," for each bus that meets the criteria in Table A, "Criteria for Buses to be Evaluated."
11. The Transmission Planner will provide the following information in accordance with the data request reporting template.[13]

- Statistics concerning the buses evaluated

[11] Simulate clearing based on whatever remote protection would operate for the bus fault. Do not simulate operation of any local protection unless the only single point of failure for protection systems on all Elements connected to the bus and the physical bus(es), if any, is a single trip coil and local breaker failure protection is provided, in which case operation of the breaker failure protection may be modeled. In some cases, an element may not trip at its remote terminals if the Protection System at those terminals will not detect the fault. In such cases, the fault will remain un-cleared in the simulation.

[12] By mutual agreement with the Transmission Owners and Generator Owners, the Transmission Planner may combine steps 3 through 6 by testing all buses on the List of Buses to be Tested developed in step 2, using actual clearing times provided by the Generator Owner, Transmission Owner, and Distribution Provider.

[13] Data reporting will be facilitated through a web-based application based on the data request reporting template provided with the data request. The accompanying template is unofficial and intended to assist the Transmission Planner. NERC will issue instructions on the method of reporting consistent with the reporting schedule.

- Statistics concerning the attributes of the protection system(s) associated with each identified Element
- Statistics concerning the attributes of the station DC supply at selected buses in each transmission planning area

Table A: Criteria for Buses to be Tested
Buses operated at 200 kV or higher with 4 or more circuits
Buses operated at 100 kV to 200 kV with 6 or more circuits
Buses directly supplying off-site power to a nuclear generating station
Any additional buses the Transmission Planner believes are necessary for the reliable operation of the bulk power system

Notes:

1. For the purpose of applying Table A, circuits include transmission lines, transmission transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher, and generator step-up transformers connecting generating resources with gross nameplate rating greater than 20 MVA.
2. For the purpose of applying Table A, a radial line is not counted as a circuit if the only Elements connected to the line are transformers that step-down to a voltage below 100 kV.
3. The number of circuits includes BES and non-BES Elements.

Table B: Protection System Attributes to be Evaluated
Protective Relays: The protection system includes two independent protective relays that are used to measure electrical quantities, sense an abnormal condition such as a fault, and respond to the abnormal condition.
Communication Systems: The protection system includes two independent communication channels and associated communication equipment when such communication between protective relays for communication-aided protection functions (i.e., pilot relaying systems) is needed to satisfy BES performance required in the TPL standards.
AC Current and Voltage Inputs: The protection system includes two independent AC current sources and related inputs, except that separate secondary windings of a free-standing current transformer (CT) or multiple CTs on a common bushing can be used to satisfy this requirement; and includes two independent AC voltage sources and related inputs, except that separate secondary windings of a common capacitance coupled voltage transformer (CCVT), voltage transformer (VT), or similar device can be used to satisfy this requirement.
DC Control Circuitry: The protection system includes two independent DC control circuits with no common DC control circuitry, auxiliary relays, or circuit breaker trip coils.

Notes:

1. For the purpose of applying Table B, "independent" components indicates that a single point of failure on either component will not prevent protection system operation, except as noted in the table.
2. Physical separation of protection system components is not necessary for protection system components to be reported as independent.

Table C: Performance Measures
1. Loss of synchronism of generating units totaling greater than 2,000 MW or more in the Eastern Interconnection or Western Interconnection, or 1,000 MW or more in the ERCOT or Québec Interconnections
2. Loss of synchronism between two portions of the system
3. Negatively damped oscillations

Table D: Station DC Supply Attributes to be Reported
The protection system includes two independent station DC supplies
The protection system includes one DC supply that is centrally monitored, including alarms for both low voltage and a battery open condition if the station DC supply is a battery
The protection system includes one DC supply that is centrally monitored, but does not include alarms for both low voltage and a battery open condition if the station DC supply is a battery
The protection system includes one DC supply that is not centrally monitored

Notes:

1. A station DC supply includes one station battery and charger, or other single DC source that is used for powering the protection systems and used for tripping. The station DC supply does not include the DC distribution panels; the distribution panels are part of the DC control circuitry.
2. For the purpose of applying Table D, a "centrally monitored" station DC supply is one for which alarms are reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated.

Rationale

Voltage Thresholds and Facility Selection Criteria

To balance the need for a broader understanding of the single point of failure concern against the potential burden on entities that would result by including all facilities operated at 100 kV or higher, the sampling method described in Table A, "Criteria for Buses to be Tested" is used to limit the buses to be tested to a representative sample of buses operated at 100 kV or higher. This results in an expedient approach by providing data from a representative sample of buses at all voltage levels on the bulk power system. The sampling criteria are focused on identifying buses for testing at which a single point of failure may have greater potential for adversely impacting system reliability. The criteria include the relative system strength at the bus (using the number of circuits connected that provide more than a nominal fault current contribution as a surrogate for the system strength) and whether the bus directly supplies off-site power to a nuclear plant.

Although the system events for which NERC event analysis has identified a protection system single point of failure was causal or contributory have been limited to Elements operated at 200 kV or higher, it is possible that a reliability risk may exist for Elements operated below 200 kV. It would be difficult to extrapolate the assessment results for Elements operated at 200 kV or higher to be representative of those for Elements operated below 200 kV because of differences in protection system design attributes and transmission system characteristics. The impact to bulk power system reliability associated with delayed fault clearing at voltages below 200 kV is expected to be less severe because of higher system impedance and more extensive use of remote backup protection; however, single points of failure on a protection system are more likely to exist on Elements operated below 200 kV. Significant impact to bulk power system performance has occurred for events that originated at voltages below 200 kV and some entities have identified reliability concerns through system studies of single points of failure for certain Elements operated below 200 kV.

Protection System Components and Attributes

The protection system components of interest include components whose failure could result in delayed clearing of a fault due to a protection system single point of failure. For the purpose of this data request, protection system components include those components identified in the NERC glossary definition of Protection System[14] as qualified in the System Protection and Control Task Force (SPCTF) technical paper,[15] Protection System Reliability. The distinctions in the SPCTF technical paper more accurately describe and define the components to be evaluated in the context of single point of failure than the term Protection System.

An alternative approach to limit the scope to the relay types listed in TPL-001-2[16] for the Table 1, contingency P5, is considered to restrict the components such that the data request would not identify all potential Westwing-type events.[17] Although the data used to support the NERC Industry Alert was based on failures of auxiliary relays and lockout relays, it is not reasonable to rule out the potential for a failure of other protection system components. Requesting information regarding each protection system component will provide sufficient data to assess whether there is a further system protection issue that needs to be addressed and, if so, to provide information with sufficient detail to develop appropriate and focused measures to address the concern.

Performance Measures

The performance measures in the data request are based on the characteristics of events that could adversely impact system reliability similar to the Westwing event. The performance measures identified in the data request include: (1) the loss of synchronism of 2,000 MW or more of generation in the Eastern Interconnection or Western Interconnection, or 1,000 MW or

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[14] NERC Glossary term "Protection System" approved by FERC on 02/03/2012. (http://www.nerc.com/files/Glossary_of_Terms.pdf)

[15] Protection System Reliability – Redundancy of System Protection Elements, NERC System Protection and Control Task Force (SPCTF), November 2008. (http://www.nerc.com/docs/pc/spctf/Redundancy_Tech_Ref_1-14-09.pdf)

[16] NERC Reliability Standard, TPL-001-2, adopted by the NERC Board of Trustees on August 4, 2011, filed with FERC for approval on October 19, 2011. (http://www.nerc.com/files/Final_TPL-001-2%20Petition_20111019_complete.pdf)

[17] The Westwing disturbance resulted in resulting in the loss of approximately 5,000 MW of generation and the potential for collapse of the Western Interconnection. Additional information on this issue can be found in the NERC Industry Alert, ***Protection System Single Points of Failure***. (http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf)

more of generation in the ERCOT or Québec Interconnections, (2) loss of synchronism between two portions of the system, and (3) negatively-damped oscillations.

Tripping generation due to unit instability (loss of synchronism) in excess of the thresholds stated for each interconnection, system separation (loss of synchronism) that results in isolation of a portion of an interconnection, or system oscillations that increase in magnitude (negatively-damped) are indicators of adverse impact to the reliability of an interconnection. These criteria will enable the Transmission Planner to identify system performance indicative of the potential for instability, uncontrolled separation, or cascading outages, without requesting detailed analyses to confirm the extent to which instability, uncontrolled separation, or cascading outages may occur. These indicators are adequate to assess the reliability risk associated with single points of failure.

Simulation Fault Type

Limiting the data request to a three-phase fault provides a conservative method to identify potential Westwing-type events. Although conservative, this method is appropriate in that single-line-to-ground (SLG) faults with delayed clearing can evolve to a multi-phase fault. Basing studies solely on SLG faults may understate the reliability risk and simulating three-phase faults represents a credible worst-case system condition that may result from a single point of failure, thereby bounding the potential reliability risk to system performance. Simulating a three-phase fault from inception allows Transmission Planners to use existing simulations of a three-phase fault with protection system failure (TPL-004-0, Category D[18]) and eliminates conjecture as to the timing and mechanism by which a SLG fault may evolve to a multi-phase fault.

Additionally, under the NERC Rules of Procedure, NERC is not to collect data or information for requirements of any reliability standard or compliance or enforcement information through a data request. Because the reliability standards do not specify specific performance criteria for three-phase faults, this data request avoids the collection of data that could be used to assess performance with reliability standards.

Use of Data

The data collected will be used to address the FERC directive to identify whether there is a further system protection issue that needs to be addressed and, if so, what priority it should be accorded relative to other reliability initiatives planned by NERC. If there is a further issue that

[18] NERC Reliability Standard, TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Effective June 18, 2007 (http://www.nerc.com/files/TPL-004-0.pdf)

needs to be addressed, the data collected will be used to qualify the extent of the risk and to identify appropriate and focused measures to address the concern.

This data request has been developed to establish an effective and efficient means to identify whether a reliability concern exists regarding potential single points of failure on protection systems, while limiting the burden on registered entities. Though this approach is expedient for identifying whether a reliability concern exists, an additional data request or additional analysis may be required to quantify the extent of the risk.

Entities Required to Comply

The entity responsible for coordinating the fulfillment of the data request will be the Transmission Planner. Because planning staff and protection staff may not be in the same company or business unit, this request requires the cooperation of the Generator Owners, Transmission Owners, and Distribution Providers in a Transmission Planner's area. Generator Owners, Transmission Owners, and Distribution Providers must comply with requests for assistance from the Transmission Planners.

Identifying the risk of a Westwing-type event requires information regarding both the susceptibility of the system to adverse performance if a protection system single point of failure occurs and determining where the protection systems contain single points of failure. This requires participation by Transmission Planners, Generator Owners, Transmission Owners, and Distribution Providers. Since the inquiry is related to an approved interpretation of TPL-002-0b the Transmission Planner has been designated as the responsible entity; however, Generator Owners, Transmission Owners, and Distribution Providers are required to support development of the responses to the data request.

Schedule and Reporting

The completion of this survey and submission to NERC is due within twenty-four (24) months beginning the first day of the first month following NERC Board of Trustees approval and requires periodic reporting as defined in the following table. The reporting portal will be open during the period so data can be submitted as soon as it is available, and to allow entities to update previously reported data as necessary through the end of each reporting period.

Scheduled Reporting[19]	
End of 1st month	Transmission Planners must acknowledge the request for data
End of 6th month	Transmission Planners must submit a status report stating percent of work complete
End of 12th month	Transmission Planners must report data for buses operated at 300 kV or higher
End of 18th month	Transmission Planners must report data for buses operated at 200 kV or higher and below 300 kV
End of 24th month	Transmission Planners must report data for buses operated at 100 kV or higher and below 200 kV

Dissemination of Data

Some of the requested information will contain Confidential Information as that term is defined by Section 1501 of the NERC Rules of Procedure. As such, NERC will handle that data in accordance with Sections 1500 and 1605 of the NERC Rules of Procedure. **Submitting entities are encouraged to mark all confidential or critical energy infrastructure information as instructed in Section 1502.1 of the NERC Rules of Procedure to ensure that all sensitive information will be protected.**

Burden to Entities

The burden of responding to this data request will vary from entity to entity. The most significant factor will be the number of Elements within a Transmission Planner's area or owned by a Generator Owner, Transmission Owner, or Distribution Provider. A secondary factor will be the extent to which entities are able to use information from existing studies (e.g., Category D simulations from transmission planning assessments) and existing assessments of protection systems in developing responses to the data request. Estimates are provided of the time required to perform analysis and respond to the data request.

The method defined in this data request has been developed to limit the burden on entities while assuring the data collected is sufficient to address the potential reliability risk identified in Order No. 754. Time estimates are based on an assumption that entities follow the method provided in the data request. Entities are not required to follow this method and may use an alternate method, including combining steps, skipping steps, or reordering steps, to minimize burden based on their particular circumstances, provided that the data submitted is consistent

[19] Periods are referenced from the first day of the first month following NERC Board of Trustees approval of the data request.

(in form and substance) with the data that would be developed by using the method in the data request.

Transmission Planners

The burden on Transmission Planners will be similar to the effort to simulate Category D contingencies in accordance with TPL-004-0.[20] In some cases, the Transmission Planner may have simulations from past studies that can be used to support this effort; however, that will depend on a number of factors including the extent to which three-phase faults with protection system failure have been performed and evaluated as part of those Category D contingencies that would produce the more severe system results or impacts.

The request will necessarily require coordination and cooperation between planning staff and protection staff. The planning and protection engineers that will need to conduct the studies and submit the data will often be working for different companies or business units. Therefore, time has been included in the estimated burden to accommodate data requests that cross company or business unit lines.

Identification of buses that meet Table A, "Criteria for Buses to be Tested" (Step 1): The estimated time is 8-24 engineer-hours. The time required for this step will vary according to the number of buses in the transmission planning area.

Initial Screening Testing (Step 3): The estimated time is 2 engineer-hours per bus. The time required for this step will vary based on the number of buses tested as some economy of scale is anticipated. The number of buses for which testing is required will depend on the number of buses eliminated in step 2 and the number of buses for which the Transmission Planner may use information from existing studies.

Testing Using Actual Clearing Times (Step 7): The estimated time is 3 engineer-hours per bus. The time required for this step will vary based on the number of buses tested as some economy of scale is anticipated. The number of buses for which testing is required will depend on the number of buses eliminated in step 5 and the number of buses for which the Transmission Planner may use information from existing studies.

Data Submittal (Step 10): The estimated time is 8-24 engineer-hours. The time required for this step will vary according to the number of buses in the transmission planning area.

[20] NERC Reliability Standard, TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

Generator Owners, Transmission Owners, and Distribution Providers

The burden on Generator Owners, Transmission Owners, and Distribution Providers to support this effort will include time to provide fault clearing times to Transmission Planners and to review protection system documentation to assess where single points of failure may exist. The method defined in this data request also has been developed to limit the burden on Generator Owners, Transmission Owners, and Distribution Providers by grouping the components for which protection system(s) must be evaluated and by only requiring entities to identify whether single points of failure exist in each component category, rather than documenting all single points of failure. Generator Owners, Transmission Owners, and Distribution Providers are required to evaluate the protection system(s) only for locations on the system for which the Transmission Planner has identified that a protection system failure could result in a potential reliability risk. The burden will vary depending on factors such as how recently each protection system was installed or modified and availability of past assessments of protection systems. For more recent installations or modifications there may be less work involved as entities will be more familiar with the protection system design and may require limited documentation review. Older installations may require more time to review documentation to identify where single points of failure exist.

<u>Initial Screening and Identification of Transformers with Through-Fault Protection (Step 2)</u>: The estimated time is 8-24 engineer-hours. The time required for this step will vary according to the number of buses owned by the entity, as well as the extent to which standard designs are used on the entity's system.

<u>Provide Maximum Expected Fault Clearing Times (Step 3)</u>: The estimated time is 0.5 engineer-hour per bus. The time required for this step will vary according to the number of buses to be evaluated, as well as the extent to which standard designs are used on the entity's system. The number of buses will depend on the number of buses eliminated in step 2.

<u>Review Protection System Documentation (Step 4)</u>: The estimated time is 2 engineer-hours per bus. The time required for this step will vary depending on the number of buses to be evaluated, availability of past assessments, the extent to which standard designs are used on the entity's system, and the age and voltage class of the installation. The number of buses to be evaluated will depend on the number of buses eliminated in step 3. The time required for a bus may be significantly less than 2 engineer-hours if a single point of failure is identified early in the review. The time required for a bus may be significantly more that 2 engineer-hours if no single points of failure are identified.

<u>Provide Actual Fault Clearing Times (Step 6)</u>: The estimated time is 1 engineer-hour per bus.

The time required for this step will vary according to the number of buses to be evaluated, as well as the extent to which standard designs are used on the entity's system. The number of buses for which clearing times are required will depend on the number of buses eliminated in step 5.

Review Protection System Documentation (Step 9): The estimated time is 4 engineer-hours per bus. The time required for this step will vary depending on the number of buses to be evaluated, availability of past assessments, the extent to which standard designs are used on the entity's system, and the age and voltage class of the installation. The number of buses to be evaluated will depend on the number of buses eliminated in step 8. If the bus was reviewed in step 4 and no single points of failure were identified it is not necessary to repeat the review in step 9; if a single point of failure was identified it is necessary to complete the review in step 9.

Organization Information and Approval

Transmission Planning Entity Contact Information			
Entity Name:			
Contact Name:		Office Phone:	
Title:		Cell Phone:	
Email:		NERC ID:	

Approval

To the best of my knowledge, the information provided in the response to this survey is correct.

Supervisor approving this survey:[21]

Name:

Date:

Title:

[21] This approval should be completed by a company employee, consistent with the entities' process and authorized persons for submitting such data.

Appendix 1 – Examples[22]

Example Illustrating Application of the Method

Step 1: A Transmission Planner identifies that it has 800 buses operated at 100 kV or higher as follows:

115 kV	465
138 kV	20
161 kV	15
230 KV	290
500 kV	10
Total	800

Of these 800 buses, 522 meet the criteria in Table A for "Criteria for Buses to be Evaluated." The number of buses on the "List of Buses to be Tested" developed in step 1 are:

115 kV	240
138 kV	12
161 kV	10
230 KV	250
500 kV	10
Total	522

Step 2: After coordinating with its Generator Owners, Transmission Owners, and Distribution Providers, the Transmission Planner is able to eliminate 147 buses based on the asset owners' knowledge of their protection systems confirming that the protection systems for the Elements connected to the buses and for the physical bus(es), if any, meet the attributes for all categories of components in Table B, "Protection System Attributes to be Evaluated." The numbers of buses on the initial "List of Buses to be Evaluated" developed in step 2 are:

115 kV	220
138 kV	10
161 kV	8
230 KV	132
500 kV	5
Total	375

[22] These examples are provided only for illustrative purposes and e not indicative of the expected number of buses or protection systems that may meet the criteria and attributes defined in this Request for Data or Information.

Steps 3 and 4: The Transmission Planner simulates a three-phase fault on each of these buses as defined in step 3 and identifies that for 215 buses the simulated system performance based on maximum expected remote clearing times does not exhibit any of the adverse impacts identified in Table C, "Performance Measures." The "List of Buses to be Evaluated" is revised by removing these buses and the numbers of buses remaining are:

115 kV	55
138 kV	5
161 kV	3
230 KV	92
500 kV	5
Total	160

Steps 5 and 6: The Generator Owner, Transmission Owner, and Distribution Provider review protection systems at the buses remaining on the "List of Buses to be Evaluated" and identify that 95 of the buses have at least one Element connected for which the protection does not meet the attributes in Table B, "Protection System Attributes to be Evaluated." The numbers of buses on the "List of Buses to be Evaluated" is further reduced as follows:

115 kV	45
138 kV	4
161 kV	2
230 KV	42
500 kV	2
Total	95

Steps 7, 8, and 9: The Transmission Planner obtains actual clearing times and simulates a three-phase fault on each of these buses as defined in step 8 and identifies that for 30 buses the simulated system performance based on actual clearing times does not exhibit any of the adverse impacts identified in Table C, "Performance Measures." The "List of Buses to be Evaluated" is revised by removing these buses and the numbers of buses in the final "List of Buses to be Evaluated" are:

115 kV	28
138 kV	2
161 kV	1
230 KV	32
500 kV	2
Total	65

Step 10: The Generator Owner, Transmission Owner, and Distribution Provider that own Elements connected to any of the buses identified in the final "List of Buses to be Evaluated"

assess the protection system attributes for each component category in Table B, “Protection System Attributes to be Evaluated.” The Generator Owner, Transmission System Owner, and Distribution Provider also evaluate the station DC supply for each bus on the “List of Buses to be Tested.”

Step 11: The Transmission Planner reports the data. An excerpt is provided in the following table of the data the Transmission Planner in this example would report on the Buses Evaluated tab.

Figure 1-1 – Example Data Reported on the Buses Evaluated Tab

Buses Evaluated						
		≥100 kV - <200 kV	≥200 kV - <300 kV	≥300 kV - <400 kV	≥400 kV - <600 kV	≥ 600 kV
1.	Total number of buses in the transmission planning area:	500	290	0	10	0
2.	Total number of buses in the transmission planning area that meet the criteria in Table A, "Initial Criteria for Buses to be Tested":	262	250	0	10	0
3.	Total number of buses evaluated by the Transmission Planner based on actual clearing times:	51	42	0	2	0
4.	Total number of buses evaluated by the Transmission Planner based on actual clearing times that resulted in system performance exhibiting any adverse impact defined in Table C, "Performance Measures":	31	32	0	2	0
5.	Comments:					

Example Application of the Criteria in Table A

The following figures provide examples of applying the criteria in Table A to determine the initial "List of Buses to be Tested."

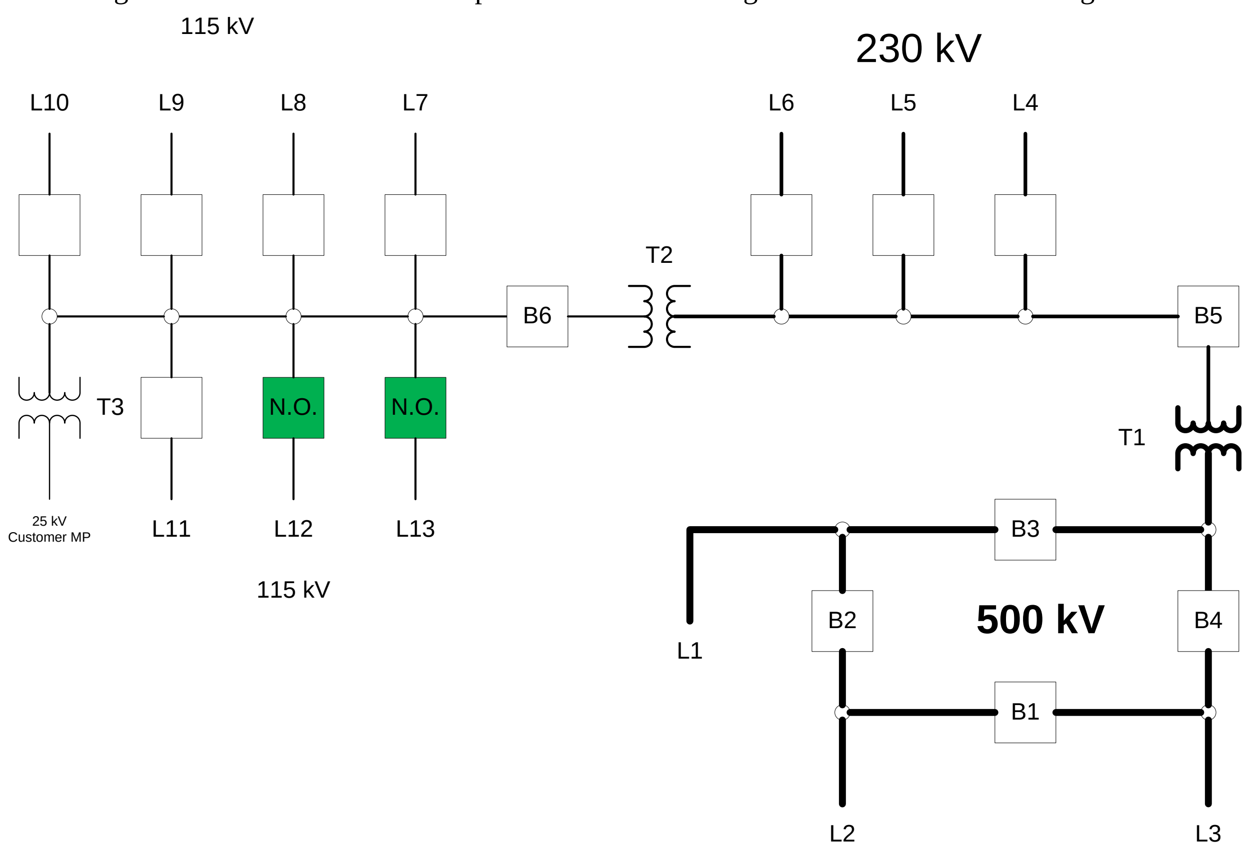
In Figure 1-2, the Transmission Planner would include the 115 kV, 230 kV and 500 kV buses on the "List of Buses to be Tested."

The 115 kV bus has five transmission lines (L7 through L11) and one 230/115 kV transformer (T2) connected; a total of six circuits connected at 115 kV which meets the second criterion in Table A. Note that for the purpose of applying Table A the normally open transmission lines L12 and L13 and the 115/25 kV step-down transformer do not qualify as circuits.

The 230 kV bus has three transmission lines (L4 through L6), one 500/230 kV transformer (T1), and one 230/115 kV transformer (T2) connected; a total of five circuits connected at 230 kV which meets the first criterion in Table A.

The 500 kV bus has three transmission lines (L1 through L3) and one 500/230 kV transformer (T1) connected; a total of four circuits connected at 500 kV which meets the first criterion in Table A.

Figure 1-2 – Table A Example with Two Straight-Buses and One Ring Bus



In Figure 1-3, the Transmission Planner would include the 345 kV and 138 kV buses on the left side of the figure would be excluded from the “List of Buses to be Tested.” The 345 kV and 138 kV buses on the right side of the figure would be excluded.

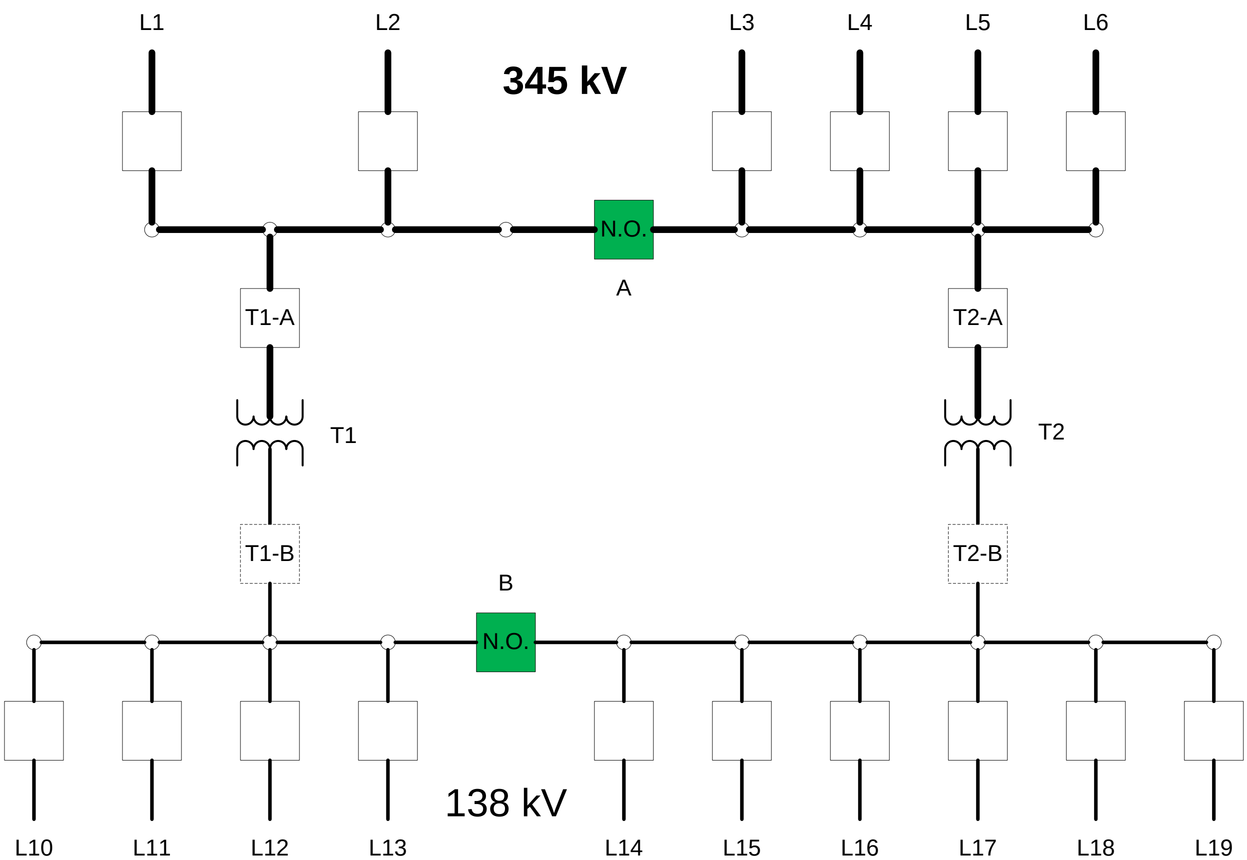
The 345 kV bus on the left has two transmission lines (L1 and L2) and one 345/138 kV transformer (T1) connected; a total of three circuits connected at 345 kV which does not meet any criterion in Table A.

The 345 kV bus on the right has four transmission lines (L3 through L6) and one 345/138 kV transformer (T2) connected; a total of five circuits connected at 345 kV which meets the first criterion in Table A.

The 138 kV bus on the left has four transmission lines (L10 through L13) and one 345/138 kV transformer (T1) connected; a total of five circuits connected at 138 kV which does not meet any criterion in Table A.

The 138 kV bus on the right has six transmission lines (L14 through L19) and one 345/138 kV transformer (T2) connected; a total of seven circuits connected at 138 kV which meets the first criterion in Table A.

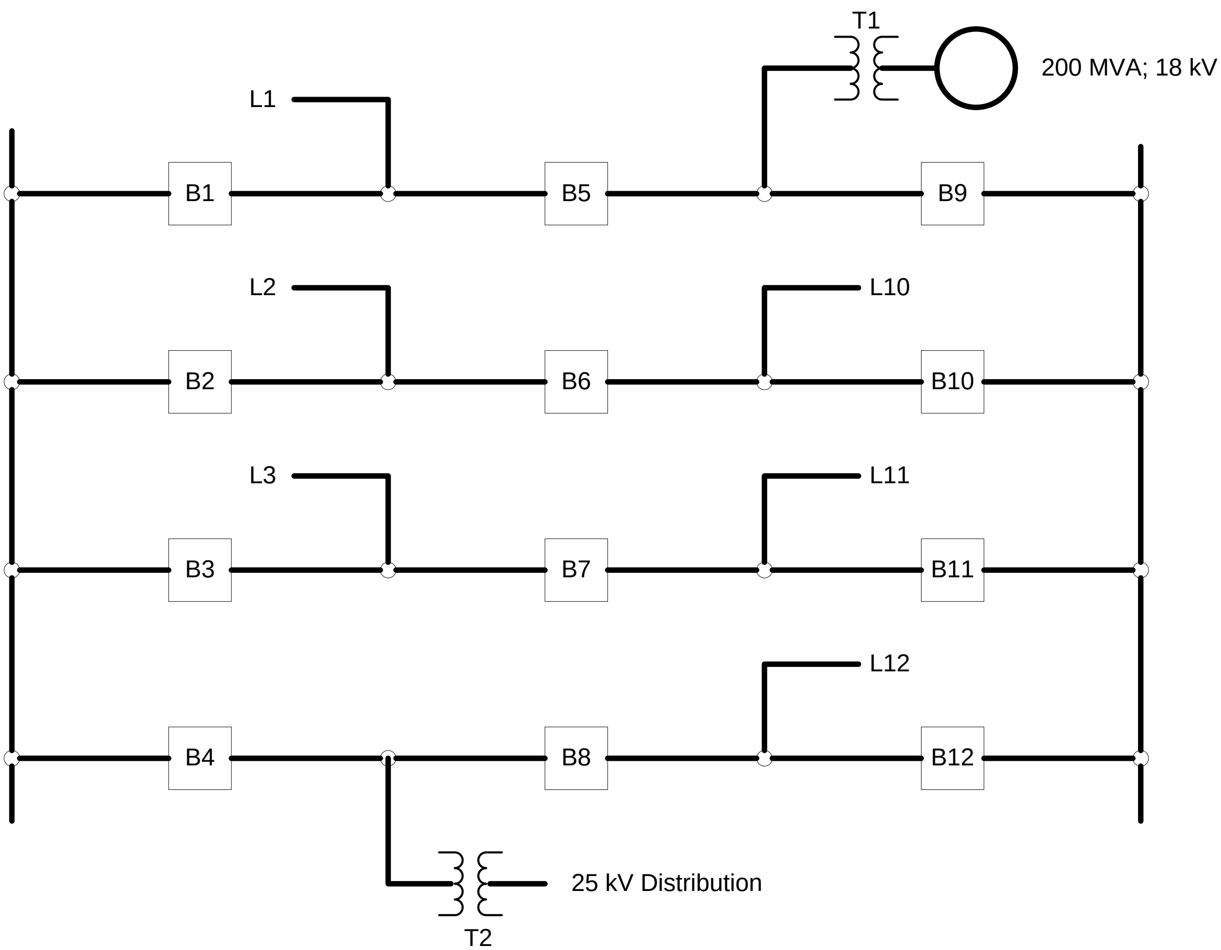
Figure 1-3 – Table A Example with Straight-Buses and Normally Open Bus-Ties



In Figure 1-4, the Transmission Planner would include the bus on the “List of Buses to be Tested,” as long as the bus voltage is 100 kV or higher.

The bus has six transmission lines (L1 through L3 and L10 through L12) and one generator step-up (GSU) transformer (T1) connected; a total of seven circuits connected at 100 kV or higher which meets the first or second criterion in Table A depending on the voltage. Note that for the purpose of applying Table A the step-down transformer does not qualify as a circuit. Also note that the generator step-up transformer qualifies as a circuit because the generator is greater than 20 MVA. If the generator gross nameplate rating was 20 MVA or less, the GSU transformer would not qualify as a circuit.

Figure 1-4 – Table A Example with a Breaker-and-a-Half Bus

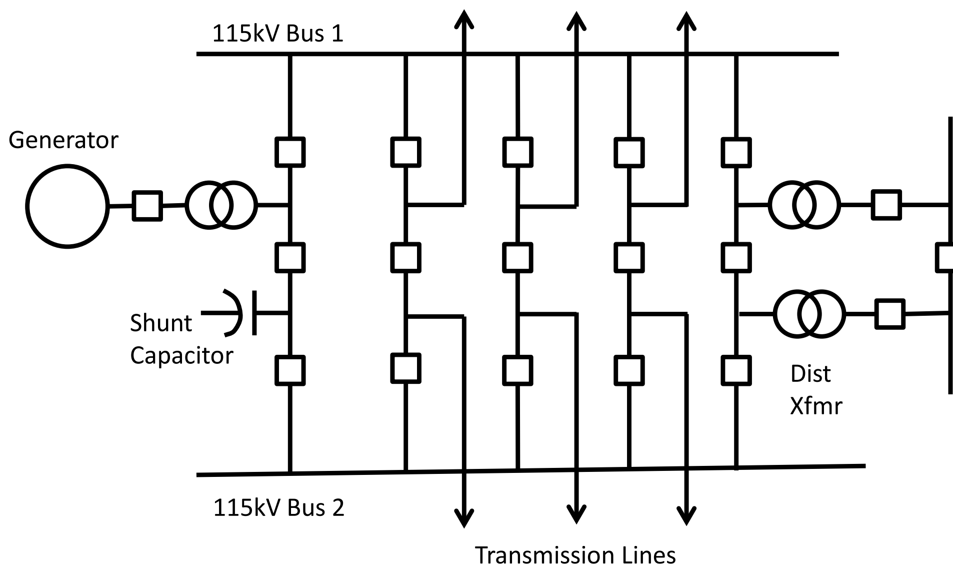


Example Application of the Criteria in Table B

Figure 1-5 shows a 115kV breaker-and-a-half installation with a generator (registered), six non-radial transmission lines, two distribution step-down banks, and a shunt capacitor connected. Since there are seven qualifying circuits (the six lines plus the generator), this is a “Table A” bus.

For the Transmission Planner's three-phase fault simulation, the bus is collapsed into a single node. For analyzing the protection systems, the actual topology must be maintained. Several examples of this analysis are discussed below, and illustrated in subsequent figures.

Figure 1-5 – Bus Configuration for Table B Example



Bus Protection: Figure 1-6 illustrates a set of bus differential protection schemes that would result in a protection system with the required attributes of Table B for redundancy. The schemes have separate CT secondary windings, separate protective relays, and separate auxiliary relays. If the auxiliary relays (the lockouts) have separate DC circuits, and operate separate trip coils, this set of schemes meets the necessary redundancy requirements.

Figure 1-6 – Bus Protection Design Meeting Table B Attributes

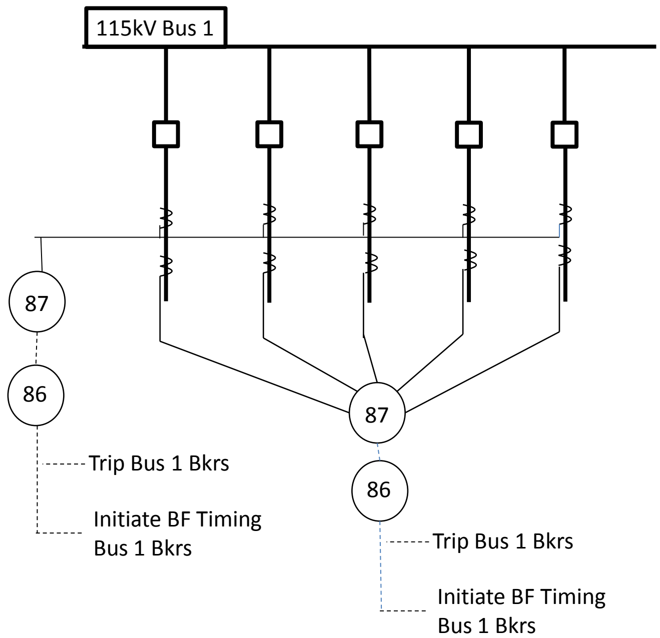
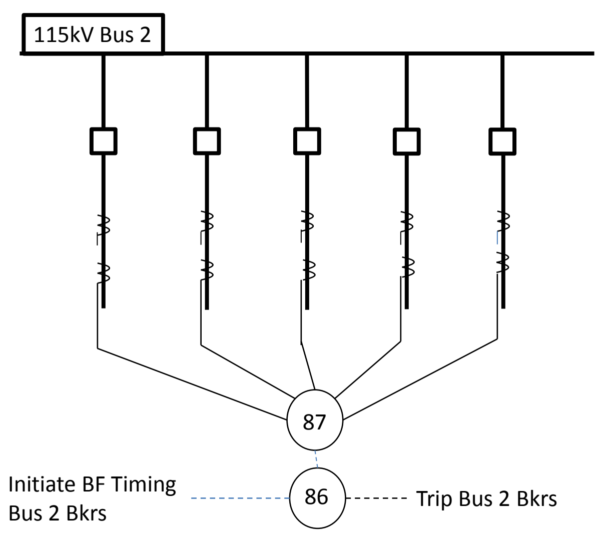


Figure 1-7 shows a scheme that in general, does not meet any of the Table B redundancy requirements.

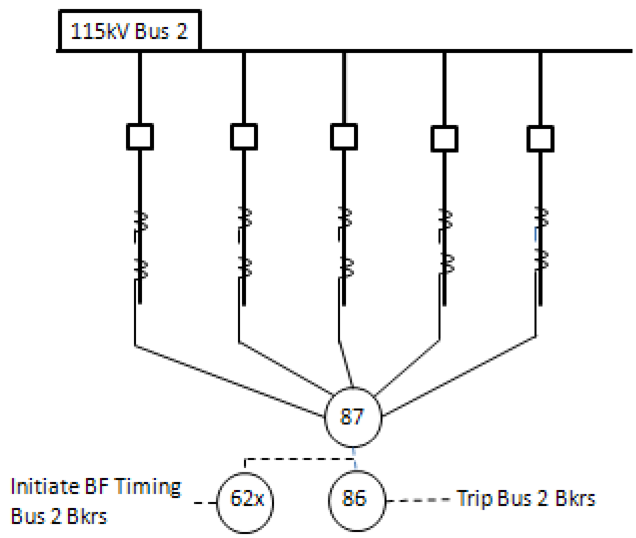
Figure 1-7 – Bus Protection Design Not Meeting Table B Attributes



Filling out the template for the breaker-and-a-half installation in the first slide would yield the following values for the rows in the 100 -200kV column: row 1 = 2, rows 2, 3, 5, & 6 all = 1.

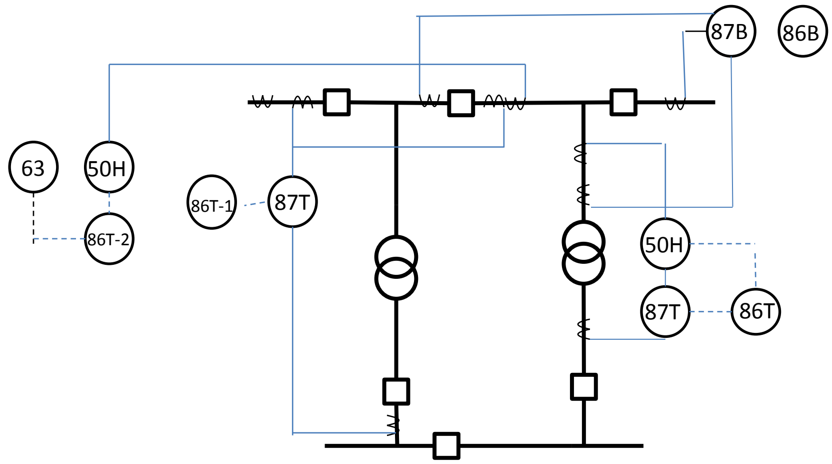
Figure 1-8 shows the same scheme as the previous, but with a separate auxiliary relay to initiate breaker failure timing. If we assume an electro-mechanical relay scheme using one relay per phase (such as a CA-16 or PVD), this scheme has many interesting characteristics relative to Order 754. For a three phase fault, there are three separate protective relays, each with its own CT set. Separate auxiliary relays are used for tripping, and for arming breaker failure protection, so a single trip coil should not be an issue. The limitation of this scheme is that it is likely that while the DC circuits of each breaker failure scheme is most probably separate from the bus differential scheme, it is likely that the lockout relay and 62X relay share the same DC source. An estimated 95 percent or more of systems that use separate auxiliary relays for tripping and BF initiation (including separate reed relays in microprocessor relays) probably use the same DC source for both. While this scheme would have prevented the Westwing event, for the purpose of this survey it does have a single point of failure associated with the DC circuit operating the lockout and auxiliary relay used to initiate breaker failure relaying.

Figure 1-8 – Alternate Bus Protection Design Not Meeting Table B Attributes



Distribution Transformers: Figure 1-9 illustrates some Order 754 points; it is not intended to be widely representative of typical distribution transformer protection. Only faults which are essentially the same as bus faults need to be considered. No fault on the low side, or any fault within the transformer, but with enough impedance between the bus and the fault that an instantaneous over current relay set to operate for a bus fault would not operate, need be considered.

Figure 1-9 – Step-down Distribution Transformer Example



Right Hand Transformer: The CTs indicate the zones of protection. The bus, including any lightning arrestors on the high side of the transformer is protected by a bus differential. The transformer is protected by an instantaneous over current relay and a transformer differential. As drawn none of this is redundant except for the minimal area between the transformer bushing CTs. The situation could be substantially improved if the 50H relay were connected to a redundant set of CTs (not shown) covering the bus. In that case the entire 115kV bus would be covered by both a bus differential and the 50H, each provided with separate CT, and tripping through separate lockouts. Faults within the tank, before the winding, would be covered by the 50H and 87T, but they would have a single point of failure as they both trip through the same lockout.

Left Hand Transformer: The protection for bus equivalent faults on this transformer meets all the requirements of Table B. The differential protection uses dedicated CT, and trips through its own lockout. The 50H covers the bus and transformer with dedicated CT and trips through its own lockout. The 50H lockout is also operated by a fault pressure relay (perhaps an SPR or Bucholtz) which will trip high speed for bus equivalent faults within the tank.

Template Entries There are two Step Down Transformers evaluated here. The left hand transformer meets the redundancy requirements of Table B, so 1 would be entered in row 2 under the 100kV column. The bus is entirely covered by the transformer protection; however, this would not be reported on the Buses tab and indicated in Note 1 on the Buses tab.

As drawn, the right hand transformer would have one entered on rows 5 & 6. If the 50H were wrapped around the bus, there would still be one entered in row 6, due to the common lockout. The single bus differential scheme would be handled on the bus tab. If the 50H were connected to CTs covering the bus, this installation would meet all requirements for Table B (relative to the bus). As drawn, the bus has multiple single points of failure.

GSU Transformers: Analysis of the protection for GSU transformers is similar to distribution transformers in that only protection systems required to clear bus equivalent (high-side) faults need to be redundant. Unlike distribution transformers however, GSU transformers have a source behind them. If a single point of failure exists, clearing time from behind the GSU needs to be used in the planning study. In many cases with very large generators, there is no low side breaker. When there is a fault in the GSU zone the generator is tripped from the high side, excitation is tripped, but permanent magnetization remains in the rotor iron. The generator will contribute to the fault until it spins down to a stop. However, this fault contribution will not contribute to the overall system performance once the rest of the BES is cleared from the GSU.

Shunt Devices: In the case of large reactors, especially reactors in oil filled tanks, the relay redundancy analysis will be similar to distribution transformers. Smaller air core reactors are more commonly found on autotransformer tertiary windings than on transmission buses or lines, and therefore not an issue. In the case of shunt capacitors, voltage unbalance and neutral current unbalance schemes, which are typically used to provide protection for small failures within the array of capacitors, are not suitable for responding quickly to single-line-to-ground or three-phase faults at the capacitor. Usually there will be instantaneous overcurrent relaying for these faults for which single points of failure must be considered. As such, when evaluating whether capacitor bank protection meets the attributes in Table B, one scheme that detects single-line-to-ground and three-phase faults at the capacitor and one scheme that detects unbalance within the bank would not need to meet the attributes in Table B.

Radial Transmission Lines:_If a line is radial and the only Elements connected to the line are transformers that step-down to a voltage below 100 kV, the line is not counted as a circuit when applying Table A to identify the initial “List of Buses to be Tested.” However, if the radial line is connected to a bus on the final “List of Buses to be Evaluated” the asset owner does need to evaluate the protection system against the attributes in Table B.